Federal Energy Regulatory Commission

Office of Energy Projects

June 2024

Corpus Christi Liquefaction, LLC
CCL Midscale 8-9, LLC

Docket No. CP23-129-000

Corpus Christi Liquefaction Midscale Trains 8 & 9 Project

Environmental Assessment

Cooperating agencies:

U.S. Department of Energy

U.S. Coast Guard

U.S. Department of Transportation

Contact: Office of External Affairs, (866) 208-FERC

Federal Energy Regulatory Commission
Office of Energy Projects
Washington, DC 20426

FEDERAL ENERGY REGULATORY COMMISSION

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas Branch 2
Corpus Christi Liquefaction, LLC
CCL Midscale 8-9, LLC
CCL Midscale Trains 8 & 9 Project
Docket No. CP23-129-000

TO THE INTERESTED PARTY:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Corpus Christi Liquefaction Midscale Trains 8 & 9 Project (Project), proposed by Corpus Christi Liquefaction, LLC and CCL Midscale 8-9, LLC (collectively referred to as CCL) in the above-referenced docket. CCL proposes to construct and operate an expansion of the previously authorized Liquefaction Project and Stage 3 Project facilities (authorized under Docket Nos. CP12-507-000 and CP18-512-000, respectively, and collectively referred to as the CCL Terminal) in San Patricio and Nueces Counties, Texas.

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

The U.S. Department of Energy, U.S. Coast Guard, and U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration 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.

CCL's proposed Project includes the construction and operation of two midscale liquification trains, on-site refrigerant storage, an end flash gas unit, and a boil-off gas compressor. Additionally, CCL proposes to increase the authorized loading rate at the existing CCL Terminal marine berth from 12,000 cubic meters per hour (m^3/hr) (previously authorized in the Liquefaction Project) to 14,000 m^3/hr from any single jetty using a combination of two or three existing LNG storage tanks. Further, CCL proposes to provide for simultaneous loading capabilities at a combined rate of 22,500 m^3/hr (not to exceed 12,000 m^3/hr on a single line) using the three existing LNG storage tanks. Modifications to allow for increased single ship loading and simultaneous ship loading include the addition of a fifth pump in each of the three existing LNG storage tanks, addition of new interlocks, and modification of existing interlocks.

The Commission mailed a copy of the *Notice of Availability* 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 the 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 the 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. CP23-129). 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, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will 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 **5:00 p.m. Eastern Time on July 22, 2024.**

For your convenience, there are three methods you can use to file your comments with 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 also file your comments electronically 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." You must select the type of filing you are making. If you are filing a comment on a particular project, please select "Comment on a Filing"; 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 (CP23-129-000) in 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 which 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 Acronyms

2014 FEIS	2014 Liquefaction Project Final Environmental Impact Statement
2019 EA	2019 Stage 3 Project Environmental Assessment
ADCC	Agua Dulce Corpus Christi
AEGL	Acute Exposure Guideline Level
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AIChE	American Institute of Chemical Engineers
APE	area of potential effects
API	American Petroleum Institute
AQCR	Air Quality Control Regions
ASCE	American Society of Civil Engineers
ASIS	American Society for Industrial Security
ASME	American Society of Mechanical Engineers
AWWA	American Water Works Association
BACT	best available control technology
BG	Block Group
BLEVE	boiling liquid expanding vapor explosion
BMP	best management practice
BOG	boil-off gas
BPCS	basic process control system
BPVC	Boiler and Pressure Vessel Code
Btu/ft^2-hr	British thermal units per square foot per hour
CCL	Corpus Christi Liquefaction, LLC and CCL Midscale 8-9, LLC
CCL Terminal	Liquefaction Project and Stage 3 Project authorized under Docket Nos. CP12-507-000 and CP18-512-000, respectively
CCPS	Center for Chemical Process Safety
CCSC	Corpus Christi Ship Channel
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CH_4	methane
CII	Construction Industry Institute
CLH	Cheniere Land Holdings, LLC
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalents
Coast Guard	U.S. Coast Guard
COE	U.S. Army Corp of Engineers
Commission	Federal Energy Regulatory Commission
COTP	Captain of the Port
CPT	cone penetration test
CSA	Canadian Standards Association
CT	Census Tract
CWA	Clean Water Act

dB	decibels
dBA	A-weighted decibels
dBC	C-weighted decibels
DCS	Distributed Control System
DHS	Department of Homeland Security
District	San Patricio Municipal Water District
DOD	Department of Defense
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EA	environmental assessment
EFG	End Flash Gas
EFH	essential fish habitat
EI	environmental inspector
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
EPC	engineering, procurement, and construction
ERP	Emergency Response Plan
ERPG	Emergency Response Planning Guidelines
ESA	Endangered Species Act
ESD	emergency shutdown
ºF	degrees Fahrenheit
FAA	Federal Aviation Administration
FDCP	Fugitive Dust Control Plan
FECM	Office of Fossil Energy and Carbon Management
FEED	front-end-engineering-design
FERC	Federal Energy Regulatory Commission
FSA	Facility Security Assessment
FSP	Facility Security Plan
ft^2	square foot
FTA	Free Trade Agreement
FWS	U.S. Fish and Wildlife Service
GHG	greenhouse gas
GIWW	Gulf Intracoastal Waterway
gpm	gallons per minute
GWP	global warming potential
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HAZOP	Hazard and Operability
HHRA	Human Health Risk Assessment
HIPPS	high integrity pressure protection system
HMB	heat and mass balances
HUC	hydrologic unit code
HVL	highly volatile liquid
IEC	International Electrotechnical Commission

IES	Illuminating Engineering Society
IMO	International Marine Organization
ISA	International Society for Automation
ISO	International Organization for Standardization
IWG	interagency working group
kW/m^2	kilowatts per square meter
lb/hr	pounds per hour
lb/min	pounds per minute
LCI	Lettis Consultants International
L_{dn}	day-night equivalent sound level
L_{eq}	equivalent sound level
LFL	lower flammable limit
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
LOD	Letter of Determination
LOI	Letter of Intent
LOPA	Layer of Protection Analysis
LOR	Letter of Recommendation
LPG	liquefied petroleum gas
m^3	cubic meters
m^3/hr	cubic meters per hour
MAWP	maximum allowable working pressure
mm	millimeter
MMBtu/hr	million British Thermal Units per hour
MOU	Memorandum of Understanding
mph	miles per hour
MSA	Magnuson-Stevens Fishery Conservation and Management Act
MTSA	Maritime Transportation Security Act
NAAQS	National Ambient Air Quality Standards
NAVD88	North American Vertical Datum of 1988
NEPA	National Environmental Policy Act
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NGLC	net ground-level concentration
NGO	non-governmental organization
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
N_2O	nitrous oxide
NO_x	oxides of nitrogen
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NPS	nominal pipe size
NSA	noise sensitive area

NSPS	New Source Performance Standards
NSR	New Source Review
NVIC	Navigation and Inspection Circular
O^3	ozone
OEP	Office of Energy Projects
OSHA	Occupational Safety and Health Administration
P&ID	piping and instrument diagram
Pb	lead
PCCA	Port of Corpus Christi Authority
PFD	process flow diagram
PHA	process hazard analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
Plan	FERC *Upland Erosion Control, Revegetation, and Maintenance Plan*
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
ppb	parts per billion
ppm	parts per million
Procedures	FERC *Wetland and Waterbody Construction and Mitigation Procedures*
Project	Corpus Christi Liquefaction Midscale Trains 8 & 9 Project
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
PSSR	pre-startup safety review
PVB	pressure vessel bursts
QAQC	quality assurance and quality control system
QMS	quality management system
RPT	rapid phase transition
RRC	Railroad Commission of Texas
RWL	Raw Water Lake
SCPT	seismic cone penetration test
Secretary	Secretary of the Commission
SH	State Highway
SIL	Significant Impact Levels
SO_2	sulfur dioxide
SPCC Plan	Spill Prevention, Control, and Countermeasures Plan
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPWD	Texas Parks and Wildlife Department
tpy	tons per year
TVRA	threat, vulnerability, and risk assessment
TWIC	Transportation Worker Identification Credential
TxDOT	Texas Department of Transportation
$\mu g/m^3$	micrograms per cubic meter

U.S.C.	United States Code
UFC	Unified Facilities Criteria
UFL	upper flammable limit
UL	Underwriters Laboratories
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
VOC	volatile organic compound
WSA	Waterway Suitability Assessment

A. PROPOSED ACTION

1. Introduction

In accordance with the Natural Gas Act (NGA, Title 15 United States Code [U.S.C.] Section 717 [15 U.S.C. 717]), the Federal Energy Regulatory Commission (FERC or Commission) is responsible for deciding whether to authorize the construction and operation of onshore natural gas export facilities. The National Environmental Policy Act (NEPA, 42 U.S.C. 4321 et seq.) requires that the Commission consider the environmental impacts of a proposed project prior to making a decision.

On March 30, 2023, Corpus Christi Liquefaction, LLC and CCL Midscale 8-9, LLC (collectively referred to as CCL) filed an application with the Commission for the CCL Midscale Trains 8 & 9 Project (Project) in Docket No. CP23-129-000 pursuant to Section 3(a) of the NGA. CCL proposes to construct and operate an expansion of the previously authorized Liquefaction Project and Stage 3 Project facilities (authorized under Docket Nos. CP12-507-000 and CP18-512-000, respectively, and collectively referred to as the CCL Terminal) in San Patricio and Nueces Counties, Texas.

FERC is the lead federal agency for authorizing liquefied natural gas (LNG) export facilities under the NGA and the lead federal agency for preparation of this environmental assessment (EA). We[1] prepared this EA in compliance with NEPA according to the regulations issued by the Council on Environmental Quality (CEQ) at Title 40 Code of Federal Regulations (CFR) Parts 1500–1508 (40 CFR 1500–1508) and by the Commission at 18 CFR 380.

2. Project Purpose and Need

CCL states in its application that the purpose and need for the Project is to expand the CCL Terminal production capabilities to meet immediate and future global demand for LNG, which requires the liquefaction and export of abundant U.S. natural gas supplies to overseas markets via ocean-going vessels. CCL also states the liquefaction of natural gas for export as LNG to global allies would promote further diversification of natural gas supplies globally and provide macroeconomic benefits domestically.

We received multiple comments from the public during the scoping period stating that the Commission should not approve the Project due to a narrow purpose and need, the lack of demonstrated need for such infrastructure, and the lack of local or national benefit provided by the Project, as perceived by the commenters. FERC does not plan, design, build, or operate natural gas transmission infrastructure. As an independent regulatory commission, FERC reviews proposals to construct and operate such facilities. Accordingly, the project proponent is the source for identifying the purpose for developing, constructing, and operating a project. CCL's purpose and objective in proposing the Project were defined in its application with the Commission. Under Section 3 of the NGA, FERC considers as part of its decision to authorize natural gas facilities, all factors bearing on the public interest. Specifically, regarding whether to authorize natural gas facilities used for importation or exportation, FERC shall authorize the proposal unless it finds that the proposed facilities will not be consistent with the public interest.

3. Scope of this Environmental Assessment

Our principal purposes in preparing this EA are to:

- identify and assess potential impacts on the natural and human environment that would result from construction and operation of the Project;
- describe and evaluate reasonable alternatives to the Project that would avoid or minimize adverse effects on environmental resources;

[1] "We," "us," and "our" refer to the environmental and engineering staff of the Office of Energy Projects.

- recommend mitigation measures as necessary, that could be implemented by CCL to reduce impacts on specific environmental resources; and
- encourage and facilitate involvement by the public and interested agencies in the environmental review process.

The topics we address in this EA include geology and soils; groundwater, surface water, and wetlands; vegetation, wildlife, aquatic resources, and special status species; land use, recreation, and visual resources; socioeconomics and environmental justice; cultural resources; air quality and noise; reliability and safety; and cumulative impacts including climate change. In this EA, we describe the affected environment as it currently exists, discuss the environmental consequences of the Project, and present our recommended mitigation measures.

We received comments that CCL's application for expansion at the existing CCL Terminal should be denied. The EA will be used by the Commission in its decision-making process to determine whether to authorize CCL's proposal.

4. Lead and Cooperating Agencies

FERC is an independent federal regulatory agency that regulates the interstate transportation of natural gas, among other industries, in accordance with the NGA, as amended. Pursuant to the Energy Policy Act (EPAct) of 2005 Section 313(b)(1), FERC is the lead federal agency for the coordination of all applicable federal authorizations. As the lead federal agency for the Project, FERC is required to comply with Section 7 of the Endangered Species Act (ESA), as amended, and Section 106 of the National Historic Preservation Act (NHPA), as amended. These statutes have been considered in the preparation of this EA. In addition to FERC, other federal, state, and local agencies may use this EA in approving or issuing permits for all or part of the Project. Permits, approvals, and consultations for the Project are discussed in section A.11 of this EA.

The U.S. Coast Guard (Coast Guard), U.S. Department of Energy (DOE), and U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) participated as cooperating agencies in the preparation of the EA. Cooperating agencies have jurisdiction by law or special expertise with respect to environmental impacts involved with a proposal. Cooperating agencies, and other federal, state, and local agencies may use this EA in approving or issuing permits for all or part of the Project.

As required by its regulations, the Coast Guard is responsible for issuing a Letter of Recommendation (LOR) and an LOR Analysis regarding the suitability of the waterway for LNG marine traffic following a Waterway Suitability Assessment (WSA) submitted by CCL. Following submittal to the Coast Guard of its initial Letter of Intent (LOI), CCL performed both a Preliminary and Follow-on WSA, as required by 33 CFR 127.007 and the Coast Guard's Navigation and Inspection Circular (NVIC) – *Guidance Related to Waterfront Liquefied Natural Gas (LNG) Facilities* (NVIC 01-11). On February 9, 2023, CCL submitted a follow-on WSA to the Coast Guard with a request for a LOR confirming that the waterway can adequately accommodate the increase of up to 480 liquefied natural gas carriers (LNGCs) per year. In a letter dated January 25, 2024, the Coast Guard issued the LOR for the Project, recommending that the evaluated portion of the Corpus Christi Ship Channel (CCSC) and the entirety of the La Quinta Ship Channel can be considered suitable for the increased LNGC traffic associated with the Project. The Coast Guard's responsibilities and jurisdiction related to LNGC traffic and facilities are discussed in further detail in section B.9. and appendix J.

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.

The DOT's PHMSA has prescribed the minimum federal safety standards for natural gas pipelines and LNG facilities in compliance with 49 U.S.C 1671 *et seq*. and 49 U.S.C 60101, respectively. Those standards are codified in 49 CFR Parts 192 and 193 and apply to safety regulations and standards related to the design, construction, and operation of natural gas pipelines and the siting, design, construction, operation, maintenance, and security of LNG facilities, respectively. The National Fire Protection Association (NFPA) Standard 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*, is incorporated into these requirements by reference, with regulatory preemption in the event of conflict.

In accordance with the 1985 Memorandum of Understanding (MOU) on LNG facilities and the 2004 Interagency Agreement on the safety and security review of waterfront import/export LNG facilities, PHMSA participates as a cooperating agency and assists in assessing any mitigation measures that may become conditions of approval for any project. In addition, the August 31, 2018 MOU between FERC and PHMSA provides guidance and policy on each agency's respective statutory responsibility to ensure that each agency works in a coordinated and comprehensive manner.

5. Public Participation and Comment

On August 19, 2022, CCL filed a request to enter into the Commission's pre-filing review process. We approved CCL's request on September 9, 2022 and established pre-filing docket number PF22-10-000 for the Project. The pre-filing review process provides opportunities for interested stakeholders to become involved early in project planning, facilitates interagency cooperation, and assists in the identification and early resolution of issues, prior to a formal application being filed with FERC. During the pre-filing process, we conducted biweekly conference calls with CCL and interested agencies to discuss Project progress and identify and address issues and concerns that had been raised by FERC staff or other agencies. Project information and documents and summaries of the conference calls are available for viewing on FERC's eLibrary system.

CCL held an open house meeting on October 12, 2022, in Gregory, Texas to provide information to the public about the Project. FERC staff participated in the meeting to describe the Commission's process and provide those attending with information on how to file comments. On November 10, 2022, FERC issued a *Notice of Scoping Period Requesting Comments on Environmental Issues for the Planned Corpus Christi Liquefaction Midscale Trains 8 & 9 Project and Notice of Public Scoping Sessions*. This notice was sent to affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; Native American tribes; other interested parties; and local libraries and newspapers. In response to the Notice of Scoping, the Commission received comments from the U.S. Environmental Protection Agency (EPA), Texas Parks and Wildlife Department (TPWD), National Oceanic and Atmospheric Administration (NOAA), Texas Commission on Environmental Quality (TCEQ), non-governmental organizations (NGOs), and individuals.

We conducted a public scoping session at the Gregory Community Center on December 1, 2022, to provide an opportunity for the public to learn more about the Project and provide oral comments on environmental issues to be addressed in the EA. During the meeting, we received oral comments from 12 individuals that were transcribed by a court reporter.[2] The primary issues raised by the commenters included concerns about permitting, outreach, vessel traffic, shoreline erosion, socioeconomics, environmental justice, air quality, water resources, aquatic resources, safety, and cumulative impacts.

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[2] These transcripts can be viewed on the FERC eLibrary under accession number 20221220-4000.

The pre-filing process ended on March 30, 2023, when CCL filed its application with FERC, in Docket No. CP23-129-000. On April 13, 2023, the Commission issued a *Notice of Application and Establishing Intervention Deadline* for the Project announcing that CCL had filed an application with the FERC, which established a 21-day period for the submission of comments, concerns, and issues related to the proposed Project, and for motions to intervene. During this period and including all comments received up to the issuance of this EA, we received comments from Ingleside on the Bay Coastal Watch Association, Sierra Club et. al., and multiple individuals concerned with impacts from the Project regarding vessel traffic, recreational and commercial fisheries, cumulative impacts, air quality, socioeconomics, purpose and need, alternatives, reliability and safety, aquatic resources, special status species, climate change. We also received comments from the Sierra Club et. al. and multiple individuals concerned with the increase of domestic gas and utility prices resulting from increased LNG exports. Analysis of the LNG market and associated trends are non-environmental in nature and outside the scope of this EA.

Table B1 in appendix B summarizes the environmental issues identified during the scoping process. All substantive comments are addressed in the relevant resource sections of the EA.

6. Proposed Facilities

CCL's proposed Project includes the construction and operation of two midscale liquification trains, on-site refrigerant storage, an end flash gas (EFG) unit, and a boil-off gas (BOG) compressor (collectively referred to as the direct footprint of the Project)[3]. Additionally, CCL proposes to increase the authorized loading rate at the existing CCL Terminal marine berth from 12,000 cubic meters per hour (m^3/hr) (previously authorized in the Liquefaction Project) to 14,000 m^3/hr from any single jetty using a combination of two or three existing LNG storage tanks. Further, CCL proposes to provide for simultaneous loading capabilities at a combined rate of 22,500 m^3/hr (not to exceed 12,000 m^3/hr on a single line) using the three existing LNG storage tanks. Modifications to allow for increased single ship loading and simultaneous ship loading include the addition of a fifth pump in each of the three existing LNG storage tanks, addition of new interlocks, and modification of existing interlocks. The Coast Guard has established that it is not necessary to provide a Safety or Security Zone around the CCL Terminal jetties under their authority as defined in 33 CFR Part 165.[4]

CCL proposes to construct the Project using workspace within and adjacent to the existing CCL Terminal in San Patricio and Nueces Counties, Texas as shown in figure 1 below and figure A1 in appendix A. The direct footprint of the proposed Project facilities would be within the fence line of the CCL Terminal. The Project would use shared infrastructure with the CCL Terminal including LNG storage and marine facilities. The specific Project components are summarized in the following sections and are further detailed in appendix J.

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3 The detailed explanation of the proposed facilities can be found in Resource Report 1, accession number 20230330-5209.

4 This determination is available on the FERC eLibrary as attachment 4 of accession number 20231023-5112.

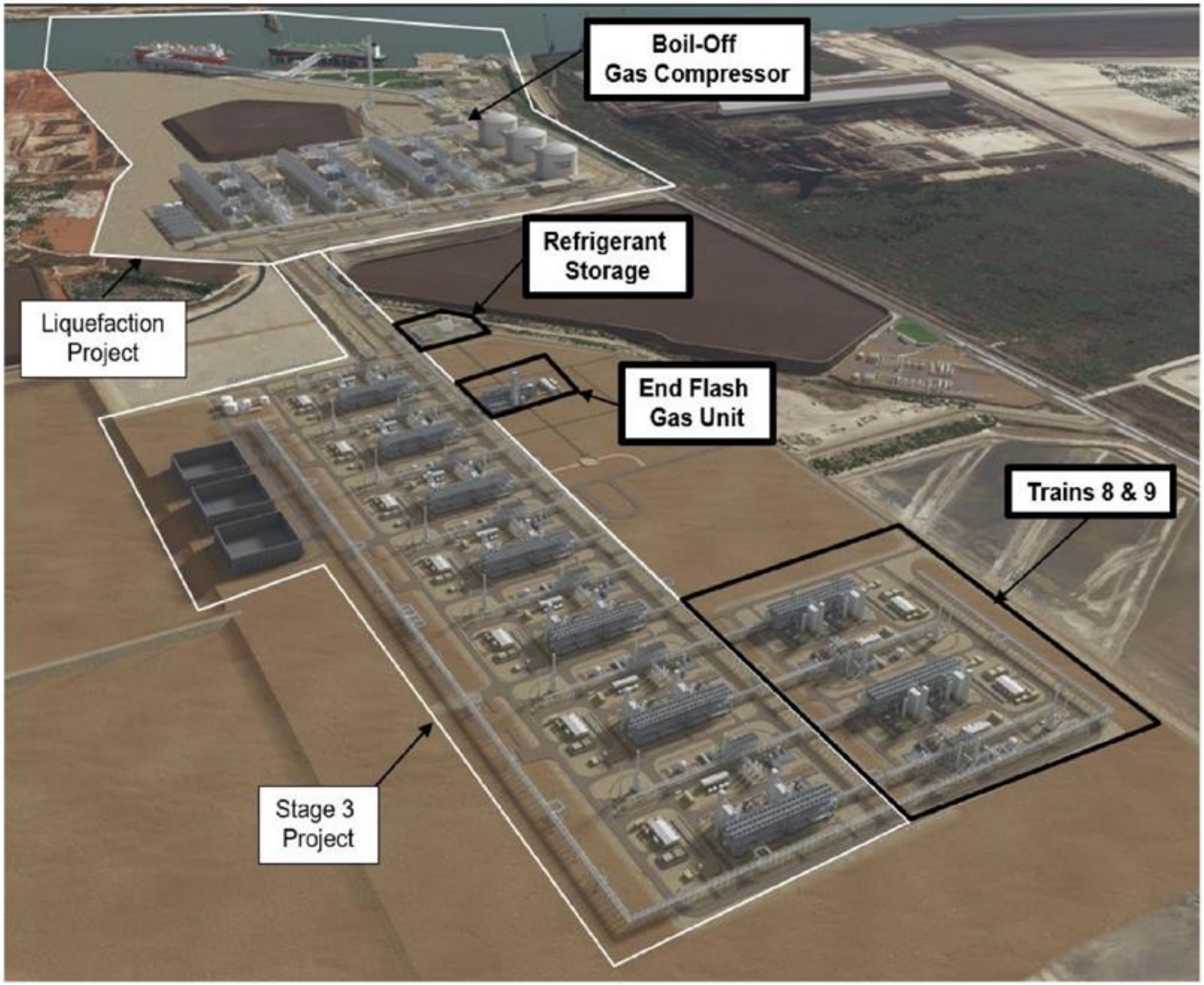

Figure 1. Artist Rendition of the Project and CCL Terminal

6.1 Marine Facilities

CCL is proposing to use the existing CCL Terminal marine facilities, including the existing marine flare, to support the Project. The existing marine facilities would not be affected by the Project, and no new marine equipment or facilities are proposed. The Project would also use the existing CCL Terminal tug fleet.

The Project would result in an increase in the maximum marine vessel traffic from the 400 LNGCs per year, previously authorized as part of the Stage 3 Project, up to 480 LNGCs per year. CCL has submitted a follow-on WSA to the Coast Guard and received a LOR confirming that the waterway can adequately accommodate the proposed 480 LNGC calls per year, as discussed in section A.4.2. The maximum size and draft of the LNGCs arriving at the CCL Terminal would not change as a result of the Project. Deepwater access from the Gulf of Mexico to the Project is the same marine transit route that was analyzed by the Coast Guard for the CCL Terminal. The general access route is shown in figure A2 of appendix A.

6.2 Site Access and Traffic

Construction traffic, including materials deliveries, would access the site via six entrances along State Highway (SH) 361. No new access roads into the facility would be required for the Project. Access within the facility would be the path of least resistance using an internal network of private roads including, but not limited to those shown in figure A3 of appendix A. Private roads include two paved roads, La Quinta Road, which parallels the western boundary of the permanent site, and Sherwin Road on the east side of the Project area. Public roads would not be required for access between the direct Project footprint and construction laydown yards. Some heavy materials and equipment deliveries would occur via barge to the existing construction dock. Additional information on construction traffic and materials deliveries is provided in section B.7.1.

7. Land Requirements

Land requirements for the Project are quantified in table A.7-1 and depicted in figure A4 of appendix A.

Table A.7-1
Land Requirements for the CCL Midscale Trains 8 & 9 Project

Operations/Construction			Construction Only [e]			Total Workspace
Previously Authorized Workspaces [a, b] (acres)	Additional Workspace (acres)	Total Workspace (acres)	Previously Authorized Workspaces [c, d] (acres)	Additional Workspace (acres)	Total Workspace (acres)	
1,294	101	1,395	342	0	342	**1,737**

[a] Workspaces authorized by FERC for construction and operation of CCL Terminal under FERC Docket Nos. CP12-507-000 & CP18-512-000.
[b] The direct footprint of the proposed Project facilities (approximately 39 acres) falls within previously reviewed and approved land.
[c] Workspace authorized by FERC for construction of the CCL Terminal under FERC Docket Nos. CP12-507-000 and CP18-512-000. Includes lands leased for construction staging and would not be used for long-term operations activities.
[d] Previously authorized workspace includes approximately 36 acres of open water and 4 acres of dock space over open water that are included for consistency with previous approvals, however, would not be disturbed by the Project.
[e] Acreages presented in this column are in addition to the values presented in the 'Operations/Construction' column.

Construction of the Project would require a total of 1,737 acres of land, of which 1,395 acres would be retained for operation. Of the 1,395 acres impacted by operation of the Project, 101 acres of workspace would be additional impacts that have not been previously reviewed and approved for the CCL Terminal (hereinafter referred to as Raw Water Lake [RWL] area) and 1,294 acres overlap areas previously authorized for the CCL Terminal. An additional 342 acres of land previously authorized for the CCL Terminal would be used only for construction of the Project.

The Project would be part of an integrated facility, and all land previously approved for use for the CCL Terminal would be utilized for the proposed Project. Permanent operational areas would be utilized during maintenance turnarounds and other operational support activities. Construction areas would be utilized for parking, staging, and general construction support.

8. Construction Procedures, Schedule, and Workforce

CCL anticipates starting construction of the Project in the 2nd half of 2024 upon receipt of all required permits and authorizations. Under optimal construction conditions, the Project is anticipated to take 4 years to complete. CCL anticipates the Project could be placed in service as early as 2028 but has requested authorization to place the facilities in their entirety in service by 2031 to accommodate potential for phasing, schedule changes, or disruptions.

During the peak of construction for the Project, which is anticipated to last approximately 12 months, 2,100 workers would be required. Approximately 45 permanent workers would be employed for operation of the Project. Additional information regarding the Project workforce is presented in section B.7.1.

All Project components would be sited, constructed, owned, operated, and maintained in accordance with applicable law. The Project would implement and adhere to the FERC's 2013 *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures). In addition to the Plan and Procedures, CCL would implement other Project-specific plans to reduce potential environmental impacts during construction, including: Spill Prevention, Containment, and Countermeasures (SPCC) Plan,[5] Fugitive Dust Control Plan (FDCP),[6] and Plan and Procedures for Addressing Unanticipated Discoveries of Cultural Resources and Human Remains.[7] Additionally, CCL would follow a management plan for arsenic affected groundwater developed for the Stage 3 Project[8] and would provide an updated Erosion and Sediment Control Plan, utilized during the Stage 3 Project, with submittal of the Project implementation plan.

In general, the Project facilities would be constructed in the same manner in which similar facilities were constructed as described in FERC's 2014 Liquefaction Project Final Environmental Impact Statement (2014 FEIS) [9] and 2019 Stage 3 Project EA (2019 EA),[10] respectively. These documents are incorporated by reference in this EA as much of the background setting and impacts are similar to that discussed in previous NEPA analyses for the CCL Terminal. Detailed construction procedures are described in appendix C for the midscale liquefaction trains and temporary construction facilities.

FERC may impose conditions on any authorization that it grants for the Project. These conditions include additional requirements and mitigation measures recommended in this EA to minimize the environmental impact that would result from construction and operation of the Project (see section B and section D). We recommend that these additional requirements and mitigation measures (presented in

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5 CCL's SPCC Plan can be viewed on the FERC eLibrary as appendix 2b under accession number 20230330-5209.

6 CCL's FDCP can be viewed on FERC's eLibrary as appendix 9C of accession number 20230330-5209.

7 CCL's Plan and Procedures for Addressing Unanticipated Discoveries of Cultural Resources and Human Remains can be viewed on FERC's eLibrary as attachment 32 of accession number 20230720-5073.

8 The management plan for arsenic affected groundwater is filed on the FERC eLibrary as privileged under appendix 2A of accession number 20230330-5209.

9 The 2014 Liquefaction Project FEIS can be viewed on the FERC eLibrary under accession number 20141008-4001.

10 The 2019 Stage 3 Project EA can be viewed on the FERC eLibrary under accession number 20190329-3010.

bold type in the text of the EA) be included as specific conditions to any authorization issued for the Project. We also recommend that CCL be required to implement the mitigation measures proposed as part of the Project unless specifically modified by other authorization conditions. CCL would be required to incorporate all environmental conditions and requirements of FERC authorization, and associated construction permits into the construction documents for the Project.

