Office of Energy Projects

March 2024

Elba Liquefaction Company, LLC and Southern LNG Company, LLC — **Docket No. CP23-375-000**

Elba Liquefaction Optimization Project

ENVIRONMENTAL ASSESSMENT

Cooperating Agencies:

US Department of Energy | **United States Coast Guard** | **U.S. Department of Transportation**

Washington, DC 20426

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:

OEP/DG2E/Gas Branch 2
Elba Liquefaction Company, LLC and
Southern LNG Company, LLC
Elba Liquefaction Optimization Project
Docket No. CP23-375-000

TO THE INTERESTED PARTIES:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) have prepared an environmental assessment (EA) for the Elba Liquefaction Optimization Project (Project) in Elba Island, Chatham County, Georgia, proposed by Elba Liquefaction Company, LLC (ELC) and Southern LNG Company, LLC (SLNG) in the above referenced docket.

On April 28, 2023, ELC and SLNG filed a joint application requesting Authorization pursuant to Section 3 of the Natural Gas Act to amend existing authorizations under CP14-103-000, originally approved by the Commission on June 1, 2016,[1] to modify certain Movable Modular Liquefaction System (MMLS) Dehydration and Heavies Removal units within the existing liquefied natural gas terminal. The modifications would reduce the fouling rate in the liquefaction units, reduce flaring events, and allow the MMLS units to operate in an optimized condition for longer periods of time.

Specifically, ELC and SLNG request authorization to make modifications to ten (10) MMLS units; construct and operate a new condensate plant; install three (3) new liquid nitrogen vaporizers; and increase the total liquefaction capacity of the MMLS units up to approximately 2.9 million tonnes per anum (MTPA) from 2.5 MTPA.

The EA assesses the potential environmental effects of the construction and operation of the Project in accordance with the requirements of the National Environmental Policy Act (NEPA). FERC staff concludes that approval of the proposed Project would not constitute a major federal action significantly affecting the quality of the human environment.

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[1] Elba Liquefaction Company, L.L.C., 155 FERC ¶ 61,219, (2016).

The U.S. Department of Energy, the U.S. Coast Guard, and the U.S. Department of Transportation participated as cooperating agencies in the preparation of the EA. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposal and participate in the NEPA analysis.

The Commission mailed a copy of the *Notice of Availability of the Environmental Assessment for the Elba Liquefication Optimization Project* to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; and newspapers and libraries in the Project area. The EA is only available in electronic format. It may be viewed and downloaded from FERC's website (www.ferc.gov), on the natural gas environmental documents page (https://www.ferc.gov/industries-data/natural-gas/environment/environmental-documents). In addition, the EA may be accessed by using the eLibrary link on FERC's website. Click on the eLibrary link (https://elibrary.ferc.gov/eLibrary/search) select "General Search" and enter the docket number in the "Docket Number" field (i.e. CP23-375). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659.

The EA is not a decision document. It presents Commission staff's independent analysis of the environmental issues for the Commission to consider when addressing the merits of all issues in this proceeding. Any person wishing to comment on the EA may do so. Your comments should focus on the EA's disclosure and discussion of potential environmental effects, measures to avoid or lessen environmental impacts, the completeness of the submitted alternatives, and information and analyses. The more specific your comments, the more useful they would be. To ensure that the Commission has the opportunity to consider your comments prior to making its decision on this Project, it is important that we receive your comments in Washington, DC on or before 5:00pm Eastern Time on **April 8, 2024**.

For your convenience, there are three methods you can use to submit your comments to the Commission. The Commission encourages electronic filing of comments and has staff available to assist you at (866) 208-3676 or FercOnlineSupport@ferc.gov. Please carefully follow these instructions so that your comments are properly recorded.

1) You can file your comments electronically using the eComment feature on the Commission's website (www.ferc.gov) under the link to FERC Online. This is an easy method for submitting brief, text-only comments on a project;

2) You can file your comments electronically by using the eFiling feature on the Commission's website (www.ferc.gov) under the link to FERC Online. With eFiling, you can provide comments in a variety of formats by attaching them as a file with your submission. New eFiling users must first create an account by clicking on "eRegister." If you are filing a comment on a particular project, please select "Comment on a Filing" as the filing type; or

3) You can file a paper copy of your comments by mailing them to the Commission. Be sure to reference the Project docket number (CP23-375-000) on your letter. Submissions sent via the U.S. Postal Service must be addressed to: Debbie-Anne A. Reese, Acting Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Room 1A, Washington, DC 20426. Submissions sent via any other carrier must be addressed to: Debbie-Anne A. Reese, Acting Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, Maryland 20852.

Filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered. Only intervenors have the right to seek rehearing or judicial review of the Commission's decision. At this point in this proceeding, the timeframe for filing timely intervention requests has expired. Any person seeking to become a party to the proceeding must file a motion to intervene out-of-time pursuant to Rule 214(b)(3) and (d) of the Commission's Rules of Practice and Procedures (18 CFR 385.214(b)(3) and (d)) and show good cause why the time limitation should be waived. Motions to intervene are more fully described at https://www.ferc.gov/how-intervene.

Additional information about the Project is available from the Commission's Office of External Affairs, at **(866) 208-FERC**, or on the FERC website (www.ferc.gov) using the eLibrary link. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

The Commission's Office of Public Participation (OPP) supports meaningful public engagement and participation in Commission proceedings. OPP can help members of the public, including landowners, environmental justice communities, Tribal members and others, access publicly available information and navigate Commission processes. For public inquiries and assistance with making filings such as interventions, comments, or requests for rehearing, the public is encouraged to contact OPP at (202) 502-6595 or OPP@ferc.gov.

In addition, the Commission offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to https://www.ferc.gov/ferc-online/overview to register for eSubscription.

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TECHNICAL ABBREVIATIONS AND ACRONYM

AEGL	acute exposure guideline levels
APE	area of potential effects
AQCRs	air quality control regions
BLEVE	boiling liquid expanding vapor
BOP	Balance of Plant
CAA	Clean Air Act
CCED	Chatham County Engineering Department
Certificate	Certificate of Public Convenience and Necessity
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CH4	methane
CO	carbon monoxide
COTP	Captain of the port
CO2	carbon dioxide
CO2e	carbon dioxide equivalents
Commission	Federal Energy Regulatory Commission
dBA	A-weighted decibel
DOE	U.S. Department of Energy
EA	environmental assessment
ECS	Environmental Construction Standards
EH&S	Environmental Health and Safety
EIS	environmental impact statement
ELC	Elba Liquefaction Company, LLC
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
ERP	Emergency Response Plan
ERPG	Emergency Response Planning Guidelines
ESA	Endangered Species Act
E&SCP	Erosion and Sediment Control Plan
FECM	Office of Fossil Energy and Carbon Management
FEED	Front-end Engineering Design
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FTA	Free Trade Agreement
GDOT	Georgia Department of Transportation
GHG	greenhouse gas
GWP	global warming potential
HAPs	hazardous air pollutants
HMBs	heat and mass balances
Hp	horsepower
HRU	heavies removal unit and dehydration system
HUC	Hydrologic unit code

IWG	Interagency Working Group
Ldn	day-night sound level
Leq	equivalent sound level
LFL	Lower flammability limit
LNG	liquified natural gas
LOR	Letter of Recommendation
LPG	liquified flammable gas
MMLS	Movable Modular Liquefaction System
MTPA	million tonnes per annum
N2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NFPA	Nation Fire Protection Association
NGA	Natural Gas Act
NHPA	National Historic Preservation Act
NOA	Notice of Application
NPS	National Park Service
NOS	Notice of Scoping Period Requesting Comments on Environmental
NOx	nitrogen oxides
NRHP	National Register of Historic Places
NSA	noise sensitive area
SPCC Plan	Spill Prevention Control and Countermeasure Plan
Terminal	Elba Island LNG Terminal
tpy	tons per year
UFL	Upper flammable limit
U.S.	United States
USACE	U.S. Army Corps of Engineers
USC	United States Code
USCG	United States Coast Guard
USDOT	U.S. Department of Transportation
USGS	U.S. Geological Survey
USGCRP	U.S. Global Change Research Program
VOC	volatile organic compound

1. INTRODUCTION

In accordance with the Natural Gas Act (NGA), Title 15 United States Code (USC) § 717 (15 USC 717), the Federal Energy Regulatory Commission (Commission or FERC) is responsible for deciding whether to authorize the construction and operation of interstate natural gas transmission facilities. The National Environmental Policy Act (NEPA)[1] requires that the Commission consider the environmental impacts of a proposed project prior to making a decision.

The Commission's environmental staff has prepared this Environmental Assessment (EA) to comply with NEPA, and to assess the potential environmental impacts that could result from the construction and operation of the Elba Liquefaction Optimization Project (Project), as proposed by Elba Liquefaction Company, LLC (ELC) and Southern LNG Company, LLC (SLNG) in Docket No. CP23-375-000. The U.S. Department of Energy (DOE), The U.S. Department of Transportation (DOT), and the U.S. Coast Guard (USCG) participated as cooperating agencies in the preparation of the EA.

On April 28, 2023, ELC and SLNG filed an application requesting an Authorization, pursuant to Section 3 of the Natural Gas Act, to amend existing authorizations under CP14-103-000, originally approved by the Commission on June 1, 2016 (2016 Order). ELC and SLNG propose to modify certain Movable Modular Liquefaction System (MMLS) Dehydration and Heavies Removal units that would reduce the fouling rate in the liquefaction units, reduce the resultant flaring events associated with cold box deriming, and therefore allow the MMLS units to operate in an optimized condition for longer periods of time without fouling, all within SLNG's existing Elba Island liquefied natural gas (LNG) terminal (Terminal) in Chatham County, Georgia. Specifically, ELC and SLNG would make modifications to ten MMLS Dehydration and Heavies Removal units; construct and operate a new condensate plant; install three new liquid nitrogen vaporizers; and increase the total liquefaction capacity of the MMLS units up approximately 0.4 million tonnes per annum (MTPA) from 2.5 to 2.9 MTPA.

1.1 Purpose and Need

ELC and SLNG state that the purpose of the Project is to improve the liquefaction process at the Terminal by operating for longer periods of time without fouling and to meet market demand. The ten MMLS units were installed and placed in service in August 2020, creating a total liquefaction capacity of approximately 2.5 MTPA and allowing the Terminal to be capable of providing bidirectional service. ELC and SLNG

[1] National Environmental Policy Act of 1969, amended (Pub. L. 91-190. 42 U.S.C. §§ 4321–4347, as amended by Pub. L. 94-52, July 3, 1975, Pub. L. 94-83, August 9, 1975, Pub. L. 97-258, §4(b), September 13, 1982, Pub. L. 118-5, June 3, 2023

propose to modify the MMLS units to reduce cold box fouling and install new condensate processing equipment to provide a small increase of 0.4 MTPA.

Under Section 3 of the NGA, the Commission is responsible for authorizing the siting, modification, and construction of onshore and near-shore LNG import or export facilities. As part of its decision whether to authorize NGA Section 3 facilities, the Commission considers all factors bearing on the public interest.

1.2 Purpose and Scope of this EA

Our principal purposes in preparing this EA are to:

- identify and assess the potential impacts on the natural and human environment that would result from the construction and operation of the Project;
- describe and evaluate reasonable alternatives to the Project that would avoid or minimize adverse impacts on environmental resources;
- recommend mitigation measures, as necessary, to reduce impacts on environmental resources, enhance the reliability and safety of the facility, and to mitigate the risk of impact on the public; and
- encourage and facilitate involvement by the public and interested agencies in the environmental review process.

This EA addresses topics including Project alternatives; geology; soils; water resources; wetlands; wildlife; special status species; land use and aesthetics; environmental justice; cultural resources; air quality; noise; cumulative impacts and climate change; and reliability and safety. This EA describes the affected environment as it currently exists and analyzes the environmental consequences of the proposed Project. This EA also presents our conclusions and recommended mitigation measures.

Our description of the affected environment is based on a combination of data sources, including desktop resources such as scientific literature and regulatory agency reports, information from resource and permitting agencies, scoping comments, and field data collected by ELC and SLNG.

1.3 Federal Energy Regulatory Commission

FERC is an independent federal regulatory agency that authorizes the siting, modification, and construction of onshore and near-shore LNG import or export facilities, and regulates the interstate transportation of natural gas, among other industries, in accordance with the NGA. Pursuant to the Energy Policy Act (EPAct) Section 313(b)(1), FERC is the lead federal agency for the coordination of all applicable federal authorizations. Thus, FERC is the lead federal agency for preparation of this EA to comply with NEPA, as described in the Council on Environmental Quality's (CEQ) regulations at 40 Code of Federal Regulations (CFR) § 1501.7, and in keeping with the May 2002 Interagency Agreement with other federal agencies.[2]

As the lead federal agency, we[3] prepared this EA to assess the environmental impacts that could result from constructing and operating the Project. FERC prepared this document in compliance with the requirements set forth in CEQ's regulations at 40 CFR Parts 1500-1508, and FERC's regulations for implementing NEPA at 18 CFR Part 380. The Commission will consider the analysis and conclusions of the EA, as well as non-environmental issues, in its decision on whether to issue an Authorization to ELC and SLNG.

1.4 United States Department of Energy Role

DOE participated as a cooperating agency in the preparation of the EA. Section 3(c) of the NGA requires that proposed imports and/or exports of natural gas, including LNG, in applications to DOE's Office of Fossil Energy and Carbon Management (FECM), requesting authorization of imports and/or exports from and/or to nations with which there are in effect free-trade agreements (FTA) requiring national treatment for trade in natural gas (FTA nations), be deemed consistent with the public interest and granted without modification or delay. In the case of applications to export LNG to non-FTA nations, NGA Section 3(a) requires DOE to conduct a public interest review and grant authority to export unless DOE finds that the proposed exports would not be consistent with the public interest. Additionally, NEPA requires DOE to consider the environmental effects of its decisions regarding applications to export natural gas to non-FTA nations.

On June 15, 2012, SLNG was issued a permit to export up to 182.5 billion cubic feet per year to Free Trade Agreement countries. On December 16, 2016, SLNG was issued a permit to export up to 130 billion cubic feet of LNG per year to Non-Free Trade Agreement countries. In September 2023, SLNG submitted an application for authorization to increase its authorized export quantity to non-FTA countries. The application to export to non-FTA nations is pending with DOE.

1.5 U.S. Department of Transportation Role

Under 49 USC § 60101, the DOT has prescribed the minimum federal safety standards for LNG facilities. Those standards are codified in 49 CFR Part 193 and apply to the siting, design, construction, operation, maintenance, and security of LNG facilities. The National Fire Protection Association (NFPA) Standard 59A, "Standard for the

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[2] May 2002 Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews Conducted in Conjunction With the Issuance of Authorizations to Construct and Operate Interstate Natural Gas Pipelines.

[3] The pronouns "we," "us," and "our" refer to environmental and engineering staff of the FERC's Office of Energy Projects.

Production, Storage, and Handling of Liquefied Natural Gas," is incorporated into these requirements by reference, with regulatory preemption in the event of a conflict. In accordance with the 1985 Memorandum of Understanding on LNG Facilities and the 2004 Interagency Agreement on the safety and security review of waterfront LNG import/export facilities, the DOT participates as a cooperating agency. The DOT does not issue a permit or license but, as a cooperating agency, assists FERC staff in evaluating whether an applicant's proposed design would meet the DOT requirements. DOT staff has reviewed FERC staff's analysis and provided comments on our conclusions regarding compliance with Part 193 regulations.

1.6 U.S. Coast Guard Role

The USCG exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 USC § 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC § 1221, et seq.); and the Maritime Transportation Security Act of 2002 (46 USC § 701). The USCG is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The USCG also has authority for LNG facility security plan review, approval and compliance verification as provided in 33 CFR Part 105, and siting as it pertains to the management of vessel traffic in and around the LNG facility.

As required by its regulations, the USCG is responsible for issuing a Letter of Recommendation (LOR) as to the suitability of the waterway for LNG marine traffic. As described in this EA, the annual frequency of ship traffic for the Project is estimated to be four LNG vessels per year, which would not exceed the previously approved ship traffic described in the current Waterway Suitability Assessment (WSA).

1.7 Public Review

ELC and SLNG filed their formal FERC applications for the Project on April 28, 2023 in Docket No. CP23-375-000. Prior to and during the filing process, ELC and SLNG contacted federal, state, and local governmental agencies to inform them about the Project and discuss Project-specific issues. On May 10, 2023, FERC issued a Notice of Application (NOA).[4] The NOA detailed ways to become involved in the Commission's review of the Project, including becoming an intervenor and filing comments. The comment period to respond to the NOA closed on August 9, 2022. We received no comments on the NOA.

On June 9, 2023, the Commission issued in CP23-375-000 a *Notice of Scoping Period Requesting Comments on Environmental Issues for the Proposed Elba*

[4] 88 Fed. Reg. 31,252 (May 15, 2023)

Liquefaction Optimization Project (NOS) requesting comments by July 10, 2023.[5] The Commission received two comments on the NOS.[6] The National Park Service (NPS) relayed concerns regarding visual, noise, light pollution, and cumulative impacts from the Project and other reasonably foreseeable developments in the area, such as the Jasper Ocean Terminal. NPS recommended that the Commission consult with other federal agencies regarding threatened or endangered species. NPS noted that the Project is located within the Geechee Cultural Heritage Corridor; that a segment of the Savannah River upstream of the Project is listed on the Nationwide Rivers Inventory; and that Fort James Jackson, which is a historic fort along the Savannah River, is in proximity to the Project. NPS also expressed concern regarding the completion of Environmental Condition 28 in the 2016 Authorization Order [Docket No. CP14-103-000].[7] This comment is outside the scope of the amendment proceeding.

In a July 10, 2023 letter, the United States Fish and Wildlife Service (USFWS) detailed how the Terminal "is the most seaward terminal of the Savannah Harbor" and the closest to sea turtle nesting beaches in the area. Describing the land between the terminal and nesting beaches as generally flat and consisting of "tidal marsh, river, and sandy berms with some vegetation," the letter noted concerns that light from the terminal may affect sea turtle nesting and migratory birds. The USFWS also recommended the implementation of a Light Management Plan.

On August 9, 2023, we issued a *Notice of Schedule for The Preparation of an Environmental Assessment for the Proposed Elba Liquefaction Optimization Project*In response to this notice, the DOE asked to participate as a cooperating agency under NEPA. As detailed in table 1.6-1, among the permits and approvals for the Project, SLNG has applied for DOE authorization to export additional volumes of LNG to non-FTA countries.

On September 6, 2023, we contacted the Department of Defense (DOD) Siting Clearinghouse, requesting the agency's comments on whether the Project could potentially have an impact on the test, training, or operational activities of any active military installation. On October 13, 2023, the agency responded to FERC's letter, writing that the Project "will have minimal impact on military operations conducted in the area."

1.8 Permits, Approvals, and Regulatory Requirements

Federal statutes applicable to construction and operation of the Project include the Clean Air Act (CAA), Clean Water Act, Endangered Species Act, Migratory Bird Treaty

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[5] 88 Fed. Reg. 39,250 (June 15, 2023)

[6] All written comments are part of the FERC's public record for the Project and are available for viewing in e-library under docket number CP23-375.

[7] *Elba Liquefaction Co., L.L.C.*, 155 FERC ¶ 61,219 (2016).

Act, and the National Historic Preservation Act (NHPA). Where applicable, each of these statutes are discussed throughout this EA. A list of major federal and state environmental permits, approvals, and consultations for the Project is provided in table 1.6-1. ELC and SLNG would be responsible for obtaining all permits and approvals required to construct and operate the Project, regardless of whether or not they appear in the table.

Table 1.8-1 Environmental Permits, Approvals, Clearances, and Consultations		
Agency	**Permit, Approval, or Consultation**	**Status (Anticipated Date)**
FEDERAL		
Federal Energy Regulatory Commission (FERC)	Authorization to Amend Previously Permitted Facilities under Section 3 of the Natural Gas Act	Pending
U.S. Coast Guard (USCG)	Waterway Suitability Assessment	Complete, September 27, 2023 letter from USCG indicating no new Letter of Intent/Waterway Suitability Assessment required
U.S. Department of Interior, Fish and Wildlife Service (USFWS)	Section 7 of the Endangered Species Act	Pending
U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration	49 CFR Part 193 Consultation	Complete, Letter of Determination from DOT February 7, 2024.
U.S. Department of Energy, Office of Fossil Energy and Carbon Management (DOE/FECM)	Free Trade Agreement Countries Non-Free Trade Agreement Countries Authorization to Increase Export Quantity to Non-FTA Countries by 28.25 Bcf/yr	Issued June 15, 2012 for 182.5 billion cubic feet/year (Bcf/y) in Order No. 3106 Issued December 16, 2016 for130 Bcf/yr in Order No. 3956 Pending in DOE/FECM Docket No. 23-109-LNG
STATE OF GEORGIA		
Georgia Environmental Protection Division	Georgia Air Quality Control Rule 391-3-1-.03(10)(b)5	Pending (No changes or alterations are being requested as part of the 502(b) Change Notification)
Georgia Department of Community Affairs State Historic Preservation Office (SHPO)	National Historic Preservation Act, Section 106 Consultation	Categorical Clearance Agreement

2. DESCRIPTION OF THE PROPOSED ACTION

2.1 Proposed Facilities

ELC and SLNG propose modifications and upgrades to existing MMLS units and the installation of new condensate processing equipment in the Balance of Plant (BOP).[9] The new condensate equipment (Condensate Plant) would be common for all ten MMLS units. Gas would continue to be delivered to the Terminal from the duel 30-inch-diameter pipelines[10] to the new proposed facilities. Modifications to the MMLS units include retrofitting the existing mole-sieve vessels to function as a combined heavies removal unit and dehydration system (HRU), as well as certain other appurtenant modifications. The proposed HRU vessels would accommodate the combined functionality and increased MMLS unit throughput, and certain bed regeneration equipment is required to be upsized to compliment the new vessels. The existing cold gas separator at each MMLS unit, would be bypassed during normal operations. ELC and SLNG propose the following MMLS unit modifications:

- extension of both dehydration beds, allowing for more adsorbent media mass;
- replacement of the electric regeneration gas heater with a larger unit;
- replacement of the tube bundle and fan for the regeneration gas cooler with a more efficient design;
- replacement of the regeneration gas compressor diffuser and gearbox;
- installation of bypass piping around the current cold gas separator (V-0400); and
- replacement of certain control valves and relief valves due to the new operating condition of the MMLS units with increased throughput.

Figure 2.1-1 provides an overview map of the Project area.

[9] Balance of Plant is a term generally used in the context of power engineering to refer to all the supporting components and auxiliary systems of a power plant needed to deliver the energy, other than the generating unit itself.
[10] The pipelines consist of two 13.25-mile-long, 30-inch-diameter pipelines that connect Elba to Port Wentworth.

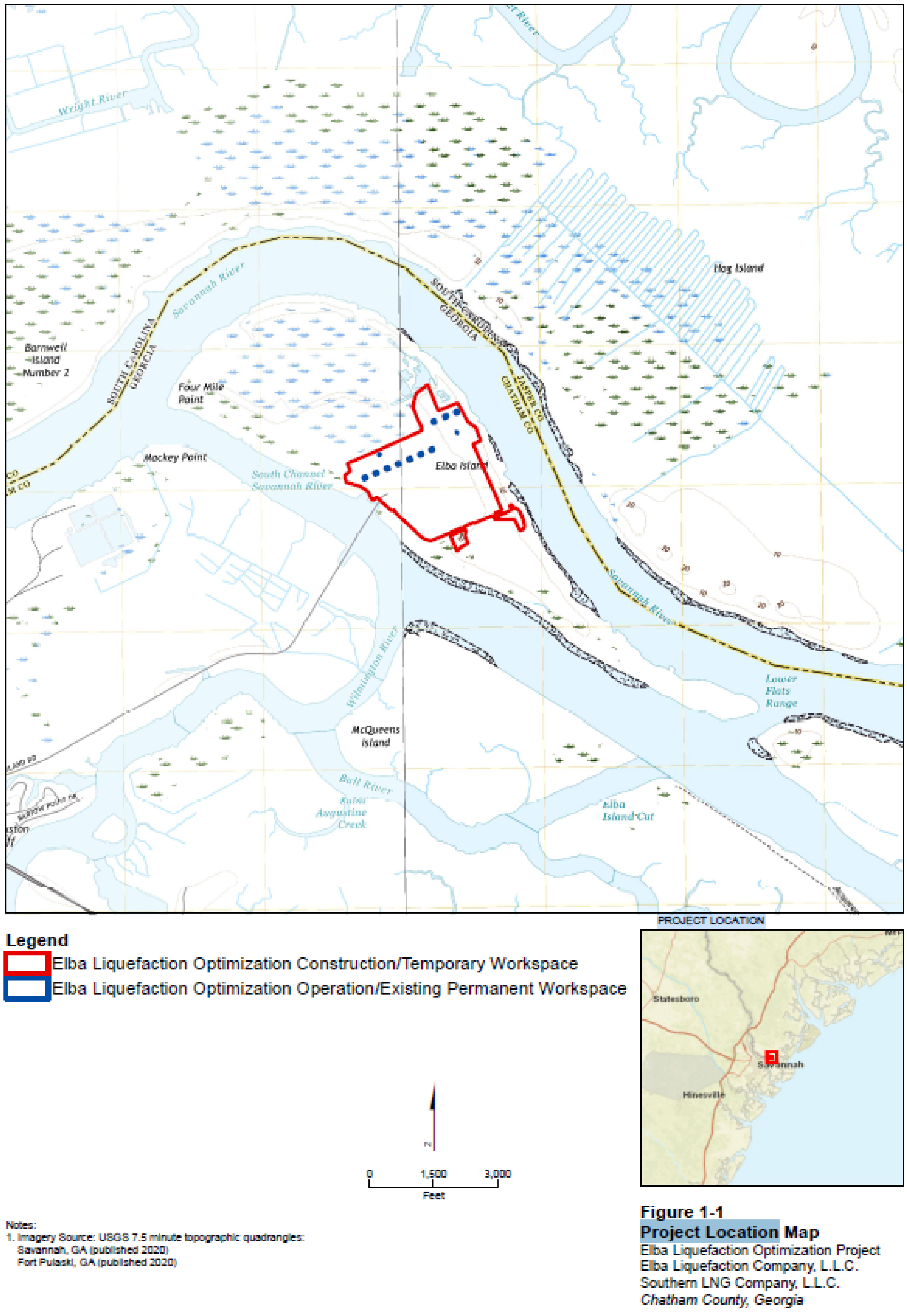

Figure 2.1-1 Project Location Map for the Elba Liquefaction Optimization Project

2.2 Land Requirements

Land requirements for construction of the Project would total approximately 163 acres to support construction, located within the existing footprint of the Terminal. Once construction is completed, operation of the proposed modifications would total approximately 1.3 acres of permanent impacts. Access to the proposed construction workspace for the Project would be directly from public roads and existing entrances currently used for access to the Terminal, private roads owned by SLNG, and roads within the fence of the Terminal would be accessed using the existing entrances to each station. These roads were used during construction of the previous Terminal expansion projects. Lay down areas or staging would occur within the existing previously disturbed Terminal areas. No lay down areas outside the Terminal boundaries would be required. Table 2.2-1 summarizes the land requirements for facilities related to the Project.

Table 2.2-1
Land Disturbance Acreages Associated with the Elba Liquefaction Optimization Project

	Construction/Temporary Impact (acres)	Operation/Existing Permanent Impact (acres)
Terminal	162.4	--
MMLS units	--	1.2
Condensate Plant	--	0.06
Nitrogen Vaporizers	--	0.02
Total	**162.4**	**1.30**

2.3 Construction Workforce, Schedule, and Procedure

ELC and SLNG anticipate that construction activities for the Condensate Plant and nitrogen vaporizers would span a 5-month period and occur between April 2024 and August 2024 following receipt of necessary authorizations. The modifications to the MMLS units would be completed over the course of four or five years, concurrent with planned maintenance. The construction peak workforce for the Project is estimated to be 50 workers, with approximately 20 workers associated with the MMLS work and 30 workers associated with the condensate and nitrogen vaporizers work, for the duration of the approximately 5-month construction period. ELC and SLNG propose to install and commission the Condensate Plant and nitrogen vaporizers according to the anticipated Project schedule, highlighted in Table 2.3-1.

ELC and SLNG would employ local workers for construction when possible; however, non-local employees would be required due to the specialized nature of certain skill positions needed. The proposed construction schedule does not include 24-hour operations. Construction activities would be completed using a typical daily work schedule, six days a week. It is anticipated that the typical construction workday at the

Project facilities would be 12 hours in length and be limited to between the hours of 7:00 a.m. and 7:00 p.m., Monday through Saturday, extending to Sunday, if needed.

Table 2.3-1
Anticipated Schedule for the Elba Liquefaction Optimization Project

Workstage	Anticipated Schedule
Installation of Condensate Plant and nitrogen vaporizers mechanical equipment	April-June 2024
Final installation of Condensate Plant and nitrogen vaporizers electrical, piping, and equipment	July 2024
Condensate Plant and nitrogen vaporizers equipment start up	August 2024
In service	**August 2024**

However, the workday may infrequently extend after 7:00 p.m., in certain situations. These situations could include schedule delays due to temporary weather shutdowns or scheduling and sequencing conflicts between work crews.

Construction Procedures

SLNG and ELC would use the construction practices outlined in FERC's *Upland Erosion Control, Revegetation and Maintenance Plan* (Plan), *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures)[11] to avoid and minimize potential impacts. Project facilities would be designed, constructed, operated, and maintained in accordance with the DOT Federal Safety Standards for LNG Facilities, 49 CFR Part 193. The facilities would also meet the NFPA 59A LNG Standards. Areas currently surfaced with aggregate and within the existing Terminal would be used for the proposed Condensate Plant and nitrogen vaporizers. The construction area would be restored to the original grade so that stormwater drains into the existing BOP stormwater system. As appropriate, erosion control devices would be installed. Following construction, affected lands would be stabilized.

The Project would follow best management practices, and would be constructed in multiple phases, as detailed in table 2.3-1. Initially, ELC and SLNG would construct the Condensate Plant and nitrogen vaporizers. ELC and SLNG would install the Condensate Plant and nitrogen vaporizers facilities inside the existing storm surge wall and approximately at the existing grade elevation. All facilities would be pile-supported. Condensate plant equipment and structures, including pipe racks, would be supported by

[11] Copies of our Plan and Procedures are available for review on the FERC website (www.ferc.gov) under the environmental guidelines for the natural gas industry at: https://www.ferc.gov/industries-data/natural-gas/environment/environmental-guidelines.

pile foundations driven into the deep, competent clay layer.[12] Precast, prestressed, concrete piles of various sizes and lengths are recommended to be used depending on the size and weight of the equipment placed on the foundation(s).

To the extent possible, ELC and SLNG would employ modular construction techniques, whereby entire sections of buildings would be pre-fabricated offsite and assembled on location in the Project area. The proposed installation location of the Condensate Plant is designed to drain to existing stormwater trenches and impoundments within the storm surge wall. The modifications to the MMLS units would be completed over the course of four or five years, concurrent with planned maintenance. This would allow the modifications to the MMLS units to be made efficiently with less impact since the construction would be done as part of the other operations-planned maintenance. ELC and SLNG would design piping systems for loads such as internal pressure, weight of pipe, fittings, insulation and process fluids, wind loads, seismic loads, thermal expansion and/or contraction, pressure safety valve reaction and structural deflections. Surge analyses would be included on piping systems where valves are quickly closed to ensure the piping system is adequate for the expected pressure pulses. ELC and SLNG would carry out testing in accordance with applicable city, state, and federal codes and requirements. ELC and SLNG would test piping using hydrostatic or pneumatic techniques.

2.4 Environmental Compliance and Monitoring

The Terminal currently employs on-site Environmental Health and Safety (EH&S) personnel full time who would be available to provide support during construction. ELC and SLNG would train EH&S personnel on FERC construction guidelines, and they would monitor construction activities for compliance. The EH&S personnel's duties would be consistent with those contained in FERC's Plan and Procedures. They would have the authority to stop activities that violate the environmental conditions of the FERC Certificate, other federal and state permits, and order corrective actions as needed. In addition, FERC staff would maintain compliance oversight of the Project throughout construction and restoration.

2.5 Operation and Maintenance

Operation of the new Project facilities would be conducted by existing employees. SLNG has on file with the FERC and USCG, operations manuals (including emergency procedures and security plans) for the current facilities. SLNG and ELC has stated that these manuals would be updated as necessary, and all amendments would be submitted to the agencies prior to commissioning the Project.

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[8] A competent clay layer is a sediment layer with relatively low permeability that is at least 10 feet thick and contains more than 50% fines with a predominance of clay-sized particles.

The additional liquefaction volume will result in up to approximately four additional ships per year on the Savannah River as compared to current operations. These additional ships are consistent with the WSA upon which the USCG based its LOR and deemed the waterway suitable, and remain within amounts analyzed and approved in CP14-103-000.

2.6 Non-Jurisdiction Facilities

Occasionally, proposed projects have associated facilities that do not come under the jurisdiction of the Commission. These non-jurisdictional facilities may be integral to the need for the proposed facilities (e.g., a gas-fueled power plant at the end of a jurisdictional pipeline) or they may be minor, non-integral components of the jurisdictional facilities that would be constructed and operated as a result of the proposed facilities. No non-jurisdictional facilities are proposed as part of the Project.

3. ALTERNATIVES

3.1 Introduction

In accordance with NEPA and Commission policy, we identified and evaluated alternatives to the applicant's proposed Project. Specifically, we evaluated the no action and system alternatives.

Alternatives were evaluated using a specific set of criteria. The evaluation criteria applied to each alternative include a determination whether the alternative:

- ability to meet the objectives of the proposed project;
- technical and economic feasibility and practicality; and
- offers a significant environmental advantage over the proposed project.

The alternatives were reviewed against the evaluation criteria in the sequence presented above. The first consideration for including an alternative in our analysis is whether or not it could satisfy the stated purpose of the Project. A preferable alternative must meet the stated purpose of the Project, which is to improve the liquefaction process at the Terminal and meet market demand. It is important to recognize that not all conceivable alternatives can meet the Project's purpose, and an alternative that does not meet the Project's purpose cannot be considered a viable alternative.

Our evaluation of alternatives is based on Project-specific information provided by the applicant; publicly available information; our consultations with federal and state resource and permitting agencies; our expertise and experience regarding the siting, construction, and operation of LNG facilities and such projects' potential environmental impacts; and the specific environmental impacts associated with the Project, as described in section 4 of this EA.

3.2 No-Action Alternative

NEPA requires the Commission to consider and evaluate the no-action alternative. According to CEQ guidance, in instances involving federal decisions on proposals for projects, no-action would mean the proposed activity would not take place and the resulting environmental effects from taking no-action would be compared with the effects of permitting the proposed activity. Further, the no action alternative provides a benchmark for decisionmakers to compare the magnitude of environmental effects of the proposed activity and alternatives.

We have prepared this EA to inform the Commission and stakeholders about the expected impacts that would occur if the Project were constructed and operated. As indicated in this EA, staff has not identified a significant impact associated with the proposed action. The Commission will ultimately determine the Project need and could choose the no-action alternative.

3.3 System Alternatives

System alternatives would use existing, modified, or proposed systems to meet the purpose and need of the Project. A system alternative could make it unnecessary to construct all or part of the Project, although some modifications or additions to the alternative system may be required. Such modifications or additions could result in environmental effects that may be less than, comparable to, or greater than those associated with the proposed Project. Our analysis of system alternatives includes an examination of existing and proposed natural gas treatment plants upstream of the MMLS units at the Terminal site that would meet a similar project objective to attain closer to the original planned rate of production. However, installation of gas treatment facilities would result in a larger facility footprint. As such, we did not identify any system alternatives that would provide a significant environmental advantage over the proposed Project.

3.4 Alternative Conclusions

We considered alternatives to ELC and SLNG's proposal and conclude that no alternatives would provide a significant environmental advantage over the Project as proposed. Therefore, we conclude that the Project, with our recommended mitigation measures, is the preferred alternative to meet the Project objectives.

4. ENVIRONMENTAL ANALYSIS

The following sections describe the Project's potential impacts on the natural and human environment. Our description of the affected environment is based on a combination of information sources, including the application and ELC and SLNG's responses to our requests for environmental information, scientific literature, regulatory agency reports, and stakeholder comments.

For the purposes of this analysis, we discuss four impact durations: temporary, short-term, long-term, and permanent. A temporary impact generally occurs during construction with an affected resource returning to a condition similar to that prior to construction almost immediately afterward. A short-term impact could continue for up to three years following construction. An impact is considered long-term if the resource would require more than three years to recover. A permanent impact would occur if an activity modifies a resource to the extent that it would not be restored during the life of the Project. For example, constructing and operating aboveground facilities would cause permanent impacts as the land use and visual character would not return to pre-construction (or similar) conditions. Permanent impacts may also extend beyond the life of a project. When determining the significance of an impact, we consider the duration of the impact; the geographic, biological, and/or social context in which the impact would occur; and the magnitude and intensity of the impact. The duration, context, and magnitude of impacts vary by resource and therefore significance would vary accordingly.

Based on our review of the Project, surrounding land uses, and existing environmental resources, we have determined several resources including geology, soils, wetlands and waterbodies, visual resources, wildlife, protected species, and land use would experience only minimal impacts. Therefore, the discussions of these resources and the impacts on them are commensurate to the scope of the Project and its potential impact on the environment. The Project would have no impact on vegetation and it is not discussed further.

4.1 Baseline Environmental Trends

The Project is located in Chatham County, Georgia, on Elba Island. Elba Island is an island in the Savannah River, near the U.S. port city of Savannah, Georgia and is owned by SLNG. Elba Island functions as an import and export facility for LNG, located 5 miles seaward from Savannah and about 8.5 miles upstream of the river's discharge into the Atlantic Ocean. The Savannah River acts as a natural boundary between Georgia and South Carolina, and serves as a source for water, transportation, and power. The area is within the Savannah River drainage on the Atlantic Coastal Plain. This region consists of about three-fifths of the total land area in the state. The terrain is slightly rolling to level with elevations ranging from sea level to 600 feet. The low-lying coastal sections are marshy and large with slow-moving streams bordered by wide, swampy, dense woodland. Streams draining the region include the Altamaha, Flint, Ocmulgee, Oconee, Ogeechee, and Savannah Rivers. Soils on the Coastal Plain are generally sandy and well adapted to a wide variety of agricultural products. Annual average high temperatures eclipse 77° Fahrenheit (F), whereas annual average low temperature dips to around 54° F. Conditions are warm from north to south. The traditional industries include manufacturing, agriculture, petroleum.

4.2 Geology and Soils

The Project is in the Barrier Island Sequence District of the Sea Island Section, within the Atlantic Coastal Plain Physiographic Province (Clark and Zisa, 1976). The Atlantic Coastal Plain Province is comprised of Coastal Plain sediments up to 4,000 feet thick and ranging in age from Holocene to Cretaceous. The upper Holocene sediments overlie indurated limestone of Oligocene and Eocene age. These sediments thicken toward the southeast, from the inland Fall Line toward the Atlantic coastline. The Holocene to Cretaceous sediments overlie basement rocks of Paleozoic age, consisting of intrusive igneous rocks and low-grade metamorphic rocks of Triassic to Early Jurassic age (Chowns and Williams, 1983). Project elevations within the existing LNG facility generally range from 10 to 19 feet above mean sea level.

ELC and SLNG completed a geotechnical assessment of the proposed Project location. Based on the assessment, the geology at the Project site consists of imported fill and dredge spoils about 2 to 19 feet thick at the land surface, underlain by organic clay with interbedded sand about 20 to 40 feet thick, sand about 10 to 35 feet thick, marl (mixed clay, sand, and shell) about 35 to 50 feet thick, clayey and silty sand about 45 feet thick, and limestone bedrock occurring at about 140 feet below land surface. The Project activities would generally involve shallow excavations that would not impact the bedrock. Construction activities would include pile driving; however, the piles would likely be driven to depths of up to about 70 feet below grade and would not reach bedrock.

Mineral Resources

No active mining operations were identified within 0.25 mile of the Project (South Carolina Department of Health and Environmental Control [DHEC], 2023a; U.S. Geological Survey [USGS], 2023a). No oil and natural gas wells were identified within 0.25 mile of the Project (South Carolina DHEC,2023b; USGS, 2016). Based on the absence of active mineral extraction sites near the Project, we conclude that availability of, and access to, mineral resources would not be impacted as a result of the Project.

Geologic Hazards

Geologic hazards are natural, physical conditions that can result in damage to land and structures and injury to people. Such hazards are typically seismic-related, including earthquakes and soil liquefaction. The facilities would be designed and constructed in accordance with applicable DOT regulations and applicable federal and state standards and design requirements, which would allow the Project components to withstand probable seismic risks. Geologic hazards and SNG and ELC's designs are discussed in Appendix B.

Paleontological Resources

Paleontological resources are the fossilized remains of prehistoric plants and animals, as well as the impressions left in rock or other materials. No known fossil beds were located based on publicly available information regarding known paleontological sites (e.g., Fossil Spot, 2008; Fossil Guy, 2022; Google Maps, 2022). If any fossils are encountered, ELC and SLNG would follow pre-planned procedures, including isolating remains, and ceasing construction activities if significant paleontological remains are found. In the event that significant paleontological remains are found, ELC and SLNG would also notify the appropriate agencies, including FERC. Based on this assessment and ELC and SLNG's proposed measures, we conclude the Project would not significantly impact paleontological resources.

Soils

Based on the U.S. Department of Agriculture's Natural Resources Conservation Service's Web Soil Survey, the Project is within the Made Land mapped soil unit. This soil unit is comprised of imported fill material dredged mainly from the Savannah River in shipping channels and harbors. Made Land consists of mixed sediments ranging from coarse sand to clay in layers of varying thickness. No prime farmland, hydric soils, or compaction or erosion hazards are associated with this Project.

Ground disturbance associated with the Project would be limited to Made Land soils previously disturbed by development of the existing facilities. ELC and SLNG would minimize impacts on soils by following measures in FERC's Plan and Procedures. We conclude impacts on soils would be permanent but would not be significant.

Groundwater

Groundwater resources underlying the Project area consist of an unconfined surficial aquifer, underlain by the Floridan Aquifer System. The surficial aquifer is recharged locally by stormwater runoff and surface water bodies. The Floridan Aquifer System is recharged through precipitation, leakage from overlying aquifers, and seasonal input from rivers (Williams and Kuniansky, 2016). The Upper Floridan Aquifer occurs at depths of about 300 to 600 feet below grade and is highly productive. About 70 percent of permitted wells in Chatham County, Georgia and Jasper County, South Carolina terminate within the Upper Florida Aquifer (Williams and Kuniansky, 2016). The Lower Floridan Aquifer occurs at depths of about 700 to 1,200 feet below grade and is generally not potable due to lower water quality.

No U.S. Environmental Protection Agency (EPA) Sole Source Aquifers are located in the Project area. No Wellhead Protection Areas or springs are located within 150 feet of the Project (EPA, 2023). No Surface Water Protection Areas are located within 3 miles downstream of the Project areas (DHEC, 2023b). There are two surficial aquifer water supply wells within the existing facility for facility use and operations. No other water supply wells are located within 150 feet of the Project.

The proposed construction activities would not significantly alter ground cover or infiltration in the near-surface soils within the Project footprint. Installing the proposed deep pile foundation may densify deeper sediments, reducing the permeability within the surficial aquifer adjacent to the piles. These impacts would be permanent but given the limited lateral extent would not be significant. We conclude that groundwater resources would not be significantly impacted by the Project.

4.3 Surface Water and Wetlands

The Project would be within the existing footprint of the Terminal. Construction activities would not directly affect the Savannah River or any other nearby waterbodies or wetlands. Stormwater from Project activities could potentially impact nearby wetlands and waterbodies. Land disturbing activities required for the construction of the Project would be confined to the approved graded portions of the Terminal with no grubbing or clearing and minimal grading. The Condensate Plant and nitrogen vaporizers facilities would be installed inside the existing storm surge wall and approximately at the existing grade elevation, south of the dredge material containment area. The Condensate Plant would drain to existing stormwater trenches and impoundments within the storm surge wall. Therefore, the Project would not result in a significant increase of stormwater runoff.

The Project would result in a slight increase in LNG carrier ships (3 to 4 per year). LNG carrier ships would discharge ballast water to the Savannah River to maintain a constant draft at berth. The discharge of ballast water into the Savannah River could have minor, short-term impacts on salinity, dissolved oxygen, water temperature, and pH concentrations. Depending on its source, discharged ballast water could have a higher or lower salinity than the Savannah River. The environmental impacts from the increase of 3 to 4 LNG carrier ships per year would be consistent with the level of ship traffic originally analyzed in the Elba Liquefaction Project environmental assessment (2016 EA) under Docket No. CP14-103-000. There would not be a significant increase in surface water impacts from LNG carrier ships associated with the Project.

4.4 Wildlife and Migratory Birds

The Project would not result in vegetation clearing or habitat destruction. Impacts on wildlife species and migratory birds would result from increased lighting and noise. USFWS expressed concerns that light from the Terminal may affect migratory birds. ELC and SLNG are proposing to install approximately 15 new lights, specifically associated with the new condensate management equipment. The new lights would be located toward the center of balance of plant and over 900 feet from the south channel of the Savannah River. Artificial lighting can interfere with the behavior of nocturnal animals, seemingly having the greatest impact on nocturnal migrating birds, causing disorientation and collisions with over-lit structures. Construction-related noise could affect animal behavior, foraging, or breeding patterns, and cause wildlife species to move away from the noise or relocate to avoid the disturbance. To the extent possible, the new lights would have the lights angled down, mounting lights as low as possible, and shielding lights to reduce unnecessary illumination and sky glow. Noise impacts would only occur for the duration of the Project. The Project would not increase the existing operational noise. Therefore, we conclude the Project would not significantly impact wildlife or migratory bird species.

Threatened and Endangered Species

The Commission is required by Section 7 of the Endangered Species Act (ESA) to ensure that the Project would not jeopardize the continued existence of a federally listed threatened or endangered species or result in the destruction or adverse modification of the designated critical habitat of a federally listed species. ELC and SLNG, acting as our nonfederal designee, used USFWS's Information for Planning and Consultation system to obtain an official species list. Due to the lack of suitable habitat in or near the Project area, we have determined the Project would have no effect on the federally listed northern long-eared bat (*Myotis septentrionalis*), West Indian Manatee (*Trichechus manatus*), eastern black rail (*Laterallus jamaicensis ssp. jamaicensis*), wood stork (*mycteria americana*), eastern indigo snake (*Drymarchon couperi*), pondberry (*Lindera melissifolia*), and the candidate for federal listing monarch butterfly (*Danaus plexippus*).

The NPS commented that revisions to the proposed critical habitat designation for the rufa red knot were recently proposed by the USFWS including Cockspur and Daymark Island beaches within Fort Pulaski National Monument as part of a new unit. ELC and SLNG did not identify rufa red knot or critical habitat for rufa red knot using the USFWS IPaC system. Therefore, the Project would have no effect on rufa red knot.

In its July 10, 2023 comment letter, the USFWS identified potential suitable habitat for the federally listed loggerhead sea turtle (*Caretta caretta*), leatherback sea turtle (*Dermochelys coriacea*), green sea turtle (*Chelonia mydas*), and Kemp's Ridley sea turtle (*Lepidochelys kempii*) within 7 miles east of the Terminal. In this letter, USFWS stated that due to the relatively flat terrain and low vegetation, the additional lights could be visible from the sea turtle nesting beaches under some environmental conditions. Increased artificial lighting can disorient or misorient nesting female sea turtles and hatchling sea turtles emerging from the nests and attempting to go to the ocean. In addition to the lighting being directly visible from the Terminal, it may also be visible from indirect illumination or sky glow.

USFWS recommended that ELC and SLNG create and implement a Light Management Plan for the entire Elba facility and provide the USFWS and Georgia Department of Natural Resources- Wildlife Resource Division the opportunity to review it. Additionally, USFWS recommended that the Project use fully shielded, full cut-off, downward directed lights, mounted as low as practical, and with wavelength restrictions; long-wavelength lights (e.g., those that produce light that measures equal to or greater than 560 nanometers on a spectroscope) and to comply with the guidelines from the Florida Fish and Wildlife Conservation Commission.

ELC and SLNG have agreed that the new lights would comply the Florida Fish and Wildlife Conservation Commission's established guidelines, including having the lights angled down, mounting lights as low as possible, and shielding lights to reduce unnecessary illumination and sky glow to the extent practicable. ELC and SLNG noted that for safety purposes due to compliance with USCG, Occupational Safety and Health Administration, Pipeline and Hazardous Materials Safety Administration (PHMSA) and U.S. Federal Aviation Association regulations that a Light Management Plan for the entire facility (beyond the limits of the proposed action) with all of USFWS's recommendations would not meet the requirements of the other regulations and would not be pursing it further.

On October 12, 2023, ELC and SLNG conducted a field light survey from Little Tybee Island. Little Tybee Island is approximately 11 miles away from the Terminal, and it is listed in the July 10, 2023 USFWS letter as nesting habitat for sea turtles in Georgia. The survey showed that no ambient lighting effects would be detected with the exception of skyglow. The lighting measured on Little Tybee Island was zero footcandle[13] at each survey point. During the survey, no light sources from Elba Island were readily discernable or identifiable from skyglow. Figure 4.5.1 shows the skyglow visible from turtle nesting areas located at Little Tybee Island is mostly from the city of Savannah. ELC and SLNG propose to use new light fixtures with full cutoff LED type, low wattage, short mounting height, and light would not be emitted at or above 90° horizontal. These fixtures would not add uplighting. The new lighting would be a small, incremental addition to the light associated with the existing facility but could potentially be observable beyond the facility. Due to ELC and SLNG's proposed mitigation measures, we conclude the Project *may affect, but is not likely to adversely affect* the listed sea turtle species. We are requesting USFWS concurrence with our determinations of effect. To ensure the Section 7 ESA consultation process is complete prior to construction, **we recommend that**:

ELC and SLNG should not begin construction activities until:

> **a. FERC staff receives additional comments from the USFWS regarding the proposed action;**
>
> **b. FERC staff completes ESA consultation with the USFWS; and**
>
> **c. ELC and SLNG have received written notification from the Director of the Office of Energy Projects (OEP), or the Director's designee, that construction or use of mitigation may begin.**

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[13] a unit of illumination equal to that given by a source of one candela at a distance of one foot

ELC and SLNG identified the state listed short nose Sturgeon, bald eagle, and least tern as potentially occurring in the Project area. There is no suitable habitat for these species in the Project area. Therefore, the Project would have no impact on state listed species.

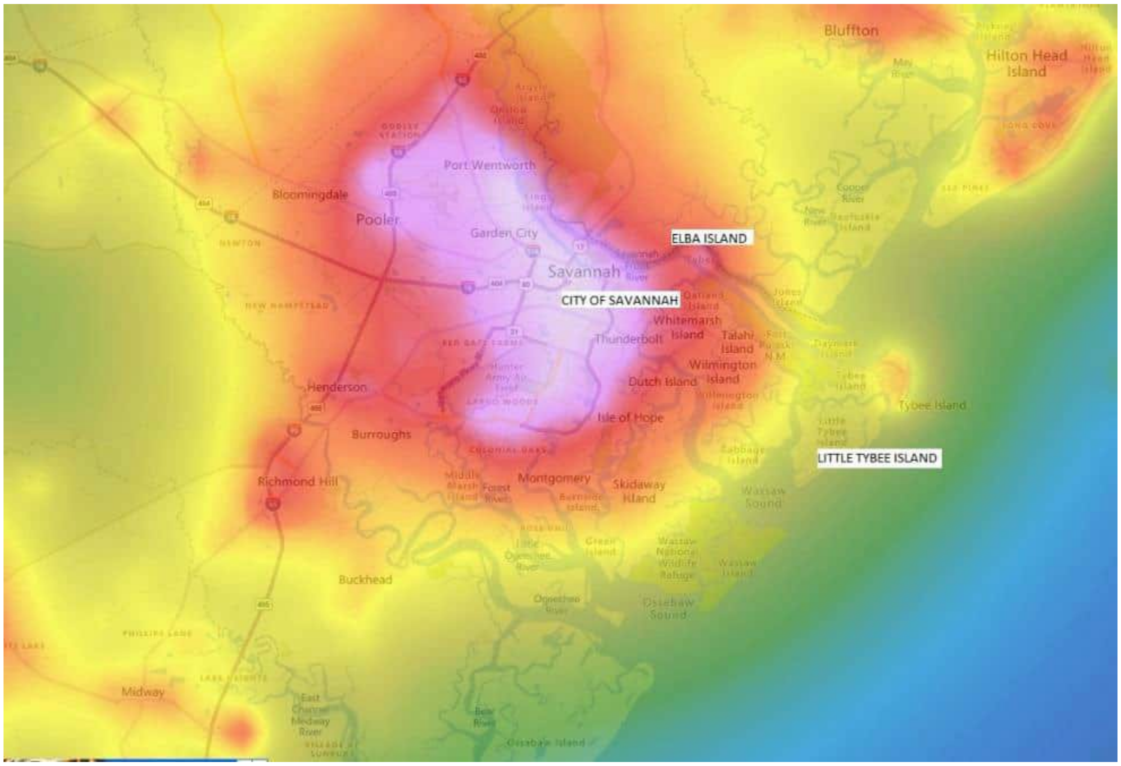

Figure 4.5.1: Nighttime Lighting Over the City of Savannah and Elba Island

4.5 Cultural Resources

In addition to accounting for impacts on cultural resources under NEPA, Section 106 of the NHPA, as amended, requires FERC to take into account the effects of its undertakings on historic properties listed, or eligible for listing on the National Register of Historic Places (NRHP),[14] and to afford the Advisory Council on Historic Preservation an opportunity to comment. ELC and SLNG, as non-federal parties, assisted FERC in

[14] In accordance with 36 CFR § 800.16(l)(1), a historic property means any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion in, the National Register of Historic Places maintained by the Secretary of the Interior. This term includes artifacts, records, and remains that are related to and located within such properties. The term includes properties of traditional religious and cultural importance to an Indian tribe or Native Hawaiian organization and that meet the National Register criteria.

meeting our obligations under Section 106 and its implementing regulations at 36 CFR Part 800. The Section 106 process is coordinated at the state level by the Georgia State Historic Preservation Officer (SHPO).

Area of Potential Effects

The area of potential effects (APE) is the "geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist" (36 CFR § 800.16(d)). Specifically, the Project's APE would consist of Project-related ground disturbance limited to the approximately 163 acres of temporary construction impacts for the Project, which would be located on land initially surveyed and permitted for the 2016 EA. Due to the Project's location within the boundary of previously surveyed and permitted lands, the APE is sufficient to account for all the potential direct and indirect effects to historic properties by the Project.

Cultural Resources Investigations

Due to the industrial and disturbed nature of the property the Project would be located upon, situated on land previously surveyed and permitted, a Phase I archaeological survey was not required.

Due to the industrial and disturbed nature of the property the Project would be located upon, situated on land previously surveyed and permitted, a Phase I archaeological survey was not required. The Project activities within Elba's existing facilities are authorized under their Categorical Clearance Agreement with the Georgia State Historic Preservation Officer (SHPO) (Effective 2021-2026).

We agree.

Tribal Outreach

On March 27, 2023, ELC and SLNG sent Project notification letters to the Catawba Indian Nation, Eastern Band of Cherokee, Muscogee (Creek) Nation of Oklahoma, Poarch Band of Creek Indians, Lower Muscogee Creek Tribe, Georgia Tribe of Eastern Cherokee, and Cherokee of Georgia Tribal Council to inform them about the Project and to request information on any concerns they may have with respect to possible impacts to properties of traditional religious and cultural significance. There were no comments received.

On June 9, 2023, FERC sent out its NOS to the Alabama-Quassarte Tribal Town, Catawba Indian Nation, Coushatta Tribe of Louisiana, and the Muscogee (Creek) Nation. To date, no comments have been received.

Compliance with the National Historic Preservation Act

FERC has completed its compliance requirements with Section 106 for the Project.

4.6 Land Use and Aesthetics

The Elba Liquefaction Optimization Project is wholly within the pre-disturbed, developed limits of the Terminal and does not convert any undeveloped areas. The Project does not implicate any new land use, recreation, or aesthetic issues.

No special or unique features or viewsheds are present in or near the Project area. There is no residential land located in the vicinity of the Terminal and modification to the existing facilities would not require the removal of residences or associated structures. This additional liquefaction volume would result in up to approximately four additional ships per year, resulting in an incremental impact on adjacent communities over the existing vessel traffic impacts. These additional ships would not exceed the current WSA and the USCG's LOR and are consistent with amounts analyzed and approved in CP14-103-000. We conclude the increase in vessel traffic associated with the Project is not expected to significantly impact marine transportation or result in any significant impacts on surrounding communities. The Project would have no cumulative impacts on land use or impacts to visual resources.

The NPS noted that the Project location is 0.3 miles at its closest point to McQueen's Island, which is the location of Fort Pulaski National Monument. The NPS commented that the existing "Elba LNG terminal impacts Fort Pulaski National Monument resources and visitor experiences primarily through its visual impact on scenery, light pollution, and noise, and FERC should evaluate changes to those impacts and others as applicable from the Project." However, as noted in CP14-103, this portion of the island consists almost entirely of wetland and marshes that would not be easily accessible by the public except by boat. The new liquefaction facilities would be obscured by existing tanks and buildings at the terminal and would be consistent with the industrial nature of the existing facility and, therefore, would not represent a significant change in the viewshed during operation. As such, we conclude that construction of the liquefaction facilities would not result in significant or adverse visual impacts.

4.7 Environmental Justice

According to the EPA, "environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies." Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies (EPA 2020a). Meaningful involvement means:

1. people have an opportunity to participate in decisions about activities that may affect their environment and/or health;
2. the public's contributions can influence the regulatory agency's decision;
3. community concerns will be considered in the decision-making process; and

4. decision makers will seek out and facilitate the involvement of those potentially affected (EPA 2020a).

In conducting NEPA reviews of proposed natural gas projects, the Commission follows the instruction of Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations,* and Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, which directs federal agencies to identify and address "disproportionately high and adverse human health or environmental effects" of their actions on minority and low-income populations (i.e., environmental justice communities).[15] Executive Order 14008, *Tackling the Climate Crisis at Home and Abroad*, also directs agencies to develop "programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts."[16] The term "environmental justice community" includes disadvantaged communities that have been historically marginalized and overburdened by pollution.[17] Environmental justice communities include, but may not be limited to minority populations, low-income populations, or indigenous peoples.[18]

We used the Federal Interagency Working Group on Environmental Justice & NEPA Committee's publication*, Promising Practices for EJ Methodologies in NEPA Reviews (Promising Practices)* (EPA 2016), which provides methodologies for conducting environmental justice analyses throughout the NEPA process for this Project. Commission staff's use of these methodologies is described throughout this section.

We used EJScreen 2.2 as an initial step to gather information regarding minority and/or low-income populations; potential environmental quality issues; environmental and demographic indicators; and other important factors. EPA recommends that screening tools, such as EJScreen 2.2, be used for a "screening-level" look and a useful first step in understanding or highlighting locations that may require further review.

Meaningful Engagement and Public Involvement

CEQ's *Environmental Justice Guidance Under the National Environmental Policy Act (CEQ Environmental Justice Guidance)* (CEQ 1997) and *Promising Practices* recommend that federal agencies provide opportunities for effective community participation in the NEPA process, including identifying potential effects and mitigation measures in consultation with affected communities and improving the accessibility of public meetings,

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15 Exec. Order No. 12,898, 59 Fed. Reg. 7629, at 7629, 7632 (Feb. 11, 1994).
16 Exec. Order No. 14,008, 86 Fed. Reg. 7619, at 7629 (Jan. 27, 2021).
17 *Id.*
18 *See* EPA, EJ 2020 Glossary (Aug. 18, 2022), https://www.epa.gov/environmentaljustice/ej-2020-glossary.

crucial documents, and notices.[19] They also recommend using adaptive approaches to overcome linguistic, institutional, cultural, economic, historical, or other potential barriers to effective participation in the decision-making processes of federal agencies. In addition, Section 8 of Executive Order 13985, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government*, strongly encourages independent agencies to "consult with members of communities that have been historically underrepresented in the Federal Government and underserved by, or subject to discrimination in, federal policies and programs."

There have been opportunities for public involvement during the Commission's environmental review processes. Following SLNG's April 28, 2023 filing of its formal FERC application onto the public record, ELC and SLNG provided copies of the application to local libraries to facilitate access and review for all members of the communities in the Project area. FERC issued its *Notice of Application for Amendment and Establishing Intervention Deadline* on May 10, 2023, which was published in the Federal Register on May 16, 2023.