CCL would employ at least one environmental inspector (EI) for the Project in accordance with the FERC's Plan. In addition to the EI, we would conduct periodic compliance inspections during all phases of construction and enter inspection reports into the Commission's public record. Other agencies may conduct inspections as well and representatives could issue work stoppages, impose fines, and/or require the implementation of additional and/or corrective environmental measures.

After construction, we would continue to conduct oversight inspection and monitoring during operation of the Project to ensure successful restoration. Additionally, FERC staff would conduct routine engineering safety inspections of the CCL Terminal operations throughout the life of the Project.

9. Operation and Maintenance

The Project is an expansion of the existing CCL Terminal, and therefore would be fully integrated and incorporated into the existing Operations and Maintenance Programs. CCL would operate and maintain the Project in accordance with applicable federal, state, and local regulations and guidelines, including the requirements of the DOT or PHMSA minimum federal safety standards specified in 49 CFR Part 193. The full-time plant maintenance staff, supplemented by a general maintenance contract workforce, would conduct routine maintenance and minor overhauls. Unscheduled maintenance would be addressed on a criticality basis. If a problem requires immediate attention, the appropriate person(s) would be notified.

10. Non-jurisdictional Facilities

Under the NGA, the Commission is required to consider, as part of its decision to approve facilities under its jurisdiction, all factors bearing on the public interest. 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 such as utility lines to support the jurisdictional facilities, or they may be minor, non-integral components of the facilities.

Feed gas for the Project, the Liquefaction Project, and the Stage 3 Project, would be transported to the CCL Terminal by a combination of the previously permitted and FERC jurisdictional Corpus Christi Pipeline as well as the non-jurisdictional Agua Dulce Corpus Christi (ADCC) pipeline. The ADCC pipeline is a 42-inch-diameter intrastate pipeline, approximately 43-miles-long, to be operated by WWM Operating, LLC and owned by ADCC Pipeline, LLC (WhiteWater Midstream, 2024). The ADCC pipeline would be constructed and operated by private entities. Construction of the pipeline is under the jurisdiction of the State of Texas regulatory agencies. Federal regulatory responsibility will be limited to issuance by the U.S. Army Corps of Engineers (COE) of nationwide permits under Section 404 of the Clean Water Act (CWA) for any waterbodies or wetlands crossed by the pipeline, compliance with the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA, and compliance with Section 106 of the NHPA, as amended. All necessary federal and state permits for the ADCC pipeline have been received.

The ADCC pipeline, which would connect the Agua Dulce natural gas hub to the CCL Terminal, is currently under construction and is anticipated to be in service in 2024. The locations of the Corpus Christi Pipeline and the non-jurisdictional ADCC pipeline in relation to the CCL Terminal and Project facilities are depicted in figure A5 of appendix A. There are no other non-jurisdictional facilities proposed as part of the Project.

11. Permits, Approvals, and Regulatory Consultation

Table B2 of appendix B lists the major federal and state permits, approvals, and consultations for construction and operation of the Project and provides the current status of each. CCL would be responsible for obtaining and abiding by all permits and approvals required to construct and operate the Project regardless of whether they appear in this table.

B. 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 CCL's application and its responses to our requests for environmental information, scientific literature, regulatory agency reports, and stakeholder comments. Further, certain environmental impacts, where applicable, for the proposed Project would remain unchanged from those analyzed in the 2014 FEIS under Docket No. CP12-507-000 and the 2019 EA under Docket No. CP18-512-000.

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 3 years following construction. An impact is considered long-term if the resource would require more than 3 years to recover. A permanent impact would occur if an activity modified 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 because the land use and visual character would not return to preconstruction (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; therefore, significance would vary accordingly. An impact would be considered significant if it would result in a substantial adverse change in the physical environment.

The analysis contained in this EA is based upon CCL's application and supplemental filings and our experience with the construction and operation of natural gas infrastructure. However, if the Project is approved and proceeds to the construction phase, it is not uncommon for a project proponent to require modifications (e.g., minor changes in workspace configurations). These changes are often identified by a company once on-the-ground implementation work is initiated. Any Project modifications would be subject to review and approval from FERC's Director of the Office of Energy Projects (OEP), or the Director's designee, and any other permitting/authorizing agencies with jurisdiction.

Based on field surveys conducted by CCL in 2021, no wetlands, as defined in our Procedures, were identified within the Project workspace. Therefore, wetland resources are not discussed further.

1. Geology

The geological setting at the Project site is unchanged from that described in the 2014 FEIS and the 2019 EA.

1.1 Mineral Resources

Based on review of the U.S. Geological Survey (USGS) Mineral Resource Data System and aerial imagery, as well as CCL's knowledge of the Project area as a result of its local presence as an operator of the Liquefaction Project, there are no active, historic, or proposed surface or subsurface mines within 0.25 mile the Project workspace (USGS, 2011; Google Earth, 2023). According to Railroad Commission of Texas (RRC) database information, there is one dry hole within the RWL area. No other active, inactive, or historic oil or natural gas wells were identified within the RWL area (RRC, 2020). One natural gas well and one oil well are recorded in RRC database information as being within the previously authorized workspace for the Stage 3 Project; however, CCL states it has not observed any evidence of these wells during surveys or construction and operation of the CCL Terminal. Based on RRC database information, no additional active, inactive, or historic oil or natural gas wells are within 0.25 mile of the Project other than those described in the 2014 FEIS and the 2019 EA. The nearest salt dome to the Project area is the South Texas Salt Basin, located more than 50 miles southwest of the Project (Beckman and Williamson, 1990). Based on this assessment, we conclude that Project construction and operation would not impact the availability of or access to fuel and non-fuel mineral resources.

1.2 Geologic Hazards

Geologic hazards are natural, physical conditions that can result in damage to land and structures or injury to people. Such hazards typically include seismicity (e.g., earthquakes, surface faults, and soil liquefaction), landslides, flash flooding, coastal zone hazards, and ground subsidence. A discussion of geologic hazards is presented in appendix J; however, in general, there is a low probability for geologic hazards to significantly affect construction or operation of Project facilities.

2. Soils

All Project area soils are identified in table B3 of appendix B; however, baseline conditions and potential impacts on soils previously analyzed in the 2014 FEIS and the 2019 EA would be similar to those of the Project. Therefore, the subsequent analysis focuses on the RWL area that has not been previously reviewed and approved by the FERC. As identified in table B3 of appendix B, the entirety of the RWL area is classified as "waste land." This is a "miscellaneous area" classification by the Natural Resources Conservation Service, characterized as having little or no soil material and supporting little or no vegetation due to disturbance from previous industrial activities. Waste land is not rated by the Natural Resources Conservation Service for farmland classification, erodibility, revegetation potential, or compaction potential. This area was previously used for bauxite residue and ore storage associated with the historic Sherwin Alumina plant and was further modified through use as a Dredged Material Placement Area during construction of the Liquefaction Project.

2.1 Soil Contamination

CCL reviewed publicly available federal and state databases for potentially hazardous or contaminated sites within the Project area; there are no superfund sites or leaking petroleum storage tanks within 0.5 mile of the Project (EPA, 2023a; TCEQ, 2023a). As previously stated, the Project area was formerly used by the Sherwin Alumina plant for bauxite residue storage. Further discussion regarding the historical use of the site is presented in the 2014 FEIS and the 2019 EA. Bauxite residue is a waste product from refining raw bauxite and is characterized as a Class 2 non-hazardous industrial solid waste by TCEQ. As such, the site was formerly a Class 2 non-hazardous industrial solid waste facility (Facility 200) but has since been capped with dredged material and administratively closed in coordination with TCEQ.[11]

The Project area also contains the RWL, a man-made above grade structure used by Sherwin Alumina company for bauxite residue storage and raw water.[12] The RWL is currently being remediated by Cheniere Land Holdings, LLC (CLH), an affiliate of CCL, in accordance with TCEQ industrial solid waste requirements under 30 Texas Administrative Code (TAC) 335.8, and CCL state they would not utilize the RWL during Project construction or operation until remediation is complete. Remediation activities include waste removal, backfill, and grading of the RWL, and capping the waste material in the southwest portion with clean clay material. As remediation would conclude before the utilization of the RWL, the Project is not anticipated to disturb or spread associated contaminated materials. However, in

11 Closure of Facility 200 was confirmed via letter from TCEQ on September 10, 2019. This document can be viewed on FERC's eLibrary as attachment 10 of accession number 20231023-5112.

12 Raw water is water that has not been chemically treated to remove particles, bacteria, minerals, or other impurities.

the event bauxite residue waste materials are encountered during construction, CCL would segregate and contain the contaminated material within an on-site solid waste management unit for final disposition as a Class 2 non-hazardous industrial solid waste.

2.2 Soil Impacts and Mitigation

The Project area has been highly modified by previous industrial activity, is largely unvegetated, and would remain unvegetated following construction; therefore, revegetation potential would not be a concern. Additionally, most of the Project would be constructed atop an elevated Dredged Material Placement Area that was previously used for placement of material dredged from the marine berths for the CCL Terminal. As such, Project activities would not encounter shallow bedrock, are unlikely to encounter stony/rocky soils, and would not significantly contribute additive impacts on soil compaction. The primary Project impacts on soil resources could result from erosion during construction.

CCL would implement erosion and sedimentation controls in accordance with the FERC Plan and an updated Erosion and Sediment Control Plan, utilized during the Stage 3 Project. Temporary erosion controls would be installed immediately following land disturbing activities. CCL would inspect these devices on a regular basis and after each rainfall event of 0.5 inch or greater to ensure proper function. CCL would additionally utilize dust-control measures, including routine wetting of the construction workspace, as necessary, where soils are exposed; as presented in the FDCP.[13] Upon completion of construction, all Project areas would be stabilized with pavement or gravel, which would minimize erosion during operation. Temporary erosion control devices would be maintained until the Project area is successfully stabilized. Therefore, given CCL's mitigation measures that would be implemented during construction as described above, we conclude that Project impacts on soils during construction and operation would not be significant.

3. Water Resources and Wetlands

3.1 Groundwater

Baseline conditions and potential impacts on groundwater quality and availability analyzed in the 2014 FEIS and the 2019 EA are similar to those of the Project.

Water supply wells have not been identified within 150 feet of the Project during previous field surveys or construction activities related to the Liquefaction and Stage 3 Projects. The nearest public and private water supply wells are approximately 3 miles and 2 miles from the Project site, respectively (Texas Water Development Board, 2022a, 2022b). The Project would not overlie a sole source aquifer, as designated by the EPA, and there are no locally zoned aquifer protection areas or springs within the Project area (TCEQ, 2023b; San Patricio County Groundwater Conservation District, 2023; Corpus Christi Aquifer Storage and Recovery Conservation District, 2018; EPA, 2023b).

Known or Potential Occurrences of Contaminated Groundwater

A search of the TCEQ Groundwater Contamination Viewer located three instances of groundwater contamination within 0.25 mile of the Project site, as identified in table B.3-1 below.

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[13] CCL's FDCP can be viewed on FERC's eLibrary as appendix 9C of accession number 20230330-5209.

Table B.3-1 Groundwater Contamination within 0.25 mile of the CCL Midscale Trains 8 & 9 Project Area					
Name of Responsible Party	**Type Of Contamination**	**TCEQ File #**	**Location**	**Distance / Direction from the Project**	**Status**
The Koch Pipeline	Total petroleum hydrocarbons and benzene, toluene, ethylbenzene and xylene	5140	La Quinta Road	Within Project workspace	Active as of 2021
Reynolds Metals San Patricio Plant	Heavy metals	32027	South Highway 361	Within Project workspace	Active as of 2021
Corpus Christi Alumina	Diesel fuel	120676	South Highway 361	0.13 mile southeast	Active as of 2021
Source: TCEQ, 2023a					

The sites of groundwater contamination identified above in table B.3-1 are outside the direct footprint of the proposed Project facilities (i.e., the two midscale trains, refrigerant storage, (EFG) unit, and BOG compressor) where no excavation or other interfaces with groundwater are anticipated.

In addition to the sites identified in table B.3-1 above, the Project site was used to store bauxite residue for the now decommissioned Sherwin Alumina plant. CCL stated that, per a letter from the TCEQ, previous investigations in the area south of the Stage 3 Project revealed that the alkaline process waters contained elevated concentrations of arsenic, leached out of the bauxite residue causing an impact to the shallow groundwater zone. As discussed in the 2019 EA, the letter from the TCEQ indicated that the groundwater in the area is not suitable for human consumption, regardless of the arsenic concentration, so active groundwater remediation would not be required by the TCEQ.

CCL maintains a groundwater monitoring program and a groundwater management plan, which details groundwater containment and disposal guidelines as well as practices that would be implemented in areas of known groundwater contamination.[14] Groundwater monitoring wells are not present within the direct footprint of the proposed Project facilities. While wells do occur within the construction workspace, these are protected by bollards and impacts are not anticipated.

Groundwater Impacts and Mitigation

Based on geotechnical studies and data from onsite monitoring wells, shallow groundwater in the Project area occurs at approximately 15 feet below natural ground surface, which is at an elevation of +24 feet North American Vertical Datum 1988 (NAVD88). Most of the Project would be constructed atop an elevated dredged material placement area at a finished grade elevation of +49 feet NAVD88 (about 25 feet above natural ground surface) that was previously used for placement of material dredged from the marine berths for the CCL Terminal. The anticipated deepest excavation for the Project is +26 feet NAVD88, which is about 23 feet below the finished grade elevation of +49 feet NAVD88. Therefore, the planned depth of the deepest excavation would occur 17 feet above shallow groundwater. If shallow perched water is encountered during excavations, it would be pumped out of excavations and managed as affected groundwater (as applicable) in accordance with CCL's groundwater management plan for arsenic affected groundwater.

[14] The management plan for arsenic affected groundwater was coordinated with the TCEQ and was originally filed as privileged with FERC in response to a condition of the Stage 3 Project Order. This plan remains privileged and was re-filed with the Project's application as appendix 2A of accession number 20230330-5209.

The Project would require the installation of drilled piling to an approximate maximum depth of +6 feet NAVD88. At this depth, the pilings may intercept shallow groundwater but would not breach the confining layer between shallow groundwater and the deeper aquifer system. In addition, CCL plans to utilize drilled displacement piles. This pile type displaces soil laterally into the surrounding formation, minimizing cross contamination between soils at different depths.

Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment could adversely affect groundwater. CCL would implement its SPCC Plan that includes measures to minimize the potential impacts of spills of hazardous materials.[15]

Due to the non-potable saline groundwater conditions that naturally occurs at the site, lack of water supply wells in the area, and mitigation measures that would be implemented by CCL in the event of spills during construction, we conclude impacts on the groundwater resources underlying the Project would be minor and not significant.

3.2 Surface Water

Existing Surface Water Resources

The Project is in the North Corpus Christi Bay watershed (Hydrologic Unit Code [HUC] 12110201). The proposed Project would be constructed within areas formerly used for industrial purposes; however, several small, ephemeral ditches and ponds occur within the Project site. These waterbodies were determined by the COE to be non-jurisdictional under the CWA on June 15, 2016, in association with the CCL Terminal, as they were excavated from uplands. CCL requested an updated Approved Jurisdictional Determination from the COE on July 7, 2022 and received determination on March 8, 2023. No impacts to COE jurisdictional waterbodies or FERC-defined waterbodies are anticipated to occur from construction or operation of the proposed Project.

The RWL was registered with the TCEQ Dam Safety Program until 2021 when it was formally released from the program. Water levels have fluctuated over the years from evaporation and rainfall but have maintained high pH and elevated levels of alkalinity and arsenic concentrations due to the past use. In 2022, CLH began managing water levels by treating and discharging under a TCEQ permit issued on October 28, 2021. On March 8, 2023, CCL received a letter with a determination that the RWL is not a Water of the United States and is not subject to COE jurisdiction.

Water Use During Operations

Water used during Project operation, including potable water, utility water, and demineralized water would be supplied directly from the San Patricio Municipal Water District (District) to the Project area via the existing CCL Terminal infrastructure and would be intermittent or periodic in nature. Approximately 170,000 gallons and 175,000 gallons of potable water and utility water, respectively, would be used annually during Project operation. Usage of demineralized water during Project operation is estimated, under normal operating conditions, to be 1.1 gallons per minute (gpm), which equates to approximately 600,000 gallons per year. The peak flow rates of potable water, utility water, and demineralized water during Project operation are 53 gpm, 130 gpm, and 54 gpm, respectively. Potable water would only be used for safety showers and emergency eyewash stations; employees would use existing facilities for all other uses of potable water. Utility water would be required for hose stations around the facility as well as for sample coolers. Demineralized water would be used in the pre-treatment facilities located in the two liquefaction trains. We received a comment from the Sierra Club, et. al. concerned with impacts on water supply resulting from the Project. CCL states they have a long-standing business relationship with the District, which includes collaboration on water supply and demand related matters, and would communicate proactively with the District to minimize CCL's impact to water supply

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15 CCL's SPCC Plan for the Project can be viewed on the FERC eLibrary as Appendix 2B of accession number 20230330-5209.

and District operations. Further, CCL states they would work with the District and its' other customers, most notably municipalities, in the service area prior to and during times of drought and/or peak demand to promote reliability of the overall supply.

Public Water Supplies

The Project is not within a source water protection area (District, 2023). Public water in the area is supplied from the Nueces River and Navidad River/Lake Texana via the District. A water treatment complex maintained by the District is located on SH 361, just east of the Project workspace, and includes two small, lined surface reservoirs (Naismith and Plant B reservoirs) (District, 2023). The water intake for the Naismith Reservoir is about 600 feet north of the Project construction workspace and the intake for the Plant B reservoir is about 800 feet southeast of the construction workspace (District, 2023). The surface reservoirs are protected from and not affected by drainage from adjacent areas; therefore, the Project is not anticipated to impact the reservoirs.

Hydrostatic Test Water and Stormwater Discharge

The total cumulative volume of water required for hydrostatic testing and dust suppression would be about 500,000 gallons and 600,000 gallons, respectively and would be obtained from the District. Water from an on-site stormwater detention pond, Lake Dressen, may also be used for dust suppression. Lake Dressen was tested in the past and was determined to be suitable for dust suppression. No chemical additives are expected to be used during hydrostatic testing or in water used for dust suppression.

Hydrostatic test water would be discharged into La Quinta Ditch to the west of the proposed site, authorized under CCL's existing Texas Pollutant Discharge Elimination System Permit. Discharge of hydrostatic test water to alternative locations not already authorized under CCL's existing permit would be eligible for authorization under Texas Pollutant Discharge Elimination System General Permit. Further, small volumes of hydrostatic test water may be discharged to the ground surface on-site when used for dust suppression, which would require a minor permit issued by the RRC. Pumps control the discharge rate of the hydrostatic test water. Energy dissipation devices, such as a splash plate or hay bale structures, would be used during discharge of the hydrostatic test water, to prevent scouring and erosion, per our Procedures. Given CCL would implement measures in relevant permits and our Procedures, impacts to and from water usage and impacts from discharges would be sufficiently minimized.

Stormwater discharges from construction and operation of the Project would be exempt from industrial stormwater permitting. CCL would file an update to the Stage 3 Project's Erosion and Sedimentation Control Plan to include the proposed Project components as part of the Project's implementation plan.

Sensitive Surface Waters

Corpus Christi Bay is a sensitive surface waterbody for water quality and important ecological and habitat elements and is designated in the National Estuary Program as an estuary of "national significance." Based on the TCEQ Draft 305(b) Water Quality Inventory, designated uses for Corpus Christi Bay are Contact Recreation, Aquatic Life, Fish Consumption, Oyster Waters, and General Use. All designated uses that were assessed in the 305(b) inventory are fully supported and Corpus Christi Bay is not considered impaired (TCEQ, 2022). Indirect impacts from turbidity due to vessel traffic during construction and operation of the Project would temporarily impact Corpus Christi Bay. However, due to the temporary and intermittent transit of the proposed increase in LNGCs (up to an additional 80 LNGCs per year), no significant, permanent impacts would result from construction and operation of the Project.

Surface Water Impacts and Mitigation

Temporary and minor surface water impacts could result from the construction and operation of the Project. In compliance with the Procedures, CCL would implement their SPCC Plan for fuel and related oil storage to prevent or reduce the likelihood of a spill during construction and would provide for prompt identification and proper removal of contaminated materials if a spill were to occur.

We received comments concerned with the Project's impacts on water quality resulting from the increase of LNGC traffic, ballast, and cooling water discharge. As discussed in section A.6.5, the Project would increase the maximum marine vessel traffic from the currently authorized 400 LNGCs per year, up to 480 LNGCs per year. LNGC transits would include the Gulf of Mexico, a portion of the CCSC between Port Aransas and Ingleside, and the La Quinta Ship Channel. The CCSC and La Quinta Ship Channel are federally authorized and maintained deep draft navigation channels. Additionally, the Commission does not have jurisdiction over LNGCs. Baseline conditions and potential impacts on surface water quality regarding vessel traffic and ballast and cooling water discharge analyzed in the 2014 FEIS and the 2019 EA are similar to those of the Project. Discharge of ballast and cooling water may result in a temporary increase in water salinity and temperature (respectively) within the marine berth; however, the discharged water would quickly disperse and diminish shortly after discharge, and return to ambient levels. Potential impacts from discharge of ballast and cooling water on aquatic resources are discussed in section B.4.2.

The proposed increase of LNGC traffic is not anticipated to result in significant impacts to surface water quality in the Project area. Additional information on vessel traffic is discussed in section B.7.1.

Through implementation of CCL's proposed best management practices (BMPs) and the measures in its SPCC Plan, state permit requirements, and our Procedures, potential impacts resulting from stormwater runoff, the discharge of hydrostatic test water, or other impacts as discussed in the above sections would be adequately minimized and/or avoided, and not significant.

4. Vegetation, Wildlife, and Threatened and Endangered Species

4.1 Vegetation

The Project area is primarily industrial, consisting of bare ground with improvements, and largely devoid of vegetation. The vegetation present in open land portions of the Project area (about 184 acres) consists of herbaceous cover interspersed with scattered shrubs; these areas were previously used for parking and laydown during construction of the CCL Terminal. No clearing of previously undisturbed vegetation communities would occur for the Project and all permanent facilities proposed for the Project are within industrial areas. Once construction is completed, the RWL area would be converted to permanent industrial land use. CCL anticipates that all areas occupied by the proposed facilities, and areas disturbed during installation of those facilities, would be finished with pavement or gravel. Therefore, we conclude that impacts on vegetation would not be significant.

Exotic or Invasive Plant Communities and Noxious Weeds

Based on a review of available data, eight noxious weeds or invasive plant species could potentially occur within the Project area: balloon vine, Brazilian peppertree, Chinese tallow tree, giant reed, salt cedar, water hyacinth, water lettuce, and chinaberry (Texas Invasive Database, 2023; U.S. Department of Agriculture, 2023; University of Georgia, 2023). Based on field surveys conducted by CCL in August and December 2021, none of these noxious weeds or invasive species were identified. CCL would use measures outlined in our Plan and Procedures to minimize risk of invasive species and monitor disturbed areas for invasive species.

4.2 Wildlife and Aquatic Resources

Wildlife

The current wildlife and aquatic resources found in the vicinity of the CCL Terminal and Project facilities are similar to that described in the 2014 FEIS and the 2019 EA. The Project area is highly disturbed, currently industrialized, and as such, does not support abundant wildlife, species diversity, or quality habitat for wildlife. Although, some portions of the area may still be occupied by more opportunistic wildlife species or those that are tolerant of bare ground, disturbed habitat types, and ongoing human disturbances.

We received comments from TPWD, NGOs, and individuals during the scoping period concerned with potential impacts on wildlife from construction and operation of the Project. Potential impacts on wildlife include increased noise, lighting, human presence, and loss of habitat. Other impacts such as incidental take of wildlife, would be minimal due to the current disturbed nature of the site. For opportunistic species that thrive in disturbed habitats, the areas nearby and adjacent to the site provide similar habitats, and wildlife that would be displaced by the Project would likely move to adjacent habitats. CCL would adhere to certain mitigation measures and recommendations from FWS and TPWD for special status species, as discussed in section B.4.3 below. Some mitigation measures CCL would implement to minimize impacts on wildlife include installing sediment and erosion control measures in compliance with our Plan and Procedures; the use of minimal and down-shielding lights (see sections B.4.3 and B.6.2); and daily rounds of inspections of any open trenches by a dedicated EI to ensure no wildlife species have been trapped.

A spill of hazardous materials during construction could adversely affect any lifeforms that encounter these materials, resulting in potential mortality of individuals or exposed populations. CCL would follow our Plan, Procedures, and the Project's SPCC Plan to avoid and minimize the risk of hazardous spills from occurring, as well as minimize the exposure of any hazardous materials to adjacent environments.

Aquatic Resources

We received multiple comments during the scoping period concerned with the Project's impacts on aquatic resources. Although the Project would not include any in-water work, alteration to any shoreline, or marine habitats; CCL proposes to increase the maximum marine vessel traffic from the currently authorized 400 LNGCs per year, up to 480 LNGCs per year. FERC and CCL have no authority over the navigation or operations of LNGCs. LNGCs are required to adhere to all applicable U.S. laws, regulations, and policy documents (e.g., the CWA and the Act to Prevent Pollution from Ships) related to maritime transport and given that the potential impacts to marine resources are associated with vessels in transit, mitigation criteria are predetermined by the applicable authority.

<u>Marine Fisheries and Essential Fish Habitat</u>

We received multiple comments from Ingleside on the Bay Coastal Watch Association, Inc. and multiple individuals concerned with Project impacts on essential fish habitat (EFH), including seagrasses. The Gulf of Mexico, surrounding estuarine waters, and seagrass communities support a diversity of fishery resources typically consist of species found in both estuarine and offshore oceanic habitats. LNGC transits would include the Gulf of Mexico, a portion of the CCSC, Port Aransas, Ingleside on the Bay, and the La Quinta Ship Channel. The most currently available geospatial data for seagrass communities within the channel from the TPWD Geographic Information System indicates several seagrass areas within the shallow margins of Redfish Bay and adjacent shoreline and spoil islands (TPWD, 2022a). Seagrass communities include shoal grass, star grass, manatee grass, turtle grass, and widgeon grass and function as nursery habitat for commercially important fishes and crustaceans (TPWD, 2022a). The Project would not include any in-water work or alteration to any shoreline or marine habitats, including seagrass communities that may support established marine fisheries.

The Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires federal agencies to consult with NOAA Fisheries on all actions or actions authorized, funded, or undertaken by the agency that may adversely impact EFH. The MSA defines EFH as "those waters and substrate necessary to fish for spawning, breeding, feeding, or growth to maturity" (16 U.S.C 1802 [10]). In a scoping letter dated December 15, 2022, NOAA Fisheries stated that because the Project lacks in-water activities which would impact EFH, and accounting for any support vessels used for construction and operation of the Project, no further consultation is required for the Project under the MSA unless there is a change in the Project scope.

Aquatic Resources Impacts and Mitigation

The discharge of ballast water from the 80 additional LNGC visits per year could impact marine organisms through the unintentional introduction of non-indigenous aquatic organisms. To minimize and avoid potential impacts to wildlife species that could result from ballast water discharges, the Coast Guard has inspection and regulatory enforcement jurisdiction over all shipping in U.S. waters and would require all LNGCs visiting the Project (and all other U.S. waters) to adhere to all applicable ballast water management rules and regulations. LNGCs would need to adhere to the guidelines listed in the Coast Guard Office of Operation and Environmental Standards' *Mandatory Practices for All Vessels with Ballast Tanks on All Waters of the U.S.* and compliance with Coast Guard ballast water regulations (33 CFR Part 151, subpart D and 46 CFR 162.060). To minimize and avoid potential impacts on marine species from ballast water discharges, CCL would request visiting vessels to provide documentation to demonstrate their compliance with ballast water regulations and BMPs.

Cooling water impacts would be similar to those described in the 2019 EA. No significant effects on marine organisms from elevated temperatures resulting from the periodic discharge of cooling water from LNGCs during loading while at the berth are anticipated to occur. Further, discharges of cooling and hoteling water are regulated under the Vessel Incidental Discharge Act.

The increased LNGC traffic has the potential to adversely impact marine resources in the event of an accidental release of a hazardous substance such as fuel, lubricants, coolants, or other materials on board the vessel. LNGCs are outside of the Commission's jurisdiction; however, the Coast Guard requires LNGCs to develop and implement a Shipboard Oil Pollution Emergency Plan, which includes measures to be taken when an oil pollution incident has occurred, or a ship is at risk of one.

With adherence to the rules, regulations, and BMPs for ballast water discharge, cooling water discharge, and inadvertent spills, as well as the implementation of vessel strike avoidance measures, we conclude the Project would not have a significant impact on aquatic resources.

4.3 Threatened and Endangered Species and Other Protected Species

Protected species and special status species are afforded protection by law, regulation, or policy by federal and state agencies. Protected species and special status species include marine mammals; migratory birds, including bald and golden eagles; federally listed threatened and endangered species that are protected under the ESA; and state-listed species.

Marine Mammals

The Marine Mammal Protection Act serves to protect all marine mammals, both in coastal waters and on the high seas. Thirty species of marine mammals have been observed in the Gulf of Mexico, eight of which are also listed as threatened or endangered by FWS and National Marine Fisheries Service (NMFS) (see table B4 of appendix B).

Vessel traffic can result in strikes with marine species, which can cause mortality, injury events, increased stress levels, and/or avoidance of the area. Due to their preference for offshore waters and their relative rarity in Texas waters, the occurrence of federally listed marine mammals within the Project area would be limited to the portion of the LNGC transit route through the Gulf of Mexico between Aransas Pass and the Exclusive Economic Zone. In general, LNGCs move slowly and make more noise than other vessels, allowing them to be more easily avoided by mobile wildlife. To minimize potential vessel strikes, CCL would provide LNGC captains with a web link to the NMFS and Coast Guard issued documents, notices, and regulations addressing vessel strike avoidance measures and reporting requirements, including the NMFS Vessel Strike Avoidance Measures. The measures listed above would also be implemented for any barges used to deliver materials to the site during construction. As a result, significant impacts on marine mammals associated with vessel traffic during construction are not anticipated. Additional measures designed to avoid or minimize vessel strikes of the West Indian manatee in nearshore waters within Corpus Christi Bay would be identical to measures described in the 2019 EA.[16]

Migratory Birds

On March 30, 2011, the FWS and the Commission signed a MOU that focuses on avoiding or minimizing adverse effects on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the two agencies. Additional information regarding federal protections of migratory birds is discussed in the 2014 FEIS and 2019 EA.