FERC's communication and involvement with the surrounding communities began when the Commission issued on June 9, 2023, a *Notice of Scoping Period Requesting Comments on Environmental Issues for the Planned Elba Liquefaction Optimization Project*. This notice was published in the Federal Register on June 16, 2023. The notice was mailed to the parties on FERC's environmental mailing list, which included federal and state resource agencies; elected officials; environmental groups and non-governmental organizations; Native American Tribes; potentially affected landowners; local libraries and newspapers; and other stakeholders who had indicated an interest in the Project. Issuance of the notice opened a 30-day formal scoping period that expired on July 10, 2023. FERC subsequently included nine environmental justice advocacy groups to its environmental mailing list, which will afford them an opportunity to comment upon this EA.[20]

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[19] CEQ, Environmental Justice: Guidance Under the National Environmental Policy Act, 4 (Dec. 1997) (CEQ's Environmental Justice Guidance), https://www.epa.gov/sites/default/files/2015-02/documents/ej_guidance_nepa_ceq1297.pdf

[20] FERC's mailing list now includes the following civic organizations and environmental justice stakeholders: Anthropocene Alliance; Black Belt Citizens Fighting For Health & Justice; Chatham-Savannah Citizen Advocacy; Gullah Geechee Cultural Heritage Corridor Commission; Gullah/Geechee Nation Headquarters; Harambee House, Inc./Citizens for Environmental Justice; Islands Christian Church; Jasper County Chamber of Commerce; Kingdom Hall of Jehovah's Witnesses-East; Life Church of the Islands; Saint Mark Church; Saint Paul AME Church; Saint Stephens RMUE Church; Savannah Area Chamber; the Talahi Island Community Center; and The Imani Group.

All documents that form the administrative record for these proceedings are available to the public electronically through the internet on the FERC's website (www.ferc.gov). Anyone may comment to FERC about the Project, either in writing or electronically. All substantive environmental comments received prior to issuance of this EA have been addressed within this document.

Regarding future engagement and involvement, in 2021, the Commission established the Office of Public Participation (OPP) to support meaningful public engagement and participation in Commission proceedings. OPP provides members of the public, including environmental justice communities, landowners, Tribal citizens, and consumer advocates, with assistance in FERC proceedings - including navigating Commission processes and activities relating to the Project. For assistance with interventions, comments, requests for rehearing, or other filings, and for information about any applicable deadlines for such filings, members of the public are encouraged to contact OPP directly at 202-502-6595 or OPP@ferc.gov for further information.

We recognize that not everyone has internet access or is able to file electronic comments. Each notice was physically mailed to all parties on the environmental mailing list. Furthermore, FERC staff has consistently emphasized in meetings with the public that all comments, whether mailed in, or submitted electronically, receive equal weight by FERC staff for consideration in the EA.

We did not receive any comments regarding environmental justice issues for the Project.

Identification of Environmental Justice Communities

According to the CEQ's Environmental Justice Guidance and *Promising Practices*, minority populations are those groups that include: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. Following the recommendations set forth in *Promising Practices*, FERC uses the 50 percent and the meaningfully greater analysis methods to identify minority populations. Using this methodology, minority populations are defined in this EA where either: (a) the aggregate minority population of the block groups in the affected area exceeds 50 percent; or (b) the aggregate minority population in the block group affected is 10 percent higher than the aggregate minority population percentage in the county. The guidance also directs low-income populations to be identified based on the annual statistical poverty thresholds from the U.S. Census Bureau. Using *Promising Practices'* low-income threshold criteria method, low-income populations are identified as block groups where the percent of low-income population in the identified block group is equal to or greater than that of the county. Here, we selected Chatham County, Georgia and Jasper County, South Carolina as the comparable reference community to ensure that affected environmental justice communities are properly identified. A reference community may vary according to the characteristics of the particular project and the surrounding communities. Table 4.9-1 identifies the minority population (by race and ethnicity) and low-income population within Georgia and South Carolina.

Table 4.9-1
Minority Populations by Races and Ethnicity and Low-Income Populations in the Project Area

	RACE AND ETHNICITY											LOW-INCOME
State/County/Census Tract/ Block Group	**Total Population**	**White Alone Not Hispanic (%)**	**African American (%)**	**Native American/ Alaska Native (%)**	**Asian (%)**	**Native Hawaiian & Other Pacific Islander (%)**	**Some Other Race (%)**	**Two or More Races (%)**	**Hispanic or Latino (%)**	**Total Minority [a] (%)**		**Below Poverty Level[b] (%)**
Georgia	10,799,566	50	30	0.2	4	0.04	0.5	4	10	50		13
Chatham County	296,329	47	40	0.03	2	0.0	0.3	4	7	53		14
Census Tract 111.07, Block Group 1[c]	911	68	0.0	0.0	3	0.0	0.0	27	2	32		4
Census Tract 118, Block Group 2	835	71	19	0.4	0.7	0.0	0.0	0.7	8	29		12
South Carolina	5,190,705	63	25	0.02	2	0.04	0.4	4	6	37		14
Jasper County	28,363	44	39	0.1	0.6	0.0	0.0	2	14	56		20
Census Tract 9503.02, Block Group 4	1281	30	60	0.0	0.0	0.0	0.0	0.0	9.5	**70**		**34**

Source: U.S. Census Bureau. American Community Survey, 2017-2021, File # B03002 and B17017.
a "Minority" refers to people who reported their ethnicity and race as something other than non-Hispanic White.
b Low-income or minority populations exceeding the established thresholds are indicated in red, bold, type and blue shading.
c Census Tract 111.07 Block Group 1 contains the Elba Island LNG Terminal.
Due to rounding differences in the dataset, the totals may not reflect the sum of the addends.

Data is provided for the counties affected by the Project (Chatham County, Georgia and Jasper County, South Carolina), and census block groups[21] within 2 miles of the Terminal. A 2-mile radius for the plant is sufficiently broad considering the likely concentration of construction-period air and noise emissions, visual impacts, and traffic impacts proximal to the Terminal construction site. To ensure we are using the most recent available data, we use the U.S. Census American Community Survey[22] File# B03002 as the source for race and ethnicity data, and File# B17017 as the source for poverty data at the census block group level. According to the current U.S. Census Bureau information, an environmental justice population exists within the geographic scope of the Project area, as discussed further below and depicted in figure 4.8.1-1.[23]

As presented in table 4.8-1, while there are no Project facilities or work areas within any environmental justice block groups, one low-income environmental justice block group is within the geographic scope of the Project, identified as Census Tract 9503.02, Block Group 4.

Impacts on Environmental Justice Communities

As previously described, *Promising Practices* provides methodologies for conducting environmental justice analyses. Issues considered in the evaluation of environmental justice include human health or environmental hazards; the natural physical environment; and associated social, economic, and cultural factors. Consistent with *Promising Practices* and Executive Order 12898, we reviewed the Project to determine if its resulting impacts would be disproportionate and adverse on minority and low-income populations and also whether impacts would be significant.[24] *Promising Practices* provides that agencies can consider any of a number of conditions for determining whether an action would cause a disproportionate

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[21] Census block groups are statistical divisions of census tracts that generally contain between 600 and 3,000 people. USCB. 2022. Glossary: Block Group. Available online at: https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_4. Accessed December 2022.

[22] USCB, American Community Survey 2021 ACS 5-Year Estimates Detailed Tables, File# B17017, Poverty Status in the Past 12 Months by Household Type by Age of Householder, https://data.census.gov/cedsci/table?q=B17017; File #B03002 Hispanic or Latino Origin By Race, https://data.census.gov/cedsci/table?q=b03002

[23] In response to our October 14, 2022 data request, Transco provided census block group data for race, ethnicity, and poverty populations within 1 mile of the Project's facilities.

[24] *See* Promising Practices at 33 (stating that "an agency may determine that impacts are disproportionately high and adverse, but not significant within the meaning of NEPA" and in other circumstances "an agency may determine that an impact is both disproportionately high and adverse and significant within the meaning of NEPA").

and adverse impact.[25] The presence of any of these factors could indicate a potential disproportionate and adverse impact. For this Project, a disproportionate and adverse effect on an environmental justice community means the adverse effect is predominantly borne by such population. Relevant considerations include the location of project facilities and the project's human health and environmental impacts on identified environmental justice communities, including direct, indirect, and cumulative impacts.

Impacts on the natural and human environment from construction and operation of Project facilities are identified and discussed throughout this document. Factors that could affect environmental justice communities include visual impacts (see section 4.6) and air impacts (see section 4.8). Potentially adverse environmental effects on surrounding communities associated with the Project, including environmental justice communities, would be minimized and/or mitigated. In general, the magnitude and intensity of the aforementioned impacts would be greater for individuals and residences closest to the Project's facilities and would diminish with distance. These impacts are addressed in greater detail in the associated sections of this EA. Environmental justice concerns are not present for other resource areas such as geology, soils, groundwater, surface water, wetlands, vegetation, wildlife, fisheries, land use, or cultural resources due to the minimal overall impact the Project would have on these resources.

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[25] *See* Promising Practices at 45-46 (explaining that there are various approaches to determining whether an impact will cause a disproportionately high and adverse impact). We recognize that CEQ and EPA are in the process of updating their guidance regarding environmental justice and we will review and incorporate that anticipated guidance in our future analysis, as appropriate.

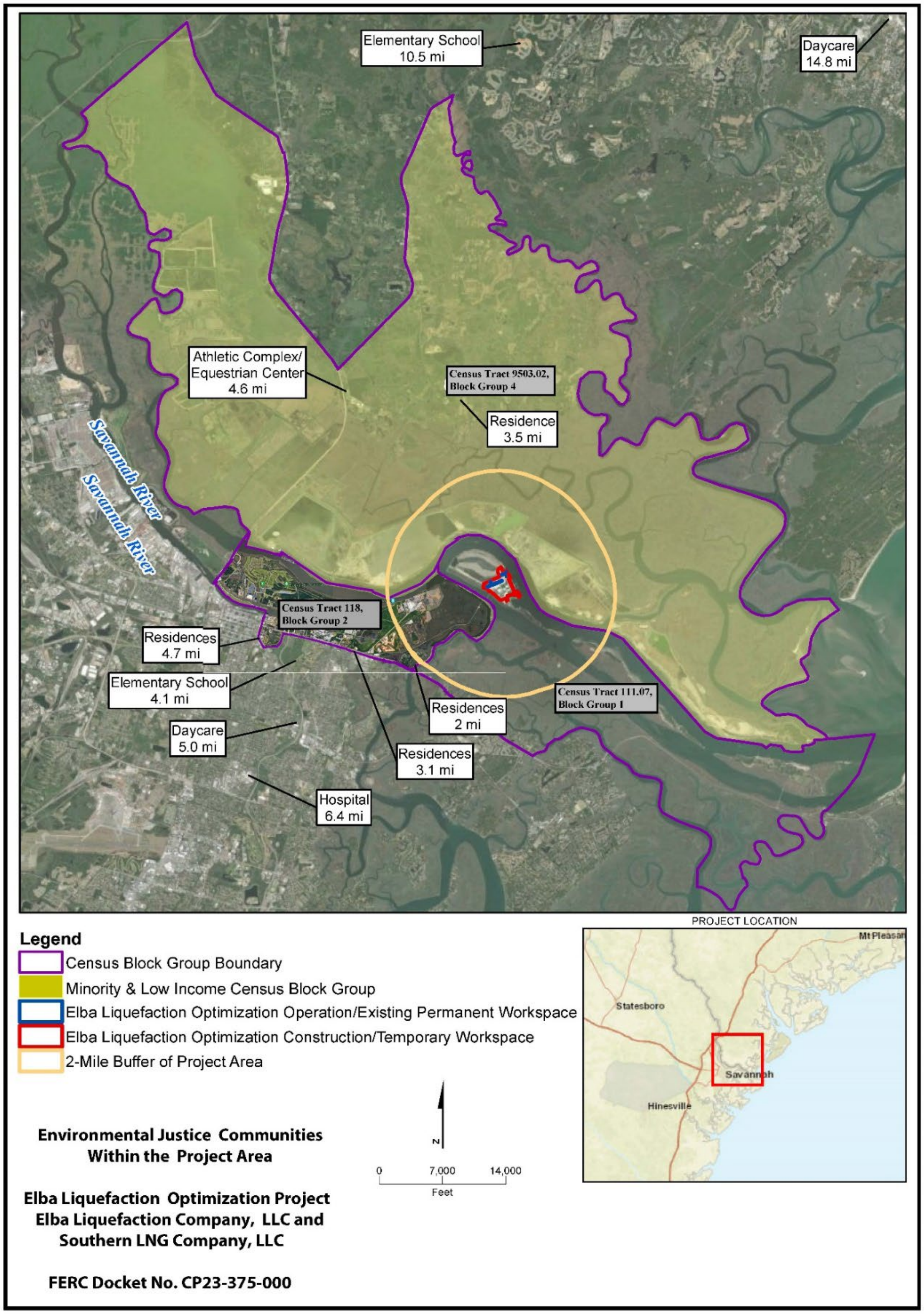

Figure 4.8.1-1: Environmental Justice Communities Within the Project Area

Visual Resources

With respect to visual impacts on environmental justice populations, as described in section 4.8, the Project area is wholly within the pre-disturbed, developed limits of the Terminal. The surrounding area is predominately characterized as rural coastal tidal marshlands in the surrounding areas. Land use south of Elba Island consists of adjacent heavy industry-zoned land uses along the south bank of the Savannah River tending toward the urban areas of Savannah Georgia. Land use north of Elba Island consists of tidal marshlands, protected marine areas, and United States Army Corps of Engineers-approved dredge material fill sites.

The closest residences located in an environmental justice community are located 3.5 miles north of the facility. Although the existing Terminal tanks and some of the upper portions of the trains are currently visible at this location, the modifications associated with this Project would not be visible, given their limited height. The Port of Savannah is heavily used shipping corridor and provides vessel access to many facilities. The Project is on previously disturbed land, historically used for industrial purposes, in an existing industrial setting. Thus, the visual impacts would be similar to those of the surrounding industrial complexes and would blend into the existing industrial background. Marine woody vegetation obstruct views toward the Project site and the facility modifications. Visual impacts to the residences and sensitive land uses to environmental justice communities are anticipated to be limited and are not anticipated to be disproportionate adverse when compared to other surrounding areas. Additionally, these facility modifications would not be visible to recreational users of nearby waterbodies within an environmental justice community (the closest areas used for recreation beginning approximately 1 mile away). Furthermore, the increase in shipping traffic would be approximately four vessels annually and due to the distance to the shipping channel, existing vegetation, and normal shipping corridor use, the increase would not be readily perceptible by residences along the waterway.

ELC and SLNG has committed to installing its planned 15 new lighting structures to reduce illumination and nighttime sky glow by angling the lights angled down, mounting lights as low as possible, and shielding lights. ELC and SLNG would be able to reduce the frequency of flaring upon installation of its Terminal modifications. Given the distance to the closest residences within an environmental justice community (3.5 miles north) and the masked nature of facility upgrades in relation to the existing tall structures of the Terminal, visual impacts on environmental justice communities from the Project would not be significant.

Socioeconomics

A nominal sized workforce would be required for the facility additions and modifications to the Terminal consisting of at most 50 workers, some of which would be on-local, hired from the Chatham County area. Approximately 30 workers would perform the condensate equipment modifications and nitrogen vaporizer upgrades during the 5-month construction period. Approximately 20 of these workers would conduct the MMLS units modification work across four years. The 50-person workforce would represent at most a 0.01 percent change in Chatham County's population, and no new operational workforce would be required to operate the facilities. Thus, we believe that impacts on socioeconomic resources within the environmental justice communities (e.g., population, housing demand, or the provision of community services such as police, fire, or schools) would be less than significant, as there would be a negligible change from current conditions.

Traffic impacts would be concentrated on access roads (Elba Island Road and Islands Expressway) south of the terminal. Project construction would result in a maximum of 20 vehicle passages per day for commuting workers and hauling materials and equipment along both of these roads during the construction period. This construction traffic volume would be negligible compared to the typical traffic levels on these access roads. While neither of these access roads would be located within the Census Tract 9503.02, Block Group 4 environmental justice community, ELC and SLNG would minimize construction traffic impacts on area roadways and residents by working with the construction contractor, city of Savannah, local law enforcement, and other regulatory agencies, including using traffic control personnel to manage traffic in areas of active construction. Given this minimal volume of temporary traffic and ELC and SLNG's commitment to employ traffic mitigation measures, we conclude that these impacts on environmental justice communities would be less than significant.

Air Quality

ELC and SLNG's proposed construction activities potentially affecting air quality at the Terminal would consist of commuter traffic and delivery vehicles, use of construction engines within the Terminal, and fugitive dust emissions associated with disturbance of surfaces inside the Terminal. Construction emissions would occur in the form of particulate matter (e.g., dust) and equipment exhaust emanating from construction equipment and vehicles occurring in the immediate vicinity of construction work areas occurring over a short-term period of construction. Given that the closest residential or non-residential receptors within environmental justice communities are at least 3.5 miles from the Terminal, we conclude that no receptors would experience construction air impacts. Recreational use within the tidal marsh or heritage areas within the closest environmental justice community (Census Tract 9503.02, Block Group 4), located more than 1 mile north of Elba Island, may experience temporary construction related air impacts. ELC and SLNG would limit fugitive dust emissions by spraying water to dampen the surfaces of dry work areas and/or by the application of calcium chloride or other dust suppressants as needed. Construction activities would be completed using a typical daily work schedule of 7:00 am to 7:00 pm, seven days a week. Taking into consideration ELC and SLNG's proposed mitigation measures, we conclude construction emissions would not result in a significant impact on air quality in the immediate environs affecting environmental justice communities.

There would be a minor increase in operational air emissions as a result of the Project along with the potential to eliminate up to 11,855 tons per year of CO_2e emissions. In addition, operations would result in minor increases in air emissions from fugitive emissions stemming from modifications to the movable modular liquefaction system and stabilized condensate plant.[26] ELC and SLNG's increase in emissions would not exceed their current permit allowances for emissions of nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), or greenhouse gas (GHG). Overall, the construction and operational emissions from the Project would not have significant adverse air quality impacts on the environmental justice populations in the Project area.

Noise

Construction activities at the Terminal producing noise would include grading using mechanized equipment, transportation of materials using dump trucks and concrete trucks, installation of structures using pile drivers, and modifications to Terminal facilities using new or additional pumps, tower cranes, forklifts, air compressors and tools. Pile driving would be avoided during nighttime hours. No residential or non-residential receptors are located within 3.5 miles of the Terminal within the Census Tract 9503.02, Block Group 4 environmental justice community. No operational noise emissions would occur from the Project.

Based on the distance to noise-sensitive receptors within nearby environmental justice communities and the temporary nature of ELC and SLNG's proposed construction activities, the project would not result in significant construction noise impacts on local residents within the Census Tract 9503.02, Block Group 4 environmental justice community. There would be no additional operational noise associated with the Project; therefore, there would be no operational noise impacts on local residents within the Census Tract 9503.02, Block Group 4 environmental justice community.

Environmental Justice Impact Mitigation

As described in *Promising Practices*, when an agency identifies potential adverse impacts it may wish to evaluate practicable mitigation measures. ELC and SLNG have committed to several minimization and mitigation measures to reduce construction-related impacts to visual quality, traffic, air quality and noise, as well as long-term operational noise and air quality. Though not specifically targeted at mitigating impacts on environmental justice communities, mitigation measures would be implemented across the Project area, including within the identified environmental justice communities. These measures include:

- using best management practices to control fugitive dust emissions during construction;
- generally limiting construction activities to 7:00 a.m. to 7:00 p.m.;
- limiting pile driving to daytime hours;
- installing facility lighting to minimize addition of nighttime illumination and sky

[26] There would be no exceedance of the SIL for any criteria pollutant; therefore, operational air emissions are not anticipated to contribute to adverse ambient air quality.

glow; and

- complying with applicable air quality regulations.

Following construction, temporary workspaces associated with Project facilities would be restored in accordance with the federal, state, and local permit requirements. In addition, FERC staff would maintain compliance oversight of the Project throughout construction.

Determination of Disproportional Adverse Impacts on Environmental Justice Communities

As described throughout this EA, the proposed Project would have a range of impacts on the environment and on individuals living in the vicinity of the Project facilities, including environmental justice populations. As highlighted in table 4.9-1, one census tract block group within the geographic scope of the Project is considered an environmental justice community. As previously stated, no Project work within any environmental justice community would take place. Thus, there would be no impacts associated with these facilities on environmental justice communities that would be disproportionate and adverse. Project construction impacts associated with visual, socioeconomics, air quality, and noise for these components would be less than significant. In addition, there would be no permanent impacts on environmental justice communities associated with noise and air quality from operation of the Project's facilities.

4.8 Air Quality

This section summarizes federal and state air quality regulations that are applicable to the proposed Project and the difference in emissions between the 2016 Order and the estimated emissions disclosed in the application. The term air quality refers to relative concentrations of pollutants in the ambient air. Air quality would be affected by the construction and operation of Project facilities. During construction, short-term emissions would be generated from the usage of equipment, land disturbance, and increased traffic from worker and delivery vehicles occurring over a 5-month period. Once completed, the Project would transition to operational phase emissions associated with the new condensate management equipment and MMLS modifications.

Existing Air Quality

Ambient air quality is protected by federal and state regulations. Under the CAA and its amendments, the EPA has established National Ambient Air Quality Standards (NAAQS)[27] for criteria pollutants, including CO, lead (Pb), NO_2, ozone, particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and SO_2.

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[27] The current NAAQS are listed on EPA's website at https://www.epa.gov/criteria-air-pollutants/naaqs-table.

States have the authority to adopt ambient air quality standards if they are at least as stringent as the NAAQS. While states can promulgate more stringent standards than the NAAQS, the Georgia Environmental Protection Division (GEPD) has adopted all the NAAQS established by the EPA. These standards incorporate short-term (hourly or daily) levels and long-term (annual) levels to address acute and chronic exposures to the pollutants, as appropriate. The NAAQS include primary standards, which are designed to protect human health, including the health of sensitive subpopulations, such as children and those with chronic respiratory problems. The NAAQS also include secondary standards designed to protect public welfare, including economic interests, visibility, vegetation, animal species, and other concerns not related to human health. Volatile organic compounds (VOC) are also regulated by the EPA to prevent the formation of ozone $(O)_3$, a constituent of photochemical smog. Many VOCs form ground level ozone by reacting with sources of oxygen molecules such as NOx in the atmosphere in the presence of sunlight. NOx and VOCs are referred to as ozone precursors. Hazardous air pollutants (HAP) are also emitted during fossil fuel combustion. HAPs are chemicals known to cause human health and environmental impacts. There are no national air quality standards for HAPs, but their emissions are limited through permit thresholds and technology standards.

GHGs occur in the atmosphere both naturally and as a result of human activities, such as the burning of fossil fuels. GHGs produced by fossil-fuel combustion are primarily carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). GHGs status as a pollutant is not related to toxicity; GHGs are non-toxic and non-hazardous at normal ambient concentrations, and there are no applicable ambient standards or emission limits for GHGs under the Clean Air Act. GHGs absorb infrared radiation in the atmosphere, and an increase in emissions of these gases is the primary cause of warming of the climatic system.[28] During construction activities, GHGs would be emitted from construction equipment; during operations GHGs would be produced by the modified MMLS and dehydration units. GHGs occur in the atmosphere both naturally and as a result of fossil-fuel combustion and land use change. Emissions of GHGs are typically expressed in terms of CO_2 equivalents (CO_2e).[29] The CO_2e unit of measure takes into account the global warming potential (GWP) of each GHG over a specified timeframe. The GWP is a ratio relative to CO_2 that is based on the particular GHG's ability to absorb solar radiation as well its residence time in the atmosphere. Thus, CO_2 has a GWP of 1, has a GWP of 25, and N_2O has a GWP of 298 on a 100-year timescale. To obtain the CO_2e quantity, the mass of the particular compound is multiplied by the corresponding GWP, the product of which is the CO_2e for that compound. The CO_2e value for each of

[28] Further information regarding GHGs and increasing levels of CO_2 can be found at https://www.epa.gov/climate-indicators

[29] Other GHG gases are converted to CO_2e by means of the global warming potential of each gas.

the GHG compounds is summed to obtain the total CO_2e GHG emissions. There are no NAAQS or other significance thresholds for GHG.

Air quality control regions (AQCRs) are areas established by the EPA and local agencies for air quality planning purposes, in which state implementation plans describe how the NAAQS would be achieved and maintained. The AQCRs are intra- and interstate regions such as large metropolitan areas where improvement of the air quality in one portion of the AQCR requires emission reductions throughout the AQCR. Each AQCR, or smaller portion within an AQCR (such as a county), is designated, based on compliance with the NAAQS, as attainment, unclassifiable, maintenance, or nonattainment, on a pollutant by-pollutant basis. Areas in compliance or below the NAAQS are designated as attainment, while areas not in compliance or above the NAAQS are designated as nonattainment. Areas previously designated as nonattainment that have since demonstrated compliance with the NAAQS are designated as maintenance for that pollutant. Maintenance areas may be subject to more stringent regulatory requirements to ensure continued attainment of the NAAQS. Areas that lack sufficient data to determine attainment status are designated unclassifiable and treated as attainment areas. The Project is located in Chatham County, in the Savannah-Beaufort Interstate Air Quality Control Region and is designated as attainment for all criteria pollutants.

Permitting/Regulatory Requirements

The CAA is the basic federal statute governing air pollution in the United States. Adherence to the applicable regulations would remain consistent with those identified in the 2016 EA. Based on Project activities, we have reviewed the following federal requirements and determined that they are not applicable to the proposed Project:

- New Source Review;
- Title V (Amendment would not impact the SLNG Title V Permit number 4922-051-0003-V-06-0 issued 12/1/2022);
- National Emissions Standards for Hazardous Air Pollutants;
- New Source Performance Standards; and
- General Conformity of Federal Actions.

Greenhouse Gas Reporting Rule

In September 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule, requiring reporting of GHG emissions from: suppliers of fossil fuels; and facilities where the aggregated maximum heat input from all combustion sources is greater than 30 million British thermal units per hour and that emit greater than or equal to 25,000 metric tons per year (tpy) of GHGs (reported as CO_2e). ELC and SLNG would continue to report emissions in accordance with the reporting rule as proposed additional emissions associated with proposed Project activities are expected to be greater than 25,000 metric tons per year.

Applicable State and Local Air Quality Requirements

Based on the limited scope of activities, there are no state air quality requirements that would apply to the Project.

Construction Emissions

Construction of the proposed Project would result in short-term increases in emissions of some pollutants from the use of fossil fuel-fired equipment and the generation of fugitive dust due to earthmoving activities. Some temporary indirect emissions, attributable to construction workers commuting to and from work sites during construction and from on-road and off-road construction vehicle traffic, could also occur. Large earth-moving equipment and other mobile equipment are sources of combustion-related emissions, including criteria pollutants (i.e., NO_x, CO, VOCs, SO_2, and PM_{10}). Due to the scope of the Project, construction emissions would be limited to vehicle exhaust emissions from additional vehicle traffic commuting, and proposed activities at the worksite. These emissions are in addition to those analyzed in the 2016 EA.

ELC and SLNG would continue to utilize mitigation measures described in the 2016 EA and required by the June 2016 Order to minimize exhaust and fugitive dust emissions for the Elba Liquefaction Project, including limiting idling time of equipment, and maintaining and tuning engines per manufacturer's specifications. Fugitive dust would be mitigated by Elba continuing to utilize the measures reviewed and found adequate in the 2016 EA,[30] including dust suppression techniques, such as spraying water or dust suppressants to dampen the surfaces of dry work areas.

Construction related emission estimates were based on a typical construction equipment list, hours of operation, and vehicle miles traveled by the construction equipment and supporting vehicles for the Project. These emission-generating activities would occur over a 5-month period, and include earthmoving, construction equipment exhaust, on-road vehicle traffic, and off-road vehicle traffic. These emissions present the combined emissions for the construction equipment's combustion, on-road vehicle travel, off-road vehicle travel, and earthmoving fugitives. Emissions during construction would increase pollutant concentrations in the vicinity of the Terminal; however, their effect on ambient air quality would vary with time due to the construction schedule, and the mobility of the sources. Construction emissions associated with the Project would be considered temporary and cease at completion of construction. Following the limited construction modifications, air quality impacts associated with the Project would revert back to current existing conditions. Estimated construction emissions for the Project are presented in table 4.10-1.

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[30] The 2016 EA can be found on eLibrary under accession number 20000111-0192 CP99-579.

Table 4.10-1 Construction Emissions (tons)							
Operation	**NO_X Emissions**	**CO Emissions**	**SO_2 Emissions**	**PM_{10} Emissions**	**$PM_{2.5}$ Emissions**	**VOC Emissions**	**GHG Emissions**
Construction Equipment[a]	2.23	1.02	0.002	0.11	0.11	0.26	171.24
Commuter Traffic[b]	0.19	1.78	0.002	0.01	0.07	0.18	168.69
Delivery Vehicles[b]	2.09	1.46	0.002	0.08	0.01	0.23	203.23
Fugitive Dust[c]	-	-	-	45.98	5.1	-	-
Total	4.51	4.26	0.01	46.19	5.3	0.67	543.16

a Construction equipment emissions based on emissions factors from California's South Coast Air Quality Management District .
b Commuter and delivery vehicle traffic emissions based on emission factors from California's South Coast Air Quality Management District.
c Fugitive dust emissions based on EPA AP-42 Chapters 13.2.1 for paved roads, 13.2.2 for unpaved roads, and 13.2.3 for heavy construction operations.

Given the temporary and intermittent nature of construction emissions, adherence to applicable regulatory thresholds, and the implementation of mitigation measures discussed in the 2016 EA, we find that the Project would not be expected to cause or significantly contribute to a violation of any applicable ambient air quality standard, or significantly affect local or regional air quality.

Operational Emissions

Modifications to the MMLS units include retrofitting the existing mole-sieve vessels to function as a combined HRU, as well as certain other appurtenant modifications. The proposed HRU vessels would accommodate the combined functionality and increased MMLS unit throughput, and certain bed regeneration equipment, required to be upsized to compliment the new vessels.

The modification of the dehydration system to function as a combined dehydration and heavies removal system would reduce the fouling rate of the cold boxes and subsequent flaring associated with deriming the cold boxes. The modifications would also allow the MMLS units to be operated with higher efficiency in the cold boxes, resulting in increased LNG production. Since the existing MMLS HRU is proposed to be bypassed during normal operation, as a result of the proposed modifications and upgrades to the MMLS units, where stabilized condensate is currently generated, a new Condensate Plant would be constructed to take the effluent from the modified dehydration system and generate stabilized condensate. A breakdown of operational emissions associated with the proposed Project modifications is presented in table 4.9.1-1.

The existing air permit conservatively used the daily LNG maximum production fuel gas rate annualized without consideration for downtime. The proposed changes would not increase the levels of any criteria pollutants or GHG emissions above what

Table 4.9.1-1
Potential Emissions Related to Operation of the Project

Pollutant	Baseline Actual Emissions (tpy)	Projected Future Actual Emissions (tpy)	Projected Emissions Increase (tpy)
Total PM_{10}	6.73	7.54	0.808
Total $PM_{2.5}$	6.73	7.54	0.808
NO_X	25.9	29.01	3.12
CO	79.95	89.54	9.59
VOC	19.27	21.58	2.31
SO_2	24.58	27.53	2.95
GHG (CO_2e)	323,772.43	362,625.12	38,852.69
Total HAP	1.69	1.89	0.20

was authorized by the terminal's existing air permits and analyzed by FERC under CP14-103. A copy of the required Section 502(b)10 Change Notification would be provided to GEPD for the proposed Project.

GHG emissions from the Project would be minimal as the modifications and upgrades aimed at improving reliability and minimizing fouling which results in MMLS unit shutdown and the associated flaring of these MMLS unit shutdowns would eliminate up to approximately 11,855 tons of GHG annually from derime[31] flaring activities.

Air Quality Modeling

To assess air quality impacts from the Project on regional air quality, air dispersion modeling was performed for the Project modifications using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee's "AERMOD" modeling system, the most advanced sequential Gaussian plume model sanctioned by the EPA. The modeling was performed according to the GDEP guidelines. A source impact analysis is a modeling analysis designed to show that the allowable emissions from a project would not result in a violate on of the NAAQS. The predicted modeled concentrations, when added to the representative ambient background concentration and compared to the NAAQS, demonstrate compliance with their respective standards for normal operation. Air quality impacts from operation of the Project's condensate plant would be minimized by the use of equipment, emissions controls, and operating practices that meet or exceed industry standards to minimize emissions and compliance with federal and state emission thresholds. Compliance with federal and state air regulations and state permit requirements would ensure that air quality impacts would be minimized during installation and operation of the Project components.

The Significant Impact Levels (SIL) are used to determine if the ambient impact of a project is significant enough to warrant further review. If a project is below the SIL for a pollutant and averaging period, further analysis is not required. The maximum modeled concentrations are below the SILs for the Project. Therefore, there is no radius of impact, and the Project modeling results are below the SIL and NAAQS at the Project site.

[31] Derime is a procedure in which the cryogenic distillation, air cooling and liquefaction, and oxygen mixing systems are warmed with hot, dry, purified air in order to purge all traces of moisture, carbon dioxide, and hydrocarbons from the cold end of the plant.

Table 4.10.1 provides a summary of 1-hour and 8-hour of CO impacts for the existing facility and proposed modifications.[32] The results of the modeling analysis demonstrate that the operation of the proposed Project would not cause or contribute to

Table 4.10.1 Summary of 1-hour and 8-hour Project CO Impacts				
	8-hour average		1-hour average	
Meteorological Data Year	**Modeled Concentration (ug/m3)**	**SIL (ug/m3)**	**Modeled Concentration (ug/m3)**	**SIL (ug/m3)**
2017	43.00	500	83.03	2,000
2018	41.18		84.63	
2019	36.02		84.41	
2020	38.72		81.19	
2021	42.53		83	

an exceedance of the established relevant SII.

Due to the temporary nature of construction emissions and limited operational emission changes associated with remaining Project activities, and compliance with NAAQS and permitting thresholds, we conclude that the Project would not have a significant impact on air quality.

4.9 Noise

Construction of the Project would affect the local noise environment in the area. The ambient sound level of a region, which is defined by the total noise generated within the specific environment, is usually composed of sounds emanating from both natural and artificial sources. At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week and year, in part due to changing weather conditions and the impacts of seasonal vegetative cover.

In 1974, the EPA published its *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*. Two measurements used to relate the time-varying quality of environmental noise to its known effects on people are the 24-hour equivalent sound level (Leq) and the day-night sound level (Ldn). The Leq is an A-weighted sound level containing the same sound energy as the instantaneous sound levels measured over a specific time period. Noise levels are

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[32] CO would be the largest pollutant increase as part of Project modifications; dispersion modeling was completed at FERC staff's request to demonstrate continued compliance and lack of contributing impact to air quality in the area.

perceived differently depending on length of exposure and time of day. The Ldn takes into account the duration and time the noise is encountered. Specifically, in the calculation of the Ldn, late night to early morning (10:00 PM. to 7:00 AM) noise exposures are penalized +10 decibels (dB) to account for people's greater sensitivity to sound during the nighttime hours. Due to the 10 A-weighted scale (dBA) nighttime penalty added prior to calculation of the Ldn, for a facility to meet the 55 dBA Ldn limit established by the EPA to protect the public from indoor and outdoor activity interference, a facility must be designed such that the constant 24-hour noise level does not exceed an Leq of 48.6 dBA at any NSA. The dBA is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies. For an essentially steady sound source that operates continuously over a 24-hour period and controls the environmental sound level, the Ldn is approximately 6.4 dB above the measured Leq.

The EPA has indicated that an Ldn of 55 dBA protects the public from indoor and outdoor activity interference. We have adopted this the EPA's Ldn of 55 dBA noise criterion and use it to evaluate the potential noise impacts from the proposed Project at NSAs, such as residences, schools, or hospitals. Also, in general, a person's threshold for a perceivable change in loudness on the A-weighted sound level is about 3 dBA, whereas a 5 dBA change is clearly noticeable, and a 10 dBA change is perceived as either twice or half as loud.

There are no state or local noise regulations applicable to the Project.

Construction Noise

Noise would be generated during construction of the aboveground facility modifications for the Project. Noise levels would be highest in the immediate vicinity of construction activities and would diminish with distance from each work area. These impacts would be localized and temporary. Sound level changes would depend on the type of equipment used, the duration of use for each piece of equipment, the number of construction vehicles and machines used simultaneously, and the distance between the sound source and receptor. Construction activities associated with the Project would be performed with standard heavy equipment, such as front-end loaders or backhoes; installation of structures using pile drivers, dump trucks, and concrete trucks; as well as noise from modifications to the Terminal to include new or additional pumps, installation and connection assembly of modules, using equipment such as tower cranes, forklifts, air compressors and tools. The Project facilities would be installed within the existing Terminal. Noise would also be generated by trucks and other light vehicles traveling in and near areas under construction. Construction equipment and worker vehicles generally operate intermittently and may change depending on Project activity or phase.

Construction activities may have minor, short-term impacts to noise and visual resources, however, these would be attenuated by the operational noise and existing structures of the facility.

Modification of the MMLS units would be scheduled during the planned maintenance turn arounds for each MMLS unit which routinely occur and consist of approximately two to four units per year through 2027. The work on the MMLS units proposed herein would require an additional 7 days to the planned maintenance schedule of 28 days per turn around and would take less time than if the modifications to the MMLS units were being done separate from the planned maintenance. Construction activities would not add noise beyond normal operating conditions. There are no noise sensitive areas within 0.5 mile of the construction site, and construction activities would be completed using a typical daily work schedule of 7:00 am to 7:00 pm, seven days a week. Construction personnel would peak around approximately 20 workers associated with the MMLS work and 30 workers associated with the condensate and nitrogen vaporizers work.

Based on the short duration and intermittent nature of construction activities, distance to nearest NSA, and that construction of the Project would be limited to daytime hours and obscured by current operational activities, we conclude that construction noise would not have a significant impact on the environment.

There would be no additional operational noise associated with the Project.

4.10 Reliability and Safety

As part of the NEPA review and NGA determinations, Commission staff assesses the potential impact to the human environment in terms of safety and whether the proposed facilities would operate safely, reliably, and securely.

As a cooperating agency, DOT assists the FERC by determining whether the Project's proposed design would meet DOT's 49 CFR Part 193 Subpart B siting requirements. On February 7, 2024, PHMSA provided an LOD on the Project's compliance with 49 CFR Part 193 Subpart B. This determination is provided to the Commission as further consideration on the Commission's decision to authorize or deny the Project. If the Project is authorized, constructed, and operated, the facility would be subject to DOT's inspection and enforcement program and final determination of whether a facility is in compliance with the requirements of 49 CFR Part 193 would be made by DOT PHMSA.

As a cooperating agency, USCG also assisted the FERC staff by reviewing the proposed project and the associated LNG marine vessel traffic. On September 27, 2023, the USCG issued a letter stating ELC and SLNG does not need to submit a new Letter of Intent, nor submit a new WSA since the proposed Project would not result in a significant increase in the size and/or frequency of LNG marine traffic that would impact the waterway. If the Project is authorized, constructed, and operated, the facilities would be subject to the USCG's inspection and enforcement program to ensure compliance with the requirements of 33 CFR Part 105 and 33 CFR Part 127.

FERC staff conducted a preliminary engineering and technical review of the Project design, including potential external impacts based on the site location. This review is provided in Appendix B. Based on this review, we recommend a number of mitigation measures in section 5 of this EA, which would ensure continuous oversight prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout life of the facility to enhance the reliability and safety of the facility to mitigate the risk of impact on the public. With the incorporation of these mitigation measures and oversight, FERC staff concludes that the Project design would include acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could impact the offsite public.

4.11 Cumulative Impacts

In accordance with CEQ regulations implementing NEPA (40 CFR Parts 1500-1508), we identified other actions in the vicinity of the Project and evaluated the potential for a cumulative impact on the environment. As defined by CEQ, a cumulative effect is the impact on the environment that results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of the agency or party undertaking such other actions. Cumulative impacts can result from individually minor, but collectively significant actions, taking place over time. CEQ guidance states that an adequate cumulative effects analysis may be conducted by focusing on the current aggregate effects of past actions without delving into the historical details of individual past actions.

In this analysis, we consider the impacts of past projects within defined geographic scopes as part of the affected environment (environmental baseline) which were described and evaluated in the preceding environmental analysis. However, present effects of past actions that are relevant and useful are also considered. Our cumulative effects analysis focuses on potential impacts from the proposed Project on resource areas or issues where the incremental contribution could result in cumulative impacts when added to the potential impacts of other actions. To avoid unnecessary discussions of insignificant impacts and projects and to adequately address and accomplish the purposes of this analysis, an action must first meet the following three criteria to be included in the cumulative analysis:

- affects a resource also potentially affected by the Project;
- causes this impact within all, or part of, the Project area defined by the resource specific geographic scope; and
- causes this impact within all, or part of, the time span of the Project's estimated impacts.

Constructing and operating the Project would temporarily and permanently affect the environment. Project-related impacts would be contained within or adjacent to the temporary construction workspaces, existing pipeline and roadway corridors, or utility easements. Due to the existing conditions at the Terminal, there would be no impact to cultural resources and vegetation. Furthermore, along with the proposed minimization and mitigation measures described in ELC and SLNG's construction procedures, we have concluded that most of the Project impacts on soils and geology would be limited to workspaces and adjacent areas. There are no NSAs within 1 mile of the Terminal, cumulative noise impacts would not occur as a result of the proposed activities. Therefore, we do not assess the potential for cumulative operational noise impacts. Resources that could be affected outside the immediate Project area and are subject to our cumulative impacts review include groundwater, surface water, wetlands, wildlife, land use, visual resources, air quality, socioeconomics, and environmental justice.

Based on the impacts of the proposed Project as identified and described in this EA and consistent with CEQ guidance, we have determined that the resource-specific geographic scope described below are appropriate to assess cumulative impacts.

- impacts on groundwater, surface water, wetlands, and wildlife were assessed within the watershed boundary [Hydrologic Unit Code (HUC) 12];
- impacts to land use were assessed within 1 mile of the proposed Project;
- impacts to visual resources were assessed based upon the proximity of proposed Project facilities to visually sensitive areas and residential areas;
- for impacts on air quality from construction emissions, we searched for other projects and actions that overlap in time and are located within 0.25 mile of construction activities;
- impacts on socioeconomics were assessed within the county where Project activities are proposed;
- impacts on environmental justice communities were assessed within the census block groups affected by the Project construction and operation.

We note that GHGs do not have a localized geographic scope. GHG emissions from the proposed Project combined with projects all over the planet lead to increased CO_2, methane, and other GHG concentrations in the atmosphere. Thus, the geographic scope for analysis of GHG emissions is global.

Planned Activities

The actions considered in our cumulative impact analysis may vary from the proposed Project in nature, magnitude, and duration. These actions are included based on the likelihood of their impacts coinciding with the proposed project, meaning the other actions have current or ongoing impacts or are “reasonably foreseeable.” The actions we considered are those that could affect similar resources during the same timeframe as the proposed Project. Multiple projects were identified as possible contributors to cumulative impacts in the area, these are listed in appendix A.

The projects listed in appendix A that were evaluated for potential cumulative impacts include Georgia Department of Transportation bridge projects, roadway paving, and a dredging project. However, based on the anticipated construction schedule for many of the Georgia Department of Transportation projects and the paving project, we conclude there would not be a temporal overlap with the Project; however, the projects that may have a temporal overlap located a distance from the proposed Project such that the only potential resource impact overlap would be socioecomomics.

The anticipated cumulative impacts of the Project and these other actions are discussed below.

Geologic and Soil Resources

The projects identified in appendix A may result in permanent impacts to surface topography or river bed contours, as well as temporary impacts on shallow geologic materials and soils within or adjacent to areas of ground or riverbed disturbance. Direct effects on geology and soils would be highly localized and limited primarily to the period of construction; therefore, cumulative impacts on geologic and soil resources would only occur if other projects are constructed at the same time and in the same geographic footprint as the proposed Project. Given the proposed Project's low probability of mineral resource impacts, the low potential of geologic hazards for the proposed Project as discussed in appendix B, the less than significant, if permanent, soil impacts, and ELC and SLNG's adherence to protective and restorative measures, we conclude that the cumulative impacts on geologic resources and soils resulting from the proposed Project and other nearby projects would not be significant.

Groundwater, Surface Water, and Wetlands

The geographic scope established for water resources is the hydrologic unit code (HUC)-12 subwatersheds crossed by the proposed Project. Any projects listed in appendix A involving ground disturbance within HUC-12 subwatersheds crossed by the Project could result in cumulative impacts on water resources.

Concurrent construction of projects involving clearing, grading, or other groundwork may also increase the potential for cumulative impacts on water quality from increased runoff. All project sponsors would be required to adhere to state and federal regulations regarding hydrostatic test water, construction, and industrial stormwater and wastewater discharges. Therefore, the proposed Project is not anticipated to adversely impact groundwater quality or supply, and cumulative impacts on groundwater are anticipated to be minor.

Concurrent construction activities within the geographic scope could result in potential impacts on surface water and wetland resources including increases in turbidity and sedimentation, depletion of dissolved oxygen levels, and decreased water quality during and immediately following project construction. Primary impacts on these resources would result from alteration of vegetation within or adjacent to these resources during clearing, excavation, rutting, compaction, and mixing of topsoil and subsoil. Additionally, inadvertent spills could also affect water quality. These impacts would be the greatest during and immediately following concurrent construction of the proposed Project and other projects within the HUC-12 subwatershed.

The Project is wholly within the pre-disturbed, developed limits of the Terminal, does not convert any undeveloped areas, and does not include any marine infrastructure or dredging activities. The proposed Project does not have any direct impacts to wetlands or waterbodies or implicate any new water use or quality issues. The Project would have no cumulative impacts on water use or quality. Therefore, overall cumulative impacts on groundwater, surface water, and wetland resources are anticipated to be minor.

Wildlife

Cumulative effects on wildlife affected by the Project, including threatened and endangered species, could occur in the HUC-12 subwatersheds where Project modifications would occur. Any regional projects in the HUC-12 area that involve clearing or grading could result in cumulative impacts on wildlife resources. Because the Project would be situated within the pre-disturbed, developed limits of the Terminal, it would not convert any undeveloped areas, and would not include any marine infrastructure or dredging activities. The Project would not involve any new fish, wildlife, and vegetation issues. Following construction, all temporary workspaces would return to pre-construction conditions and revegetated in accordance with the FERC Plan and Procedures.

If federal or state-listed threatened and endangered species might be affected by other projects in the geographic scope, these impacts would be addressed in permits or clearances issued for each project and appropriate mitigation to minimize these impacts would be implemented as needed. Given the minor, temporary impacts on vegetation and wildlife from the Project, and the abundant available habitat within the geographic area surrounding the Project we conclude that the Project would not contribute significant cumulative impacts on wildlife.

Land Use

Projects with permanent aboveground components, such as buildings, residential projects, roads, and aboveground electric transmission lines generally have similar impacts on land use as oil and gas infrastructure improvements. Land use impacts from the Project would be minor, as all impacts for the Project would be within or existing Terminal and located in areas with existing oil and gas infrastructure. The Project would not result in a significant change in the physical characteristics of the existing environment, and we conclude that there would not be cumulative impacts to land use.

Visual Resources

Permanent visual changes would involve the construction of the aboveground facilities; however, these would be attenuated by the location amongst the existing structures of the active, operational Terminal. Due to the location of the Project within an area with existing natural gas infrastructure, we conclude that there would be no significant cumulative impacts on visual resources as a result of construction.

Air Quality

Cumulative impacts on air could occur during construction activities. Proposed construction impacts would be temporary and limited in scope. Should construction of the Project overlap the construction timeframe for the identified projects in Appendix A, each project sponsor would continue to adhere to their respective construction permits, minimizing overall impacts on air quality in the area. Based on the temporary nature of construction emissions, and that the proposed activities would not contribute to a violation of the NAAQS, we conclude the Project would not have a significant impact on air quality during construction when considered in conjunction with existing or reasonably foreseeable projects in the area.

There would be no operational cumulative impacts on air quality for affected resources due to proposed Project activities. Based on the scope of the Project and our analysis of the proposed action's impacts on the environment as described, we conclude that the Project would not significantly contribute to cumulative impacts to air quality in the vicinity when considered with other potential project emissions.

Socioeconomics

The Project and nearby planned projects (see Appendix A) within Chatham County combined would not cause a significant increase in local population or housing demand within Chatham County, given the relatively small and temporary nature of the Project's workforce. Nearby planned projects in this geographic scope would likely add some combined impact on socioeconomic resources such as police, fire, and school community services, but only temporarily during construction. The Georgia Port Authority's O&M Building Project (pipeline), Southern Natural Gas (SNG) Maintenance, Pressure Test Stone Container Line, SNG maintenance Wrens-Savannah 2nd Loop Line, Georgia Department of Transportation (GDOT) County Route 787/Islands Expressway at Bascule Bridge Replacement, and GDOT CS 1097/Delesseps/La Roche Ave from Waters Ave to Skidaway Road Project components are widely spaced throughout Chatham County and are scheduled to run concurrent with the Project's construction timeframe. Thus, cumulative traffic impacts could occur from combined construction related use of public and private roads impacted by the planned projects and the Project. The Project and planned projects would likely have a beneficial effect on the local economy through sales and property tax generation and the consumption of goods and services. Given the minor and short-term nature of Project construction, and the lack of additional workers for Project operations, we do not anticipate any adverse cumulative negative impact on socioeconomics in the Project area.

The NPS recommended we evaluate the Project with the nearby Jasper Ocean Terminal project, a joint venture between Georgia and South Carolina Port Authorities, related to the vessel traffic in the area. The Jasper Ocean Terminal is a planned deepwater container port in in Jasper County, South Carolina across from Elba Island on the north bank of the Savannah River, about 10 miles (16 km) downstream from Savannah. It is planned to open between 2035 and 2037. We expect the four additional LNG ships per year on the Savannah River associated with the proposed Project would constitute a negligible impact on vessel traffic overall; however, the Jasper Ocean Terminal is under NEPA review by USACE Charleston District and the project's impacts on vessel traffic have not been identified. Vessel traffic impacts would be dependent on forecasted growth in the demand for containerized cargo within the region. The USACE is preparing an EIS to evaluate the proposed container terminal and any associated navigation improvements to the Savannah Harbor Federal navigation channel.[33] We note the USCG exercises regulatory authority over LNG marine vessels and deemed the waterway suitable for the LNG vessel traffic associated with the Project.

Environmental Justice

The Project would be located in close proximity to existing utility rights-of-way in an urban setting with dense residential areas interspersed with industries and transportation corridors with the Savannah, Georgia. Planned construction projects in the Project area are related to ongoing natural gas energy development, port development, and highway development and maintenance. No Project facilities or access roads are located within an environmental justice community; however, the adjacent environmental justice community (Census Tract 9503.02, Block Group 4) within the geographic scope of cumulative impacts could experience impacts. It is possible that their construction impacts could intersect with the construction of the Project and thus could contribute to cumulative impacts.

Based on the scope of the proposed Project and our analysis of the Project's impacts on the environment, we determined that Project-related cumulative impacts may occur on socioeconomics (including traffic), noise, and air quality within environmental justice communities. No cumulative visual impacts could occur from this Project given that the Project's modifications would not be visible to residences within the adjacent environmental justice community. Cumulative impacts within environmental justice communities are not present for other resource areas such as geology, soils, groundwater, wetlands, wildlife, or cultural resources due to the minimal overall impact the Project would have on these resources.

Cumulative socioeconomic impacts on the Census Tract 9503.02, Block Group 4 environmental justice community could occur from ELC and SLNG's Project in combination with the six nearby planned projects. Impacts on population, employment, housing, public services, and tax revenue would be minor and limited to periods of concurrent construction. The increase in construction workforce could also have a beneficial, short-term impact on employment, local goods and service providers and result in greater sales tax revenues. The combined use of public roads and private access roads for the Project and six nearby planned projects could result in cumulative impacts on road traffic within the Census Tract 9503.02, Block Group 4 environmental justice community. However, given the temporary duration of construction activities, overall cumulative impacts on traffic within environmental justice communities would be less than significant.

Cumulative air quality impacts to the Census Tract 9503.02, Block Group 4 environmental justice community would not occur during construction given that none of the six nearby planned projects are located within 0.25 miles of the Project. Operational air quality impacts to environmental justice communities from the combination of the Project

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[33] *See* Environmental Impact Statement | Jasper Ocean Terminal (jasperoceanterminaleis.com).

and the six nearby planned projects would not occur given that none of them would add emissions while being operated. Thus, we conclude that the Project would not significantly contribute to cumulative impacts on air quality in the vicinity when considered with other potential project emissions, including on environmental justice communities.

No cumulative noise impacts within environmental justice communities would occur from Project operations given that there are no environmental justice NSAs within 1 mile of the Project facilities.

Climate Change

Climate change is the variation in the Earth's climate (including temperature, precipitation, humidity, wind, and other meteorological variables) over time. Climate change is driven by accumulation of GHG in the atmosphere due to the increased consumption of fossil fuels (e.g., coal, petroleum, and natural gas) since the early beginnings of the industrial age and accelerating in the mid- to late-20th century.[34] The GHGs produced by fossil-fuel combustion are CO_2, CH_4, and N_2O.

In 2017 and 2018, the U.S. Global Change Research Program (USGCRP)[35] issued its *Climate Science Special Report: Fourth National Climate Assessment*, Volumes I and II.[36] This report and the recently released report by the Intergovernmental Panel on Climate Change, *Climate Change 2021: The Physical Science Basis*, states that climate change has resulted in a wide range of impacts across every region of the country and the

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[34] Intergovernmental Panel on Climate Change, United Nations, *Summary for Policymakers* of Climate Change 2021: The Physical Science Basis. (Valerie Masson-Delmotte et al., eds.) (2021), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM.pdf (IPCC Report) at SPM-5. Other forces contribute to climate change, such as agriculture, forest clearing, and other anthropogenically driven sources.

[35] The U.S. Global Change Research Program is the leading U.S. scientific body on climate change. It comprises representatives from 13 federal departments and agencies and issues reports every 4 years that describe the state of the science relating to climate change and the effects of climate change on different regions of the United States and on various societal and environmental sectors, such as water resources, agriculture, energy use, and human health.

[36] U.S. Global Change Research Program, Climate Science Special Report, Fourth National Climate Assessment | Volume I (Donald J. Wuebbles et al. eds) (2017), https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf (USGCRP Report Volume I); U.S. Global Change Research Program, Fourth National Climate Assessment, Volume II Impacts, Risks, And Adaptation In The United States (David Reidmiller et al. eds.) (2018), https://nca2018.globalchange.gov/downloads/NCA4_2018_FullReport.pdf (USGCRP Report Volume II).

globe.[37] Those impacts extend beyond atmospheric climate change alone and include changes to water resources, agriculture, ecosystems, human health, and ocean systems.[38] According to the Fourth National Climate Assessment Report, the United States and the world are warming; global sea level is rising and oceans are acidifying; and certain weather events are becoming more frequent and more severe.[39] These impacts have accelerated throughout the end of the 20th and into the 21st century.[40]

GHG emissions do not result in proportional local and immediate impacts; it is the combined concentration in the atmosphere that affects the global climate. These are fundamentally global impacts that feed back to local and regional climate change impacts. Thus, the geographic scope for cumulative analysis of GHG emissions is global rather than local or regional. For example, a project 1 mile away emitting 1 ton of GHGs would contribute to climate change in a similar manner as a project 2,000 miles distant also emitting 1 ton of GHGs.

Climate change is a global phenomenon; however, for this analysis, we will focus on the existing and potential climate change impacts in the general Project area. The USGCRP's Fourth Assessment Report notes the following observations of environmental impacts attributed to climate change in the Southeast region of the United States: [41]

- the near decade of 2010 through 2017 has been warmer than any previous decade since 1920 for average daily maximum and average daily minimum temperature;
- since 1960, there have been lower numbers of days above 95°F compared to the pre-1960 period but during the 2010's the number of nights above 75°F has been nearly double the average over 1901 – 1960. The length of the freeze free season was 1.5 weeks longer on average in the 2010s compared to any other historical period on record;
- the number of days with 3 or more inches of rain has been historically high over the past 25 years. The 1990s, 2000s, and 2010s rank first, third, and second, respectively in number of events;

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37 IPCC, 2021: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu and B. Zhou (eds.)]. Cambridge University Press. In Press.
38 6 IPCC Report at SPM-5 to SPM-10.
39 USGCRP Report Volume II at 73-75.
40 *See e.g.*, USGCRP Report Volume II at 99 (describing accelerating flooding rates in Atlantic and Gulf Coast cities).
41 USGCRP Report Volume I and II.

- summers have been either increasingly dry or extremely wet, depending on location;
- due to a combination of sea level rise and soil subsidence, approximately 2,006 square miles of land have been lost in Louisiana between 1932 and 2016, or about 23 square miles per year; and
- in Georgia, relative sea level is rising at a rate of 1 to 3 feet per 100 years.

The USGCRP'S Fourth National Climate Assessment Report notes the following projections of climate change impacts in the Project's Southeast United States region with a high or very high level of confidence:[42]

- climate models project nighttime temperatures above 75°F and daytime maximum temperatures above 95°F become the summer norm. Nights above 80°F and days above 100°F, which are now relatively rare, would become common;
- lowland coastal areas are expected to receive less rainfall on average, but experience more frequent intense rainfall events followed by longer drought periods;
- coastal areas along the Atlantic are flat; therefore, expected sea level rises may cause inundation in certain low-lying areas;
- drought and sea level rise will create stressful conditions for coastal trees that are not adapted to higher salinity levels;
- other coastal species may also be stressed by sea level rise and warmer temperatures, prompting migration out of the area; and
- tropical storms and hurricanes may become more intense.

It should be noted that while the impacts described above taken individually may be manageable for certain communities, the impacts of compound events (such as simultaneous heat and drought, wildfires associated with hot and dry conditions, or flooding associated with high precipitation on top of saturated soils) can be greater than the sum of the parts.[43]

Construction and operational GHG emissions associated with the Project, expressed in terms of CO_2e, were identified and quantified in section 4.8 of this EA. Construction emissions would result in 543 tons of CO_2e emissions (equivalent to 493 metric tons per year). These GHG emissions would occur during a temporary period during Project activities. Operational CO_2e emissions would be increased above 2016 EA levels by approximately 38,853 tons per year (35,240 metric tons per year). There are no downstream emissions associated with the proposed Project. Construction and operation of

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[42] USGCRP Report Volume II.
[43] USGCRP Report Volume II.

Project facilities would increase the atmospheric concentration of GHG in combination with past, current, and future emissions from all other sources globally, and would contribute incrementally to future climate change impacts. To assess impacts on climate change associated with the Project, we considered whether we could identify discrete physical impacts resulting from the Project's GHG emissions or compare the Project's GHG emissions to established targets designed to combat climate change.

To date, we have not identified a methodology to attribute discrete, quantifiable, physical effects on the environment resulting from a project's incremental contribution to GHGs. Without the ability to determine discrete resource impacts, we are unable to assess the Project's contribution to climate change through any objective analysis of physical impact attributable to the Project. Additionally, we have not been able to find an established threshold for determining the GHG significance when compared to established GHG reduction targets at the state or federal level. Ultimately, this EA is not characterizing the GHG emissions as significant or insignificant. [44] However, as we have done in prior NEPA analyses, we disclose the Project's GHG emissions in comparison to national and state GHG emission inventories.

In order to provide context of the changed GHG emissions on a national level, we compare the GHG emissions to the total GHG emissions of the United States as a whole. At a national level, 5,586.0 million metric tons of CO_2e were emitted in 2021 (inclusive of CO_2e sources and sinks) (EPA 2022). Construction emissions from the Project could potentially increase CO_2e emissions based on national 2021 levels by 0.000009 percent. In subsequent years, Project operations could result in a potential increase in CO_2e emissions by 0.0006 percent based on national 2021 levels.

In order to provide context of the changed GHG emissions on a state level, we compare the GHG emissions to the state GHG inventory. The Project construction and operational emissions would occur fully in Georgia. At the state level, energy related CO_2 emissions in Georgia were 124.1 million metric tons of CO_2e in 2021 (inclusive of CO_2 sources and sinks) (U.S. Energy Information Administration, 2023). Project construction in could potentially increase CO_2 emissions based on Georgia statewide 2021 levels by 0.0004 percent. In subsequent years, operational emissions from the Project could potentially increase CO_2 emissions based on Georgia statewide 2021 levels by 0.03 percent.

[44] *See e.g.*, *Driftwood Pipeline LLC*, 183 FERC ¶ 61,049, at P 63 (2023) ("…there currently are no accepted tools or methods for the Commission to use to determine significance, therefore the Commission is not herein characterizing these emissions as significant or insignificant.)

We also evaluate the change in emissions in the context of established state reduction goals. At the time of this Project analysis, Georgia has no established GHG reduction goals.[45]

Below, we include a disclosure of the social cost of GHG (SC-GHG), also referred to as the social cost of carbon (SCC). Calculating the SC-GHGs does not enable the Commission to determine whether the reasonably foreseeable GHG emissions associated with the Project are significant or not significant in terms of their impact on global climate change.[46] In addition, there are no criteria to identify what monetized values are significant for NEPA purposes, and we are currently unable to identify any such appropriate criteria.[47]

As both the EPA and CEQ participate in the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), we used the methods and values contained in the IWG's current draft guidance but note that different values would result from the use of

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[45] We reviewed the U.S. State Greenhouse Emission Targets site for individual state requirements at: https://www.c2es.org/document/greenhouse-gas-emissions-targets/.

[46] *See Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043 at P296, (2017), *aff'd sub nom.*, *Appalachian Voices v. FERC*, 2019 WL 847199 (D.C. Cir. 2019); *Del. Riverkeeper v. FERC*, 45 F.th 104, 111 (D.C. Cir. 2022); and *Driftwood Pipeline LLC*, 183 FERC ¶ 61,049, at P 61 (2023). The Social Cost of GHGs tool merely converts GHG emissions estimates into a range of dollar-denominated figures; it does not, in itself, provide a mechanism or standard for judging "significance."