Table B5 of appendix B lists the Birds of Conservation Concern that have some probability of occurring in the general region in or near the Project, and the breeding season for each within the Project region. Suitable habitat for these species is not present within the Project site due to the highly disturbed and industrial nature of the site; however, suitable habitats are present in the general region near the Project and as a result, these species may pass through the Project area while transitioning between suitable habitats.

There are no bald eagle nests known to occur near the Project area. In addition, bald eagles were not identified as species of concern by the FWS or TPWD during review of the Project.

We received comments from NGOs and individuals concerned with the Project's impacts on migratory birds. The Project is in a highly industrialized area. The high amount of human activity on the site and surrounding properties likely limits the extent of migratory bird use of these marginal habitats. The new structures, the tallest being the flash gas column at approximately 165 feet above grade, would be easily visible to avian species, and it is likely that avian species would avoid these new structures while in flight; however, some limited avian impacts during flight could occur which could result in individual avian mortalities.

The Project would not include construction of new flares but would use the existing CCL Terminal flares and the previously authorized Stage 3 Project ground flares. The Project would result in occasional and intermittent flaring from the existing authorized flares; and therefore, would have an increase in flaring activity. These flaring events could impact some migratory birds, during the event (e.g., if a bird was resting on the ground flare prior to or during a flaring event) but are not expected to result in a population level effect. Notably, the Stage 3 Project ground flares are surrounded by a 45-foot-tall fence, with the actual flare equipment at 9 feet above ground level. This flare design contributes to a low likelihood of direct interactions between birds and the flare equipment.

Additionally, we received a comment during the scoping period from an individual concerned with impacts from facility lighting on migratory birds. Artificial lighting can interfere with the behavior of nocturnal migrating birds, causing disorientation and collisions with over-lit structures. The Project would use the minimum lighting necessary to allow personnel to safely work and inspect the equipment. New permanent lighting would be required for operation of the Project but would be consistent with the lighting at the existing CCL Terminal. Additional details on lighting impact mitigation are discussed below.

On January 25, 2023, CCL received recommendations from FWS on ground disturbance and clearing. If mechanical vegetation clearing or ground disturbance in vegetated areas is required between March 15 and September 15, CCL states it would conduct nesting bird surveys no more than 5 days prior to the clearing or ground disturbance and look for birds, nests, and eggs. If active nests are found, CCL

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16 Measures to avoid or minimize vessel strikes of the West Indian manatee are presented in section B.4.2.2 of the 2019 EA, which is available on the FERC eLibrary under accession number 20190329-3010.

would leave a buffer of vegetation at least 100 feet around nests (0.5-mile buffer for nesting raptors) until young have fledged or the nest is abandoned.

CCL would avoid or minimize impacts on migratory birds by monitoring for and avoiding active nests during construction, including ground nests; using light systems with minimum intensity, using maximum off-phased white strobe lighting as per Federal Aviation Administration (FAA) regulations; down-shielding lights on the facilities, marking guy wires with visual markers/bird diverters, and use of ground flares instead of elevated flare stacks. These measures can reduce the likelihood of avian collisions with structures, as well as the likelihood of disturbing individuals found in adjacent habitats.

We conclude that the Project would not result in significant impacts on migratory birds.

Federally Listed Species

The Commission is required by Section 7 of the 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. CCL acting as our non-federal designee used FWS and TPWD online sources to identify federally and/or state listed threatened and endangered species that could potentially occur in the Project area, including the portion of the Gulf of Mexico traversed by LNGCs. No ESA designated critical habitat has been identified within the Project workspace area. Transit of LNGCs would occur in loggerhead sea turtle critical habitat (LOGG-S-2, Gulf of Mexico Sargassum). However, because there would be no disturbance of the water bottom in areas of critical habitat, utilization of the routes by LNGCs would have *no effect* on the designated critical habitat.

Twenty-two species are federally listed as threatened or endangered in San Patricio County, including two fish, five turtles, five birds, one mammal, seven marine mammals, and two plants (see table B6, appendix B). In addition, one species, the monarch butterfly, is a candidate species for listing. Of these species, 10 are under the jurisdiction of the FWS and 13 are under the jurisdiction of NMFS.

The Project would have *no effect* on the oceanic whitetip shark, northern aplomado falcon, ocelot, slender rush-pea, and South Texas ambrosia. Additionally, the Project would *not contribute to a trend toward federal listing* of the monarch butterfly.

The Project *may affect, but is not likely to adversely affect* the giant manta ray, Atlantic hawksbill sea turtle, green sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, black rail, piping plover, rufa red knot, whooping crane, North Atlantic right whale, fin whale, sei whale, blue whale, sperm whale, rice's whale, and West Indian manatee through the implementation of minimization and avoidance measures proposed by CCL.

The giant manta ray and North Atlantic right whale are the only species that the Project may affect that were not previously analyzed in the 2019 EA. Discussions as well as a description of potential impacts on these two species are presented below. Summaries and potential impacts and mitigation measures for the federally listed reptile, bird, and remaining mammal species that may be affected by the Project would be similar to what was discussed in the 2019 EA.

<u>Giant Manta Ray</u>

The federally threatened giant manta ray is commonly found offshore; however, it has been observed in estuarine waters near oceanic inlets, with the use of these waters as potential nursery grounds (NMFS, 2023). There is no designated critical habitat for this species (NMFS, 2020). Threats to the giant manta ray include overutilization for commercial purposes and being caught as bycatch in fisheries throughout their range.

Potential Project-related impacts on the giant manta ray could occur due to increased LNGCs in the shipping channel during construction and operation of the Project. The giant manta ray is a surface-oriented species and is therefore somewhat susceptible to LNGC strikes; however, the LNGCs create a very large bow wave which is likely to push animals such as turtles and mantas up and away from the vessel. Therefore, it is unlikely that the increase in vessel traffic would result in an increase in vessel strikes on the giant manta rays. The LNGCs and barges/other vessels carrying construction equipment would use established and well-traveled shipping lanes. Impacts on the manta ray would be minimized through the implementation of measures similar to those discussed above for marine mammals. Therefore, we have determined that the Project *may affect, but is not likely to adversely affect* the giant manta ray.

North Atlantic Right Whale

This whale is primarily found in Atlantic coastal waters on the continental shelf, but they are known to travel farther offshore into deep waters (NOAA, 2022). Potential impacts on the North Atlantic right whale as a result of the Project could result from the increase in LNGC vessel traffic through vessel strikes, accidental spills of hazardous materials, and vessel usage of ballast and cooling water. Impacts on the North Atlantic right whale would be minimized through the implementation of measures similar to those discussed in the marine mammal section above. Therefore, we have determined that the Project *may affect, but is not likely to adversely affect* the North Atlantic right whale.

Conclusions

The scope of effects that could occur to species would be similar to the previously authorized CCL Terminal. In addition, the Project would comply with applicable requirements found in our Plan and Procedures and requirements outlined in past FERC Orders and authorizations for the CCL Terminal. In addition, an EI would be onsite during construction to ensure that listed species (including but not limited to Texas horned lizards, as discussed below as a state listed species) observed are either allowed to safely leave the site or are safely relocated. It is anticipated that the increased LNGC traffic resulting from the Project would comply with all requirements of the International Maritime Organization and Coast Guard during transit to and from the CCL Terminal.

The Project area has little to no suitable habitat available for threatened and endangered species. CCL received concurrence from the FWS on January 25, 2023, stating they agree with the determinations of *may affect but is not likely to adversely affect*. FWS does not provide concurrence letters for *no effect* determinations. CCL would continue to work with both FWS and TPWD should any threatened or endangered species be within the Project site. In a letter dated February 15, 2024, NMFS concurred with the conclusion that the proposed Project is not likely to adversely affect ESA-listed species under NMFS jurisdiction and/or designated critical habitat. Given the lack of or minimal suitable habitat available, the avoidance and minimization measures that CCL would implement as part of the Project, and FWS's and NMFS's concurrence, we conclude that impacts on federally listed species would not be significant.

State Listed Species

There are 27 state-listed threatened or endangered species identified by the TPWD as potentially occurring in San Patricio County or that could be present along vessel transit routes. Table B7 of appendix B summarizes these species. CCL determined that the Project would have *no impact* on one fish species, two amphibian species, five bird species, and two mammal species due to lack of suitable habitat. Construction and operation of the Project would *not likely adversely impact* the remaining species, inclusive of 3 reptile species, 3 bird species, and 11 marine mammal species.

On August 15, 2022, CCL initiated consultation with TPWD, introducing the Project and requesting information on resources under TPWD's jurisdiction. On September 26, 2022, TPWD responded with their recommendations and CCL provided TPWD with their proposed measures of protection of resources on November 17, 2022. On December 11, 2023, TPWD determined CCL's responses to agency recommendations/comments were acceptable.

As discussed above for federally listed species, the scope of effects that could occur to species would be similar to the previously authorized CCL Terminal and the avoidance and minimization measures discussed above for federally listed species would also minimize and/or avoid impacts on state-listed species. No additional measures outside of those previously discussed would be followed to protect state-listed species. Given the existing industrial nature of the Project area and the avoidance and minimization measures that CCL would implement as part of the Project, we conclude that impacts on state-listed species would not be significant.

5. Cultural Resources

Section 106 of the NHPA, as amended, requires the FERC to take into account the effects of its undertakings on properties listed, or eligible for listing, on the NRHP, and to afford the Advisory Council on Historic Preservation an opportunity to comment. CCL, as the non-federal party, is assisting the FERC in meeting our obligations under Section 106 by preparing the necessary information, analyses, and recommendations, as authorized by 36 CFR 800.2(a)(3) and FERC's regulations at 18 CFR 380.12(f).

Area of Potential Effects

The Project 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)). The Project APE includes the construction footprint, or direct APE, as well as the indirect APE that could be affected by the installation of visual or atmospheric, and, in some cases, physical elements that would alter a property's setting and feeling.

The Project's APE for direct effects is limited to the area where ground disturbance will or could take place and is comprised of previously authorized workspace and additional workspace totaling 1,737 acres. The Project's APE also includes an area in which historic structures lie within a direct line of sight within a 0.25-mile-wide buffer from the Project area boundary.

Unanticipated Discoveries Plan

CCL provided a plan addressing the unanticipated discovery of cultural resources or human remains during construction to the FERC and State Historic Preservation Officer. We requested revisions to the plan. CCL submitted a revised plan which we find acceptable. The Texas State Historic Preservation Officer has yet to provide their concurrence of the plan.

Texas Historical Commission Consultations

As the Project includes a combination of previously authorized workspace, and additional workspace situated entirely within a heavily developed industrial setting, Phase I cultural resources inventory surveys were deemed not warranted. CCL sent a letter to the Texas Historical Commission (THC) on August 15, 2022, requesting concurrence with the recommendation that the Project would have no impacts to historic properties. In correspondence dated September 9, 2022, the Texas Historical Commission provided a determination that the Project would have no impact to historic properties, and no further work is warranted for the Project. We also concur.

Tribal Consultation

CCL sent letters to three federally recognized tribes on August 15, 2022, which included a Project description and maps. CCL requested any information or concerns regarding places of traditional or cultural significance that may be present within the Project area. CCL contacted the following tribes: Tonkawa Tribe of Indians of Oklahoma, Wichita and Affiliated Tribes, and the Caddo Nation. We further requested that CCL send letters requesting any information or concerns regarding places of traditional or cultural significance to the following tribes not previously contacted by CCL: Apache Tribe of Oklahoma, Comanche Nation of Oklahoma, Jicarilla Apache Nation of New Mexico, Kickapoo Tribe of Oklahoma, Kickapoo Traditional Tribe of Texas, and Kiowa Indian Tribe of Oklahoma. On August 8, 2023, CCL sent letters to these six additional tribes as well as the Mescalero Apache Tribe of New

Mexico, Ysleta Del Sur Pueblo, and Kickapoo Tribe of Kansas. To date, no responses have been received from contacted tribes.

Status of Compliance with the National Historic Preservation Act

No Native American traditional cultural properties, sacred sites, aboriginal burials, or objects of cultural patrimony have been identified to date within the APE by the Texas Historical Commission, or an interested Indian tribe. FERC has completed its compliance requirements with Section 106 of the NHPA for the proposed Project.

6. Land Use, Recreation, and Visual Resources

6.1 Land Use

Table B.6-1 lists land uses that would be affected by construction and operation of the Project.

Table B.6-1
Land Use Affected by the CCL Midscale Trains 8 & 9 Project

Land Use	Operations/Construction			Construction Only			Total Workspace
	Previously Authorized Workspaces [a] [b] (Acres)	Additional Workspace (Acres)	Total Workspace (Acres)	Previously Authorized Workspaces [c] (Acres)	Additional Workspace (Acres)	Total Workspace (Acres)	
Open Land	35	0	**35**	149	0	**149**	**184**
Seasonally Flooded [d]	0	0	**0**	8	0	**8**	**8**
Industrial [e]	1,223	101	**1,324**	185	0	**185**	**1,509**
Open Water [f]	36	0	**36**	0	0	**0**	**36**
Total	**1,294**	**101**	**1,395**	**342**	**0**	**342**	**1,737**

[a] Workspaces authorized by FERC for construction and operation of the CCL Terminal under FERC Dockets CP12-507-000 & CP18-512-000.

[b] The direct footprint of the proposed Project facilities (about 39 acres) falls within land required to support Project Operations.

[c] Workspace authorized by FERC for construction of the CCL Terminal under FERC Dockets CP12-507-000 and CP18-512-000. Includes lands leased for construction staging and would not be used for long-term operations activities.

[d] Inland areas that may be seasonally flooded but are not considered jurisdictional waterbodies (feature 2E, table 2.3-1, Resource Report 2). No impacts are anticipated to occur to wetlands or waterbodies from construction or operation of the Project.

[e] Industrial areas includes 4 acres of dock space over water and features 15E, 16E, 5W and 6W represented in 2.3-1 of CCL's Resource Report 2.

[f] Previously authorized workspace includes about 36 acres of open water within Corpus Christi Bay that is included in this table for consistency with previous approvals, however this area would not be disturbed by the Project.

Land use in the Project area is categorized as industrial, seasonally flooded, or open land. Of the 1,395 acres that would support Project construction and operation, 1,324 acres are currently industrial use, and 35 acres are open land and primarily associated with the CCL Terminal. The RWL area adjacent to the existing CCL Terminal was previously part of the Sherwin Alumina processing facility. Other than the RWL area, no new land areas would be used to support construction or operation of the Project.

The additional 342 acres that would support construction of the Project include 149 acres of open land, 8 acres of seasonally flooded land and 185 acres of industrial land adjacent to the CCL Terminal which would be leased to support construction. The 342 acres that would be used to support construction are previously authorized construction workspace used for parking and laydown during construction of the CCL Terminal and would be used for similar purposes for the Project.

After construction, the 1,294 acres of previously approved workspace would be retained as part of the overall CCL Terminal operating footprint. Additionally, the RWL area not previously authorized would be incorporated into the overall CCL Terminal site footprint and would continue to be used as industrial land. While there is no operational infrastructure for the RWL area at present, its central location within the CCL Terminal would provide space for maintenance turnarounds and other operational support activities. CCL anticipates that all areas occupied by the facilities, and any other areas within the operational Project footprint during construction that are disturbed during installation of those facilities, would be finished with pavement or gravel. As such, no seeding or revegetation plantings are proposed within the operational footprint.

The 342 acres for construction only are leased from the Port of Corpus Christi Authority (PCCA) and CLH. The current condition of the PCCA owned lands consists of work areas stabilized with limestone road base and drainage improvements. A portion of the CLH-owned lands consists of work areas stabilized with limestone road base. This land was previously used for industrial activity and the Stage 3 Project has the option to use the land for construction laydown and parking. The PCCA and CLH plan to develop these leased areas for industrial purposes following Project construction. Per the landowner's request, no restoration would occur on leased properties.

Due to the industrial use of lands in the general vicinity and the previously disturbed nature of the surrounding area, impacts on land use from the Project would be minor and not significant.

6.2 Existing and Planned Residential and Commercial Development

Residential areas closest to the Project workspace include Gregory (0.08 mile north), Portland (0.2 mile southwest), and Ingleside (2.1 miles southeast). The residential areas in Gregory and Portland would be greater than a mile from the proposed Trains 8 & 9, which are sited toward the center of the property. The nearest commercial developments to the Project remain unchanged from that described in the 2019 EA.

LNGCs access the CCL Terminal via the CCSC from the open Gulf of Mexico through the CCSC entrance jetties at Aransas Pass, and up the La Quinta Ship Channel. Commercial activity in the channel consists of offshore drilling rigs and platforms, liquid bulk carriers and barges carrying chemicals and products to and from the chemical plants, and LNGCs travelling to and from the CCL Terminal.

There are no planned residential areas within 0.25 mile of the Project (San Patricio County Economic Development Corporation, 2022). The City of Corpus Christi has announced plans to construct the La Quinta Desalinization project along the La Quinta Ship Channel about 0.6 mile east of the CCL Terminal (City of Corpus Christi, 2022). No additional commercial developments were identified as being planned or under construction in the immediate Project area.

We received multiple comments during the scoping period from individuals concerned with the Project's impact on residential properties. In addition to gathering general feedback in public forums such as open houses and other community-based activities, CCL state they visited two waterfront properties owned by residents that have commented on the FERC docket for in-person discussions. Feedback received is summarized below:

- Recreational and commercial fishing – residents issued concern regarding reduced quality of recreational fishing and number of shrimps in the area in recent years.
- Erosion – residents reported erosion of submerged/intertidal land between their bulkheads and the top of slope of the La Quinta Ship Channel.
- Bulkhead overtopping - one resident described their bulkhead had been overtopped on numerous occasions by wakes from vessels transiting the CCSC; but that phenomenon has

not been observed since the Port recently completed construction of a protective island between the CCSC and Ingleside on the Bay.

- Vessel speed – residents are concerned about the speed of vessels transiting the channel and the effect of vessel speed on shoreline erosion.
- Property damage – one resident could not identify specific property damage related to vessel traffic but expressed concern over potential impacts that may be present but cannot currently be seen (such as potential undermining of bulkhead) and expressed they have observed subsidence landward of their bulkhead.

CCL state they would continue to engage with community members, including those in Ingleside on the Bay, and stakeholders regarding evaluation of shoreline trends and prospective mitigation alternatives, as needed. Feedback received would be taken into consideration by CCL during planning for avoidance, minimization, and mitigation of impacts to neighboring communities. CCL has participated in discussions with the PCCA and other waterway users regarding the interface between La Quinta Ship Channel and Ingleside on the Bay, with a focus on potential shoreline effects from vessel movements and other factors. Potential impacts from LNGC traffic are further discussed in sections B.7.1 and B.7.2.

Recreation and Special Interest Areas

There are no public, conservation, or special use lands within 0.25 mile of the Project site (TPWD, 2021; San Patricio County Economic Development Corporation, 2022). Additionally, there are no designated natural, recreational, or scenic areas, or National or State Wild and Scenic Rivers, or registered natural landmarks within 0.25 mile of the Project site (U.S. Department of the Interior, 2023).

Recreational fishing and boating occur in Corpus Christi Bay and in the La Quinta Ship Channel, and fishing takes place off piers along the shoreline in the Ingleside and Portland areas. Numerous charter fishing boats operate in Corpus Christi Bay, originating out of the communities of Corpus Christi, Ingleside, Port Aransas, Aransas Pass, and Rockport. Common species sought by recreational anglers in the bay are redfish, speckled trout, black drum, flounder, and sheepshead (Corpus Christi Convention & Visitors Bureau, 2022).

We received comments during the scoping period from individuals, including residents in Ingleside on the Bay, concerned with impacts to fishing, swimming, kayak, and boating opportunities within the La Quinta Ship Channel from existing and additional LNGC traffic. The proposed increase in LNGCs, when combined with existing vessel traffic within the La Quinta and CCSC, may impede or delay recreational boat traffic, although the impact is expected to be short term and minimal. LNGCs and other deep draft vessels are restricted to the existing deep draft navigation channels. Recreational users and boaters do not depend exclusively on the deep draft navigation channels; therefore, potential significant conflicts with recreational use and boating traffic are unlikely. Project impacts on recreation are discussed further in sections B.7.1 and B.7.2.

Visual Resources

The degree of visual impact potentially resulting from the Project is determined by considering the general character of the existing landscape and the visually prominent features of the facilities. The Project would not include construction of any new flares but would utilize the existing CCL Terminal flares and the previously authorized Stage 3 ground flares. The Project would result in occasional and intermittent flaring from the previously authorized flares and therefore would have an increased visual impact. All proposed facilities (i.e., the two midscale trains, refrigerant storage, EFG unit, and BOG compressor) would be within the existing CCL Terminal. The tallest feature proposed is the end-flash gas column, which would be approximately 165 feet above grade. CCL states the estimated view radius extends up to approximately 6 miles from the Project. CCL provided daytime and nighttime visual simulations from noise sensitive area (NSA) 6, as well as existing daytime conditions at various NSAs and at a western point of the Ingleside on the Bay community (see appendix D). Based on visual simulations and existing conditions, the proposed Project facilities would either be obscured by vegetation and/or existing infrastructure or would be consistent with the current industrial use and viewshed of the area.

We received a comment during the scoping period from Sierra Club et. al. concerned with the Project's lighting impacts on nearby residents. The Project would use the minimum lighting necessary to allow personnel to safely work and inspect the equipment. Lighting would be shared with the permitted Stage 3 Project to the extent practicable and impacts to the environment are expected to be minimal. New permanent lighting would be required for operation of the Project; the lighting and associated impacts would be consistent with the lighting at the CCL Terminal, as reviewed in the 2014 FEIS and 2019 EA.

The Project would not significantly alter the landscape of the region and would not result in significant changes to the existing viewshed. Therefore, we conclude that visual impacts would not be significant.

Coastal Zone Management

Section 307(c)(3) of the Coastal Zone Management Act requires that all federally licensed and permitted activated be consistent with approved state Coastal Zone Management Act Programs. CCL requested a Texas Coastal Management Program consistency determination for the Project on March 1, 2023, and on April 24, 2023, the RRC determined that a Texas Coastal Management Program consistency determination is not required for the Project.

7. Socioeconomics and Environmental Justice

7.1 Socioeconomics

Construction of the Project would have temporary and localized impacts on the socioeconomic conditions in the area of the Project based on the duration of construction activities (approximately 4 years under optimal conditions) and the distribution of the workforce across the Project area. The study area for this socioeconomic analysis includes San Patricio and Nueces Counties, where a majority of the Project workforce is anticipated to reside during construction and operation. Additional details on the existing population, economy, employment, tourism and recreation, housing, public services, and transportation and traffic in the region are summarized in section B.7 of the 2019 EA[17]; however updated data and discussions, as applicable, are presented below.

Population

Table B.7-1 provides a summary of current and projected populations of the potentially affected counties in the Project vicinity.

Table B.7-1
Population by County and State

Geographic Area	2020 Population	2020 Population Density (persons/square mile)	Population Change (percent)		Projected Population Change (percent)	
			2000 to 2010	2010 to 2020	2020 to 2030	2030 to 2040
Texas	29,145,505	112	20.6	15.9	17.6	16.6
Nueces County	353,178	421	8.5	3.8	11.9	9.6
San Patricio County	68,755	99	-3.5	6.1	9.7	6.0

[17] See section B.4.2.2 of the 2019 EA, which is available on the FERC eLibrary under accession number 20190329-3010.

Table B.7-1 Population by County and State						
Geographic Area	2020 Population	2020 Population Density (persons/square mile)	Population Change (percent)		Projected Population Change (percent)	
			2000 to 2010	2010 to 2020	2020 to 2030	2030 to 2040
Source: U.S. Census Bureau, 2022a						

As discussed in section A.8, construction of the Project is expected to take 4 years to complete but could extend an additional 3 years due to unforeseen circumstances. Table B.7-2 provides a summary of the construction and operational workforce for the Project.

Table B.7-2 CCL Midscale Trains 8 & 9 Project Workforce			
Approximate Number of Workers During Construction	Approximate Number of Workers at Peak Construction	Total Duration (months)	Approximate Number of Permanent Workers During Operation
1,500	2,100 [a]	47	45
[a] Peak construction is anticipated to last for 12 months			

Based on the presence of a construction workforce with experience in petrochemical facilities in the Corpus Christi area, CCL anticipates 40 percent of the workforce would be local (workers currently residing within a 50-mile commuting distance of the Project) and 60 percent of the workforce is anticipated to be non-local. An estimated 900 workers during non-peak construction and 1,260 workers during peak construction would consist of non-local workers that would temporarily relocate to the Project vicinity for the duration of their employment. CCL anticipates less than 2 percent of the non-local workers may bring their families to the Project area during construction of the Project. The influx of these non-local workers and their families would represent a minor but permanent increase in population in the vicinity of the Project.

The Project would employ about 45 additional full-time operational staff divided into three daily shifts for Project operations. Most of these positions are expected to be hired locally, with a limited number of workers expected to permanently relocate to the area.

Economy and Employment

Total employment[18] in Nueces and San Patricio Counties is 213,351 and 30,396 individuals, respectively, in 2021 (U.S. Bureau of Economic Analysis, 2021).

Economic impacts from construction and other pre-operational activities associated with the Project are anticipated to lead to a temporary increase in employment as well as business activity in the region. Project expenditures, including payroll and material purchases, along with spending on equipment and services in the region would generate economic activity. Overall, Project construction would generate minor, temporary economic benefits in the counties in the study area, as there would be a greater demand for labor, goods, and services around the Project facilities.

While most of the positions would be temporary, only lasting the length of construction, the Project is estimated to lead to annual gains in U.S. business activity of over $110 million in gross product

[18] Employment estimates include self-employed individuals. Employment data are by place of work, not place of residence, and, therefore, include people who work in the area but do not live there. Employment is measured as the average annual number of jobs, both full- and part-time, with each job counted at full weight.

and over 800 permanent jobs, as well as about $16 million in additional federal tax receipts.[19] As such, we conclude operation of the Project would have minor, permanent beneficial impacts on local employment and the economy in the study area.

Local Taxes and Government Revenue

County resources and allocations for Fiscal Year 2021-2022 for Nueces County and Fiscal Year 2022 for San Patricio County are $23.66 million and $16.70 million, respectively (Nueces County Auditor, 2021; San Patricio County, 2021).

Estimated tax revenues associated with construction and operation of the Project would result in increased tax revenues for local taxing entities, the State of Texas, and the Federal government. Once in-service, the Project would generate annual ad valorem or property tax revenues. CCL states that in December 2022, the Gregory-Portland Independent School District Board of Trustees entered into agreements with CCL that provided temporary appraised value limitations for certain school district property tax payments. CCL states they may submit applications for certain temporary property tax abatements from other local entities as permitted under Texas state law.

Tourism and Recreation

Travel and tourism contribute to the local economy in the Corpus Christi metropolitan area and Corpus Christi Bay supports abundant marine life that drives the tourism industry in the area.

We received comments from the Sierra Club and multiple individuals concerned with the Project impacts on tourism and recreation in the area. While some construction-related cargos would be delivered to the site via barge and/or ship, waterside deliveries would be restricted to the existing deep draft waterways and the CCL Terminal marine facilities, thereby resulting in minimal interference with recreation and tourism-related activities. During Project operations, recreational boaters would be required to give way to stand on vessels (e.g., LNGCs) while the LNGC passes. After the LNGC passes, boaters could return and continue their prior activities. Each LNGC visiting would be under the guidance of two licensed members of the Aransas-Corpus Christi Pilots between the sea buoy and the CCL Terminal marine facilities. The total piloted channel transit times in each direction for an LNGC, based on observations since the CCL Terminal came online, is 3 to 4 hours for an inbound transit, including the docking operations, and 3 hours for the outbound transit, including the unmooring operation. As discussed in the 2019 EA, actual underway time would be approximately 1.25 hours in the CCSC and approximately 45 minutes to 1 hour in the La Quinta Ship Channel. CCL is engaged with the Coastal Bend Bays and Estuaries Program to identify and support projects that improve the health of the bay system, which has positive impacts to recreational fishing and boating. In 2022, CCL states they provided funding for shoreline improvements at a local waterfront park in Portland that includes improved waterway access. In addition, CCL provides funds toward local oyster reef restoration designed to support recreational fishing. We have determined construction and operation of the Project, accounting for the arrival and departure of additional LNGCs, is not expected to have significant adverse impacts on recreation and tourism.

Housing

It is expected that about 60 percent construction workforce is assumed to permanently reside further than commuting distance (50 miles), from the Project and would be expected to temporarily relocate to the Project vicinity for the duration of their employment.

Review of temporary housing resources in the Project area indicates that there is sufficient temporary housing available to accommodate non-local construction workers, with sufficient temporary

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19 Based on an analysis completed by The Perryman Group. *The Projected Impact of the Corpus Christi Liquefaction Midscale Trains 8 & 9 Project on Business Activity in Corpus Christi, Texas, and the United States* can be viewed on FERC's eLibrary as Attachment 20 under accession number 20231023-5112.

housing resources available in the communities near the Project, as well as in the City of Corpus Christi, about 9 miles southwest of the Project.

Table B.7-3
Temporary Housing Units Available in the CCL Midscale Trains 8 & 9 Project Area

County/City	Housing Units [a]			
	Total Housing Units	Rental Vacancy Rate (Percent)	Units Available for Rent	For Seasonal, Recreational, or Occasional Use [b]
Nueces County	150,840	7.6	4,469	4,928
Corpus Christi	133,180	7.1	3,918	2,967
San Patricio County	29,165	4.5	381	1,135
Gregory	754	2.8	120	0
Ingleside	3,819	5.3	61	63
Portland	8,063	8.7	248	69
Sinton	2,254	0	0	12
Taft	1,266	7	31	0

Sources: U.S. Census Bureau 2022b, 2022c, Tables CP04 and B25004
[a] Data on housing units are from the American Community Survey 5-year estimates for 2017 to 2021.
[b] Housing units for seasonal, recreational, or occasional use are generally considered to be vacation homes. They are not included in the estimated number of housing units available for rent.