[47] *Tenn. Gas Pipeline Co., L.L.C.*, 181 FERC ¶ 61,051 at P 37; *see also Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043 at P 296, *order on reh'g*, 163 FERC ¶ 61,197, at PP 275-297 (2018), *aff'd*, *Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at 2 (D.C. Cir. Feb. 19, 2019) (unpublished) ("[The Commission] gave several reasons why it believed petitioners' preferred metric, the Social Cost of Carbon tool, is not an appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act. That is all that is required for NEPA purposes."); *EarthReports*, 828 F.3d 949, 956 (D.C. Cir. 2016) (accepting the Commission's explanation why the social cost of carbon tool would not be appropriate or informative for project-specific review, including because "there are no established criteria identifying the monetized values that are to be considered significant for NEPA purposes"); *Tenn. Gas Pipeline Co., L.L.C.*, 180 FERC ¶ 61,205, at P 75 (2022); *See, e.g., LA Storage, LLC*, 182 FERC ¶ 61,026, at P 14 (2023); *Columbia Gulf Transmission, LLC*, 180 FERC ¶ 61,206, at P 91 (2022); and *Driftwood Pipeline LLC*, 183 FERC ¶ 61,049, at P 61 (2023).

other methods.[48] Accordingly, we calculated the SC-GHG for CO_2, CH_4, and N_2O. For the calculation, staff assumed discount rates of 5 percent, 3 percent, and 2.5 percent.[49]

We assumed the Project would begin service in 2024 and that the emissions would be at a constant rate throughout the 17-years remaining under their current precedent agreements for the Project. Noting these assumptions, the emissions from increased GHGs disclosed are calculated to result in a total SC-GHG equal to $7,972,614, $29,438,877, and $44,258,977, respectively (all in 2020 dollars). Using the 95th percentile of the SCC using the 3 percent discount rate, the total SCC from the Project is calculated to be $89,240,228 (in 2020 dollars).

Cumulative Impacts Conclusion

The cumulative impacts review as part of the NEPA process evaluates the incremental effects of a proposed project and multiple similar projects in the same region at the same time, or in a similar timeframe, to determine whether the additive effect of those projects would result in significant impacts to the regional environment. As discussed previously, the Project and other projects in the area would have or have had minimal cumulative impacts. As a result, no significant cumulative impacts are anticipated when combining the Project with other identified projects.

Additionally, we identified planned activities in the Project area that met the criteria for inclusion in the cumulative impact analysis. Implementation of Best Management Practices and proposed mitigation plans would minimize environmental impacts and when the impacts of the Project are added to the impacts from the other identified projects, the cumulative impacts would be minimal. We conclude that impacts would be temporary in

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[48] *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*, Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, February 2021 (IWG Interim Estimates Technical Support Document).

[49] IWG Interim Estimates Technical Support Document at 24. To quantify the potential damages associated with estimated emissions, the IWG methodology applies consumption discount rates to estimated emissions costs. The IWG's discount rates are a function of the rate of economic growth where higher growth scenarios lead to higher discount rates. For example, IWG's method includes the 2.5 percent discount rate to address the concern that interest rates are highly uncertain over time; the 3 percent value to be consistent with the U.S. Office of Management and Budget circular A-4 (2003) and the real rate of return on 10-year Treasury Securities from the prior 30 years (1973 through 2002); and the 5 percent discount rate to represent the possibility that climate related damages may be positively correlated with market returns. Thus, higher discount rates further discount future impacts based on estimated economic growth. Values based on lower discount rates are consistent with studies of discounting approaches relevant for intergenerational analysis. *Id*. at 18-19, 23-24.

nature and no significant cumulative impacts would be incurred from the Project.

Based on the analysis of each resource and the potential for geographic and temporal cumulative impacts, the Project maintains the 2016 EA finding of no significant cumulative impacts and no additional mitigation measures are recommended.

5. STAFF'S CONCLUSION AND RECOMMENDATIONS

Overall, we conclude that approval of the proposed Project would not result in significant environmental impacts. This determination is based on a review of the information provided by ELC and SLNG and further developed from environmental and engineering information requests; literature research; alternatives analysis; and correspondence with federal and state agencies. Based on a preliminary engineering and technical review of the Project design, and with incorporation of our recommended mitigation measures, we conclude that the Project would include acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could impact the offsite public. We also conclude that no system or other alternative would provide a significant environmental advantage over the Project as proposed. Therefore, we conclude that the proposed Project, with our recommended mitigation measures, is the preferred alternative to meet the Project objectives.

We recommend that the Order contain a finding of no significant impact and include the following mitigation measures listed below as conditions to any authorization the Commission may issue. We have determined that these measures would further mitigate the environmental impacts associated with Project construction and operation as proposed. In addition, the engineering and technical recommendations would be implemented prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility to enhance the reliability and safety of the facility and to mitigate the risk of impact on the public.

1. ELC and SLNG shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA, unless modified by the Order. ELC and SLNG must:
    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;
    b. justify each modification relative to site-specific conditions;
    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
    d. receive approval in writing from the Director of OEP, or the Director's designee, **before using that modification**.
2. The Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order, and take whatever steps are necessary to ensure the protection of life, health, property, and the environmental during construction and operation of the Project. This authority shall allow:

a. the modification of conditions of the Order;

b. stop-work authority and authority to cease operation; and

c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

3. **Prior to any construction**, ELC and SLNG shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, environmental inspectors (EIs), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EA, as supplemented by filed alignment sheets and diagrams. **As soon as they are available, and before the start of construction**, ELC and SLNG shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

5. ELC and SLNG shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP, or the Director's designee, **before construction in or near that area**.

   This requirement does not apply to extra workspace allowed by the Commission's *Upland Erosion Control, Revegetation, and Maintenance Plan* and/or minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands.

   Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;
b. implementation of endangered, threatened, or special concern species mitigation measures;
c. recommendations by state regulatory authorities; and
d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **Within 60 days of the authorization and before construction begins**, ELC and SLNG shall file an Implementation Plan with the Secretary for review and written approval by the Director of OEP, or the Director's designee. ELC and SLNG must file revisions to the plan as schedules change. The plan shall identify:

   a. how ELC and SLNG will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by the Order;
   b. how ELC and SLNG will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;
   c. the number of EIs assigned, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;
   d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;
   e. the location and dates of the environmental compliance training and instructions ELC and SLNG will give to all personnel involved with construction and restoration (initial and refresher training as the project progresses and personnel change);
   f. the company personnel (if known) and specific portion of ELC and SLNG 's organization having responsibility for compliance;
   g. the procedures (including use of contract penalties) ELC and SLNG will follow if noncompliance occurs; and
   h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:
      (1) the completion of all required surveys and reports;
      (2) the environmental compliance training of onsite personnel;
      (3) the start of construction; and
      (4) the start and completion of restoration.

7. ELC and SLNG shall employ at least one EI for the Project. The EI shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;
b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;
c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;
d. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and
e. responsible for maintaining status reports.

8. Beginning with the filing of its Implementation Plan, ELC and SLNG shall file updated status reports with the Secretary on a **monthly** basis until all construction and restoration activities are complete. Problems of a significant magnitude shall be reported to the FERC **within 24 hours.** On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on ELC and SLNG's efforts to obtain the necessary federal authorizations;
   b. project schedule, including current construction status of the project and work planned for the following reporting period;
   c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EI during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);
   d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;
   e. the effectiveness of all corrective and remedial actions implemented;
   f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the order, and the measures taken to satisfy their concerns; and
   g. copies of any correspondence received by ELC and SLNG from other federal, state, or local permitting agencies concerning instances of noncompliance, and ELC and SLNG's response.

9. ELC and SLNG must receive written authorization from the Director of OEP, or the Director's designee, **before commencing construction of any Project facilities.** To obtain such authorization, ELC and SLNG must file with the

Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

10. ELC and SLNG must receive written authorization from the Director of OEP, or the Director's designee, **prior to introducing hazardous fluids into the Project facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

11. ELC and SLNG must receive written authorization from the Director of OEP, or the Director's designee, **before placing into service** the Project facilities. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval, can be expected to operate safely as designed, and the rehabilitation and restoration of areas affected by the project are proceeding satisfactorily.

12. **Within 30 days of placing the authorized facilities in service**, ELC and SLNG shall file an affirmative statement with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

    b. identifying which of the conditions in the Order ELC and SLNG has complied with or will comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

13. ELC and SLNG shall **not begin** construction activities **until:**

    a. FERC staff receives additional comments from the USFWS regarding the proposed action;

    b. FERC staff completes ESA consultation with the USFWS; and

    c. ELC and SLNG have received written notification from the Director of OEP, or the Director's designee, that construction or use of mitigation may begin.

14. **Prior to construction of final design,** ELC and SLNG shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in the State of Georgia:

    a. soil improvement procedures for the proposed project site;
    b. site preparation drawings and specifications;
    c. the corrosion control and prevention plan for any underground piping,

structure, foundations, equipment, and components

d. finalized civil and structural design basis, criteria, specifications;

e. finalized wind and seismic design basis;

f. Issued for Construction of LNG terminal structures and foundation design drawings and calculations (including prefabricated and field constructed structures);

g. quality control procedures to be used for civil/structural design and construction;

h. the total and differential settlement of final designed foundations for structures, systems, and components for the project site**.**

In addition, ELC and SLNG shall file, **in its Implementation Plan**, the schedule for producing this information.

Information pertaining to the following specific recommendations shall be filed with the Secretary for review and written approval by the Director of OEP within the timeframe indicated by each recommendation. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, shall be submitted as critical energy infrastructure information pursuant to 18 CFR §388.113. See Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016). Information pertaining to items such as offsite emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements would be subject to public disclosure. All information shall be filed <u>a minimum of 30 days</u> before approval to proceed is requested.

15. **Prior to initial site preparation,** ELC and SLNG shall file an overall Project schedule, which includes the proposed stages of initial site preparation, final design, procurement, construction, commissioning, introduction of hazardous fluids, and commencement of service.

16. **Prior to initial site preparation,** ELC and SLNG shall file procedures for controlling access during construction. The procedures shall address how unauthorized construction personnel will be restricted from entering the operational areas of the plant.

17. **Prior to initial site preparation,** ELC and SLNG shall file quality assurance and quality control procedures for construction activities, including initial equipment laydown receipt and preservation.

18. **Prior to initial site preparation,** ELC and SLNG shall develop an updated ERP

(including evacuation and any sheltering and re-entry) and coordinate procedures with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and other appropriate federal agencies. This plan shall be consistent with recommended and good engineering practices, as defined in National Fire Protection Association (NFPA) 1660, NFPA 470, NFPA 475, or approved equivalents, and based on potential impacts and onset of hazards from accidental and intentional events at the LNG terminal, including but not limited to a catastrophic rupture of the largest flowing pipe or vessel. This plan shall address any special considerations and pre-incident planning for infrastructure and public with access and functional needs and shall include at a minimum:

a. materials and plans for periodic dissemination of public education and training materials for evacuation and/or shelter in place of the public within LNG terminal hazard areas;
b. plans to competently train emergency responders required to effectively and safely respond to hazardous material incidents including, but not limited to, LNG fires and dispersion;
c. plans to competently train emergency responders to effectively and safely evacuate or shelter public within hazard areas from LNG terminal;
d. designated contacts with federal, state and local emergency response agencies responsible for emergency management and response within hazard areas from LNG terminal;
e. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;
f. scalable procedures for mobilizing response and establishing a unified command, including identification, location, and design of any emergency operations centers and emergency response equipment required to effectively and safely to respond to hazardous material incidents and evacuate or shelter public within LNG terminal hazard areas;
g. scalable procedures for notifying public, including identification, location, design, and use of any permanent sirens or other warning devices required to effectively communicate and warn the public prior to onset of debilitating hazards within hazard areas from LNG terminal;
h. scalable procedures for evacuating the public, including identification, location, design, and use of evacuation routes/methods and any mustering locations required to effectively and safely evacuate the public within hazard areas from LNG terminal; and
i. scalable procedures for sheltering the public, including identification, location, design, and use of any shelters demonstrated to be needed and demonstrated to effectively and safely shelter the public prior to onset of debilitating hazards within hazard areas that may better benefit from sheltering in place.

ELC and SLNG shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals.** ELC and SLNG shall file public versions of offsite emergency response procedures for public notification, evacuation, and shelter in place.

19. **Prior to initial site preparation,** ELC and SLNG shall file an updated Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. This comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. This plan shall include sustained funding of any requirement or resource gap(s) identified to effectively and safely evacuate and shelter the public and to effectively and safely respond to hazardous material incidents consistent with recommended and good engineering practices. ELC and SLNG shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its Cost Sharing Plan at **3-month intervals.**

20. **Prior to initial site preparation,** ELC and SLNG shall file buried pipeline and utility damage prevention procedures for personnel and contractors. The procedures shall include provisions to mark buried pipelines and utilities prior to any site work and subsurface activities.

21. **Prior to construction of final design,** ELC and SLNG shall file change logs that list and explain any changes made from the FEED provided in ELC and SLNG's application and filings. A list of all changes with an explanation for the design alteration shall be provided, and all changes shall be clearly indicated on all diagrams and drawings.

22. **Prior to construction of final design,** ELC and SLNG shall file information/revisions pertaining to ELC and SLNG's response numbers 27, 41 and 48 of their October 2, 2023 filing, which indicated features to be included or considered in the final design.

23. **Prior to construction of the final design,** ELC and SLNG shall file a re-evaluation technical report of seismic hazard analysis for the proposed project site. The report shall adequately incorporate the USGS foreseeable increase of ground motion and determine the finalized seismic design ground motion would be sufficient for the proposed project site.

24. **Prior to construction of the final design,** ELC and SLNG shall file a seismic monitoring program for the Project site. The seismic monitoring program shall comply with NFPA 59A (2019 edition) sections 8.4.14.10, 8.4.14.12, 8.4.14.12.1,

8.4.14.12.2, and 8.4.14.13; ACI 376 (2023 edition) sections 10.7.5 and 10.8.4; U.S Nuclear Regulatory Commission Regulatory Guide RG 1.12 (Revision 3) sections 1 and 3 through 9 and all subsections, or approved equivalents. A free-field seismic monitoring device shall be included in the seismic monitoring program for the Project site. Additional seismic instruments shall be considered for critical Structures, System, and Components. The proposed seismic monitoring system must include installation location plot plan; description of the triaxial strong motion recorders or other seismic instrumentation; the proposed alarm set points and operating procedures (including emergency operating procedures) for control room operators in response to such alarms/data obtained from seismic instrumentation; and testing and maintenance procedures.

25. **Prior to construction of final design,** ELC and SLNG shall file drawings of vehicle protections internal to the plant, such as guard rails, barriers, and bollards to protect transfer piping, pumps, compressors, hydrants, monitors, post indicator valves, etc. to ensure that the facilities would be protected from inadvertent damage from vehicles, unless the facilities are located sufficiently away from in-plant roadways and areas accessed by vehicle.

26. **Prior to construction of final design,** ELC and SLNG shall file updated drawings of the security fence that reflects the most up to date plot plan. The fencing drawings shall provide details of fencing that demonstrate it is in accordance with NFPA 59A (2019 edition) and would restrict and deter access around the entire facility and have a setback from exterior features (e.g., power lines, trees, etc.) and from interior features (e.g., piping, equipment, buildings, etc.) by at least 10 feet and that would not allow the fence to be overcome.

27. **Prior to construction of final design,** ELC and SLNG shall file a photometric analyses or equivalent and associated lighting drawing(s) for the condensate plant area. The lighting drawing(s) shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall depict illumination coverage in accordance with federal regulations (e.g., 49 CFR Part 193, 29 CFR Part 1910, and 29 CFR Part 1926) and API 540 or approved equivalent.

28. **Prior to construction of final design,** ELC and SLNG shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.

29. **Prior to construction of final design,** ELC and SLNG shall file three-dimensional plant drawings of the condensate plant to confirm plant layout for maintenance, access, egress, and the extent and density of congested areas used in overpressure modeling.

30. **Prior to construction of final design,** ELC and SLNG shall file up-to-date process flow diagrams (PFDs), heat and mass balances (HMBs), and piping and instrument diagrams (P&IDs) including vendor P&IDs. The HMBs shall demonstrate a peak export rate of 2.9 million metric tonnes per annum. The P&IDs shall include the following information:

    a. equipment tag number, name, size, duty, capacity, and design conditions;
    b. equipment insulation type and thickness;
    c. storage tank pipe penetration size and nozzle schedule;
    d. valve high pressure side and internal and external vent locations;
    e. piping with line number, piping class specification, size, and insulation type and thickness;
    f. piping specification breaks and insulation limits;
    g. all control and manual valves numbered;
    h. relief valves with size and set points; and
    i. drawing revision number and date.

31. **Prior to construction of final design**, ELC and SLNG shall file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities.

32. **Prior to construction of final design,** ELC and SLNG shall file a car seal and lock philosophy and car seal and lock program, including a list of all car-sealed and locked valves consistent with the P&IDs. The car seal and lock program shall include monitoring and periodically reviewing correct car seal and lock placement and valve position. The physical car seal to be used shall have sufficient mechanical strength to prevent unauthorized valve operation.

33. **Prior to construction of final design,** ELC and SLNG shall file information to verify how the EPC contractor has addressed all FEED HAZID recommendations.

34. **Prior to construction of final design,** ELC and SLNG shall file a hazard and operability (HAZOP) and any layer of protection analysis (LOPA) or safety integrity level (SIL) verification studies of the final design P&IDs, a list of the resulting recommendations, and action taken on the recommendations. The issued for construction P&IDs shall incorporate the HAZOP review and any LOPA or SIL verification studies recommendations and justification shall be provided for any recommendations that are not implemented.

35. **Prior to construction of final design,** ELC and SLNG shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (e.g., temperature, pressures, flows, and compositions).

36. **Prior to construction of final design,** ELC and SLNG shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

37. **Prior to construction of final design,** ELC and SLNG shall specify that all ESD valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS)/SIS.

38. **Prior to construction of final design,** ELC and SLNG shall file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications shall include:

    a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, blast resistant buildings);
    b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, other specialized equipment);
    c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable, other electrical and instrumentation); and
    d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, firewater).

39. **Prior to construction of final design,** ELC and SLNG shall file a final list of all applicable codes and standards that will be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the final specifications and document numbers.

40. **Prior to construction of final design,** ELC and SLNG shall file an evaluation of emergency shutdown valve closure times. The evaluation shall account for the time to detect an upset or hazardous condition, notify plant personnel, and close the emergency shutdown valve(s).

41. **Prior to construction of final design,** ELC and SLNG shall file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump operations that demonstrate that the surge effects do not exceed the design pressures or pipe support design loads.

42. **Prior to construction of final design,** ELC and SLNG shall file a pipe stress analysis for critical or potential higher consequence lines that evaluates all loads in ASME B31.3 (2020 edition), including but not limited to consideration of hazardous fluid lines that are cryogenic, high temperature, subject to slug flow, and that include 2-phase flow. ELC and SLNG shall also demonstrate, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.

43. **Prior to construction of final design,** ELC and SLNG shall file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. Additionally, sizing basis shall be provided for pressure relief valves protecting from overpressures due to mixed refrigerant compressor blocked outlet cases, and basis for necessity of thermal relief valves in non-cryogenic process piping.

44. **Prior to construction of final design,** ELC and SLNG shall specify that the common, non-spared process vessels are installed with spare pressure relief valves to ensure overpressure protection during relief valve testing or maintenance.

45. **Prior to construction of final design,** ELC and SLNG shall file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). The justification for the flammable and combustible gas detection and flame and heat detection systems shall be in accordance with ISA 84.00.07 or approved equivalent methodologies and would need to demonstrate 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de inventory within 10 minutes. The analysis shall take into account the set points, voting logic, wind speeds, and wind directions. The justification for firewater shall provide calculations for all firewater demands based on design densities, surface area, and throw distance as well as specifications for the corresponding hydrant and monitors needed to reach and cool equipment.

46. **Prior to construction of final design,** ELC and SLNG shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, tertiary containment and capacity calculations considering any foundations and equipment within impoundments. The spill containment drawings shall show containment for all hazardous fluids including all liquids handled above their

flashpoint, from the largest flow from a single line for 10 minutes, including de-inventory, or the maximum liquid from the largest vessel (or total of impounded vessels) or otherwise demonstrate that providing spill containment would not significantly reduce the flammable vapor dispersion or radiant heat consequences of a spill.

47. **Prior to construction of final design,** ELC and SLNG shall file electrical area classification drawings, including cross sectional drawings. The drawings shall demonstrate compliance with NFPA 59A, NFPA 70, NFPA 497, and API RP 500, or approved equivalents. In addition, the drawings shall include revisions to the electrical area classification design or provide technical justification that supports the electrical area classification using most applicable API RP 500 figures (i.e., figures 20 and 21) or hazard modeling of various release rates from equivalent hole sizes and wind speeds (see NFPA 497 release rate of 1 lb-mole/minute).

48. **Prior to construction of final design,** ELC and SLNG shall file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001) and NFPA 70 (1999 or 2020, as applicable).

49. **Prior to construction of final design,** ELC and SLNG shall file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that shall continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems. Alternatively, ELC and SLNG shall file details on a system providing an approved equivalent protection, in accordance with NFPA 59A (2023 edition), from the migration of flammable fluid through the electrical conduit or wiring.

50. **Prior to construction of final design,** ELC and SLNG shall file complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment as well as their coverage area. The list shall include the instrument tag number, type, manufacturer, model, location, alarm indication locations, and shutdown functions of the hazard detection equipment.

51. **Prior to construction of final design,** ELC and SLNG shall file an evaluation of the voting logic and voting degradation for hazard detectors.

52. **Prior to construction of final design,** ELC and SLNG shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas

of the hazard detectors when determining the set points that are intended to detect different gases or mixtures than the calibration gas.

53. **Prior to construction of final design,** ELC and SLNG shall file drawings and specifications detailing the installation of low oxygen detection in the nitrogen vaporizer area.

54. **Prior to construction of final design,** ELC and SLNG shall file a drawing showing the location of the emergency shutdown buttons associated with the Project. Emergency shutdown buttons shall be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.

55. **Prior to construction of final design**, ELC and SLNG shall file facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Plan drawings shall clearly show the location and elevation by tag number of all fixed, wheeled, and hand-held extinguishers and shall demonstrate the spacing of extinguishers meet prescribed NFPA 10 travel distances. The list shall include the equipment tag number, type, manufacturer and model, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units and shall demonstrate they meet NFPA 59A.

56. **Prior to construction of final design,** ELC and SLNG shall file drawings and specifications for new and relevant existing structural passive protection systems to protect equipment and supports from pool fires and from jet fires of design spills that may exacerbate the initial hazard, as well as electrical, instrument, and control equipment, which would activate emergency systems or would be relied upon for isolation to withstand a minimum 20-minute fire exposure, per UL 1709 (6th edition) or approved equivalent.

57. **Prior to construction of final design,** ELC and SLNG shall file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from pool or jet fires; each critical structural component and emergency equipment item that could fail within the 4,900 BTU/ft^2-hr zone from a pool or jet fire that could exacerbate the hazard. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires shall be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation shall be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation shall be supported by

reliability information by calculations or test results, such as demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the component. The total firewater demand shall account for all components that could fail due to a pool or jet fire.

58. **Prior to construction of final design,** ELC and SLNG shall file an analysis that evaluates and optimizes the firewater layout at the southern side of the Condensate Plant to provide adequate monitor coverage for any equipment whose failure could exacerbate the initial hazard, or alternatively demonstrate that equivalent or adequate fire mitigation would be provided. The firewater coverage shall be provided by at least two monitors or hydrants in the event that the fire prohibits the ability to use the one or more of the monitor(s) and/or hydrant(s).

59. **Prior to construction of final design**, ELC and SLNG shall file an analysis that demonstrates jet fire impacts on the main pipe rack due to release scenarios (e.g., design spills) from the Condensate Plant would not lead to failure of the structural steel or hazardous fluid containing lines within the main pipe rack that would exacerbate the initial hazard.

60. **Prior to construction of final design,** ELC and SLNG shall file facility plan drawings showing the proposed location of the firewater systems. Plan drawings shall clearly show the location of firewater piping, post indicator and sectional valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, water-mist system, and sprinkler. The drawings shall demonstrate that each process area, fire zone, or other sections of piping with several users can be isolated with post indicator or sectional valves in accordance with NFPA 24 (2022 edition) or approved equivalent, and that firewater coverage is provided by at least two monitors or hydrants with sufficient firewater flow to cool exposed surfaces subjected to a fire. The drawings shall also include piping and instrumentation diagrams of the firewater systems.

61. **Prior to commissioning**, ELC and SLNG shall file an updated maintenance plan for the storm surge wall. The maintenance plan shall include an annual elevation survey plan for the storm surge wall and shall consider relative sea level rise and settlements at the project site.

62. **Prior to construction of the final design,** ELC and SLNG shall file a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. ELC and SLNG shall file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be

issued.

63. **Prior to commissioning,** ELC and SLNG shall file detailed plans and procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.

64. **Prior to commissioning,** ELC and SLNG shall file the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions procedures, simultaneous operations procedures, and management of change procedures and forms. The operational maintenance and testing procedures for fire protection components shall be in accordance with NFPA 59A (2019) or approved equivalent.

65. **Prior to commissioning,** ELC and SLNG shall file a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice, and shall provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing.

66. **Prior to commissioning,** ELC and SLNG shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.

67. **Prior to commissioning,** ELC and SLNG shall file a plan to maintain a detailed training log to demonstrate that all staff have completed all required training for operating, maintenance, safety, security, and emergency response. In addition, ELC and SLNG shall file signed documentation that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation.

68. **Prior to commissioning,** ELC and SLNG shall file the procedures for pressure/leak tests which address the requirements of ASME BPVC Section VIII and ASME B31.3. In addition, ELC and SLNG shall file a line list of pneumatic and hydrostatic test pressures.

69. **Prior to introduction of hazardous fluids,** ELC and SLNG shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed.

70. **Prior to introduction of hazardous fluids,** ELC and SLNG shall complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS and SIS that demonstrates full functionality and operability of the system.

71. **Prior to introduction of hazardous fluids,** ELC and SLNG shall file an updated alarm management program to maximize the effectiveness of operator response to alarms in accordance with ISA 18.2 (2016 edition) or approved equivalent.

72. **Prior to introduction of hazardous fluids,** ELC and SLNG shall complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s).

73. **Prior to commencement of service,** ELC and SLNG shall notify the FERC staff of any proposed revisions to the security plan and physical security of the plant.

74. **Prior to commencement of service,** ELC and SLNG shall label piping with fluid service and direction of flow in the field, consistent with ASME A13.1 (2020 edition) or approved equivalent, in addition to the pipe labeling requirements of NFPA 59A (2001).

75. **Prior to commencement of service,** ELC and SLNG shall provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring.

76. **Prior to commencement of service,** ELC and SLNG shall develop and file procedures for offsite contractors' responsibilities, restrictions, monitoring, training, and limitations and for supervision of these contractors and their tasks by ELC and SLNG staff. Specifically, the procedures shall address:

    a. selecting a contractor, including obtaining and evaluating information regarding the contract employer's safety performance and programs.

    b. informing contractors of the known potential hazards, including flammable and toxic release, explosion, and fire, related to the contractor's work and systems they are working on.

    c. developing and implementing provisions to control and monitor the entrance, presence, and exit of contract employers and contract employees from process areas, buildings, and the plant.

    d. developing and implementing safe work practices for control of personnel safety hazards, including lockout/tagout, confined space entry, work permits, hot work, and opening process equipment or piping.

e. developing and implementing safe work practices for control of process safety hazards, including identification of layers of protection in systems being worked on, recognizing abnormal conditions on systems they are working on, and re-instatement of layers of protection, including ensuring bypass, isolation valve, and car-seal programs and procedures are being followed.

f. developing and implementing provisions to ensure contractors are trained on the emergency action plans and that they are accounted for in the event of an emergency.

g. monitoring and periodically evaluating the performance of contract employers in fulfilling their obligations above, including successful and safe completion of work and re-instatement of all layers of protection.

In addition, we recommend that the following measures shall apply <u>throughout the life of the Elba Liquefaction Optimization Project</u>.

77. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual** basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, ELC and SLNG shall respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted.

78. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tank, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the

effect on the facility also shall be reported. Reports shall be submitted within **45 days after each period ending June 30 and December 31.** In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance at the LNG facilities.

79. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to the FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately,** without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to the **FERC staff within 24 hours.** This notification practice shall be incorporated into the liquefaction facility's emergency plan. Examples of reportable hazardous fluids-related incidents include:

    a. fire;
    b. explosion;
    c. estimated property damage of $50,000 or more;
    d. death or personal injury necessitating in-patient hospitalization;
    e. release of hazardous fluids for 5 minutes or more;
    f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;
    g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;
    h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure-limiting or control devices;
    i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;
    j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, the FERC staff would determine the need for a separate follow- up report or follow up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident.

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LIST OF PREPARERS

Bathrick, Karla – LNG Reliability and Safety
M.E., Environmental Eng./Project Management, University of Maryland, 2008
B.S., Chemical Engineering, University of Maryland, 2003

Cornwall, Joel – Geology, Soils, Groundwater Resources
M.S., Hydrogeology, 2014, University of South Florida
B.S., Geology, 2002, Western Washington University

Dague, Brady – LNG Reliability and Safety
B.S., Civil Engineering, University of Maryland, 2010

Koirala, Shesh – LNG Reliability and Safety
Ph.D., Civil and Environmental Engineering, University of Tennessee, Knoxville, TN 2007
M.A., Geography, Western Illinois University, Macomb, IL, 2003
B.E., Civil Engineering, Tribhuvan University, Nepal, 1997

McDaniel, Nina – Air Quality, Noise, Safety and Reliability
M.S., Engineering Management, 2012, University of New Orleans
B.S., Civil Engineering, 2010, University of New Orleans

Plummer, Amber – Surface Waters, Wetlands, Vegetation, Wildlife, and Listed species
M.S., Environmental Biology, 2020 Hood College
B.S., Environmental Science, 2016, Towson University

Polit, Juan — Socioeconomics and Environmental Justice
M.S., Forest Ecology, 1992, University of Illinois
B.S., Forest Science, 1989, University of Illinois

Telci, Ilker – LNG Reliability and Safety
Ph.D., Environmental Engineering, Georgia Institute of Technology, 2012
M.S., Environmental Engineering, Georgia Institute of Technology, 2010
M.S., Civil Engineering, Middle East Technical University, Turkey, 2002
B.S., Civil Engineering, Middle East Technical University, Turkey, 1999

Washington, Charlotte – LNG Reliability and Safety
B. S., Mechanical Engineering, University of Houston
B. S., Chemical Engineering, Mississippi State University

Wazaney, Brad – Project Manager, Project Description, Land Use, Alternatives, and Cultural Resources

Ph.D., Anthropology, 2006, Washington State University
M.A., American Studies, 2001, University of Wyoming
B.A., History, 1996, Old Dominion University

APPENDIX A:

PROJECTS POTENTIALLY CONTRIBUTING TO CUMULATIVE IMPACTS WITH THE ELBA LIQUEFACTION OPTIMIZATION PROJECT

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PROJECTS POTENTIALLY CONTRIBUTING TO CUMULATIVE IMPACTS WITH THE ELBA LIQUEFACTION OPTIMIZATION PROJECT

Project Name	Project Developer	Project Type	Project Overview	Distance to Project	Status (Past Present, Future)
Projects Affecting ELC and SLNG's Assets in Chatham County					
GPA O&M Building	Southern Natural Gas (SNG)	LNG	SNG is relocating approximately 1,566 linear ft. of Wrens-Savannah Line to accommodate construction of the Georgia Port Authority O&M Building Project. The pipeline within existing ROW will be abandoned in place. Relocated pipeline will be placed within newly granted ROW and constructed using ATWS. Land disturbance is estimated at 3 acres.	8.75 miles	Present
SNG Maintenance, Pressure Test Stone Container Line	SNG	LNG	SNG is pressure testing the SNG Stone Container line in Savannah which runs between multiple railroad track, warehouses, and terminates at a meter station on International Paper property.	10.3 miles	Present
SNG maintenance Wrens-Savannah 2nd Loop Line	SNG	LNG	SNG is conducting anomaly dig inspections along the 2nd Loop line from Wrens to Port Wentworth.	14.25 miles	Present
Georgia Department of Transportation Projects (GDOT)					
CR 787/Islands Expressway at Wilmington River/Bascule Bridge	GDOT	Transportation	The project replaces the existing Island Expressway bridges over the Wilmington River with two fixed span structures. Project will improve traffic efficiency.	2.65 miles	Present
GDOT Brampton Road Connector	Georgia Department of Transportation (GDOT)	Transportation	The proposed project consists of a 2035 linear ft. relocation of the SNG 14-inch Wrens-Savannah Line to accommodate a GDOT Highway Project,	8.1 miles	Future
SR 26 from east of CS 188/Ogeechee Road to Wilmington River	GDOT	Transportation	The maintenance project is the resurfacing at SR 26 to improve the roadway's current low Pavement Surface Evaluation and Rating.	5.20 miles	Future
CS 1097/Delesseps/La Roche Ave from Waters Ave to Skidaway Rd	GDOT	Transportation	The project adds curb and gutters, sidewalks, and storm drainage. From the east side of Truman Parkway to Skidaway Rd 4-ft bike lanes is being constructed	6.55 miles	Present
SR 26 FM / Pulaski Rd to Byers Street	GDOT	Transportation	Reconstruction/Rehabilitation Projevt on SR 26 FM west of Ft Pulaski Road west of Byers Street	7.40 miles	Present

Project Name	Project Developer	Project Type	Project Overview	Distance to Project	Status (Past Present, Future)
Chatham County Engineering Department (CCED)					
Island Expressway at Oatland Island Road	CCED	Safety	This operational improvement project would shift the connection between Islands Expressway and Oatland Island Road on the north side and add turn lanes to improve the function and safety of the intersection.	2.35 miles	Future
US 80 Whitemarsh Island Sidewalk	CCED	Safety	This is a proposed project to construct a new sidewalk/path along Highway 80 from Johnny Mercer Boulevard to Whitemarsch Village Way	2.95 miles	Future
Johhny Mercer at Lyman Hall Intersection Improvements	CCED	Safety	A new traffic signal and improvements are proposed at the intersection of Johnny Mercer Boulevard and Lyman Hall Road	3.22 miles	Future
US Army Corps of Engineers Projects (USACE)					
Upper Savannah Harbor Maintenance Dredging	USACE	Transportation	The project's purpose is to maintain depths at the existing berths to provide sufficient underkeel clearance for the vessels that call on the facilities. The project will annually remove accumulated sediment from 33 existing facilities.	5.9 miles	Present

APPENDIX B:

RELIABILITY AND SAFETY

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RELIABILITY AND SAFETY

B.1 TERMINAL FACILITIES

B.1.1 LNG Facility Reliability, Safety, and Security Regulatory Oversight

LNG facilities handle flammable and sometimes toxic materials that can pose a risk to the public if not properly managed. These risks are managed by the companies owning the facilities, through selecting the site location and plant layout, as well as through suitable design, engineering, construction, and operation of the LNG facilities. Multiple federal agencies share regulatory authority over the LNG facilities and the operator's approach to risk management. The safety, security, and reliability of the Elba Liquefaction Optimization (ELO) Project (Project) would be regulated by PHMSA, the Coast Guard, and the FERC.

In February 2004, PHMSA, the Coast Guard, and the FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals and LNG marine vessel operations and maximizing the exchange of information related to the safety and security aspects of LNG facilities and related marine operations. Under the Interagency Agreement, the FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with terminal construction and operation. PHMSA and the Coast Guard participate as cooperating agencies but remain responsible for enforcing their regulations covering LNG facility siting, design, construction, operation, and maintenance. All three agencies have some oversight and responsibility for the inspection and compliance during the LNG facility's operation.

PHMSA establishes and has the authority to enforce the minimum federal safety standards for the location, design, installation, construction, inspection, testing, operation, and maintenance of onshore LNG facilities under the Natural Gas Pipeline Safety Act (49 USC 1671 et seq.). PHMSA's LNG safety regulations are codified in 49 CFR 193, which prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to federal pipeline safety laws (49 USC 60101 et seq.), and 49 CFR 192. On August 31, 2018, PHMSA and FERC signed a MOU regarding methods to improve coordination throughout the LNG permit application process for FERC jurisdictional LNG facilities. In the MOU, PHMSA agreed to issue an LOD stating whether a proposed LNG facility would be capable of complying with the siting requirements in Subpart B of Part 193. The Commission committed to relying upon the PHMSA's determination in conducting its review of whether the facilities would be consistent with the public interest. The issuance of the LOD does not abrogate PHMSA's continuing authority and responsibility over a proposed project's compliance with Part 193 during construction and future operation of the facility. PHMSA's conclusion on the siting and hazard analysis required by Part 193 is based on preliminary design information which may be revised as the engineering design progresses to final design. PHMSA regulations also contain requirements for the design, construction, installation, inspection, testing, operation, maintenance, qualifications and training of personnel, fire protection, and security for LNG facilities as defined in 49 CFR 193, which would be completed during later stages of the Project. If the Project is authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, would be subject to PHMSA's inspection and enforcement programs to ensure compliance with the requirements of 49 CFR 193.

The Coast Guard has authority over the safety of an LNG terminal's marine transfer area and LNG marine vessel traffic, as well as over security plans for the waterfront facilities handling LNG and LNG marine vessel traffic. The Coast Guard regulations for waterfront facilities handling LNG are codified in 33 CFR 105 and 33 CFR 127. As a cooperating agency, the Coast Guard assists the FERC staff in evaluating whether an applicant's proposed waterway would be suitable for LNG marine vessel traffic and whether the waterfront facilities handling LNG would be operated in accordance with 33 CFR 105 and 33 CFR 127. The Project would result in no physical modifications to the existing marine facilities. In addition, although the Project would use approximately 3 to 4 more LNG marine vessels per year than current operations, those would be within the number of LNG marine vessels previously analyzed in the existing Waterway Suitability Assessment (WSA) and Letter of Recommendation (LOR). Therefore, a new LOR would not be required from the Coast Guard. If the facilities are modified and become operational as designed, the facilities would continue to be subject to the Coast Guard inspection program to ensure compliance with the requirements of 33 CFR 105 and 33 CFR 127.

FERC authorizes the siting and construction of LNG terminals under the NGA and delegated authority from the DOE. The FERC requires standard information to be submitted to perform safety and reliability engineering reviews. FERC's filing regulations are codified in 18 CFR § 380.12 (m) and (o) and requires each applicant to provide information on the reliability and safety of its facilities and engineering design, including how its proposed design would comply with DOT PHMSA requirements in 49

CFR Part 193.[50] In addition, FERC's *Guidance Manual for Environmental Report Preparation*[51] (2017 Guidance Manual) for applications filed under the Natural Gas Act, Volume II, issued February 2017, clarifies the level of information needed for our evaluation of the hazards associated with proposed LNG facilities per 18 CFR § 380.12 (m) and (o). The level of detail necessary for the reliability, safety, and engineering information requires the applicant to perform substantial front-end engineering of the complete project. The design information is required to be site-specific and developed to the extent that further detailed design would not result in significant changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs. As part of the review required for a FERC order, we use this information from the applicant to assess whether the proposed facilities would have a public safety impact and to suggest additional mitigation measures for the Commission to consider for incorporation as conditions in the order. If the facilities are approved and the suggested mitigation measures are incorporated into the order as conditions, FERC staff would review material filed to satisfy the conditions of the order and conduct periodic inspections throughout construction and operation.

In addition, the EPAct of 2005 requires FERC to coordinate and consult with the DOD on the siting, construction, expansion, and operation of LNG terminals that would affect the military. On November 21, 2007, the FERC and the DOD entered into a MOU formalizing this process.[52] On October 13, 2023, the FERC received a response letter from the DOD Military Aviation and Installation Assurance Siting Clearinghouse indicating that the Project would have a minimal impact on military operations conducted in the area.

B.1.2 PHMSA Siting Requirements and 49 CFR Part 193 Subpart B Determination

Siting LNG facilities, as defined in 49 CFR 193, to ensure that the proposed site selection and location would not pose an unacceptable level or risk to the safety of plant personnel and the public is required by the PHMSA's regulations in 49 CFR 193 Subpart B. The Commission's regulations under 18 CFR § 380.12 (o) (14) require ELC and SLNG to identify how the proposed design complies with the applicable federal, state,

[50] Effective December 29, 2023, 18 CFR §380.12 (o) (14) was updated to require applicants to identify all federal, state, and local regulations and requirements that are applicable to the project. In addition, the update required applicants to explain how the project would comply with the applicable regulations, including codes and standards incorporated by reference. In nearly all cases, including this Project, 49 CFR 193 will still be the applicable federal regulations that apply to import and export terminals. Furthermore, 18 CFR §380.12 (o) (15) was updated to codify existing practice for geotechnical investigations and for evaluating seismic and other natural hazards.

[51] FERC's *Guidance Manual for Environmental Report Preparation*, Volume II, https://www.ferc.gov/sites/default/files/2020-04/guidance-manual-volume-2.pdf, accessed February 2024.

[52] Memorandum of Understanding between the FERC and US DOD to ensure consultation and coordination on effect of LNG Terminals on Active Military Installations, https://www.ferc.gov/media/2007-mou-dod, accessed January 2024.

and local siting requirements, including PHMSA's regulations under 49 CFR 193 Subpart B. The scope of PHMSA's siting authority under 49 CFR 193 applies to LNG facilities used in the transportation of gas by pipeline subject to the federal pipeline safety laws and 49 CFR 192.[53]

The regulations in 49 CFR 193 Subpart B require the establishment of an exclusion zone surrounding an LNG facility in which an operator or government agency must exercise legal control over the activities where specified levels of thermal radiation and flammable vapors may occur in the event of a release for as long the facility is in operation. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The siting requirements specified in NFPA 59A (2001), an industry consensus standard for LNG facilities, are incorporated by reference into 49 CFR 193 Subpart B by reference, with regulatory preemption in the event of conflict. The following sections of 49 CFR 193 Subpart B specifically address siting requirements:

- Section 193.2051, Scope, states that each LNG facility designed, constructed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.
- Section 193.2057, Thermal radiation protection, requires that each LNG container and LNG transfer system have a thermal exclusion zone in accordance with section 2.2.3.2 of NFPA 59A (2001).
- Section 193.2059, Flammable vapor-gas dispersion protection, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001).
- Section 193.2067, Wind forces, requires that shop fabricated containers of LNG or other hazardous fluids less than 70,000 gallons must be designed to withstand wind forces based on the applicable wind load data in American Society of Civil Engineers (ASCE) 7 (2005). All other LNG facilities must be designed for a sustained wind velocity of not less than 150 mph unless the PHMSA Administrator finds a lower wind speed is justified or 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

[53] 49 CFR § 193.2001 (b) (3), Scope of part, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the LNG marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

less, if adequate wind data are available and the probabilistic methodology is reliable (a 10,000-year mean return interval).

As stated in 49 CFR § 193.2051, under Subpart B, LNG facilities must meet the siting requirements of NFPA 59A (2001), Chapter 2, which include but are not limited to:

- NFPA 59A (2001) section 2.1.1 (c) requires consideration of protection against forces of nature.
- NFPA 59A (2001) section 2.1.1 (d) requires that other factors applicable to the specific site that have a bearing on the safety of plant personnel and surrounding public be considered, including an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility.
- NFPA 59A (2001) section 2.2.3.2 requires provisions to minimize the damaging effects of fire from reaching beyond a property line and requires provisions to prevent a radiant heat flux level of 1,600 British thermal units per square foot per hour (Btu/ft^2-hr) for ignition of a design spill and fire over an impounding area from reaching beyond a property line that can be built upon. The distance to this flux level is to be calculated with LNGFIRE3 or with models that have been validated by experimental test data appropriate for the hazard to be evaluated and that have been approved by PHMSA.
- NFPA 59A (2001) section 2.2.3.4 requires provisions to minimize the possibility of any flammable mixture of vapors from a design spill from reaching a property line that can be built upon and that would result in a distinct hazard. Determination of the distance that the flammable vapors extend is to be determined with DEGADIS or approved alternative models that take into account physical factors influencing LNG vapor dispersion.[54]

NFPA 59A (2001) also specifies three radiant heat flux levels which must be considered for the damaging effects of fire from the LNG storage tank impounding areas for as long as the facility is in operation:

[54] PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones in accordance with 49 CFR § 193.2059: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Version 6.6 and 6.7 (Oct. 7, 2011). On April 13, 2023, PHMSA also approved PHAST Version 8.4.

- 1,600 Btu/ft^2-hr - This level can extend beyond the plant property line that can be built upon but cannot include areas that are used for outdoor assembly by groups of 50 or more persons;[55]
- 3,000 Btu/ft^2-hr - This level can extend beyond the plant property line that can be built upon but cannot include areas that contain assembly, educational, health care, detention or residential buildings or structures;[56] and
- 10,000 Btu/ft^2-hr - This level cannot extend beyond the plant property line that can be built upon.[57]

NFPA 59A (2001) requires the design spill be determined in accordance with Table 2.2.3.5. For containers, design spills are based upon the largest flow from any single line or penetration below the liquid level resulting in the largest flow from an initially full container. For impounding areas serving only vaporization, process, or LNG transfer areas, the design spill is based on any single accidental leakage source. However, NFPA 59A (2001) does not define a single accidental leakage source. In order to clarify single accidental leakage source, PHMSA provides guidance on the determination of single accidental leakage sources on their website of frequently asked questions, which indicate use of 2-inch diameter holes in piping 6 inches in diameter or larger and full guillotine ruptures of piping less than 6 inches in diameter and full guillotine ruptures of transfer hoses and single ply expansion bellows. In addition, section 2.1.1 of NFPA 59A (2001) requires that factors applicable to the specific site with a bearing on the safety of plant personnel and the surrounding public must be considered, including an evaluation of potential incidents and safety measures incorporated into the design or operation of the facility. PHMSA has indicated that potential incidents, such as vapor cloud explosions and toxic releases should be considered to comply with Part 193 Subpart B.[58]

In accordance with the August 31, 2018 MOU, PHMSA issued an LOD on February 7, 2024 to the Commission on the 49 CFR 193 Subpart B siting requirements.

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[55] The 1,600 Btu/ft^2-hr flux level is associated with producing pain in less than 15 seconds, first degree burns in 20 seconds, second degree burns in approximately 30 to 40 seconds, 1 percent mortality in approximately 120 seconds, and 100 percent mortality in approximately 400 seconds, assuming no shielding from the heat, and is typically the maximum allowable intensity for emergency operations with appropriate clothing based on average 10-minute exposure.

[56] The 3,000 Btu/ft^2-hr flux level is associated with producing pain in less than 5 seconds, first degree burns in 5 seconds, second degree burns in approximately 10 to 15 seconds, 1 percent mortality in approximately 50 seconds, and 100 percent mortality in approximately 180 seconds, assuming no shielding from the heat, and is typically the critical heat flux for piloted ignition of common building materials (e.g., wood, PVC, fiberglass, etc.) with prolonged exposures.

[57] The 10,000 Btu/ft^2-hr flux level is associated with producing pain in less than 1 seconds, first degree burns in 1 seconds, second degree burns in approximately 3 seconds, 1 percent mortality in approximately 10 seconds, and 100 percent mortality in approximately 35 seconds, assuming no shielding from the heat, and is typically the critical heat flux for unpiloted ignition of common building materials (e.g., wood, PVC, fiberglass) and degradation of unprotected process equipment after approximate 10 minute exposure and to reinforced concrete after prolonged exposure.

[58] PHMSA's "LNG Plant Requirements: Frequently Asked Questions" item H1, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions , accessed January 2024.

The LOD provided PHMSA's analysis and conclusions regarding the proposed Project's compliance with 49 CFR 193 Subpart B for the Commission to consider in its decision to authorize, with or without modification or conditions, or deny an application.

B.1.3 Coast Guard Safety Regulatory Requirements

The USCG exercises regulatory authority over LNG marine vessels under 46 CFR Part 154, which contains the United States safety standards for self-propelled LNG marine vessels transporting bulk liquefied gases and require documents to certify that the LNG marine vessel is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG marine vessels under 46 CFR Part 154. The USCG also exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 U.S.C. section 191); the Ports and Waterways Safety Act of 1972, as amended (33 U.S.C. section 1221, et seq.); and the Maritime Transportation Security Act (MTSA) of 2002 (46 U.S.C. section 701). The USCG is responsible for matters related to navigation safety, LNG marine vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The USCG also has authority for LNG facility security plan review, approval, and compliance verification as provided in 33 CFR Part 105.

The USCG regulations in 33 CFR Part 127 apply to the marine transfer area of waterfront facilities between the LNG marine vessel and the last manifold or valve immediately before the receiving tanks. Title 33 CFR Part 127 applies to the marine transfer area for LNG of each new waterfront facility handling LNG and to new construction in the marine transfer areas for LNG of each existing waterfront facility handling LNG. The scope of the regulations include the design, construction, equipment, operations, inspections, maintenance, testing, personnel training, and firefighting of the marine transfer area of LNG waterfront facilities. The safety systems, including communications, emergency shutdown, gas detection, and fire protection, must comply with the regulations in 33 CFR Part 127. Under 33 CFR §127.019, the existing Elba LNG facility has already submitted copies of its Operations and Emergency Manuals to the USCG Captain of the Port (COTP) for examination. The Project proposes no changes to the berths, ship transit routes, or the maximum number of ships previously evaluated for the existing WSA. As such, on September 27, 2023,[59] the USCG issued a letter which states the Project is not required to submit an LOI and the facility's existing WSA and LOR are adequate for the proposed project. Therefore, the ship transit, related hazards,

[59] Accession Number 20231002-5362, Enclosure 1 Attachments.

and WSA are not under the scope of this project. Modifications, including process conditions and resultant changes in risks (i.e., likelihood and/or consequences), have a negligible or no impact to the marine transfer piping, transfer arms, or other aspects jurisdictional to USCG. Those that relate to security are summarized below.

B.1.4 LNG Facility Security Regulatory Requirements

The security requirements for the proposed Project are governed by 33 CFR Part 105 and 49 CFR Part 193 Subpart J - Security. Title 33 CFR Part 105, as authorized by the MTSA, requires all terminal owners and operators to submit a Facility Security Assessment (FSA) and a Facility Security Plan (FSP) to the USCG for review and approval before commencement of operations of the proposed project facilities. The SLNG Terminal is currently operating with a USCG-approved FSP. Any updates to the existing FSP would need to be coordinated with the USCG in accordance with 33 CFR Part 105. Similar to the existing SLNG Terminal, for the proposed Project, ELC and SLNG would also be required to control and restrict access, patrol and monitor the plant, detect unauthorized access, and respond to security threats or breaches under 33 CFR Part 105. Some of the responsibilities of the applicant include, but are not limited to:

- designating a Facility Security Officer with a general knowledge of current security threats and patterns, security assessment methodology, vessel and facility operations, conditions, security measures, emergency preparedness, response, and contingency plans, who would be responsible for implementing the FSA and FSP and performing an annual audit for the life of the Project;
- conducting a FSA to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures; developing a FSP based on the FSA, with procedures for: responding to transportation security incidents; notification and coordination with federal, state, and local authorities; prevention of unauthorized access; measures to prevent or deter entrance with dangerous substances or devices; training; and evacuation;
- defining the security organizational structure with facility personnel with knowledge or training in current security threats and patterns; recognition and detection of dangerous substances and devices, recognition of characteristics and behavioral patterns of persons who are likely to threaten security; techniques to circumvent security measures; emergency procedures and contingency plans; operation, testing, calibration, and maintenance of security equipment; and inspection, control, monitoring, and screening techniques;
- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, LNG marine vessel stores and bunkers, and monitoring; ensuring

that the Transportation Worker Identification Credential (TWIC) program is properly implemented;

- ensuring coordination of shore leave for LNG marine vessel personnel or crew change out as well as access through the facility for visitors to the LNG marine vessel;
- conducting drills and exercises to test the proficiency of security and facility personnel on a quarterly and annual basis; and
- reporting all breaches of security and transportation security incidents to the National Response Center.

Title 33 CFR Part 127 has requirements for lighting and emergency power. In addition, an LNG facility regulated under 33 CFR Part 105 would be subject to the TWIC Reader Requirements Rule issued by the USCG on August 23, 2016. This rule requires owners and operators of certain vessels and facilities regulated by the USCG to conduct electronic inspections of TWICs (e.g., readers with biometric fingerprint authentication) as an access control measure. The final rule would also include recordkeeping requirements and security plan amendments that would incorporate these TWIC requirements. The USCG's June 22, 2018 notice initially delayed the effective date to implement this rule to August 23, 2021. Subsequently, USCG's March 9, 2020 final rule delayed the effective date to implement requirements for electronic inspections of TWICs for facilities that handle certain dangerous cargoes in bulk and transfer such cargoes from or to a vessel to May 8, 2023. On April 17, 2023, USCG's final rule further delayed the effective date to implement these TWIC requirements to May 8, 2026. Although the implementation of this rule has been postponed, the company should consider the rule when developing access control and security plan provisions for the facility.

Title 49 CFR Part 193 Subpart J also specifies security requirements for the onshore components of LNG facilities, as defined in 49 CFR Part 193, including requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources, and warning signs. If the Project is authorized, constructed, and operated, it would be subject to the security requirements of 33 CFR Part 105 and 49 CFR Part 193 Subpart J and the respective USCG and PHMSA inspection and enforcement programs.

The Project would be constructed entirely within the existing SLNG Terminal site. ELC and SLNG indicate that the Project would not require any changes to the existing security plan and existing physical security features such as security fencing and camera coverage. However, we note that the security fencing and the camera coverage drawings would need to be updated to include the new proposed facilities. Therefore, we recommend in section 5 that ELC and SLNG provide updated security fencing and camera coverage drawings that reflect the Project facilities. ELC and SLNG also provide that facility lighting in the MMLS unit and LNG rundown areas are sufficient and would not require any additional lighting. However, ELC and SLNG provided a modified lighting plan for the proposed condensate plant area and confirmed the existing lighting provided in the proposed condensate plant area was designed in accordance with API 540 requirements. We reviewed drawings of the existing facility and while we believe the existing system provides adequate security to the existing facility and proposed Project, we recommend in section 5 that ELC and SLNG provide final design details, for review and approval, of the modified lighting design for the proposed condensate plant area. The final design of the modified lighting plan should include a photometric analyses or equivalent and associated lighting coverage drawing that illustrates the lux levels in accordance with API 540 and applicable federal regulations.

Additionally, during construction of the Project, the primary security concern would be ensuring that the operational portions of the plant are secured from construction and contractor personnel. ELC and SLNG's application did not address how unauthorized personnel would be prevented from entering the operational portions of the plant. During detailed design, ELC and SLNG should develop measures that prevent unauthorized personnel from entering the operational areas of the facility (e.g., installation of hard barricades and/or temporary fencing, security at ingress and egress points between the construction site and operational site, identification badging, etc.), and would need to develop plans to perform construction activities within a secure facility with respect to SLNG's existing USCG-approved FSP. Therefore, we recommend in section 5 that, prior to initial site preparation, ELC and SLNG should file, for review and approval, procedures for controlling access during construction. The procedures should address how unauthorized construction personnel would be restricted from entering the operational areas of the plant.

As part of their application to FERC, ELC and SLNG indicates the Project would not include proposed changes to the cybersecurity plans provided in the Liquefaction Project (Docket No. CP14-103). In response to staff data request, ELC and SLNG indicated the relevant standards used to develop the existing cybersecurity plans. ELC and SLNG provided the frequency interval the cybersecurity plan is reviewed. They indicated that the Elba facility is regulated under Maritime Transportation Security Act (MTSA). Owners and operators have the responsibility for establishing policy, procedures, and controls to guard against cybersecurity threats to energy system architectures. Government agencies establish regulatory requirements and coordinate and share threat information, promote best protection practices, and help improve energy sector response for mitigation of adverse impacts. The National Institute of Standards and Technology (NIST) also has legal authorities for researching and developing cybersecurity standards, guidelines, and best practices. Nearly all of the government agencies authorized for security are under the Department of Homeland Security (DHS). The DHS Cybersecurity and Infrastructure Security Agency leads the effort in defending against cybersecurity threats to U.S. infrastructure and partners with private sector facility owners/operators to detect and mitigate cyber threats and vulnerabilities.[3] In addition, under the MTSA of 2002, 46 U.S.C. 2101, the USCG within DHS has authority to establish security requirements for any structure or facility of any kind located in, on, under, or adjacent to any waters subject to the jurisdiction of the United States. The USCG has codified these requirements under 33 CFR parts 104 and 105 and has issued NVIC 01-20, Guidelines for Addressing Cyber Risks at MTSA Regulated Facilities, which establishes requirements to assess and address computer system or network vulnerabilities in the Facility Security Assessment under 33 CFR Part 105. The DHS Transportation Security Administration (TSA) is also assessing its programs related to cybersecurity oversight for pipelines and other transportation infrastructure. On November 30, 2022, TSA published an advance notice of proposed rulemaking titled, Enhancing Surface Cyber Risk Management, under TSA Docket No TSA-2022-0001. The notice requested input on how the pipeline sector, including natural gas facilities, implements cyber risk management in its operations so that TSA has a better understanding for developing a comprehensive and forward-looking approach to cybersecurity requirements for its jurisdictional facilities. The extended comment period for the Advanced Notice of Proposed Rulemaking ended on February 1, 2023, and a Notice of Proposed Rulemaking has not been published. Also, the Department of Energy (DOE), Federal Bureau of Investigations (FBI) under the Department of Justice, Central Intelligence Agency (CIA), National Security Agency (NSA)/Central Security Service (CSS), and Department of Defense (DoD) have legal authorities for intelligence, counterintelligence, and/or response for physical and cyber security.

Furthermore, in accordance with the February 2004 Interagency Agreement among FERC, PHMSA, and USCG, FERC staff would collaborate with the USCG and PHMSA on the Project's security features including but not limited to any cybersecurity vulnerabilities identified by FERC staff.

B.1.5 FERC Engineering and Technical Review of the Preliminary Engineering Designs

LNG Facility Historical Record

The operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment with the exception of the October 20, 1944, failure at an LNG plant in Cleveland, Ohio. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people.[60] The failure of the LNG storage tank was due to the use of materials not suited for cryogenic temperatures. LNG migrated through streets and into underground sewers due to inadequate spill impoundments at the site. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used in the design and that spill impoundments are designed and constructed properly to contain a spill at the site. To ensure that this potential hazard would be addressed for proposed LNG facilities, we evaluate the preliminary and final specifications for suitable materials of construction and for the design of spill containment systems that would properly contain a spill at the site.

Another operational accident occurred in 1979 at the Cove Point LNG plant in Lusby, Maryland. A pump electrical seal located on a submerged electrical motor LNG pump leaked causing flammable gas vapors to enter an electrical conduit and settle in a confined space. When a worker switched off a circuit breaker, the flammable gas ignited, causing severe damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident led to changes in the national fire codes to better ensure that the situation would not occur again. To ensure that this potential hazard would be addressed for proposed facilities that have electrical seal interfaces, we evaluated the preliminary designs and recommend in section 5 that ELC and SLNG provide, for review and approval, the final design details of the electrical seal design at the interface between flammable fluids and the electrical conduit or wiring system, details of the electrical seal leak detection system, and the details of a downstream physical break (i.e., air gap or approved equivalent) in the electrical conduit to prevent the migration of flammable vapors.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction plant that killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced into a high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40 and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard would be addressed for proposed facilities, in the Spacing and Layout section below, we evaluated the preliminary design philosophy for mitigation of flammable vapor

[60] For a description of the incident and the findings of the investigation, *see* "U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944," dated February 1946.

dispersion and ignition in buildings and combustion equipment to ensure these facilities would be adequately covered by hazard detection equipment that could isolate and deactivate any ventilation or combustion equipment whose continued operation could add to or sustain an emergency. We also recommend in section 5 that ELC and SLNG provide, for review and approval, the final design details of hazard detection equipment, including their locations and elevations, instrument tag numbers, types, alarm indication locations, and shutdown functions.

On March 31, 2014, a detonation occurred within a gas heater at Northwest Pipeline Corporation's LNG peak-shaving plant in Plymouth, Washington.[61] This internal detonation subsequently caused the failure of pressurized equipment, resulting in high velocity projectiles. The plant was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No members of the public were injured, but one worker was sent to the hospital for injuries. As a result of the incident, the liquefaction trains and a compressor station located onsite were rendered inoperable. Projectiles from the incident also damaged the control building that was located near pre-treatment facilities and penetrated the outer shell of one of the LNG storage tanks. All damaged facilities were ultimately taken out of service for repair. The accident investigation showed that an inadequate purge after maintenance activities resulted in a fuel-air mixture remaining in the system. The fuel-air mixture auto-ignited during startup after it passed through the gas heater at full operating pressure and temperature. To ensure that this potential hazard would be addressed for proposed facilities, we recommend in Commissioning, Schedule, Plans and Procedures clean-out, dry-out, purging and tightness testing be in accordance with American Gas Association's *Purging Principles and Practice*, and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing. In addition, we recommend in Inspection, Testing, and Maintenance Plans and Procedures to file all maintenance plans and procedures, which would need to follow American Gas Association's *Purging Principles and Practice* and against other recommended and generally accepted good engineering practices, such as NFPA 56, *Standard for Fire and Explosion Prevention during Cleaning and Purging of Flammable Gas Piping Systems*. Also, in order to prevent other sources of projectiles from affecting occupied buildings and storage tanks, we discuss and recommend in later sections for ELC and SLNG to incorporate mitigation into their final design with supportive information, for review and approval, that demonstrates it would mitigate the risk of a pressure vessel burst or boiling liquid expanding vapor explosion (BLEVE) from occurring and for the tanks to withstand projectiles of a certain risk.

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[61] For a description of the incident and the findings of the investigation, *see* Root Cause Failure Analysis, Plymouth LNG Plant Incident Investigation under Docket No. CP14-515.

On June 8, 2022, a pipe rupture and subsequent fireball and fire occurred at Freeport LNG Development, L.P.'s (Freeport LNG) terminal near Quintana, Texas. The energy release from the pipe rupture damaged adjacent process piping and compromised nearby electrical wiring that likely ignited the released gases to form a fireball and subsequent onsite fires. The resulting fires were extinguished in approximately 40 minutes after the initial pipe rupture. The incident did not injure onsite personnel, visitors, or members of the public. The incident investigation found that an LNG filled piping segment was blocked off, and operators associated with the pressure relief valve testing failed to re-open and car seal the stop valve used to isolate and test the pressure relief valve. Furthermore, operators were trained to assist contractors led PSV testing by observing more experienced operators, but were provided no further training or procedures. As a result, ambient heat leak warmed and expanded the LNG without it having a pressure relief valve protecting it, and the piping segment underwent a BLEVE and ruptured. [62] To address this potential hazard for the proposed facilities, we recommend in Operational Plans and Procedures to incorporate a car seal program and contractor oversight. We also re-emphasize the training requirements in regulations to ensure supervisors only assign personnel tasks who are qualified by training and experience unless supervised by a qualified operator. Other lessons learned from contributing factors would also be applied to the review of recommendations related to other layers of protection to ensure their effectiveness and reliability, such as ensuring maintenance procedures refer back to car seal requirements and procedures, ensuring management of change procedures include changes to procedures, ensuring operating and safety procedures as well as personnel training to include identification of abnormal operations and conditions (e.g., pipe movement), ensuring emergency response plans account for all personnel, including contractors, and address contingency plans when firewater systems may need to be isolated for continued effective operation, loss of firewater supply, etc.

[62] Freeport LNG, "Freeport LNG Provides Summary of Root Cause Failure Analysis Report on June 8 Incident", November 2022, http://freeportlng.newsrouter.com/news_release.asp?intRelease_ID=9752&intAcc_ID=77, Accessed January 2023.

FERC Preliminary Engineering Review

FERC regulations under Title 18 CFR § 380.12 (m) and (o) requires an applicant to provide safety, reliability, and engineering design information as part of its application, including hazard identification studies and front-end-engineering-design (FEED) information for its proposed Project. FERC staff evaluates this FEED information with a focus on potential hazards from within and nearby the site, including external events, which may have the potential to cause damage or failure to the Project facilities, and the engineering design and safety and reliability concepts of the various protection layers to mitigate the risks of potential hazards.

The primary concerns are those events that could lead to a hazardous release of sufficient magnitude to create an offsite hazard or interruption of service. Furthermore, the potential hazards are dictated by the site location and the engineering details. In general, FERC staff considers an acceptable design to include various layers of protection or safeguards to reduce the risk of a potentially hazardous scenario from developing into an event that could impact the offsite public. These layers of protection are generally independent of one another so that any one layer would perform its function regardless of the initiating event or failure of any other protection layer. Such design features and safeguards typically include:

- a facility design that prevents hazardous events, including the use of inherently safer designs; suitable materials of construction; adequate design margins from operating limits for process piping, process vessels, and storage tanks; adequate design for wind, flood, seismic, and other outside hazards;
- control systems, including monitoring systems and process alarms, remotely operated control and isolation valves, and operating procedures to ensure that the facility stays within the established operating and design limits;
- safety instrumented prevention systems, such as safety control valves and emergency shutdown systems, to prevent a release if operating and design limits are exceeded;
- physical protection systems, such as appropriate electrical area classification, proper equipment and building spacing, pressure relief valves, spill containment, and cryogenic, overpressure, and fire structural protection, to prevent escalation to a more severe event;
- site security measures for controlling access to the plant, including security inspections and patrols, response procedures to any breach of security, and liaison with local law enforcement officials; and
- onsite and offsite emergency response, including hazard detection and control equipment, firewater systems, and coordination with local, state, and federal emergency management officials and first responders, to mitigate the consequences of a release and prevent it from escalating to an event that could impact the public.

The inclusion of such protection systems or safeguards in a plant design can minimize the potential for an initiating event to develop into an incident that could impact the safety of the offsite public. The review of the engineering design for these layers of protection are initiated in the application process and carried through to the next phase of the proposed project in final design if authorization is granted by the Commission.

The reliability of these layers of protection is informed by occurrence and likelihood of root causes and the potential severity of consequences based on past incidents and validated hazard modeling. As a result of the continuous engineering review, we recommend mitigation measures and continuous oversight to the Commission for consideration to include as conditions in the order. If a facility is authorized and recommendations are adopted as conditions to the order, FERC staff would continue its engineering review through final design, construction, commissioning, and operation, as described and recommended more generally below.

Managing Changes

Title 18 CFR § 153.5 requires any person proposing to site, construct or operate facilities for the export of natural gas from the Unites States to a foreign country or to amend an existing Commission authorization, including modification of existing authorized facilities, to file with the Commission an application for authorization. As part of the application, Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, section 13.O.1, management of change (MOC) systems would typically be used during the final design, construction, and operation phases, and should be discussed in the application as part of the engineering planning approach to the construction of any new facilities. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and Title 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Title 49 CFR § 193.2017(a) requires operators to maintain at each LNG plant plans and procedures required for the plant, for these documents to be available upon request for review and inspection by the [PHMSA] Administrator or any State Agency that has submitted a current certification or agreement with respect to the plant under the pipeline safety laws, and that each change to the plans and procedures be available at the LNG plant for review and inspection within 20 days after the change is made. Title 49 CFR § 193.2017(b) enables the Associate Administrator or the aforementioned State Agencies to require an operator to amend its plans and procedures as necessary to provide a reasonable level of safety. Title 49 CFR § 193.2017(c) requires each operator to review and update the plans and procedures in 49 CFR § 193 when a component is changed significantly or a new component is installed; and at intervals not exceeding 27 months, but at least once every 2 calendar years.

Similarly, 33 CFR § 127.007(d)(1) requires an owner or operator who submits a Letter of Intent (LOI) to notify the Captain of the Port (COTP) in writing within 15 days when there is a change in the information submitted in the LOI. Title 33 CFR § 127.007(e) requires an owner or operator intending to build a new LNG facility, or an owner or operator planning new construction to expand marine terminal operations in any facility handling LNG, where the construction or expansion will result in an increase in the size or frequency of LNG marine traffic on the waterway associated with a facility to file or update a waterway suitability assessment (WSA) with the COTP of the zone in which the facility is or will be located. The WSA must consist of a Preliminary WSA and a Follow-on WSA and the COTP may request additional information during review of the Preliminary WSA or Follow-on WSA. Title 33 CFR § 127(h)(1) also requires owners or operators, until the facility begins operation, to annually review their WSA and submit a report to the COTP as to whether changes are required, the details of the necessary revisions, along with a timeline for completion. They also require owners or operators to report and update the WSA if there are any changes in conditions, such as changes to the port environment, the LNG facility, or the tanker route, that would affect the suitability of the waterway for LNG traffic. The annual report must coincide with the date of the COTP's LOR and a final report must be submitted to the COTP at least 30 days, but not more than 60 days, prior to the start of operations.

USCG also reviews Operations Manual and Emergency Manuals for changes. Title 33 CFR § 127.019(a) requires the owner or operator of an active facility to submit an Operations Manual and Emergency Manual to the COTP and at least 30 days before transferring LNG, the owner or operator of a new or an inactive facility must submit an Operations Manual and Emergency Manual to the COTP, unless the manuals have been examined and there have been no changes since that examination. The Operations Manuals and Emergency Manuals must include a date, revision date or other revision-specific identifying information and if the COTP finds that the Operations Manual meets § 127.305 or § 127.1305 and that the Emergency Manual meets § 127.307 or § 127.1307, the COTP will provide notice to the facility stating each manual has been examined by the USCG, including the revision date of the manual or other revision-specific identifying information. If the COTP finds that the Operations Manual or the Emergency Manual does not meet 33 CFR Part 127, the COTP will notify the facility with an explanation of why it does not meet this part.

However, most of these changes managed under 49 CFR Part 193 and 33 CFR Part 127 deal with changes to the facilities after operation or as it pertains to specific procedures and compliance with 49 CFR Part 193 and 33 CFR Part 127. This is similar to management of change procedures throughout operations required in similar facilities under EPA's 40 CFR § 68.75 Chemical Accident Prevention Provisions and OSHA's 29 CFR § 1910.119(l) PSM of Highly Hazardous Chemicals regulations, but those are not applicable to LNG facilities regulated under 49 CFR Part 193. We also note that NFPA 59A (2019 edition) section 4.6 requires components shall not be constructed or significantly altered until a qualified person from process, mechanical, geotechnical and civil, electrical and instrumentation, materials and corrosion, and fire protection and safety engineering reviews the design drawings and specifications and determines that the design will not impair the safety or reliability of the component or any associated components. However, 49 CFR Part 193 adopts NFPA 59A (2001 edition) that predates this requirement where it first became part of NFPA 59A (2019 edition) and while 33 CFR Part 127 incorporates NFPA 59A (2019 edition), it does not incorporate section 4.6. Furthermore, it is unclear whether the NFPA 59A (2019 edition) section 4.6 requirement covers construction and alteration after operation or before any construction.

As such, the regulations do not cover changes from the FEED through final design, construction, and operation and 49 CFR Part 193 and 33 CFR Part 127 are limited to reviewing compliance with applicable regulations and not necessarily review for other safety impacts in general. In practice, LNG companies would typically base their solicitations for final engineering, procurement, and construction (EPC) contract on a completed FEED, and then manage changes from FEED to final design and throughout construction and operation. Similarly, FERC staff based our reviews, recommendations, and conclusions on safety and reliability to the Commission on the design submitted in application[63], and then manage changes from the application to final design and throughout construction and operation. Therefore, we recommend in section 5 that ELC and SLNG should follow the construction procedures and mitigation measures described in its application and supplements, including responses to staff data requests and as identified in the EA, unless modified by the Order. ELC and SLNG should:

a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);
b. justify each modification relative to site-specific conditions;
c. explain how that modification provides an equal or greater level of protection than the original measure; and
d. receive approval in writing from the Director of the Office of Energy Projects (Director of OEP), or the Director's designee, before using that modification.

Similarly, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file, for review and approval, change logs that list and explain any changes made from the front-end engineering design provided in ELC's and SLNG's application and filings. A list of all changes with an explanation for the design alteration

[63] Our 2017 Guidance Manual suggests the design filed in an application be based on a completed FEED.

should be filed and all changes should be clearly indicated on all diagrams and drawings. In addition, ELC and SLNG committed to making certain changes in response to data requests to FERC staff. Therefore, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file information/revisions pertaining to ELC and SLNG's response numbers 27, 41 and 48 of their October 2, 2023 filing, which indicated features to be included or considered in the final design.

FERC staff would review these requested and filed changes to determine whether there is equivalent or greater levels of protection than the original measure and would also review whether the changes with through appropriate change management procedures by evaluating against the requirements for managing change in applicable codes, standards, and recommended and generally accepted good engineering practices, such as NFPA 59A (2023 edition) section 4.6 and American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS), *Guidelines for Management of Change for Process Safety*, or equivalents to ensure companies are managing changes safely.

Project Schedule

18 CFR § 380.12(c) requires the application to include construction timetables. As suggested in our 2017 Guidance Manual, section 13.1.5, companies should provide a description of the project schedule detailing project design, construction, commissioning, and in-service schedule with milestones. As suggested in our 2017 Guidance Manual, the project schedule description should be in the form of a Gantt Chart or equivalent and should provide sufficient detail to show the feasibility of the engineering, procurement, construction, commissioning, and startup of the facilities. ELC and SLNG provided a project schedule in the application, but it was a high level overview that provided general timelines for FERC approval, detailed engineering, procurement, site preparation, construction, pre-commissioning and commissioning, startup, and commencement of operations for the entire Project, which did not include the details suggested in our 2017 Guidance Manual and would be akin to a "Level 0" schedule specified in recommended and generally accepted good engineering practices, such as:

- Construction Industry Institute (CII) RS6-1, *Project Control for Engineering*, 1986
- CII RS6-5, *Project Control for Construction*, 1987
- CII RS6-6, *Work Packaging for Project Control*, 1988
- CII RR272-11, *Enhanced Work Packaging: Design through Workface Execution*, 2013
- CII RS272-12, *Advanced Work Packaging: Design, through Workface Execution,* 2016

- CII Implementation Resource (IR) 272-2, Volume I, *Advanced Work Packaging: Design through Workface Execution*
- CII IR 272-2, Volume II, *Advanced Work Packaging: Implementation Guidance*, or equivalents

Given that the project schedule would continue to become more detailed and potentially change from the submittal in the application, and given that a more detailed schedule helps FERC staff plan and manage its resources for reviewing notices to proceed and conducting inspections, we recommend in section 5 that prior to initial site preparation, ELC and SLNG should file, for review and approval, an overall Project schedule, which includes the proposed stages of initial site preparation, final design, procurement, construction, commissioning, introduction of hazardous fluids, and commencement of service. We also recognize the initial project schedule filed may not be detailed, but would continue to become more detailed and potentially change as construction progresses. Therefore, as recommended and discussed further under Construction Progress and Reporting, we also recommend monthly reports with updates and development on the schedule. We would review the filed schedules and expect the companies to eventually develop and file a more detailed and comprehensive schedule that would provide a meaningful critical path network that can be supported by a work breakdown structure (WBS) consistent with a "Level 3" project level schedule specified in the above-mentioned recommended and generally accepted good engineering practices. At a minimum, we would expect the schedule to include the milestones listed in our 2017 Guidance Manual Appendix 13.A.5 for each area or system as they may relate to potential notices to proceed for different stages of the project based on potential conditional requirements.

Final Specifications and Quality Management Systems

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, section 13.O.2, a quality assurance and quality control system (QAQC), or quality management system (QMS), would typically become available during the final detailed design phase to be used during construction and should be discussed in the application as part of the engineering planning approach to the construction of any new facilities. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Title 49 CFR Part 193, Subpart D Construction covers the DOT PHMSA regulatory requirements for construction. Title 49 CFR Part 193 Subpart E Equipment covers the DOT PHMSA regulatory requirements for the fabrication and installation of vaporization equipment, liquefaction equipment, and control systems. As part of those requirements, 49 CFR § 193.2301 and 49 CFR § 193.2401 require each LNG facility to comply with requirements of NFPA 59A (2001 edition). In addition, 49 CFR § 193.2303 requires that no components may be placed in service until it passes all applicable inspections and tests prescribed in 49 CFR Part 193 Subpart D and NFPA 59A (2001 edition). In addition, 49 CFR § 193.2703 requires each operator for the design and fabrication of components with respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable parts. Similarly, 49 CFR § 193.2705 requires supervisors and other personnel utilized for construction, installation, inspection, or testing to have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments; and requires each operator to periodically determine whether inspectors performing construction, installation, and testing duties required by 49 CFR Part 193 are satisfactorily performing their assigned functions.

Title 33 CFR Part 127, Subpart B covers USCG regulatory requirements of the marine transfer area, including 33 CFR **§** 127.101 for design and construction, which incorporates NFPA 59A (2019 edition) Chapter 5, Section 5.3.1.7; Chapter 6, Section 6.7; Chapter 10; Chapter 11, except Sections 11.9, and 11.10; Chapter 12; Chapter 15, except Sections 15.4 and 15.6; and Annex B. We note that 33 CFR Part 127 does not incorporate Chapter 4, which has similar competence requirements for fabricator, constructor, installer, inspector, testers, and supervisors as 49 CFR § 193.2703 and 49 CFR § 193.2705. However, there are no changes or modifications to the marine transfer lines or marine transfer area where 33 CFR 127 would be applicable for this Project.

NFPA 59A (2001 edition) section 3.4.2 requires boilers to be fabricated in accordance with American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (BPVC), Section I, 1992 edition, or CSA Standard B51, *Boiler, Pressure Vessel and Piping Code*, 1997 edition, and pressure vessels to be fabricated in accordance with ASME BPVC (1992 edition), Section VIII, or CSA B51 (1997 edition). Similarly, NFPA 59A (2001 edition) section 3.4.3 requires shell and tube heat exchangers to be fabricated in accordance with standards of the Tubular Exchanger Manufacturer Association (TEMA), and the shells and internals of all exchangers to be pressure tested and inspected in accordance with ASME BPVC (1992 edition), Section VIII, or CSA B51 (1997 edition), where such components fall within the scope of the pressure vessel code. NFPA 59A (2001 edition) section 5.2.1 also requires vaporizers be fabricated and inspected in accordance with the ASME BPVC (1992 edition), Section VIII, Division 1.[64] NFPA 59A (2001 edition) section 4.5.2 also requires stationary LNG storage containers designed for pressure in excess of 15 psi to be pressure tested by the manufacturer prior to shipment to the installation site and the inner tank to be tested in accordance with ASME BPVC (1992 edition) or CSA B51 (1997 edition), the outer tank to be leak tested, and the piping to be tested in accordance with NFPA 59A (2001 edition) section 6.6. The stationary LNG storage containers and associated piping must also be leak tested prior to filling the container with LNG.

NFPA 59A (2001 edition) section 4.1.1 requires stationary LNG storage containers, with exception of ASME containers, to be inspected to ensure compliance with the engineering design and material, fabrication, assembly, and test provisions of NFPA 59A (2001 edition) and that the operator be responsible for this inspection. It also requires the performance of any part of the inspection to be permitted to be delegated to inspectors who are employees of the operator's own organization, an engineering or scientific organization, or a recognized insurance or inspection company, and that the inspectors be qualified in accordance with the code or standard applicable to the container and as specified in NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 4.2.1 requires welded containers designed for not more than 15 psi (100 kPa) to comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, 1990 edition, and states that API 620, Appendix Q, be applicable for LNG, but requires 100% radiographic inspection of all vertical and horizontal butt-welds associated with the container wall in Q-7.6.1 through Q-7.6.4, and requires 100% of all butt-welded annual plate radial joints to be radiographed in Q-7.6.5. In addition, section 4.2.1 requires API 620, Appendix C, C.11, to be mandatory, which requires the purchaser of the tank to take level readings with surveyor's instruments around the entire periphery of the tank before water is introduced into the tank for the hydrostatic test with the readings to be continued at reasonable intervals during the entire filling operation and to be plotted promptly in suitable form to indicate whether any undue or uneven settlement is occurring. The results of the observations must be reported to the tank erector and the purchaser's engineering representative, and if at any time any questionable amount or rate of settlement does occur, further filling of the tank must be stopped until a decision is reached as to what, if any, corrective measures are needed. Reference points on a tank or its foundations for use in making such observations must be selected with care to ensure that the readings accurately reflect settlement of the subgrade and are not affected by possible changes in the shape of the tank walls. If a minor amount of settlement is observed during the course of the filling operation and still continues after a tank is filled

[64] the rules of the ASME *Boiler and Pressure Vessel Code*, Section I, Part PVG, are not applicable because these vaporizers operate over a temperature range of −260°F to +100°F (−162°C to +37.7°C).

to the highest level required in the hydrostatic test, the water level in the tank shall not be lowered until further settlement has substantially ceased, or a decision is reached that it might be unsafe to hold the water at that level any longer. In addition, the water test cannot be used as a planned means of soil compaction. However, there are no LNG tanks proposed for this Project, and there are no requirements for other tanks in 49 CFR Part 193 or NFPA 59A (2001 edition).

NFPA 59A (2001 edition) section 6.1.1 requires all piping systems to be in accordance with ASME B31.3, *Process Piping*, 1996 edition, with exception of fuel gas systems covered by NFPA 54, *National Fuel Gas Code*, 1999 edition. NFPA 59A (2001 edition) section 6.6 and NFPA 59A (2019 edition) section 10.8 also require inspection, examination, and testing of piping to be performed in accordance with Chapter VI of ASME B31.3 (1996 and 2016 editions, respectively), for piping systems and components for flammable liquids and flammable gases with service temperatures below -20°F. In addition, NFPA 59A (2001 edition) section 6.9.2 requires piping systems and components for flammable liquids and flammable gases with service temperatures below -20°F made of austenitic stainless steels and aluminum alloys to be protected to minimize corrosion and pitting from corrosive atmospheric and industrial substances during storage, construction, fabrication, testing, and service. Section 6.9.2 also prohibits the use of tapes or other packaging materials that are corrosive to the pipe or piping components and requires inhibitors or waterproof barriers to be utilized where insulation materials can cause corrosion of aluminum or stainless steels. Similarly, 33 CFR Part 127 incorporates NFPA 59A (2019 edition) section 10.2.1, which requires all process piping that is a part of an ASME container (i.e., container exceeding 15 psig, also known as a pressure vessel), including piping between the inner and outer containers to be in accordance with either ASME BPVC (2017 edition) or ASME B31.3 (2016 edition), and all other process piping meet ASME B31.3 (2016 edition), but again no changes to marine transfer piping or marine transfer area is being proposed for this Project.

ELC and SLNG did not discuss a QAQC or QMS in their application as part of the engineering planning approach to the construction of any new facilities, which would typically be developed by the EPC contractor during final detailed design and include the elements discussed above. While ELC and SLNG would need to meet the requirements of 49 CFR Part 193 as discussed, FERC staff has observed fabrication, installation, construction, inspections and tests and inspectors performing construction, installation and testing duties are typically enhanced by instituting a QAQC plan or QMS, and that the scope include design, fabrication, construction, installation, and testing duties beyond those required by regulations. FERC staff has also observed varying level of oversight of fabrication and compliance with regulations and applicable codes and standards that a company lists in its application. In some cases, lack of a robust QAQC program and oversight of fabrication, construction, installation, and testing has resulted in more frequent and substantial nonconformances and deficiencies. The nonconformances/deficiencies in other projects have included use of unqualified welders, improper or inadequate weld procedures, non-conforming welds, unqualified inspectors, incorrect installation of carbon steel gaskets in cryogenic lines that required stainless steel gaskets, or other failures in a QMS. In nearly all of the observed nonconformances/deficiencies, the leading contributing causes have been a lack of oversight of fabrication and compliance with regulations, a lack of adherence to other codes, standards, and specifications, and reductions of QAQC in some newer codes, standards, and specifications. In some cases, this has led to construction and commissioning delays and extensions and sometimes even failures of equipment and leaks. Therefore, we recommend in section 5 that prior to initial site preparation, ELC and SLNG file, for review and approval, quality assurance and quality control procedures for construction activities, including initial equipment laydown receipt and preservation. FERC staff would review the filed QAQC procedures consistent with International Organization for Standardization (ISO) 9001, *Quality Management Systems*, and Project Management Institute (PMI), Project *Management Body of Knowledge (PMBOK)*, or other equivalent standards. However, we have also seen wide variation in QAQC programs, including those that have committed to ISO 9001 because ISO 9001 provides only a general framework of a QAQC and does not suggest the specific inspection and testing plans that should or must be done to comply with regulations, including incorporations by reference, and to meet Project specific specifications, including incorporated codes, standards, and recommended and generally accepted good engineering practices. Therefore, FERC staff would review the filed QAQC plans in coordination with DOT PHMSA and USCG as well as review all nonconformance logs during construction inspections, which would include not just nonconformances with federal regulations, but all Project specifications and applicable codes and standards the company has listed and committed to meeting beyond the regulatory requirements.

Furthermore, the QAQC or QMS plan would check that all final equipment selections met the requirements in datasheets and specifications. While ELC and SLNG provided preliminary equipment lists, and datasheets and specifications for select equipment, the datasheets and specifications were not provided for all proposed equipment, and any proposed specifications would be subject to change when an EPC contractor is selected. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications should include:

a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, blast resistant buildings);
b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, other specialized equipment);
c. electrical and instrumentation specifications (e.g., power system, control system, SIS, cable, other electrical and instrumentation); and
d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, firewater).

In addition, the codes and standards referenced in the specifications for final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance are also subject to change. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file a final list of all applicable codes and standards that would be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the final specifications and document numbers.

Construction Progress and Reporting

If the Project is authorized and proceeds, and if recommendations are adopted as conditions of the order, the ELC and SLNG final design and QAQC would be subject to FERC staff review and approval. ELC and SLNG would then install equipment in accordance with final specifications, final designs, and QAQC program, which would typically include non-conformance report (NCR) or deficiency logs consistent with ISO 9001, ISO 9002, PMI PMBOK, and other QMS standards. We recommend in section 5 and as discussed in previous and later subsections that these final specifications, final designs, and QAQC plans be filed for review and approval. We also recommend in section 5 that beginning with the filing of its Implementation Plan, ELC and SLNG file monthly status reports until all construction and restoration activities are complete. Problems of a significant magnitude should be reported to the FERC within 24 hours. On request, these status reports should also be provided to other federal and state agencies with permitting responsibilities. Status reports should include:

a. an update on the ELC's and SLNG's efforts to obtain the necessary federal authorizations;
b. project schedule, including current construction status of the project and work planned for the following reporting period;
c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EI during the reporting period (both for the conditions imposed by the Commission and any

environmental conditions/permit requirements imposed by other federal, state, or local agencies);

d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;
e. the effectiveness of all corrective and remedial actions implemented;
f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the order, and the measures taken to satisfy their concerns; and
g. copies of any correspondence received by the ELC and SLNG from other federal, state, or local permitting agencies concerning instances of noncompliance, and the ELC's and SLNG's response.

In addition, FERC staff would conduct construction inspections including reviewing QAQC plans and resultant documentation, such as NCR logs and remedial actions. We would inspect and review this information to ensure construction work (e.g., pile driving, welds, non-destructive examination, etc.) is being performed in accordance with final Project specifications, procedures, and applicable codes and standards. We would also conduct spot checks during our own inspections, such as P&ID walkdowns, and equipment nameplate verifications to ensure installed equipment is consistent with the approved design.

Training

If the Project is authorized, ELC and SLNG would begin ramping up training of any new or existing operation, maintenance, safety, security, and other personnel as it prepares for commissioning and starting up of its new facilities.

Title 49 CFR § 193.2707, under Subpart H, requires the operator perform assigned functions only after they have demonstrated capability to perform their assigned functions by: successful completion of training required by 49 CFR §§ 193.2713 and 193.2717; experience related to the assigned function; and acceptable performance on a proficiency test relevant to the assigned function. Otherwise, the operator or maintenance personnel must be accompanied and directed by an individual that has met those requirements. Title 49 CFR § 193.2713 requires each operator provide and implement a written plan of initial training to instruct all permanent maintenance, operating, and supervisory personnel about the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray; about the potential hazards involved in operating and maintenance activities; and to carry out aspects of the operating and maintenance procedures under §§ 193.2503 and 193.2605 that relate to their assigned functions. In addition, all operating and appropriate supervisory personnel must be trained to understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and to understand the LNG transfer procedures provided under

§ 193.2513. It also requires all personnel to carry out the emergency procedures under § 193.2509 that relate to their assigned functions; and to give first-aid. Title 49 CFR § 193.2713 also requires a written plan of continuing instruction be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.

Title 49 CFR § 193.2709 requires personnel having security duties to be qualified to perform their assigned duties by successful completion of the training required under § 193.2715, which requires personnel responsible for security at an LNG plant be trained in accordance with a written plan of initial instruction to: (1) recognize breaches of security; (2) carry out the security procedures under § 193.2903 that relate to their assigned duties; (3) be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and (4) recognize conditions where security assistance is needed. In addition, 49 CFR § 193.2715 also requires a written plan of continuing instruction be conducted at intervals of not more than two years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction.

Similarly, 49 CFR § 193.2717 requires all personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, be trained according to a written plan of initial instruction, including plant fire drills, to: (1) know the potential causes and areas of fire; (2) know the types, sizes, and predictable consequences of fire; and (3) know and be able to perform their assigned fire control duties according to the procedures established under § 193.2509 and by proper use of equipment provided under § 193.2801, and also requires a written plan of continuing instruction, including plant fire drills, be conducted at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of the section. It also requires that plant fire drills provide personnel hands-on experience in carrying out their duties under the fire emergency procedures required by § 193.2509.

Title 49 CFR § 193.2719 requires each operator to maintain a system of records for this training, which provides evidence that the training programs required by this subpart have been implemented; and provide evidence that personnel have undergone and satisfactorily completed the required training programs. The records must be maintained for one year after personnel are no longer assigned duties at the LNG plant.

Title 33 CFR § 127.501 also has similar requirements for written operations, training, and experience for persons in charge of shoreside transfer operations. 33 CFR § 127.503 requires the operator ensure that all full-time employees have training in: (1) basic LNG firefighting procedures; and (2) LNG properties and hazards. In addition, each person assigned for transfer operations is required to have training in: (1) the examined Operations Manual and examined Emergency Manual; (2) advanced LNG firefighting procedures; (3) security violations; (4) LNG vessel design and cargo transfer operations; (5) LNG release response procedures; (6) First aid procedures for frostbite, burns, cardiopulmonary resuscitation; and transporting injured personnel. The personnel who received this respective must also receive refresher training in the same subjects at least once every five years.

However, there are no requirements for this information to be submitted, reviewed, or demonstrated prior to commissioning, therefore we recommend in section 5, that prior to commissioning, ELC and SLNG should file, for review and approval, a plan to maintain a detailed training log to demonstrate that all staff have completed all required training for operating, maintenance, safety, security, and emergency response. In addition, ELC and SLNG should file signed documentation that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation. We would evaluate these training logs in coordination with PHMSA and the USCG, as applicable to the Project.

Commissioning Schedule, Plans, and Procedures

If the Project is authorized and constructed, ELC and SLNG would begin commissioning its facilities following construction. Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, section 13.O.3, commissioning plans would typically become available after the application stage, but development of the commissioning plans should be discussed in the application as part of the engineering planning approach to the construction of any new facilities. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

ELC and SLNG did not discuss commissioning plans, or schedules, in detail in their application as part of the engineering planning approach to the construction of any new facilities, which would typically be developed by the EPC contractor. However, ELC and SLNG would need to meet the requirements of 49 CFR Part 193 and 33 CFR Part 127 as discussed, including 49 CFR § 193.2303, which requires that no components may be placed in service until it passes all applicable inspections and tests, as prescribed in 49 CFR Part 193 Subpart D and NFPA 59A (2001 edition). As mentioned, FERC staff has also observed commissioning plans and procedures are enhanced by meeting additional inspections and tests consistent with Project specifications, including codes, standards, and recommended and generally accepted good engineering practices listed in its application that go above and beyond the minimum federal regulations. Therefore, we recommend in section 52 that prior to commissioning, ELC and SLNG should file a detailed schedule for commissioning through equipment startup. The schedule should include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. ELC and SLNG should file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued. In addition, we recommend in section 5 that prior to commissioning, the ELC and SLNG should file, for review and approval, detailed plans and procedures for: testing the integrity of on-site mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. We also recommend in section 5 and as discussed in later subsection that specific commissioning plans and procedures be provided for review and approval, such as pressure/leak testing; clean-out, dry-out, purging, and tightness testing; and those associated with the distributed control system (DCS) and safety instrumented system. FERC staff would review the commissioning plans and procedures consistent with codes, standards, and recommended and generally accepted good engineering practices, such as aforementioned AGA, *Purging Principles and Practices*, NFPA 56, *Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems*. FERC staff also discusses and recommends in later sections specific commissioning plans and procedures to be filed with applicable codes, standards, and recommended and generally accepted good engineering practices.

In addition, FERC staff have observed, and historical incidents have demonstrated, there are more frequent failures and incidents during initial start-ups and start-ups after maintenance activities. This is often due to valves being in incorrect positions, instrumentation not working properly, operating procedures not being in place, or other safety layers not installed or functioning properly. Other federal regulations, such as 40 CFR 68.77 and 29 CFR 1910.119(i), and industry also recognize this increase in risk and will require a pre-startup safety review (PSSR) to ensure all equipment, valves, operations, and safety layers are checked to be in accordance with specifications; operating, safety, and emergency response procedures are in place and adequate; all PHA recommendations and punch list items that are safety related are resolved or implemented; and all personnel have been trained on the startup procedures. We agree with this recommended and good engineering practice, and we recommend in section 5 that, prior to introduction of hazardous fluids, ELC and SLNG should complete and document a PSSR to ensure that installed equipment is ready for startup and introduction of hazardous fluids. The PSSR should verify any open changes since the last hazard review have been reviewed and mitigations implemented, operating procedures are in place, and operator training is complete. A copy of the hazard review with a list of recommendations, and actions taken on each recommendation, should be filed and is discussed further in the Process Hazard Analysis section. FERC staff would review the PSSR for consistency with recommended and good engineering practices, such as AIChE CCPS, *Guidelines for Effective Pre-Startup Safety Reviews*, or equivalent. We also recommend in section 5 that ELC and SLNG should receive written authorization from the Director of OEP, or the Director's designee, prior to introducing hazardous fluids into the Project facilities. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids should be installed and functional. In addition, ELC and SLNG should receive written authorization from the Director of OEP, or the Director's designee, before placing into service the Project facilities, and that such authorization only be granted following a determination that the facilities have been constructed in accordance with FERC approval, can be expected to operate safely as designed, and the rehabilitation and restoration of areas affected by the project are proceeding satisfactorily.

Operational Inspections

Once operational, we recognize there can still be changes that can also deviate from assumptions made in the basis of engineering and design reviewed in the application by FERC staff that formed the basis of its recommendations and conclusion on safety and reliability to the Commission and deviate from assumptions made during previous reviewed and approved plans and procedures. Operation and maintenance procedures may also need to change for other reasons, such as changes in feed gas composition over time as depleted, new, and different sources of gas emerge in the market, or may be required to change over time based on the results of federal, state, and local agency inspection findings, project modifications, new regulations, PHA studies and recommendations, incident and near miss investigation root causes and recommendations, and other studies to continuously improve safe and reliable operations. We also recognize the interpretation of what constitutes "generally accepted engineering practices" that maintenance procedures are required to meet under 49 CFR § 193.2605 may change over time and they may be based on prescriptive, performance, and risk-based standards not included in the original application or operation and maintenance procedures reviewed by FERC staff that formed the basis of its recommendations and conclusion on safety and reliability to the Commission. In addition, LNG companies must periodically update and re-validate their plans and procedures in accordance with 49 CFR Part 193 and 33 CFR Part 127 as discussed under Managing Changes, but most LNG companies also conduct PHAs and update and re-validate PHAs consistent with other federal regulations, such as Title 40 CFR § 68.67(c) and 29 CFR § 1910.119(c)(6) that require PHA studies be updated and re-validated at least every 5 years even though these regulations are not applicable to LNG facilities regulated under 49 CFR Part 193 and 33 CFR Part 127. However, these practices better ensure continued safe and reliable operations. Therefore, we recommend in section 5 that throughout the life of the facilities, the facilities be subject to regular FERC staff technical reviews and site inspections on at least an annual basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, we recommend information be filed in response to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. We also recommend up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports, including facility events that have taken place since the previously submitted semi-annual report, be filed. As part of the regular inspections, FERC staff would coordinate its inspections with DOT PHMSA and USCG. FERC staff have requested information in preparation of these technical reviews and inspections, including, but not limited to additional information on:

- abnormal operating conditions such as those reported in the semi-annual operational reports discussed;
- a list of all Federal (other than FERC), state, and local agencies inspections, and any associated documents, recommendations, and/or reports, including all design, operating, maintenance, and security conditions which have been imposed or specific recommendations by these agencies/companies to improve or enhance the operational safety of the LNG facilities, which items were requirements with force of law and which were recommendations, and how the company has complied with each;
- changes in the facility design, process equipment, process piping, control/instrumentation systems, hazard detection and control systems, operations, or operating philosophy, and for each such change, describe in detail the original design, the current design, and the rationale for the change;
- management of change (MOC) reviews conducted, including a descriptive title or summary/sentence for each item and for identification and copies of any changes to MOC procedure(s) and forms;
- copies of any reports, investigations, and studies on the facility related to safety, reliability, integrity, or abnormal operations including but not limited to process hazard analyses (PHAs), root cause analyses (RCAs), incident reports, near misses related to process safety, investigations and studies on abnormal conditions, and insurance reports since the last FERC inspection/review. Identify how the company has or will address any resulting recommendations;
- up-to-date detailed plot plan(s); hazard detection and hazard control drawings; and piping and instrumentation diagrams for the facilities reflecting all modifications and changes;
- identification and copies of any updates to operating and maintenance manual and safety manuals;
- a list of corrective maintenance work orders;
- most recent LNG storage tank settlement elevation survey reports, including survey data and results, analysis and calculations, criteria used to determine if the settlement range is considered acceptable and within acceptable settlement design range, and which standards were used for the criteria assessment (e.g., API 620, 625, 650, 653, ACI 376, etc.);
- date and results of the gas compositions analyzed, acceptable range for each constituent and/or characteristic (e.g., mole percent, ppm, heating value, etc.), and if the range is based on a process basis of design, alarm set point, pipeline/customer specification, and/or other criteria;

- date and results of annual firewater pump test(s), including resulting pump test curve(s) compared to the original field acceptance test curve as well as the previous annual test curve(s);
- date and results of latest emergency shutdown (ESD) test. Describe how the facility's emergency shutdown test is conducted. Also, provide a list, description, cause, and corrective actions resulting from all ESD's that have occurred at the facility since the last FERC inspection/review;
- a list of all venting and/or flaring events that have occurred at the facility since the last FERC inspection/review. Indicate which vent/flare was utilized, as well as the cause, process conditions, duration, and amount vented/flared for each event. Also, indicate if the venting/flaring was related to planned start-up or shut-down activities, maintenance activities, process upset during normal operations, or other; and
- Identification and copies of any updates to emergency response plans.

These requests may also include more specific follow ups to information filed in semi-annual reports as discussed in more detail below and may constitute the earliest leading indicators of potential safety and reliability impacts, such as those considered as Tier 4 events in API 754*, Process Safety Performance Indicators for the Refining and Petrochemical Industries*, 3rd (2021) edition.

Semi-Annual Reports

To head off both similar data requests in preparation of inspections and also to provide consistent and regular notification of plant modifications planned, changes to operating conditions, and potentially significant abnormal operating experiences and activities that may provide leading indicators for impacts to the safety and reliability of the facilities, we also recommend in section 5 that throughout the life of the ELC and SLNG Project, ELC and SLNG file semi-annual operational reports that identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. We recommend abnormalities to be reported include, but not be limited to:

- unloading/loading/shipping problems;
- potential hazardous conditions from offsite vessels;
- storage tank stratification or rollover;
- geysering;
- higher than predicted boil off rates;
- storage tank pressure excursions (high or low);
- negative pressure (vacuum) within a storage tank;
- relative movement of storage tank inner vessels;

- cold spots on the storage tanks;
- storage tank vibrations and/or vibrations in associated cryogenic piping;
- storage tank settlement;
- pipe movement including spring hanger position indicator(s) outside of normal range;
- significant equipment or instrumentation malfunctions or failures;
- non-scheduled maintenance or repair (and reasons therefore);
- leaking or inoperative isolation valves;
- hazardous fluids releases;
- fires involving hazardous fluids and/or from other sources; and
- adverse weather conditions and the effect on the facility.

We recommend these reports be submitted within 45 days after each period ending June 30 and December 31. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" should be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance at the LNG facilities.

These events constitute plant modifications, activities, and abnormalities that may constitute leading and lagging indicators for potential safety and reliability impacts, such as those considered Tier 1 through 3 events in API 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*, 3rd (2021) edition. Knowing about these plant modification, activities, and abnormalities helps FERC staff coordinate as to whether more significant modifications are being planned during operations that could require an amendment or new proceeding. It also helps identify whether there are any potential safety or reliability impacts that FERC staff may want to issue information requests or that the Commission may want to issue supplemental orders on to protect the health and safety of the public or the environment. Further, as discussed below and recommended below, more imminent hazards that could jeopardize the health and safety of the public incidents should require more immediate notification.

Incidents and Investigations

Title 18 CFR § 375.308(x)(7) delegates the Director of Office of Energy Projects to take whatever steps are necessary to ensure the protection of all environmental resources during the construction or operation of natural gas facilities, including authority to design and implement additional or alternative measures and stop work authority and 18 CFR § 376.209 stipulates that as part of its emergency functions, the Commission will ensure that its personnel are available to respond to plant accidents or reportable incidents at LNG facilities and to address other matters involving the safety of human life or protection of property. As such, there are events that may show reason to take more immediate action to protect public safety. Incident reporting and subsequent agency actions are typically coordinated between PHMSA, USCG, and FERC under their respective authorities, as described more below.

Under Title 49 CFR § 191.1, PHMSA requires reporting of incidents and safety-related conditions, which are defined in 49 CFR § 191.3 and includes:

- an event that involves a release of LNG, LPG, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
    - A death, or personal injury necessitating in-patient hospitalization;
    - Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.
    - Unintentional estimated gas loss of three million cubic feet or more.
- An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.
- An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

Similarly, 49 CFR § 193.2515(a) requires each operator to investigate the cause of each explosion, fire, or LNG spill or leak which results in:

- death or injury requiring hospitalization;
- or property damage exceeding $10,000.

Title 49 CFR § 193.2515(b) also requires appropriate action must be taken to minimize recurrence of the incident as a result of the investigation and 49 CFR § 193.2515(c) requires if the Administrator or relevant state agency under the pipeline safety laws (49 U.S.C. 60101 et seq.) investigates an incident, the operator involved make available all relevant information and provide reasonable assistance in conducting the investigation. It also requires that unless necessary to restore or maintain service, or for safety, no component involved in the incident may be moved from its location or otherwise altered until the investigation is complete or the investigating agency otherwise provides, and where components must be moved for operational or safety reasons, they must not be removed from the plant site and must be maintained intact to the extent practicable until the investigation is complete or the investigating agency otherwise provides.

In addition, 49 CFR § 191.23(a) requires each LNG facility operator report in accordance with 49 CFR § 191.25[65] the existence of any of the following safety-related conditions involving LNG facilities in service except as provided in paragraph (b) described below:

- Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of a LNG facility that contains, controls, or processes gas or LNG.
- Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.
- Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength.
- Any malfunction or operating error that causes the pressure—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.
- A leak in a LNG facility containing or processing gas or LNG that constitutes an emergency.
- Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.
- Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of an LNG facility that contains or processes gas or LNG.

Title 49 CFR § 191.23(b) does not require a report for any safety-related condition that:

- Is an incident or results in an incident before the deadline for filing the safety-

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[65] Filed in writing within 5 working days, not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists), but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related.

related condition report;

- Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report.

Under Title 33 CFR § 127.321, USCG requires if there is a release of LNG, vessels near the facility are notified of the release by the activation of the warning alarm, and the person in charge of shoreside transfer operations must immediately notify the person in charge of cargo transfer on the vessel of the intent to shutdown, shutdown transfer operations; notify the COTP of the release; and not resume transfer operations until authorized by the COTP. Title 33 CFR § 105.200(b)(12) requires reporting of all breaches of security and transportation security incidents to the National Response Center in accordance with 33 CFR Part 101. Title 33 CFR § 101.305 requires notification of suspicious activities that may result in a transportation security incident, breaches of security, and transportation security incidents to the National Response Center without delay. Transportation security incidents must also be reported without delay to their local COTP.

Similarly, for incidents, near misses, and events that constitute significant non-scheduled events, such as lagging indicators considered as Tier 1 and 2 events in API 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*, 3rd (2021) edition, agencies and companies may need to take more immediate actions taken to ensure the protection of the public. In order to take coordinated responsive actions to protect the safety of human life and protection of property, we also recommend in section 5 that throughout the life of the ELC and SLNG Project, ELC and SLNG should report to the FERC staff significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities). In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to the FERC staff within 24 hours. This notification practice should be incorporated into the liquefaction facility's emergency plan. Examples of reportable hazardous fluids-related incidents include:

a. fire;
b. explosion;
c. estimated property damage of $50,000 or more;
d. death or personal injury necessitating in-patient hospitalization;
e. release of hazardous fluids for 5 minutes or more;
f. unintended movement or abnormal loading by environmental causes,

such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow- up report or follow up in the upcoming semi-annual operational report. All company follow-up reports should include investigation results and recommendations to minimize a reoccurrence of the incident.

FERC staff would take any necessary steps commensurate with the incident risk to ensure operational reliability and public safety and investigate such incidents in coordination with DOT PHMSA and USCG, as applicable, to ensure operators mitigate any risk of reoccurrence.

Process Design

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(10) requires piping and instrumentation drawings and process flow diagrams along with heat and material balances. As suggested in our 2017 Guidance Manual, the information should include narrative descriptions of each major system and the related process design information, including, but not limited to: basis of design and design philosophies, process flow diagrams (PFDs), heat and material balances (HMBs), P&IDs, and equipment lists and data sheets. This engineering design information is consistent with the scope of engineering design information defined in NFPA 59A (2019 and later editions) section 3.3.9, including the items in section A.3.3.9, that would be expected to be developed at this stage of the project design (FEED). Also, 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Title 49 CFR Part 193 and 33 CFR Part 127 contain limited requirements for the process design. Title 33 CFR Part 127 scope only applies to design criteria for the marine area facilities and a majority of the ship transfer lines, which are not being proposed as part of this Project. For the design of LNG facility components, 49 CFR § 193.2703, under Subpart H, does require the use of persons who have demonstrated competence by training or experience in the design of comparable components. In addition, under Subpart C Design, 49 CFR § 193.2101(a) incorporates requirements of NFPA 59A (2001 edition). NFPA 59A (2001 edition) also has very limited provisions that pertain to the process design. Like 49 CFR 193, NFPA 59A (2001 edition) section 2.4.1 requires designers and fabricators of LNG facilities to have competence in the design or fabrication of LNG containers, process equipment, refrigerant storage and handling equipment, loading and unloading facilities, fire protection equipment, and other components of the facility; section 2.4.2 requires supervision be provided for the fabrication of, and for the acceptance tests of, facility components to the extent necessary to ensure that they are structurally sound and otherwise in compliance with this standard; section 2.4.3 requires soil and general investigations shall be made to determine the adequacy of the intended site for the facility; and section 2.4.4 requires designers, fabricators, and constructors of LNG facility equipment be competent in the design, fabrication, and construction of LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility. It also requires supervision be provided for the fabrication, construction, and acceptance tests of facility components to the extent necessary to ensure that the facilities are structurally sound and otherwise in compliance with this standard.

While it is important to ensure competent designers, fabricators, and constructors of LNG facility equipment, LNG containers, cryogenic equipment, piping systems, fire protection equipment, and other components of the facility are used, 49 CFR Part 193 and NFPA 59A provide limited requirements on the process design necessary to reliably and safely operate the LNG facilities. Provisions that are general to the process design in NFPA 59A (2001 edition) are mostly in Chapters 3 and 7, as follows:

General Process Systems:

- section 3.2.4 requiring each pump be provided with an adequate vent, relief valve, or both, that will prevent over-pressuring the pump case during the maximum possible rate of cooldown;
- section 3.2.3 requiring pumps and compressors be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum safe working pressure of the casing and downstream piping and equipment, unless these are designed for the maximum discharge pressure of the pumps and compressors;
- section 3.2.2 requiring valving be installed so that each pump or compressor can be isolated for maintenance, and where pumps or centrifugal compressors are installed for operation in parallel, each discharge line be equipped with a check valve;
- section 3.4.5 requiring boil-off and flash gas handling systems to be installed for the safe disposal of vapors generated in the process equipment and LNG containers, which is inherently safer and less impactful to environment than venting to atmosphere;
- section 7.2 requiring each container be equipped with a pressure gauge connected to the container at a point above the maximum intended liquid level;
- section 7.3 requiring vacuum-jacketed equipment be equipped with instruments or connections for checking the absolute pressure in the annular space; and
- section 7.5 requiring instrumentation for liquefaction, storage, and vaporization facilities be designed so that, if power or instrument-air failure occurs, the system will proceed to a failsafe condition that is maintained until the operators can take appropriate action either to reactivate or to secure the system.

Provisions that are more specific to the process design in NFPA 59A (2001 edition) mostly pertain to the tank, vaporization, and transfer systems in Chapters 4, 5, 7, and 8, as follows:

Tank Systems:

- section 4.1.2.4 requiring all LNG containers be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification;
- section 7.1.1.1 requiring LNG containers be equipped with two independent liquid level gauging devices with density variations be considered in the selection of the gauging devices. In addition, these gauges must be designed

and installed so that it is possible to replace them without taking the tank out of operation;

- section 7.1.1.2 requiring LNG containers be provided with two high-liquid level alarms, which are allowed to be part of the liquid level gauging devices, but the alarms must be independent of each other. In addition, the alarm must be set so that the operator has sufficient time to stop the flow without exceeding the maximum filling height and must be located so that it is audible to personnel controlling the filling;
- section 7.1.1.3 requiring LNG containers be equipped with a high-liquid-level flow cutoff device, which must be separate from all gauges. In addition, the high-liquid-level flow cutoff device cannot substitute the alarm required in 7.1.1.2;
- section 7.1.2.1 requiring each refrigerant and flammable process fluid tanks be equipped with a liquid level gauging device and, if it is possible to overfill the tank, a high-liquid level alarm in accordance with 7.1.1.2;
- section 7.1.2.2 requiring flammable refrigerant tanks to also meet the requirements of section 7.1.1.3;
- section 7.4 requiring temperature-monitoring devices be provided in field-erected containers to assist in controlling temperatures when placing the container into service or as a method of checking and calibrating liquid level gauges; and
- section 7.4.2 requiring temperature-monitoring systems be provided where foundations supporting cryogenic containers and equipment could be affected adversely by freezing or frost heaving of the ground.

Vaporization Systems:

- section 5.3.1 requiring manifolded vaporizers have both inlet and discharge block valves at each vaporizer;
- section 5.3.3 requiring vaporizers have automatic equipment to prevent the discharge of either LNG or vaporized gas into a distribution system at a temperature either above or below the design temperatures of the sendout system, where such automatic equipment must be independent of all other flow control systems and must incorporate a line valve(s) used only for emergency purposes;
- section 5.3.4 requiring isolation of an idle manifolded vaporizer to prevent leakage of LNG into that vaporizer be accomplished with two inlet valves, and a safe means be provided to dispose of the LNG or gas that can accumulate between the valves;
- section 5.3.5 requiring each heated vaporizer be provided with a device to shut off the heat source that can be operated both locally and remotely;
- section 5.3.6 requiring a shutoff valve shall be installed on the LNG line to a

heated vaporizer;

- section 5.3.7 requiring any ambient vaporizer or a heated vaporizer installed within 50 ft (15 m) of an LNG container shall be equipped with an automatic shutoff valve in the liquid line, and this valve must close when loss of line pressure (excess flow) occurs, when abnormal temperature is sensed in the immediate vicinity of the vaporizer (fire), or when low temperature in the vaporizer discharge line occurs;
- section 5.3.8 requiring shutoff valves be provided on both the hot and cold lines of the intermediate fluid system if a flammable intermediate fluid is used with a remote heated vaporizer; and
- section 7.4.1 requiring vaporizers be provided with indicators to monitor inlet and outlet temperatures of LNG, vaporized gas, and heating-medium fluids to ensure effectiveness of the heat transfer surface.

Transfer Systems:

- section 8.2.1 requiring all transfer systems handling LNG, refrigerants, flammable liquids, and flammable gases to have isolation valves installed so that each transfer system can be isolated at its extremities;
- section 8.2.2 requiring all transfer piping systems handling LNG, refrigerants, flammable liquids, and flammable gases used for periodic transfer of cold fluid be provided with a means for precooling before use;
- section 8.2.3 requiring all transfer systems handling LNG, refrigerants, flammable liquids, and flammable gases to have check valves be provided as required in transfer systems to prevent backflow and be located as close as practical to the point of connection to any system from which backflow might occur;
- section 8.3.1 requiring all transfer systems handling LNG, refrigerants, flammable liquids, and flammable gases to have remotely located pumps and compressors used for loading or unloading tank cars, tank vehicles, or marine vessels be provided with controls to stop their operation that are located at the loading or unloading area and at the pump or compressor site, and allowing controls located aboard a marine vessel to be considered to be in compliance with this provision;
- section 8.5.5 requiring tank vehicle and tank car transfer systems to have isolation valving and bleed connections be provided at the loading or unloading manifold for both liquid and vapor return lines so that hoses and arms can be blocked off, drained of liquid, and depressurized before disconnecting with bleeds or vents discharging to a safe area;
- section 8.6.1 requiring pipeline transfer systems to have isolation valves provided at all points where transfer systems connect into pipeline systems;
- section 8.6.2 requiring pipeline transfer systems include provisions to ensure

that transfers into pipeline delivery systems cannot exceed the pressure or temperature limitations of the pipeline system; and

- section 8.6.5 requiring pipeline transfer systems to have bleed or vent connections provided so that loading arms and hoses can be drained and depressurized prior to disconnecting with bleeds or vents discharging to a safe area.

Similarly, 33 CFR 127 has requirement for marine transfer systems, including by incorporation of NFPA 59A (2019 edition) Chapters 10, 11, 12, and Chapter 15 (except Sections 15.4 and 15.6). However, they are not described herein because ELC and SLNG do not propose new facilities or modified facilities within the Project scope that would impact facilities regulated under 33 CFR 127.

While it is good that 49 CFR 193, 33 CFR 127, and NFPA 59A (2001 edition) provides process design requirements for the LNG storage container, vaporization, and transfer systems, most of the new or modified facilities that ELC and SLNG are proposing within the Project scope are systems outside of the scope of these systems and subsequent requirements, as described in Process Description. And, as mentioned, 49 CFR 193, 33 CFR 127, and NFPA 59A (2001 and 2019 editions) do not have the same level of process design requirements for the pre-treatment, liquefaction, and many other process systems throughout a LNG plant. For example, in order to liquefy natural gas, all liquefaction technologies require that the feed gas stream be pre-treated to remove components that could freeze out and clog the liquefaction equipment or would otherwise be incompatible with the liquefaction process or equipment. As suggested in our 2017 Guidance Manual, most large-scale liquefaction facilities will have processes to remove mercury, hydrogen sulfide (H_2S), carbon dioxide (CO_2), water, and heavy hydrocarbons. If water and carbon dioxide are not removed to certain concentrations, the downstream plate heat exchangers could clog and over-pressurize leading to a catastrophic failure of equipment, or if mercury is not limited to certain concentrations, it can induce embrittlement and corrosion of downstream brazed aluminum heat exchangers, resulting in a catastrophic failure of equipment. However, there are no regulatory requirements that water, carbon dioxide, or mercury be removed, and proposed facility designs have not always included these features. Therefore, FERC staff confirmed that the appropriate systems necessary for LNG facilities to operate reliably and safely are included in the FEED process design. We have also proposed for the next NFPA 59A (2026 edition) to include some minimum requirements for process design for these systems.

As such and as part of the process design review, FERC staff evaluated the P&IDs to verify equipment operating and design conditions are consistent with the PFDs and HMBs and that adequate process monitoring, controls, and shutdowns would be in place, consistent with the operating and design conditions, and that their reliability or redundancy would be commensurate with potential consequences of failure. However, the FEED P&IDs would be subject to changes in final design after additional detailed engineering is conducted. Therefore, we recommend in section 5 that ELC and SLNG provide updated P&IDs reflective of the final design.

Below we discuss each major system in the proposed project and the specific requirements and recommendations applicable to those major systems based upon our process design review. DOT PHMSA and USCG would be responsible for enforcing any of the minimum federal requirements in their respective regulations that would be applicable.

Process Description

The existing liquefaction facilities at the SLNG Terminal utilize movable modular liquefaction systems (MMLS), a proprietary technology involving offsite fabrication of modular system components that were delivered to, installed, and placed in service at the site. Ten (10) MMLS units were installed under a previous approved FERC application, Elba Liquefaction Project (Docket No. CP14-103). Each MMLS unit has a liquefaction capacity of 0.25 million tonnes per annum (MTPA) and contains two major processing systems: 1) gas treating, and 2) liquefaction. Feed gas is currently supplied via two existing 30-inch-diameter pipelines. In gas treating, feed gas is heated in an existing feed gas heater and then an existing feed gas filter separator is used to remove any liquids prior to the gas entering the acid gas removal system. Next, the amine absorption unit removes H_2S and CO_2, collectively referred to as acid gas. After acid gas removal, the feed gas passes to the dehydration equipment which removes water, and the mercury guard beds to remove mercury. Liquefaction occurs in a refrigeration area within each MMLS unit using a mixed refrigerant (MR) cycle where natural gas is cooled through a multi-stage refrigeration process to the point that it becomes liquefied (-260 ºF). The refrigerant used to cool down the natural gas to change it from a gas to a liquid state is a mixture of nitrogen, methane, ethylene, propane, and isopentane. Within the existing liquefaction process, hydrocarbon liquids are extracted in the debutanizer. In the debutanizer, the heavy hydrocarbons ("Stabilized Condensate") are separated from the lighter components. The lighter components are routed to the existing boil-off gas (BOG) system, which is consistent with NFPA 59A (2001 edition) section 3.4.5 above.

The Project is being proposed to improve the liquefaction process at the terminal, partially by reducing the fouling rate in the MMLS cold box units.[66] One factor which has contributed to the increased fouling rate in the MMLS cold boxes is the current feed

[66] The cold box is a self-supporting structure, typically box-shaped, containing cryogenic equipment, such as the main heat exchanger and mixed refrigerant distributors, surrounded by insulation and often purged with nitrogen to remove oxygen (to prevent flammable atmosphere in an enclosure) and moisture (to prevent freezing/icing).

gas composition is more lean (i.e., less heavier hydrocarbons like, propane, butane, pentane, etc.), with a heavy hydrocarbon tail, compared to the feed gas characteristics originally used in the design for the Elba Liquefaction Project under Docket No. CP14-103. This composition and the existing hydrocarbon liquid extraction system allows trace heavy hydrocarbons to pass through the existing cold gas separator and ultimately freeze on the heat transfer surfaces inside the existing cold box,. After enough operating time, the frozen heavy hydrocarbon particles accumulate and restrict the flow through the existing cold box, degrading production and eventually require removal. The process of removing the frozen particles is called "deriming" the existing cold box. Deriming requires the existing cold box be warmed up by allowing dry feed gas to pass through the existing cold box to defrost and remove the heavy hydrocarbons. Once completed, the existing cold box needs to be cooled back down prior to returning to service. The defrost gas is sent to the existing flare during the deriming process. Therefore, ELC and SLNG propose this Project to modify the existing feed gas dehydration system within each MMLS unit to remove heavy hydrocarbons prior to the feed gas entering the existing cold box and reduce the fouling rate in the existing MMLS units. This would reduce the resultant flaring events associated with the existing cold box deriming and allows the existing MMLS units to operate for longer periods of time without fouling, yielding improved LNG production with fewer thermal cycles of the existing cold box from deriming, and lower GHG emissions associated with derime flaring. In addition, ELC and SLNG indicate that the relatively minor modifications to the existing MMLS units would achieve a combined incremental increase in production of 0.4 MTPA total.

To reduce cold box fouling, cold box thermal cycling from deriming, and flaring events associated with cold box deriming, ELC and SLNG are proposing to make modifications to the existing ten (10) MMLS units located within the Terminal. The modifications would include retrofitting the current molecular sieve vessels to function as a combined Heavies Removal Unit (HRU) and dehydration system, installation of a common condensate plant, and other appurtenant modifications.

Each MMLS unit has two existing molecular sieve units, which operate in a staggered configuration, where one is absorbing water from the feed gas while the other regenerates the absorbent material. The absorbent material is regenerated by heating a slip stream of dry feed gas (regeneration gas) from the operating molecular sieve and passing through the regenerating bed, which transfers the water from the absorbent material to the regeneration gas. To remove the water from the regeneration gas, the gas is cooled through an air-cooled fin-fan heat exchanger and then flows to a regeneration separation vessel where water drops out the bottom of the vessel and the regeneration gas exits at the top. The exiting regeneration gas is then compressed, cooled in an aerial cooler, and then injected back into the process upstream of the amine absorber. The water collected from the bottom of the separator is then routed back to the amine system.

The modified molecular sieve system would absorb and regenerate the absorbent material the same way as the existing system, except that the absorbent material would be replaced with a different absorbent that is designed to remove both water and heavy hydrocarbons. Since the absorbent material would absorb both water and heavy hydrocarbons, instead of the bottoms of the regeneration separation vessel being routed back to the amine system, the bottoms would have both water and heavy hydrocarbons and would be routed to the Condensate Plant for further processing. To facilitate the absorbent media change, the existing molecular sieve vessel would be retrofitted by increasing in height and media would be replaced. Additionally, the tubes of the regeneration gas compressor aftercooler and regeneration gas cooler would be replaced with groovy finned tubes, and the fan motors would be replaced; the regeneration gas compressor's impeller, diffuser and motor would be replaced, and; the regeneration gas electric heater vessel would be replaced with a new heater. Other necessary modifications would include replacing the pressure control valve downstream of the feed gas heater, and the level control valve downstream of the amine contactor. The existing cold gas separator in each MMLS would be blinded off, and new piping would be installed to bypass the existing cold gas separator. The existing debutanizer, debutanizer reboiler, and condensate cooler in each MMLS would be blinded off and retired in place.