Hotel and motel rooms, recreational vehicle parks, and campsites in the area may also be available (South Texas Economic Development Center, 2021; Source Strategies, 2016).

Most of the staff that would be required to operate the Project (about 45 workers) are expected to be hired locally. Therefore, we conclude that operation of the Project would have a negligible but permanent impact on the local housing market and the purchase or rental of local housing may benefit the local economy.

Public Services

CCL states they would engage the public, including members of the surrounding environmental justice communities, on its emergency notification and response plans for the Project. CCL developed public brochures and materials in English[20] and Spanish[21] for community members that included information on the role and capabilities of Refinery Terminal Fire Company, a contracted company to the existing CCL Terminal which provides firefighting and emergency services, how CCL would communicate with the community in the case of an onsite emergency, what to know if local officials were to recommend an evacuation, and the efforts being undertaken by CCL to ensure ongoing coordination with local first responder entities in the region. The materials also include contact information for local first responder agencies and instructions on how to sign up for text alert notifications. CCL states these brochures were mailed on January 25, 2024.

In addition to communication with local governments and first responders, CCL would use the OnSolve/CodeRED mass text notification systems in San Patricio to notify the public about potential incidents/hazards at the site. The text alert system is an elective system and is administered by the

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20 A copy of CCL's Emergency planning & response information brochure in English is available at https://cheniere.s3.amazonaws.com/media/CCL-Emergency-Planning-Response-Booklet.pdf.

21 A copy of CCL's Emergency planning & response information brochure in Spanish is available at https://cheniere.s3.amazonaws.com/media/CCL-Emergency-Planning-Response-Booklet-Spanish-version-final.pdf.

Coastal Local Emergency Planning Committee (LEPC), which CCL provides annual funding to help ensure continued operation and awareness of these important public notification systems. For Nueces County, the Reverse Alert system would be used during an emergency which is equivalent of CodeRED system in San Patricio County. CCL states they engage with and provide annual funding to both the Coastal Plain LEPC and the City of Corpus Christi-Nueces County LEPC to help ensure coordinated emergency response efforts in the region and participates in quarterly meetings with each LEPC.

Based on CCL's commitment to supplement local fire department gaps and aid in the local emergency response system efforts and coordination, we conclude impacts on public services due to the Project would not be significant.

The 2019 EA provides information on the school districts and relative school enrollment numbers in San Patricio and Nueces Counties. As stated above, CCL assumes that less than 2 percent of non-local workers (estimated 18 workers during non-peak construction and 26 workers during peak construction) would be accompanied by their families. This potential addition of a limited number of students to the Project vicinity would not be expected to affect existing average student/teacher ratios in any one location; therefore, we conclude the Project's impact on the public school system would not be significant.

Available power capacity from the Stage 3 Project is sufficient for construction and operation of the Project and would be supplied via American Electric Power Texas. Reliability of the electric grid is currently being enhanced via the Corpus Christi Northshore Project, developed by American Electric Power Texas for the purpose of promoting reliability in response to regional industrial load growth (Billo, 2020). Therefore, we conclude the Project is not anticipated to have a significant adverse impact on the reliability of the regional electric power transmission grid, or the local provision of electric power.

Transportation and Traffic

Potential impacts on vehicular traffic would generally be related to the influx of construction workers commuting to and from the Project site, as well as the transport of construction materials. Marine traffic impacts would result from the increase in large vessel movements in the CCSC and La Quinta Ship Channel during construction and operation of the Project.

<u>Land Transportation</u>

The main land transportation routes in the vicinity of the Project are SH 35 and U.S. 181. There are six access points to the CCL Terminal. Access within the facility would be the path of least resistance using an internal network of private roads including but not limited to those shown in figure A3 in appendix A. Private roads include two paved roads, La Quinta Road, which parallels the western boundary of the permanent site, and Sherwin Road on the east side of the Project. Public roads would not be used for access between the direct Project footprint and construction laydown yards.

Table B.7-4 provides the average daily traffic and roadway designation or capacity for the major transportation roadways in the Project area and estimated number of roundtrips that would be generated during construction of the Project. No level of service ratings are assigned to roads in the Project vicinity.

Table B.7-4 Major Roadway Traffic				
Major Roadway	**Average Daily Existing Traffic [a]**	**Designated Capacity**	**Estimated Total Daily Peak Construction Traffic (roundtrips per day) [c]**	**Estimated Total Daily Non-Peak Construction Traffic (roundtrips per day) [c]**
SH 35	44,181	NA [b]	800	530
U.S. 181	37,611	NA [b]		
SH 361	18,604	NA [b]		

[a] Source: Texas Department of Transportation, 2023.
[b] No official level of service ratings are assigned to roads in the Project vicinity.
[c] Including truck deliveries and workforce trips.

As shown in table B.7-4, 800 daily roundtrips are estimated to occur during peak construction and 530 daily roundtrips are estimated during non-peak construction. Based on CCL's observations made during construction of the CCL Terminal, workers are expected to share rides to the site. The proposed Project workspace is inclusive of parking areas and all workers would park at the CCL Terminal; no offsite parking areas are proposed. Overall, potential impacts on land transportation from the Project site would primarily occur during the construction phase of the Project. The overall increase in traffic during construction would be temporary and represent a relatively small increase in existing traffic volumes on surrounding roadways. During construction, CCL would continue to evaluate traffic patterns in consideration of potential impacts to local roadways and public services. Therefore, we conclude Project construction would have short-term and less than significant impacts on roadway transportation.

During operation of the Project, the additional vehicle trips associated with the 45 new permanent workers would not be expected to affect existing traffic patterns. Therefore, we have determined that operation of the Project would have permanent but minor impacts on roadway transportation.

Marine Transportation

Materials required for construction of the Project may be delivered via barge utilizing the existing construction dock at the CCL Terminal. Deliveries from the waterside would help reduce potential land transportation-related impacts during peak construction. CCL estimates that material and equipment deliveries would be shipped from the Port of Corpus Christi (approximately 8 barges in 2026) and the Port of Houston (approximately 9 barges in 2026 through 2027 per year) to the existing construction dock. The Port of Corpus Christi in 2021 handled 6,843 vessels and over 167 million tons of cargo (The Waterways Journal, Inc., 2022; Port of Corpus Christi, 2021). Based on the number of barge deliveries estimated for the Project, we conclude the increase in construction vessel traffic is not expected to significantly impact marine transportation.

The general access route for LNGCs as analyzed by the Coast Guard for the CCL Terminal is shown in figure A2 of appendix A. The La Quinta Ship Channel and CCSC are existing, federally authorized and maintained deep-draft marine transportation projects. Most of the vessel traffic that enters Corpus Christi Bay is bound for the Port of Corpus Christi Inner Harbor. With a portion of the CCSC and the Gulf Intracoastal Waterway (GIWW) both seaward of the La Quinta Ship Channel, transiting LNGCs could have a transient effect on vessel traffic flow in the CCSC and GIWW. Much of this other vessel traffic consists of tug and barge tows utilizing the GIWW. Their potential to intersect with the LNGC route would be for about 1.5 nautical miles between the GIWW's intersection with the CCSC and the branch to the La Quinta Ship Channel.

Fishing boats and other small craft that use the Aransas Channel and the Aransas Pass Outer Bar Channel to transit between Aransas Pass and the Gulf of Mexico could be affected by LNGC traffic, which would overlap for about 4 nautical miles.

As discussed in section B.6.2, we received comments during the scoping period from residents in Ingleside on the Bay concerned with impacts to the properties and residences along the La Quinta Ship Channel from existing and additional LNGC traffic. Commentors stated that existing LNGC traffic passes the community with excessive speed at night, and that vessel wakes cause shoreline erosion and infrastructure damage, especially when vessels pass at high storm tides. Additionally, several commentors provided videos and photos of passing vessels from their properties along the shoreline of the La Quinta Ship Channel. Transit speed is at the discretion of the harbor pilot responsible for safely maneuvering each vessel through the waterway. Night transits are allowed under PCCA Rules and Regulations and allow for flexibility to transiting the channel during night-time hours, which aids in reducing potential for congestion in the waterway. CCL has begun an outreach effort with residents of Ingleside on the Bay to develop a better understanding of concerns and explore ways in which CCL can potentially participate in development and/or implementation of mitigations for those concerns.

Each LNGC visiting would be under the guidance of two licensed members of the Aransas-Corpus Christi Pilots who would be aboard the vessel for the entire transit between the sea buoy and the CCL Terminal marine facilities. LNGCs would move at speeds determined to be safe to maintain proper maneuverability by the vessel's master and pilots. The total piloted channel transit times in each direction for an LNGC, based on observations since the CCL Terminal came online, is 3 to 4 hours for an inbound transit, including the docking operations, and 3 hours for the outbound transit, including the unmooring operation.

The Coast Guard has not invoked a mandatory moving safety and security zone for the LNGC transits and instead imposed the moving safety and security zone using a risk-based approach, when appropriate for specific transits. The Port of Corpus Christi has established Rules and Regulations governing the Pilots and Pilotage on the CCSC (Port of Corpus Christi, 2022a). The rules are regularly reviewed and updated, to reflect traffic on the CCSC including those affecting LNGCs. Feedback from the Pilots indicates that the addition of up to 80 LNGC transits is not expected to have adverse impacts on overall marine traffic patterns. In addition, the Port of Corpus Christi Ship Channel Improvement Project is currently ongoing (Port of Corpus Christi, 2022b) and will increase the channel depth and width, which is expected to reduce the impact of barge traffic coming from the GIWW. The additional LNGC visits to the CCL Terminal for the Project would result in an incremental impact on adjacent communities over the existing vessel traffic impacts. However, 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.

7.2 Environmental Justice

In conducting NEPA reviews of proposed natural gas projects, the Commission follows the instruction of Executive Order 12898 and Executive Order 14096, which direct federal agencies to identify and address disproportionate and adverse human health or environmental effects of their actions on minority and low-income populations (i.e., environmental justice communities).[22] Executive Order 14008, *Tackling the Climate Crisis at Home and Abroad*, also directs agencies to develop programs, policies, and activities to address the disproportionate and adverse "human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts."[23] Environmental justice is "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to

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22 Exec. Order No. 12,898, 59 *Federal Register* 7629, at 7629, 7632 (Feb. 11, 1994); Exec. Order No. 14,096, 88, Fed. Reg. 25251 (Apr. 21, 2023).

23 Exec. Order No. 14,008, 86 *Federal Register* 7619, at 7629 (Jan. 27, 2021).

the development, implementation, and enforcement of environmental laws, regulations, and policies."[24] The term "environmental justice community" includes disadvantaged communities that have been historically marginalized and overburdened by pollution.[25]

Commission staff used *Promising Practices for EJ Methodologies in NEPA Reviews* (*Promising Practices*),[26] which provides methodologies for conducting environmental justice analyses throughout the NEPA process for this Project. Additionally, consistent with EPA recommendations, Commission staff used EPA's Environmental Justice Screening and Mapping Tool (EJScreen) as an initial screening tool to better understand locations that require further review or additional information regarding minority and/or low-income populations; potential environmental quality issues; environmental and demographic indicators; and other important factors.[27]

Meaningful Engagement and Public Involvement

The CEQ *Environmental Justice Guidance Under the National Environmental Policy Act (CEQ Environmental Justice Guidance)*[28] and *Promising Practices* recommend that federal agencies provide opportunities for effective community participation in the NEPA decision-making process by: identifying potential effects and mitigation measures in consultation with affected communities; improving accessibility of public meetings, crucial documents, and notices; and using adaptive approaches to overcome potential barriers to effective participation. In addition, Executive Order 13985 and Executive Order 14096 strongly encourage 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"[29] and "provide opportunities for the meaningful engagement of persons and communities with environmental justice concerns who are potentially affected by Federal activities."[30]

There have been opportunities for public involvement during the Commission's environmental review processes.[31] CCL initiated its public outreach program for the Project in September 2022. Community stakeholders include nearby residents, local elected officials, school districts, civic and business organizations, environmental groups, and first responder agencies. CCL states they sent initial

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24 EPA, *Learn About Environmental Justice*, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (Sep. 6, 2022). 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. *Id.* Meaningful involvement of potentially affected environmental justice community residents means: (1) people have an appropriate opportunity to participate in decisions about a proposed activity 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. *Id.*

25 Environmental justice communities include, but may not be limited to minority populations, low-income populations, or indigenous peoples. *See* USEPA, *EJ 2020 Glossary* (Jul. 31, 2023), https://www.epa.gov/system/files/documents/2024-02/ej-2020-glossary.pdf.

26 Federal Interagency Working Group on Environmental Justice & NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* (Mar. 2016) (*Promising Practices*), https://www.epa.gov/sites/default/-files /2016-08/documents/nepa_promising_practices_document_2016.pdf.

27 The EPA recommends that screening tools, such as EJScreen, be used for a "screening-level" look and a useful first step in understanding or highlighting locations that may require further review.

28 CEQ, *Environmental Justice Guidance Under the National Environmental Policy Act 4 (Dec. 1997) (CEQ Environmental Justice Guidance)*, https://ceq.doe.gov/docs/ceq-regulations-and-guidance/regs/ej/justice.pdf.

29 Exec. Order No. 13985, 86 Fed. Reg. at 7011 (Jan. 20, 2021).

30 Exec. Order No. 14,096, 88, Fed. Reg. 25254 (Apr. 21, 2023).

31 *See supra* at P 3 - 4.

letters describing the Project to adjacent landowners and community stakeholders including an invitation to participate in the FERC process and open house. Individual mailers translated in English and Spanish[32] were sent to all residences in the Cities of Gregory, Portland, and Taft, with an invitation to the community open house for the Project, as well as information on how to engage with CCL to provide feedback and ask questions regarding the Project. A notice of the open house was also posted by CCL in the local newspaper. A community open house was held on October 12, 2022, from 4 to 7 P.M. at the Gregory Community Center located within the Census Tract (CT) 105, Block Group (BG) 1 environmental justice community. Project description handouts were made available to guests in both English and Spanish[33] and Project representatives fluent in Spanish were in attendance to ensure residents could communicate in their preferred language.

All documents that form the administrative record for these proceedings are available to the public electronically through the internet on the FERC website (www.ferc.gov). Anyone may comment to FERC about the Project, either in writing or electronically.[34] All substantive environmental comments received prior to issuance of this EA have been addressed within this document.

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. Further, Commission staff has consistently emphasized in public notices and scoping sessions that all comments, whether spoken or delivered in person at meetings, mailed in, or submitted electronically, receive equal weight by FERC staff for consideration in the EA.

Though not specifically targeted at environmental justice communities, CCL states they would continue providing information to community stakeholders through individual meetings, public presentations, direct mailings to nearby residences and Community Advisory Panels with representatives from nearby communities, including within the identified environmental justice communities. The Project would continue to engage with stakeholders and solicit feedback through multiple communication channels, including its public e-mail address and community phone line. A formal Community Feedback Mechanism is in place to track community feedback and concerns and ensure a timely response.[35]

We received multiple comments during the scoping period from individuals and NGOs generally concerned with the Project's impacts on environmental justice communities in the vicinity of the Project. Commentors expressed concern on the Project's potential general and disproportionate impacts, pollution and health impacts, climate change and overall environmental impacts, and socioeconomic impacts on environmental justice communities. Mitigation measures that CCL would implement across the Project area, including within the identified environmental justice communities, are described in the sections below.

Additionally, we received environmental justice-related comments from the EPA. The EPA recommended that Commission staff simplify a means for the public at large to review FERC's federal

32 Spanish was identified as the second most common spoken language in the Project area based on U.S. Census Bureau 2017-2021 ACS 5-Year Estimates table B01001.

33 Populations of limited English speakers in the block groups within the study area range from 0 to 18 percent based on U.S. Census Bureau, 2017-2021 ACS 5-Year Estimates File # C1600.

34 The Office of Public Participation (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.

35 The Community Feedback Mechanism was created by CCL to be used at any time by the public throughout construction and the life of the Project. CCL communicated information on how to provide feedback during its various stakeholder engagement activities and by its distributed public open house information. CCL can be reached at 888-371-3607 or community@cheniere.com.

projects that have potential adverse impacts on its populations. The EPA recommended FERC include names of environmental justice organizations, advocates, and/or groups that were coordinated with for the Project. CCL provided an expanded stakeholder list to include additional environmental justice community members and organizations that were subsequently added to FERC's mailing list.[36] CCL stated letters containing basic Project information, points of contact, and resources to learn more about the Project were sent to the expanded stakeholder list entities on August 14, 2023. The EPA also recommended the Commission staff incorporate a map in the EA depicting the locations and alignments of all projects directly, indirectly, and cumulatively impacting the minority and low-income populations in San Patricio and Nueces Counties. The EA addresses EPA's comments in section B.10 and appendix E.

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 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, Commission staff selected San Patricio, Nueces, and Aransas Counties, Texas, as comparable reference communities 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 E1 of appendix E identifies the minority populations (by race and ethnicity) and low-income populations within Texas, as well as the counties and census block groups[37] within 50-kilometers of the Project area. We have determined that a 50-kilometer radius is the appropriate unit of geographic analysis for assessing impacts for the Project on environmental justice communities. We believe the 50-kilometer radius is sufficiently broad as it represents the furthest possible extent of impacts, the most distant of which would be associated with air quality impacts.[38] Also, due to the Project's proposed increased vessel traffic and comments from residents of nearby communities, we also included census block groups within a 1-mile radius of the La Quinta Ship Channel and CCSC. We believe the 1-mile radius is sufficiently broad considering the vessel traffic and visual impacts proximal to the La Quinta Ship Channel and CCSC due to the additional LNGC visits associated with the Project. To ensure we are using the most recent available data, we used the 2021 U.S. Census American Community Survey[39] as the source for the race and ethnicity data and poverty data at the census block group level.

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36 See attachment 19 at accession number 20231023-5112 for CCL's expanded stakeholder list.

37 Census block groups are statistical divisions of census tracts that generally contain between 600 and 3,000 people. U.S. Census Bureau, 2023, Glossary: Block Group, accessed April 2023, https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_4.

38 Fifty kilometers is the distance used by the EPA for cumulative air modeling for major stationary sources under its Prevention of Significant Deterioration (PSD) air permitting requirements. 40 C.F.R. § 51, Appendix W, and is generally considered to be the maximum distance that can be accommodated by the assumptions inherent in refined steady-state Gaussian plume air modeling applications.

39 U.S. Census Bureau, 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*,

As presented in table E1 of appendix E, 283 block groups out of 353 block groups within the geographic scopes of the Project are considered environmental justice communities. For the 353 block groups within 50 kilometers of the proposed Project workspace, 283 block groups are considered environmental justice communities (135 based on the minority threshold alone, 19 based on the low-income threshold alone, and 129 based on both the minority and low-income thresholds). For the 9 block groups within 1 mile of the La Quinta Ship Channel and CCSC,[40] 5 block groups are considered environmental justice communities (2 based on the minority threshold alone, 2 based on the low-income threshold alone, and 1 based on both the minority and low-income thresholds).

Impacts on Environmental Justice Communities

Promising Practices provides methodologies for evaluating environmental justice impacts related to human health or environmental hazards; the natural physical environment; and associated social, economic, and cultural factors. Consistent with *Promising Practices*, Executive Order 12898, and Executive Order 14096, 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.[41] *Promising Practices* provides that agencies can consider any of a number of conditions for determination and the presence of any of these factors could indicate 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.

The direct footprint of the proposed Project facilities, the RWL area, and a portion of the proposed Project workspace previously reviewed during the 2014 FEIS and 2019 EA, are within CT 107, BG 2, which is defined as a minority population. The remainder of the proposed Project workspace is located within CT 105, BG 1, which is identified as a minority and low-income population.

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 socioeconomic impacts (section B.7.1), water resources (section B.3), land traffic (section B.7.1), marine traffic (section B.7.1), recreational fishing and boating impacts (sections B.6.2 and B.7.1), visual impacts (section B.6.2), and air and noise impacts from construction and operation (section B.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 impacts would be greater for individuals and residents 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, wildlife, wetlands, land use, or cultural resources, due to the minimal overall

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https://data.census.gov/cedsci/table?q=B17017; File #B03002 *Hispanic or Latino Origin By Race*, https://data.census.gov/cedsci/table?q=B03002.

40 As noted in table E1 of appendix E, all 9 block groups within 1 mile of the La Quinta Ship Channel and CCSC overlap with the 50-kilometer geographic scope of the Project workspace.

41 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 with the meaning of NEPA"); *see also 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.

impact the Project would have on these resources and/or the absence of any suggested connection between such resources and environmental justice communities.

Socioeconomics

Project impacts on environmental justice communities may include impacts on socioeconomic factors. The Project is estimated to cost $818 million, which includes labor, materials, and equipment. The average workforce for the duration of Project construction would be about 1,500 workers and the workforce during peak construction, which would last approximately 12 months, is estimated to be 2,100. The temporary flux of workers could affect economic conditions and increase the demand for community services, such as traffic, housing, police enforcement, and medical care. The proposed increase in workforce for the Project would be a benefit to the surrounding area, and may benefit environmental justice communities, by providing additional job opportunities and local revenue through direct expenditures of materials and services, in addition to generating sales and tax revenues.

Approximately 45 full-time workers would be hired permanently across three shifts. The influx of these workers and their families would represent a minor and permanent increase in the population. This increase in permanent workers would have a negligible impact on environmental conditions and community infrastructure; thus, socioeconomic impacts on the environmental justice communities would be less than significant.

Water Resources

Construction and operation of the Project, as well as marine traffic to and from the Project, have the potential to adversely impact water quality for surrounding environmental justice communities in the event of an accidental release of a hazardous substance such as fuel, lubricants, coolants, or other material. CCL would implement the Procedures and its SPCC Plan to minimize the likelihood of a spill and would implement its SPCC Plan in the event of a spill. Additionally, LNGCs are required to develop and implement a Shipboard Oil Pollution Emergency Plan, which includes measures to be taken when an oil pollution incident has occurred, or a ship is at risk of one.[42] An accidental release could have an adverse effect on environmental justice communities along the ship channels, as well as individuals from these communities that use the ship channels. However, with the mitigation measures CCL and LNGCs would implement, we conclude water resource impacts on environmental justice communities would be less than significant.

Land Traffic

Potential impacts on the environmental justice communities during construction of the Project may include traffic delays. The overall increase in traffic during Project construction would not be permanent but is anticipated to last four to seven years. Additional Project vehicular traffic will represent a relatively small increase in existing traffic volumes on surrounding roadways (see section B.7.1), including those nearby in the city of Gregory, CT 106.01, BGs 1, 2, and 4 and CT 103.02, BG 4.

Increases in traffic volume during the operation of the Project are expected to be smaller, resulting from the 45 permanent employees and periodic deliveries, and are not expected to result in a significant increase in overall area traffic. Traffic impacts on environmental justice communities would be less than significant.

Marine Traffic, Recreational Fishing, and Boating

The increase of up to an additional 80 LNGC visits per year to the CCL Terminal along marine transportation routes would result in an incremental impact on adjacent environmental justice communities over the existing vessel traffic impacts. The anticipated increase in LNGCs would result in about 1.5 additional vessels a week. As discussed in section B.7.1 and the 2019 EA, actual underway

42 LNGCs are outside of the Commission's jurisdiction.

time of LNGCs would be approximately 1.25 hours in the CCSC. During Project operations, recreational boaters would be required to give way to stand on vessels (e.g., LNGCs) while the LNGC passes. After the LNGC passes, boaters could return and continue their prior activities. Operational impacts on recreational fisheries in the ship channels, as well as on individuals from environmental justice communities, would be temporary, lasting only while an LNGC is present. To evaluate and minimize potential impacts on marine transportation associated with the Project, CCL submitted a follow-on WSA to the Coast Guard on February 9, 2023. The Coast Guard issued an LOR for the Project on January 25, 2024, recommending that the evaluated portion of the CCSC and the entirety of the La Quinta Ship Channel can be considered suitable for the increased LNGC traffic associated with the Project.

Deliveries by barge are similarly expected to have minimal interference with recreation-related activities. Due to the overall size of the ship channels (combined total of approximately 17 miles along the Project marine transportation route and wider than 720 feet at the narrowest point), access to and maneuverability within the ship channels would not be significantly affected by the use of barges. The construction impacts on recreational fishing would be temporary, lasting the duration it takes for barges to clear the area throughout the duration of construction activities.

Although aquatic species commonly fished could be present, the La Quinta Ship Channel and CCSC do not have any unique features or habitat characteristics that would draw recreational users to this particular location versus other nearby locations. In addition, public access to other recreational resources in the vicinity of the Project (such as Corpus Christi Bay) would not be restricted. Based on the La Quinta Ship Channel's and CCSC's existing traffic patterns and capacity, unrestricted access to recreational resources, and the presence of other recreational fishing areas nearby, the Project's additional deliveries and LNGC traffic are not expected to result in waterway congestion or significantly impact other waterway users such as residents along the ship channels and recreational boaters and fishermen, which likely include individuals from these environmental justice communities. Marine traffic and recreation impacts are more fully addressed in section 7.1.

Visual Resources

The Project is on previously disturbed land, historically used for industrial purposes, in an existing industrial setting. All proposed facilities (i.e., the two midscale trains, refrigerant storage, EFG unit, and BOG compressor) would be within the existing CCL Terminal. The tallest feature proposed is the end-flash gas column, which would be approximately 165 feet above grade. CCL states the estimated view radius extends up to approximately 6 miles from the Project. Intervening land uses include the SH 35 highway corridor, including sections of elevated highway that obstruct views toward the Project site, and other industrial and commercial land uses. The closest residences and sensitive receptors located within environmental justice communities range from 0.07 to 1.5 miles from the boundaries of the Project workspace. As provided in appendix D, CCL provided daytime and nighttime visual simulations from NSA 6, which is within CT 105, BG 1, an environmental justice community. CCL also provided existing daytime conditions at various NSAs within environmental justice communities, including NSAs 4 and 9 within CT 107, BG 2 and NSA 7 within CT 107, BG 1. Based on visual simulations and existing conditions, the proposed Project facilities would either be obscured by vegetation and/or existing infrastructure or would be consistent with the current industrial use and viewshed of the area. Visual impacts from the CCL Terminal proposed facilities are not anticipated to be significant for environmental justice communities.

Recreational activities, sensitive receptors such as parks (see above) and residences occur within and/or along the La Quinta Ship Channel and CCSC. The La Quinta Ship Channel and CCSC are heavily used shipping corridors and provide vessel access to many facilities. Based on the existing use of the shipping channels and the amount of additional LNGC traffic proposed (approximately 1.5 additional LNGC visits per week), the Project's additional 80 LNGC visits per year would be consistent with the current use and visual character of the waterways and are not anticipated to have a significant visual impact on surrounding environmental justice communities.

Air Quality

We received multiple comments from individuals, NGOs, and the EPA regarding impacts on environmental justice communities related to worsening air quality, resulting health impacts, and emission exceedances. Emissions during construction of the Project would generally be associated with onshore construction activities conducted using on-road and off-road mobile equipment and marine vessels such as tugboats or barges for delivery of equipment and materials. Construction equipment exhaust emissions would be minimized by using construction equipment and vehicles that are maintained in accordance with manufacturers' maintenance schedules; complying with EPA vehicle and non-road engine emissions regulations; and using commercial fuels (e.g., diesel) that meet specifications of applicable federal and state air pollution control regulations. Fugitive dust emissions from earth-moving/material handling and equipment/vehicle traffic during construction, and gaseous emissions from fuel combustion in construction equipment would result in short-term, localized impacts in the immediate vicinity of construction work areas. Fugitive dust generation would be minimized, in part, by applying water in active construction areas (e.g., unpaved roads, material storage piles) and imposing speed limits for on-site vehicles in accordance with CCL's FDCP. These use of such mitigation measures in conjunction with an awareness of conditions (e.g., weather) and knowledge of specific construction activities at the site, would minimize the potential for excessive fugitive dust/particulate matter levels (see section B.8.1 for additional detail). With implementation of these measures, we conclude the construction-related impact on local air quality during the temporary construction period for the Project would not be significant.

CCL conducted detailed air quality impact assessments for emissions of criteria pollutants (subject to Prevention of Significant Deterioration [PSD] review) from the Project to show compliance with the relevant National Ambient Air Quality Standards (NAAQS). CCL also conducted a detailed impact assessment for emissions from the Stage 3 Project that included the proposed Trains 8 & 9. The results of these assessments showed the furthest distance that the model-predicted impacts would make a significant contribution to the cumulative impacts for the NAAQS compliance assessment beyond the CCL-controlled property boundary. The assessment results for the Project emissions alone showed no model-predicted impacts greater than Significant Impact Levels (SILs). The assessment results for the Project emissions combined with the Stage 3 Project emissions showed that operational emissions would result in 1-hour and annual average nitrogen dioxide (NO_2) impacts that exceed the relevant EPA-defined SILs over a very limited area adjacent to and within 0.5 mile of the northern property boundary. These impacts would occur within CT 107, BG 1, which shows the presence of an environmental justice minority population. FERC requested that CCL conduct a NAAQS compliance assessment for all criteria pollutants, including emissions from: 1) all stationary sources at the CCL Terminal; 2) marine vessels associated with terminal operations; and 3) representative criteria pollutant background concentrations. The results show maximum concentrations below the NAAQS for all criteria pollutants and associated averaging periods.

FERC also conducted a Human Health Risk Assessment (HHRA) for the hazardous air pollutant (HAP) emissions from the CCL Terminal facilities (see section B.8.1 and appendix F). Based on the results of this HHRA, which addressed chronic cancer risks and non-cancer hazards, as well as acute hazards, we conclude there would be no significant impacts associated with exposures to emissions of HAPs, including benzene.

Overall, we conclude the construction and operational air emissions from the Project would not be significant for the identified environmental justice communities.