ELC and SLNG are proposing to add one (1) new condensate plant ("Condensate Plant") that would be co-located with the Balance of Plant (BOP) facilities[67]. In the new condensate plant, the regen gas from the modified molecular sieves would enter a proposed three-phase separator where flashed vapor would go to the fuel gas system, recovered water would be collected in a recovered water tank, and filtered through several carbon beds to remove any trace heavy hydrocarbons before being sent back to the amine system[68]. Hydrocarbon condensate would be sent to the proposed Stabilizer Column, where heat is added from the Reboiler with hot oil. Vaporized condensate would enter the LP fuel gas system, and stabilized condensate would be sent to the existing condensate storage tank. The new Condensate Plant would be common to all ten (10) MMLS units and would be required to take the effluent from the modified MMLS dehydration system and generate stabilized condensate.

ELC and SLNG estimate an increase in the Terminal's liquefaction capacity from

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[67] Balance of Plant (BOP) facilities typically refer to ancillary facilities, such as utilities and other supportive systems, use for the main processing facilities, such as the gas pretreatment and liquefaction facilities. The areas where the main processing facilities are located are often referred to as inside battery limits (ISBL) and the areas located away or outside of the main processing facilities are often referred to as outside battery limits (OSBL).
[68] Removal of hydrocarbons prior to returning back to amine is important because of the potential foaming problems caused by hydrocarbons entering amine solutions.

approximately 2.5 MTPA to approximately 2.9 MTPA as a result of the proposed modifications. FERC staff evaluated the PFDs and HMBs to determine the liquefaction capacities relative to the requested capacity in the application. The application requests exports with peak rates of up to 2.9 MTPA for ideal conditions. FERC staff confirmed the HMBs support the application export capacity in terms of net maximum production capacity. However, HMBs may be updated in final design in a way that could further increase liquefaction production without increasing export capacity, therefore we recommend later in this subsection for ELC and SLNG to file up-to-date PFDs and HMBs. This increase of 0.4 MTPA would require increased flow rates in the LNG rundown line from the MMLS units to the LNG storage tanks. As discussed and recommended in the Mechanical Design, Piping sub-section, ELC and SLNG should address this impact in the mechanical design of the piping, valves, and support systems. Alternatively, adjusting valve closure times may also mitigate some of these changes for which we also discuss and have recommendations later in Process Shutdown section.

The relief valves in the proposed condensate plant would discharge to a proposed flare knockout (KO) drum dedicated to the proposed condensate plant. While the separated liquid in the flare KO drum is sent to the existing low pressure (LP) drain header using the new flare KO drum pumps, the overhead of the flare KO drum is sent to the existing high pressure (HP) flare header. Existing flare systems at the SLNG Terminal would be utilized to handle and control the vent gases from the process areas. Safety relief valves would be designed to handle process upsets and thermal expansion and would relieve process gasses and liquid to the existing flares. ELC and SLNG provided P&IDs which shows major non-spared process vessels would be installed with a spare relief valve to ensure overpressure protection for process vessels is maintained during relief valve testing. We recommend in section 5 that ELC and SLNG specify redundant pressure relief valves for non-spared process vessels in their final design. Preliminary relief valve capacity and governing cases were reviewed and found to be consistent with operating and design pressures and sizing scenarios that are consistent with NFPA 59A, API 520 and API 521. However, FERC staff notes that the sizing of some PSVs installed to protect piping against compressor blocked outlet cases may need to be revisited during final design on account of the uprated liquefaction production and increased mixed refrigerant flowrate. FERC staff also notes that ELC and SLNG has not incorporated the use of thermal relief safety valves on piping segments with process fluids susceptible to thermal expansion, such as on condensate lines. Therefore, based on the above, we recommend in section 5 that prior to construction of final design, ELC and SLNG file, for review and approval, the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. Additionally, sizing basis should be provided for pressure relief valves protecting from overpressures due to mixed refrigerant compressor blocked outlet cases, and basis for necessity of thermal relief valves in non-cryogenic process piping. Mechanical design of pressure relief devices is also discussed in Mechanical Design, Pressure and Vacuum Relief Devices sub-section.

Utility supplied power would be used for all incremental power consumed by the proposed facilities. Therefore, no main power generators are being proposed for this project. The existing switchgear would be used as the main power supply to feed an existing motor control center (MCC). ELC and SLNG indicated that no new emergency power is required for this project. A battery back-up system, also called an Uninterruptable Power Supply system, would provide emergency power for essential services.

Hot oil would provide heat to the Reboiler in the condensate plant from the existing the hot oil heaters.

The instrument air for all control valves and ESD valves introduced in the Project would be supplied from the existing Instrument Air supply header. ELC and SLNG indicate that while the Liquefaction Optimization project introduces several new control valves (continuous users) and shutdown valves (UZVs), the total estimated instrument air consumption is minimal.

Three (3) new liquid nitrogen vaporizers would be installed as spares to tie the existing sendout nitrogen injection system to the existing utility nitrogen distribution headers to provide redundancy into the Terminal and BOP facilities. A new liquid nitrogen line from the existing liquid nitrogen supply to the existing nitrogen distribution header would be installed. The existing liquid nitrogen vessels and new vaporizers would be operated in standby for the existing Terminal and BOP nitrogen equipment. New nitrogen vaporizers would be operated using pressure control and would only discharge product if the existing terminal nitrogen facilities cannot keep up with terminal demand or are out of service. ELC and SLNG stated that the Project would not require additional liquid nitrogen deliveries.

Additional detail of the process design is depicted in the PFDs, HMBs, and P&IDs that detail all the piping, valves, equipment, instrumentation, controls, and other key features of the process design that also provides information used in other disciplines, such as the piping and insulation specifications to be used in the mechanical design. If the Project is authorized and moves forward with final design, these designs would be subject to change. Therefore, in order to verify any changes that are made would be consistent with those for which FERC staff's evaluations, recommendations, and conclusions are based upon, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file up-to-date process flow diagrams (PFDs), heat and mass balances (HMBs), and piping and instrument diagrams (P&IDs) including vendor P&IDs. The HMBs should demonstrate a peak export rate of 2.9 million metric tonnes per annum. The P&IDs should include the following information:

a. equipment tag number, name, size, duty, capacity, and design conditions;

b. equipment insulation type and thickness;
c. storage tank pipe penetration size and nozzle schedule;
d. valve high pressure side and internal and external vent locations;
e. piping with line number, piping class specification, size, and insulation type and thickness;
f. piping specification breaks and insulation limits;
g. all control and manual valves numbered;
h. relief valves with size and set points; and
i. drawing revision number and date.

In addition, the piping would need to tie into operating portions of the facilities that would necessitate more careful procedures to safely connect subsequently constructed facilities with operational facilities. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities.

Process Control Systems

The failure of process equipment could pose potential harm if not properly safeguarded through the use of appropriate engineering controls and operation. ELC and SLNG would install process instrumentation, controls, and valves to safely operate and monitor the facilities. Title 18 CFR § 380.12(o)(10) requires a description of the instrumentation and control philosophy, type of instrumentation (pneumatic, electronic), use of computer technology, and control room display and operation. It also requires piping and instrumentation drawings and process flow diagrams along with heat and material balances. Also, 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual in sections 13.4 through 13.22 and subsections, each major process systems should describe its basic process control systems (BPCS), including reference to design basis, criteria, and philosophies, regulations, codes and standards, engineering design information, and specifications. In addition, as suggested in our 2017 Guidance Manual section 13.30, applicants should provide a description of the BCPS, including all PLCs and DCS, including reference to design basis, criteria, and philosophies, regulations, codes and standards, engineering design information, specifications, instrument lists, and system architecture drawings. As discussed below, we evaluated the applicable federal regulations, codes, standards, and recommended and generally accepted good engineering practices.

Title 49 CFR § 193.2401, under Subpart E Equipment, requires each new, replaced, relocated or significantly altered control system69 be designed, fabricated, and installed in accordance with requirements of this part and of NFPA 59A (2001 edition). In addition, 49 CFR § 193.2441, under Subpart E, require each LNG plant to have a control center from which:

- operations and warning devices are monitored;
- each remotely actuated control system and each automatic shutdown control system required by 49 CFR 193 be operable;
- each control center have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance;
- each control center have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

The control center must be located apart or protected from other LNG facilities so that it is operational during a controllable emergency, and if more than one control center is located at an LNG Plant, each control center must have more than one means of communication with each other center.

Title 49 CFR § 193.2445, under Subpart E, also requires electrical control systems have at least two sources of power, which function so that failure of one source does not affect the capability of the other source. It also requires, where auxiliary generators are used as a second source of electrical power, that they be located apart or protected from components so that they are not unusable during a controllable emergency; and that the fuel supply be protected from hazards.

Title 49 CFR § 193.2619, under Subpart G Maintenance, require each control system be properly adjusted to operate within design limits. Title 49 CFR § 193.2619, under Subpart G, also requires control systems that are normally in operation, such as required by a base load system, to be inspected and tested once each calendar year but with intervals not exceeding 15 months. NFPA 59A (2001 edition) 11.3.2 similarly requires operating manuals to include procedures ensuring that each control system is properly adjusted to operate within its design limits and section 11.5.5.1(d) requires control systems be inspected and tested once each calendar year at intervals that do not exceed 15 months with exception to control systems that are used seasonally, which must be inspected and tested before use each season and control systems for fire protection

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[69] 49 CFR § 193.2007 defines control system as a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.

systems, which must be inspected and tested in accordance with the applicable fire code in addition to maintenance requirements in various NFPA standards that apply to fire protection systems.

Typically, alarms and shutdowns setpoints are established to operate within design limits and should be designed early enough in a process upset that there is an alarm to an operator initiated by a basic process control system (BPCS) (e.g., distributed control system (DCS)) or by a safety instrumented system (SIS) first setpoint (low, high, etc.) that an operator can effectively take action before progressing to an unsafe condition, and if that is not done and/or the process upset continues to progress, there is typically an automatic emergency shutdown initiated by a BPCS, or more commonly SIS, at a second setpoint (e.g., low-low, high-high, etc.). The setpoints typically should take into account the safety alarm response time. This is recognized in standards, such as the International Society for Automation (ISA 84) series and International Electrotechncial Commission (IEC) 61511 series discussed in Process Shutdowns, which FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) not yet incorporated into federal regulations. Many of the instrumentation and control set points would not be determined and finalized until final design. Therefore, we recommend in section 5 that, prior to construction of final design, ELC and SLNG file, for review and approval, the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (e.g., temperature, pressures, flows, and compositions).

ELC and SLNG indicated in their application that alarms would have visual and audible notification in the control room and in the field to warn operators that process conditions may be approaching design limits. However, there are no further requirements on how the alarms should be visually or audibly notified in the control room. Typically, a human-machine interface (HMI) provides the visual and audible notification to an operator and is subject to human error. For example, the use of red- and green- are often used, but can be subject to human error due to colorblindness. There are numerous applicable codes, standards, and recommended and generally accepted good engineering practices for control systems and human machine interfaces to address symbology and process displays, annunciator sequences, and other human factors. ELC and SLNG's application included the following applicable codes, standards, and recommended and generally accepted good engineering practices for control systems and human machine interfaces among others in their list of codes and standards that they would use for the Project:

- ISA 5.3, *Graphic Symbols for Distributed Control/Shared Display Instrumentation Logic and Computer Systems*
- ISA 5.5*, Graphic Symbols for Process Displays*
- ISA 18.1, *Annunciator Sequences and Specifications*
- ISA 55.1, *Hardware Testing of Digital Process Computers*
- ISA 60.1, *Recommended Practice for Control Center Facilities*

- ISA 60.3, *Human Engineering for Control Centers*
- ISA 60.4, *Documentation for Control Centers*
- ISA 60.5, *Control Centre Graphic Displays*
- ISA 60.6, *Nameplates Labels and Tags for Control Centers*
- ISA 71.04, *Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants*
- IEC 61131-3, *Programmable Controllers – Part 3: Programming Languages*
- IEC 61158, *Digital Data Communications for Measurement and Control*

These codes, standards, and recommended and generally accepted good engineering practices for control systems and human machine interfaces are consistent with recognized standards FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) annex A.11.7.1 not yet incorporated into federal regulations.

In order to ensure the functionality of the Basic Process Control Systems, we also recommend in section 5 that ELC and SLNG should complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS/SIS that demonstrates full functionality and operability of the system.

ELC and SLNG implemented an alarm management program and procedures for the control of equipment as part of the Elba Liquefaction Project (Docket No. CP14-103) in accordance with ISA 18.2, *Management of Alarm Systems for the Process Industries*, which is the most commonly referenced standard in LNG facilities under FERC jurisdiction to ensure an effective alarm management program. ISA 18.2.1, *Alarm Philosophy*, ISA 18.2.2, *Alarm Identification and Rationalization*, ISA 18.2.3, *Basic Alarm Design*, ISA 18.2.4, *Enhanced and Advanced Alarm Methods*, ISA 18.2.5, *Alarm System Monitoring, Assessment, and Auditing*, and ISA 18.2.7, *Alarm Management when Utilizing Packaged Systems* may also provide additional guidance. ELC and SLNG indicated the facilities being added as a part of the Liquefaction Optimization would be included in the alarm management program, but noted that ISA 18.2 would be covered by Engineering Equipment and Materials Users Association (EEMUA) 191, Alarm Systems – A guide to Design Management and Procurement. We disagree as EEMUA 191 is a guideline and not a standard and addresses not only what should be included but how to a lesser extent to the ISA 18.2.1, ISA 18.2.2, etc. guidance already referenced. In addition, Elba has previously referenced ISA 18.2 in their alarm management program and NFPA 59A (2023 edition) also makes reference to ISA 18.2. Therefore, we recommend in section 5 that prior to introduction of hazardous fluids, ELC and SLNG update the existing alarm management program to include the Liquefaction Optimization facilities, consistent with ISA 18.2 (2016 edition) or approved equivalent. If authorized and recommendations are adopted as conditions, FERC staff would evaluate whether ELC and SLNG have incorporated the proposed facilities into their existing alarm management program and would use that information to evaluate their alarm management during operations. FERC staff often request or review alarm monitoring and metrics, such as average alarm rates per operator console, peak alarm rate per operator console, alarm flood (i.e., more than 10 alarms in 10 minutes) percentages and counts, alarm priority distributions, and other metrics, to help assess the performance of alarms during operational inspections.

Operation Plans and Procedures

In order for the control systems to operate safely and reliably, operators need to know what controls to operate for various operating modes for the various process systems, such as pretreatment, liquefaction, tank, transfer, and any vaporization and sendout systems. Outside of the process design and control systems, operators would have the capability to act from the control room to act as one of the first layers of protection to mitigate an upset. Title 18 CFR § 380.12(m)(3) requires companies to discuss operational measures to avoid or reduce risk. As suggested in our 2017 Guidance Manual, section 13.O.4, operating plans and procedures would typically be developed after the application, but the development of those procedures should be discussed in the application. ELC and SLNG would develop facility operation and maintenance plans after completion of final design and prior to the introduction of hazardous fluids; this timing is fully consistent with accepted industry practice. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Title 49 CFR § 193.2503, under Subpart F Operations, requires each operator to follow one or more manuals of written operating procedures for normal and abnormal operation, including, but not limited to purging and inerting components, cooldown, startup and shutdown, including initial startup and performance testing to demonstrate components will operate satisfactorily in service; liquefaction, transfer, and vaporization, as applicable, as well as recognizing abnormal operating conditions. More specifically, 49 CFR § 193.2503(f) requires written procedures for liquefaction, maintaining temperatures, pressures, pressure differentials and flow rates, as applicable, within their design limits for: (1) boilers; (2) turbines and other prime movers; (3) pumps, compressors, and expanders; (4) purification and regeneration equipment; and (5) equipment within cold boxes.

However, this does not cover all equipment, such as other fired equipment that do not qualify as boilers, and does not cover the provide requirements on how the operating limits are kept within their design limits. As discussed in Process Control Systems subsection, there is typically a margin between operating limits and design limits where alarms and shutdowns are set to be early enough in a process upset before reaching the design limits such that an operator can effectively take action before progressing to an unsafe condition. Taking into account the safety alarm response time is recognized in standards, such as the above-mentioned ISA 84 series and IEC 61511 series, and FERC staff has proposed and is now referenced in newer editions of NFPA 59A (2019 and 2023 editions) not yet incorporated into federal regulations. These margins between operating limits and design limits would not be finalized until final design and many of the instrumentation and control set points would not be determined until final design. Therefore, we recommend in section 5 that ELC and SLNG file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (e.g., temperature, pressures, flows, and compositions). We also recommend in section 5 that prior to commissioning, ELC and SLNG should file, for review and approval, the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions procedures, simultaneous operations procedures, and management of change procedures and forms. The operational maintenance and testing procedures for fire protection components should be in accordance with NFPA 59A (2019) or approved equivalent. We would evaluate any new or updated procedures in coordination with DOT PHMSA and USCG to ensure that an operator can operate and maintain all systems safely, based on benchmarking against other operating and maintenance plans and comparing against recommended and generally accepted good engineering practices, such as AIChE CCPS, *Guidelines for Writing Effective Operating and Maintenance Procedures*, AIChE CCPS, *Guidelines for Management of Change for Process Safety*, AIChE CCPS, *Guidelines for Effective Pre-Startup Safety Reviews, AGA, Purging Principles and Practices*, and NFPA 51B, *Standards for Fire Prevention During Welding, Cutting, and Other Hot Work*.

In addition, 49 CFR § 193.2017, under Subpart A General, requires that operating and maintenance plans and procedures are reviewed and updated when a component is changed significantly or a new component is installed and at intervals not exceeding 27 months, but at least once every 2 calendar years. Title 33 CFR Part 127 also has similar requirements for written operations, training, and experience for persons in charge of shoreside transfer operations. As discussed and recommended in Managing Changes and Semi-Annual Reports, FERC staff is also recommending managing of change procedures and forms as well as semi-annual reporting on modifications.

In addition, NFPA 59A (2001 edition) section 6.5 requires piping to be identified by color-coding, painting, or labeling and indicates any existing company color code scheme for the identification of piping systems is permitted to be used. NFPA 59A (2001 edition) section 8.1.2 also requires truck, rail car, and pipeline transfer systems handling LNG, refrigerant, flammable liquid, and flammable gas LNG, refrigerant, flammable liquid, and flammable gas to also meet these piping requirements, including section 6.5, and section 8.6.4 requires pipeline loading arms, hoses, or manifolds be identified or marked to indicate the product or products to be handled by each system where multiple products are loaded or unloaded at the same location. However, these identification provisions are limited to piping and pipeline transfer systems and do not apply to instrumentation, valves and equipment, and there have been a number of incidents attributed in similar facilities for unintentionally reading the wrong instrument or operating the incorrect valve or equipment. Therefore, we recommend in section 5 that prior to commissioning, ELC and SLNG should tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. In addition, once facilities have gone through commissioning there is typically a normal direction of flow and identifying piping by color code or paint does not provide the normal direction of flow that can further aid in reducing human error. Therefore, we recommend prior to commencement of service, ELC and SLNG should label piping with fluid service and direction of flow in the field, consistent with ASME A13.1 (2020 edition) or approved equivalent, in addition to the pipe labeling requirements of NFPA 59A (2001). This is also consistent with what FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) section 10.7.2 not yet incorporated into federal regulations.

Also, recent incidents in the LNG industry and in similar industries have highlighted the importance of ensuring not only permanent plant personnel, but also contractors are subject to oversight to reduce the potential risk of incidents. Such requirements are in regulations of other similar industries under 29 CFR 1910.119 and 40 CFR 68. Therefore, we recommend in section 5 that prior to commencement of service, ELC and SLNG should develop procedures for offsite contractors' responsibilities, restrictions, monitoring, training, and limitations and for supervision of these contractors and their tasks by ELC and SLNG staff. Specifically, the procedures should address: a) selecting a contractor, including obtaining and evaluating information regarding the contract employer's safety performance and programs; b) informing contractors of the known potential hazards, including flammable; and toxic release, explosion, and fire, related to the contractor's work and systems they are working on; c) developing and implementing provisions to control and monitor the entrance, presence, and exit of contract employers and contract employees from process areas, buildings, and the plant; d) developing and implementing safe work practices for control of personnel safety hazards, including lockout/tagout, confined space entry, work permits, hot work, and opening process equipment or piping; e) developing and implementing safe work practices for control of process safety hazards, including identification of layers of protection in systems being worked on, recognizing abnormal conditions on systems they are working on, and re-instatement of layers of protection, including ensuring bypass, isolation valve, and car-seal programs and procedures are being followed; f) developing and implementing provisions to ensure contractors are trained on the emergency action plans and that they are accounted for in the event of an emergency; g) monitoring and periodically evaluating the performance of contract employers in fulfilling their obligations above, including successful and safe completion of work and re-instatement of all layers of protection. FERC staff have also proposed similar requirements for contractor oversight to be adopted into NFPA 59A (2026 edition).

Safety Instrumented Systems and Emergency Shutdown Systems

In the event of a process deviation, safety instrumented systems and ESD valves would monitor, alarm, shutdown, and isolate equipment and piping during process upsets or emergency conditions. ELC and SLNG would install safety instrumented systems and ESD valves to safely operate and monitor the facilities. Title 18 CFR § 380.12(o)(3) requires identification of all safety provisions incorporated in the plant design, including automatic and manually activated emergency shutdown systems. Title 18 CFR 380.12(o)(10) also requires piping and instrumentation drawings, which would normally include this information. Also, 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual in sections 13.4 through 13.22 and subsections, each major process systems should describe its basic process control systems safety instrumented systems (SIS), including the feed gas high integrity pressure protection system (HIPPS), and should reference the design basis, criteria, and philosophies, regulations, codes and standards, engineering design information, and specifications. In addition, as suggested in our 2017 Guidance Manual section 13.31, applicants should provide a description of the SIS, including emergency shutdown and fire and gas systems (FGS), and should reference the design basis, criteria, and philosophies, regulations, codes and standards, engineering design information, specifications, cause and effect matrices, block diagrams, list of shutoff valves, drawings of ESD manual activation devices, and any shutoff valve manufacturer's data.

As already discussed, 49 CFR § 193.2401, under Subpart E Equipment, requires each new, replaced, relocated or significantly altered control system[70] be designed, fabricated, and installed in accordance with requirements of this part and of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 9.1.2 requires an evaluation to determine the equipment and processes to be incorporated within the ESD system, including analysis of subsystems, if any, and the need for depressurizing specific vessels or equipment during a fire emergency and the type and location of sensors necessary to initiate automatic operation of the ESD system or its subsystems. In addition NFPA 59A (2001 edition) section 9.2.1 requires each LNG facility to incorporate ESD system(s)

[70] 49 CFR § 193.2007 defines control system as a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.

that, when operated, isolate or shut off a source of LNG, flammable liquid, flammable refrigerant, or flammable gas, and shutdown equipment whose continued operation could add to or sustain an emergency. It also allows for any equipment, such as valves or control systems, that is specified in another chapter of this standard be permitted to be used to satisfy the requirements of an ESD system except where indicated in this standard. NFPA 59A (2001 edition) section 9.2.5 allows initiation of the ESD system(s) to be manual, automatic, or both manual and automatic, depending on the results of the evaluation performed in accordance with 9.1.2, but manual actuators must be located in an area accessible in an emergency, at least 50 ft (15 m) from the equipment they serve, and be marked distinctly and conspicuously with their designated function. NFPA 59A (2001 edition) section 9.2.4 also requires operating instructions identifying the location and operation of emergency controls be posted conspicuously in the facility area.

However, 49 CFR § 193.2401 provide limited requirements for where instrumentation and shutdowns must be installed, as discussed in Process Design, and FERC staff have observed the deferral to an evaluation for the requirements on what type and location of SIS and ESD should be installed, what equipment and processes they would shutdown, and whether automatic and/or manual ESD systems should be installed does not provide regulatory certainty or necessarily provide a safe and reliable SIS and ESD systems. In addition, while NFPA 59A (2001 edition) allows for BPCS and SIS to have common controls and valves in most areas, which is counter to other codes, standards, and recommended and generally accepted good engineering practices as it can increase the risk of common cause failures. Therefore FERC staff evaluated what types and where SIS and ESD systems were installed from the P&IDs, what equipment and processes they would shutdown from the cause and effect matrices, and the list of codes, standards, and recommended and generally accepted good engineering practices that would be used in the design.

ELC and SLNG application also included the following applicable SIS and ESD system codes, standards, and recommended and generally accepted good engineering practices among others in their list of codes and standards that they would use for the Project:

- IEC 61508, *Functional Safety of Electrical/Electronic/Programmable Electronic Safety-Related Systems*
- IEC 61511, *Functional Safety – Safety Instrumented Systems for the Process Industry Sector,*
- *International Society of Automation (ISA) 84.00.01 Part 1, Functional Safety: Safety Instrumented Systems for the Process Industry Sector – Part 1: Framework, Definitions, System, Hardware and Software Requirements*
- ISA 84.00.01 Part 2, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector – Part 2: Guidelines for the Application of ANSI/ISA-84.00.01-2004 Part 1 – Informative*

- ISA 84.00.01 Part 3, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector – Part 3: Guidance for the Determination of the Required Safety Integrity Levels – Informative*

These codes, standards, and recommended and generally accepted good engineering practices for SIS and ESD systems are consistent with recognized standards FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) annex A.11.2, A.11.7.1, not yet incorporated into federal regulations and with recognized standards FERC staff proposed for NFPA 59A (2026 edition).

ELC and SLNG application indicated that the current version at the time of design would be used. Therefore, we recommend ELC and SLNG in section 5 as also discussed in Final Specifications and Quality Management System, that prior to construction of final design ELC and SLNG file, for review and approval, a final list of all applicable codes and standards that would be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the final specifications and document numbers.

In their application, ELC and SLNG also provided P&IDs depicting the locations of SIS and ESD valves and cause and effect matrices that indicate what equipment and processes would shutdown and whether those are automatically and/or manually initiated. While limited in being able to publicly discuss those due to them being considered as Critical Energy Infrastructure Information (CEII), ELC and SLNG did include SIS and ESD that was commensurate with the risk of the Project and include multiple SIS and ESD systems to initiate closure of valves and shutdown of the process during emergency situations as well as the ability to shutdown specific areas to address local emergency conditions that would be consistent with NFPA 59A (2001 and later editions) for ensuring tanks with flammable fluids would have appropriate alarms and shutdowns to prevent overfilling consistent with section 7.1.2.1 and consistent with other general SIS and ESD systems FERC observe in commensurate facilities, such as prime movers (e.g., motors) that shutdown on abnormal conditions (e.g., amperage, vibration, etc.). However, given that this information is preliminary and subject to change, we also recommend in section 5 that, prior to construction of final design, ELC and SLNG should file, for review and approval, cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

NFPA 59A (2001 edition) section 7.5 requires instrumentation for liquefaction, storage, and vaporization facilities be designed so that, in the event that power or instrument air failure occurs, the system will proceed to a failsafe condition that is maintained until the operators can take appropriate action either to reactivate or to secure the system. NFPA 59A (2001 edition) section 9.2.3 also requires the ESD system(s) be of a failsafe design or be otherwise installed, located, or protected to minimize the possibility that it becomes inoperative in the event of an emergency or failure at the normal control system. ESD valves and other safety valves which isolate and depressurize a process in emergencies have a failsafe position. If the valve loses instrument air or control signal, the valve will resort to its position which shuts off the source of hazardous fluids or reduces the pressure of the hazardous fluids within the process. For instance, in the event of loss of instrument air or control signal, an ESD valve might failsafe to the closed position to shutoff the source of hazardous fluids to or from a vessel, while a blowdown valve would failsafe to the open position to reduce the vessel pressure. All ESD valves with a failsafe position rely on an electrical signal to an instrument air solenoid valve to keep the process valve in its non-failsafe position during normal operation. In the event of an emergency, that signal would change, and the valve would move to the failsafe position. If during an emergency failsafe valve control and power cables are exposed to high heat and fire, they may become damaged and may cause electrical shorts and faults, potentially resulting in spurious valve actuation from its failsafe position. To ensure the operation of failsafe valves during an emergency, cables with passive protection ratings may be specified, and is discussed further in the passive protection section.

Also, in order for operators to be able to verify whether the ESD valves are open and closed from the control room, we also recommend in section 5 that, prior to construction of final design, ELC and SLNG should specify that all emergency shutdown valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS)/safety instrument system (SIS). The effectiveness of these valves are based on the closure times of them, which is typically determined during final detailed design. FERC staff assume that the valves would generally be able to be activated and isolate within 10 minutes or shorter time demonstrable by the time to detect an upset or hazardous condition, notify plant personnel, personnel to initiate valve closure, and for the valve to close. Therefore, we also recommend in section 5 that prior to construction of final design, ELC and SLNG should file an evaluation of emergency shutdown valve closure times. The evaluation should account for the time to detect an upset or hazardous condition, notify plant personnel, and close the emergency shutdown valve(s). The hydraulic impacts of these valve closures are also discussed in Mechanical Design. In order to ensure their functionality, we also recommend in section 5 that ELC and SLNG should complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS/SIS that demonstrates full functionality and operability of the system.

Process Hazard Analysis

In order to assess the process design, control systems, safety instrumented sytems, and emergency shutdown systems, companies will typically conduct a process hazard analysis (PHA) to help identify potential process hazards and analyze whether there are sufficient layers of protection to mitigate the risk to a tolerable level. Title 18 CFR § 380.12(m)(1) requires applicants to describe measures proposed to protect the public from failure of the proposed facilities, 18 CFR § 380.12(m)(2) requires applicants to discuss hazards which could reasonably ensue from failure of the proposed facilities, and 18 CFR § 380.12(m)(2) (3) requires applicants to discuss operational measures to avoid or reduce risk. In addition, 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, section 11.2.2 covers a description of the process hazard identification and analyses conducted to date to identify potential hazardous events possible from the hazardous materials stored, processed, and handled onsite and analyze the safeguards necessary to mitigate such hazards with reference to engineering design information (e.g., P&IDs, PFDs, etc.), project specifications, and PHAs.

In developing the FEED, ELC and SLNG conducted a Hazard Identification (HAZID) review of the project's preliminary design based on the proposed process flow diagrams and the plot plans. This is consistent with NFPA 59A (2019 and 2023 editions) which require consideration of a process hazard analysis (PHA) for the plant and a site evaluation. Initial PHAs are required in similar facilities regulated under EPA's 40 CFR § 68.67 Chemical Accident Prevention Provisions and OSHA's 29 CFR § 1910.119 Process Safety Management (PSM) of Highly Hazardous Chemicals regulations that are not applicable to LNG facilities regulated under 49 CFR Part 193, which incorporates NFPA 59A (2001 and 2006 edition), or waterfront facilities handling LNG under 33 CFR Part 127, which incorporates NFPA 59A (2019 edition) that requires initial PHA during siting, but 33 CFR Part 127 does not incorporate this requirement in section 5.2.1 where it first became part of NFPA 59A (2019 edition). In addition, in accordance with recommended and generally accepted good engineering practices, such as AIChE CCPS, *Guidelines for Hazard Evaluation Procedures*, the PHA methodology should be commensurate with the project scope and complexity as well as the stage of the project and that each subsequent PHA be sure to that prior PHAs done in previous stages ensure the recommendations have been resolved or are carried over into the next PHA. Subsequently, we recommend in section 5 that, prior to construction of final design, ELC and SLNG should file, for review and approval, information to verify how the EPC contractor has addressed all FEED HAZID recommendations.

Further, while a HAZID is technically a PHA recognized in literature, it tends to be less comprehensive, rigorous, and regimented than other PHA methods and often does not yield the same level of quality or meaningful recommendations. As such, a more detailed PHA, such as a Hazard and Operability Review (HAZOP), would be typically performed during the final design to identify the major process hazards that may occur during the operation of the facilities. The HAZOP study would be intended to address hazards of the process, engineering, and administrative controls and would provide a qualitative evaluation of a range of possible safety, health, and environmental consequences that may result from the process hazard, and identify whether there are adequate safeguards (e.g., engineering and administrative controls) to prevent or mitigate the risk from such events. Where insufficient engineering or administrative controls were identified, recommendations to prevent or minimize these hazards would be generated from the results of the HAZOP review. In many cases, companies have also conducted a Layer of Protection Analysis (LOPA) that builds off of a HAZOP to provide a semi-quantitative evaluation of all or select safeguards that is intended to quantify the likelihood of events with qualitative consequences and uses a safety integrity level (SIL) to define the reliability through average probabilities of failure on demand ($PFD_{average}$) for the safeguards, or layers of protection. The SIL is often specified as a SIL 1, SIL 2, or higher SIL corresponding to a $PFD_{average}$ of 10%, 1%, or lower, or, in other words, a risk reduction factor (RRF) of 10, 100, or higher. The estimated initiating event frequency and SILs of the safeguards, often safety-instrumented systems (SIS), are then specified until they would meet specified targeted risk tolerance criteria. The SIL of a safeguard is then often verified through a SIL verification study that evaluates historical failure frequencies of those safeguards. In some cases, companies will skip the LOPA and jump straight to defining a SIL during the HAZOP and conduct a SIL verification study. In any case, the HAZOP, and any LOPAs and SIL verification studies define the safeguards, or layers of protection, that are being depended upon and therefore define the safety and often reliability intended to be included in the final design. Once identified, these safeguards are incorporated into the construction, commissioning, inspection, testing, operation and maintenance procedures. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, a HAZOP, and any LOPA or SIL verification studies, on the completed final design. In addition, the issued for construction P&IDs should incorporate the HAZOP review and any LOPA or SIL verification studies recommendations and justification should be provided for any recommendations that are not implemented. If the Project is authorized and our recommendation is adopted into the order, we would evaluate the HAZOP, and any LOPA and SIL verification studies, to ensure all systems and process deviations are addressed appropriately based on likelihood, severity, and risk values with commensurate layers of protection in accordance with recommended and generally accepted good engineering practices, such as AIChE's, *Guidelines for Hazard Evaluation Procedures*. In addition, FERC staff would monitor whether the resolutions of the recommendations generated by the PHA reviews were resolved.

Mechanical Design

Once the process design and conditions are defined, typically the mechanical design team would define the mechanical design of the piping and equipment that would be able to contain the process fluids at the temperatures and pressures defined in the process design. This typically involves the production of equipment lists, mechanical datasheets, and mechanical specifications. Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, this includes mechanical design and specifications and preventative maintenance of various equipment, including piping, valves, pressure vessels, heat exchangers, rotating equipment, fire equipment, and relief valves.

DOT PHMSA regulations in 49 CFR § 193.2703 requires the design and fabrication of components to be completed by those who have a demonstrated competence by training or experience in the respective design and fabrication of comparable components. Similarly, 49 CFR § 193.2705 requires supervisors and other personnel utilized for construction, installation, inspection, or testing to have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments. In addition, 49 CFR § 193.2304 also requires a person qualified under 49 CFR § 193.2707(c) review the applicable design drawings and materials specification from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the components or any associated components. Title 49 CFR § 193.2631 also requires each component that is subject to internal corrosive attack to be protected from internal corrosion by material that has been designed and selected to resist the corrosive fluid involved or suitable coating, inhibitor, or other means.

Companies will typically contract FEED and final design to EPC firms with expertise planning and overseeing the engineering, procurement, construction, and commissioning (i.e., inspection and testing) of facilities, including selecting vendors for equipment with specialized training or experience in the design and fabrication of comparable components. As part of this process, the engineering firms would typically provide specifications for the project to the vendors, which would typically stipulate the regulations (e.g., 49 CFR Part 193, 33 CFR Part 127, etc.), codes and standards (e.g., ASME B31.3, ASME B31.5, ASME B31.8, etc.) and other information the EPC contractor would require in the design, fabrication, construction, installation, and testing. For example, EPC firms would typically use and specify codes and standards, such as ASME B31.3, to determine the minimum thickness of the piping and equipment based on the process conditions (e.g., pressure, temperature, etc.) and properties of the materials of construction to limit the piping and equipment from exceeding specified allowable stresses. Additional codes and standards, such as ASME B36.10 and ASME B36.19, are then often used to select standard schedule of piping and class of valves that have minimum pressure ratings and corresponding minimum thicknesses for different materials of construction. These codes and standards also specify their fabrication, construction, installation, and inspection and testing requirements, such as welding and non-destructive examination requirements for those welds as well as pressure/leak testing requirements. As discussed in more detail below, we reviewed these specifications. Based on our reviews, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, mechanical data sheets, and specifications, including mechanical specifications (e.g., piping, valves, insulation, rotating equipment heat exchanger, storage tank and vessel, other specialized equipment). In addition, as discussed in Final Specifications and Quality Management Systems, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, a final list of all applicable codes and standards that would be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the final specifications and document numbers.

Piping

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.23 covers piping design, including references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

FERC staff evaluated the mechanical engineering design of the piping by evaluating the federal regulations, list of applicable piping codes, standards, and recommended and generally accepted good engineering practices that would be used in the Project and piping specifications denoted on the P&IDs. When evaluating the piping specifications, FERC staff focused on the associated piping design code, materials of construction, wall thickness, branch connections, etc. within the piping specifications to ensure they would be suitable for the fluid service (e.g., internal corrosion rates), process conditions (e.g., temperature, pressure, etc.) provided in the PFDs and HMBs, and external environmental (e.g., aboveground, belowground, etc.).

Title 49 CFR § 193.2007 defines piping as including fittings. Fittings are used to fit two or more pipes or other components together of the same or different size, such as pipe couplings, flanges and gaskets, tees, elbows, nipples[71] (e.g., threaded one end, threaded both ends, concentric and eccentric swage nipples, etc.,), reducers[72], olets (e.g., weldolets, threadolets, sockolets, etc.), and end caps, plugs, and blinds. FERC staff similarly evaluated the mechanical engineering design of pipe fittings by evaluating the piping specifications to ensure the materials of construction, dimensioning, etc. were suitable for the fluid services, process conditions, external environments.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 6.1.1 requires all piping systems be in accordance with ASME B31.3, Process Piping, 1996 edition. Similarly, 33 CFR 127 Subpart B covers USCG regulatory requirements of the marine transfer area, including 33 CFR **§** 127.101 for design and construction, which incorporates NFPA 59A (2019 edition) Chapter 5, Section 5.3.1.7; Chapter 6, Section 6.7; Chapter 10; Chapter 11, except Sections 11.9, and 11.10; Chapter 12; Chapter 15, except Sections 15.4 and 15.6; and Annex B.

The mechanical design of the piping would be largely determined based on the fluid service and applicable piping design code. Commonly specified piping design codes include ASME B31.1, *Power Piping*, ASME B31.3, *Process Piping*, ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*, ASME B31.5, *Refrigeration Piping and Heat Transfer Components*, ASME B31.8, *Gas Transmission and Distribution Piping Systems*, ASME B31.9 *Building Services Piping*, NFPA 54/ANSI Z223.1, *National Fuel Gas Code*, NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, AWWA C150, *Thickness Design of Ductile-Iron Pipe*, AWWA C200, *Steel Water Pipe 6 inches and Larger*, AWWA C900, *Polyvinyl Chloride (PVC) Pressure Pipe and Fabricated Fittings 4 inches through 60 inches*.

ELC and SLNG listed NFPA 59A (2001 through 2019 editions), ASME B31.3, *Process Piping*, 2010 edition, ASME B31.5, *Refrigeration Piping and Heat Transfer Components*, 2010 edition, ASME B31.8, *Gas Transmission and Distribution Piping Systems*, 2010 edition, in their list of applicable codes and standards that they would use for the Project. However, ELC and SLNG are not proposing any power generation or any

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[71] Pipe nipples are short piece of pipe typically with at least one threaded end used to connect two pipes of same or different sizes together. Threaded pipes and nipples are limited

[72] Pipe reducers are short piece of pipe used to connect a larger diameter pipe with a smaller diameter pipe. These are different than pipe nipple swages in that they are typically welded at both ends as opposed to having threaded ends.

new transmission lines with this Project and while there is liquefaction equipment that involves refrigeration, ASME B31.3 (1996 edition) is what is specified in NFPA 59A (2001) and ASME B31.3 (1996 edition) allows the use of either ASME B31.3 or ASME B31.5 to be used for packaged refrigeration piping. In addition, ELC and SLNG process piping specifications markups indicate the Project would comply with ASME B31.3 (*2020 edition*) and NFPA 59A (2001 edition) or just ASME B31.3 (2020 edition), and the proposed piping specifications recommend that ASME B31.3 edition be updated per contract award date. ELC and SLNG's proposed piping specifications also indicated firewater piping would meet NFPA 24*, Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, 2022 edition. While FERC staff generally supports the use of more up-to-date piping design codes and standards because they generally capture more lessons learned from safety incidents and typically reflect more state-of-the-art and more accurate performance-based and risk-based approaches (e.g., incorporation of a weld joint strength factor in 2016 edition), it is not clear whether the use of ASME B31.3 (2014 or 2020 or later editions) would be considered equivalent by DOT PHMSA for compliance with 49 CFR Part 193. Compliance with 49 CFR 193 would be subject to DOT PHMSA inspection and enforcement program. However, FERC staff found the proposed piping codes referenced to be suitable for each fluid service and use and do not pose any safety or reliability impacts.

As previously mentioned, materials of construction will depend primarily on the fluid service, process conditions, and external environment. Typically, in LNG plants under FERC jurisdiction, process piping in normal fluid services above -20°F will generally specify the use of carbon steel, process piping in normal fluid service between -20°F and -50°F will generally specify low temperature impact tested carbon steel, and process piping in normal fluid service below -50°F will generally specify the use of stainless steel. Other common process piping materials of construction in LNG plants include aluminum subject to the limitations in NFPA 59A (2001 and later editions). NFPA 59A (2001 and 2019 editions) requires liquid lines on storage containers, cold box, or other major item of insulated equipment external to the outer shell or jacket, whose failure can release a significant quantity of flammable fluid, not be made of aluminum, copper or copper alloy, or other material that has low resistance to flame temperatures. NFPA 59A (2001 edition) also specifies that cast iron, malleable iron, and ductile iron cannot be used for pipes and fittings and NFPA 59A (2019 edition) clarified that this exclusion is for hazardous fluids. NFPA 59A (2001 and 2019 editions) also require that piping materials of construction meet ASME B31.3 (1996 and 2016 editions, respectively). ASME B31.3 (1996 and 2016 editions) requires the use of listed materials specified within it and any use of unlisted materials is only allowed if they conform to a published specification covering chemistry, physical and mechanical properties, method and process of manufacturer, heat treatment, and quality control, and does not allow the use of unknown materials. Listed and unlisted materials therefore must conform to published specifications, such as those published by the American Society of Testing and Materials (ASTM). As such, the piping specification typically indicates the listed ASTM standard for the piping or piping component material of construction, which standardizes the chemical compositions and material properties, as described above. Typically, in LNG plants under FERC jurisdiction, carbon steel is specified as ASTM A106, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service* and stainless steel is specified as ASTM A312, *Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes*. ASTM A106 Grade B and ASTM A312 TP304/304L are also the most common grades/types specified. Similarly, the fittings and flanges will also typically have corresponding specified and listed ASTM standard, such as ASTM A105, *Standard Specification for Carbon Steel Forgings for Piping Applications*, or ASTM A182, *Standard Specification for Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service*. Similarly, NFPA 24 (2022 edition) requires firewater piping to be in accordance with NFPA 24 listed materials of construction, and are commonly specified as ductile iron, carbon steel, and/or high density polyethylene (HDPE). Non-potable water piping (e.g., utility water, waste water, etc.) and potable water service piping is commonly specified in accordance with International Code Council (ICC), *International Building Code* (IBC), and ICC, *International Plumbing Code* (IPC), and is commonly specified as polyvinyl chloride (PVC) or chlorinated PVC (CPVC), respectively. ELC and SLNG's proposed materials of construction would be consistent with the fluid service, process conditions, and external environment. In addition, the materials of construction are consistent with the materials of construction and ASTM standards listed in ASME B31.3 (1996, 2016, and 2020 editions) and consistent with those commonly specified and in operation. Therefore, FERC staff found the piping materials of construction to be adequate and do not pose any safety or reliability impacts.

FERC staff also evaluated the nominal piping diameter selected for the facility. The nominal pipe diameter is driven by the required flow and pressures for the process design. Selecting the nominal pipe diameter is based on velocity limits and pressure drop limits. The pressure drop will depend on the friction losses due to the material friction factor and the inner diameter of the piping when considering the distance the fluid must travel through the piping. ELC and SLNG nominal piping diameters were commensurate with typical velocity and pressure drop limits. Therefore, FERC staff found the nominal piping diameters to be adequate and do not pose any safety or reliability impacts.

While the piping design codes and nominal piping diameter are informative, FERC staff also evaluated whether the resultant wall thicknesses (i.e., schedule of piping) and flange class rating in the piping specifications were consistent with the applicable piping design codes and standards based on the pressures. The piping wall thickness and corresponding outer diameter will be driven by the applicable piping design code (e.g., power generation, process, refrigeration, transmission, etc.), material of construction, nominal piping diameter, fluid service, process conditions (e.g., pressure, temperature, etc.), corrosion allowance based on internal corrosion and external corrosion (e.g., whether the line is buried underground or located aboveground and external corrosion controls), and other potential factors and loads. The minimum wall thickness also accounts for potential corrosion for piping used in corrosive services, which requires the use of either materials of constructions not subject to internal or external corrosion or material of construction that have a corrosion allowance, typically from 1/16-inch (0.0625 inches) to 1/8-inch (0.125 inches) over a 15-year to 30-year design life with periodic wall thickness testing throughout operation for LNG plants. Companies will then commonly specify wall thicknesses in accordance with standards, such as ASME B36.10M, *Welded and Seamless Wrought Steel Pipe* for carbon steel and ASME B36.19M, *Stainless Steel Pipe* for stainless steel to fabricate piping with standardized inner and outer diameters and corresponding thicknesses that meet or exceed the minimum thicknesses calculated in the aforementioned piping design codes and standards. For carbon steel, the wall thickness generally will be specified with "Schedules" of 5, 10, 20, 40, 80, or 160 or identification of Standard (STD), extra strong (XS), or double extra strong (XXS) and for stainless steel wall thicknesses generally will be specified with Schedules 5S, 10S, 40S, and 80S. Schedule 40 and STD are identical for up to and including a NPS of 10 inches diameter and Schedule 80 and XS are identical for up to and including a NPS of 8 inches diameter. Schedule 40 and Schedule 80 are thicker than STD and XS, respectively, thereafter (noting Schedule 80 does not exist for NPS of 26 inch diameter and larger and Schedule 40 does not exist for NPS of 26 inches diameter and up to NPS of 30 inch diameter or for NPS of 38 inch diameter and larger). Conversely, Schedule 160 is thicker than XXS for up to and including a NPS of 6 inches diameter and becomes thinner than XXS for NPS of 8 inches diameter and larger (noting there is no Schedule 160 for NPS of 22 inch diameter and larger and there is no XXS for NPS of 14 inch diameter and larger). ELC and SLNG specified wall thicknesses and flange classes commensurate with the maximum pressure and temperature ranges in the piping specifications. In addition, FERC staff spot checked internal pressures listed in the heat and material balances against the maximum pressure and temperature ranges in the piping specifications and also found them to be appropriate.

In addition, ASME B31.3 (1996 and 2016 editions) paragraph 301.5.1 require that piping be designed for impact forces by external conditions. However, it does not specify what external conditions that could result in an impact load. FERC staff has also observed the plastic deformation (i.e., permanent bending) and failure of 2 inch and less diameter piping and appurtenances due to operators stepping or grabbing onto piping when there is a lack of access to valves, instrumentation, or other components that need to be operated in the field. In addition, ASME B31.3 (1996 and 2016 editions) require that piping be designed, arranged, and supported to eliminate excessive and harmful effects of vibration. FERC staff has observed failures in the industry due to vibration in proximity to rotating equipment. For these reasons, FERC staff typically evaluate, as a screening analysis, whether piping and piping nipples 2 inches and less would be specified as at least schedule 160 for carbon steel or 80S for stainless steel. We note that ELC and SLNG specifies all hazardous fluid piping and piping nipples 2-inch and less as schedule 160 for carbon steel piping and all hazardous fluid piping and piping nipples as schedule 80S for stainless steel. However, FERC staff recognize the pipe schedule and materials of construction proposed could change in final design and that such a prescriptive approach on schedule would not apply to all potential materials of construction, and therefore support a more performance- and risk-based approach over prescriptive approach to allow for a more comprehensive analysis that demonstrate whether such piping could withstand those loads. Such analyses are more suitable for final design and would be consistent with ASME B31.3 (1996 and 2016 editions). Therefore, we recommend in section 5 that ELC and SLNG file, for review and approval, documentation demonstrating that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators prior to construction of final design.

ASME B31.3 (1996 and 2016 editions) paragraph 301.5.1 also require that piping be designed for impact forces by internal conditions. NFPA 59A (2001 and 2019 editions) have similar requirements for transfer of LNG refrigerants, flammable liquids, and flammable gases between storage containers or tanks and points of receipt or shipment by pipeline, tank car, tank vehicle, or marine vessel. NFPA 59A (2001 and 2019 editions) section 8.2.1 and section, for each edition respectively, require isolation valves be installed so that each transfer system can be isolated at its extremities, and where power-operated isolation valves are installed, an analysis be made to determine that the closure time will not produce a hydraulic shock capable of causing line or equipment failure. If excessive stresses are indicated by the analysis, an increase of the valve closure time or other methods shall be used to reduce the stresses to a safe level. While the LNG from the liquefaction trains to the LNG storage containers would not constitute a transfer of LNG subject to these requirements, the increase of 0.4 MTPA in the LNG production rate would require increased flowrates in the LNG rundown line from the production trains to the LNG storage tanks. When the LNG rundown flowrates are increased, hydraulic transient events such as emergency shutdowns or valve closures would result in higher surge pressures in the rundown system piping and higher dynamic loads acting on the pipe supports. To mitigate against dynamic surge effects due to increased rundown flowrates, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an evaluation of dynamic pressure surge effects from valve opening and closure times and pump operations that demonstrate that the surge effects do not exceed design pressures or pipe support design loads.

NFPA 59A (2001 and 2019 editions) also require piping systems and components to be designed to accommodate the effects of fatigue, resulting from the thermal cycling to which the systems are subjected. NFPA 59A (2001 edition) section 6.1.4 and NFPA 59A (2019 edition) section 10.2.4 also require provision for expansion and contraction of piping and piping joints due to temperature changes in accordance with paragraph 319 of ASME B31.3 (1996 and 2016 editions, respectively). ASME B31.3 (1996 and 2016 editions) paragraph 319.1.1 requires piping systems to have sufficient flexibility to prevent thermal expansion or contraction or movements of piping supports and terminals from causing failure of piping or supports from overstress ore fatigue; leakage at joints; and detrimental stresses or distortion in piping and valves or in connected equipment (pumps and turbines, for example), resulting from excessive thrusts and moments in the piping. ASME B31.3 (1996 and 2016 editions) paragraph 319.1.2 further requires that the computed stress range at any point due to displacements in the system not exceed the allowable stress range in ASME B31.3 (1996 and 2016 editions) paragraph 302.3.5. In addition, the reaction forces computed must not be detrimental to supports or connected equipment and the computed movement of the piping must be within any prescribed limits and properly accounted for in the flexibility calculations. Additional requirements are also provided in subsequent requirements under ASME B31.3 (1996 and 2016 editions) paragraph 319. In order to verify the adequacy of these analyses done typically in final design, we recommend in section 5 that prior to construction of final design, ELC and SLNG file a pipe stress analysis for critical or potential higher consequence lines that evaluates all loads in ASME B31.3 (2020 edition) or approved equivalent, including but not limited to consideration of hazardous fluid lines that are cryogenic, high temperature, subject to slug flow, and that include 2-phase flow.

NFPA 59A (2001 and 2019 editions) also limit the type of pipe fittings. Piping joints of 2 inches nominal diameter or less must be threaded, welded or flanged while piping joints larger than 2 inches nominal diameter must be welded or flanged (i.e., cannot be threaded), but where necessary for connections to equipment or components, where the connection is not subject to fatigue-producing stresses, allows joints of 4 inches nominal diameter or less to be threaded welded or flanged. NFPA 59A (2001 and 2019 editions) also prohibit the use of expanded joints, caulked joints, and special joints. ELC and SLNG specifications indicated that all nominal pipe size (NPS) of 2 inches diameter and larger would be buttwelded or flanged in accordance with these requirements. We also note that NFPA 59A (2001 and 2019 editions) specify threaded pipe and threaded nipples must be at least Schedule 80 and threaded plugs must use solid plugs or bull plugs made of at least Schedule 80 seamless pipe. ELC and SLNG's proposed piping specifications would also meet these requirements for all hazardous fluid piping.

ASME B31.3 (1996 and 2016 editions) paragraph 306 indicates a listed fitting is suitable for use in Normal Fluid Service in accordance with paragraph 303. Similarly, ASME B31.3 (1996 and 2016 editions) paragraph 308 indicates a listed flange, blank, or gasket is suitable for use in Normal Fluid Service in except as stated elsewhere in paragraphs 308 and 309 indicates listed bolting is suitable for use in Normal Fluid Service, except as stated elsewhere in paragraph 309. ASME B31.3 (1996 and 2016 editions) paragraph 303 explains that components manufactured in accordance with standards listed in ASME B31.3 (1996 and 2016 editions) Table 326.1 are considered suitable for use at pressure-temperature ratings in accordance with paragraphs 302.2.1 and 302.2.2, as applicable. The listed fittings, flanges, blanks, gaskets, and bolting, in

ASME B31.3 (1996 edition) include:

- ASME B1.1, *Unified Screw Threads*
- ASME B1.20.1, *Pipe Threads General Purpose (Inch)*
- ASME B16.5, *Pipe Flanges and Flanged Fittings*
- ASME B16.9, *Factory-Made Wrought Buttwelding Fittings*
- ASME B16.11, *Forged Fittings, Socket-Welding and Threaded*
- ASME B16.14, *Ferrous Pipe Plugs, Bushings, and Locknuts With Pipe Threads*
- ASME B16.20, *Metallic Gaskets for Pipe Flanges – Ring, Join, Spiral Wound, and Jacketed*
- ASME B16.21, *Nonmetallic Flat Gaskets for Pipe Flanges*
- ASME B16.25, *Buttwelding Ends*
- ASME B16.36, *Orifice Flanges, Class 300, 600, 900, 1500, and 2500*
- ASME B16.47, *Large Diameter Steel Flanges, NPS 26 through NPS 60*
- ASME B46.1, *Surface Texture (Surface Roughness, Waviness, and Lay)*
- MSS SP-95, *Swage Nipples and Bull Plugs*
- MSS SP-97, *Forged Carbon Steel Branch Outlet Fittings - Socket Welding, Threaded, and Buttwelding Ends*

We also note that ASME B31.3 (2016 edition) also includes ASME B16.48, *Steel Line Blanks*, and ASME B31.3 (1996 and 2016 editions) Appendix E provides the full list of referenced standards, including editions.

ELC and SLNG listed the following codes, standards, and recommended and generally accepted good engineering practices in their application:

- ASME B1.1, *Unified Screw Threads*, 2008 edition
- ASME B1.20.1, *Pipe Threads General Purpose (Inch)*, 2006 edition
- ASME B16.5, *Pipe Flanges and Flanged Fittings—NPS ½ through 24*, 2009 edition
- ASME B16.9, *Buttwelding Fittings*, 2007 edition
- ASME B16.11, *Forged Fittings, Socket-Welding and Threaded*, 2009 edition
- ASME B16.20, *Metallic Gaskets for Pipe Flanges – Ring, Join, Spiral Wound, and Jacketed*, 2007 edition
- ASME B16.21, *Nonmetallic Flat Gaskets for Pipe Flanges*, 2011 edition
- ASME B16.25, *Buttwelding Ends*, 2007 edition
- ASME B16.47, *Large Diameter Steel Flanges, NPS 26 through NPS 60*, 2011 edition

Although not listed in their application under codes and standards to be used in the project, ELC and SLNG specifications referenced ASME B16.14, *Ferrous Pipe Plugs, Bushings, and Locknuts With Pipe Threads*, ASME B16.36, *Orifice Flanges, Class 300, 600, 900, 1500, and 2500*, ASME B46.1, *Surface Texture (Surface Roughness, Waviness, and Lay)*, MSS SP-95, *Swage Nipples and Bull Plugs,* MSS SP-97, *Forged Carbon Steel Branch Outlet Fittings - Socket Welding, Threaded, and Buttwelding Ends*, and ASME B16.48, *Steel Line Blanks*. As discussed in Final Specifications and Quality Management Systems, we recommend in section 5 that prior to construction of final design ELC and SLNG file, for review and approval, a final list of all applicable codes and standards that would be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the final specifications and document numbers. In addition, ELC and SLNG valve specifications indicate the use of the latest edition and addenda in effect at the time of purchase. While FERC staff believes the use of more up-to-date standards generally captures more lessons learned from safety incidents and typically reflects more state-of-the-art and more accurate approaches, it is not clear whether the newer editions would be considered equivalent by DOT PHMSA. Compliance with 49 CFR 193 would be subject to DOT PHMSA inspection and enforcement program.

FERC staff also evaluated whether the flange facings and gaskets would be suitable for the intended service, required seating load, flange strength, and its bolting. While non-mandatory, ASME B31.3 (1996 and 2016 editions) F308.4 indicates gasket materials not subject to cold flow (i.e., viscoelasticity) should be considered for use with raised face flanges for fluid services at elevated pressures with temperatures significantly above or below ambient and use of full face gaskets with flat faced flanges when using gasket materials subjected to cold flow for low pressure and vacuum services at moderate temperatures. ELC and SLNG have proposed flange facings consistent with fluid service, flange class ratings, and process pressures and temperatures. FERC staff also evaluated the piping specifications for the use of spiral wound gaskets with stainless steel windings, stainless steel inner ring, and stainless steel outer/centering ring in low temperature and cryogenic service because they have demonstrated better performance in low temperature and cryogenic service and have been less likely to fail catastrophically. ELC and SLNG specified gaskets consistent with these expectations.

In order to verify the integrity of the piping in accordance with ASME B31.3, we also recommend in section 5 that prior to commissioning, the ELC and SLNG should file the procedures for pressure/leak tests which address the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code section VIII and ASME B31.3. The procedures should include a line list of pneumatic and hydrostatic test pressures.

<u>Valves</u>

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.23 covers valve design, including references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 6.2.4.1 requires valves to comply with ASME B31.3 (1996 edition) paragraph 307, as well as ASME B31.5, *Refrigeration Piping*, 1992 edition, ASME B31.8, *Gas Transmission and Distribution*, 1992 edition, or API 6D, *Specification for Pipeline Valves*, 1994 edition, if design conditions fall within the scope of these standards. ASME B31.3 (1996 and 2016 editions) paragraph 307 indicates a listed valve is suitable for use in Normal Fluid Service, with the following exceptions:

- a bolted bonnet valve whose bonnet is secured to the body by less than four bolts, or by a U-bolt, may be used only for Category D Fluid Service (i.e., nonflammable, nontoxic, and not damaging to human tissues[73]); and
- valves must be designed so that the stem seal retaining fasteners (e.g., packing, gland fasteners) alone do not retain the stem. Specifically, the design shall be such that the stem shall not be capable of removal from the valve, while the valve is under pressure, by the removal of the stem seal retainer (e.g., gland) alone.

As aforementioned, ASME B31.3 (1996 and 2016 editions) paragraph 303 explains that components manufactured in accordance with standards listed in ASME B31.3 (1996 and 2016 editions) Table 326.1 are considered suitable for use at pressure-temperature ratings in accordance with sections 302.2.1 and 302.2.2, as applicable. The listed valves in ASME B31.3 (1996 edition), include:

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[73] Damaging to human tissues describes a fluid service in which exposure to the fluid, caused by leakage under expected operating conditions, can harm skin, eyes, or exposed mucous membranes so that irreversible damage may result unless prompt restorative measures are taken (restorative measures may include flushing with water, administration of antidotes, or medication).

- ASME B16.10, *Face-to-Face and End-To-End Dimensions of Valves*
- ASME B16.34, *Valves, Flanged, Threaded, and Welding End*
- API 526, *Flanged Steel Pressure-Relief Valves*
- API 594, *Check Valves: Flanged, Lug, Wafer, and Butt-welding*
- API 600, *Bolted Bonnet Steel Gate Valves for Petroleum and Natural Gas Industries*
- API 602, *Gate, Globe, and Check Valves for Sizes DN 100 and Smaller for the Petroleum and Natural Gas Industries*
- API 608, *Metal Ball Valves-Flanged, Threaded, and Welding End*
- API 609, *Butterfly Valves: Double-flanged, Lug- and Wafer-type*

We also note that ASME B31.3 (2016 edition) includes API 6D, *Pipeline Valves*, and ASME B31.3 (1996 and 2016 edition) Appendix E provide the list of all referenced standards, including editions.

ELC and SLNG listed the following codes, standards, and recommended and generally accepted good engineering practices in their application:

- ASME B16.10, *Face-to-Face and End-To-End Dimensions of Valves*
- ASME B16.34, *Valves, Flanged, Threaded, and Welding End*
- API 526, *Flanged Steel Safety Relief Valves for Flanged Pressure Relief Valves*, 6th, 2009 edition
- API 600, *Bolted Bonnet Steel Gate Valves for Petroleum and Natural Gas Industries*, 2009 edition
- API 602, *Steel Gate Globe and Check Valves for Sizes DN 100 and Smaller for the Petroleum and Natural Gas Industries*, 2009 edition
- API 609, Butterfly Valves: Double Flanged Lug and Wafer Type, 2009 edition
- API 6D, *Specification for Pipeline Valves*, 2008 edition

Although not listed in their application under codes and standards to be used in the project, ELC and SLNG specifications referenced API 594, *Check Valves: Flanged, Lug, Wafer, and Butt-welding*, and API 608, *Metal Ball Valves-Flanged, Threaded, and Welding End,* as well as API 623, *Steel Globe Valves – Flanged and Buttwelding Ends, Bolted Bonnets*. As discussed in Final Specifications and Quality Management Systems, we recommend in section 5 that prior to construction of final design ELC and SLNG file, for review and approval, a final list of all applicable codes and standards that would be used in the final design, fabrication, construction, commissioning, inspection, testing, operation and maintenance of the Project facilities, systems, and components that cross references the specifications and document numbers. In addition, ELC and SLNG valve specifications indicate the use of the latest edition and addenda in effect at the time of purchase. While FERC staff believes the use of more up-to-date standards generally captures more lessons learned from safety incidents and typically reflects more state-of-the-art and more accurate approaches, it is not clear whether the newer editions would be considered equivalent by DOT PHMSA. Compliance with 49 CFR 193 would be subject to DOT PHMSA inspection and enforcement program.

Pressure Vessels

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.24 covers process vessel design, including references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001) section 3.4.2 requires pressure vessels to be designed and fabricated in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), Section VIII, 1992 edition, including Addenda and applicable Code Interpretation Cases, or in accordance with Canadian Standards Association (CSA), Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, 1997 edition, and shall be code-stamped. However, ASME BPVC has required new editions become mandatory within 6 months of a new edition, and pressure vessels can only be code-stamped if the manufacturer meets the requirements laid out in the latest edition of ASME BPVC. ASME BPVC are published on two-year cycles with a July 1 publication date and therefore, in order for a pressure vessel to be code stamped it must meet the latest edition of ASME BPVC. This presents a regulatory challenge because a boiler or pressure vessel cannot be code stamped if it meets only the 1992 edition requirements and yet it would not meet the 1992 edition if it is code-stamped because the 1992 edition required higher design factors and pressure/leak test factors. As a result, FERC staff worked with DOT PHMSA to resolve this challenge for pressure vessels[74], and coordinated on the development of frequently asked questions

74 DOT PHMSA FAQs do not address how to resolve this challenge explicitly with boilers that may not meet 1992 edition and are code-stamped.

(FAQs) to address compliance. [75] The DOT PHMSA FAQs provide companies with three options of having either to 1) specify it meets the 1992 edition, 2) submit an application for a special permit in accordance with 49 CFR § 190.341, or 3) demonstrate an equivalent level of safety as described in NFPA 59A (2001) section 1.2. FERC staff has observed most operators opt for the equivalency option. As explained in DOT PHMSA FAQs, PHMSA provides some additional guidance for demonstrating equivalency for engineering firms that design and fabricate to the current ASME BPVC. This guidance provides supplemental methods to demonstrate equivalency, such as meeting the more stringent pressure and design margin factors in 1992 edition; reducing MAWP by the amount that results in a test pressure for all pressure vessels meeting the requirements of the 1992 edition; subjecting all longitudinal and circumferential welds and nozzle-to-shell welds for process nozzles six inches or larger in diameter to 100% non-destructive examination that are accepted; implementing a documented 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 the pressure vessels; or an alternative method for evaluation and review by DOT PHMSA on a case-by-case basis. ELC and SLNG would need to pursue one of these options with PHMSA. At the time of application, ELC and SLNG indicated in their application they would comply with ASME BPVC Section VIII, but did not specify an edition in their list of codes and standards and noted that if no version is noted then the current version at the time of design would be used. The most current edition is the 2023 edition.

From the information filed in the application, FERC staff evaluated the proposed materials of construction and design pressures relative to the pressure and temperature conditions of the process design. The materials of construction and design pressures were commensurate with the process conditions. However, ELC and SLNG also did not provide any specifications for the pressure vessels. Therefore, FERC staff recommends in section 5, as discussed in Final Specifications and Quality Management Systems section, that prior to construction of final design, ELC and SLNG file, for review and approval, the final mechanical specifications, which should include pressure vessels and the edition of ASME BPVC it would meet.

In order to verify the integrity of the pressure vessels in accordance with ASME BPVC, we also recommend in section 5 that prior to commissioning, the ELC and SLNG should file the procedures for pressure/leak tests which address the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code section VIII and ASME B31.3. The procedures should include a vessel list of pneumatic and hydrostatic test pressures.

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75 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *LNG Plant Requirements: Frequently Asked Questions*, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions, Accessed February 2024,

Heat Exchangers

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.25 covers process vessel design, including heat exchangers, and references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001) section 3.4.3 requires shell and tube heat exchangers to be designed and fabricated in accordance with the standards of the Tubular Exchanger Manufacturers Association and the shells and internals of *all* exchangers to be pressure tested, inspected, and stamped in accordance with American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (BPVC), Section VIII, 1992 edition, including Addenda and applicable Code Interpretation Cases, or in accordance with Canadian Standards Association (CSA), Standard B 51, *Boiler, Pressure Vessel and Pressure Piping Code*, 1997 edition where such components fall within the jurisdiction of the pressure vessel code.

ELC and SLNG listed TEMA, *Standards of the Tubular Exchanger Manufacturers Association*, 2007 edition and ASME BPVC as well as API 660, *Shell and Tube Heat Exchangers for General Refinery Services*, 2007 edition in their list of applicable codes, standards, and recommended and generally accepted good engineering practices that they would use in their Project. In addition, ELC and SLNG indicated the TEMA type in their equipment list for each applicable heat exchanger. However, ELC and SLNG did not indicate the TEMA type in their datasheets and did not discuss development on any specifications for their heat exchangers, which we note as something that may be developed after the application stage during final design. Therefore, FERC staff recommends in section 5, as discussed in Final Specifications and Quality Management Systems, that prior to construction of final design, ELC and SLNG file, for review and approval, the final equipment lists, datasheets, and specifications, which should include heat exchangers.

Title 49 CFR Part 193 and 33 CFR Part 127 do not require any other applicable standards to be met for the design, fabrication, construction, or installation of other heat exchangers, such as air-cooled heat exchangers or plate heat exchangers. NFPA 59A (2001 edition) similarly predates any requirements for such heat exchangers. However, ELC and SLNG application also included the following applicable heat exchanger codes, standards, and recommended and generally accepted good engineering practices among others in their list of codes and standards that they would use for the Project:

- API 660, *Shell and Tube Heat Exchangers for General Refinery Services*, 2006 edition
- API 661, *Air Cooled Heat Exchangers for General Refinery Services*, 2006 edition

In addition, ELC and SLNG referenced API 661 and API 662, *Plate Heat Exchangers for General Refinery Services, Parts 1 and 2* in their application for evaluating nozzle loads in future pipe stress analyses. These codes, standards, and recommended and generally accepted good engineering practices for heat exchangers are consistent with recognized standards for heat exchangers that FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) annex A.7.5.6, not yet incorporated into federal regulations.

FERC staff agree the adherence to recognize standards in the design and fabrication would better ensure the materials of construction and design are suited to the pressure and temperature conditions of the process design. However, specifications were not provided and would be subject to change until the design is finalized, so as discussed in Final Specifications and Quality Management Systems, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project.

Rotating Equipment

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.25 covers rotating equipment design, including references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 3.2.1 requires pumps and compressors be constructed of materials suitable for the temperature and pressure conditions that might be considered. NFPA 59A (2001 edition) also requires installation of internal combustion engines or gas turbines not exceeding 7500 horsepower per unit to conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*. However, NFPA 59A (2001 edition) does not provide any further requirements on what materials are suitable for the temperature and pressure conditions or any other requirements that would feed into the mechanical design of rotating equipment, and does not cover other rotating equipment, such as blowers and fans. Title 49 CFR Part 193, 33 CFR Part 127, and NFPA 59A (2001 edition) also do not include any requirements on the seals at the shaft that are often the highest frequency leak points on rotating equipment.

However, as part of their application, ELC and SLNG did include the following in their list of applicable codes, standards, and recommended and generally accepted good engineering practices that they would use in their Project:

- API 541, *Form-Wound Squirrel-Cage Induction Motors - 500 Horsepower and Larger*, 2004 edition
- API 547, *General-purpose Form-wound Squirrel Cage Induction Motors 250 Horsepower and Larger*, 2005 edition
- API 613, *Special-Purpose Gear Units for Petroleum Chemical and Gas Industry Services*, 2003 edition
- API 614, *Lubrication Shaft-Sealing and Control-Oil systems and Auxiliaries for Petroleum Chemical and Gas Industry Services*, 2008 edition
- API 617, *Axial and Centrifugal Compressors and Expander-Compressors for Petroleum Chemical and Gas Industry Services*, 2009 edition
- API 619, *Rotary Type Positive Displacement Compressors for Petroleum Petrochemical and Natural Gas Industries*, 2010 edition
- API 670, *Machinery Protection Systems*, 2010 edition
- API 675, *Positive Displacement Pumps – Controlled Volume*, 2005 edition
- API 676, *Positive Displacement Pumps – Rotary*, 2009 edition
- API 677, *General-Purpose Gear Units for Petroleum Chemical and Gas Industry Services*, 2010 edition
- API 682, *Pumps—Shaft Sealing Systems for Centrifugal and Rotary Pumps*, 2006 edition
- API 686, *Machinery Installation and Installation Design*, 2009 edition
- ASME B73.1, *Specification for Horizontal End Suction Centrifugal Pumps for Chemical Process*, 2007 edition
- ASME B73.2, *Specification for Vertical In-line Centrifugal Pumps for Chemical Process*, 2008 edition

- ASME PTC-10, *Test Code on Compressors & Exhausters*, 1981 edition
- NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*, 2010 edition

In addition, ELC and SLNG referenced API 610, API 617, and API 618 in their application for evaluating nozzle loads in future pipe stress analyses. The data sheets also used API 610 forms and made reference to API 682 for seal arrangement. These codes, standards, and recommended and generally accepted good engineering practices for heat exchangers are consistent with recognized standards for pumps and compressors, seals, fans and blowers, and motors that FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) section 7.3.1, 7.3.2, 7.3.9, 7.3.10 and 7.3.11, and associated annexes A.7.3.1, A7.3.2, A7.3.9, A7.3.10 and A7.3.11, not yet incorporated into federal regulations.

FERC staff agree the adherence to recognize standards in the design and fabrication would better ensure the materials of construction and design are suited to the pressure and temperature conditions of the process design. However, specifications were not provided and would be subject to change until the design is finalized, so as discussed in Final Specifications and Quality Management Systems, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project.

<u>Fired Equipment</u>

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.26 covers fired equipment design, including references to any mechanical specifications in 13.F.2, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). NFPA 59A (2001) section 1.7.12 defines fired equipment as any equipment in which the combustion of fuels takes place; equipment can include fired boilers, fired heaters, internal combustion engines, certain integral heated vaporizers, the primary heat source for remote heated vaporizers, gas-fired oil foggers, fired regeneration heaters, and flared vent stacks. NFPA 59A (2001 edition) requires boilers to meet ASME BPVC Section VIII (1992 edition) and requires internal combustion engines or gas turbines not exceeding 7500 hp per unit conform to NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*, 1998 edition. NFPA 59A (2001 edition) also has requirements for vaporizers to be designed, fabricated, and inspected in accordance with ASME BPVC (1992 edition).

Title 49 CFR Part 193 and 33 CFR Part 127 do not require other fired equipment to meet any requirements. Title 49 CFR Part 193, 33 CFR Part 127, and NFPA 59A (2001 edition) also do not include any requirements on the burner management systems for fired heaters that are often considered the most critical system in preventing an incident.

However, ELC and SLNG listed the following in in their list of applicable codes, standards, and recommended and generally accepted good engineering practices that they would use in their Project:

- API 556, *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*, 2011 edition
- ASME, *BPVC*
- NFPA 37, *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*, 2010 edition

In addition, ELC and SLNG referenced API 560, in their application for evaluating nozzle loads in future pipe stress analyses. ELC and SLNG also referenced NFPA 85, NFPA 86, NFPA 87 in their instrument and control design basis, but note ELC and SLNG are not proposing any boilers as part of this Project. These codes, standards, and recommended and generally accepted good engineering practices for fired equipment and burner management systems are consistent with recognized standards for fired equipment and burner management systems that FERC staff proposed and are now referenced in newer editions of NFPA 59A (2019 and 2023 editions) section 7.5.3, 7.5.4 and 11.2, and associated annexes A.7.5.3, A7.5.4 and A.11.2, not yet incorporated into federal regulations. Other guidance, such as ISA-TR84.00.05, *Guidance on the Identification of Safety Instrumented Functions (SIF) in Burner Management Systems (BMS)*, may also be relevant.

FERC staff agree the adherence to recognize standards in the design and fabrication would better ensure the materials of construction and design are suited to the pressure and temperature conditions of the process design. However, specifications were not provided and would be subject to change until the design is finalized, so as discussed in Final Specifications and Quality Management Systems, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project.

Pressure and Vacuum Relief Valves

Pressure and vacuum safety relief valves are installed to protect storage containers, pressure vessels, process equipment, and piping from an unexpected or uncontrolled pressure excursion in the event an operator or safety instrumented system is unable to intervene and prevent a pressure excursion from reaching design limits. The pressure safety relief valves can discharge locally or be routed to vent stack or flare headers and systems.

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. As suggested in our 2017 Guidance Manual, section 13.33 covers relief valve, flare, and vent system designs, including references to any mechanical specifications in 13.F.2, capacities and sizing in 13.R, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101, § 193.2301, and § 193.2401 require each LNG facility to comply with the design, fabrication, construction, and installation requirements of NFPA 59A (2001 edition). Similarly, 33 CFR 127 Subpart B covers USCG regulatory requirements of the marine transfer area, including 33 CFR **§** 127.101 for design and construction, which incorporates NFPA 59A (2019 edition) Chapter 5, Section 5.3.1.7; Chapter 6, Section 6.7; Chapter 10; Chapter 11, except Sections 11.9, and 11.10; Chapter 12; Chapter 15, except Sections 15.4 and 15.6; and Annex B.

For piping, NFPA 59A (2001 edition) section 6.1.1 requires all piping systems to be in accordance with ASME B31.3 (1996 edition). For piping systems and components for flammable fluids with services below -20F, NFPA 59A (2001 edition) has additional requirements in section 6.8. Section 6.8.1 requires pressure-relieving safety devices be arranged so that the possibility of damage to piping or appurtenances is reduced to a minimum and the means for adjusting relief valve set pressure be sealed; section 6.8.2 requires a thermal expansion relief valve be installed to prevent overpressure in any section of a liquid or cold vapor pipeline that can be isolated by valves; section 6.8.2.1 requires a thermal expansion relief valve be set to discharge at or below the design pressure of the line it protects; and section 6.8.2.2 requires the discharge from such valves be directed to minimize hazard to personnel and other equipment. ASME B31.3

(1996 edition) paragraph 301.2.2(a) requires provision be made to safely contain or relieve, in accordance with paragraph 322.6.3, any pressure to which the piping may be subjected and piping not protected by a pressure relieving device, or that can be isolated from a pressure relieving device, must be designed for at least the highest pressure that can be developed. ASME B31.3 (1996 edition) paragraph 301.4.2 also requires provision be made in the design either to withstand or to relieve, in accordance with paragraph 322.6.3, increased pressure caused by the heating of static fluid in a piping component. ASME B31.3 (1996 edition) paragraph 322.6.3(a) requires pressure relieving devices required by paragraph 301.2.2(a) to be in accordance with ASME BPVC (1995 edition) Section VIII, Division I, UG-125(c), UG-126 through UG-128, and UG-132 through UG-136, excluding UG-135(e) and UG-136(c) where the terms "design pressure" and "piping system" are substituted for "maximum allowable working pressure" and "vessel," respectively, in these paragraphs. It also requires the relieving capacity of any pressure relieving device include consideration of all piping systems which it protects. ASME B31.3 (1996 edition) paragraph 322.6.3(b) requires relief set pressure to be in accordance with ASME BPVC (1995 edition) Section VIII, Division 1, with the following exceptions:

(1) With the owner's approval the set pressure may exceed the limits in Section VIII, Division 1, provided that the limit on maximum relieving pressure stated in ASME B31.3 (1996 edition) paragraph 322.6.3 (c) below would not be exceeded.
(2) For a liquid thermal expansion relief device which protects only a blocked-in portion of a piping system, the set pressure must not exceed the lesser of the system test pressure or 120% of design pressure.

ASME B31.3 (1996 edition) paragraph 322.6.3(c) requires the maximum relieving pressure be in accordance with Section VIII, Division 1, with the exception that the allowances in ASME B31.3 (1996 edition) paragraph 302.2.4(f) are permitted, provided that all other requirements of ASME B31.3 (1996 edition) paragraph 302.2.4 are also met. Requirements in ASME BPVC (1992 edition), which are largely same as 1995 edition and are discussed in more detail below.

For pressure vessels, NFPA 59A (2001 edition) section 3.4.2, requires pressure vessels be designed and fabricated in accordance with the ASME BPVC (1992 edition) Section VIII, or CSA B51 (1997 edition) and must be code-stamped. Similarly, for heat exchangers, NFPA 59A (2001 edition) section 3.4.3 requires the shells and internals of all heat exchangers to meet ASME BPVC (1992 edition). For vaporizers[76], NFPA 59A (2001 edition) section 5.4 also contains requirements for relief devices on vaporizers.

ASME BPVC (1992 edition) UG-125(a) requires all pressure vessels, irrespective of size or pressure, be provided with protective devices in accordance with the requirements of U-125 through UG-136 other than unfired steam boilers, which are required in UG-125(b) to be equipped with pressure relief devices required by ASME BPVC (1992 edition) Section I. ASME BPVC (1992 edition) Section VIII UG-125(e) allows pressure relief valves or non-reclosing pressure relief devices be used to protect against overpressure either alone or, if applicable, in combination. ASME BPVC (1992 edition) Section VIII UG-126(a) requires safety, safety relief, and relief valves be the direct spring loaded type and UG-126(b) allows pilot-operated pressure relief valves to be used, provided that the pilot is self-actuated and the main valve will open automatically at not over the set pressure and will discharge its full rated capacity if some essential part of the pilot should fail. UG-127 contains requirements for non-reclosing pressure relief devices, such as rupture disc devices, pin devices, spring loaded non-reclosing pressure relief device, and open flow paths or vents.

ASME BPVC (1992 edition) Section VIII UG-125(g) allows for the pressure relief devices required in UG-125(a) described above to be installed indirectly (i.e., not directly, but by system design) on a pressure vessel when: either (1) the source of pressure is external to the vessel and is under such positive control that the pressure in the vessel cannot exceed the maximum allowable working pressure (MAWP)[77] at the operating temperature except as permitted in (c) described below, or under the conditions set forth in Nonmandatory Appendix M; or (2) there are no intervening stop valves between the vessel and the pressure relief device or devices except as permitted under UG-135(d). UG-135(d) allows intervening stop valves when they are so constructed or

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[76] We note that vaporizers are defined in 49 CFR 193 as a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid to a vapor or gaseous state. We also note that NFPA 59A (2001 edition) does not define it, but NFPA 59A (2019 edition) defines similarly as equipment designed to introduce thermal energy in a controlled manner for changing a liquid to a vapor or gaseous state.

[77] The maximum allowable working pressure (MAWP) for a vessel is defined in UG-98(a) as the maximum pressure permissible at the top of the vessel in its normal operating position at the designated coincident temperature specified for that pressure, and must no greater than the MAWP determined for a vessel part determined in UG-98(b) as the maximum internal or external pressure, including the static head thereon, as determined by the rules and equations in this Division, together with the effect of any combination of loadings listed in UG-22 that is likely to occur, for the designated coincident temperature, excluding any metal thickness specified as corrosion allowance.

positively controlled that the closing of the maximum number of block valves possible at one time will not reduce the pressure relieving capacity provided by the unaffected pressure relief devices below the required relieving capacity; or under conditions set forth in Nonmandatory Appendix M.

ASME BPVC (1992 edition) Section VIII UG-126(c) requires the set pressure of a pressure relief device not be adjusted outside the range of set pressure specified by the device manufacturer and that the initial adjustment be performed by the manufacturer, his authorized representative, or an Assembler, and a valve data tag be provided that identifies the set pressure capacity and date. The valve must be sealed with a seal identifying the manufacturer, his authorized representative, or the Assembler performing the adjustment. UG-126(d) requires the set pressure tolerances, plus or minus, of pressure relief valves not exceed 2 psi for pressures up to and including 70 psi and 3% for pressures above 70 psi.

ASME BPVC (1992 edition) UG-125(c) requires all applicable pressure vessels above be protected by a pressure relieving device that prevents the pressure from rising more than 10% (i.e., 1.10 MAWP) or 3 psi, whichever is greater, above the MAWP with an exception for when multiple pressure reliving devices are installed (where maximum of 1.16 MAWP or 4 psi is allowed). In addition, there is an exception for 1.21 MAWP where supplemental pressure relieving devices must be installed to protect against excessive pressure if an additional hazard can be created by exposure of a pressure vessel to fire or other unexpected sources of external heat. ASME BPVC (1992 edition) Section VIII UG-125(c)(3) stipulates the requirements the exceptions described above are excluded if the pressure relief devices are intended primarily for protection against exposure of a pressure vessel to fire or other unexpected sources of external heat installed on vessels having no permanent supply connection and used for storage at ambient temperatures of nonrefrigerated liquefied compressed gases, and: the relief devices are capable of preventing the pressure from rising more than 1.20 MAWP; the set pressure of these devices does not exceed the MAWP; the vessels have sufficient ullage to avoid a liquid full condition; the MAWP of the vessels on which these devices are installed is greater than the vapor pressure of the stored liquefied compressed gas at the maximum anticipated temperature that the gas will reach under atmospheric conditions; and the pressure relief valves used to satisfy these provisions also comply with the requirements of UG-129(a)(5), UG-131(c)(2), and UG-134(d)(2).

For rotating equipment, NFPA 59A (2001 edition) section 3.2.3 requires pumps and compressor be provided with a pressure-relieving device on the discharge to limit the pressure to the maximum safe working pressure of the casing and downstream piping and equipment, unless these are designed for the maximum discharge pressure of the pumps and compressors. In addition, section 3.2.4 requires Each pump shall be provided with an adequate vent, relief valve, or both, that will prevent over-pressuring the pump case during the maximum possible rate of cooldown.

NFPA 59A (2001 edition) section 3.3 requires installation of storage tanks for flammable refrigerants and liquids to comply with NFPA 30, *Flammable and Combustible Liquids Code*; NFPA 58, *Liquefied Petroleum Gas Code*; NFPA 59, *Utility LP Gas Plant Code*; API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*; or NFPA 59A (2001 edition) section 2.2, which contains site provisions for spill and leak control. Therefore, it is unclear as to whether there are requirements for pressure relief devices, or other requirements, for low-pressure tanks that would contain flammable fluids, other than stationary LNG storage containers, which NFPA 59A (2001 edition) section 4.7 contains requirements on. However, ELC and SLNG are not proposing any atmospheric (i.e., 0 psig) or low-pressure (i.e., less than 15 psig) storage tanks for flammable refrigerants, liquid, or LNG as part of this Project.

NFPA 59A (2001 edition) section 3.4.6 also requires piping, process vessels, cold boxes, or other equipment, the facilities subject to vacuum be designed to withstand the vacuum conditions or provision be made to prevent the development of a vacuum in the equipment that might create a hazardous condition. If gas is introduced to obviate this problem, it must be of such composition or so introduced that it does not create a flammable mixture within the system.

While the regulations and incorporations by reference are fairly comprehensive on requiring pressure relief valves for most equipment, it is not as clear whether it requires pressure relief for fired equipment that would not qualify as pressure vessels or for low or atmospheric pressure tanks. In addition, while the requirements on what the set pressures and pressure buildup limits must be to protect equipment, they are less clear on the scenarios to be considered or parameters used to define them, which are critical in determining the effectiveness and reliability of them. As stated ASME BPVC (2015 and later editions) UG-125(a)(1), it is the user's or his/her designated agent's responsibility to identify all potential overpressure scenarios and the method of overpressure protection used to mitigate each scenario. ASME BPVC (2015 and later editions) non-mandatory Appendix M-13 indicates several formulas have evolved over the years for calculating the pressure relief capacity required under fire conditions, and the major differences involve heat flux rates and that there is no single formula yet developed which takes into account all of the many factors which could be considered in making this determination. ASME BPVC (2015 and later editions) non-mandatory Appendix M continues that when fire conditions are a consideration in the design of a pressure vessel, the following references which provide recommendations for specific installations may be used:

- API 520, *Sizing, Selection, and Installation of Pressure-Relieving Systems in Refineries, Part I — Sizing and Selection*, 7th (2000) edition
- API 521, *Guide for Pressure-Relieving and Depressuring Systems*, 4th (1997) edition
- API 2000, *Venting Atmospheric and Low-Pressure Storage Tanks*

(*Nonrefrigerated and Refrigerated)*, 5th (1998) edition

- AAR M-1002, *Specifications for Tank Cars*, 1978 edition
- Compressed Gas Association (CGA) Safety Relief Device Standards: *S-1.1, Cylinders for Compressed Gases; S-1.2, Cargo and Portable Tanks; and S-1.3, Compressed Gas Storage Containers*
- NFPA 30, 58, 59, and 59A
- *Pressure-Relieving Systems for Marine Cargo Bulk Liquid Containers*, 1973
- Phillips Petroleum Company, Bulletin E-2, *How to Size Safety Relief Devices*
- Phillips Petroleum Company, *A Study of Available Fire Test Data as Related to Tank Car Safety Device Relieving Capacity Formulas*, 1971

ASME BPVC (2015 and later editions) also provide provisions on protecting pressure vessels by system design in UG-140 that requires the user conduct a detailed analysis to identify and examine all potential overpressure scenarios and requires API 521, *Pressure-Relieving and Depressuring Systems*, be considered. UG-140 also references other standards or recommended practices that are more appropriate to the specific application that may also be considered, such as a multidisciplinary team experienced in methods such as hazards and operability analysis (HAZOP); failure modes, effects, and criticality analysis (FMECA); "what-if" analysis; or other equivalent methodology to establish that there are no sources of pressure that can exceed the MAWP at the coincident temperature. ASME BPVC also makes several references to API 527, *Seat Tightness of Pressure Relief Valves*.

In addition to the requirements in NFPA 59A, NFPA 30, NFPA 58, NFPA 59, ASME B31.3, and ASME BPVC, FERC staff has observed that LNG companies under its jurisdiction will typically list:

- API 520-1, *Sizing, Selection, and Installation of Pressure-relieving Devices, Part I-Sizing and Selection*
- API 520-2, *Sizing, Selection, and Installation of Pressure-relieving Devices, Part II-Installation*
- API 521, *Pressure-relieving and Depressuring Systems*
- API 526, *Flanged Steel Pressure Relief Valves*
- API 527, *Seat Tightness of Pressure Relief Valves*
- API 537, *Flare Details for General Refinery and Petrochemical Service*
- API 2000, *Venting Atmospheric and Low-Pressure Storage Tanks (Nonrefrigerated and Refrigerated)*

Collectively, these codes, standards, and recommended and generally accepted good engineering practices guide them on the potential overpressure scenarios, method of overpressure protection used to mitigate each scenario, and to then size and design the pressure relief, vent, and flare devices and systems based on those scenarios to meet the pressure limit requirements.

ELC and SLNG provided P&IDs showing relief devices on isolatable sections of piping, directly on pressure vessels and heat exchangers or within system without intervening stop valves with exception of those that have positive controls (e.g., car seals and locks). In addition to NFPA 59A, NFPA 30, NFPA 58, NFPA 59, ASME 31.3, and ASME BPVC already discussed, ELC and SLNG listed they would use the following applicable codes, standards, and and recommended and generally accepted good engineering practices:

- API 520-1, *Sizing, Selection, and Installation of Pressure-relieving Devices, Part I-Sizing and Selection*
- API 520-2, *Sizing, Selection, and Installation of Pressure-relieving Devices, Part II-Installation*
- API 521, *Pressure-relieving and Depressuring Systems*
- API 526, *Flanged Steel Pressure Relief Valves*
- API 527, *Seat Tightness of Pressure Relief Valves*

ELC and SLNG are not proposing any new or modified atmospheric or low-pressure storage tanks, vent stacks, or flare stacks. In addition, ELC and SLNG provided a list of pressure relief valves with most including set pressures, sizing, and capacities in Appendix R. In addition, ELC and SLNG provided a flare load table and summary in Appendix R. However, some of the pressure relief valve capacities were noted as for detailed design and the scenarios and subsequent calculations that form the basis of these capacities demonstrating the pressure were within allowable limits were not provided. Therefore, as discussed and recommended in Process Description, ELC and SLNG should file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. Additionally, sizing basis should be provided for pressure relief valves protecting from overpressures due to mixed refrigerant compressor blocked outlet cases, and basis for necessity of thermal relief valves in non-cryogenic process piping.

In order to facilitate testing and maintenance of pressure relief valves such that more consequential vessels are continuous protected during pressure relief testing, and to reduce the likelihood of accidentally defeating a pressure relief device that could lead to more catastrophic and consequential failure, we also recommend in section 5 that prior to construction of final design, ELC and SLNG should specify that the common, non-spared process vessels are installed with spare pressure relief valves to ensure overpressure protection during relief valve testing or maintenance.

Although FERC staff generally agreed the design specifies appropriate materials of construction and ratings suited to the pressure and temperature conditions of the process design, we also recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project.

Inspection, Testing, and Maintenance Plans and Procedures

If the Project is authorized and complete commissioning, ELC and SLNG would prepare to plan on how it would maintain its facilities. Title 18 CFR § 380.12(m)(4) and (5) requires companies to discuss contingency plans for maintaining service or reducing downtime and discuss measures used to minimize problems arising from malfunctions and accidents and identify standard procedures for protecting services and public safety during maintenance and breakdown. As suggested in our 2017 Guidance Manual, section 13.O.5, maintenance plans and procedures would typically be developed after the application, but the development of those procedures should be discussed in the application. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Title 49 CFR 193 Subpart G prescribes requirements for maintaining components at LNG plants, including that each component in service, including its support system, be maintained in a condition that is compatible with its operational or safety purpose by repair, replacement, or other means. Title 49 CFR § 193.2603 also requires that an operator not place, return, or continue in service any component which is not maintained, each component taken out of service must be recorded, including if a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means and if the inadvertent operation of a component taken out of service could cause a hazardous condition, that component must have a tag attached to the controls bearing the words “do not operate” or words of comparable meaning. Further, 49 CFR § 193.2605 requires:

- each operator to determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart and to verify that components meet the maintenance standards prescribed by this subpart;
- each operator follow one or more manuals of written procedures for the maintenance of each component, including any required corrosion control;
- the procedures include the details of the inspections or tests and their frequency of performance and a description of other actions necessary

to maintain the LNG plant according to the requirements of this subpart;
- each operator include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions discussed subject to the reporting requirements of 49 CFR § 191.23 discussed in Incident and Investigations.

Similarly, 33 CFR § 127.401 requires the operator of the waterfront facility handling LNG ensure that the equipment required in 33 CFR Part 127 is maintained in a safe condition so that it does not cause a release or ignition of LNG. In addition, 33 CFR § 127.407 requires the operator verify the set pressure of the pressure relief valves after the system or the valves are altered; after the system or the valves are repaired; after any increased in the MAWP; or for those components that are not continuously kept at cryogenic temperature, at least once each calendar year, with intervals between testing not exceeding 15 months .

Title 49 CFR Part 193 does not define "generally accepted engineering practices" and 33 CFR Part 127 does not provide any requirements on what procedures or standards should be followed to "maintain the facilities in a safe condition so that it does not cause a release or ignition of LNG". As a result, FERC staff has observed wide variation in operating and maintenance procedures in terms of inspections, testing, and maintenance scopes and frequencies. Therefore, we recommend in section 5 that prior to commissioning, ELC and SLNG should file, for review and approval, the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, simultaneous operations procedures, and management of change procedures and forms. In addition, we recommend prior to commencement of service, ELC and SLNG should provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring. These reviews would be done in coordination with DOT PHMSA and USCG. In addition to the requirements in federal regulations, we note that some current codes and standards that could be referenced in inspection, testing, and maintenance procedures may include, but are not limited to:

- API 510, *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration*
  - API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*
  - API 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*,
  - API 572, *Inspection Practices for Pressure Vessels*
  - API 573, *Inspection of Fired Boilers and Heaters*
  - API 574, *Inspection Practices for Piping System Components*

- API 575, *Inspection Practices for Atmospheric and Low-Pressure Storage Tanks*
- API 576, *Inspection of Pressure-Relieving Devices*
- API 580, *Risk-Based Inspection*
- API 581, *Risk-Based Inspection Methodology*
- API 584, *Integrity Operating Windows*
- API 585, *Pressure Equipment Integrity Incident Investigation*
- API 598, *Valve Inspection and Testing*
- API 653, *Tank Inspection, Repair, Alteration, and Reconstruction*
- ISA 84.00.03, *Automation Asset Integrity of Safety Instrumented Systems (SIS)*
- ISA 84.91.01, *Identification and Mechanical Integrity of Process Safety Controls, Alarms, and Interlocks in the Process Industry Sector*
- NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water Based Fire Protection Systems*

In order to facilitate maintenance while also preventing the inadvertent opening and closing of valves, NFPA 59A (2001 edition) ASME B31.3 and ASME BPVC require or suggest having administrative controls to prevent the accidental opening and closing of valves that could cause a safety impact, such as inadvertent isolation of pressure relief valves. As discussed in LNG Facility Historical Record, incidents have demonstrated additional needs of ensuring such administrative controls are carefully controlled. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG file, for review and approval, their car seal and lock philosophy and car seal and lock program, including a list of all car-sealed and locked valves consistent with the piping and instrumentation diagrams (P&IDs). The car seal and lock program should include monitoring and periodically reviewing correct car seal and lock placement and valve position. The physical car seal to be used should have sufficient mechanical strength to prevent unauthorized valve operation.

Hazard Mitigation Design

If operational control of the facilities were lost and operational controls and emergency shutdown systems failed to maintain the Project within the design limits of the piping, containers, and safety relief valves, a release could potentially occur. FERC regulations under 18 CFR § 380.12 (o) (1) through (4) require applicants to provide information on spill containment, spacing and plant layout, hazard detection, hazard control, and firewater systems. In addition, 18 CFR § 380.12 (o) (7) requires applicants to provide engineering studies on the design approach and 18 CFR § 380.12 (o) (14) requires applicants to demonstrate how they comply with applicable federal, state, and local requirements including 49 CFR Part 193 and NFPA 59A.

Title 49 CFR Part 193.2801, under Subpart I Fire Protection, requires each operator to provide and maintain fire protection at LNG plants according to section 9.1 through 9.7 and section 9.9 of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 9.1.2 requires fire protection be provided for all LNG facilities and the extent of such protection to be determined by an evaluation based on sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. NFPA 59A (2001) 9.1.3 indicates the wide range in size, design, and location of LNG facilities precludes the inclusion of detailed fire protection provisions that apply to all facilities comprehensively. If authorized, constructed, and operated, LNG facilities as defined in 49 CFR Part 193, must comply with the requirements of 49 CFR Part 193 Subpart I and would be subject to PHMSA's inspection and enforcement programs.

While NFPA 59A (2001 or later editions) do not define or provide guidance on what constitutes "sound fire protection engineering principles", FERC staff believe sound fire protection engineering principles to include NFPA 550, *Fire Safety Concepts Tree*, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. NFPA 550 (2022 edition) section 1.2 purpose is to provide tools to assist the Fire Safety Practitioner (e.g., designer, engineer, code official) in communication fire safety and protection concepts and its use can assist with the analysis of codes or standards and facilitate the development of performance-based designs. Further, NFPA 550 (2022 edition) section 1.3 application it to provide an overall structure with which to analyze the potential impact of fire safety strategies as an aide in making fire safety decisions and should be accompanied by the application of sound fire protection engineering principles. NFPA 550 (2022 edition) then logically breaks up fire safety concepts and mitigation strategies into a Fire Safety Concept Tree with top gates for Prevent Fire Ignition and Manage Fire Impact with lower gates for how to accomplish those concepts, including Managing the Fire and Managing the Exposed. Each one of these is further broken down that are directly related to the fire protection mitigation required to be evaluated in NFPA 59A (2001 and later editions) for the fire protection evaluation. In addition, NFPA 551 (2022 edition) section 1.1 scope indicates it is intended to provide assistance, primarily to authorities having jurisdiction (AHJs), in evaluating the appropriateness and execution of a fire risk assessment (FRA), for a given fire safety problem. NFPA 551 (2022 edition) section 1.2 purpose is intended to assist with the evaluation of FRA methods used primarily in a performance based regulatory environment. NFPA 551 (2022 edition) section 4.4.3.5 indicates that acceptance criteria may be based on: prescriptive regulations, performance regulations, other agreed-to criteria, and standards and guides. NFPA 551 (2022 edition) section 4.4.4.2 indicates methods may include a variety of elements that may be qualitative or quantitative and many involve deterministic or probabilistic models. FERC staff used these same principles and methods to evaluate the proposed spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response to ensure they would provide adequate protection of the LNG facilities as described below.

ELC and SLNG performed a preliminary fire protection evaluation to ensure that adequate mitigation would be in place, including spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response. We recommend in section 5 that ELC and SLNG provide a final fire protection evaluation that evaluates the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001), and to provide more information on the final design, installation, and commissioning of spill containment, hazard detection, hazard control, firewater systems, structural fire protection, and onsite and offsite emergency response procedures for review and approval.

Spill Containment

In the event of a release, sloped areas at the base of storage and process facilities would direct a spill away from equipment and into the impoundment system. This arrangement would minimize the dispersion of flammable vapors into confined, occupied, or public areas and minimize the potential for heat from a fire to impact adjacent equipment, occupied buildings, or public areas if ignition were to occur.

Title 18 CFR § 380.12(o)(4) requires a detailed layout of the spill containment system showing the location of impoundments, sumps, sub-dikes, channels, and water removal systems. Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

Further, under NFPA 59A (2001), section 2.2.2.2, the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or during a shorter period based upon demonstrable surveillance and shutdown provisions acceptable to the PHMSA. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR Part 193, must comply with the requirements of 49 CFR Part 193 Subpart C and would be subject to PHMSA's inspection and enforcement programs. We evaluate whether all hazardous liquids are provided with spill containment based on the largest flow capacity from a single pipe for 10 minutes accounting for de- inventory or the liquid capacity of the largest vessel (or total of impounded vessels) served, whichever is greater and whether providing spill containment reduces consequences from a release.

ELC and SLNG proposes to install the facilities within existing sloped graveled areas that would direct potential hazardous liquid spills, involving LNG, refrigerant, heavy hydrocarbon and other hazardous material releases to existing impoundment basins. ELC and SLNG indicate that all containment areas for the proposed condensate plant facilities would be paved and would use the existing spill conveyance system constructed of earthen and graveled material that would direct any spills to the existing Mixed Refrigerant Impoundment Basin. Liquid releases from the modified MMLS units or the main LNG rundown line piping would be directed by existing sloped areas into an existing trench system that would direct spills to the existing LNG Impoundment Basin. ELC and SLNG provided sizing basis information for the existing trenches leading to the existing impoundment basins to demonstrate the existing spill containment system is sized sufficiently for the proposed project. FERC staff confirmed the existing trenches and existing LNG Impoundment Basin would be sized sufficiently to handle the proposed increased LNG rundown flow rate. Also, a spill from all other proposed project facilities and modifications would be less than those considered in the final design of the existing spill containment system. FERC staff also confirmed that any spill from a proposed project tie-in point would flow over the sloped surface by gravity towards existing sloped trenches and then, depending on its' location, either to the existing LNG or Mixed Refrigerant Impoundment Basins.

Additionally, ELC and SLNG's existing LNG and Mixed Refrigerant impoundment basins include water removal pumps that are automatically actuated to remove rainwater that collects in an impoundment. Existing low temperature and flammable gas interlocks are provided to automatically shut off or prevent startup of the water removal pumps upon detection of a spill in the existing impoundments. Additional information on the existing spill containment systems that would be utilized by the Project were discussed in detail in the Elba Liquefaction Project Environmental Assessment (Docket No. CP14-103) and the final design and construction of the existing spill containment systems were reviewed to ensure the facilities were designed and constructed in accordance with June 1, 2016 Commission Order. However, given that the FEED P&IDs for the Project would be subject to changes in final design after additional detailed engineering is conducted, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, tertiary containment and capacity calculations considering any foundations and equipment within impoundments. The spill containment drawings should show containment for all hazardous fluids including all liquids handled above their flashpoint, from the largest flow from a single line for 10 minutes, including de-inventory, or the maximum liquid from the largest vessel (or total of impounded vessels) or otherwise demonstrate that providing spill containment would not significantly reduce the flammable vapor dispersion or radiant heat consequences of a spill.

If the project is authorized and constructed, ELC and SLNG would install spill containment systems in accordance with its design and FERC staff would verify during construction inspections that the spill containment system including dimensions, and slopes of curbing and trenches, and volumetric capacity matches final design information. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility to verify that impoundments are being properly maintained.

Spacing and Plant Layout

Title 18 CFR § 380.12(o)(1) requires a detailed plot plan showing the location of all major components to be installed. Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

PHMSA regulations incorporates NFPA 59A (2001) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. NFPA 59A (2001 edition) section 2.2.6 requires process equipment containing flammable liquids, or flammable gases to be located at least 50 ft from sources of ignition, a property line that can be built upon, control rooms, offices, shops and other occupied structures with exception of control rooms located in a building housing flammable gas compressors where the building construction complies with other parts of NFPA 59A (2001 edition). NFPA 59A (2001 edition) section 2.2.6.2 requires fired equipment and other sources of ignition to be located at least 50 ft from any impounding area or container drainage system. Section 2.3.3 requires buildings or structural enclosures to be located, or provisions otherwise be made, to minimize the possibility of entry of flammable gases or vapors. NFPA 59A (2001 edition) section 3.3 also requires installation of storage tanks for flammable refrigerants and liquids to comply with NFPA 30, *Flammable and Combustible Liquids Code*, 2000 edition, NFPA 58, *Liquefied Petroleum Gas Code*, 2001 edition, NFPA 59, *Utility LP Gas Plant Code*, 2001 edition, API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, 1989 edition, or NFPA 59A (2001 edition) section 2.2. If authorized, constructed, and operated, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA's inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001 edition), which references NFPA 30 (2000 edition), NFPA 58 (2001 edition), NFPA 59 (2001 edition), API 2510 (1989 edition) for installation of storage tanks for flammable refrigerants and liquids.

FERC staff evaluated the spacing based on a mixture of prescriptive-, performance- and risk-based approach using codes and standards consistent with NFPA

550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that ELC and SLNG proposed to use and the spacing to determine if there could be cascading damage over a range of different consequences and likelihoods to inform what measures may be necessary to reduce the risk of cascading damage. If spacing to mitigate the potential for cascading damage was not practical, we evaluated whether other mitigation measures were in place and evaluated those systems in further detail as discussed in subsequent sections.

ELC and SLNG listed NFPA 59A (2001 through 2009 editions) as "most significant codes and standards applicable to the Project" and ELC and SLNG also listed NFPA 30, NFPA 58, NFPA 59, and API 2510, *Design and Construction of LPG Installations (LPG)*, 8th edition, among other applicable standards that would be used in the design, construction, and operation of the Project. ELC and SLNG added that for each code and standard listed, the current version at the time of preparation of the applicable document would be used. Where any requirements differ or a conflict exists, ELC and SLNG provided that the more stringent or more conservative requirement would be applied.

To minimize the risk of cryogenic spills causing structural supports and equipment from cooling below their minimum design metal temperature, the existing SLNG facilities generally located cryogenic equipment away from other types of process areas and have spill containment systems for cryogenic spills that would direct them to a remote impoundment. The Project would not contain any new equipment that would handle cryogenic or below-freezing hazardous fluids, and the pressures in the existing main LNG rundown line to the LNG tanks would nominally increase. However, the project would increase pressures in the existing LNG rundown lines from each MMLS unit due to the increased liquefaction rate associated with the project. The information provided in the application did not address the potential increased impacts of potential cold release scenarios on existing structural steel and equipment due to the increased pressure in the LNG rundown lines, i.e., design spills, that could have a significant jetting liquid component extending beyond the existing protected zone. Therefore, we recommend in section 5 that ELC and SLNG file, for review and approval, drawings and specifications for structural passive protection systems to protect equipment and supports that could be exposed to low temperature releases below the minimum design metal temperatures.

To minimize risk for flammable or toxic vapor ingress into buildings and from reaching areas that could result in cascading damage from explosions, ELC and SLNG would generally locate process areas away from buildings, fired equipment, ignition sources, and LNG storage tanks. The proposed modifications to the MMLS units and LNG rundown line would be located in areas previously reviewed by FERC staff as part of the Elba Liquefaction Project Environmental Assessment (Docket No. CP14-103). Included in the previous assessment was flammable or toxic vapor ingress into buildings and combustion air intakes and flammable vapors reaching areas that could result in cascading damage from explosions. FERC staff reviewed the proposed modifications to the MMLS units and LNG rundown piping and verified that any potential releases and impacts would be less than those previously analyzed and addressed in the Elba Liquefaction Project (Docket No. CP14-103). However, flammable vapors from the proposed Condensate Plant could reach existing buildings located within the MMLS units and the existing electrical building located west of the LNG Impoundment. Although, these existing buildings would not be normally occupied, flammable gas detection are typically provided near all combustion and building ventilation air intakes within the facility such that upon activation, the gas detectors would alert personnel and the associated air intake would shut down. Shutdown would be based on gas detection from two out of the total gas detectors for that air intake. The specific locations of the existing detectors would need to be verified as appropriate during final design. Therefore, we recommend in section 5 that ELC and SLNG conduct a technical review of the final design of the facility, for review and approval, identifying all combustion/ventilation air intake equipment and the detailed placement of detectors at those air intakes to detect flammable gas or toxic releases; and verify that these areas would be adequately covered by hazard detection devices that would isolate or shut down any combustion or ventilation equipment whose continued operation could add to or sustain an emergency. We also recommend in section 5 that Project facilities be subject to periodic inspections during construction to verify flammable/toxic gas detection equipment is installed in heating, ventilation, and air condition intakes of buildings at appropriate locations. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that flammable/toxic gas detection equipment installed in building air intakes function as designed and are being maintained and calibrated.

To minimize overpressures from vapor cloud explosions, we evaluated how flammable vapors would be prevented from accumulating within confined areas. The proposed modifications to the MMLS units and LNG rundown line would be located in areas previously reviewed and discussed in the Elba Liquefaction Project Environmental Assessment (EA) (Docket No. CP14-103). The Elba Liquefaction EA (Docket No. CP14-103) specifically evaluated overpressures from vapor cloud explosions for various hazardous fluids including LNG, ethylene, propane, isopentane, mixed refrigerant, and stabilized condensate, that could result in cascading damage to surrounding equipment. FERC staff reviewed the proposed modifications to the MMLS units and LNG rundown piping and verified that any potential overpressures from vapor cloud explosions would be less than those previously analyzed and addressed in the Elba Liquefaction Project (Docket No. CP14-103). In addition, FERC staff reviewed the proposed Condensate Plant which would be located north of the liquefaction trains. The overall footprint of the Condensate Plant area would be smaller and less congested than an MMLS unit given the number of equipment and piping associated with the Condensate Plant. Therefore, FERC staff consider the Condensate Plant area to be low congestion and the Project would not introduce any overpressure hazards greater than what was previously analyzed in the Elba Liquefaction Project EA (Docket No. CP14-103). The previous EA also discussed the measures ELC and SLNG included as part of the Liquefaction Project to mitigate the vapor dispersion and ignition into any confined areas such as include hazard detection devices installed on ventilation air intake equipment include shutdown capabilities and sufficient equipment spacing and layout. The final design and installation of these mitigation measures were also reviewed by FERC staff to ensure compliance with applicable Conditions of the June 1, 2016 Order.

To minimize the risk of pool fires from causing cascading damage, ELC and SLNG has proposed to use the existing LNG and Mixed Refrigerant Impoundments. Pool fire impacts from these existing impoundments were previously reviewed by FERC staff as part of the Elba Liquefaction Project Environmental Assessment (Docket No. CP14-103). The previous analysis evaluated heat levels for an LNG and mixed refrigerant fire in the existing impoundments, thus, the use of a model that accounts for the actual composition of condensate would show less radiant heat for fires involving condensate. FERC staff also confirmed that fires within the impoundments are spaced such that there would not likely be high radiant heats on the Project. Therefore, the Project would not introduce any higher radiant heat pool fire hazards than what was analyzed in the Elba Liquefaction Project Environmental Assessment (Docket No. CP14-103).

To minimize the risk of jet fires from causing cascading damage that could exacerbate the initial hazard, ELC and SLNG would generally locate flammable and combustible containing piping and equipment away from buildings and process areas that do not handle flammable and combustible materials. Jet fire impacts from the existing main LNG rundown line to the LNG storage tanks were previously analyzed in the Elba Liquefaction Project Environmental Assessment (Docket No. CP14-103). The pressures in the existing main LNG rundown header to the LNG tanks and the rundown lines from each MMLS unit would nominally increase. FERC staff verified these pressure increases would have a negligible effect on hazard distances compared to existing process conditions. Additional discussion related to passive protection to prevent failure of structural supports of equipment and pipe racks is discussed in subsequent sections below.

FERC staff also reviewed the proposed Condensate Plant to determine the thermal radiation hazard distances from a potential jet fire for the design spill scenarios and results showed that impacts would remain within the property boundary. FERC staff note the Condensate Plant is proposed to be located adjacent to the existing refrigerant storage area, existing condensate storage area, and existing main pipe rack and a potential jet fire could expose the existing vessels and piping to high thermal loads. As discussed in further detail in the Firewater section below, the facility would have fire water available that would mitigate any potential jet fire impacts to the existing refrigerant and condensate storage areas. However, ELC and SLNG did not discuss in the application or subsequent information what mitigation would be provided for a potential jet fire impacts from the Condensate Plant to the existing main pipe rack. This is also discussed in detail the Firewater section below. We note that the proposed Condensate Plant would include hazard detection, hazard control, emergency shutdown systems that would limit the duration of a jet fire event, and depressurization systems that would reduce the pressure in equipment. Therefore, we recommend in section 5 that ELC and SLNG file an analysis that demonstrates jet fire impacts onto the existing main pipe rack from the Condensate Plant would not lead to failure of structural steel or hazardous fluid containing lines within the existing main pipe rack. Additionally, it appears that ELC and SLNG would include some passive protection on structural steel at the Condensate Plant, but it is unclear to what extent on structural steel and whether any fireproofing of equipment or vessels would be provided. Therefore, we recommend in section 5 that ELC and SLNG file final design details including drawings and specifications of the passive structural fire protection for review and approval for structural supports and equipment. We also recommend in section 5 that ELC and SLNG file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from pool or jet fires; each critical structural component and emergency equipment item that could fail within the 4,900 BTU/ft^2-hr zone from a pool or jet fire that could exacerbate the hazard. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires should be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation should be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation should be supported by reliability information by calculations or test results, such as demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the component. The total firewater demand should account for all components that could fail due to a pool or jet fire.

If the project is authorized, ELC and SLNG would finalize the plot plan, and we recommend in section 5 that ELC and SLNG provide any changes for review and approval to ensure capacities and setbacks are maintained. If the facilities are constructed, ELC and SLNG would install equipment in accordance with the spacing indicated on the plot plans. In addition, we recommend in section 5 that Project facilities be subject to periodic inspections during construction to verify equipment is installed in appropriate locations and the spacing is met in the field. We also recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that equipment setbacks from other equipment and ignition sources are being maintained during operations.

Ignition Controls

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, this should include engineering plans for electrical area classification. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. Depending on the risk level, areas where electrical equipment would be located and wiring routed would either be unclassified or classified as Class 1 Division 1 or Class 1 Division 2. Electrical equipment and wiring located in these areas would be designed such that in the event a flammable vapor is present, the equipment would have a minimal risk of igniting the vapor.

PHMSA regulations incorporates NFPA 59A (2001) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. NFPA 59A (2001 edition) section 7.6.1 requires electrical equipment and wiring to be of the type specified by and installed in accordance with NFPA 70, *National Electrical Code*, 1999 edition, or CSA 22.1, *Canadian Electrical Code*, 1998 edition, for hazardous locations. In addition, NFPA 59A (2001 edition) section 7.6.2 requires fixed electrical equipment and wiring installed within the classified areas specified in Table 7.6.2 and Figures 7.6.2(a) through 7.6.2 (d) and to be installed in accordance with NFPA 70 (1999 edition) for hazardous locations. If authorized, constructed, and operated, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001 edition), which reference NFPA 70 (1999 edition) for installation of electrical equipment and wiring.

FERC staff evaluated the ignition controls based on a mixture of prescriptive-, performance- and risk-based approach using codes and standards consistent with NFPA 550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that ELC and SLNG proposed to use and whether the electrical area classification drawings for the proposed ELC and SLNG facilities were consistent with those standards or other applicable codes and standards. ELC and SLNG listed NFPA 59A (2001 through 2009 editions) as "most significant codes and standards applicable to the Project" and ELC and SLNG also listed NFPA 70, NFPA 496, *Standard for Purged and Pressurized Enclosures for Electrical Equipment in Hazardous Areas* (2008 edition), NFPA 497, *Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas* (2012 edition), and API 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified* *as Class I, Division 1 and Division 2* (3rd edition), ISA 12.01.01, *Electrical Instruments in Hazardous Atmospheres*, ISA 12.06.01, *Recommended Practice for Wiring Methods for Hazardous (Classified) Locations Instrumentation Part 1: Intrinsic Safety*, among other applicable standards that would be used in the design, construction, and operation of the Project. ELC and SLNG added that for each code and standard listed, the current version at the time of preparation of the applicable document would be used. Where any requirements differ or a conflict exists, ELC and SLNG provided that the more stringent or more conservative requirement would be applied. ELC and SLNG provided a set of drawings and figures for the area classification philosophies that also includes notes incorporating the applicable codes as well as references to the applicable code's figure, mentioned above. The proposed project facilities would generally be located in areas classified as Class 1 Division 2. FERC staff confirmed the existing spill trenches and impoundments that would direct and collect spills from the proposed new facilities are classified as Class 1 Division 1. We also reviewed cross-sectional electrical classification figures to confirm the extent in elevation the electrical classification would cover for areas that would contain the proposed facilities, modified equipment, spill containment areas, relief/vent areas, storage areas, pumps, etc. and found them to be consistent with the distances in NFPA 59A and API 500. However, given that this information is part of the FEED, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, electrical area classification drawings, including cross sectional drawings. The drawings should demonstrate compliance with NFPA 59A, NFPA 70, NFPA 497, and API RP 500, or approved equivalents. In addition, the drawings should include revisions to the electrical area classification design or provide technical justification that supports the electrical area classification using most applicable API RP 500 figures (i.e., figures 20 and 21) or hazard modeling of various release rates from equivalent hole sizes and wind speeds (see NFPA 497 release rate of 1 lb-mole/minute).

If our recommendations are adopted and facilities are constructed, ELC and SLNG would install appropriately classed electrical equipment, and we recommend in section 5 that Project facilities be subject to periodic inspections during construction for FERC staff to spot check electrical equipment and verify equipment is installed per classification and are properly bonded or grounded in accordance with NFPA 70. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility to ensure electrical equipment is maintained (e.g., bolts on explosion proof equipment properly installed and maintained, panels provided with purge, etc.), and electrical equipment are appropriately deenergized and locked out and tagged out when being serviced.

In addition, submerged pumps and instrumentation must be equipped with electrical process seals, and instrumentation in accordance with NFPA 59A (2001) and NFPA 70 (1999 and 2020). ELC and SLNG indicated that pump process seals are not applicable to the Project, however, the Project would add two new condensate pumps.

ELC and SLNG did not provide detailed pump drawings, therefore, it's unclear whether the new condensate pumps would include process seals that would require an air gap or vent. We recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001) and NFPA 70 (1999 or 2020, as applicable). In addition, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that should continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems. Alternatively, ELC and SLNG should file details on a system providing an approved equivalent protection, in accordance with NFPA 59A (2023 edition), from the migration of flammable fluid through the electrical conduit or wiring. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout construction and life of the facility to ensure electrical process seals for submerged pumps continue to conform to NFPA 59A and NFPA 70 and that air gaps are being properly maintained.

Hazard Detection, Emergency Shutdown, and Depressurization Systems

Title 18 CFR § 380.12(o)(3) requires applicants to provide a layout of the hazard detection system showing the location of combustible-gas detectors, fire detectors, heat detectors, smoke or combustion product detectors, and low temperature detectors and to identify detectors that activate automatic shutdowns and the equipment that would shut down. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project. 111

PHMSA regulations incorporates NFPA 59A (2001) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. NFPA 59A (2001 edition) section 9.1.2 requires fire protection "…be provided for all LNG facilities. The extent of such protection…be determined by an evaluation based on sound fire protection principles, analysis of local conditions, hazards within the facility, and exposure to or from other property." In addition, NFPA 59A (2001 edition) section 9.1.2 requires "The evaluation shall determine the following, as a minimum: (1) the type, quantity, and location of equipment necessary of equipment necessary for the detection and control of fires, leaks, and spills of LNG, flammable refrigerants, or flammable gases…and of potential non-process and electrical fires". NFPA 59A (2001 edition) also incorporates NFPA 72 (1999 edition). NFPA 72 (1999 edition) stipulates that "initiating devices shall be installed in all areas where required by other NFPA codes and standards or the authority having jurisdiction". In addition, NFPA 72 (1999 edition) section 2-4 on radiant energy-sensing detectors requires "the type and quantity of…be determined based on the performance characteristics of the detector and analysis of the hazard, including the burning characteristics of the fuel, the fire growth rate, the environment, the ambient conditions, and the capabilities of the extinguishing media and equipment" and "detector quantity…be based on the detectors being positions so that no point requiring detection in the hazard area is obstructed or outside the field of view of at least one detector" and "the location and spacing of detectors…be the result of an engineering evaluation that includes the following: size of the fire that is to be detected, fuel involved, sensitivity of the detector, field of view of the detector, distance between the fire and detector, radiant energy absorption of the atmosphere, presence of extraneous sources of radiant emissions, purpose of the detection system, and response time required" and "the system shall specify the size of the flaming fire of given fuel that is to be detected" among other requirements. If authorized, constructed, and operated, LNG facilities, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001 edition), which references NFPA 72 (1999 edition) for installation of hazard detectors.

NFPA 59A (2001 and 2019 editions) do not define minimum spacing, performance, or risk-based criteria for locating hazard detection. As such, FERC staff has observed wide variation in applications for proposed hazard detection layouts. Therefore, FERC staff evaluated the hazard detection systems based on a mixture of prescriptive-, performance- and risk-based approach using codes and standards consistent with NFPA 550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that ELC and SLNG proposed to use and whether the engineering design of the hazard detection system for the proposed ELC and SLNG Condensate Plant were consistent with those standards or other applicable codes and standards. ELC and SLNG would install hazard detection systems to detect cryogenic spills, flammable and toxic vapors, low oxygen environments, and fires. The hazard detection systems would alarm and notify personnel in the area and in the control room to initiate an emergency shutdown, depressurization, or appropriate procedures. ELC and SLNG listed NFPA 59A (2001 edition), NFPA 72, *National Fire Alarm and Signaling Code,* 2010 edition, ISA 12.13[.1], *Performance Requirements for Combustible Gas Detectors,* and ISA 12.13[.2], *Recommended Practice for Installation, Operation, and Maintenance of Combustible Gas Detectors,* as relevant codes and standards.

FERC staff also evaluated the adequacy of the general hazard detection type, location, and layout to ensure adequate coverage to detect flammable vapors and fires near potential release sources (i.e., pumps, flanges, and instrument and valve connections). The proposed hazard detection design utilizes an array of point gas, open path, and flame detectors to provide coverage of process equipment containing flammable fluids. Furthermore, the alarm setpoints for these detectors are appropriate for the hazard they would detect. FERC staff evaluated the hazard detection layout and noted a lack of flame and open path detectors on the second floor of the condensate plant skid. ELC and SLNG provided updated drawings that includes cones-of-vision for flame detectors showing hazard detectors installed in the areas FERC staff noted as lacking. The updated drawings indicate open path detection on the eastern and western sides of the condensate plant skid for both levels, numerous point gas detection on both levels, and two flame detectors on both levels. FERC staff also noted flame detector specifications were not provided. ELC and SLNG stated flame detector specifications and cone-of-vision drawings would be provided during detailed design. Lastly, FERC staff noted the NFPA 59A Preliminary Fire Protection Evaluation did not contain any new recommendations pertaining to the new condensate skid. ELC and SLNG stated the NFPA 59A evaluation would be provided during detailed design. No new combustion/ventilation air intake equipment is associated with the Project that would require gas detection on intake systems; additionally, existing fired equipment and occupied buildings have gas detection systems installed on air intakes. Therefore, no new air intake gas detectors would be required due to potential increased dispersion distances associated with the Project. Lastly, no new toxic hazardous fluids would be associated with the project and, therefore, no toxic gas detectors would be installed. We recommend in section 5 that ELC and SLNG file a hazard detection study to evaluate the effectiveness of their flammable and combustible gas detection and flame and heat detection systems in accordance with ISA 84.00.07 or approved equivalent methodologies. However, ISA 84.00.07 does not account for the potential higher consequences of liquefied gaseous releases and treats those consequences as the same as gaseous releases. We do not agree with this consequence scoring given the much higher potential consequences of liquefied gasses and highly volatile liquids. In addition, ISA 84.00.07 does not specify the release of concern. Given the goal to reduce offsite impacts and potential consequences to the public, we stipulate that the releases that need to be detected be based on releases that could result in offsite impacts. Therefore, the ISA 84.00.07 evaluation would need to demonstrate that 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de-inventory within 10 minutes. The analysis should also consider the set points, voting logic, wind speeds, and wind directions. This may also result in changes to the hazard detection layout. Therefore, we recommend in section 5, that, prior to construction of final design, ELC and SLNG should file, for review and approval, complete drawings and a list of the hazard detection equipment. The drawings should clearly show the location and elevation of all detection equipment as well as their coverage area. The list should include the instrument tag number, type, manufacturer, model, location, alarm indication locations, and shutdown functions of the hazard detection equipment.