Noise

It is expected that construction noise impacts from the Project would be similar or less than assessed for the 2019 EA. The noise analysis prepared for the Project evaluated potential impacts on NSAs; which included the closest residential area in Gregory, approximately 1.6 miles from Trains 8 & 9 and within CT 105, BG 1, an environmental justice community. Existing traffic from nearby highways was identified as the dominant existing noise source in environmental justice communities in Gregory (CT 105, BGs 1 and 2) and environmental justice communities CT 106.01, BGs 1, 2, and 4. Noise during construction of the Project would primarily be from diesel engines used to power equipment. The previous construction acoustical analysis prepared for the Stage 3 Project found that noise produced during construction would be below FERC established criteria. A cumulative noise study completed for the CCL Terminal and the Project concluded the noise level during Project operation is expected to be below the FERC day-night level (L_{dn}) noise limit of 55 A-weighted decibels (dBA) at any of the nearest noise sensitive areas (see appendix I and section B.8.2). Overall, the Project would not result in significant noise impacts on the surrounding communities, which include environmental justice communities.

Environmental Justice Impact Mitigation

As described in *Promising Practices*, when an agency identifies potential adverse impacts, it may wish to evaluate practicable mitigating measures. Though not specifically targeted at mitigating impacts on environmental justice communities, mitigation measures would be followed across the Project area, including within the identified environmental justice communities. CCL would follow the Plan, Procedures, Project-specific plans, and any conditions in permits to minimize any potential impacts to environmental justice communities.

Though not specifically targeted at environmental justice communities, mitigation measures would be implemented across the Project area, including within the identified environmental justice communities. CCL has committed to continue providing information to community stakeholders through individual meetings, public presentations, direct mailings to nearby residences and Community Advisory Panels; evaluating traffic patterns in consideration of potential impacts to local roadways and public services; using light systems with minimum intensity, using maximum off-phased white strobe lighting as per FAA regulations; and using down-shielding lights on the facilities

Determination of Disproportionate and Adverse Impact Environmental Justice Communities

As described throughout this EA, the Project would have a range of impacts on the environment and on individuals living in the vicinity of the Project, including environmental justice populations. As previously stated, the direct footprint of the proposed Project facilities, the RWL area, and the proposed Project workspace which was previously approved are within environmental justice communities. The construction and operation of the Project would have a disproportionate and adverse impact on environmental justice communities as they would be predominantly borne by these communities, but the impacts would be less than significant.

8. Air Quality and Noise

8.1 Air Quality

The term air quality refers to the relative concentrations of pollutants in the ambient air. Air quality would be affected by construction and operation of the Project. We received comments from individuals, NGOs, TCEQ, and the EPA concerned with the Project's impacts on air quality in the surrounding region. This section of the EA addresses the construction and operational air emissions from the Project, as well as applicable regulatory requirements and projected impacts on air quality.

Existing Air Quality

Federal and state air quality standards are designed to protect human health and welfare. The EPA has developed NAAQS[43] for criteria pollutants including carbon monoxide (CO), lead (Pb), oxides of nitrogen (NO_x), ozone (O_3), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and sulfur dioxide (SO_2). Primary standards are limits set by the EPA to protect human health including sensitive populations such as children, the elderly, and asthmatics. Secondary standards are set to protect public welfare from detriments such as reduced visibility and damage to crops, vegetation, animals, and buildings. Individual state air quality standards cannot be less stringent than the NAAQS. The state standards established by the TCEQ as outlined in 30 TAC 101.21, are the same as the federal NAAQS for criteria pollutants. In addition, the TCEQ has established 30-minute average property line standards for SO_2 and hydrogen sulfide (H_2S) in 30 TAC 112. The NAAQS are listed in table G1 of appendix G. Volatile organic compounds (VOCs) are also regulated by the EPA to prevent the formation of ozone, a constituent of photochemical smog. Many VOC form ground level ozone by reacting with sources of oxygen molecules such as NO_x in the atmosphere in the presence of sunlight. NO_x and VOC are referred to as ozone precursors. HAPs are also emitted during fossil fuel combustion. HAPs are chemicals known to cause human health and environmental impacts.

The EPA has defined air pollution to include the mix of six directly emitted and long-lived greenhouse gasses (GHG): carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. GHGs occur in the atmosphere both naturally and due to human activities, including the burning of fossil fuels. The primary GHGs produced by fossil fuel combustion are CO_2, CH_4, and N_2O. There are no NAAQS for GHGs and their status as pollutants is not related to toxicity; GHGs are non-toxic and non-hazardous at normal ambient concentrations. The EPA found that the current and projected concentrations of the six GHGs in the atmosphere threaten the public health and welfare of current and future generations through climate change. Emissions of GHGs are typically expressed in terms of CO_2 equivalents (CO_{2e}). The GHG CO_{2e} unit of measure considers the global warming potential (GWP) of each GHG. GWP is a ratio relative to CO_2 that is based on GHG's ability to absorb solar radiation as well as its residence time within the atmosphere. Based on this definition, CO_2 has a GWP of 1, CH_4 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 GHG 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 the GHG compounds is summed to obtain the total CO_{2e} GHG emissions. We have selected these GWPs over other published GWPs for other timeframes because these are the GWPs the EPA has established for reporting of GHG emissions and air permitting requirements.

Other pollutants, not produced by combustion, are fugitive dust and fugitive emissions. Fugitive dust is a mix of $PM_{2.5}$, PM_{10}, and larger particles in the atmosphere by moving vehicles, construction equipment, earth movement, and wind erosion. Fugitive emissions, in the context of this EA, includes fugitive emissions of CH_4 and VOCs from operational pipelines and aboveground facilities. Ambient air quality concentrations in the vicinity of the Project are presented in appendix G.

Air Quality Control Regions and Attainment Status

Air Quality Control Regions (AQCRs) are areas established for air quality planning purposes in which state implementation plans describe how ambient air quality standards would be achieved and maintained. AQCRs were established by the EPA and local agencies, in accordance with Section 107 of the Clean Air Act and its amendments, to implement the Clean Air Act and comply with the NAAQS through state implementation plans. The AQCRs are intrastate and interstate regions, such as large metropolitan areas, where the improvement of the air quality in one portion of the AQCR requires

43 The current NAAQS are listed on the EPA's website at https://www.epa.gov/criteria-air-pollutants/naaqstable.

emission reductions throughout the AQCR. The entire Project area is in the Corpus Christi-Victoria Intrastate AQCR. Likewise, emissions from ship transit would impact the same AQCR.

An AQCR, or portion thereof, is designated based on compliance with the NAAQS. AQCR designations fall under three general categories as follows: attainment (areas in compliance with the NAAQS); nonattainment (areas not in compliance with the NAAQS); or unclassifiable (air quality data are not available). AQCRs that were previously designated nonattainment but have since met the requirements to be classified as attainment are classified as maintenance areas. The Corpus Christi-Victoria Intrastate AQCR is designated as unclassifiable and/or attainment for all criteria pollutants.

Transport of construction materials associated with the Project could occur within the Houston-Galveston-Brazoria rea, which is a marginal nonattainment area for the 2015 8-hour ozone standard. Additionally, the Houston-Galveston-Brazoria area is still classified as a "moderate" nonattainment area for the 2008 8-hour ozone standard and a "severe" nonattainment area for the 1997 8-hour ozone standard. Construction emissions from the Project occurring within the Houston-Galveston-Brazoria area would not result in an exceedance of applicable general conformity thresholds for this area (see appendix G).

Air Quality Permitting Requirements

The Project would be subject to a variety of federal and state regulations pertaining to the construction and operation of air emission sources and are listed in appendix G.

Construction Emissions

Construction of the Project facilities would result in short-term increases in emissions of some air pollutants due to the use of equipment powered by diesel fuel or gasoline and the generation of fugitive dust due to the disturbance of soil and other dust-generating activities.

CCL presented emission estimates for a 4-year construction period (2025 to 2028), including commissioning activities. CCL requested a seven-year authorization to accommodate the potential for phasing, schedule changes, or disruptions, but assumed that the construction period could be condensed to a four-year period under optimal conditions.

Fugitive dust would be produced primarily during the site preparation activities, when the site would be cleared of debris, leveled, and graded. Additionally, movement of off-road equipment would generate fugitive dust on site. On-road truck traffic (e.g., supply trucks) and worker commuter vehicles at the Project site also would generate fugitive dust from travel on paved and unpaved surfaces. These sources of fugitive dust would be reduced by mitigating measures, such as watering unpaved roads, outlined in CCL's FDCP.[44]

Site preparation equipment would include bulldozers, excavators, backhoes, graders, loaders, dump trucks, and other mobile construction equipment. In addition to the equipment involved in site preparation, equipment such as cranes, aerial lifts, welders, and forklifts would be used in the Project construction. This site preparation construction equipment, including trucks and barges delivering equipment and materials, would be powered primarily by diesel-fueled internal combustion engines that would generate PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC, and CO emissions. Most of the on-road passenger cars and trucks would burn gasoline, although supply trucks and some worker pickup trucks would burn ultra-low-sulfur diesel fuel.

Some construction equipment and materials would be delivered to the terminal site by barge. CCL estimates that approximately 17 marine deliveries would occur in 2026 and 2027. Barge/tug operations would result in fuel combustion emissions from the diesel-fired engines.

[44] CCL's FDCP can be viewed on FERC's eLibrary as appendix 9C of accession number 20230330-5209.

CCL developed an inventory of off-road equipment and vehicles, on-road vehicles, and expected activity levels (either hours of operation or vehicle miles travelled) based on the expected duration of construction at the site for the purposes of calculating emissions. The engine rating and load level and activity level for each piece of construction equipment was combined with the relevant EPA emission factors (e.g., Motor Vehicle Emission Simulator [MOVES]) to quantify annual emission estimates. Fuel combustion emissions from barges/tugs were calculated using engine sizes, activity levels, and EPA emission factors/emissions development guidance (EPA, 2020). Fugitive dust emission estimates associated with site preparation activities for the Project were based on an estimate of total disturbed acreage and the use of EPA-accepted emission factors with a control factor (50 percent reduction) for application of dust suppressant (i.e., watering).

The estimated total annual criteria air pollutant and HAP emissions associated with construction-related activities for the Project are summarized by construction year in table H1, appendix H; total annual GHG emissions are summarized by construction year in table H2, appendix H. These emission rates include fuel combustion emissions as well as fugitive dust emissions. The total PM_{10} and $PM_{2.5}$ emissions shown in these tables are mainly the result of fugitive dust-generating activities. Note that the estimated annual construction emissions are based on the latest available information on Project schedule; the timing and magnitude of annual emissions vary based on when construction activities occur, which is dependent on business-related and other regulatory factors.

Mitigation Measures

As discussed previously, fugitive dust accounts for most of the particulate matter emissions during the construction period for the Project. Therefore, fugitive dust controls would play an important role in reducing impacts on air quality in the Project area. Project construction activities would be subject to 30 TAC Chapter 111, Subchapter A, which includes a requirement to use water or suitable chemicals for control of dust during construction activities.

As mentioned above, CCL developed a FDCP for Project construction, which encompassed regulatory requirements to reduce fugitive dust emissions. CCL also would implement additional measures (see appendix G) to enhance the effectiveness of the measures outlined in the FDCP.

In general, construction activities would increase air pollutant emissions and ambient concentrations in the vicinity of the Project site at various points during the approximate four-year construction period. The magnitude of the effect on air quality would vary with time due to the construction schedule (i.e., intensity of construction activities), mobility of the sources, and the type of construction equipment. Considering these factors, we conclude that construction of the Project would not have a significant impact on air quality during Project construction.

Operational Emissions

Operation of the Project equipment would result in emissions of criteria pollutant, GHG, and HAP from onshore stationary sources (e.g., furnaces, oxidizers, and flares) and mobile marine vessels (e.g., LNGCs and tugs). Operational-phase emissions from these sources would be permanent (lasting the life of the Project). The various emission sources and associated emission rates are discussed in more detail in the following sections. Also discussed are the mitigation measures to be implemented for the operating emission sources. The emissions summarized in tables H11 and H12 of appendix H regarding the mobile marine sources are representative of 80 additional LNGC calls per year.

Onshore Emission Sources

The onshore stationary emissions sources associated with the Project, once permanent commercial operation is initiated, includes two gas-fired hot oil furnaces, two gas-fired thermal oxidizers, three multi-point ground flares, two diesel-fired standby generators, condensate storage (existing storage tank) and truck loading, marine flare (existing), and fugitive VOC and GHG emissions sources (e.g., leaks from equipment such as valves, flanges, and connectors).

Emissions from certain existing sources at the CCL Terminal would increase because of the Project operation. Specifically, emissions from the existing marine flare and condensate storage and loading operation would increase due to Project operation and are accounted for in the emissions estimates presented in this EA. Air emissions would not be generated by the electric motor driven refrigerant compressors on the two new liquefaction trains.

Once constructed, the Project equipment would undergo a commissioning process before it could be fully operational. The commissioning activities are one-time activities that are necessary to test the new equipment to verify proper functionality and ensure safety. Emissions from these activities for each train are purged to the flares. The initial start-up process is projected by CCL to occur over a an approximate 7-month period, with commissioning activities ending in November 2028. The estimated criteria air pollutant and HAP emissions for the commissioning process are given in table H3, appendix H; estimated GHG emissions for the commissioning process are given in table H4, appendix H.

After completing the commissioning process, the Terminal Facilities would start commercial operations. The estimated annual criteria air pollutant and HAP emission rates for sources associated with the Project operation are given in table H5, appendix H; annual GHG emission rates for sources associated with the Project operation are given in table H6, appendix H. The emissions for the multi-point ground flares are based on routine, anticipated maintenance, start-up, and shutdown activities.

A portion of the total number of additional LNGCs calling on the port each year for the Project would have their tanks filled with inert gas (mixture of mainly nitrogen and CO_2), which is vented out of the tanks directly to the marine flare, via a gassing up and cooldown process, before loading of LNG can begin. This process would result in additional CO_2 emissions to the atmosphere. A summary of the estimated short-term (pounds per hour [lb/hr]) controlled criteria air pollutant and HAP emission rates for routine operation of the Project emission sources (excluding marine vessels) are given in table H7, appendix H. Note that the short-term emission rates are needed as input for the pollutant dispersion modeling analysis to estimate ground-level concentrations or impacts from the Project.

Marine Vessel Emission Sources

The additional LNGCs and supporting marine vessels, namely tugboats and pilot boats, associated with the Project would routinely generate air emissions. CCL developed the emission rates for the LNGCs and supporting marine vessels based on specific engine duties and fuel types for each mode of operation (e.g., transiting, maneuvering, hoteling). All emission calculations for the marine vessels were based on an additional 80 carrier calls per year at the CCL Terminal.

Air pollutant emissions from LNGCs would occur along the entire route from the open seas to the ships' berth. Air emissions generated during ship transit in offshore areas would be temporary, transient, and occur at distances allowing for considerable dispersion before reaching any sensitive receptors. Therefore, air emissions from ship transit outside the point where the pilot boards the vessel would not be expected to result in a significant impact on air quality.

For LNGCs, CCL estimated emissions assuming maneuvering to and away from the pier would occur over an eight-minute period total with the assistance of four tugboats for each call. While the LNGC is docked at the pier, emissions would be generated by carrier hoteling and one tugboat idling for an approximate representative time of 20 hours.

Marine diesel oil would be used as fuel for maneuvering with slow speed diesel engines; natural gas would be used as fuel for all other operating scenarios. CCL assumed an LNGC main engine size rating of 30,000 kilowatts for the emission calculations. The emission calculations are based on use of emission factors from EPA's recent port emissions inventory guidance (EPA, 2020). The NO_x emission factor used for maneuvering with slow speed diesel engines fueled by marine diesel oil is consistent with the International Maritime Organization MARPOL Annex VI, Regulation 13, Tier III NO_x emission limit for the North America Emissions Control Area. In calculating the SO_2 emissions, the marine diesel oil was assumed to have a sulfur content representative of ultra-low sulfur diesel.

CCL's emission calculations for the tugboats and pilot boats were based on EPA Tier 4 and Tier 3 exhaust emission standards, respectively, and EPA's recent port emission inventory guidance. In calculating the SO_2 emissions, CCL assumed that tugboats and pilot boats would be using ultra-low sulfur diesel.

The estimated highest annual criteria air pollutant and HAP emission rates associated with: LNGCs and tugboats (2 per call) transiting with pilot boat; LNGCs and tugboats (4 per carrier call) maneuvering to the CCL Terminal pier; and LNGCs hoteling at the pier and one tugboat idling nearby are presented in table H8, appendix H; GHG emission rates are presented in table H9, appendix H. Estimated highest short-term criteria air pollutant emission rates (lb/hr) associated with marine vessel operations are presented in table H10, appendix H.

Emission Source Mitigation

Best available control technology (BACT) must be evaluated for affected sources under the Project, per state (30 TAC 116.111(a)(2)(C)) and federal PSD (40 CFR Part 52.21) permitting rules. Emission control technologies and techniques evaluated for BACT for affected sources were evaluated based on technical feasibility and economic reasonableness.

The hot oil furnaces would be equipped with Ultra-LNB, which is considered BACT for NO_x emissions from these units. The use of low-sulfur gaseous fuel would minimize SO_2 and particulate matter emissions. The use of good combustion practices would serve to minimize emissions of other regulated pollutants, such as CO. These measures are considered BACT for emissions from the hot oil heaters.

The thermal oxidizers for the acid gas recovery units would be equipped with LNB, which is considered BACT for NO_x emissions from these units. The use of low-sulfur gaseous fuel would minimize SO_2 and particulate matter emissions. The use of good combustion practices (e.g., air-to-fuel ratio optimization) would serve to minimize emissions of other regulated pollutants, such as VOCs. These measures are considered BACT for emissions from the thermal oxidizers.

The limited-use emergency generators/engines would be built to meet the applicable emission standards outlined in 40 CFR 60, Subpart IIII. Additionally, these generators would utilize ultra-low sulfur diesel fuel to minimize emissions of other regulated pollutants (e.g., SO_2).

Regarding the process fugitive VOCs from equipment leaks, CCL would reduce the potential for leaks by operating equipment and conducting maintenance in accordance with manufacturers' specifications. Also, CCL would detect and reduce fugitive emissions by application of the TCEQ 28M Leak Detection and Repair Program. This program includes instrument monitoring for all valves, relief valves, and pump and compressor seals in VOC service (with a leak definition of 10,000 parts per million [ppm]) as well as olfactory monitoring of flanges in VOC service and all components in methane service. Also, the 28M Leak Detection and Repair Program would be implemented for all components in methane service (with a leak definition of 10,000 ppm) for the Project. This monitoring program satisfies TCEQ BACT[45] requirements.

Emissions from the ground flares would be reduced through proper flare/burner design and implementation of applicable work standards outlined under 40 CFR part 63, Subparts YY and FFFF.

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[45] Texas Commission on Environmental Quality (TCEQ). 2006. BACT Guidelines for Chemical Sources – Equipment Leak Fugitives. TCEQ, Austin, Texas. Accessed at: https://www.tceq.texas.gov/permitting/air/nav/air_bact_chemsource.html.

Additionally, for the marine flare, emissions would be reduced through recovery of cargo loading return gas.

Regarding GHGs for the emergency engines, hot oil heaters, and acid gas thermal oxidizers, emissions would be minimized through use of low-carbon gaseous fuel only, proper combustion, operations, and maintenance practices, and proper insulation for surfaces above 120 ºF to prevent heat loss and improve combustion efficiency. Fugitive GHG emissions (from equipment leaks) would be minimized through proper design and construction.

In summary, the proposed BACT and resulting BACT-based emission rates for the Project emissions sources would be consistent with New Source Performance (NSPS) Standards, National Emission Standards for Hazardous Air Pollutants (for organics liquids distribution – subpart EEEE, stationary combustion turbines – subpart YYYY, and stationary reciprocating internal combustion engines – subpart ZZZZ), and TCEQ-stipulated emission standards (via recent PSD permits for other similar sources), as applicable.

Summary of Total Project Emissions

A summary of the total annual criteria air pollutant and HAP emissions, by year, for all facets of the Project – construction, commissioning, and operation – is presented in table H11, appendix H; GHG emissions are presented in table H12, appendix H. The emission rates for Project operation in 2028 are estimated by ratioing the total projected stationary source and marine vessel emission rates by the equivalent number of trains anticipated to be in operation that year (i.e., Train 8 operating four months and Train 9 operating three months in 2028).

The emission rates shown in tables H11 and H12, appendix H, are based on the maximum operating capacity of the Project. Actual annual emissions could be somewhat lower than these values and would vary year to year over the operational life of the Project.

Operations Impact Assessment

To provide a more quantitative evaluation of the potential impacts of the Project operation on air quality, CCL conducted a dispersion modeling analysis of Project criteria air pollutant emissions following an approved modeling protocol. The analysis was conducted using the EPA-recommended American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) pollutant dispersion model with the regulatory default option invoked to predict off-site (i.e., ambient) ground-level concentrations. Representative surface and upper air meteorological data for the 5-year period 2017 through 2021 from the Corpus Christi International Airport were input to AERMOD.

Initially, CCL conducted a Significance Analysis to determine if Project emissions for criteria air pollutants would cause a significant impact at or beyond the property line of the CCL Terminal. Generally, the Significance Analysis considers emissions only associated with the Project sources and compares the model-predicted highest concentrations to corresponding SILs to determine if any such pollutant concentrations would be "significant." If the Significance Analysis shows that model-predicted concentrations for a particular pollutant and averaging period(s) are greater than the applicable SIL, a full or cumulative impact analysis (i.e., NAAQS analysis) and a PSD increment consumption analysis, as applicable, would need to be performed for this pollutant and averaging period(s). A full or cumulative impact analysis must consider emissions from existing regional sources in addition to the Project sources. If the predicted Significance Analysis results for a particular pollutant and averaging period are below the applicable SIL, then no further analyses are required for that pollutant and averaging period.

Significance Analysis Results

To assess compliance with the NAAQS, CCL initially conducted a retrospective air quality impact analysis for significance ("Significance Analysis") that included the combined set of emission sources for the Project and the Stage 3 Project (i.e., Midscale Trains 1 through 9). The results of that analysis show maximum model-predicted 1-hour NO_2 ground-level concentrations exceeding the SIL. These impacts are located just beyond (about 0.4 mile) the property boundary. Maximum model-predicted concentrations for all other criteria air pollutants are less than the relevant SILs. Table H13, appendix H, presents the Significance Analysis results.

NAAQS Compliance Assessment Results

Based on the results of the Significance Analysis, CCL conducted a cumulative impact analysis for NO_2 to demonstrate compliance with the 1-hour NO_2 NAAQS, per EPA and TCEQ requirements. This analysis accounted for the NO_2 emissions from: 1) all stationary sources at the CCL Terminal (Liquefaction Project, Stage 3, and Midscale Trains 8 and 9); 2) off-site stationary sources; and 3) a representative NO_2 background concentration. Also, at FERC's request, this analysis accounted for NO_2 emissions from marine vessels (LNGCs and assist tugboats) associated with CCL Terminal operations.

Additionally, FERC requested that CCL conduct a NAAQS compliance assessment for all other criteria pollutants and associated averaging periods. At FERC's direction, this analysis accounted for emissions from: 1) all stationary sources at the CCL Terminal; 2) marine vessels associated with terminal operations; and 3) representative criteria pollutant background concentrations.

The results of the NAAQS compliance assessment are summarized in Table H14. These results show maximum concentrations below the NAAQS for all criteria pollutants and associated averaging periods. Of note, this assessment shows that the maximum annual $PM_{2.5}$ concentration, after accounting for a representative background concentration, is below the current NAAQS of 9.0 micrograms per cubic meter ($\mu g/m^3$).

FERC also requested that CCL conduct an ozone analysis for LNG terminal-wide precursor emissions of NO_x and VOC.[46] This analysis was based on the application of EPA guidance using the Tier 1 demonstration tool.[47,48,49] This methodology yielded an ozone concentration from precursor emissions of 4.0 parts per billion (ppb). Adding this concentration to the 3-year average ozone background concentration of 0.063 ppm or 63 ppb (see appendix G, table G2) yields a total concentration of 67 ppb, which is below the 8-hour ozone NAAQS of 70 ppb.

Human Health Risk Assessment

CCL has provided FERC with a detailed impact assessment for HAP emissions. This assessment considered HAP emissions from stationary sources and marine vessels associated with the Liquefaction Project and Stage 3 Project, in addition to the proposed Project. The results of this analysis were used by FERC to develop a HHRA for HAP emissions across the entire CCL Terminal (see appendix F).

The inhalation HHRA demonstrates that, except for benzene exposure for hypothetical adult residents, individual HAP cancer risks, chronic (long-term) non-cancer hazards, and acute (short-term) hazards are below EPA's most stringent target levels.

The highest estimated benzene cancer risk for the maximum off-property adult resident is very slightly above EPA's most stringent target cancer risk level of 1-in-a-1,000,000. The benzene cancer risk for the maximum off-property child resident, as well as the cancer risks for all other individual HAPs for both adult and child residents and all chronic non-cancer hazards at the maximum model-predicted impact location(s) are below EPA's target levels. The estimated maximum benzene acute non-cancer hazard for

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46 This analysis can be viewed on the FERC eLibrary under accession number 20240424-5159.

47 EPA, 2022. Guidance for Ozone and Fine Particulate Matter Permit Modeling, EPA-454-R-22-005. 29 July 2022.

48 40 CFR Part 51, Appendix W – Guideline on Air Quality Models.

49 EPA, 2019. Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, EPA-454/R-19-003. 30 April 2019.

the maximum off-property adult/child resident is twice EPA's target value of one (1). However, this hypothetical off-property resident is assumed to live at the location of the highest model-predicted off-property annual and hourly benzene concentrations, which occurred in a highly industrial, uninhabited area where no one is expected to remain for any length of time. The model-predicted annual and hourly benzene concentrations at the closest residences north of the CCL Terminal in Gregory are at least an order of magnitude lower, with estimated cancer risks and acute hazards well below EPA's lower-bound (most stringent) target cancer risk level and acute non-cancer hazard target value. The total cancer risk and chronic non-cancer and acute hazards summed across all carcinogenic HAPs and HAPs with similar chronic non-cancer and acute health effects from the CCL terminal are below EPA's target levels. The total cancer risk summed across all carcinogenic HAPs from the CCL terminal is below the EPA target cancer risk for individual facilities of 1-in-100,000. Note that this individual facility risk management objective is ten times more stringent than the highest cancer risk that EPA deems acceptable (1-in-10,000) and is intended to account for the potential for background risk from other sources and environmental factors in the surrounding area. Based on the results of this HHRA, which addressed chronic cancer risks and non-cancer hazards, as well as acute hazards, potentially associated with HAP emissions from the CCL terminal, we conclude that there is no need for concern about health effects potentially associated with exposures to emissions of HAPs, including benzene.

8.2 Noise

Construction and operation of the Project would affect the local noise environment in the Project area. The ambient sound level of a region, which is defined by the total sound 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, in part due to changing weather conditions and the impacts of seasonal vegetative cover.

Two metrics used to relate the time-varying quality of environmental noise to its known effects on people are the 24-hour equivalent sound level (L_{eq}) and the L_{dn}. The L_{eq} is an A-weighted sound level containing the same sound energy as the instantaneous sound levels measured over a specific time period. Sound levels, measured in decibels (dB), are perceived differently depending on the length of exposure and time of day. The L_{dn} considers the duration and time the noise is encountered. In the calculation of the L_{dn}, nighttime (10:00 PM to 7:00 AM) noise exposures are increased by 10 dB to account for people's greater sensitivity to sound during nighttime hours.

The dBA is used because human hearing is less sensitive to low and very high frequencies than mid-range frequencies. A person's threshold of perception for a perceivable change in loudness on the A-weighted sound level is on average 3 dBA, whereas a 5 dBA change is clearly noticeable, and a 10 dBA change is perceived as twice or half as loud. Table I1 in appendix I demonstrates the relative A-weighted sound levels of common sounds measured in the environment and industry and their loudness as perceived relative to a baseline sound level (i.e., conversation at a 3-foot distance).

The EPA has determined that, to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an L_{dn} of 55 dBA (EPA, 1974). FERC has adopted this criterion for assessing the potential noise impact from the construction and operation of the Project.

For a continuously operating noise source, the maximum permissible L_{eq} at a nearby NSAs would be 48.6 dBA throughout the daytime and nighttime periods. The 6.4-dBA difference between L_{eq} 48.6 dBA and L_{dn} 55 dBA is due to the 10-dBA penalty for night-time hours used in the logarithmic calculation.

Local Noise Ordinances

The State of Texas penal code states that a noise is presumed to be unreasonable if it exceeds a dB level of 85. Such a limit is considerably less restrictive than FERC criterion. Counties in Texas do not have any legal authority to enact noise ordinances that are more restrictive than the 85-dB state limit. Due to the distance of the Project from the nearest point in Corpus Christi, the city's ordinance requirements are not applicable to the Project. Section 11-182(b) "Noise nuisance enumeration" from the City of Portland's Municipal Code of Ordinances provides noise limits based on land use zoning. Noise which exceeds 63 dBA at any residentially zoned property boundary would be considered "unreasonable conduct". The 63-dBA limit is assumed to be an L_{eq} sound level. In that 63 dBA L_{eq} exceeds 48.6 dBA L_{eq}, the FERC criterion is more restrictive than the City of Portland Code.

A sound level of 55 dBA L_{dn} (48.6 dBA L_{eq}) at all NSAs is the design goal for the Project.

Existing Sound Levels and Noise Sensitive Areas

CCL identified nine NSAs closest to the Project. The locations of the NSAs are presented in table I2 in appendix I, which also includes the A-weighted baseline ambient day-night sound level (L_{dn}, dBA). Figure I1 in appendix I presents the NSAs over aerial imagery.

Construction Noise Impacts and Mitigation

The Project construction noise impact would be the same or less than that previously authorized by the Commission for the Stage 3 Project. The Project will increase the construction duration but would not increase the construction activity. The 2019 EA states that the construction noise impact due to both daytime and limited nighttime construction will be lower than 55 dBA L_{dn} at all NSAs. The Project would use a screw piling technique and not traditional pile driving. Approximately 480 nightshifts are planned, and nightshifts will not include high noise generating activities such as pile driving or blowdowns. Typical nightshift activities include but are not limited to housekeeping, equipment maintenance, and fueling. Therefore, no additional noise impact due to construction of the Project is expected. The construction noise contribution for the Project is provided in table I3 of appendix I, showing the three closest NSAs. Construction sound levels were extrapolated from the 2019 EA, correcting for the number of trains and distance to the NSAs.

Operation Noise Impacts and Mitigation

Operation of the Project would produce noise on a continuous basis. Equipment planned for the Project is consistent with the Stage 3 Project on a per train basis. The primary noise-generating sources will be fans, compressors, and motors associated with the mixed refrigerant process:

- air-cooled heat exchangers for the mixed refrigerant process – primary sound emission is due to fan operation (approximately 70 per midscale train);
- mixed refrigerant compressor units;
- regeneration compressor units (and motors);
- compressor piping, solvent pumps, air compressor;
- BOG compressor and motor;
- EFG unit compressor, gas pumps, and air-cooled heat exchangers.

A sound propagation model for the full load production operation of the CCL Terminal was developed. The modeling results in the 2014 FEIS and the 2019 EA predicted sound levels based on vendor data and the Engineering Procurement and Construction contractor's internal noise libraries.

Recent updates were performed for both the Liquefaction Project and the Stage 3 Project modeling, yielding results that are expected to be more representative of the CCL Terminal. Updates included updated vendor noise data sheets (sound power data) and ground absorption factors in the model. The result of the most recent assessments and the estimated cumulative noise impact from all development stages (together with the ambient sound level) were used to calculate the total operational CCL Terminal noise, as shown in table I4 of Appendix I.

As presented in table I4, appendix I, calculated sound levels attributable to the total CCL Terminal are below FERC's requirement of 55 dBA L_{dn} or less at the existing NSAs, with all equipment in full load operation. The calculated ambient noise increases associated with the addition of the Stage 3 and proposed Project are 0 to 2 dBA at the NSAs.

To ensure that the nearest NSAs are not significantly affected by noise during operation of the Terminal, **we recommend that the following measure be included as an environmental condition in the Commission's Order:**

- **CCL shall file a noise survey with the Secretary of the Commission (Secretary), <u>no later than 60 days</u> after placing the Project into service. If a full load condition noise survey is not possible, CCL shall provide an interim survey at the maximum possible horsepower load <u>within 60 days</u> of placing Trains 8 & 9 into service and provide the full load survey <u>within 6 months</u>. If the noise attributable to operation of the equipment at the CCL Terminal exceeds an L_{dn} of 55 dBA at any nearby NSA under interim or full horsepower load conditions, CCL shall file a report on what changes are needed and shall install the additional noise controls to meet the level <u>within 1 year</u> of the in-service date. CCL shall confirm compliance with the above requirement by filing an additional noise survey with the Secretary <u>no later than 60 days</u> after it installs the additional noise controls.**

<u>Flaring</u>

Emergency flaring would be infrequent and short-term in duration. For commissioning, the highest noise levels could occur when eight midscale trains are in operation and the ninth midscale train is starting up with flaring. Planned or scheduled blowdowns would not occur as maintenance, start-up, and shutdown activities are routed to the flares.

CCL's acoustical consultant performed a modeling simulation to estimate noise levels during the startup of a single midscale train. The assessment assumed that eight midscale trains would be operating under normal full load operation, with a ninth train operating in commissioning mode with startup flaring occurring.

The flaring activities would be in the center of the CCL Terminal flare fields. This flaring scenario would occur near the end of any single midscale train startup when most of the starting train is running, and the startup flaring is ongoing. Table I5, appendix I provides the existing ambient levels inclusive of the Liquefaction Project; the predicted noise contribution of all midscale trains including ground flare; and the total CCL Terminal sound during this startup condition. As presented in the table, sound from flaring is expected to result in a temporary 1 to 4 dBA increase in the ambient sound level. Such increases would be barely noticeable to most people.

<u>Vibration</u>

The operation of industrial equipment has the potential to create perceptible vibrations in lightweight structures and windows. Vibration transmission from the equipment supports through the ground is one possible cause for perceptible vibration effects off-site. However, the large forces needed to create significant ground-borne vibration are typically not present in the equipment used in LNG facilities.

Elevated levels of low frequency airborne sound can travel extended distances. High amplitude, low frequency sound can result in observable vibrations in lightweight structures such as residential windows. The C-weighted sound level has been used to estimate the effects of low frequency sound.

Sound levels with a C-weighted decibel (dBC) value of 65 dBC or lower are unlikely to create perceptible vibration sensations in building structures. Table I6, appendix I shows the projected dBC levels due to the normal operation of the individual development stages and the total facility. Predicted total-facility levels at all NSAs are at or below the 65-dBC perceptible vibration threshold.

9. Reliability And Safety

Multiple federal agencies share regulatory authority over the LNG facilities and the operator's approach to risk management. DOT PHMSA, Coast Guard, and FERC share primary safety, security, and reliability regulatory oversight over the proposed LNG facilities, as discussed in more detail in appendix J. FERC staff assessment of the potential impact to the human environment in terms of safety and whether the proposed Project could operate safely, reliably, and securely is also described in more detail in appendix J. The following summarizes DOT PHMSA, Coast Guard, and FERC staff analyses for Commission consideration.

As a cooperating agency, DOT PHMSA assists FERC by determining whether the Project's proposed design would meet PHMSA's 49 CFR Part 193 Subpart B siting requirements. On February 14, 2024, PHMSA provided a Letter of Determination (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 PHMSA'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, Coast Guard also assisted the FERC staff by reviewing the proposed Project and the associated LNGC traffic. On August 15, 2022, CCL submitted a Letter of Intent to the Captain of the Port (COTP), Sector Corpus Christi, to notify the Coast Guard of the increased ship traffic related to the proposed CCL Midscale Trains 8 & 9 Project. On August 18, 2022, the COTP accepted CCL's previous WSA dated February 29, 2016 as the preliminary WSA for this expansion project. CCL submitted the Follow-on WSA to the Coast Guard on February 9, 2023 and requested a LOR to confirm that the waterway is suitable to accommodate the proposed increase in the maximum marine vessel traffic from the 400 LNGCs per year that was authorized as part of the Stage 3 Project to 480 LNGCs per year. On January 25, 2024, the USCG issued an LOR indicating that the proposed Project would have a minimal impact on 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 performed a reliability and safety analysis for the proposed CCL Midscale Trains 8 & 9 Project to assess the potential impact of a risk associated with the handling of hazardous materials for the proposed CCL Project facilities and determine whether these facilities would operate safely, reliably, and securely. The review assessed the proposed design and discussed the applicable federal codes, regulations, and incorporated standards as well as discussed FERC staff assessment of the engineering design based on other prescriptive, performance, and risk-based recommended and generally accepted good engineering practices. FERC staff's assessment included a thorough evaluation of the engineering design changes and the impacts to the layers of protections that are present in the facility. Each layer of protection was assessed by reviewing the modifications proposed and either quantified or qualified the impacts to those layers. If the impact renders the layer as ineffective or as significantly diminished, then FERC staff recommended mitigation measures for the Commission to consider for incorporation as conditions in the order.

Through the implementation of recommended mitigation measures and oversight, FERC staff has determined that the proposed Project design would include acceptable layers of protection or safeguards that would reduce the risk of potential cascading damage or offsite impact. The complete reliability and safety review is found in appendix J and its conclusions and recommendations are found in section D.

10. Cumulative Impacts

In accordance with NEPA, we evaluated the Project's potential for cumulative impacts. Cumulative impacts represent the incremental effects of a proposed action (Project) when added to other past, present, or reasonably foreseeable future actions (projects), 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. Our cumulative impact analysis in this proceeding generally follows a method set forth in relevant CEQ and EPA guidance and focuses on the proposed Project's potential impacts on resources or areas of concern where incremental contributions could be potentially significant when added to the potential impacts of other actions. To be included in this cumulative impacts analysis, an action must:

- affect a resource potentially affected by the proposed Project;
- cause this impact within all, or part of, the Project's geographic scope; and
- cause this impact within all, or part of, the time span for the potential impact from the Project.

The geographic scope is a series of resource-specific proximity criteria used to describe the general areas where the Project could contribute to cumulative impacts. The geographic scope varies depending on the resource affected and the magnitude of impact. The resources with potential for the Project to contribute to overall cumulative impacts are geology, soils, groundwater, surface water, special status species, recreation, visual resources, socioeconomics, environmental justice, air quality, and noise. Cultural resources, wetlands, wildlife, vegetation, fisheries, and land use were not included because the Project would either not affect or have a very limited effect on these resources. The geographic scope for each resource is unique and is generally more localized for somewhat stationary resources (e.g., soils) and more expansive for resources with a large geographic area (e.g., air quality). Table K1 in appendix K summarizes the resource-specific geographic boundaries considered in this cumulative impacts analysis. Actions occurring outside these boundaries were generally not evaluated because their potential to contribute to a cumulative impact diminished with increasing distance from the Project.

In addition to the geographic relationship between the Project and other projects in the area, we also considered temporal relationships. If the Commission authorizes the Project, CCL plans to initiate construction of the Project in the second half of 2024 and Project in-service could occur between 2028 through 2031. Several past, present, and reasonably foreseeable actions with impacts during the Project's temporal extent occur or would commence construction or operation during the Project's construction period. Reasonably foreseeable projects that might cause cumulative impacts in combination with the Project include projects that are under construction, approved, proposed, or planned through 2031 or shortly thereafter.

Table K2 in appendix K identifies 45 past, present, proposed, and reasonably foreseeable future actions that could cause a cumulative impact when considered along with the Project. We conclude construction of the Project and other projects identified would not result in a significant cumulative impact on geology, soils, groundwater, surface water, special status species, recreation, visual resources, socioeconomics, environmental justice, air quality, and noise. A detailed discussion of cumulative impacts is presented in appendix K.

10.1 Climate Change

During the scoping period, several commentors, including the EPA, raised concerns regarding the Project's emissions of GHGs and associated climate change impacts. 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 GHGs 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.[50] 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) issued its Climate Science Special Report: Fourth National Climate Assessment, Volumes I and II[51]. This report and the recently released report by the Intergovernmental Panel on Climate Change, Climate Change 2021: The Physical Science Basis, state that climate change has resulted in a wide range of impacts across every region of the country and the globe.[52] Those impacts extend beyond atmospheric climate change alone and include changes to water resources, transportation, agriculture, ecosystems, human health, and ocean systems.[53] According to the Fourth Assessment Report, the U.S. 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.[54] These impacts have accelerated throughout the end of the 20th and into the 21st century.[55]

GHG emissions do not result in proportional local and immediate impacts; it is the combined concentration in the atmosphere that affects the global climate system. These are fundamentally global impacts that feed back to local and regional climate change impacts. Thus, the geographic scope for the 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 concern; however, for this analysis, we focus on the existing and projected climate change impacts on the general Project area. The USGCRP's Fourth Assessment Report notes that the following observations of environmental impacts are attributed to climate change in the U.S. Southeast Gulf Coast region (USGCRP, 2017; USGCRP, 2018).

- The region has experienced an increase in annual average temperature of 1°-2 degrees Fahrenheit (°F) since the early 20th century, with the greatest warming during the winter months; there have been increasing number of days above 95°F and nights above 75°F, with a decreasing number of extremely cold days since the 1970s.
- Over the past 50 years, significant flooding and rainfall events followed drought in approximately one-third of the drought-affected periods in the region when compared against the early part of the 20th century.
- The number of strong (Category 4 and 5) hurricanes, including in the Gulf of Mexico, has increased since the early-1980s.

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50 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.

51 U.S. Global Change Research Program. *Climate Science Special Report: Fourth National Climate Assessment, Volume 1, Chapter 3 Detection and Attribution of Climate Change* (2017), available at: https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf (accessed June 3, 2021).

52 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.

53 6 IPCC Report at SPM-5 to SPM-10.

54 USGCRP Report Volume II at 73-75.

55 See, e.g., USGCRP Report Volume II at 99 (describing accelerating flooding rates in Atlantic and Gulf Coast cities).

- Along the Gulf Coast, sea levels have risen 5-17 inches over the past 100 years depending on local topography and subsidence.

The USGCRP's Fourth Assessment Report notes the following projections of climate change impacts in the Southeast Gulf Coast region with a high or very high level of confidence (USGCRP, 2018).

- Annual average temperatures are projected to increase by 3.6°F to 5.1°F by the mid-21st century and by 4.4°F to 8.4°F by the late 21st century, compared to the average for 1976-2005.
- The region is projected to experience an additional 30 to 60 days per year above 100°F than it does currently.
- Tropical storms are projected to be fewer in number globally, but stronger in force, exacerbating the loss of barrier islands and coastal habitats.
- Southern Texas is projected to see longer dry spells, although the number of days with heavy precipitation is expected to increase by mid-century. Longer periods of time between rainfall events may lead to declines in recharge of groundwater, which would likely lead to saltwater intrusion into shallow aquifers and decreased freshwater availability.
- Sea level rise along the Gulf of Mexico during the remainder of the 21st century is likely to be greater than the projected global average of 1 foot to 4 feet or more, which would result in the loss of a large portion of remaining coastal wetlands.

It should be noted that while the impacts described above taken individually may be manageable for certain communities, the impacts of compound extreme 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 (USGCRP, 2018).

The GHG emissions associated with construction, commissioning, and operation of the Project are presented in section B.8.1 and appendix H. Construction and commissioning of the Project may result in total emissions of up to about 456,440 tons (414,076 metric tons) of CO_2e over the duration of construction and commissioning (2025 through 2028 for construction and 2028 for commissioning). Operation of the new emission sources associated with the Project would result in emissions of up to 453,983 tons per year (tpy) (411,846 metric tpy) of CO_2e (see table H6 of appendix H). The annual emissions estimate for Project operation is based on assuming that the Project emission sources are operated at maximum annual capacity and include fugitive emissions.

As stated in section A.2, the natural gas transported and liquefied by the Project would be exported as LNG overseas. The courts have explained that because the authority to authorize LNG exports rests with DOE, NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the related LNG export facility satisfies section 3 of the NGA.[56] Nevertheless, NEPA requires that the Commission consider the direct GHG emissions associated with a proposed LNG export facility.[57] Therefore, the downstream emissions from the Project are not analyzed in this EA.

The construction and operation of the Project would increase the atmospheric concentration of GHGs, in combination with past, current, and future emissions from all other sources globally and contribute incrementally to future climate change impacts. To assess impacts on climate change associated with the Project, Commission staff considered whether it could identify discrete physical

56 *See Freeport*, 827 F.3d at 46-47; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (*Sabal Trail*) (discussing *Freeport*).

57 *See Freeport*, 827 F.3d at 41, 46.

impacts resulting from the Project's GHG emissions or compare the Project's GHG emissions to targets established to combat climate change.

To date, Commission staff have not identified a methodology to attribute discrete, quantifiable, physical effects on the environment resulting from the Project's incremental contribution to GHGs. Without the ability to determine discrete resource impacts, Commission staff are unable to assess the Project's contribution to climate change through any objective analysis of physical impact attributable to the Project. Additionally, Commission staff have not been able to find an established threshold for determining the Project's significance when compared to established GHG reduction targets at the state or federal level. Ultimately, this EA is not characterizing the Project's GHG emissions as significant or insignificant.[58] 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.

To provide a measure of context of the Project emissions on a national level, we compare the Project's GHG emissions to the total CO_2 emissions of the United States as a whole. At a national level, 4,911 million metric tons of CO_2 were emitted in 2021(U.S. Energy Information Administration, 2023). The total of construction and commissioning emissions from the Project could potentially increase CO2e emissions, based on the national 2021 level of CO_2 emissions, by no more than 0.008 percent in any one year of construction/commissioning; in subsequent years, the Project operations could potentially increase annual emissions nationally by approximately 0.008 percent.

To provide a measure of context of the Project emissions on a state level, we compare the Project's GHG emissions to the total CO_2 emissions for the State of Texas alone. For Texas, 663.5 million metric tons of CO_2 were emitted in 2021 (U.S. Energy Information Administration, 2023). The total of construction and commissioning emissions from the Project (for the multi-year construction period) could potentially increase CO_2e emissions, based on the state 2021 level of CO_2 emissions, by no more than 0.06 percent in any one year of construction/commissioning; in subsequent years, the Project operations could potentially increase annual emissions in Texas by approximately 0.06 percent. We also compare operational emissions in context of state GHG reduction goals. At the time of analysis, the state of Texas had no established GHG reduction goals.

Below, we include a disclosure of the social cost of GHGs (also referred to as the "social cost of carbon"). Calculating the social cost of 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.[59] 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.[60]

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[58] *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.)

[59] *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.

[60] *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

As both EPA and CEQ participate in the interagency working group (IWG), Commission staff used the methods and values contained in the IWG's current draft guidance but note that different values will result from the use of other methods.[61]

Accordingly, Commission staff calculated the social cost of CO_2, N_2O, and CH_4. For the calculation, staff assumed discount rates of 5 percent, 3 percent, and 2.5 percent, assumed the Project would begin service in 2028, and that the operational emissions would be at a constant rate throughout the life of a generic 20-year contract. Noting these assumptions, the GHG emissions from activities disclosed in the EA are calculated to result in a total SC-GHG equal to $121,996,006, $449,187,966 and $674,172,961 respectively (all in 2020 dollars).[62] Using the 95th percentile of the social cost of GHGs using the 3% discount rate,[63] the total SC-GHG from the Project is calculated to be $1,356,887,604 (in 2020 dollars).

C. ALTERNATIVES

As required by NEPA and FERC policy, we identified and evaluated reasonable alternatives to the Project and its various components to determine whether the implementation of an alternative would be environmentally preferable to the proposed action. A reasonable alternative would meet the Project's purpose and would be technically and economically feasible and practical. The range of alternatives analyzed includes the no-action alternative, system alternatives, site alternatives, other methods of transporting natural gas oversea, layout alternatives, and alternative liquefaction methods. An alternative would be environmentally preferable if it offers a significant environmental advantage over the proposed action.

We generally consider an alternative to be preferable to a proposed action using three evaluation criteria, as discussed in greater detail below. These criteria include:

1. the ability of an alternative to meet CCL's stated purpose of expanding the CCL Terminal production capabilities to meet immediate and future global demand for LNG;
2. the technical and economic feasibility and practicality of each alternative; and
3. whether each alternative would provide a significant environmental advantage relative to the proposed action.

1. No-Action Alternative

NEPA requires the Commission to consider and evaluate the no-action alternative. Under the no-action alternative, the Project would not be developed and CCL's objective of an expansion of liquefying and exporting natural gas to foreign markets would not be realized. In addition, the potential environmental impacts discussed in section B of this EA would not occur.

We received multiple comments during the scoping period generally in opposition to the Project. We have prepared this EA to inform the Commission and stakeholders about the expected impacts that

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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).

61 *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).

62 The IWG draft guidance identifies costs in 2020 dollars. *Id*. at 5 (Table ES-1).

63 This value represents "higher-than-expected economic impacts from climate change further out in the tails of the [social cost of CO*2*] distribution." *Id*. at 11. In other words, it represents a higher impact scenario with a lower probability of occurring.

would occur if the Project were constructed and operated. The Commission will ultimately determine the Project need and could choose the no-action alternative.

2. System Alternatives

System alternatives are those alternatives that could replace all or part of the Project by making use of other existing, approved, or proposed natural gas export facilities, including modifications or expansions, to meet the stated objectives of the Project. We reviewed system alternatives for the Project, which included other existing, approved, and proposed LNG export facilities in the U.S. to determine if a system alternative existed that would have less significant adverse environmental impacts than those associated with the proposed Project. The status identified for each system alternative is current as of the issuance of this EA and their total million tons per annum capacities are identified in table B8 of appendix B.

Our analysis was predicated on the assumption that each project has an equal chance of being constructed and would therefore be available as a potential alternative. However, market forces would factor heavily into which and how many of these facilities are built. As identified in table B8 of appendix B, 7 existing facilities and 22 planned, proposed, or approved projects were identified in our system alternatives analysis. Increasing the capacity at existing or approved LNG terminals would result in impacts that are likely comparable to those of the proposed Project.

Commercial, technical, and site availability factors limit the feasibility of other projects as viable system alternatives. Each planned, proposed, or approved project would be authorized from or would apply to DOE to export to FTA countries. The NGA, as amended, has deemed FTA exports to be in the public interest; therefore, we would not speculate or conclude that excess capacity is available from the listed proposed projects to accommodate the purpose and need of the Project. Consequently, we must conclude CCL's proposed export capacity at any other existing or proposed LNG facility would require an expansion or new facilities. Some of the facilities are unlikely to have the available acreage to expand their facilities to accommodate the purpose and need of the Project. For those remaining LNG facilities, there may be available acreage to expand the existing or proposed facilities. However, expansion would require similar structures as the facilities proposed for the Project, resulting in environmental impacts similar to the proposed Project (which already minimizes impacts by constructing on land almost entirely used by existing facilities). These system alternatives, therefore, offer no significant environmental advantage over the proposed Project and are not considered to be preferable.

3. Site Alternatives

To minimize the potential environmental impacts from the proposed action, we evaluated potential alternative sites for the Project within the Gulf Coast region that meet the following criteria:

- provide a significant environmental advantage by co-location with existing facilities;
- provide access to major navigable waterways with existing water frontage and deepwater maritime shipping channels in the Gulf of Mexico;
- provide access to domestic natural gas supplies;
- meet the Project purpose and need, as well as scheduled in-service timing;
- allow for compliance with federal safety regulations for liquefaction and pipeline facilities; and
- be technically and economically feasible and practicable.

Additionally, we considered public lands, environmentally sensitive or protected areas, congested residential or commercial areas, and the presence of environmental justice factors in identifying alternative locations for the Project. The proposed Project would be sited on land previously used for industrial purposes and/or construction of the CCL Terminal; would primarily be sited on lands previously reviewed and approved by FERC; would be co-located with similar technology and infrastructure; and would utilize existing operating infrastructure of the CCL Terminal. Development of a new site would result in additional environmental and socioeconomic impacts associated with construction of new berths and marine facilities, flares, and other LNG terminal infrastructure that would not be required for the Project, because it would share existing infrastructure with the CCL Terminal. Therefore, we do not find site alternatives to be preferable to the proposed action.

D. CONCLUSIONS AND RECOMMENDATIONS

Based on the analysis in this EA, we have determined that if CCL constructs and operates the proposed Project in accordance with its application, supplements, and the staff's recommended mitigation measures below, approval of the Project would not constitute a major federal action significantly affecting the quality of the human environment.

We recommend that the Commission Order contain a finding of no significant impact and that the following measures be included as conditions to any authorization the Commission may issue to CCL.

1. CCL shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to data requests) and as identified in the EA, unless modified by the Order. CCL must:
    a. request any modifications 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 environment 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**, CCL shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, EIs, and contractor personnel would be informed of the EI's authority and have been or would 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. **As soon as they are available, and before the start of construction**, CCL shall file with the Secretary any revised detailed survey maps/sheets at a scale not smaller than 1:6,000 with station positions for the facility authorized by the order. All requests for modifications of environmental conditions of the order or site-specific clearances must be written and must specify locations designated on these alignment maps/sheets.

5. CCL shall file with the Secretary detailed maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all facility relocations, staging areas, new access roads, and other areas that would be used or disturbed that have not been previously identified in filings with the Secretary. Approval for use of 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, or 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*. Examples of alterations requiring approval include all facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;

   b. implementation of endangered, threatened, or special concern 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**, CCL shall file an Implementation Plan with the Secretary for review and written approval by the Director of OEP, or the Director's designee. CCL must file revisions to the plan as schedules change. The plan shall identify:

   a. how CCL 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 CCL 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 CCL 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 CCL's organization having responsibility for compliance;

   g. the procedures (including use of contract penalties) CCL 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. CCL shall employ at least one EI during construction of 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. a full-time position, separate from all other activity inspectors;

e. 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

f. responsible for maintaining status reports.

8. Beginning with the filing of its Implementation Plan, CCL 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 CCL's efforts to obtain the necessary federal authorizations;

b. the construction status of the Project, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally-sensitive areas;

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 CCL from other federal, state, or local permitting agencies concerning instances of noncompliance, and CCL's response.

9. CCL 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, CCL must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

10. CCL 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. CCL 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 the Commission's 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,** CCL 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 CCL 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. CCL shall file a noise survey with the Secretary, **no later than 60 days** after placing the Project into service. If a full load condition noise survey is not possible, CCL shall provide an interim survey at the maximum possible horsepower load **within 60 days** of placing Trains 8 & 9 into service and provide the full load survey **within 6 months**. If the noise attributable to operation of the equipment at the CCL Terminal exceeds an L_{dn} of 55 dBA at any nearby NSA under interim or full horsepower load conditions, CCL shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. CCL shall confirm compliance with the above requirement by filing an additional noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls.

14. **<u>Prior to construction of final design</u>**, CCL shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in the State of Texas:

    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 foundations 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, CCL shall file, in its Implementation Plan, the schedule for producing this information.

Information pertaining to the following specific conditions, shall be filed with the Secretary for review and written approval by the Director of OEP, or the Director's designee, within the timeframe indicated by each condition. 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 will be subject to public disclosure. All information shall be filed a minimum of 30 days before approval to proceed is requested.

15. **Prior to initial site preparation**, CCL 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**, CCL shall file procedures for controlling access during construction. The procedures shall address how unauthorized construction personnel would be restricted from entering the operational areas of the plant.

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

18. **Prior to initial site preparation**, CCL shall file an analysis demonstrating that the anticipated traffic loads on buried pipelines and utilities at temporary and permanent crossings will be adequately distributed during construction and operation of the project. The analysis must consider anticipated traffic loads along the facility entrance/exit roads during construction and operation to determine whether provisions are needed to dissipate the loads on the active buried natural gas and hydrocarbon pipelines situated along the facility entrance/exit roads. If provisions are required, the analysis must demonstrate the effectiveness of such provisions. The analysis shall be based on American Petroleum Institute (API) RP 1102 or other approved methodology.

19. **Prior to initial site preparation**, CCL shall file an updated Emergency Response Plan (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 onsets of hazards from accidental and intentional events along the LNG marine vessel route and potential impacts and onset of hazards from accidental and intentional events at the LNG terminal, including but not limited to a catastrophic failure of the largest LNG tank. 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 potential hazards and impacts, identification of potential hazards, and steps for notification, evacuation and/or shelter in place of the public within any transient hazard areas along the LNG marine vessel route and within LNG terminal hazard areas in the event of an incident;

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 transient hazard areas along the LNG marine vessel route and within hazard areas from LNG terminal;

d. designated contacts with federal, state and local emergency response agencies responsible for emergency management and response within any transient hazard areas along the LNG marine vessel route and 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 and/or shelter public within transient hazard areas along the LNG marine vessel route and 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 any transient hazard areas along the LNG marine vessel route and 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 any transient hazard areas along the LNG marine transit route and 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 transient hazard areas that may better benefit from sheltering in place (i.e., those within Zones of Concern 1 and 2), along the route of the LNG marine vessel and within hazard areas of the LNG terminal that may benefit from sheltering in place (i.e., those within areas of 1,600 British thermal units per square foot per hour (Btu/ft^2-hr) and 10,000 Btu/ft^2-hr radiant heats from fires with farthest impacts, including from a catastrophic failure of largest LNG tank).

CCL 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. CCL shall file public versions of offsite emergency response procedures for public notification, evacuation, and shelter in place.

20. **Prior to initial site preparation**, CCL shall file a 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. CCL 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**.

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

22. **Prior to construction of final design**, CCL shall file information/revisions pertaining to CCL's response numbers 5, 13, 18, 40, 41, 42, 44, 45, 46, 47, 48, and 53 of their September 11, 2023 filing, which indicated features to be included or considered in the final design.

23. **Prior to construction of final design**, CCL 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, firewater post indicator valves per NFPA 24 section 6.3, 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.

24. **Prior to construction of final design**, CCL shall file photometric analyses or equivalent and associated lighting drawings. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall depict illumination coverage along the perimeter of the terminal, process equipment, and along paths/roads of access and egress to facilitate security monitoring and emergency response operations in accordance with federal regulations (e.g., 49 CFR Part 193, 33 CFR 127, 29 CFR Part 1910, and 29 CFR Part 1926) and API 540 or approved equivalent.

25. **Prior to construction of final design**, CCL shall file updated drawings of the security enclosure that show the new Project facilities. The security enclosure drawings shall provide details of the enclosure that demonstrate it is in accordance with NFPA 59A (2019 edition) or approved equivalent 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 enclosure to be overcome.

26. **Prior to construction of final design**, CCL shall file updated closed-circuit television (CCTV) and intrusion detection drawings. The CCTV drawings shall show the locations,

mounting elevation, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, etc.) and shall provide camera coverage at access points and along the entire perimeter of the terminal with redundancies and CCTV coverage interior of the facility to enable rapid monitoring of the terminal, including coverage within new Project areas and buildings. The drawings shall show or note the location and type of the intrusion detection and shall demonstrate coverage of the entire perimeter surrounding the Project facilities.

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

28. **Prior to construction of final design**, CCL shall file an evaluation that demonstrates overpressures would not cause failure of the firewater tanks and pumps, emergency diesel generators, and any other significant components. Alternatively, CCL shall provide drawings and calculations for mitigation measures that would be installed to prevent failure of these components due to overpressures.

29. **Prior to construction of final design**, CCL shall file an evaluation to demonstrate a fire at the ISBL and refrigerant impoundments would not pose cascading damage risk to any of the firefighting equipment and vessels in the refrigerant storage area using methods and/or models that would appropriately account for the composition of a ISBL and refrigerant impoundment fires.

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

31. **Prior to construction of final design**, CCL 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 3.28 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.

32. **Prior to construction of final design**, CCL 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.

33. **Prior to construction of final design**, CCL 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.

34. **Prior to construction of final design**, CCL shall file information to verify how the engineering, procurement, and construction (EPC) contractor has addressed all FEED Hazard and Operability (HAZOP) recommendations.

35. **Prior to construction of final design**, CCL shall file a HAZOP study and any Layer of Protection Analysis (LOPA) or safety integrity level verification studies on the final design, a list of the resulting recommendations, and actions taken on the recommendations. The issued for construction P&IDs shall incorporate the recommendations and justification shall be provided for any recommendations that are not implemented.

36. **Prior to construction of final design**, CCL shall provide a check valve upstream of the Acid Gas Removal Column to prevent backflow or provide a dynamic simulation that shows that upon plant shutdown, the vertical piping segment would be sufficient for this purpose.

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

38. **Prior to construction of final design**, CCL 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.