Additionally, ELC and SLNG would install an ESD system in accordance with NFPA 59A. The ESD shutdown would include failsafe, or fireproof, valves within 50 feet of the equipment they protect. ESD manual push buttons would be installed at least 50 feet from the equipment they serve. ELC and SLNG indicated the ESD layout plans would be developed during detailed engineering. Therefore, we recommend in section 5 that, prior to construction of final design, ELC and SLNG should file a drawing showing the location of the emergency shutdown buttons associated with the Project. Emergency shutdown buttons should be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency. In addition, we recommend in section 5 that ELC and SLNG provide specifications, for review and approval, for the final design of fire safety specifications, including hazard detection, hazard control, and firewater systems.

ELC and SLNG would add three new liquid nitrogen vaporizers as spares to the existing nitrogen facilities. However, low oxygen detection was not specified for the new vaporizer area. ELC and SLNG stated operators would be required to bring portable oxygen detectors prior to entering the liquid nitrogen vaporizer area per their portable gas detectors policy. However, FERC staff disagree with this approach as it relies on procedural controls. Therefore, we recommend in section 5 that ELC and SLNG provide drawings and specifications that details the installation of low oxygen detection in the nitrogen vaporizer area.

FERC staff also noted the fire and gas cause and effect matrices that would indicate if the detectors would initiate an alarm, shutdown, depressurization, or other action based on the FEED were not provided. ELC and SLNG stated the new fire and gas detectors would be integrated with the existing fire and gas system and that a single gas detector detecting 20% LEL would initiate a visual and audible alarm in the fire and control room, and any combination of two detectors detecting 40% LEL would initiate local equipment shutdown in addition to visual and audible alarms. Because cause-and-effect matrices including the fire and gas system were not provided, we recommend in section 5 that ELC and SLNG provide, for review and approval, the final cause-and-effect matrices for fire and gas detection system. In addition, we recommend in section 5 that ELC and SLNG provide additional information, for review and approval, on the final design of all hazard detection systems (e.g., manufacturer and model, elevations, etc.) and hazard detection layout drawings. Given that the effectiveness and reliability of the detectors would also be impacted by the voting logic and voting degradation logic, we also recommend in section 5 that, prior to construction of final design, ELC and SLNG should file an evaluation of the voting logic and voting degradation for hazard detectors. Also, given the detectors would respond differently to different flammable and combustible gases, we recommend in section 5, that, prior to construction of final design, ELC and SLNG should file, for review and approval, a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of the hazard detectors when determining the set points that are intended to detect different gases or mixtures than the calibration gas.

If the project is authorized, constructed, and operated, ELC and SLNG would install hazard detectors according to its final specifications and drawings, and we recommend in section 5 that Project facilities be subject to periodic inspections during construction to verify hazard detectors and ESD pushbuttons are appropriately installed per approved design and functional based on cause-and-effect matrices prior to introduction of hazardous fluids. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility to verify hazard detector coverage and functionality is being maintained and not being bypassed without appropriate precautions.

Hazard Control

If ignition of flammable vapors occurred, hazard control devices would be installed to extinguish or control incipient fires and releases. Title 18 CFR § 380.12(o)(2) requires a detailed layout of the fire protection system, including the location of dry chemical systems and auxiliary or appurtenant service facilities. As suggested in our 2017 Guidance Manual section 13.37, this should include a description of the hazard control systems, including the design and layout for portable and fixed dry chemical systems, clean agent systems, carbon dioxide systems, and other hazard control systems. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

PHMSA regulations incorporates NFPA 59A (2001 edition) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. NFPA 59A (2001 edition) section 9.1.2 requires fire protection "…be provided for all LNG facilities. The extent of such protection…be determined by an evaluation based on sound fire protection principles, analysis of local conditions, hazards within the facility, and exposure to or from other property." In addition, NFPA 59A (2001 edition) section 9.1.2 requires "The evaluation shall determine the following, as a minimum: (1) the type, quantity, and location of equipment necessary of equipment necessary for the … control of fires, leaks, and spills of LNG, flammable refrigerants, or flammable gases…and of potential non-process and electrical fires". Section 9.1.2 also explicitly requires the evaluation determine the fire extinguishing and other fire control equipment. NFPA 59A (2001 edition) section 9.5.1 also requires portable or wheeled fire extinguishers recommended by their manufacturer for gas fires be available at strategic locations, as determined in accordance with 9.1.2, within an LNG facility and on tank vehicles and that these extinguishers be provided and maintained in accordance with

NFPA 10, Standard for Portable Fire Extinguishers, 1998 edition. Similarly, NFPA 59A (2001 edition) section 11.5.5.1 requires portable and wheeled fire extinguishers to also be inspected, tested, and maintained in accordance with NFPA 10 (1998 edition) and fixed fire extinguishing systems to be inspected, tested, and maintained in accordance with NFPA 12, *Standard on Carbon Dioxide Extinguishing Systems*, 2000 edition, NFPA 17, *Standard for Dry Chemical Extinguishing Systems*, 1998 edition, and NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*, 2000 edition. If authorized, constructed, and operated, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA inspection and enforcement programs, which require compliance with the hazard control requirements described.

FERC staff evaluated the proposed hazard control systems based on a mixture of prescriptive-, performance- and risk-based approach using codes and standards consistent with NFPA 550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that the company proposed to use and whether the engineering design of the hazard control system for the proposed facilities were consistent with those standards or other applicable codes and standards.

ELC and SLNG proposed the installation of hazard control systems to extinguish various types of incipient fires that could occur within the Project. ELC and SLNG listed NFPA 59A (2001 edition), NFPA 10 (2010 edition), and NFPA 2001 (2012 edition), and API 2510A, *Fire Protection Considerations for the Design and Operation of Liquefied Petroleum Gas (LPG) Storage Facilities*, 2010 edition, among others. FERC staff evaluated whether the agent type and capacities would meet NFPA 59A (2023 edition) and whether the spacing of the fire extinguishers would meet NFPA 10 (2022 edition). NFPA 59A (2023 edition) section 16.6.1.4 also stipulates LNG plant hazard areas where minimal Class A fire hazards are present should select potassium bicarbonate as the agent type and NFPA 59A (2023 edition) sections 16.6.1.3 and 16.6.1.5 stipulate handheld portable dry chemical extinguishers contain nominal agent capacities of 20 lb or greater and have a minimum 1 lb/sec agent discharge rate. ELC and SLNG would place two handheld fire extinguishers on the first floor of the condensate skid and one on the second and proposed extinguishers that would meet NFPA 59A (2023 edition) stipulations for agent type and agent storage capacities. However, the flow rates of extinguishers were not specified to verify whether they meet NFPA 59A (2023 edition) stipulations. NFPA 10 (2022 edition) section 6.3.1 stipulates a maximum travel distance of 50 ft for portable handheld extinguishers and section 6.3.3 stipulates where installed or positioned for obstacle, gravity/three dimensional or pressure fire hazards, the actual travel distance should not exceed 30 ft. The available FEED hazard control plans appeared to meet NFPA 10 travel distances to components containing flammable or combustible fluids (Class B) for handheld fire extinguishers (30 to 50 feet) and travel distances to most other components that could pose an ordinary combustible hazard (Class A) or associated electrical (Class C) hazard for handheld extinguishers (75 feet). Travel distances, installation heights, visibility, flow rate capacities, and other requirements should be confirmed in final design and in the field where design details, such as manufacturer, obstructions, and elevations, would be better known. Therefore, we recommend in section 5, that prior to construction of final design, ELC and SLNG should file, for review and approval, facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Plan drawings should clearly show the location and elevation by tag number of all fixed, wheeled, and hand-held extinguishers and should demonstrate the spacing of extinguishers meet prescribed NFPA 10 travel distances. The list should include the equipment tag number, type, manufacturer and model, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units and should demonstrate they meet NFPA 59A. FERC staff would confirm travel distances, installation heights, visibility, flow rate capacities, and other requirements in final design and in the field where design details, such as manufacturer, obstructions, and elevations, would be better known.

If the Project is authorized, constructed, and operated, ELC and SLNG would install hazard control equipment, and we recommend in section 5 that Project facilities be subject to periodic inspections during construction to verify hazard control equipment is installed in the field and functional prior to introduction of hazardous fluids. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility to verify in the field that hazard control coverage and is being properly maintained and inspected.

Passive Cryogenic Temperature and Fire Protection

If cryogenic releases or fires could not be mitigated from impacting facility components to insignificant levels, passive protection (e.g., fireproofing structural steel, cryogenic protection, etc.) should be provided to prevent failure of structural supports of equipment and pipe racks.

Title 18 CFR § 380.12(o)(7) requires copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants. As suggested in our 2017 Guidance Manual, this should include engineering plans for passive protection systems. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

PHMSA regulations incorporate NFPA 59A (2001) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. NFPA 59A (2001) section 6.4.1 requires pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, to be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure. We also note that 49 CFR § 193.2801 under Subpart I for fire protection only incorporates sections 9.1 through 9.7 and 9.9 of NFPA 59A (2001), which requires an evaluation of methods necessary for protection of equipment and structures from effects of fire exposure, but does not reference requirements for passive low temperature protection. In addition, NFPA 59A (2001) does not address passive low temperature protection for equipment or structures other than pipe supports. Moreover, NFPA 59A (2001) does not provide the criteria anywhere for determining if pipe supports, equipment, or structures are subject to cold liquid or fire exposures or the level of protection needed to protect the pipe supports, equipment, or structures against such exposures. If authorized, constructed, and operated, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA inspection and enforcement programs, which require compliance with the structural passive protection from low temperatures and fires as discussed above.

FERC staff evaluated the proposed passive protection systems based on a mixture of prescriptive-, performance-, and risk-based approach using codes and standards consistent with NFPA 550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that ELC and SLNG proposed to use and whether the engineering design of the passive protection systems for the proposed ELC and SLNG Liquefaction Optimization facilities were consistent with those standards or other applicable codes, standards, and recommended and generally accepted good engineering practices.

ELC and SLNG listed codes and standards applicable to the design, including NFPA 59A (2001 edition), API 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*, 3rd (2013), API 2510, *Design and Construction of LPG Installations (LPG)*, 8th (2001) edition, and API 2510A, *Fire Protection Considerations for the Design and Operation of Liquefied Petroleum Gas (LPG) Storage Facilities*, 2010 edition, among other applicable standards. ELC and SLNG also listed additional codes and standards that contain technical requirements for the passive fire protection, including API RP 553, *Refinery Valves and Accessories for Control and Safety*, UL 1709 *Rapid Rise Fire Tests of Protection Materials for Structural Steel*, and UL 2196, *Standard for Tests for Fire Resistive Cables*.

We also note that API 2218 (2013 edition) discusses the various standards for testing of fireproofing systems under different fire exposures, such as those under UL 1709, *Rapid Rise Fire Tests of Protection Materials for Structural Steel*, commonly used for pool fires and ISO 22899-1 commonly used to represent jet fires. API 2218 (2013 edition) also includes *considerations* for defining scenarios and areas for fireproofing, installation and quality assurance, inspection and maintenance, and other guidance. API 2510 (2001 edition) section 10.7.1 stipulates except for remote facilities, which require no protection, fireproofing be used to protect vessels if portable equipment is the only means of applying fire water and section 10.7.2 stipulates where fireproofing is used, it provide protection of the structural steel or LPG vessel for the time period required for operation of fire water systems. Section 10.7.3 and subsections also stipulate that the thickness of the fireproofing material be equivalent to a fire endurance of 1 ½ hours per UL 1709 when tested on a 10W49 column among other stipulations. Similarly, API 2510 (2001 edition) section 10.8.1 stipulates except for remote facilities, which require no protection, structural supports be provided with fireproofing, and sections 10.8.2 thru 10.8.4 stipulates fireproofing be provided on aboveground portions of the vessel's supporting structures and for horizontal vessel saddles fireproofing be provided where the distance between the bottom of the vessel and the top of the support is greater than 12 inches and for vertical vessel supported by a skirt fireproofing be provided on the exterior of the skirt. In addition, 10.8.5 stipulate fireproofing be provided on all pipe supports within 50 ft of the vessel and on all pipe supports within the spill containment area of the vessel. Similar to section 10.7.2, API 2510 (2001 edition) section 10.8.8 also stipulates that the thickness of the fireproofing material be equivalent to a fire endurance of 1 ½ hours per UL 1709 when tested on a 10W49 column. API 2510A (1996 edition) section 5.8.2 stipulates additional *consideration* for applications of fireproofing, including section 5.8.2.3 for vessel surfaces, 5.8.2.4 for instrument and control systems, 5.8.2.5 for pipe supports, and 5.8.2.6 for supports for fire-protection equipment and piping. API 2510A (1996 edition) also stipulates fire protection equipment and piping that may be exposed to fire be fireproofed to prevent failure and loss of the protection during a fire and that the thickness of the fireproofing be equivalent to a fire endurance of 1 ½ hours per UL 1709 when tested on a 10W49 column.

Given the subjectivity in where to apply passive protection, FERC staff also evaluated whether passive cold and fire protection would be applied to pressure vessels and structural supports that could be exposed to cold liquids below minimum design metal temperatures that could result in failures or from radiant heats of 4,000 Btu/ft^2-hr or greater from fires with durations that could result in failures[78] and that the passive protection is specified in accordance with recommended and generally accepted good engineering practices with a fire protection rating commensurate to the exposure.

The Project would not contain any new equipment that would handle cryogenic or below-freezing hazardous fluids. The pressures in the existing main LNG rundown header to the LNG tanks and the rundown lines from each MMLS unit would nominally increase. FERC staff verified these pressure increases would have a negligible effect on hazard distances compared to existing process conditions and therefore would not increase the risk to existing facilities.

FERC staff also evaluated whether passive fire protection would be applied to proposed pressure vessels and structural supports to facilities that could be exposed to radiant heats of 4,000 Btu/ft^2-hr or greater from fires with durations that could result in failures[79] and that they are specified in accordance with recommended and generally accepted good engineering practices with a fire protection rating commensurate to the exposure. The structural fire protection design would comply with NFPA 59A (2001), API RP 2218, UL 1709, and other recommended and generally accepted good engineering practices.

To minimize the risk of a pool or jet fire from causing cascading damage, ELC and SLNG would generally locate flammable and combustible containing piping, equipment, and impoundments away from buildings and other process areas that do not handle flammable and combustible materials. ELC and SLNG provided drawings that show fire exposed areas, including equipment and components, which indicate the majority of the proposed Condensate Plant would be located within the fire scenario envelope for the existing waste condensate storage tank, except for the northwest corner that includes the proposed stabilizer column. ELC and SLNG specified that fire-proofing would be applied to the proposed Condensate Plant's structural steel within the fire scenario envelope in accordance with their existing passive fire protection philosophy, but it is not clear whether the structural steel or equipment supports in the northwest corner would have passive protection applied. Additionally, ELC and SLNG did not indicate fire protection envelopes around equipment relevant to the project that account for jet fires from release scenarios, e.g., design spills, which would be expected to reach the proposed stabilizer column, nearby structural elements, and the recovered water storage area. Fireproofing would be provided to protect structures supporting high fire potential equipment from reaching 1000°F for a period of 1 ½hours, as defined by UL 1709 when tested on a 10W49 column. Because the condensate skid would handle small volumes of liquid and the ground under the skid would be graded toward the trenches to the mixed refrigerant impoundment, pool fires would be remote, and therefore, passive protection would not be included for the pressure vessels on the proposed condensate skid.

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79 Pool fires from impoundments are generally mitigated through use of emergency shutdowns, depressurization systems, structural fire protection, and firewater, while jet fires are primarily mitigated through the use of emergency shutdowns, depressurization systems, and firewater with or without structural fire protection.

Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, drawings and specifications for new and relevant existing structural passive protection systems to protect equipment and supports from pool fires and from jet fires of design spills that may exacerbate the initial hazard. In addition, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each pressure vessel that could fail within the 4,000 BTU/ft2-hr zone from pool or jet fires; each critical structural component and emergency equipment item that could fail within the 4,900 BTU/ft2-hr zone from a pool or jet fire that could exacerbate the hazard. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires should be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation should be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation should be supported by reliability information by calculations or test results, such as demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the component. The total firewater demand should account for all components that could fail due to a pool or jet fire.

FERC staff would also expect electrical, instrument, and control systems used to activate emergency systems needed to control a fire or mitigate its consequences (such as emergency shut-down systems, emergency isolation systems or emergency depressurization systems) would be protected from fire damage, unless they are specifically designed to fail safe during a fire exposure. NFPA 59A (2001 edition) section 9.2.3 requires ESD system(s) be of a failsafe design or be otherwise installed, located, or protected to minimize the possibility that it becomes inoperative in the event of an emergency or failure at the normal control system. Section 9.2.3 further requires ESD systems that are not of a failsafe design to have all components that are located within 50 ft (15 m) of the equipment to be controlled by either being installed or located where they cannot be exposed to a fire; or protected against failure due to a fire exposure of at least 10 minutes duration.

However, NFPA 59A (2001 edition) does not define the fire exposure that it must withstand and the basis for the 10-minute duration is unclear. Therefore, FERC staff looked across other prescriptive-, performance-, and risk-based codes, standards, and recommended and generally accepted good engineering practices across related industries. Failsafe valves are used in industries other than LNG, such as LPG facilities, petroleum and petrochemical processing plants, and the nuclear power plant industry. These industries provide useful context that we considered when evaluating the performance- and risk-based objectives for ensuring there would be effective and reliable protection against the fire exposure.

API 2510A, *Fire-Protection Considerations for the Design and Operation of Liquefied Petroleum Gas (LPG) Storage Facilities*, stipulates fireproofing instrument and control cables, and motor-operated valves, can provide sufficient operational capability in a fire to start, stop, or divert production flow or activate alarms or water systems. For example, if the control cabling for motor-operated valves necessary in an emergency is at risk during the first 15 minutes of a fire, it should be fireproofed for a 15-minute fire exposure. Alternatively, wire that is resistant to fire damage should be used. It then references API 2510, *Design and Construction of LPG Installations*, for additional information. API 2510 stipulates all shutoff valves located on nozzles below the maximum liquid level be designed to provide a visual indication of the valve position and be capable of maintaining an adequate seal under fire conditions, and that valves meeting the requirements of API 607, *Fire Test for Quarter-Turn Valves and Valves Equipped with Nonmetallic Seats*, or API 6FA, *Specification for Fire Test for Valves*, have the required fire resistance.

API 2218, *Fireproofing Practices in Petrochemical Plants*, section 5.1.8.1 stipulates electrical, instrument and control systems used to activate emergency systems needed to control a fire or mitigate its consequences (such as emergency shut-down systems, emergency isolation systems or emergency depressuring systems) should be protected from fire damage unless they are designed to fail safe during a fire exposure. The need to protect other electrical, instrument or control systems not associated with control or mitigation of the fire should be based on a risk assessment. If the control wiring used to activate emergency systems during a fire could be exposed to the fire, the wiring should be protected against a 15 to 30 minute fire exposure equivalent to UL 1709 (or functional equivalent). If activation of these emergency systems would not be necessary during any fire to which it might be exposed, then protection of the wiring is not required for emergency response purposes. API 2218 further discusses standard test methods, including ASTM E1725, *Standard Test Methods for Fire Tests of Fire-Resistive Barrier Systems for Electrical System Components*, and UL 2196, *Standard for Test of Fire Resistive Cables*, which includes different fire exposure temperature curves that can be used, including UL 1709, *Standard for Rapid Rise Fire Tests for Protection Materials for Structural Steel*. As discussed in API 2218, UL 1709 fire exposure was adopted as the first high temperature rise test that simulated hydrocarbon pool fire conditions and subjects a steel column to a hear flux that produces a temperature of 2000°F in 5 minutes and holds the temperature until the test is complete. UL1709 is recommended as the standard test for evaluating fireproofing systems for petroleum and petrochemical processing plants. API 2218 also describes ASTM E1529, *Standard Test Method for Determining Effects of Large Hydrocarbon Pool Fires on Structural Members and Assemblies*, which is described as essentially the same as UL 1709 and functionally equivalent. As described in more detail in literature from Sandia National Laboratories, the corresponding temperature for ASTM E1529 is 2000°F +/- 150°F (1095°C +/- 85°C) and the incident heat flux requirement is 50,000 BTU/ft^2-hr +/- 2,500 BTU/ft^2-hr (158 kW/m^2 +/- 8 kW/m^2).[80] We also note that 56 meter diameter large scale LNG pool fires conducted by Sandia National Laboratories have recorded equivalent surface emissive powers of up to 286 kW/m^2 with wide angle radiometers and up to 316 kW/m^2 with narrow angle radiometers and recommend a nominal surface emissive power of 286 kW/m^2 for use in pool fire modeling for LNG spills over water.[81] This is in stark contrast to their equivalent report for large scale LPG pool fires where a nominal surface emissive power of 43 kW/m^2 was specified based on 21 meter diameter LPG pool fires.[82] Jet fires, or sometimes labeled torch fires, can also exhibit much higher surface emissive powers for LPG and other hydrocarbons. NFPA 290, *Standard for Fire Testing of Passive Protection Materials for Use on LP-Gas Containers*, 2023 edition, section 5.2.1 specifies the flame temperature from the torch fire to be 2200°F +/-140°F (1200°C +/- 60°C), which is similar to maximum incident heat fluxes up to 330 kW/m^2 recorded in natural gas, LPG, and butane jet fire tests.[83,84,85] We further note that the impact from radiant heat over time is often expressed as a thermal dose unit and that the thermal dose of a 286 kW/m^2 for 10 minutes is equivalent to a thermal dose of 158 kW/m^2 for approximately 20 minutes and 330 kW/m2 for 10 minutes is equivalent to a thermal dose of 158 kW/m^2 for approximately 30 minutes.

The Nuclear Regulatory Commission has supported testing, since the Browns Ferry Fire incident in 1975, to examine how electrical cabling commonly used for control and safety purposes would behave during fire exposure. This testing expanded in 2007 to 2012, including a series of testing and reports followed for alternating current and direct current circuits. The alternating current testing methods and results are described in the Nuclear Regulatory Commission report NUREG-6931, “Cable Response to Live Fire

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[80] Baird, A.R., Gill, W., Mendoza, H., Figueroa, V., Correlating Incident Heat Flux and Source Temperature to Meet ASTM E1529 Requirements for RAM Packaging Components Thermal Testing, Proceedings of the ASME 2021 Pressure Vessels & Piping Conference, July 12-16, 2021.
[81] Luketa, A., *Recommendations on the Prediction of Thermal Hazard Distances from Large Liquefied Natural Gas Pool Fires on Water for Solid Flame Models*, Sandia Report, SAND2011-9415, December 2011.
[82] Luketa, A., Hightower, M., *Guidance on Hazard and Safety Analyses of LPG Spills on Water*, Sandia Report, SAND2018-10338, April 2018
[83] Chamberlain, G., *Developments in Design Methods for Predicting Thermal Radiation from Flares*, Chemical Engineering Res. Des., Vol 65, pp 299-309, July 1987.
[84] Bennett, J., Cowley, L., Davenport, J., Rowson, J., *Large Scale Natural Gas and LPG Jet Fires Final Reeport to the CEC*, Shell Research, Thornton Research Centre, 1991.
[85] Sekulin, A., Action, M., *Large Scale Experiments to Study Horizontal Jet Fires of Mixtures of Natural Gas and Butane – Data Report for Test 8051*, GRC Report R0367, 1995.

(CAROLFIRE)", 2007. The direct current testing methods and results are described in the Nuclear Regulatory Commission report NUREG-7100 "Direct Current Electrical Shorting in Response to Exposure Fire (DESIRRE-Fire): Test Results", 2012. Probabilistic risks are described in NUREG-7150, Joint Assessment of Cable Damage and Quantification of Effects from FIRE (JACQUE-FIRE)", 2012. The test results showed that fire exposed electrical cables could experience electrical shorts and faults which resulted in spurious action, meaning a valve position could change from its failsafe position to its normal position. The test results also showed many different types of cables experienced spurious action within 20 minutes from the onset of the fire exposure, and some experienced the duration of the spurious action for over 20 minutes.

ESD valve closures, and other safety valves moving to and remaining in their failsafe position, are a layer of protection LNG facilities utilize to mitigate hazardous fluid releases following accidents. In the event of a release and fire which damages cabling used to control failsafe valves, spurious opening and closing of the valves could unexpectedly create situations which hamper the facility personnel response to control the emergency. ELC and SLNG did not provide documentation indicating electrical and control systems would fail safe or have fire resistance. Based on the high intensity heat from potential LNG pool and jet fires equivalent for 10 minutes having a thermal dose equivalent to a UL 1709 fire exposure of 20 and 30 minutes and nearly all cable spurious operations occurring within 20 minutes, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file passive fire protection drawings and specifications for the electrical, instrument, and control equipment that activate emergency systems or would be relied upon for isolation to withstand a UL 1709 (6th edition) or approved equivalent fire exposure for at least 20 minutes.

Firewater Systems

If ignition of flammable vapors occurred, hazard control devices would be installed to extinguish or control incipient fires and releases. Title 18 CFR § 380.12(o)(2) requires a detailed layout of the fire protection system, including the location of firewater pumps, piping, hydrants, hose reels, high expansion foam systems, and auxiliary or appurtenant service facilities. Also, as suggested in our 2017 Guidance Manual section 13.38, a description of the firewater system should include description of firewater system design cases, demands, calculations, and basis of sizing. This enables FERC staff to evaluate the adequacy of the firewater system design. In addition, Title 18 CFR § 380.12(o)(14) requires demonstration of how the proposed project would comply with applicable federal regulations, including codes and standards incorporated by reference into federal regulations and 18 CFR § 380.12(o)(12) requires identification of all codes and standards that would be used in the proposed project.

PHMSA regulations incorporates NFPA 59A (2001 edition) by reference in 49 CFR § 193.2101 under Subpart C for design, 49 CFR § 193.2301 under Subpart D for construction, 49 CFR § 193.2401 under Subpart E for equipment, 49 CFR § 193.2521 under Subpart F for operational records, and 49 CFR § 193.2693 under Subpart G for maintenance records. We also note that 49 CFR § 193.2801 under Subpart I for fire protection only incorporates sections 9.1 through 9.7 and 9.9 of NFPA 59A (2001). NFPA 59A (2001 edition) section 9.1.2 requires fire protection "…be provided for all LNG facilities. The extent of such protection…be determined by an evaluation based on sound fire protection principles, analysis of local conditions, hazards within the facility, and exposure to or from other property." In addition, NFPA 59A (2001 edition) section 9.1.2 requires "The evaluation shall determine the following, as a minimum: (1) the type, quantity, and location of equipment necessary of equipment necessary for…control of fires, leaks, and spills of LNG, flammable refrigerants, or flammable gases…and of potential non-process and electrical fires". Section 9.1.2 also explicitly requires the evaluation determine the fire protection water systems. NFPA 59A (2001 edition) section 9.4.1 also requires a water supply and a system for distributing and applying water to be provided for protection of exposures; for cooling containers, equipment, and piping; and for controlling unignited leaks and spills unless the evaluation in accordance with section 9.1.2 indicates the use of water is unnecessary or impractical. Section 9.4.2 also requires the design of fire water supply and distribution systems, if provided, provide for the simultaneous supply of those fixed fire protection systems, including monitor nozzles, at their design flow and pressure, involved in the maximum single incident expected in the plant plus an allowance of 1000 gpm for hand hose streams for not less than 2 hours. NFPA 59A (2001 edition) section 9.6 also requires facility operators to prepare and implement a maintenance program for all plant fire protection equipment. If authorized, constructed, and operated, ELC and SLNG must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001 edition) for firewater systems, as discussed above.

FERC staff evaluated the proposed firewater systems based on a mixture of prescriptive-, performance-, and risk-based approach using codes and standards consistent with NFPA 550, *Guide to the Fire Safety Concepts Tree*, 2022 edition, and NFPA 551, *Guide for the Evaluation of Fire Risk Assessments*. As part of our review, we evaluated the proposed codes and standards that ELC and SLNG proposed to use and whether the engineering design of the firewater systems for the proposed ELC and SLNG Liquefaction Optimization project facilities were consistent with those standards or other applicable codes and standards.

ELC and SLNG listed the following codes and standards as applicable to the project design: NFPA 59A (2001 edition); NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, 2022 edition; NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*; API 2510, *Design and Construction of LPG Installations (LPG)*, 8^{th} (2001) edition, and API 2510A, *Fire Protection Considerations for the Design and Operation of Liquefied*

Petroleum Gas (LPG) Storage Facilities, 2nd (1996) edition; among other applicable standards. With the exception of editions referenced, these codes and standards are consistent with those referenced by NFPA 59A (2019 and 2023 editions). FERC staff also took a performance- and risk-based approach consistent with codes, standards, and recommended and generally accepted good engineering practices to determine whether sufficient firewater would provide exposure cooling across a range of pool and jet fire scenarios.

ELC and SLNG would add a single firewater monitor to the existing firewater system that would cool the surface of piping, and equipment exposed to heat from a fire at the proposed Condensate Plant. FERC staff evaluated the adequacy of the coverage for the additional firewater monitor and verified the adequacy of the existing firewater system to support the additional demand of the proposed firewater monitor. The firewater demand that would be introduced by the new firewater monitor would be bounded by the demands of other existing fire zones within the plant and would not affect the ability of the existing firewater pumps to provide peak firewater flow. ELC and SLNG indicated that the firewater demand table would be updated during final design to reflect final equipment data. ELC and SLNG provided a firewater coverage drawing including a new firewater monitor and revised coverage area for an existing firewater monitor. However, where firewater monitor coverage areas intersect pipe racks, large vessels or process equipment, the firewater coverage could be blocked, and the coverage areas should be modified to account for obstructions during the final design. The proposed additional firewater monitor would provide firewater coverage from the northeast side of the proposed Condensate Plant for the existing condensate storage area and the proposed Condensate Plant. Additionally, there is an existing firewater monitor that would provide coverage from the northwest side of the proposed Condensate Plant. However, FERC staff noted there would be no firewater monitor that would provide firewater coverage from the southwest direction to the proposed condensate plant skid. ELC and SLNG indicated the flare knockout drum in the proposed condensate plant skid would block flow from a stationary firewater monitor located at the southwest of the skid and that an existing firewater hydrant and hose would instead be used by first responders should a jet fire emanate in a direction that would not be accessible by the additional and existing monitors. ELC and SLNG indicated first responders would apply hose water in under 10 minutes. However, the closest Savannah Fire Department fire station would be located approximately 6.6 miles away that would be projected to take more than 10 minutes to arrive on scene. In addition, NFPA 1710, *Organization and Deployment of Fire Suppression Operations, EMS and Special Operations in Career Fire Departments*, establishes metrics and benchmarks for performance for career fire departments. According to the latest Savannah Fire Department Annual Compliance Report, Savannah Fire Department reported for 90 percent of all moderate risk fires, the total response time for the arrival of the first-due unit was 7:01 and would be capable of providing 500 gallons of water and 1,250 gpm pumping capacity, providing a scene size-up, establishing incident command and assigning resources, and the total response time for an effective response force (EFR) was 11:59.[86] For 90 percent of all high risk fires, the total response time for first-due unit was 7:07 and EFR was 12:33. For 90 percent of moderate risk hazardous material incidents, these numbers are 8:19 and 14:06, respectively, and there was not sufficient data to calculate times for high risk or special hazardous material response incidents. These times also start once a call is received, and as indicated in literature, process equipment including steel tanks, chemical process equipment, or machinery can become damaged within 10 minute exposure when exposed to approximately 11,000 BTU/ft^2-hr; cable insulation can degrade within 10 minutes when exposed to approximately 5,700 BTU/ft^2-hr; and structural steels can lose about one-third of strength when exposed to 4,900 BTU/ft^2-hr indefinitely assuming no heat losses.[87,88] Therefore, FERC staff believe an additional monitor should be positioned at the southern side of the Condensate Plant to provide at least two firewater monitors or hydrants for adequate monitor coverage of pressurized equipment within the skid should a jet fire preclude the use of the one or more monitor(s) and/or hydrant(s) and impinge on the Condensate Plant from equipment within the skid, the main pipe rack to the south, or the condensate storage area to the east. Therefore, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an analysis that evaluates and optimizes the firewater layout at the southern side of the Condensate Plant to adequate provide firewater coverage on all sides for any equipment whose failure could result in an off-site or cascading impact, or alternatively demonstrate that equivalent or adequate fire mitigation would be provided. The firewater coverage should be provided by at least two monitors or hydrants in the event that the fire prohibits the ability to use of the one or more of the monitor(s) and/or hydrant(s). In addition, we recommend in section 5 that prior to construction of final design, ELC and SLNG should file, for review and approval, an updated fire protection evaluation of the proposed facilities. The evaluation should justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001 edition). The justification for firewater should provide calculations for all firewater demands based on design densities, surface area, and throw distance as well as specifications for the corresponding hydrant and monitors needed to reach and cool equipment.

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86 Savannah Fire & Emergency Services, Annual Compliance Report, 8th Edition, https://www.savannahga.gov/DocumentCenter/View/19413/2019-Annual-Compliance-Report, Accessed March 2024.

87 Sandia National Laboratories, Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water, Sandia Report, SAND2004-6258, December 2004.

88 NFPA 59A, Standard for the Production, Storage, and Handling of LNG, 2023 edition.

FERC staff also reviewed the revised firewater layout for compliance with NFPA 24 (2022 edition) section 6.6.1, which states that sectional valves shall be provided on looped systems at locations within piping sections such that the number of fire protection connections does not exceed six. FERC staff found the revised design would have seven connections between the existing post indicator valves (i.e., section valves) and would not be consistent with NFPA 24 (2022 edition).

ELC and SLNG also provided a hazard analysis report that demonstrated the 1,600 BTU/ft^2-hr heat flux from a jet fire would stay onsite. However, FERC staff note that the Condensate Plant's location would be adjacent to the existing refrigerant and condensate storage vessels, as well as the main pipe rack that contains hazardous and cryogenic fluids. The hazard analysis report indicates a potential jet fire could expose the existing vessels and main pipe rack to high radiant heats. ELC and SLNG did not address the potential jet fire impacts to the existing refrigerant and condensate storage vessels or main pipe rack and whether the existing mitigation measures would be sufficient or if additional mitigation would be needed. FERC staff evaluated the existing firewater monitor layout on these adjacent vessels and verified the existing vessels would have double firewater monitor coverage and that the throw distances provided by ELC and SLNG account for wind effects and spray elevation. Therefore, the existing firewater systems would be expected to provide adequate protection to the existing storage vessels should a jet fire from the Condensate Plant impinge on them. However, with the information provided, FERC staff were unable to evaluate the mitigation measures in place should a jet fire from the Condensate Plant and impinge on the main pipe rack. Therefore, we recommend in section 5 that ELC and SLNG file an analysis that demonstrates jet fire impacts onto the main pipe rack from the Condensate Plant would not lead to the failure of structural steel or hazardous fluid containing lines within the main pipe rack.

Given the likely changes needed in the firewater design to meet the recommendations, we recommend in section 5 that, prior to construction of final design, ELC and SLNG should file facility plan drawings showing the proposed location of the firewater systems. Plan drawings should clearly show the location of firewater piping, post indicator and sectional valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, water-mist system, and sprinkler. The drawings should demonstrate that each process area, fire zone, or other sections of piping with several users can be isolated with post indicator or sectional valves in accordance with NFPA 24 (2022 edition) or approved equivalent, and that firewater coverage is provided by at least two monitors or hydrants with sufficient firewater flow to cool exposed surfaces subjected to a fire. The drawings should also include piping and instrumentation diagrams of the firewater systems.

ELC and SLNG also indicated NFPA 25 would be used during operations of the Project. However, it is not clear how the operational maintenance and testing procedures for the firewater system modifications and all other existing fire protection components would adhere to the practices in the relevant NFPA standards. Therefore, we recommend in section 5 that the operational maintenance and testing procedures for fire protection components should be in accordance with current versions of the applicable standards listed in NPFA 59A (2019) or approved equivalents.

If the Project is authorized, constructed, and operated, ELC and SLNG would install the firewater system as designed, and we recommend in section 5 that Project facilities be subject to periodic inspections during construction and that companies provide results of commissioning tests to verify the firewater system modifications associated with the Project are installed and functional as designed prior to introduction of hazardous fluids. In addition, we recommend in section 5 that ELC and SLNG complete and document a firewater pump acceptance test and firewater monitor and coverage tests and show the actual coverage area from each monitor and hydrant on facility plot plan(s). In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility to ensure firewater system modifications are being properly maintained and tested.

Geotechnical and Structural Design

ELC and SLNG provided geotechnical and structural design information for its facilities to demonstrate the site preparation and foundation designs would be appropriate for the underlying soil characteristics and to ensure that the structural design of the Project facilities would be in accordance with Federal regulations, standards, and recommended and generally accepted good engineering practices. The application focuses on the resilience of the Project facilities against natural hazards, including extreme geological, meteorological, and hydrological events, such as earthquakes, tsunamis, seiches, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, sea level rise, landslides, wildfires, volcanic activities, and geomagnetism.

<u>Geotechnical Evaluation</u>

FERC regulations under 18 CFR § 380.12 (h) (3) require geotechnical investigations to be provided[89]. In addition, FERC regulations under 18 CFR § 380.12 (o) (14) require an applicant to demonstrate compliance with regulations under 49 CFR Part 193 and NFPA 59A (2001). All facilities, once constructed, must comply with the requirements of 49 CFR Part 193 and would be subject to USDOT PHMSA's inspection and enforcement programs. USDOT PHMSA regulations incorporate by reference NFPA 59A (2001). NFPA 59A (2001) section 2.1.4 requires soil and general investigations of the site to determine the design basis for thefacility. However, no additional requirements

[89] Effective December 29, 2023, 18 CFR §380.12 was updated and information that applicants should provide for geotechnical investigations is included in 18 CFR §380.12(o)(15)(ii).

are set forth in 49 CFR Part 193 or NFPA 59A on minimum requirements for evaluating existing soil site conditions or evaluating the adequacy of the foundations. Therefore, FERC staff evaluated the existing site conditions, geotechnical report, and proposed foundations design to ensure they are adequate for the LNG facilities as described.

The proposed Project would be constructed entirely within the existing Elba Island LNG terminal in Chatham County, Georgia, approximately 8.5 miles upstream from the Savannah River. On June 1, 2016, FERC approved the Expansion Project under Docket No. CP14-103. ELC and SLNG is proposing to amend the authorization under Section 3 of Natural Gas Act. Specifically, the Project is proposing to make modifications to the ten existing movable modular liquefaction systems (MMLS) units, construct and operate a new condensate plant, install three new liquid nitrogen vaporizers, and authorize to increase in the total liquefaction capacity. During application phase of the Expansion Project, ELC and SLNG contracted Terracon Consultants, Inc. (Terracon) to conduct geotechnical investigation for the project site. FERC staff have reviewed the previously filed Expansion Project geotechnical investigation report to determine whether the existing geotechnical investigation would be sufficient for the proposed Amended Expansion Project.

As a part of approved and already constructed Expansion Project under Docket No. CP14-103, Terracon performed the geotechnical investigation for the facility in 2014. Which included a field exploration program, laboratory testing, engineering evaluation of the subsurface conditions, and the development of recommendations for foundation support and site preparation. Terracon stated that previous geotechnical investigations and studies (i.e., 2002, 2005, 2008, 2010) were also reviewed for the existing LNG facility.

As presented in the Terracon 2014 geotechnical investigation report, the proposed project area would be located in Area 1 and Area 2 at the existing LNG facility. In field exploration program, Terracon performed a serials standard penetration test (SPT), cone penetration test (CPT) soundings, seismic CPT (SCPT) testing, and Marchetti flat dilatometer test (DMT) sounding for the Area 1 and Area 2. SPT borings were drilled to depths of 65 ft to 120 ft below ground surface; CPTs borings were drilled to depth of 48.4ft to 100.6 ft below ground surface; SCPT were drilled to depth of 62.3 ft to 100ft below ground surface; and DMT were drilled to depth of 47.6ft to 72.4ft below ground surface. The shear wave velocity measurements were made using multi-channel analysis of surface waves (MASW) tests and SCPT measurements. A series laboratory tests were performed on the soil samples collected utilized either a split spoon sampler or a Shelby tube sampler to obtain soil properties and verify/modify the visual classification of soils.

As stated in the 2014 report, the finished floor elevations would be 14.5 ft MLW (mean low water) from original grade of 10.1 to 14.3 ft in Area 1. In Area 2, the finished floor elevations would be 18.5 ft MLW from original 13 ft to 19 ft. Groundwater level was analyzed for the site. From the short-term measurements in the SPT, CPT, and DMT boreholes, relatively large variations of groundwater levels were noted across the project site. Large variations of groundwater levels were also observed from the long-term monitoring in the groundwater monitoring wells. Terracon stated that the short-term measurement agreed with the long-term monitoring results. Terracon recommended a groundwater level of 10 ft MLW for design calculation for the interior areas.

Subsidence is the sudden sinking or gradual downward settling of land with little or no horizontal motion, caused by movements on surface faults or by subsurface mining or pumping of oil, natural gas, or ground water. Terracon indicated that ground subsidence is a prominent feature of the site due to the presence of very soft organic clay in the upper 30 ft. A detailed site reconnaissance was conducted to measure and document the features of the subsidence. For the structures supported on deep foundations, the structures may experience very limited settlement; however, settlements of the soft clay can develop considerable downdrag forces to the deep foundations, resulting in the reduced deep foundation capacity and stiffness. Terracon also performed slope stability analyses were performed for the site. Terracon conclude that the risk of a slope failure would be very small based on analyses. For furthermore discussion on the subsidence for the proposed facilities, refer to section 2.1.1.3 of the EA filed under Docket No. CP14-103.

Terracon performed settlement analyses for the site, including settlement analyses of the liquefied soil, post-liquefaction settlement. Terracon indicated that commonly used ground improvement measures are generally considered not effective in reducing the potential settlement to an acceptable level. A deep foundation system would be necessary to transit the loads to the deep competent soil layers for the site. ELC and SLNG stated that all equipment and structures would be supported on the deep foundation. If authorized and constructed, FERC staff would continue its review of the settlement and subsidence to ensure facility foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

Based on Terracon 2014 geotechnical investigation report, Terracon indicated that Site Classification was performed based on shear wave velocity profiles and the in-situ soil conditions in accordance with ASCE/SEI 7-05. Based on the thickness of the organic soft clay layer, the site was determined as Site Class F[90] per ASCE/SEI 7-05. Terracon evaluated fault for the site and indicated that there were no faults observed at the subject

[90] There are six different site classes in ASCE/SEI 7 (2005), A through F, that are representative of different soil conditions that impact the ground motions and potential hazard ranging from Hard Rock (Site Class A), Rock (Site Class B), Very dense soil and soft rock (Site Class C), Stiff Soil (Site Class D), Soft Clay Soil (Site Class E), to soils vulnerable to potential failure or collapse, such as liquefiable soils, quick and highly sensitive clays, and collapsible weakly cemented soils (Site Class F).

site or Elba Island during field exploration of the study. Terracon concluded that the risk of fault rupture is low based on the geologic setting and the historical evidence in the area. Terracon stated that extensive literature review and research was conducted to determine the lates and state-of-the practice procedures on the evaluation of soil liquefaction. Terracon concluded that the risk of liquefaction is very small even under the extreme seismic condition. The liquefaction consequences evaluation does not reveal and unacceptable level of deformation or stability concern. The presence of the thick layer of soft clay would require all structures to be supported on deep foundations.

Terracon performed laboratory tests to assess soil corrosion potential for the site. Soil samples were collected across the site sent to laboratory for testing of chemicals that influence corrosion potential of the soils. The analytical testing consisted of pH, electrical resistivity, chloride, and sulfate contents. Terracon concluded that the on-site shallow soils at most of the site have potential of sulfate attacks on concrete, ranging from severe to very severe. Terracon recommended using proper cement mixt to resist corrosion.

FERC staff agree that the existing geotechnical investigation conducted under Docket No. CP14-103. would be sufficient for the proposed Amended Expansion Project. The existing subsurface conditions are generally suitable for the proposed facilities, if proposed site preparation, foundation design, and construction methods are implemented appropriately. The proposed project would be consistent with the geotechnical evaluation described in the existing approved Expansion project under Docket No. CP114-103-000 since the Project would be constructed entirely within existing facility that previously authorized under the same Docket No. CP14-103). For more discussion on the Geotechnical Evaluation for the proposed facilities, refer to section 2.1.1.3 of the EA filed under Docket No. CP14-103. The proposed Project would implement the recommendation of the existing soil investigation report to design the proposed foundation design for the project.

In order to ensure the geotechnical investigation recommendations are resolved and the company should provide the final site preparation, foundation design, and construction methods, as recommended in following Sections Structural and Natural Hazard Evaluation and B.2.

If authorized and constructed, FERC staff would continue its review of the results of the geotechnical investigation to ensure facility foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

Structural and Natural Hazard Evaluation

FERC regulations under 18 CFR § 380.12(m) requires applicants address the potential hazard to thepublic from failure of facility components resulting from accidents or natural catastrophes, evaluate how these events would affect reliability, and describe what design features and procedures that would be used to reduce potential hazards. In addition, 18 CFR § 380.12(o)(14) require an applicant to demonstrate how they would comply with 49 CFR Part 193 and NFPA 59A.[91] USDOT PHMSA regulations in 49 CFR Part 193 has specific requirements on designs to withstand certain loads from natural hazards and incorporates by reference NFPA 59A (2001 and 2006) and ASCE/SEI 7-05 and ASCE 7-93 via NFPA 59A (2001). NFPA 59A (2001) section 2.1.1 (c) also requires the proposed Project to consider the plant site location in the design of the Project with respect to the proposed facilities being protected, within the limits of practicality, against natural hazards, such as from the effects of flooding, storm surge, and seismic activities. USDOT PHMSA's LOD on 49 CFR Part 193 Subpart B would discuss the Project's proposed wind speed design and studies of site-specific natural hazards. If authorized, constructed, and operated, LNG facilities as defined in 49 CFR Part193 must comply with the requirements of 49 CFR Part 193 and would be subject to USDOT PHMSA's inspection and enforcement programs. Furthermore, we evaluated the basis of design for Project facilities for all natural hazards under FERC jurisdiction, including those under DOT PHMSA and USCG jurisdiction. ELC and SLNG state that the facilities would be constructed to satisfy the FERC and NFPA 59A requirements in accordance with 2018 International Building Code (IBC), ASCE/SEI 7-05, and ASCE/SEI 7-16. These regulations and standards require various structural loads to be applied to the design of the facilities, including live (i.e., dynamic) loads, dead (i.e., static) loads, and environmental loads. FERC staff also evaluated whether the engineering design would withstand impacts from natural hazards, such as earthquakes, tsunamis, seiches, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, sea level rise, landslides, wildfires, volcanic activity, and geomagnetism. ELC and SLNG clearly state that this Amend Project does not make any changes to marine facilities from the existing Expansion Project approved under Docket No. CP14-103. In addition, ELC and SLNG must meet NFPA 59A (2019) as incorporated by 33 CFR Part 127 if needed.

ELC and SLNG state that all equipment and structures would be supported on deep foundations. The type of deep foundation would be the driven pre-stressed concrete (PSC) piles. If the proposed project is authorized, and constructed, and operated, the Project would install equipment in accordance with its final design. In addition, the existing project authorized under Docket No. CP14-103 has a condition that prior to construction of final design, the Project should file with the Secretary the final design package. Similarly, we recommend in Section 5 that, prior to construction of final design, ELC and SLNG should file with the Secretary the following information, stamped and

[91] FERC regulations do not specify what edition of NFPA 59A an applicant should demonstrate compliance with. In most applications, applicants have interpreted this as the edition(s) incorporated into DOT PHMSA regulations, which for this case would be the 2001 and 2006 editions at the time of application. Others have interpreted this as the NFPA 59A edition published at the time of application or another edition they intend on incorporating in addition to those incorporated into DOT PHMSA regulations.

sealed by the professional engineer-of-record, registered in the State of Georgia:

a. site preparation drawings and specifications;
b. finalized civil and structural design basis, criteria, specifications;
c. finalized wind and seismic design basis;
d. Issued for Construction of LNG terminal structures and foundation design drawings and calculations (including prefabricated and field constructed structures);
e. quality control procedures to be used for civil/structural design and construction;
f. soil improvement procedures for the proposed project site;
g. the finalized corrosion control and prevention plan for any underground piping, structures, foundations, equipment, and components; and
h. the total and differential settlement of final designed foundations for structures, systems, and components for the project site.
i. the finalized foundation design criteria for the project; and the associated quality assurance and quality control procedures.
j. In addition, ELC and SLNG should file, in its Implementation Plan, the schedule for producing this information.

Earthquakes, Tsunamis, and Seiche

FERC regulations under 18 CFR § 380.12 (o) (15) (iii) requires evaluation of earthquake hazards based on whether there is potential seismicity, surface faulting, or liquefaction[92]. Earthquakes and tsunamis have the potential to cause damage from shaking ground motion and fault ruptures. Earthquakes and tsunamis oftenresult from sudden slips along fractures in the earth's crust (i.e., faults) and the resultant ground motions caused by those movements but can also be a result of volcanic activity or other causes of vibration in the earth's crust. The damage that could occur as a result of ground motions is affected by the type/direction and severity of the fault activity and the distance and type of soils the seismic waves must travel from the hypocenter (or point below the epicenter where seismic activity occurs). As previously mentioned, the proposed project would be constructed entirely within the existing LNG facility.

As a part of approved and already constructed Expansion Project under Docket No. CP14-103, Terracon performed the seismic hazards study for the facility in 2014. Terracon stated that the seismic hazards study included a review of the paleo-seismicity

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[92] Effective December 29, 2023, 18 CFR §380.12 was updated and information that applicants should provide for geotechnical investigations is included in 18 CFR §380.12(o)(15)(iii)

and historical seismicity of the region to develop and analyze data to gain a better understanding of the maximum magnitude earthquakes and earthquake recurrence estimates. Comprehensive regional and local geologic studies were conducted to define the geologic setting of the region. Terracon's investigations indicated that the site is classified as Site Class F in accordance with ASCE/SEI 7 (2005), which is in accordance with IBC (2009) based on a site time-averaged shear wave velocity (Vs). ELC and SLNG indicate that the existing Seismic Design Basis under Docket No. CP 14-103-000 would be used for the proposed project design. For more discussion on the seismic design parameters for the proposed facilities, refer to sections 2.1.1.3 and 2.1.2.2 of the EA filed under Docket No. CP14-103.

FERC staff recognized that in U.S. Geological Survey (USGS) 2023 50-State Long-term National Seismic Hazard Model (NSHM) has been updated[93], 2% in 50-year probability of exceedance ground motions at site of Charleston, SC (which is approximately 78 miles from the proposed project site), National Earthquake Hazards Reduction Program (NEHRP) site class boundary B/C (VS30=760 m/s) for 1.0 second spectral acceleration and NEHRP site class D (VS30=260 m/s) for 5 second spectral acceleration would increase 15 percent and 24 percent, respectively. Per FERC staff request, ELC and SLNG commit that they would contract Terracon to perform additional seismic analyses on above-mentioned potential increase of seismic hazard on the proposed project site.

In February 2024, ELC and SLNG filed a study report of "*Development of Site-Specific Seismic Design Ground Motions for the Elba Island LNG Terminal, Chatham County, Georgia*". As stated in the study report, Terracon consulted Lettis Consultants International (LCI) to perform a site-specific probabilistic seismic hazard analysis (PSHA), deterministic seismic hazard analysis (DSHA), site response analyses, and developed seismic design spectra for the Elba Island LNG terminal. LCI stated that the study evaluation relied solely on available data and information, and it is an update to the analysis performed by Terracon Consultants and Pacific Engineering Analyses in 2014 for the project site. LCI indicated that the purpose of the study is to update site-specific seismic design ground motions for the project consistent with NFPA 59A-2006 National Fire Protection Association Standard for the Production, Storage, and Handling of Liquefied Natural Gas and ASCE 7-22 Minimum Design Loads and Associated Criteria for Buildings and Other Structures. LCI also stated that the historical seismicity record used in this study was adopted from the CEUS-SSC model updated with data from the USGS Advanced National Seismic System (ANSS) catalog to the end of 2019. This updated catalog was used solely to illustrate the most up-to-date seismicity in the site region. It was not used in any update to recurrence in the CEUS-SSC model.

[93] U.S. Geological Survey: https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model-0#overview. Accessed February, 2024.

FERC staff noted that the LCI provided site-specific seismic design ground motion parameters have been decreased compared to the data provided in Terracon 2014 seismic hazards study report. As above-mentioned, the USGS would expect increases of spectral acceleration at site of Charleston, SC (which is approximately 78 miles from the proposed project site). Therefore, we recommend in section 5 that prior to construction of the final design, ELC and SLNG should file a re-evaluation technical report of seismic hazard analysis for the proposed project site. The report should adequately incorporate the USGS foreseeable increase of ground motion and determine the finalized seismic design ground motion would be sufficient for the proposed project site. If the project is authorized and constructed, FERC staff would continue our review of the finalized seismic design basis and criteria for the proposed project site.

ELC and SLNG indicated they would implement a seismic monitoring program at the Project site to monitor seismic activities impacts on the critical structures and facilities. The details of the new seismic monitoring program such as installation details, alarm points and operator procedures are currently being developed and would be implemented prior to the commissioning of the proposed project. Therefore, we recommend in section 5 that prior to construction of the final design, ELC and SLNG should file the a seismic monitoring program for the Project site. The seismic monitoring program should comply with NFPA 59A (2019 edition) sections 8.4.14.10, 8.4.14.12, 8.4.14.12.1, 8.4.14.12.2, and 8.4.14.13; ACI 376 (2023 edition) sections 10.7.5 and 10.8.4; U.S Nuclear Regulatory Commission Regulatory Guide RG 1.12 (Revision 3) sections 1 and 3 through 9 and all subsections, or approved equivalents subject to review and approval. A free-field seismic monitoring device should be included in the seismic monitoring program for the Project site. Additional seismic instruments should be considered for critical Structures, System, and Components. The proposed seismic monitoring system must include installation location plot plan; description of the triaxial strong motion recorders or other seismic instrumentation; the proposed alarm set points and operating procedures (including emergency operating procedures) for control room operators in response to such alarms/data obtained from seismic instrumentation; and testing and maintenance procedures.

Based on ELC and SLNG provided evaluation, FERC staff agree that the proposed Project would not alter the hazard of Earthquake, Tsunami, and Seiche to the existing facility approved under Docket No. CP14-103.

Hurricanes, Tornadoes, and other Meteorological Events

Hurricanes, tornadoes, and other meteorological events have the potential to cause damage or failure of facilities due to high winds and floods, including failures from flying or floating debris. To assess the potential impact from hurricanes, tornadoes, and other meteorological events, the existing project under Docket No. CP14-103 evaluated such events historically. The severity of these events is often determined on the probability that they occur and are sometimes referred to as the average number years that the event is expected to re-occur, or in terms of its mean return/recurrence interval.

Because of its location, the Project site would likely be subject to hurricane force winds during the life of the Project. ELC and SLNG state that it would meet 49 CFR §193.2067, under Subpart B, for wind load requirements. In accordance with the 2018 MOU, USDOT PHMSA will evaluate in its LOD whether an applicant's proposed project meets the USDOT PHMSA requirements under Subpart B. If the Project is authorized and is constructed, the facilities would be subject to USDOT PHMSA's inspection and enforcement programs. Final determination of whether the facilities are in compliance with the requirements of 49 CFR Part 193 Subpart B would be made by USDOT PHMSA staff. If the Project is constructed and becomes operational, the facilities would be subject to the DOT's inspection and enforcement programs.

As noted in the limitation of ASCE/SEI 7-05, tornadoes were not considered in developing basic wind speed distributions. This leaves a potential gap in potential impacts from tornados. However, tornado speed and load design have been implemented in ASCE/SEI 7-22. Per FERC staff request, ELC and SLNG confirmed that a tornado assessment was performed using ASCE 7-22 for the proposed project site. ELC and SLNG further state that tornado speed for the condensate plant was based on an allowable wind speed of 124 mph (157 mph, ultimate), Risk Category III and Exposure C. The controlling effective plan area (Ae) can be taken as the largest standalone structure in the plant. Based on the approximate effective plan areas of 700 square ft for the proposed project, the tornado wind speed of 50 mph with an MRI of 3,000 years (equivalent to a 1.6% probability of exceedance in a 50-year period) per ASCE 7-22 which is lower than 0.6V (i.e., 94 mph). ELC and SLNG conclude that the design for tornado loads is not required per ASCE 7-22. In addition, the proposed Project would be entirely constructed within the existing LNG facility under Docket No. CP14-103. ELC and SLNG also indicate that the existing Wind Design Basis under Docket No. CP 14-103-000 would be used for the proposed project design. For more discussion on the wind design for the proposed facilities, refer to sections 2.1.1.3 and 2.1.2.2 of the EA filed under Docket No. CP14-103. If authorized and constructed, FERC staff would continue its review of finalized wind load design for the proposed project facilities. Therefore, we do not consider that construction or operation of the proposed Project would be significantly impacted by wind speed. For further discussion of wind design, see sections 2.1.1.3 and 2.1.2.2 of the existing Project EA filed under Docket No. CP14-103.

Potential flood levels may also be informed from the FEMA Flood Insurance Rate Maps, which identify Special Flood Hazard Areas (base flood) that have a 1 percent probability of exceedance in 1 year to flood (or a 100-year mean return interval) and moderate flood hazard areas that have a 0.2 percent probability of exceedance in 1 year to flood (or a 500-year mean return interval). According to the FEMA National Flood Hazard Layer FIRMette 94, the West and Northwest side of the facility are located in Zone AE, the East side facility is located in Zone VE (i.e., the land in the floodplain subject to a 1% or greater chance of flooding in any given year), and most of the facility areas are located in Zone X (i.e. the land in the floodplain subject to a 0.2% or greater chance of flooding in any given year) . Zone AE in the West and Northwest side of the project site with base flood elevation BFE at ranging approximately from +10 feet to +11 feet NAVD 88 and Zones VE on the East side is at elevation 11 to 12 feet NAVD 88. AE are defined as Areas along coasts subject to inundation by the 1-percent-annual-chance flood event with additional hazards due to storm-induced velocity wave action. Zone X is defined as an Area along coasts subject to inundation by the 0.2-percent-annual-chance (or 500-year) flood event. We also recognize that a 500-year flood event has been recommended as the basis of design for critical infrastructure in publications, including ASCE 24, Flood Resistant Design and Construction. The Project states the facilities of the existing Project was designed to withstand a 100-year and 500-year return storm, rain, and associated storm surge event, to ensure that internal flooding is of no consequence.

We generally evaluate the design against a 500-year SWEL with a 500-year wave crest and sea level rise and subsidence. The Elba Island facilities have potential to be impacted by both riverine and coastal flooding given their location on Elba Island in the Savannah River estuary and its proximity to the coast. Using storm surge inundation maps generated from the Sea, Lake, and Overland Surge from Hurricanes (SLOSH) model developed by NOAA National Hurricane Center, a 500-year event would equate to a Category 2 Hurricane. The Maximum Envelope of Water (MEOW) from the SLOSH model provides a worst-case snapshot of a particular storm category (e.g. Category 1, 2,3), forward speed (e.g. 15, 25, 35 mph), trajectory (e.g. direction such as Northeast, North, Northwest), and initial tide level (e.g. low, medium, or high tides). The Maximum of MEOWs (MOMs) provides a worst-case snapshot for a particular storm category under "perfect" storm conditions. For the project site, the MOM for category 2 hurricane with initial mean tide level elevation is 11.8 feet NAVD 88 which is slightly higher than FEMA 100-year base elevation. Similarly, the MOMs for categories 3, 4 and 5 are 17.6 feet NAVD 88, 22.4 feet NAVD 88, and 25.7 feet NAVD 88 respectively for initial mean tide level. The existing facility was protected by a storm surge wall, which has the crest elevation of 23 feet mean low water (MLW), which is equivalent to 19.16 feet NAVD 88. This data suggests that existing and current Project design may withstand up to Category 3 mean tide storm surge condition but does not withstand higher than this hurricane event. It should be noted that SLOSH values were neither used in the existing facility or current project design as it was developed by NOAA for emergency management rather

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[94] Federal Emergency Management Agency (FEMA) Flood Map Service Center: https://msc.fema.gov/portal/search?AddressQuery=-81.00166667%2C%2032.08555556#searchresultsanchor, accessed January 2024.

than for design purposes. It should also be noted that the proposed project would be entirely located within the existing LNG facility. which was designed and approved as a part of existing facility (CP14-103).