39. **Prior to construction of final design**, CCL shall file the details of the emergency shutdown system, including a Project-wide emergency shutdown button with proper sequencing and reliability or another system that is demonstrated through a human reliability analysis to provide a means to quickly and reliably shutdown the entire CCL Midscale Trains 8 & 9 Project.

40. **Prior to construction of final design**, CCL shall specify that all emergency shutdown (ESD) valves are to be equipped with open and closed position switches connected to the distributed control system (DCS)/ safety instrumented system (SIS).

41. **Prior to construction of final design**, CCL 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, 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).

42. **Prior to construction of final design**, CCL shall 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.

43. **Prior to construction of final design**, CCL shall file documentation demonstrating that the corrosion allowances for piping and pressure vessels systems are consistent with the American Society of Mechanical Engineers (ASME) B31.3 (or appropriate ASME B31 code), ASME Section VIII, and the inspection intervals prescribed by the facility's preventative maintenance program governing the internal, external, corrosion under insulation, and metal thickness inspections (e.g., API 510, API 570).

44. **Prior to construction of final design**, CCL 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).

45. **Prior to construction of final design**, CCL 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.

46. **Prior to construction of final design**, CCL shall file a pipe stress analysis for critical or potential higher consequence lines that evaluates all loads in ASME B31.3 (2016 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. CCL 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.

47. **Prior to construction of final design**, CCL 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.

48. **Prior to construction of final design**, CCL shall specify redundant, full capacity relief valves for the Ethylene, Propane, Butane, and Pentane storage drums.

49. **Prior to construction of final design**, CCL shall file a final 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 International Society for Automation (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.

50. **Prior to construction of final design**, CCL 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, as well as the sizing and design of the down-comers. 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 and 10 minutes of firewater, 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.

51. **Prior to construction of final design**, CCL shall file final design drawings and spill sizing calculations for the existing LNG Storage Tank spill collection and conveyance system, considering vapor formation rates, that demonstrates the existing spill conveyance systems, including their downcomers, would be adequately sized to convey a spill with an additional LNG pump in each storage tank.

52. **Prior to construction of final design**, CCL shall file impoundment swale hydraulics analysis on the OSBL and Jetty Impoundment Basins that demonstrates the maximum sizing spill controlled by the proposed safety integrity level 2 rated system could be contained without overtopping each trench segment and provide the dimensions of the minimum, maximum trench height, and the slope and length of each section of their trench systems.

53. **Prior to construction of final design**, CCL shall file a finalized sizing spill analysis and supporting documentation that considers the maximum LNG spill for the increased loading rate and demonstrate how the maximum LNG ship loading spill would be limited by a safety integrity level 2 rated system or equivalent to prevent overfilling the OSBL and/or Jetty Impoundment Basins and backing up into the LNG trenches. The analysis shall include spill containment drawings and calculations and consider the maximum flowrates, largest piping deinventory, and a feasible instrument response time for the surveillance and shutdown system.

54. **Prior to construction of final design**, CCL shall file details on the interlocks that specify the maximum loading rate would not exceed 14,000 m3/hr for both the East and West Jetties.

55. **Prior to construction of final design**, CCL shall file a plan, including mitigative measures or design modifications, to inhibit conveyance of an LNG spill downstream of the OSBL and Jetty Impoundment Basins into the stormwater conveyance system in the event of a safety system failure.

56. **Prior to construction of final design**, CCL shall file detailed calculations for sump pumps for all impoundments potentially impacted by proposed Project facilities demonstrating they can remove at least 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration using National Weather Service, Atlas 14, Volume 11, Version 2, or approved equivalent.

57. **Prior to construction of final design**, CCL 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).

58. **Prior to construction of final design**, CCL shall file analysis of the buildings containing hazardous fluids and the ventilation calculations that limit concentrations below the lower

flammable limits (LFLs) (e.g., 25-percent LFL), including an analysis of off gassing of hydrogen in battery rooms, and shall also provide hydrogen detectors that alarm (e.g., 20- to 25-percent LFL) and initiate mitigative actions (e.g., 40- to 50-percent LFL) or alarms in the event the ventilation is not functioning as designed, in accordance with NFPA 59A and NFPA 70, or approved equivalents.

59. **Prior to construction of final design**, CCL shall file final drawings and details that show 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).

60. **Prior to construction of final design**, CCL 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, CCL 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.

61. **Prior to construction of final design**, CCL 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.

62. **Prior to construction of final design**, CCL shall file a technical review of the final design of the locations of buildings that shows their locations are consistent with API 752 (2009 edition) and API 753 (2007 edition), or approved equivalents.

63. **Prior to construction of final design**, CCL shall file a technical review of the final design of the facility that identifies all combustion/ventilation air intake equipment, shows the detailed placement of detectors at those air intakes to detect flammable gas or toxic releases, and verifies 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.

64. **Prior to construction of final design**, CCL shall file a design that includes hazard detection suitable to detect high temperatures and smoldering combustion products in electrical buildings.

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

66. **Prior to construction of final design**, CCL 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 lower flammable limit set points for methane, ethylene, propane, iso-pentane, and condensate.

67. **Prior to construction of final design**, CCL shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of hazard detectors when determining the set points for toxic components such as condensate and hydrogen sulfide.

68. **Prior to construction of final design**, CCL shall file a drawing showing the location of the emergency shutdown buttons, including, but not limited to the refrigerant storage and area/unit emergency isolation and equipment shutdown. Emergency shutdown buttons shall be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.

69. **Prior to construction of final design**, CCL 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.

70. **Prior to construction of final design**, CCL shall file drawings and specifications for the structural passive cold protection systems, demonstrating that equipment and supports would be adequately protected from low temperature releases (e.g., design spills) below minimum design metal temperatures that may exacerbate the initial hazard.

71. **Prior to construction of final design**, CCL shall file calculations and/or test results, per International Organization for Standardization (ISO) 20088 or approved equivalent, for the structural passive protection systems to protect equipment and supports from low temperature releases below minimum design metal temperatures.

72. **Prior to construction of final design**, CCL shall file drawings and specifications for the passive fire protection systems, demonstrating that structural supports and equipment would be adequately protected from fire scenarios (e.g., design spills) that may exacerbate the initial hazard.

73. **Prior to construction of final design**, CCL shall file fire resistant cable specifications for 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 Underwriters Laboratories (UL) 1709 (6th edition) or approved equivalent.

74. **Prior to construction of final design**, CCL shall file a detailed quantitative analysis, for project facility areas and relevant existing and authorized facility areas, 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 a pool or jet fire; 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; and each occupied building that could expose unprotected personnel within the 1,600 Btu/ft^2-hr zone from a pool or jet fire. Trucks at truck transfer stations shall be included in the analysis of potential pressure vessel failures. 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.

75. **Prior to construction of final design**, CCL shall file calculations to confirm the existing firewater pumps and firewater storage are hydraulically adequate for supporting the firewater demands.

76. **Prior to construction of final design**, CCL shall file an evaluation and associated specifications, drawings, and datasheets for transformers and transformer fluid demonstrating prevention of cascading damage of transformers (e.g., fire walls or spacing) in accordance with NFPA 850 or approved equivalent.

77. **Prior to construction of final design**, CCL 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. The drawings shall also demonstrate that firewater coverage is provided by at least two monitors or hydrants with sufficient firewater flow to cool exposed surfaces subjected to a fire, with obstructions to firewater flow path and throw distance taken into account. The drawings shall also demonstrate firewater coverage in areas inaccessible or difficult to access in the event of an emergency by automatic or remotely operated monitors, or fixed fire suppression systems. The drawings shall also include piping and instrumentation diagrams of the firewater systems. Drawings of the sprinkler system design shall show coverage in applicable buildings per NFPA 850 and in applicable closed roofed buildings around the site, per NFPA 13.

78. **Prior to commissioning**, CCL 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. CCL 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.

79. **Prior to commissioning**, CCL 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.

80. **Prior to commissioning**, CCL 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.

81. **Prior to commissioning**, CCL 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.

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

83. **Prior to commissioning**, CCL shall file a plan to maintain a detailed training log to demonstrate that operating, maintenance, safety, security, and emergency response staff have completed the required training. In addition, CCL shall file signed documentation

that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation.

84. **Prior to commissioning**, CCL shall file an Organizational Chart that denotes the operations and maintenance structure and number of operation and maintenance personnel, including support staff. CCL shall also conduct periodic monitoring and assessments of the staffing levels that includes plans to reduce human error caused by periods of overtime, address any identified causes of fatigue, and any related lessons learned and deficiencies consistent with API 755 or approved equivalent.

85. **Prior to commissioning**, CCL shall file the procedures for pressure/leak tests of piping which address the requirements of ASME Boiler and Pressure Vessel Code (BPVC) Section VIII and ASME B31.3. In addition, CCL shall file a line list of pneumatic and hydrostatic test pressures.

86. **Prior to commissioning**, CCL shall file procedures for pressure/leak tests of pressure vessels, which address the requirements of ASME BPVC Section VIII. In addition, CCL shall file a list of pneumatic and hydrostatic test pressure. CCL shall demonstrate that the test pressures consistent with ASME BPVC Section VIII (1992) do not exceed the yield strength of the pressure vessels.

87. **Prior to introduction of hazardous fluids**, CCL shall complete and document a pre-startup safety review (PSSR) to ensure that installed equipment meets the design and operating intent of the facility. The PSSR 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.

88. **Prior to introduction of hazardous fluids**, CCL 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.

89. **Prior to introduction of hazardous fluids**, CCL 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.

90. **Prior to introduction of hazardous fluids**, CCL shall file documentation demonstrating they have completed clean agent acceptance tests in accordance with NFPA 2001 (2022 edition) or approved equivalent.

91. **Prior to introduction of hazardous fluids**, CCL shall complete and document firewater monitor and hydrant coverage tests. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s).

92. **After production of first LNG**, CCL shall file weekly reports on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports shall include a summary of activities, problems encountered, and remedial actions taken. The weekly reports shall also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports shall include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude shall be reported to the FERC within 24 hours.

93. **Prior to commencement of service**, CCL shall file a request for written authorization from the Director of OEP. Such authorization would only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act (MTSA) of 2002, and the Security and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by CCL or other appropriate parties.

94. **Prior to commencement of service**, CCL shall file any proposed revisions to the security plan and physical security of the plant.

95. **Prior to commencement of service**, CCL shall label piping with fluid service and direction of flow in the field, consistent with ASME A13.1 (2016 edition) or approved equivalent, in addition to the pipe labeling requirements of NFPA 59A (2001).

96. **Prior to commencement of service**, CCL shall file a written management system that it would implement to document and track process safety metrics consistent with API 754 or approved equivalent, including Tier 4 metrics that include, but are not limited to whether personnel are involved in the development of procedures they are assigned, whether supervisors are using only qualified personnel for carrying out procedures, whether personnel are adhering to procedures, whether deviations from procedures are investigated, and whether procedural and organizational changes are subjected to management of change requirements.

97. **Prior to commencement of service**, CCL shall file plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring.

98. **Prior to commencement of service**, CCL shall file procedures for offsite contractors' responsibilities, restrictions, monitoring, training, and limitations and for supervision of these contractors and their tasks by CCL 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, the following measures shall apply throughout the life of the CCL Midscale Trains 8 & 9 Project.

99. 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, CCL 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.

100. **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, 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, and fires involving hazardous fluids and/or from other sources. 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.

101. 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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Wazaney, Brad – Cultural Resources

Ph.D., Anthropology, 2006, Washington State University
M.A., American Studies, 2000, University of Wyoming
B.A., History, 1995, Old Dominion University

<u>Perennial Environmental Services, LLC</u>

Steen, Virginia –Project Manager, Project Description, Alternatives, Water Resources and Wetlands, Cumulative Impacts

M.S., Environmental Science – Biology, 2016, University of Houston – Clear Lake
B.S., Environmental Science, 2008, Florida State University

Furlong, Brittany – Deputy Project Manager, Project Description, Alternatives, Geology, Soils, Vegetation, Land Use

B.S., Environmental Science, 2017, University of Pittsburgh

Butler, Amy –Wildlife, Special Status Species, Socioeconomics, Environmental Justice

M.S., Wildlife Ecology, 2011, University of Nebraska – Lincoln
B.S., Wildlife Ecology, 2008, Washington State University

Peyton, Abby – Cultural Resources

M.A., Archaeology, 2005, Texas State University
B.A., Anthropology, 2001, Baylor University

<u>POWER Engineers, Inc.</u>

Corio, Louis A. – Resource Specialist, Air Quality

M.S., Meteorology, 1983, University of Maryland
B.S., Meteorology, 1980, Rutgers University – Cook College

Guerrero, Priscilla A. – Resource Specialist, Air Quality

Ph.D., Civil and Environmental Engineering, 2013, University of Texas
M.S., Environmental and Water Resources Engineering, 2009, University of Texas
B.S. Metallurgical and Materials Engineering, 2007, University of Texas

<u>SLR International Corporation</u>

Bell, Damien – Resource Specialist, Noise

B.S. Mechanical Engineering (Acoustics Concentration), 2005, University of Hartford

Perennial Environmental Services, LLC, POWER Engineers, Inc., and SLR International Corporation are third party contractors assisting the Commission staff in reviewing the environmental aspects of the project application and preparing the environmental documents required by NEPA. Third party contractors are selected by Commission staff and funded by project applicants. Per the procedures in 40 CFR 1506.5(b)(4), third party contractors execute a disclosure statement specifying whether any financial or other interests in the outcome of the project exist. In accordance with Commission policies, these statements are reviewed to ensure no *financial or other organizational conflicts of interest exist. Third party contractors are required to self-report any changes in financial situation and to refresh their disclosure statements annually. The Commission staff solely directs the scope, content, quality, and schedule of the contractor's work. The Commission staff independently evaluates the results of the third-party contractor's work and the Commission, through its staff, bears ultimate responsibility for full compliance with the requirements of NEPA.*