Also, we would expect an intermediate projected sea level rise and subsidence of approximate 0.87 ft between 2025 to 2050, as provided by NOAA (2017)[95]. This is about 0.37 ft higher than the designed estimate of 6 inches for the existing facility. ELC and SLNG acknowledged the current NOAA estimate has increased and stated that they would perform an elevation survey of the storm surge wall, every 5 years starting 2024 as a maintenance plan which accounts for relative sea level rise and settlements. Regarding the rationale for the determination of a frequency of 5 years for storm surge wall elevation survey to our data request, the Project states that the deep foundation sheet piling storm surge wall sections are embedded in a dense sand layer and are expected not to have any significant settlements. The Project further states the 5-year survey frequency is precautionary and if any settlement of the wall occurs in future, repairs would be done. FERC staff agree that the elevation survey would be one of industry practices to monitor settlements for the storm surge wall. However, the project site is located on a small island in the middle of the Savannah River. To effectively utilize the elevation survey program for the storm surge wall, an annual frequency of elevation survey program for the storm surge wall would work more sufficient comparing with a 5-year frequency survey program to mitigate any uncertainties at the project location. Therefore, we recommend in section 5 that prior to commissioning, ELC and SLNG should file an updated maintenance plan for the storm surge wall. The maintenance plan should include an annual elevation survey plan for the storm surge wall and should consider relative sea level rise and settlements at the project site. If the proposed project is authorized, constructed and operated, FERC staff would continue our evaluation review and inspection of storm surge wall throughout the project life cycle.

Landslides and other Natural Hazards

Landslides involve the downslope movement of earth materials under force of gravity due to naturalor human causes. Landslides in the United States occur in all 50 states. There is little likelihood that landslides or slope movement at the site would be a realistic hazard as the topography across the Project site is relatively flat. In addition, the proposed project is within the existing Project facility. FERC staff also independently evaluated the potential landslide at the proposed project site, using USGS Landslide Inventory and Interactive Map[96]. The proposed project is located outside the possible

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[95] U.S. Army Corps of Engineers, Sea Level Change Curve Calculator: https://cwbi-app.sec.usace.army.mil/rccslc/slcc_calc.html, accessed January 2024.

[96] United States Geological Survey, U.S. Landslide Inventory: https://www.usgs.gov/programs/landslide-hazards/maps, accessed February 2024.

landslide zone as indicated in the USGS Landslide Hazard map. Therefore, we conclude that the landslide would not be a significant risk for the proposed Project site.

Wildfires are prevalent on the West Coast, especially in California, Alaska, and Hawaii. The proposed Project site would be located within the existing Elba LNG facility, which is in an island surrounded by the Savannah River. . There is no significant evidence of vegetation would cause potential wildfires. Therefore, we conclude that it is unlikely that a wildfire would occur at the proposed Project site. Volcanic activity is primarily a concern along plate boundaries on the West Coastand in Alaska and Hawaii. Based on FERC staff review of maps from USGS[97] and Department of Homeland Security[98]-of the nearly 1,500 volcanoes with eruptions since the Holocene period (in the past 10,000 years) there has been no known active or historic volcanic activity closer than approximately 1280 miles across the Gulf of Mexico in Los Atlixcos, Mexico.

Geomagnetic disturbances may occur due to solar flares or other natural events with varying frequencies that can cause geomagnetically induced currents, which can disrupt the operation of transformers and other electrical equipment. USGS provides a map of geomagnetic disturbances intensitieswith an estimated 100-year mean return interval[99]. The map indicates the Project site could experience geomagnetic disturbances intensities of 300-400 nano-Tesla with a 100-year mean return interval. However, the Project would be designed such that if a loss of power were to occur the valves would move into a fail-safe position. In addition, the proposed Project would be constructed within the existing LNG facility, which is an export facility, which is an export facility that does not serve any U.S. customers.

External Impact Review

To assess the potential impact from external events, FERC staff conducted a series of reviews to evaluate transportation routes, land use, and activities within the facility and surrounding the LNG terminal site, and the safeguards in place to mitigate the risk from events, where warranted. FERC staff coordinated the results of the reviews with other federal agencies to assess potential impacts from vehicles and rail; aircraft impacts to and from nearby airports and heliports; pipeline impacts from nearby pipelines; impacts to and from adjacent facilities that handle hazardous materials under the EPA's RMP regulations and power plants, including nuclear facilities under the Nuclear Regulatory Commission's regulations. Specific mitigation of impacts from use of external roadways, rail, helipads, airstrips, or pipelines are also considered as part of the engineering review

[97] United States Geological Survey, U.S. Volcanoes and Current Activity Alerts, https://volcanoes.usgs.gov/index.html, accessed January 2024.

[98] Department of Homeland Security, Homeland Infrastructure. Foundation-Level data (HIFLD). Natural Hazards, https://hifld-geoplatform.opendata.arcgis.com/, accessed January 2024.

[99] United States Geological Survey. Magnetic Anomaly Maps and Data for North America, https://mrdata.usgs.gov/magnetic/map-us.html#home, accessed January 2024.

done in conjunction with the NEPA review.

FERC staff uses a risk-based approach to assess the potential impact of the external events and the adequacy of the mitigation measures. The risk-based approach uses data based on the frequency of events that could lead to an impact and the potential severity of consequences posed to the LNG terminal site and the resulting consequences to the public beyond the initiating events. The frequency data is based on past incidents and the consequences are based on past incidents and/or hazard modeling of potential failures.

Road

FERC staff reviewed whether any truck operations would be associated with the Project and whether any existing roads would be located near the site. FERC staff uses this information to evaluate whether the Project and any associated truck operations could increase the risk along the roadways and subsequently to the public and whether any pre-existing unassociated vehicular traffic could adversely increase the risk to a project site and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities as defined in 49 CFR Part 193, must comply with the requirements of 49 CFR Part 193 and would be subject to the PHMSA's inspection and enforcement programs. PHMSA regulations under 49 CFR § 193.2155 (a) (5) (ii) under Subpart C require that structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by or explosion of a tank car or tank truck that could reasonably be expected to cause the most severe loading if the LNG facility adjoins the right-of-way of any highway. Similarly, NFPA 59A (2001 edition), section 8.4.3 requires pipelines be located on the dock or pier so that they are not exposed to damage from vehicular traffic or other possible causes of physical damage, and section 8.5.4, requires transfer piping, pumps, and compressors to be located or protected by barriers so that they are safe from damage by rail or vehicle movements. However, the PHMSA regulations and NFPA 59A (2001 edition) requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. FERC staff evaluated consequence and frequency data from these events to evaluate these potential impacts.

FERC staff evaluated the risk of the truck operations based on the consequences from a release, incident data from the DOT Federal Highway Administration (FHWA)[100],

100 FHWA, Office of Highway Policy Information, Highway Statistics 2020, https://www.fhwa.dot.gov/policyinformation/statistics/2020/, accessed January 2024.

DOT National Highway Traffic Safety Administration[101], PHMSA[102], EPA, NOAA[103], and other reports[104,105,106], and frequency of trucks and proposed mitigation to prevent or reduce the impacts of a vehicular incident.

Incident data from PHMSA and estimated lane mileage from the FHWA and National Highway Traffic Safety Administration, indicate hazardous material incidents are very infrequent (2e-3 incidents per lane mile per year and 2e-6 incidents per vehicle-mile per year) and nearly 70 percent of hazardous material vehicular incidents occur during unloading and loading operations while the other 30 percent occur while in transit or in transit storage. In addition, approximately 95 percent of hazardous liquid releases are 1,000 gallons or less and catastrophic events that would spill 10,000 gallons or more make up less than 0.1 percent of releases. In addition, less than 1 percent of all reportable hazardous material incidents result in injuries and less than 0.1 percent of all reportable hazardous material incidents result in fatalities.

The EPA and NOAA report that 80 percent of fires that lead to container ruptures results in projectiles and that 80 percent of projectiles from liquefied petroleum gas (LPG) incidents, which constitute the largest product involved in BLEVEs, travel less than 660 feet. The EPA also reports that on average container ruptures would result in less than four projectiles for cylindrical containers and 8.3 for spherical vessels. FERC staff evaluated other reports that affirmed the EPA estimates based on data for approximately 150 experimental and accidental pressure vessel bursts (PVBs) and BLEVEs with approximately 683 total projectiles (4.6 average fragments per incident) that showed approximately 80 percent of fragments traveled 490 to 820 feet and within 6.25 times the estimated or observed fireball radius. The data also showed projectiles have traveled up to 3,900 feet for large LPG vessels and 1,200 feet for LPG rail cars. In all the documented cases, the projectiles traveled less than 15 times the fireball diameter, but one of the reports indicated up to 30 times the fireball diameter is possible albeit very rare.

Unmitigated consequences under average ambient conditions from releases of 1,000 gallons through a 1-inch hole would result in distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to 175 feet for jet fires. Unmitigated consequences under worst case weather conditions from catastrophic failures of trucks

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[101] National Highway Traffic Safety Administration, Traffic Safety Facts Annual Report Tables, https://cdan.nhtsa.gov/tsftables/tsfar.htm, accessed March 2022.
[102] PHMSA, Office of Hazardous Material Safety, Incident Reports Database Search, https://hazmatonline.phmsa.dot.gov/IncidentReportsSearch/Welcome.aspx, accessed March 2022.
[103] U.S. Environmental Protection Agency, National Oceanic and Atmospheric Administration, ALOHA®, User's Manual, The CAMEO® Software System, February 2007.
[104] Birk, A.M., BLEVE Response and Prevention Technical Documentation, 1995.
[105] American Institute of Chemical Engineers, Center for Chemical Process Safety, Guidelines for Vapor Cloud Explosion, Pressure Vessel Burst, BLEVE, and Flash Fire Hazards, Second Edition, 2010.
[106] Lees, F.P, Lees' Loss Prevention in the Process Industries: Hazard Identification, Assessment, and Control, Volume 2, Second Edition, 1996.

proposed at the site generally can range from 200 to 2,000 feet for flammable vapor dispersion, 275 to 350 feet for radiant heat of 5 kW/m^2 from jet fires, 800 to 1,050 feet to a 1 psi overpressure from a BLEVE, 850 to 1,500 feet for a heat dose equivalent to a radiant heat of 5 kW/m^2 over 40 seconds from 250 to 325 feet radii fireballs burning for 5 to 15 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. Based on distribution function of the projectile distances, FERC staff estimate approximately 90 percent of all projectiles for a 10,000-gallon tanker truck would be within 0.5 mile and there is approximately a 1 percent probability they would extend beyond 1 mile and less than 0.1 percent probability they would extend 30 times the fireball diameter. These values are also close to the distances provided by the DOT FHWA for designating hazardous material trucking routes[107] (0.5 mile for flammable gases and flammable and combustible liquids for potential impact area) and PHMSA for emergency response[108] (330 feet immediate precautionary measure, 0.5 mile downwind for large spills and 1 mile for initial evacuation involving fires, which could cause potential BLEVEs for flammable gases such as LNG, ethylene, propane, and butane).

During normal operation of the project, ELC and SLNG estimates approximately 1-2 trucks per week would be needed to handle the condensate which would be a decrease in the current number of condensate trucks. The number of trucks for other substances (refrigerants, amine, wastewater, nitrogen, etc.) would remain unchanged from the Liquefaction Project (CP14-103). During commissioning and startup, ELC and SLNG provided that no trucks would be needed, and onsite inventory would be used for nitrogen, refrigerants, and hot oil. We conclude that the Project would not pose a significant risk or significant increase in risk to the public due to vehicle impacts as a result of the potential consequences, incident data, and frequency of trucks.

Access for transporting equipment, materials and personnel to Elba Island would be provided by existing roads and marine access points. The entrance to the LNG Terminal is on Elba Island Road from its intersection with the Islands Expressway (East President Street) across from Runaway Point Road. The Islands Expressway is classified as a four-lane divided highway and has 12-foot-wide turning lanes at the intersection of Elba Island Road. Elba Island Road is a two-lane paved road having a public section with a 25 miles per hour (mph) speed limit and a private section having a 40-mph speed limit, standard 12-foot-wide travel lanes and 2-foot-wide paved shoulders. The access road

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107 U.S. Department of Transportation, Federal Highway Administration, Office of Highway Safety, 1994,

108 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Emergency Response Guidebook, 2020, https://www.phmsa.dot.gov/training/hazmat/erg/emergency-response-guidebook-erg, Accessed February 2024.

becomes a private drive for the Terminal approximately 500 feet beyond the intersection with Islands Expressway.

FERC staff did not identify any major highways or roads within close proximity to piping or equipment containing hazardous materials at the site that would raise concerns of direct impacts from a vehicle impacting the site. In addition, ELC and SLNG provided that the SLNG Terminal site has existing vehicular access gates, barriers, and fencing at the facility which have been designed and tested to withstand vehicular impacts. ELC and SLNG also provided drawings which show the areas surrounding the proposed condensate plant area and existing MMLS units would be well protected against intra-plant vehicular traffic. Bollards would be added if necessary to the area to further protect the new condensate plant and new firewater appurtenances from vehicular traffic. To ensure that the protections do not change in final design, we recommend in section 5 that, prior to construction of final design, ELC and SLNG should file drawings of vehicle protections internal to the plant, such as guard rails, barriers, and bollards to protect transfer piping, pumps, compressors, hydrants, monitors, post indicator valves, etc. to ensure that the facilities would be protected from inadvertent damage from vehicles, unless the facilities are located sufficiently away from in-plant roadways and areas accessed by vehicle.

Therefore, we conclude that the Project would not pose a significant risk or significant increase in risk to the public due to vehicle impacts as a result of the potential consequences, incident data, frequency of trucks, proposed mitigation by ELC and SLNG.

<u>Rail</u>

FERC staff reviewed whether any rail operations would be associated with the Project and whether any existing rail lines would be located near the site. FERC staff uses this information to evaluate whether the Project and any associated rail operations could increase the risk along the rail line and subsequently to the public and whether any pre-existing unassociated rail operations could adversely increase the risk to the ELC and SLNG site and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities as defined in 49 CFR Part 193, must comply with the requirements of 49 CFR Part 193 and would be subject to PHMSA's inspection and enforcement programs. The PHMSA regulations under 49 CFR § 193.2155 (a) (5) (ii) require that if the LNG facility adjoins the right-of-way of any railroad, the structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by or explosion of a train or tank car that could reasonably be expected to cause the most severe loading.

Section 8.5.4 of NFPA 59A (2001), incorporated by reference in 49 CFR Part 193, requires transfer piping, pumps, and compressors to be located or protected by barriers so that they are safe from damage by rail or vehicle movements. However, the PHMSA regulations and NFPA 59A (2001) requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. Therefore, FERC staff evaluated consequence and frequency data from these events to evaluate these potential impacts. FERC staff evaluated the risk of the rail operations based on the consequences from a release, incident data from the Federal Railroad Administration and PHMSA, and frequency of rail operations nearby ELC and SLNG.

FERC staff evaluated the risk of the rail operations based on the consequences from a release, incident data from PHMSA[109], and rail miles from DOT Bureau of Transportation Statistics (BTS)[110]. Incident data from PHMSA and rail miles from BTS indicates hazardous material incidents are very infrequent (approximately 7e-3 incidents per rail mile per year, 2e-6 per train-mile per year, 3e-8 per car-mile per year, and 7e-10 per ton-mile per year). In addition, approximately 95 percent of liquid releases are 1,000 gallons or less, and catastrophic events that would spill 30,000 gallons or more make up less than 1 percent of releases. In addition, less than 1 percent of hazardous material incidents result in hospital injuries and approximately 0.1 percent of hazardous material incidents result in fatalities.

As previously discussed, the EPA and NOAA report that 80 percent of fires that lead to container ruptures results in projectiles and that 80 percent of projectiles from LPG incidents, which constitute the largest product involved in BLEVEs, travel less than 660 feet. The EPA also reports that on average container ruptures would result in less than four projectiles for cylindrical containers and 8.3 for spherical vessels. FERC staff evaluated other reports that affirmed the EPA estimates based on data for approximately 150 experimental and accidental PVBs and BLEVEs with approximately 683 total projectiles (4.6 average fragments per incident) that showed approximately 80 percent of fragments traveled 490 to 820 feet and within 6.25 times the estimated or observed fireball radius. The data also showed projectiles have traveled up to 3,900 feet for large LPG vessels and 1,200 feet for LPG rail cars. In all the documented cases, the projectiles traveled less than 15 times the fireball diameter, but one of the reports indicated up to 30 times the fireball diameter is possible albeit very rare.

Unmitigated consequences under average ambient conditions from releases of 1,000 gallons through a 1-inch hole would result in distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to 175 feet for jet fires. Unmitigated

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[109] PHMSA, Incident Statistics, https://www.phmsa.dot.gov/hazmat-program-management-data-and-statistics/data-operations/incident-statistics, Hazmat Incident Report Search Tool 2010 – 2020, accessed March 2022.

[110] DOT Bureau of Transportation Statistics, System Milage Within the United States, https://www.bts.gov/content/system-mileage-within-united-states, 2010 – 2020, Accessed March 2022.

consequences under worst-case weather conditions from catastrophic failures of rail cars containing various flammable products generally can range from 300 to 3,000 feet for flammable vapor dispersion, 450 to 575 feet for radiant heat of 5 kW/m^2 from jet fires, 1,225 to 1,500 feet to a 1 psi overpressure from a BLEVE, 1,250 to 2,100 feet for a heat dose equivalent to a radiant heat of 5 kW/m^2 over 40 seconds from 350 to 450 feet radii fireballs burning for 7 to 20 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. Based on distribution function of the projectile distances, FERC staff estimate approximately 80 percent of all projectiles for a 30,000- gallon rail car would be within 0.5 mile and there is approximately a 5 percent probability they would extend beyond 1 mile and less than 0.1 percent probability they would extend 30 times the fireball diameter. These values are also close to the distances provided by PHMSA for emergency response (0.5 to 1 mile for initial evacuation and 1 mile for potential BLEVEs for flammable gases).

The closest rail line to the project site is located approximately 5 miles west at the Sea Point Industrial Terminal Complex. This is outside any of the potential unmitigated consequences under even worst-case weather conditions for the most severe catastrophic failures of rail cars. Therefore, FERC staff conclude there are no potential rail safety or reliability impacts of significance that railroad lines would pose due to vapor dispersion, fireball, jet fire, pool fire, BLEVE, or projectile hazard to the proposed Project.

Air

FERC staff reviewed whether any aircraft operations would be associated with the Project and whether any existing aircraft operations would be located near the site. FERC staff uses this information to evaluate whether the Project and any associated aircraft operations could increase the risk to the public and whether any pre-existing unassociated aircraft operations could adversely increase the risk to the Project site and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities, as defined in 49 CFR Part 193, must comply with the requirements of 49 CFR Part 193 and would be subject to the PHMSA's inspection and enforcement programs. PHMSA regulations under 49 CFR § 193.2155 (b) require that LNG storage tanks must not be located within a horizontal distance of one mile from the ends, or 0.25 miles from the nearest point of a runway, whichever is longer. In addition, the height of LNG structures in the vicinity of an airport must comply with DOT FAA requirements. In addition, FERC staff evaluated the risk of an aircraft impact from nearby airports.

Two aviation airports, Savannah / Hilton Head International Airport and Hunter Army Airfield would be located approximately 12 miles west and 10 miles southwest of the site, respectively. Two smaller private airports were also identified which are located approximately 16 miles southwest and 36 miles south of the site. No heliports were identified near the site.

All airports are farther than the 0.25-mile distance referenced in the DOT PHMSA regulations. DOT FAA regulations in 14 CFR Part 77 require ELC and SLNG to provide a notice to the FAA of its proposed construction. This notification should identify all equipment that are more than 200 feet above ground level or lesser heights if the facilities are within 20,000 feet of an airport (at 100:1 ratio or 50:1 ratio depending on length of runway) or within 5,000 feet of a helipad (at 100:1 ratio). In addition, mobile objects, including the LNG marine vessel that would be above the height of the highest mobile object that would normally traverse it would require notification to FAA. ELC and SLNG indicated that no temporary construction equipment or permanent structures are planned with a height greater than 200 feet.

In addition, FERC staff used DOE Standard 3014, *Accident Analysis for Aircraft Crash into Hazardous Facilities*, which utilizes a 22-mile threshold radius around the hazardous facility for consideration of hazards posed by airport and heliport operations to the Project facilities. Per the DOE Standard 3014, heliports need only be considered if there are local overflights associated with facility operations and/or area operations. FERC staff did not identify any heliports within the 22-mile radius. The methodology described in DOE Standard 3014 was employed to assess the risk posed to the operation of the proposed Project facilities by aircraft departing from or landing at airports within the 22-mile threshold radius and was found to be insignificant with a frequency of 3E-05 or less. Based upon our review, we conclude that the proposed Project would not pose a significant risk or significant increase in risk to the public due to nearby aircraft operations.

Pipelines

FERC staff reviewed whether any pipeline operations would be associated with the Project and whether any existing pipelines would be located near the site. FERC staff uses this information to evaluate whether the Project and any associated pipeline operations could increase the risk to the pipeline facilities and subsequently to the public and whether any pre-existing unassociated pipeline operations could adversely increase the risk to the Project site and subsequently increase the risk to the public. FERC staff evaluated the risk of a pipeline incident impacting the Project and the potential of cascading damage increasing the risk to the public based on the consequences from a release, incident data from the PHMSA, and proposed mitigation to prevent or reduce the impacts of a pipeline incident from the ELC and SLNG project.

For existing pipelines, FERC staff identified a number of active buried natural gas pipelines located within close proximity to the Project. These pipelines are all within previously established pipeline corridors, and no project facilities that are situated on top of the buried pipelines. However, in order to prevent inadvertent damage to the existing pipelines and any other existing buried utility piping during construction, we recommend in section 5 that, prior to initial site preparation, ELC and SLNG should file, for review and approval, pipeline and utility damage prevention procedures for personnel and contractors. The procedures should include provisions to mark buried pipelines and utilities prior to any site work and subsurface activities.

Based on the potential likelihood of pipeline incidents and potential consequences from a pipeline incident and recommendations to mitigate the risk of such incidents, we conclude that the Project would not significantly increase the risk to the public beyond existing risk levels that would be present from a pipeline leak or pipeline rupture worst-case event near the proposed Project site.

Hazardous Material Facilities and Power Plants

FERC staff reviewed whether any EPA RMP regulated facilities handling hazardous materials and power plants were located near the site to evaluate whether the facilities could adversely increase the risk to the Project site and whether the Project site could increase the risk to the EPA RMP facilities and power plants and subsequently increase the risk to the public.

There are no facilities handling hazardous materials near the site. The EPA RMP regulations require certain hazard distances to be calculated and a risk management plan to be developed commensurate with those consequences. In addition, the closest power plant identified would be the MacIntosh Steam Plant in Rincon, GA approximately 21 miles northwest. The closest nuclear plants would be the Alvin W.Vogtle Nuclear Electric (Plant Vogtle) located approximately 85 miles to the north and Edwin I. Hatch (Plant Hatch) located approximately 80 miles west of the proposed facility.

Given the distances, locations, and risk management plan requirements of the facilities relative to the populated areas near the proposed site, we conclude that the Project would not pose a significant increase in risk to the public or that the hazardous material facilities and power plants would not pose a significant risk to the Project and subsequently to the public.

Onsite and Offsite Emergency Response Plans

As part of its application, ELC and SLNG indicated that the existing Emergency Response Plan (ERP) would be updated to include the Project. The emergency procedures would provide for the protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the Project facilities. A Cost-Sharing Plan would also need to identify the mechanisms for funding any project-specific security/emergency management costs that would be imposed on state and local agencies. ELC and SLNG would continue these collaborative efforts during the development, design, and construction of the Project. FERC staff would review the revised ERP with Cost Sharing Plan to verify that adequate plans had been developed, and ELC and SLNG would need to receive approval prior to proceeding with any construction.

FERC staff would also continue to review the ongoing detailed finalization of the ERP and Cost Sharing Plan to confirm that details of the emergency procedures continue to provide for the protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the Project facilities.

As required by 49 CFR § 193.2509 under Subpart F, ELC and SLNG would need to prepare emergency procedures manuals that provide for: a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordination and cooperation with appropriate local officials. Specifically, 49 CFR § 193.2509 (b) (3) states that emergency procedures must include provisions for "Coordinating with appropriate local officials in preparation of an emergency evacuation plan which sets forth the steps required to protect the public in the event of an emergency, including catastrophic failure of an LNG storage tank." PHMSA regulations under 49 CFR § 193.2905 (d) under Subpart J also require at least two access points in each protective enclosure that are located to minimize the escape distance in the event of emergency. The Project would be located entirely within the existing protective enclosure with access points that were previously approved in prior projects.

Title 33 CFR § 127.307 also requires the development of emergency manual that incorporates additional material, including LNG release response and emergency shutdown procedures, a description of fire equipment, emergency lighting, and power systems, telephone contacts, shelters, and first aid procedures. In addition, 33 CFR § 127.207 establishes requirements for warning alarm systems. Specifically, 33 CFR § 127.207 (a) requires that the LNG marine transfer area to be equipped with a rotating or flashing amber light with a minimum effective flash intensity, in the horizontal plane, of 5000 candelas with at least 50 percent of the required effective flash intensity in all directions from 1.0 degree above to 1.0 degree below the horizontal plane. Furthermore, 33 CFR § 127.207 (b) requires the marine transfer area for LNG to have a siren with a minimum 1⁄3- octave band sound pressure level at l meter of 125 decibels referenced to 0.0002 microbars. The siren must be located so that the sound signal produced is audible over 360 degrees in a horizontal plane. Lastly, 33 CFR § 127.207 (c) requires that each light and siren must be located so that the warning alarm is not obstructed for a distance of 1.6 km (1 mile) in all directions. The warning alarms would be required to be tested in order to meet 33 CFR Part 127. The marine transfer areas are existing and were previously approved. There are no new marine transfer areas or modifications to these approved facilities in this Project.

The Project would use approximately three to four additional LNG marine vessels per year during normal operations but would not exceed the current number evaluated for the existing USCG LOR and authorized by FERC under the Elba III Terminal Expansion Project (Docket No. CP06-470). Therefore, the Project does not propose to increase LNG marine vessel transits over existing authorized levels. In accordance with the EPAct

2005, FERC must also approve an ERP covering the terminal and any proposed ship transits prior to construction. Section 3A (e) of the NGA, added by section 311 of the EPAct 2005, stipulates that in any order authorizing an LNG terminal, the Commission must require the LNG terminal operator to develop an ERP in consultation with the USCG and state and local agencies. The final ERP would need to be evaluated by appropriate emergency response personnel and officials. Section 3A(e) of the NGA (as amended by EPAct 2005) specifies that the ERP must include a Cost-Sharing Plan that contains a description of any direct cost reimbursements the applicant agrees to provide to any state and local agencies with responsibility for security and safety at the LNG terminal and in proximity to any proposed LNG marine vessels that serve the facility. The Cost-Sharing Plan must specify what the LNG terminal operator would provide to cover the cost of the state and local resources required to manage the security of the LNG terminal and any proposed LNG marine vessels, as well as the state and local resources required for safety and emergency management, such as:

- direct reimbursement for any per-transit security and/or emergency management costs (for example, overtime for police or fire department personnel);
- capital costs associated with security/emergency management equipment and personnel base (for example, patrol boats, firefighting equipment); and
- annual costs for providing specialized training for local fire departments, mutual aid departments, and emergency response personnel; and for conducting exercises.

The cost-sharing plan must include the LNG terminal operator’s letter of commitment with agency acknowledgement for each state and local agency designated to receive resources.

As part of the FEED review, FERC staff considers elements of recommended and generally accepted good engineering practices for emergency response plans and resource requirements for cost- sharing plans, including, but not limited to the following NFPA standards related to emergency response planning:

- NFPA 1660, Standard for Emergency, Continuity, and Crisis Management: Preparedness, Response, and Recovery;[111]

[111] Freely and publicly accessible to view in English and Spanish at NFPA, https://www.nfpa.org/codes-and-standards/1/6/6/1660, accessed February 2024. NFPA 1660 is a combination of Standards NFPA 1600, NFPA 1616, and NFPA 1620.

- NFPA 470, Hazardous Materials and Weapons of Mass Destruction Standard for Responders;[112]

- NFPA 475; Recommended Practice for Organizing, Managing, and Sustaining a Hazardous Materials and Weapons of Mass Destruction Response Program.[113]

Specifically, Chapter 5 of NFPA 1660 (2024 edition) provides provisions for the planning and design process of an emergency management program, and includes the following provisions:

- Section 5.2.1 and 5.2.2 specifies a risk assessment to be conducted evaluating the likelihood and severity of hazards.

- Subsection 5.2.2.1 indicates the hazards to be evaluated include accidental and intentional events that may result in hazardous material releases, explosions, and fires as well as consideration of specific causes and preceding events, such as geological events (e.g., subsidence, earthquakes, tsunamis, volcanic, etc.) and meteorological events (e.g., extreme temperatures, hurricanes, tornadoes, floods, snow and ice storms, and wildland fires, etc.) as discussed in previous sections.

- Subsection 5.2.2.2 specifies the vulnerability of people, property, operations, environment, and supply chain operations to be evaluated.

- Section 5.2.3 specifies the analysis of the impacts of the hazards identified in section 5.2.2 on the health and safety of persons in the affected area and personnel responding to the incident as well as impacts to properties, facilities, and critical infrastructure.

- Section 5.2.4 specifies an analysis of the escalation of impacts over time.

- Section 5.2.5 specifies evaluation of incidents that could have cascading impacts.

- Section 5.2.6 specifies the risk assessment to evaluate the adequacy of existing prevention and mitigation measures.

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[112] Freely and publicly accessible to view in English only at NFPA, https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=470, accessed February 2024.

[113] Freely and publicly accessible to view in English only at NFPA, https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=475, accessed February 2024.

NFPA 1660 Chapter 6 covers the implementation of the plans, including health and safety of personnel, roles and responsibilities of internal and external entities, lines of authority, process for delegation of authority, liaisons with external entities, and logistics support and resource requirements.

- Section 6.3.1 specifies the implementation of a mitigation strategy that includes measures to limit or control the consequences, extent, or severity of an incident that cannot be prevented based on the results of hazard identification and risk assessment and analysis of impacts.

- Section 6.9.2 specifies that emergency response plans should identify actions to be taken to protect people, including people with disabilities and other access and functional needs.[114]

- Sections 6.6 and 6.9.4 stipulate an emergency response plan include warning, notification, and communication should be determined and be reliable, redundant, and interoperable and tested and used to alert stakeholders potentially at risk from an actual or impending incident.

- Section 6.8 specifies the development of an incident management system to direct, control, and coordinate response, continuity and recovery operations.

- Section 6.8.1 stipulates primary and alternate emergency operations centers be established capable of managing response, continuity, and recovery operations and may be physical or virtual.

In addition, NFPA 1660 Chapter 7 provides specifications for execution of the plan, Chapter 8 provides for training and education provisions, Chapter 9 provides for exercises and tests to be conducted periodically, and Chapter 10 provides for its continued maintenance and improvement.

NFPA 1660 Chapters 11 through 16 covers organizing, planning, implementing, and evaluating a program for mass evacuation, sheltering, and re-entry, which states:

[114] Consistent with FEMA's Glossary of Terms, NFPA 1660 section A.3.3.3 defines "access and functional needs" as "individual circumstances requiring assistance, accommodation, or modification due to any temporary or permanent situation that limits an individual's ability to act in an emergency." The examples given include, but are not limited to, children, seniors, people with disabilities, people who live in institutionalized settings, people from diverse cultures, people who have limited English proficiency or are non-English-speaking, and people who are transportation disadvantaged. Further details are provided in sections A.3.3.3 and H.7.

- Section 11.6 also stipulates similar hazard identification, risk assessment, and requirements analysis as NFPA 1660 Chapters 4 through 10.

- Section 12.1 also stipulates plans to address the health and safety of personnel including persons with disabilities and access and functional needs.

- Section 12.6 also specifies a requirements analysis in sub-section 12.6.1 that is based upon the threat, hazard identification, and risk assessment. Sub-section 12.6.2(1) specifies the requirements analysis include characteristics of the potentially affected population, including persons with disabilities and other access and functional needs. In addition, sub-section 12.6.2(2) stipulates consideration of existing mandatory evacuation laws and expected enforcement of those laws. Sub-section 12.6.2(3) stipulates the requirements analysis to include characteristics of the incident that trigger consideration for evacuation based on weather, season, and ambient conditions, speed of onset, magnitude, location and direction, duration, resulting damages to essential functions, risk for cascading effects and secondary disasters, and capability of transportation routes and systems to transport life-sustaining materials (e.g., water, medical supplies, etc.) into the affected area.

- Section 12.6.3 stipulates the determination if evacuation or sheltering-in-place is appropriate to the situation and resources available based on 1) the anticipated impact and duration of the event, 2) the distance to appropriate sheltering facilities, 3) the availability of and access to transportation to those facilities, and 4) the ability to communicate with the affected population within the required timeframe.

- Section 12.6.4 stipulates the 1) establishment of a single or unified command, 2) development of information system to notify public and provide an assessment of the time needed to reach people with the information, 3) identification of appropriate sheltering facilities by location, size, types of services available, accessibility, and building safety, and 4) identification of the modes and routes for evacuee transportation and the time needed to reach them, sources of evacuee support services, and manpower requirements based on various potential shelters.

- Section 12.8 also has stipulations for dissemination of information on evacuation, shelter in place, and re-entry before, during, and after an incident to personnel and to the public.

- Section 12.9 has stipulations for warning, notification, and communication needs that are reliable and interoperable and redundant where feasible that takes into account persons with disabilities and other access and functional needs.

NFPA 1660 has stipulations in Chapter 13 on Implementation, Chapter 14 on Training and Education, Chapter 15 on Exercises, and Chapter 16 on Program Maintenance and Improvement with additional specifics for mass evacuation, sheltering in place and re-entry.

NFPA 1660 Chapters 17 through 22 specifies the characteristics of the facility and personnel onsite that should be within a pre-incident plan, such as emergency contact information, including those with knowledge of any supervisory, control, and data acquisition systems, communication systems, emergency power supply systems, and facility access controls as well as personnel accountability and assistance for people with self-evacuation limits, means of egress, emergency response capabilities, spill containment systems, water supply and fire protection systems, hazardous material information (e.g., safety datasheets), special considerations for responding to hazardous materials (e.g., firewater may exacerbate LNG fires, BLEVE potential, etc.), and access to emergency action plans developed by the facility. Section 21.5.2 also addresses the implementation of an incident management system for the duration of the event and Chapter 22 establishes maintenance of a pre-incident plan.

NFPA 1660 provisions for threat, hazard identification, and risk assessment provisions and identification of resource requirements and gaps are also consistent with Department of Homeland Security FEMA's Comprehensive Preparedness Guide 101, Developing and Maintaining Emergency Operations Plans, Version 3.0, September 2021, and Comprehensive Preparedness Guide 201, Threat and Hazard Identification and Risk Assessment and Stakeholder Preparedness Review Guide, Third Edition, May 2018, and other FEMA guidance.

NFPA 470 covers the competencies and job performance requirements for emergency response personnel to incidents involving hazardous materials, including awareness level personnel (i.e., personnel onsite that would call for emergency responders and secure the scene), operations level responders (i.e., personnel responding to incident for implementing supporting actions to protection public), hazardous material technicians (i.e., personnel responding to incident for analyzing and implementing planned response), hazardous materials officers, hazardous materials safety officers, emergency medical services personnel, incident commanders, and other specialist employees. The standard covers competencies and Job Performance Requirements, including the ability to identify hazardous material releases and hazardous materials involved and identifying surrounding conditions, such as topography, weather conditions, public exposure potential, possible ignition sources, land use and adjacent land use, overhead and underground wires and pipelines, rail lines, and highways, bodies of water, storm and sewer drains, and building information (e.g., ventilation ducts and air returns), Part of the standard also describes the ability and requirement to estimate potential outcomes in order to properly plan response strategies and tactics, and the selection and use of proper personnel protective equipment. Many of these provisions are similar and synergistic with NFPA 1660.

NFPA 475 covers the organization, management, and sustainability of a hazardous material response program, including identifying facilities with hazardous materials, analyzing the risk of hazardous material incidents, including identifying hazardous materials at each location, (e.g., quantity, concentration, hazardous properties, etc.), type and design of containers; surrounding population and infrastructure, including vulnerable populations and critical facilities (e.g., schools, hospitals, businesses, etc.). NFPA 475 similarly calls for analyzing the risk of an incident based on the consequences of a release and predicting its behavior and estimating the probability for an incident to take place and potential for cascading incidents. NFPA 475 Chapter 7 also has provisions for resource management, including the identification, acquisition, and management of personnel, equipment, and supplies to support hazardous material response programs. NFPA 475 Chapter 8 expands upon staffing requirements and use of different staffing models and Chapter 9 expands upon training program with reference and similarities to NFPA 470.

In accordance with these recommended and generally accepted good engineering practices, FERC staff evaluated the potential impacts from incidents caused by a range of natural hazards, accidental events, intentional events, and potential for cascading damage at the LNG terminal, including scenarios that would lead to a potential catastrophic failure of a tank required to be accounted in emergency response plans by in accordance with 49 CFR § 193.2509(b)(3). Consistent with these practices, FERC staff evaluated the potential hazards from incidents, the potential impacts to areas from incidents and the evaluation of characteristics of population, including those with potential access and functional needs, and infrastructure that require special considerations in pre-incident planning, including but not limited to:

- daycares;
- elementary, middle, and high schools and other educational facilities;
- elderly centers and nursing homes and other boarding and care facilities;
- detention and correctional facilities;
- stadiums, concert halls, religious facilities, and other areas of assembly;
- densely populated commercial and residential areas, including high rise buildings, apartments, and hotels;

- hospitals and other health care facilities;
- police departments, stations, and substations;
- fire departments and stations;
- military or governmental installations and facilities;
- major transportation infrastructure, including evacuation routes, major highways, airports, rail, and other mass transit facilities as identified in external impacts section; and
- industrial facilities that could exacerbate the initial incident, including power plants, water supply infrastructure, and hazardous facilities with quantities that exceed thresholds in EPA RMP and/or OSHA PSM standards as identified in external impacts section.

Many of these facilities are also identified and defined in NFPA 101, Life Safety Code, and require emergency action plans. NFPA 101 is currently used by every U.S. state and adopted statewide in 43 of the 50 states.[115] Georgia currently adopts NFPA 101 (2018) with amendments.[116,117] These areas are also similar to "identified sites" defined in 49 CFR Part 192 that define high consequence areas and those identified within Pipelines and Informed Planning Alliance for special land use planning considerations near pipelines.[118]

Potential Hazards

An incident can result in various potential hazards and are initiated by a potential liquid and/or gaseous release with the formation of vapor at the release location, as well as from any liquid that pooled. The fluid released may present low or high temperature hazards and may result in the formation of toxic or flammable vapors. The type and extent of the hazard will depend on the material released, the storage and process

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[115] NFPA, NFPA 101 Fact Sheet, https://docinfofiles.nfpa.org/files/AboutTheCodes/101/NFPA101FactSheet0809.pdf, accessed February 2024.

[116] Up Codes, Georgia Building Codes, https://up.codes/codes/georgia, accessed February 2024.

[117] Rules and Regulations of the State of Georgia, https://rules.sos.ga.gov/gac/120-3-3, accessed February 2024.

[118] Pipelines and Informed Planning Alliance, Partnering to Further Enhance Pipeline Safety in Communities through Risk-Informed Land Use Planning, Final Report of Recommended Practices, https://primis.phmsa.dot.gov/comm/pipa/landuseplanning.htm, November 2010.

conditions, and the volumes and durations released.

Exposure to either cold liquid or vapor could cause freeze burns and depending on the length of exposure, more serious injury or death. However, spills would be contained to on-site areas and the cold state of these releases would be greatly limited due to the continuous mixing with the warmer air. The cold temperatures from the release would not present a hazard to the public, which would not have access to onsite areas. The cold temperatures may also quickly cool any materials contacted by the liquid on release, causing extreme thermal stress in materials not specifically designed for such conditions. These thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength and result in cascading failures. However, regulatory requirements and recommendations made herein would ensure that these effects would be accounted for in the design of equipment and structural supports.

A rapid phase transition (RPT) can occur when a cryogenic liquid is spilled onto water and changes from liquid to gas, virtually instantaneously. Unlike an explosion that releases energy and combustion products from a chemical reaction, an RPT is the result of heat transferred to the liquid inducing a change to the vapor state. RPTs have been observed during LNG test spills onto water. In some test cases, the overpressures generated were strong enough to damage test equipment in the immediate vicinity of the LNG release point. The sizes of the overpressure events have been generally small and are not expected to cause significant damage. Six of the 18 Coyote spills produced RPT explosions. Most were early RPTs that occurred immediately with the spill, and some continued for the longer periods. Including RPTs near the end of the spills on three tests. LNG composition, water temperature, spill rate and depth of penetration all seem to play a role in RPT development and strength. The maximum strength RPT yielded equivalent to up to 6.3 kilograms of trinitrotoluene free-air point source at the maximum spill rate of 18 m^3/minute (4,750 gpm). This would produce an approximate 1 psi overpressures less than 100 feet from the spill source. These events are typically limited to the area within the spill and are not expected to cause damage outside of the area engulfed by the LNG pool. However, a RPT may affect the rate of pool spreading and the rate of vaporization for a spill on water.

Vapor Dispersion

Depending on the size and product of the release, liquids may form a liquid pool and vaporize. Additional vaporization would result from exposure to ambient heat sources, such as water or soil. The vapor may form a toxic or flammable cloud depending on the material released. The dispersion of the vapor cloud will depend on the physical properties of the cloud, the ambient conditions, and the surrounding terrain and structures. Generally, a denser-than-air vapor cloud would sink to the ground and would travel with the prevailing wind, while a lighter-than-air vapor cloud would rise and travel with the prevailing wind. The density will depend on the material releases and the temperature of the material. For example, an LNG release would initially form a denser than-air vapor cloud and transition to lighter-than-air vapor cloud as the vapor disperses downwind and mixes with the warm surrounding air. However, experimental observations and vapor dispersion modeling indicate an LNG vapor cloud would not typically be warm, or buoyant, enough to lift off from the ground before the LNG vapor cloud disperses below its LFL.

A vapor cloud formed following an accidental release would continue to be hazardous until it dispersed below toxic levels and/or flammable limits. Toxicity is primarily dependent on the airborne concentration of the toxic component and the exposure duration, while flammability of the vapor cloud is primarily dependent just on the concentration of the vapor when mixed with the surrounding air. In general, higher concentrations within the vapor cloud would exist near the spill, and lower concentrations would exist near the edge of the cloud as it disperses downwind.

Toxicity is defined by several different agencies for different purposes. Acute Exposure Guideline Level (AEGL) and Emergency Response Planning Guidelines (ERPG) can be used for emergency planning, prevention, and response activities related to the accidental release of hazardous substances. Other federal agencies, such as the DOE, EPA, and NOAA, use AEGLs and ERPGs as the primary measure of toxicity.

There are three AEGLs and three ERPGs, which are distinguished by varying degrees of severity of toxic effects with AEGL-1 and ERPG-1 (level 1) being the least severe to AEGL-3 and ERPG-3 (level 3) being the most severe.

- AEGL-1 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non sensory effects. However, these effects are not disabling and are transient and reversible upon cessation of the exposure.

- AEGL-2 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long lasting adverse health effects or an impaired ability to escape.

- AEGL-3 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death.

The EPA directs the development of AEGLs in a collaborative effort consisting of committee members from public and private sectors across the world. FERC staff uses

AEGLs preferentially as they are more inclusive and provide toxicity levels at various exposure times (10 minutes, 30 minutes, 1 hour, 4 hours, and 8 hours). The use of AEGLs is also preferred by the DOE and NOAA. Under the EPA RMP regulations in 40 CFR Part 68, the EPA currently requires the determination of distances to toxic concentrations based on ERPG-2 levels. ERPG levels have similar definitions but are based on the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to 1 hour without experiencing similar effects defined in each of the AEGLs. The EPA provides ERPGs (1 hour) for a list of chemicals. These toxic concentration endpoints are comparable to AEGLs endpoints.

In addition, any non-toxic release that does not contain oxygen would be classified as simple asphyxiants and may pose extreme health hazards, including death, if inhaled in significant quantities within a limited time. Very cold methane and heavier hydrocarbons vapors may also cause freeze burns. However, the locations of concentrations where cold temperatures and oxygen-deprivation effects could occur are greatly limited due to the continuous mixing with the warmer air surrounding the spill site. For that reason, exposure injuries from contact with releases of methane, nitrogen, and heavier hydrocarbons normally represent negligible risks to the public.

Flammable vapors can develop when a flammable material is above its flash point and concentrations are between the LFL and the upper flammable limit (UFL). Concentrations between the LFL and UFL can be ignited, and concentrations above the UFL or below the LFL would not ignite.

The extent of the affected area and the severity of the impacts on objects within a vapor cloud would primarily be dependent on the material, quantity, and duration of the initial release, the surrounding terrain, and the weather (e.g., wind speed and direction, temperature, humidity, etc.) present during the dispersion of the cloud.

Flammable Vapor Ignition

If the flammable portion of a vapor cloud encounters an ignition source, a flame would propagate through the flammable portions of the cloud. In most circumstances, the flame would be driven by the heat it generates. This process is known as a deflagration, or a flash fire, because of its relatively short duration. However, exposure to a deflagration, or flash fire, can cause severe burns and death, and can ignite combustible materials within the cloud. If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves that can cause damage would be generated. As a deflagration accelerates to super-sonic speeds, the large shock waves produced, rather than the heat, would begin to drive the flame, resulting in a detonation. The flame speeds are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance. Once a vapor cloud is ignited, the flame front may propagate back to the spill site if the vapor concentration along this path is sufficiently high to support the combustion process. When the flame reaches vapor concentrations above the UFL, the deflagration will transition to a pool or jet fire back at the source. If ignition occurs soon after the release begins, a fireball may occur near the source of the release and would be of a relatively short duration compared to an ensuing jet or pool fire. The extent of the affected area and the severity of the impacts on objects in the vicinity of a fire would primarily be dependent on the material, quantity, and duration of the fire, the surrounding terrain, and the ambient conditions present during the fire.

Overpressures

If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves that can cause damage would be generated. As a deflagration accelerates to super-sonic speeds, large pressure waves are produced, and a shock wave is created. In this scenario, the shock wave, rather than the heat, would drive the flame, resulting in a detonation. Deflagrations or detonations are generally characterized as "explosions" as the rapid movement of the flame and pressure waves associated with them cause additional damage beyond that from the heat. The amount of damage an explosion causes is dependent on the amount the produced pressure wave is above atmospheric pressure (i.e., an overpressure) and its duration (i.e., pulse). For example, a 1 psi overpressure, often cited as a safety limit in NFPA 59A (2019 and later editions) and U.S. regulations, is associated with glass shattering and traveling with velocities high enough to lacerate skin.

Flame speeds and overpressures are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance.

The potential for unconfined LNG vapor cloud detonations was investigated by the USCG in the late 1970s at the Naval Weapons Center in China Lake, California. Using methane, the primary component of natural gas, several experiments were conducted to determine whether unconfined LNG vapor clouds would detonate. Unconfined methane vapor clouds ignited with low-energy ignition sources (13.5 joules), produced flame speeds ranging from 12 to 20 mph. These flame speeds are much lower than the flame speeds associated with a deflagration with damaging overpressures or a detonation.

To examine the potential for detonation of an unconfined natural gas cloud containing heavier hydrocarbons that are more reactive, such as ethane and propane, the USCG conducted further tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane. The tests indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined natural gas vapor cloud to detonate. Less processed natural gas with greater amounts of heavier hydrocarbons would be more sensitive to detonation.

Although it has been possible to produce damaging overpressures and detonations of unconfined LNG vapor clouds, the feed gas stream proposed for the project would have lower ethane and propane concentrations than those that resulted in damaging overpressures and detonations. The substantial amount of initiating explosives needed to create the shock initiation during the limited range of vapor-air concentrations also renders the possibility of detonation of these vapors at an LNG plant as unrealistic. Ignition of a confined LNG vapor cloud could result in higher overpressures. To prevent such an occurrence, ELC and SLNG would take measures to mitigate the vapor dispersion and ignition into confined areas, such as buildings. ELC and SLNG would install hazard detection devices at all combustion and ventilation air intake equipment to enable isolation and deactivation of any combustion equipment whose continued operation could add to, or sustain, an emergency. In general, the primary hazards to the public from an LNG spill that disperses to an unconfined area, either on land or water, would be from dispersion of the flammable vapors or from radiant heat generated by a pool fire.

In comparison with LNG vapor clouds, there is a higher potential for unconfined propane clouds to produce damaging overpressures. This has been shown by multiple experiments conducted by the Explosion Research Cooperative to develop predictive blast wave models for low, medium, and high reactivity fuels and varying degrees of congestion and confinement. The experiments used methane, propane, and ethylene, as the respective low, medium, and high reactivity fuels. In addition, the tests showed that if methane, propane, or ethylene are ignited within a confined space, such as in a building, they all have the potential to produce damaging overpressures.

Fires and overpressures may also cause failures of nearby storage vessels, piping, and equipment if not properly mitigated. These failures are often termed cascading events or domino effects and can exceed the consequences of the initial hazard. The failure of a pressurized vessel could cause fragments of material to fly through the air at high velocities, posing damage to surrounding structures and a hazard for operating staff, emergency personnel, or other individuals in proximity to the event. In addition, failure of a pressurized vessel when the liquid is at a temperature significantly above its normal boiling point could result in a BLEVE. BLEVEs can produce overpressures when the superheated liquid rapidly changes from a liquid to a vapor upon the release from the vessel. BLEVEs of flammable fluids may also ignite upon its release and cause a subsequent fireball.

Potential Infrastructure Impacts from the LNG Terminal

Although the likelihood of incidents and the hazards described above are extremely low due to the mitigation required by regulations and recommendations made herein by FERC staff, the potential impacts from these hazards could impact onsite personnel and offsite public and should be part of pre-incident plans for emergency response planning purposes to meet federal regulations and applicable standards, such as NFPA 1660, Standard for Emergency, Continuity, and Crisis Management: Preparedness, Response, and Recovery, or approved equivalents.[119]

The preceding Reliability and Safety sections assessed potential impacts to the public and whether the Project would be able to operate safely, reliably, and securely. However, in order to assess potential impacts from catastrophic incidents and in response to FERC staff's data requests, ELC and SLNG evaluated potential impacts from incidents identified at the Project, including potential impacts to individuals with access and function needs as defined in NFPA 1660, Standard for Emergency, Continuity, and Crisis Management: Preparedness, Response, and Recovery, sections A.3.3.3 and H.7. FERC staff also performed an independent analysis of potential safety impacts on environmental justice communities using conservative, worst-case distances in the modeling assumptions. The analysis evaluated a range of releases to identify the potential impacts to populations and infrastructure within vicinity of the plant. Impacts would vary based on the initiating event and subsequent release characteristics (e.g., size, location, direction, process conditions), hazard (i.e., vapor dispersion, overpressures, fires, BLEVE and pressure vessel bursts), weather conditions, and surrounding terrain. Distances to radiant heats of 5 kW/m^2 (or approximately 1,600 BTU/ft^2-hr) from fires produced by accidental and intentional acts could impact onsite personnel. For example, Section 2.2.2.2 in NFPA 59A-2001 requires spill containments, serving vaporization, process, or LNG transfer area, to contain liquid releases from any single accidental leakage source (i.e., 2-inch diameter holes for piping greater than 6-inches in diameter and guillotine releases of piping less than 6-inches in diameter). Additionally, PHMSA siting regulations in Part 193, Subpart B for flammable vapor dispersion and thermal radiation exclusion zones limit the dispersion of flammable vapors and 1,600 BTU/ft^2-hr radiant heats from LNG pool fires in those spill containment systems in certain weather conditions from extending beyond the control of the operator or government agency and prevent it from extending onto areas accessible by the public. FERC staff also recommends spill containment systems to capture all liquid from guillotine ruptures of the single largest line and largest

[119] Specific distances of potential impacts from incidents at an LNG terminal have not been provided at this time to try and balance the potential security interests in releasing such information. Specific distances for various hazards described would be provided in emergency response plans for reference and use by emergency responders, Further, potential hazards have been described and potential impacts to communities are disclosed to balance the importance of public disclosure and transparency on the balance of potentially releasing information that has not been previously released and could be used by intentional actors.

vessel(s) to limit their pool spread and vaporization. This effectively limits the extent of the 1,600 BTU/ft^2-hr radiant heat from pool fires to onsite for even the largest releases from a single source and considerably reduces the dispersion distance of flammable and toxic vapors. However, ignition of releases larger than those used in the siting analyses can result in 1,600 BTU/ft^2-hr and 10,000 BTU/ft^2-hr radiant heats from jet and pool fires that extend offsite onto publicly accessible areas.

There are no infrastructure and no communities that could be impacted by a fire with 10,000 BTU/ft^2-hr and 1,600 BTU/ft^2-hr radiant heats extending offsite due to an unconfined pool fire and piping jet fires from the proposed Project facilities. The unignited vapor dispersion is extremely unlikely but, if it occurred, would also not impact any infrastructure or communities. Projectiles from a pressure vessel burst or BLEVE were also reviewed, and the analysis found that projectiles would not reach any infrastructure and communities. FERC staff did not locate any schools, daycare facilities, boarding and care facilities, or hospitals within the hazard footprints.

Potential Impacts on People with Access and Functional Needs and Environmental Justice Communities

FERC staff used EJScreen[120] and NEPAssist[121] as an initial screening tool to identify the potential impacts from incidents at the LNG terminal, including potential impacts to people with access and functional needs as defined in NFPA 1660 sections A.3.3.3 and H.7. For the Terminal Site, this includes jet fires from large piping, vapor cloud dispersion to the AEGL and LFL from a worst-case unignited release potentially due to a catastrophic rupture of the largest flowing pipe or vessel, and projectile impacts from PVBs and BLEVEs. Table B.1-1 shows there would be no population groups including people with potential access and functional needs within all potential impact areas[122] combined for that category as follows:[123]

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[120] EPA, EJScreen, https://ejscreen.epa.gov/mapper, sccessed February 2024.

[121] EPA, NEPAssist, https://nepassisttool.epa.gov/nepassist/nepamap.aspx, accessed February 2024.

[122] Potential impact areas would be representative of cumulative worst case impacts from all potential worst case hazard releases, including from all release directions and orientations subject to all worst case wind directions and conditions and may also include different applicable incident locations. Therefore, the potential impact area should not be interpreted as the impact distance from any single event, which will be dependent on release orientation and direction, wind direction and conditions, location of release, type of hazard (e.g., pool fire, jet fire, flammable vapor dispersion, etc.), and characteristics, timing, and location of any ignition that may or may not occur. However, the radius of the potential impact area would represent the maximum distance from a single event.

[123] Based on EPA, EJScreen User Guide, Version 2.2, 2023, the impact area would aggregate appropriate portions of the intersecting block groups, weighted by population, to create a representative set of data for the entire ring area, honoring variation and dispersion of the population in the block groups within it. For each indicator, the result is a population-weighted

Table-B1 People with Access and Functional Needs within the Total of Potential Incident Impact Areas (not necessarily a single event)						
Potential Incident Impact Area	**Population Density (per sq. mile) [a]**	**Households [a]**	**Housing Units [a]**	**Age 0-4 Population (percent)[a]**	**Age 65+ Population (percent) [a]**	**Linguistically Isolated Population (percent) [a, b, c]**
10,000 BTU/ft^2-hr (LNG Terminal)	0	0	0	0%	0%	0%
1,600 BTU/ft^2-hr (LNG Terminal)	0	0	0	0%	0%	0%
Flammable Vapor Cloud (LNG Terminal)	0	0	0	0%	0%	0%
[a] U.S. Census Bureau. American Community Survey, 2017-2021, ACS Estimates [b] Households in which no one 14 and over speaks English “very well” or speaks English only. [c] Calculated by dividing the number of linguistically isolated households by the total number of households multiplied by 100.						

FERC staff has determined that the risk (i.e., likelihood and consequence) of accidental and intentional events would be less than significant with implementation of the proposed safety and security measures recommendations. These measures further enhance the safety and security of the engineering design of the layers of protection for review subject to the approval by FERC staff and in accordance with recommended and generally accepted good engineering practices, which go above the minimum federal requirements that would also be required at the LNG terminal by DOT PHMSA regulations under 49 CFR Part 193 such that they would further reduce the risk of incidents impacting the public to less than significant levels, including impacts to those with access and functional needs and environmental justice communities.

average, which equals the block group indicator values averaged over all residents who are estimated to be inside the impact area. A weight factor for each block group is determined by summing each block point population percentage for that block group. If the impact area touches part of a neighboring block group that contains no block points, nothing will be aggregated; if an impact area intersects a number of block groups, EJScreen indices will be aggregated within each block group based on the affiliated block points. The aggregation is done by using factor-weighted block points.

Emergency Response Plans and Mitigation

In order to mitigate any further potential for offsite risks, including from any cascading hazards, additional recommendations are made by FERC staff to further enhance the safety and security measures beyond that which would normally be required at the LNG terminal by the minimum standards for LNG safety promulgated in PHMSA regulations under 49 CFR Part 193 and USCG regulations under 33 CFR Part 127 and 33 CFR Part 105. We recommend that Emergency Response Plans be consistent with the recognized and generally accepted good engineering practices for evacuating and sheltering in place, such as NFPA 1660, NFPA 470, and NFPA 475.

FERC staff determined that the risk of accidental and intentional events would be less than significant with implementation of the proposed safety and security recommendations that further enhance the safety and security measures that would be required at the LNG terminal by PHMSA regulations under 49 CFR Part 193 and USCG regulations under 33 CFR Part 127 and 33 CFR Part 105. Furthermore, EPAct 2005 requires that an LNG terminal operator's ERP be developed in consultation with the USCG and State and local agencies and be approved by the commission prior to final approval to begin construction. To satisfy this requirement, FERC staff recommends in section 5 that prior to initial site preparation, ELC and SLNG update the existing ERP (including evacuation and any sheltering and re-entry) to include the new facilities and modifications, as applicable, and coordinate procedures with the USCG; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and other appropriate federal agencies. This plan should be consistent with recommended and good engineering practices, as defined in NFPA 1660, NFPA 470, NFPA 475, or equivalent, and based on potential impacts and onsets of hazards from accidental and intentional events at the LNG terminal, including but not limited to a catastrophic rupture of the largest flowing pipe or vessel. We also recommend the plan include at a minimum:

- materials and plans for periodic dissemination of public education and training materials for potential hazards and impacts, identification of potential hazards, and steps for notification, evacuation and shelter in place of the public;

- plans to competently train emergency responders required to effectively and safely respond to hazardous material incidents including, but not limited to LNG fires and dispersion;

- plans to competently train emergency responders to effectively and safely evacuate or shelter public;

- designated contacts with federal, state and local emergency response agencies responsible for emergency management and response;

- scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

- scalable procedures for mobilizing response and establishing a unified command, including identification, location, and design of any emergency operations centers and emergency response equipment required to effectively and safely to respond to hazardous material incidents and evacuate or shelter public;

- scalable procedures for notifying public, including identification, location, design, and use of any permanent sirens or other warning devices required to effectively communicate and warn the public prior to onset of debilitating hazards;

- scalable procedures for evacuating the public, including identification, location, design, and use of evacuation routes/methods and any mustering locations required effectively and safely evacuate public; and

- scalable procedures for sheltering the public, including identification, location, design, and use of any shelters demonstrated to be needed and demonstrated to effectively and safely shelter public prior to onset of debilitating hazards.

FERC staff recommends ELC and SLNG notify FERC staff of all planning meetings in advance and should report progress on the development of its ERP at 3-month intervals, as well as file public versions of offsite emergency response procedures for public notification, evacuation, and shelter in place. EPAct 2005 also requires LNG terminal operators develop a cost-sharing plan to reimburse direct costs to state and local agencies. To satisfy this requirement, FERC staff also recommends an updated Cost Sharing Plan that includes sustained funding of any requirement or resource gap(s) identified above to be needed and to effectively and safely evacuate and shelter public and required to effectively and safely respond to hazardous material incidents If the project is authorized and constructed, we would evaluate the revised ERP and Cost Sharing Plan in accordance with recommended and good engineering practices such as, but not limited to, NFPA 1660, NFPA 470 and NFPA 475, or equivalents.

Based on our preliminary analysis of the hazards from the LNG facilities and recommendations herein, we recommend in section 5 that ELC and SLNG provide additional information, for review and approval, on the updated emergency response plans prior to initial site preparation. If this Project is authorized, constructed, and operated, ELC and SLNG would coordinate with local, state, and federal agencies on the development of an updated emergency response plan and cost sharing plan. We recommend in section 5 that ELC and SLNG provide periodic updates on the development of these plans for review and approval, and ensure they are in place prior to introduction of hazardous fluids. We also recommend in section 5 that ELC and SLNG file three-dimensional drawings, for review and approval, that demonstrate there is a sufficient number of access and egress within the terminal. In addition, we recommend in section 5 that Project facilities be subject to regular inspections throughout the life of the facility and would continue to require companies to file updates to the ERP.

B.2 RECOMMENDATIONS FROM FERC PRELIMINARY ENGINEERING AND TECHNICAL REVIEW

Based on our preliminary engineering and technical review of the reliability and safety of the Elba Liquefaction Optimization Project, we recommend the mitigation measures listed in section 5 of the EA as conditions to any order authorizing the Project. These recommendations would be implemented prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility to enhance the reliability and safety of the facility and to mitigate the risk of impact on the public.