Appendix A

Project Mapping

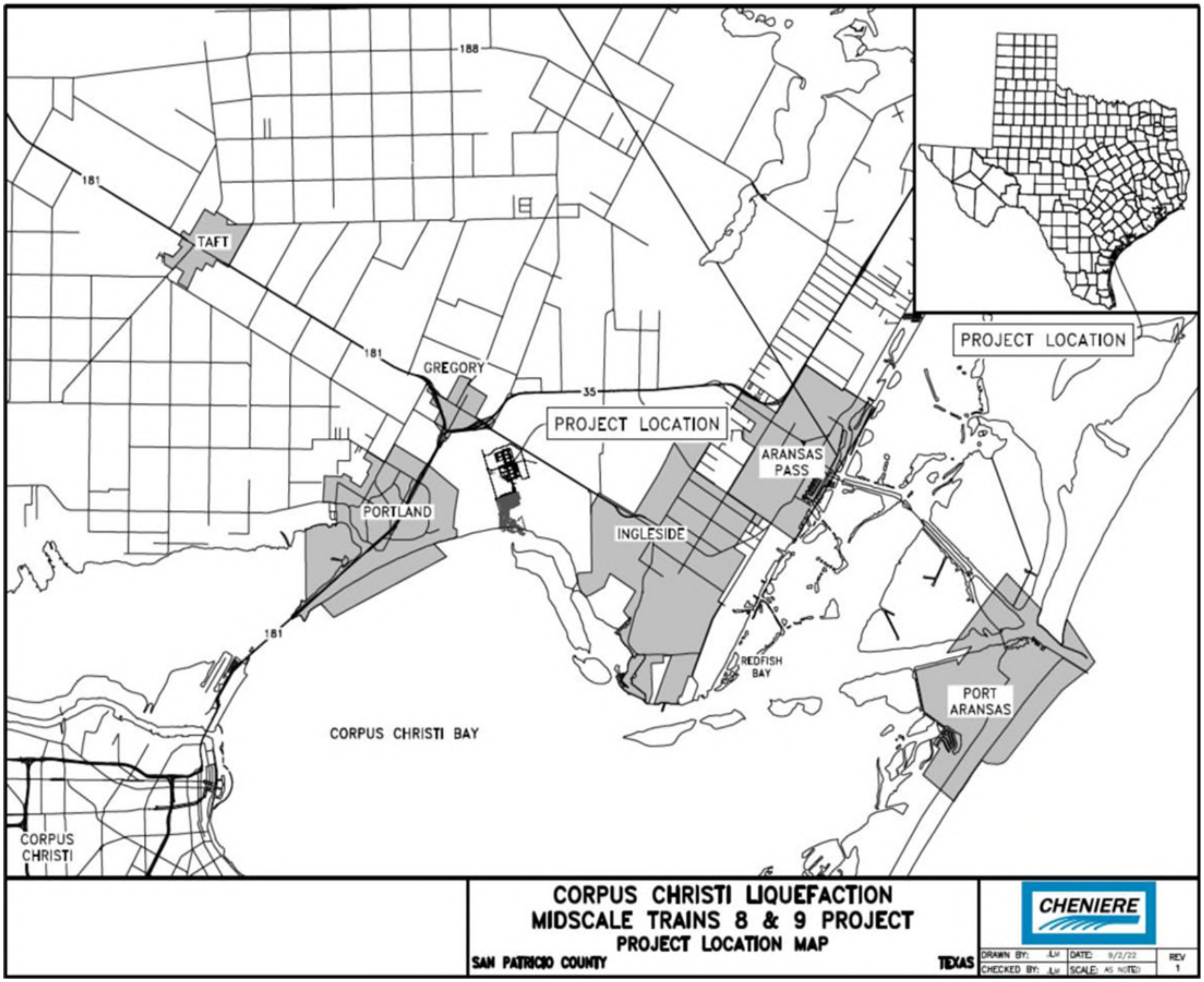

Figure A1 **Project Location Map**

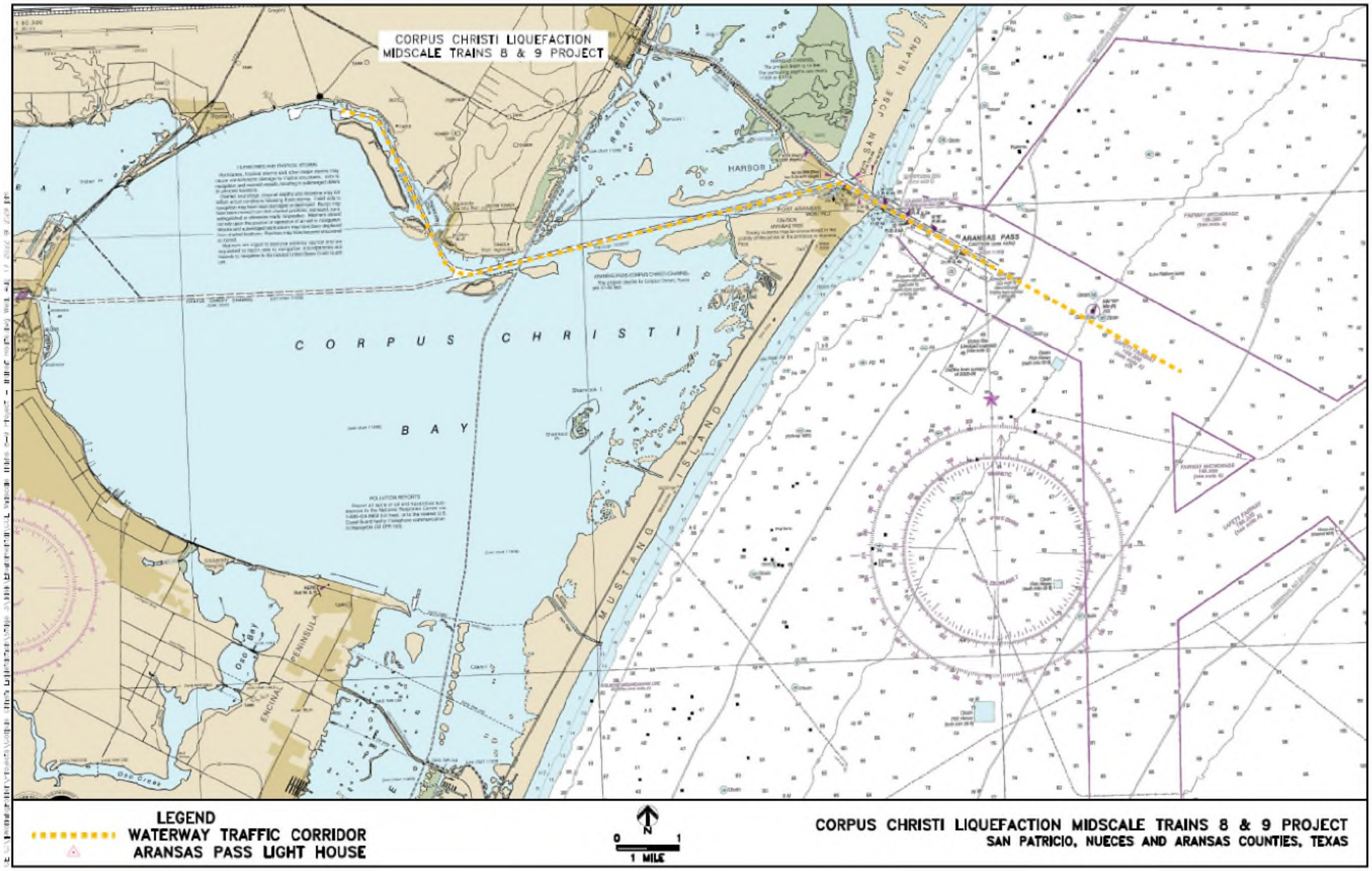

Figure A2 **LNGC Transit Route**

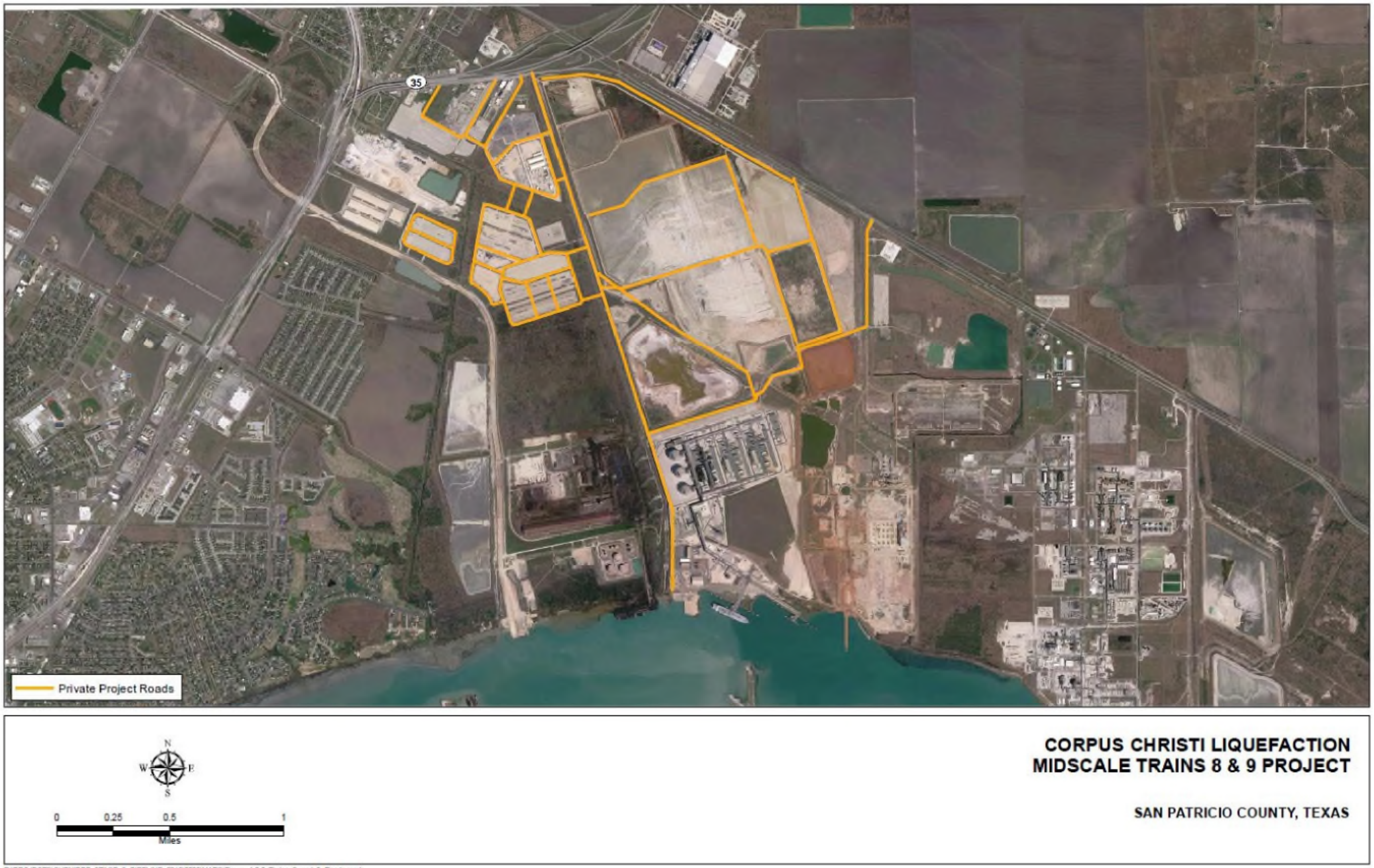

Figure A3 Project Access Roads

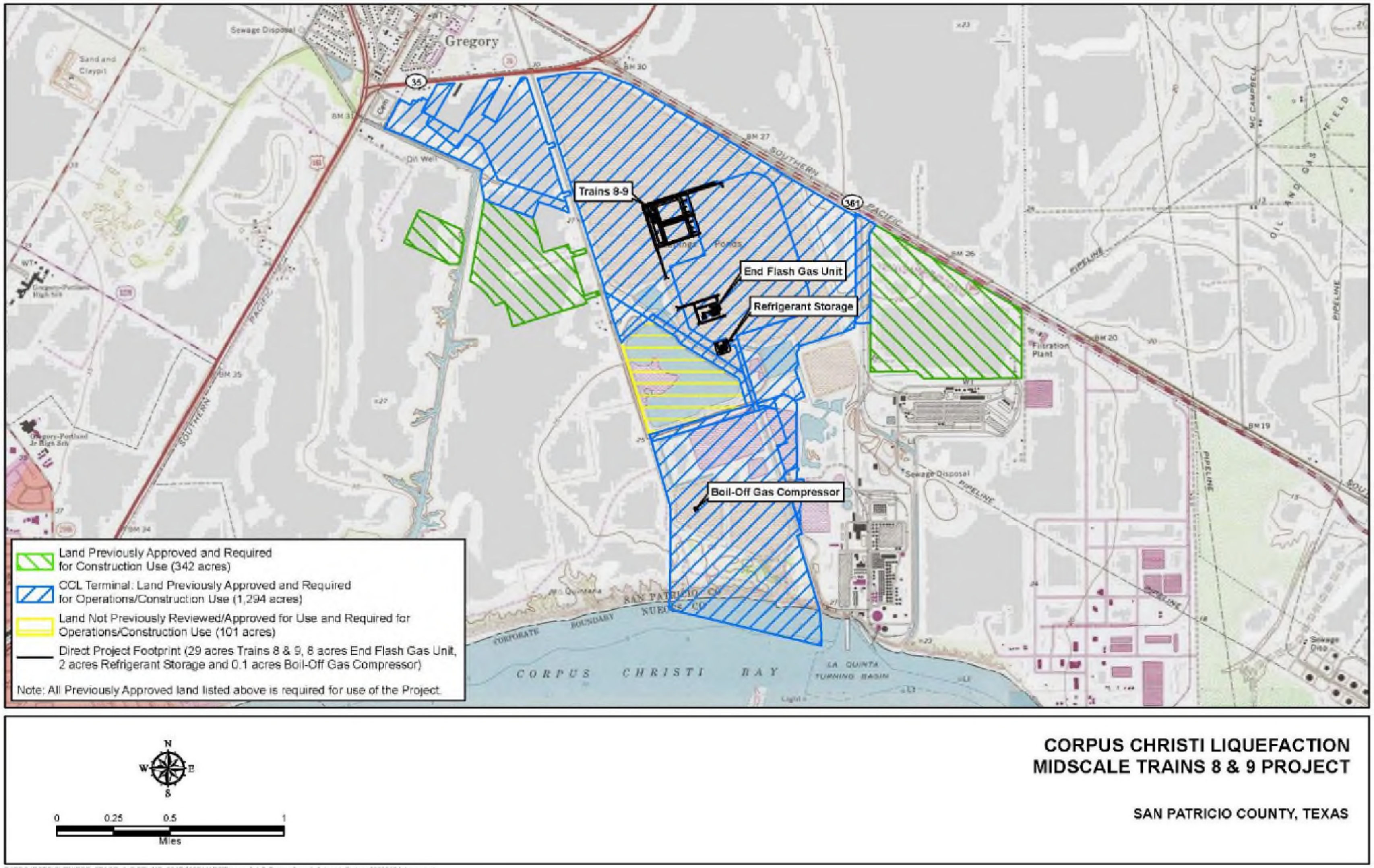

Figure A4 Project Land Requirements

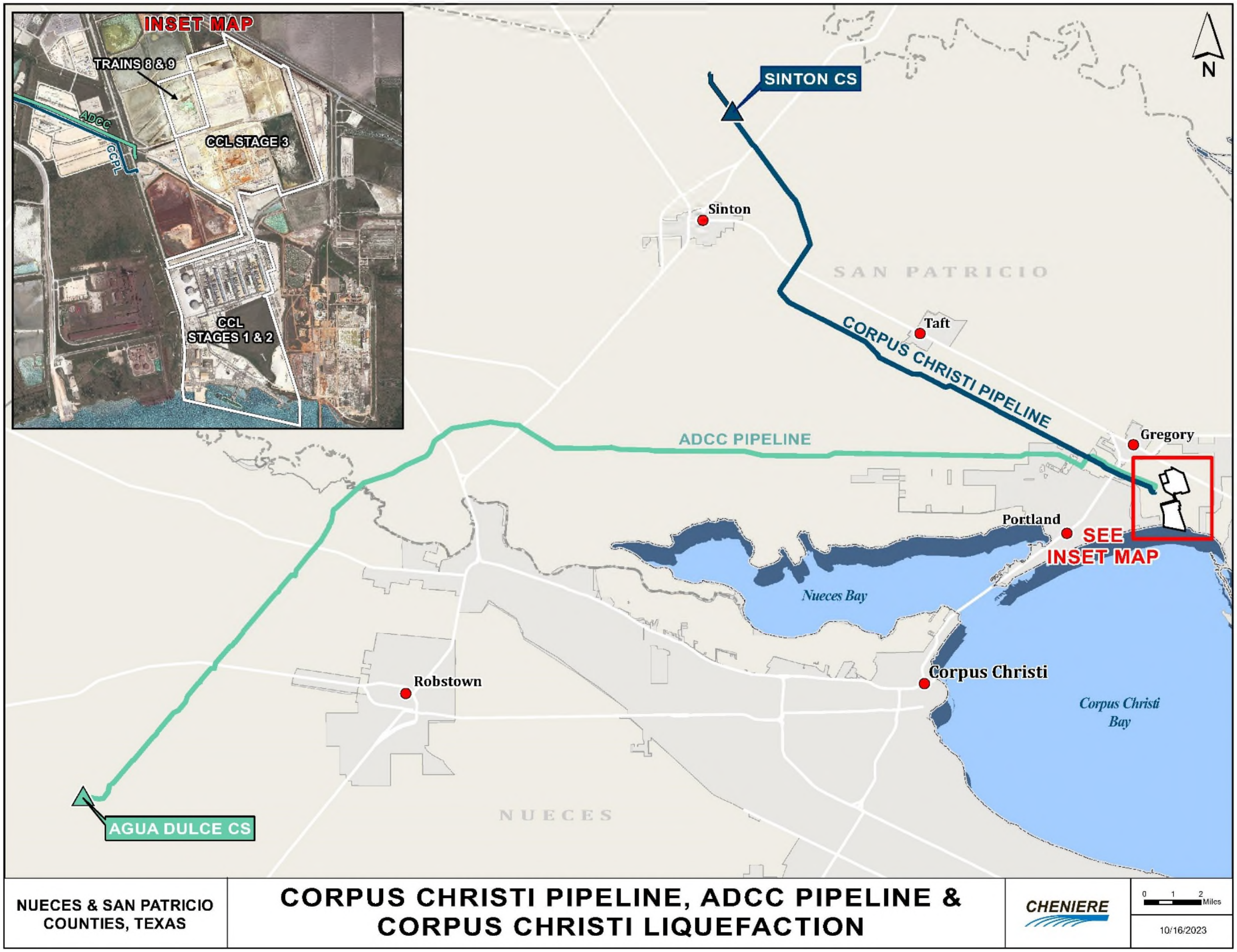

Figure A5 Non-jurisdictional Facilities Overview Map

Appendix B

Additional Tables

Table B1 Issues Identified During the Scoping Period	
Issue/Concern	**EA Section(s) Where Comments are Addressed**
General	
Need for Project is not justified.	A.2
General concern regarding environmental impacts of the Project; general statements opposing the Project.	A.5; B
General comments in support of the Project.	A.5
Alternatives	
Identify and fully consider alternative locations for the Project.	C.3
Identify whether the global demand for natural gas outweighs the local benefits of the no-action alternative.	C.1
Geology	
Vulnerability of the Project to flooding and shoreline erosion caused by rising sea level as well as hurricanes.	B.1; B.9
Vulnerability of the Project to subsidence.	B.1; B.9
Soils and Sediments	
Potential to resuspend and/or reintroduce contaminated sediments during construction.	B.2
Water Resources and Wetlands	
Effects on water quality and supply during project construction and operation.	B.3.1; B.3.2
Effects on surface waters, including surrounding waterbodies, during construction and operation	B.3.1; B.3.2
Impacts on wetlands	B.3.3
Vegetation, Wildlife, and Aquatic Resources	
Effects on vegetation during construction and operation	B.4.1
Effects on wildlife during construction and operation of the Project.	B.4.2
Effects on aquatic resources during construction and operation of the Project.	B.4.2
Effects on migratory bird species and their habitats during construction and operation of the Project.	B.4.3
Effects on threatened and endangered species and their habitats.	B.4.3
Land Use, Recreation, and Visual Resources	
Impacts on residential property from LNGC vessel traffic.	B.6.2
Impacts on fishing, swimming, and boating within the La Quinta Ship Channel.	B.6.2
Socioeconomics	
Impacts on environmental justice communities.	B.7.2
Impacts from marine vessel traffic.	B.7.1; B.7.2
Economic/socioeconomic benefits of the Project for the surrounding communities.	B.7.1; B.7.2
Cultural Resources	
Impacts on cultural resources.	B.5
Air Quality and Noise	
Greenhouse gas emissions from Project construction and operation.	B.8.1
Impacts on air quality in the vicinity of the Project.	B.8.1
Climate change-related impacts of the Project, upstream and downstream greenhouse gas emissions caused by production of fossil fuel and other life cycle emissions for the Project's production and transportation of LNG.	B.8.1

Table B1 Issues Identified During the Scoping Period	
Issue/Concern	**EA Section(s) Where Comments are Addressed**
Climate Resiliency	4.13
Impacts of increased noise levels in the vicinity of the Project.	B.8.2
Reliability and Safety	
Vulnerability of the Project to flooding and shoreline erosion caused by rising sea level as well as hurricanes.	B.1; B.9
Transparency of worst-case scenario and proposed mitigation and/or action plans.	Appendix J
Cumulative Impacts	
Consider a complete and thorough discussion on past, present, and reasonably foreseeable cumulative impacts.	B.10
Climate change-related impacts.	B.10.3

Table B2 Permits and Consultations for the CCL Midscale Trains 8 & 9 Project			
Agency and Agency Contact	**Permit/Approval/Consultation**	**Actual or Anticipated Submittal**	**Anticipated Receipt/Receipt Date**
USFWS	Section 7 ESA Consultation/Clearance; Migratory Bird Consultation; Fish and Wildlife Coordination Act	August 15 and November 14, 2022	Completed January 5, 2023
COE	Approved Jurisdictional Determination	January 5, 2023	Completed March 8, 2023
NOAA Fisheries	Essential Fish Habitat	August 15 and December 2, 2022	December 15, 2022
	ESA Aquatic Threatened and Endangered Species; Marine Mammal Protection Act; Fish and Wildlife Coordination Act	July 18, 2023; Minor revisions requested by NOAA Fisheries on January 25, 2024 and February 14, 2024	February 15, 2024
Coast Guard	Letter of Recommendation	February 9, 2023	January 25, 2024
PHMSA	49 CFR Part 193, Subpart B Facility Siting; Letter of Determination [a]	May 1, 2023	February 14, 2024 [b]
DOE/FECM	Natural Gas Act, Section 3 Application for Authorization to Export LNG	April 6, 2023 [c]	July 19, 2023 for FTA nations; 3rd Quarter 2024 for non-FTA nations [d]
Federal Aviation Administration	Determination of No Hazard to Air Navigation (14 CFR Part 77)	3rd Quarter 2023	Prior to Construction
TCEQ	Amendment to Stage 3 Project Prevention of Significant Deterioration Permit/ GHG Permit	March 30, 2023	3rd Quarter 2024
	Title V Operating Permit	Prior to 2028 estimated in-service date	One year following submittal
	Hydrotest Discharge Permit	During Construction	During Construction and prior to discharge
TPWD	State threatened and endangered species review	October 19, 2023	December 11, 2023
Texas Historical Commission	Section 106 National Historic Preservation Act Consultation, Clearance	August 15, 2022	Complete, concurrence received September 9, 2022
Railroad Commission of Texas	Consistency with the Texas Coastal Management Program	March 1, 2023	Completed April 24, 2023
	Minor discharge permit of hydrostatic test water for dust suppression	During Construction	During Construction

a The August 31, 2018 MOU between FERC and PHMSA provides guidance and policy on each agency's respective statutory responsibility to ensure that each agency works in a coordinated and comprehensive manner. In the 2018 MOU, PHMSA agreed to issue a Letter of Determination stating whether LNG facilities would be capable of complying with location criteria and design standards contained in Subpart B of Part 193.

b The Letter of Determination issued on February 14, 2024 will serve as one of the considerations in the Commission's decision-making process.

c On April 6, 2023, CCL and Cheniere Marketing, LLC submitted an application in DOE/FECM Docket No. 23-46-LNG requesting authorization to export up to the equivalent of 170 billion cubic feet of natural gas as LNG per year to FTA nations and non-FTA nations for a term extending through December 31, 2050.

d DOE granted CCL's and Cheniere Marketing, LLC's application to export to FTA nations on July 19, 2023. CCL's and Cheniere Marketing, LLC's application to export to non-FTA nations is pending with DOE.

Table B3 Soils Impacted by the CCL Midscale Trains 8 & 9 Project								
Soil Series	**Area Affected by Construction Only, Previously Authorized (acres)**	**Area Affected by Operations, Previously Authorized (acres)**	**Area Affected by Operations, Not Previously Authorized (acres)**	**Prime Farmland [a]**	**Severe Water Erosion [b]**	**Severe Wind Erosion [c]**	**Severe Compaction Potential [d]**	**Poor Revegetation Potential [e]**
Waste land [f]	0.0	945.8	101.0	N/A	N/A	N/A	N/A	N/A
Edroy clay	56.1	41.3	0.0	No	No	No	Yes	Yes
Edroy clay, depressional	42.3	20.6	0.0	No	No	No	Yes	Yes
Monteola clay, 5 to 8 percent slopes	0.0	37.3	0.0	No	No	No	Yes	No
Orelia sandy clay loam	121.3	101.1	0.0	No	No	No	No	No
Papalote fine sandy load, 0 to 1 percent slopes	0.0	43.1	0.0	Yes	No	No	No	No
Papalote fine sandy loam, 1 to 3 percent slopes	2.0	2.8	0.0	Yes	No	No	No	No
Raymondville clay loam, 0 to 1 percent slopes	65.1	37.7	0.0	Yes	No	No	No	No
Victoria clay, 0 to 1 percent slopes	0.0	24.5	0.0	Yes	No	No	Yes	Yes
Urban land [f]	55.4	0.0	0.0	No	N/A	N/A	N/A	N/A
Not Classified [g]	0.0	40.0	0.0	N/A	N/A	N/A	N/A	N/A
Total [h]	342.2	1,294.2	101.0					

Source: U.S. Department of Agriculture, Natural Resources Conservation Service, 2021

N/A – not applicable

[a] Includes soils classified as prime farmland or farmland of statewide or local importance by NRCS, Soil Survey Geographic Database (SSURGO).

[b] Areas identified as Highly Water Erodible Soils are ranked as Very Severe or Severe by SSURGO Erosion Hazard (Off-Road, Off-Trail) criteria.

[c] Areas identified as Highly Wind Erodible Soils have a Wind Erodibility Index of 1 or 2 as determined by SSURGO.

[d] Areas identified to have a severe compaction potential are limited to silt loam or finer based on particle size and ranked somewhat poor, poor, and very poor drainage as determined by SSURGO.

[e] Areas identified to have poor revegetation potential are lands that have a Capability Class 3 or greater, a low available water capacity, and slopes greater than 8 percent as determined by SSURGO.

[f] Waste land and Urban Land are mapped by SSURGO but are not official soil series and no soil limitations (e.g., erosion, compaction, and revegetation potential) are assigned.

[g] This area is open water in Corpus Christie Bay (36 acres) or dock space over the open water (4 acres) not classified as soil.

[h] Totals were rounded; therefore, addends do not match specifically.

Table B4
Marine Mammals Observed in the Gulf of Mexico

Common Name	Scientific Name	Status [a]	
		Federal	**State**
North Atlantic Right Whale	Eubalaena glacialis	E	E
Humpback Whale (Mexico DPS)	*Megapetra novaeangliae*	T	--
Fin Whale	*Balaenoptera physalus*	E	E
Sei Whale	*Balaenoptera borealis*	E	E
Minke Whale	*Balaenoptera acutorostrata*	--	--
Blue Whale	*Balaenoptera musculus*	E	E
Sperm Whale	*Physeter macrocephalus*	E	E
Dwarf Sperm Whale	*Kogia simus*	--	T
Pygmy Sperm Whale	*Kogia breviceps*	--	T
Killer Whale [b]	*Orcinus orca*	--	T
Pygmy Killer Whale	*Feresa attenuate*	--	T
Goose-Beaked Whale	*Ziphius cavirostris*	--	T
Gervais' Beaked Whale	*Mesoplodon europaeus*	--	T
Blainville's Beaked Whale	*Mesoplodon densirostris*	--	--
Sowerby's Beaked Whale	*Mesoplodon bidens*	--	--
Bryde's Whale	*Balaenoptera edeni*	--	E
Rice's Whale	*Balaenoptera ricei*	E	--
Short-finned Pilot Whale	*Globicephala macrorhynchus*	--	T
False Killer Whale [b]	*Pseudorca crassidens*	--	T
Melon-headed Whale	*Peponocephala electra*	--	--
Atlantic Spotted Dolphin	*Stenella frontalis*	--	T
Pantropical Spotted Dolphin	*Stenella attenuate*	--	--
Striped Dolphin	*Stenella coeruleoalba*	--	--
Clymene Dolphin	*Stenella clymene*	--	--
Spinner Dolphin	*Stenella longirostris*	--	--
Bottlenose Dolphin	*Tursiops truncates*	--	--
Risso's Dolphin	*Grampus griseus*	--	--
Fraser's Dolphin	*Lagenodelphis hosei*	--	--
Rough-toothed Dolphin	*Steno bredanensis*	--	T
West Indian Manatee	*Trichechus manatus*	T	T

Source: NOAA, 2022 and TPWD 2022b
[a] T = Threatened E = Endangered
[b] Indicates that certain distinct population segments of this species may be federally listed in some regions, but that the species is not federally listed in the Gulf of Mexico.

Table B5 Birds of Conservation Concern with Potential to Occur Within or Near the CCL Midscale Trains 8 & 9 Project	
Species	**Breeding Season within the Region**
American Golden-plover Pluvialis dominica	Breeds elsewhere
American Oystercatcher Haematopus palliatus	April 15 to August 31
Black Skimmer Rynchops niger	May 20 to September 15
Chimney Swift Chaetura pelagica	March 15 to August 25
Dickcissel *Spiza americana*	May 5 to August 31
Gull-billed Tern Gelochelidon nilotica	May 1 to July 31
Hudsonian Godwit Limosa haemastica	Breeds elsewhere
King Rail Rallus elegans	May 1 to September 5
Lesser Yellowlegs Tringa flavipes	Breeds elsewhere
Long-billed Curlew Numenius americanus	Breeds elsewhere
Marbled Godwit Limosa fedoa	Breeds elsewhere
Mountain Plover Charadrius montanus	Breeds elsewhere
Painted Bunting *Passerina ciris*	April 25 to August 15
Prothonotary Warbler *Protonotaria citrea*	April 1 to July 31
Reddish Egret *Egretta rufescens*	March 1 to September 15
Ruddy Tumstone *Arenaria interpres morinella*	Breeds elsewhere
Sandwich Tern *Thalasseus sandvicensis*	April 25 to August 31
Short-billed Dowitcher *Limnodromus griseus*	Breeds elsewhere
Swallow-tailed Kite *Elanoides forficatus*	March 10 to June 30
Willet *Tringa semipalmata*	April 20 to August 5
Wilson's Plover *Charadrius wilsonia*	April 1 to August 20
Source: FWS, 2022	

Table B6 Federal Threatened and Endangered Species Potentially Occurring in the CCL Midscale Trains 8 & 9 Project Area				
Common Name	**Scientific Name**	**Status [a]**		**ESA Effect Determination [b]**
		Federal	**State**	
Fish				
Oceanic Whitetip Shark [c]	*Carcharhinus longimanus*	T	T	*No Effect*
Giant Manta Ray	*Mobular birostris*	T	--	*Not Likely to Adversely Affect*
Reptiles				
Atlantic Hawksbill Sea Turtle [c]	*Eretmochelys imbricata*	E	E	*Not Likely to Adversely Affect*
Green Sea Turtle (North and South Atlantic distinct population segments [DPS]) [c]	*Chelonia mydas*	T	T	*Not Likely to Adversely Affect*
Kemp's Ridley Sea Turtle [c]	*Lepidochelys kempii*	E	E	*Not Likely to Adversely Affect*
Leatherback Sea Turtle [c]	*Dermochelys coriacea*	E	E	*Not Likely to Adversely Affect*
Loggerhead Sea Turtle (Northwest Atlantic DPS) [c]	*Caretta caretta*	T	T	*Not Likely to Adversely Affect*
Birds				
Black Rail	*Laterallus jamaicensis*	T	T	*Not Likely to Adversely Affect*
Northern Aplomado Falcon	*Falco femoralis septentrionalis*	E	E	*No Effect*
Piping Plover	*Charadrius melodus*	T	T	*Not Likely to Adversely Affect*
Rufa Red Knot	*Calidris canutus rufa*	T	T	*Not Likely to Adversely Affect*
Whooping Crane	*Grus Americana*	E	E	*Not Likely to Adversely Affect*
Mammals				
Ocelot [d]	*Leopardus pardalis*	E	E	*No Effect*
North Atlantic Right Whale	*Eubalaena glacialis*	E	E	*Not likely to Adversely Affect*
Fin Whale	*Balaenoptera aphysalu*	E	E	*Not likely to Adversely Affect*
Sei Whale	*Balaenoptera borealis*	E	E	*Not likely to Adversely Affect*
Blue Whale	*Balaenoptera musculus*	E	E	*Not likely to Adversely Affect*
Sperm Whale	*Physeter macrocephalus*	E	E	*Not likely to Adversely Affect*
Rice's Whale	*Balaenoptera ricei*	E	--	*Not likely to Adversely Affect*
West Indian Manatee	*Trichechus manatus*	T	T	*Not likely to Adversely Affect*
Insects				
Monarch Butterfly	*Danaus plexippus*	C	---	*Would Not Contribute to a Trend Toward Federal Listing*
Plants				
Slender Rush-pea	*Hoffmannseggia tenella*	E	---	*No Effect*
South Texas Ambrosia	*Ambrosia cheiranthifolia*	E	---	*No Effect*

Table B6 Federal Threatened and Endangered Species Potentially Occurring in the CCL Midscale Trains 8 & 9 Project Area				
Common Name	**Scientific Name**	**Status [a]**		**ESA Effect Determination [b]**
		Federal	**State**	

Source: FWS, 2022; TPWD, 2022b

[a] E = Endangered: species in danger of extinction throughout all or a significant portion of its range.
T = Threatened: species, which is likely to become endangered within the foreseeable future throughout all or significant portion of its range.
C = Candidate: species with sufficient information on their biological status to propose them as endangered or threatened under the ESA, but for which development of a proposed listing regulation is precluded by other higher priority listing activities.

[b] Effects determinations based on probability of occurrence, presence of/lack of suitable habitat, highly disturbed nature of the site, and previous determinations for the CCL Terminal. The effects determinations for all ESA and State listed marine mammal species (see table B4) would be "Not Likely to Adversely Affect", as addressed in the consultation for the Project.

[c] Indicates the species is under the jurisdiction of NOAA Fisheries.

[d] Species reported in the TWPD database for the area but not reported in the FWS Information for Planning and Consultation ("IPaC") query for the area.

Table B7
State Listed Threatened and Endangered Species Potentially Occurring in the CCL Midscale Trains 8 & 9 Project Area

Common Name	Scientific Name	Status [a]	Determination of Effect [b]
Fish			
Shortfin mako shark	*Isurus oxyrinchus*	T	*No Impact*
Amphibians			
Black-spotted newt	*Notophthalmus meridionalis*	T	*No Impact*
Sheep frog	*Hypopachus variolosus*	T	*No Impact*
Reptiles			
Texas horned lizard	*Phrynosoma cornutum*	T	*Not Likely to Adversely Impact*
Texas scarlet snake	*Cemophora coccinea lineri*	T	*Not Likely to Adversely Impact*
Texas tortoise	*Gopherus berlandieri*	T	*Not Likely to Adversely Impact*
Birds			
Reddish egret	*Egretta rufescens*	T	*Not Likely to Adversely Impact*
Rose-throated becard	*Pachyramphus aglaiae*	T	*No Impact*
Sooty tern [d]	*Sterna fuscata*	T	*No Impact*
Swallow-tailed kite	*Elanoides forficatus*	T	*No Impact*
Tropical parula	*Setophaga pitiayumi*	T	*No Impact*
White-faced ibis	*Plegadis chihi*	T	*No Impact*
White-tailed hawk	*Buteo albicaudatus*	T	*Not Likely to Adversely Impact*
Wood stork	*Mycteria americana*	T	*Not Likely to Adversely Impact*
Mammals			
Atlantic Spotted Dolphin [c]	*Stenella frontalis*	T	*Not Likely to Adversely Impact*
Brydes's Whale [c]	*Balaenoptera edeni*	E	*Not Likely to Adversely Impact*
Dwarf Sperm Whale [c]	*Kogia simus*	T	*Not Likely to Adversely Impact*
False Killer Whale [c]	*Pseudorca crassidens*	T	*Not Likely to Adversely Impact*
Gervais' Beaked Whale [c]	*Mesoplodon europaeus*	T	*Not Likely to Adversely Impact*
Goose-Beaked Whale [c]	*Ziphius cavirostris*	T	*Not Likely to Adversely Impact*
Killer Whale [c]	*Orcinus orca*	T	*Not Likely to Adversely Impact*
Pygmy Killer Whale [c]	*Feresca attenuate*	T	*Not Likely to Adversely Impact*
Pygmy Sperm Whale [c]	*Kogia breviceps*	T	*Not Likely to Adversely Impact*
Rough-toothed Dolphin [c]	*Steno bredanensis*	T	*Not Likely to Adversely Impact*
Short-finned Pilot Whale [c]	*Globicephala macrorhynchus*	T	*Not Likely to Adversely Impact*
Southern yellow bat	*Lasiurus ega*	T	*No Impact*
White-nosed coati	*Nasua narica*	T	*No Impact*

Source: TPWD, 2022b

[a] E = Endangered: species in danger of extinction throughout all or a significant portion of its range.
T = Threatened: species, which is likely to become endangered within the foreseeable future throughout all or a significant portion of its range.

[b] Effects determinations based on probability of occurrence, presence of/lack of suitable habitat, highly disturbed nature of the site, and previous determinations for the CCL Terminal. The effects determinations for all ESA and State listed marine mammal species would be "Not Likely to Adversely Affect", as addressed in the consultation for the Project.

[c] Indicates the species is under the jurisdiction of NOAA Fisheries.

[d] Reported in the FWS IPaC query as potentially occurring in the area but not included in the TWPD database for the area.

Table B8 Existing, Planned, Proposed, or Approved LNG Export Terminals and Expansion Projects				
Company/Project Name	**Location**	**Volume (MTPA)**	**FERC or MARAD Docket**	**Status**
Operating Terminals				
Venture Global Calcasieu Pass	Cameron Parish, LA	12.0	CP15-550	In Service
Freeport Liquefaction Project	Quintana Island, TX	16.8	CP12-509, CP12-29, CP15-518, CP20-532, & CP21-470	In Service
Elba Liquefaction Project	Chatham County, Georgia	2.5	CP14-103	In Service
Cameron LNG Terminal	Hackberry, LA	14.95	CP13-25	In Service
Liquefaction Project	Nueces and San Patricio counties, TX	17	CP12-507 & CP19-514	In Service
Cove Point LNG	Chesapeake Bay, Maryland	5.75	CP13-113	In Service
Sabine Pass Liquefaction Project – Trains 1-6	Cameron Parish, LA	32.1	CP11-72, CP13 2, CP14-12, CP13-552, CP19-11, & CP19-515	In Service
Planned, Proposed, or Approved Terminals and Expansions				
Golden Pass LNG	Sabine Pass, TX	18.1	CP14-517, CP20-459	Approved, under construction
Lake Charles LNG	Lake Charles, LA	16.45	CP14-120	Approved
Magnolia LNG	Lake Charles, LA	8.8	CP14-347	Approved
Driftwood LNG	Calcasieu Parish, LA	27.6	CP17-117	Approved, under construction
Sempra-Port Arthur LNG (Trains 1 & 2)	Port Arthur, TX	13.5	CP17-20	Approved
Freeport LNG (Train 4)	Freeport, TX	5.1	CP17-470	Approved
Gulf LNG Liquefaction	Pascagoula, MS	10.85	CP15-521	Approved
Venture Global Plaquemines LNG	Plaquemines Parish, LA	24.0	CP17-66	Approved, under construction
Texas LNG Brownsville	Brownsville, TX	4.0	CP16-116	Approved
Rio Grande LNG – NextDecade	Brownsville, TX	27.0	CP16-454	Approved
Stage 3 Project [a]	Corpus Christi, TX	11.45	CP18-512	Approved, under construction
Delfin LNG	Offshore, Plaquemines Parish, LA	13.2	MARAD	Approved (License Issuance Pending)
Commonwealth LNG	Cameron Parish, LA	9.5	CP19-502	Approved
Cameron LNG (Vacate Train 5, Modify Train 4)	Hackberry, LA	6.75	CP22-41	Approved
Sempra-Port Arthur LNG (Trains 3 & 4)	Port Arthur, TX	13.5	CP20-55	Proposed
Venture Global CP2	Cameron Parish, LA	28.0	CP22-21	Proposed

Table B8 Existing, Planned, Proposed, or Approved LNG Export Terminals and Expansion Projects				
Company/Project Name	**Location**	**Volume (MTPA)**	**FERC or MARAD Docket**	**Status**
Venture Global Calcasieu Pass	Cameron Parish, LA	0.4	CP22-25	Proposed
Venture Global Plaquemines LNG	Plaquemines Parish, LA	3.2	CP22-92	Proposed
West Delta LNG	Offshore, Plaquemines Parish, LA	6.1	MARAD	Proposed
New Fortress Energy Louisiana FLNG	Offshore, Plaquemines Parish, LA	2.8	MARAD	Proposed
Fourchon LNG	Lafourche Parish, LA	5.0	PF17-9	Pre-filed
Delta LNG-Venture Global	Plaquemines Parish, LA	24.0	PF19-4	Pre-filed

[a] Currently contemplated production from the Stage 3 Project is contracted or sold.

Appendix C

Detailed Construction Procedures

LNG Trains

Pipe installation for the two midscale liquefaction trains would be implemented across multiple work fronts, as erection of structural steel and overall readiness of pipe racks advances. Pipe spool fabrication would be done in a covered area. Structural steel members would be prefabricated off-site and erected upon arrival. Much of the straight run pipe would be field fabricated prior to placement on the pipe racks. Pipe expansion loops would be prefabricated in a shop, transported to position, and then erected with the straight run piping. Pipe would also be painted to the maximum extent possible at the shops after shop welds have been tested in accordance with the applicable codes. The pipe spool size would be as large as can be practically trucked to site to minimize site work and the number of deliveries.

Wherever practical, large equipment would arrive at the site in preassembled packages that would facilitate final hook-up and testing. All equipment would be designed, fabricated, and tested by qualified specialist suppliers at their respective facilities and shipped to site only after the necessary inspections and testing have taken place and the equipment is released. The larger equipment, such as the cold boxes, acid gas absorber, and the refrigerant compressors, would be offloaded at the CCL Terminal construction dock on multi-wheel transport crawlers, and transported to their foundations. Other materials and equipment would be delivered to the site by truck.

When construction is about 70 percent complete, the focus would shift from construction by area to completion by systems. The civil and structural work would be substantially complete, the equipment set, and most of the large bore piping installed. The Project schedule would be driven by the mechanical completion and pre-commissioning requirements. The system completion and turnover packages would be defined and scoped by the engineering team and assembled by the construction team. A turnover coordinator would prepare the systems completion and turnover packages which would include the following documentation:

- Marked-up drawings to show the limit of the system and the location of blinds;
- line list by system with pressure testing documentation;
- list of equipment including motors with data sheets and inspection reports;
- marked-up Single Line Diagrams with inspection/test reports for electrical equipment;
- cable reports;
- instrument Index with data sheets and calibration sheets;
- loop Diagrams;
- any applicable vendor documentation/drawings;
- turnover Exception Lists;
- detailed punchlist; and
- all other required process safety information.

As the piping installation, hydrostatic testing, pneumatic testing, and equipment erection work is completed and the density of craft personnel and construction equipment is reduced within each of the areas, the balance of the painting and insulation work would be completed. The pipe racks would be completed first, followed by the process and utility areas. After the installation of the equipment and piping has been completed, the final road paving, site grading, and cleanup would be done. The temporary construction facilities would be demobilized on a progressive basis when they are no longer needed.

Temporary Construction Facilities

The main construction offices would be located either on-site or in a nearby construction laydown or parking area approved by the Commission for construction use. Support/satellite offices, warehousing, lunchrooms, parking lots, and material laydown storage would be erected as necessary to support craft labor. The Project would primarily use areas that have previously been authorized and are currently being used for construction/operation of the CCL Terminal. The scheduled use of these areas for the CCL Terminal and the Project is anticipated to overlap. Work areas would be used in compliance with the Plan and Procedures. Restoration of construction areas would not occur per landowner request.

Appendix D

Visual Simulations and Existing Daytime Conditions

EXISTING CONDITIONS

Corpus Christi Liquefaction Midscale Trains 8 & 9 Project
Corpus Christi, TX

PHOTO SIMULATIONS

Key Observation Point
NSA-6
Colima St - Day

Photograph Information

Time of photograph:	2:40pm
Date of photograph:	8/24/2023
Weather Condition	Partly Cloudy
Viewing Direction:	Southeast
Latitude:	27.918462°
Longitude:	-97.288969°

Disclaimer: visualizations and plans are for reference only; Not for construction

Figure D1 Key Observation Point NSA-6: Daytime Existing Conditions

Figure D2 **Key Observation Point NSA-6: Daytime Simulated Conditions**

EXISTING CONDITIONS

Corpus Christi Liquefaction Midscale Trains 8 & 9 Project

Corpus Christi, TX

PHOTO SIMULATIONS

Key Observation Point
NSA-6
Colima St - Night

Photograph Information

Time of photograph:	11:40pm
Date of photograph:	8/31/23
Weather Condition:	Clear
Viewing Direction:	Southeast
Latitude:	27.918460°
Longitude:	-97.288967°

Disclaimer: visualizations and plans are for reference only; Not for construction

Figure D3 Key Observation Point NSA-6: Nighttime Existing Conditions

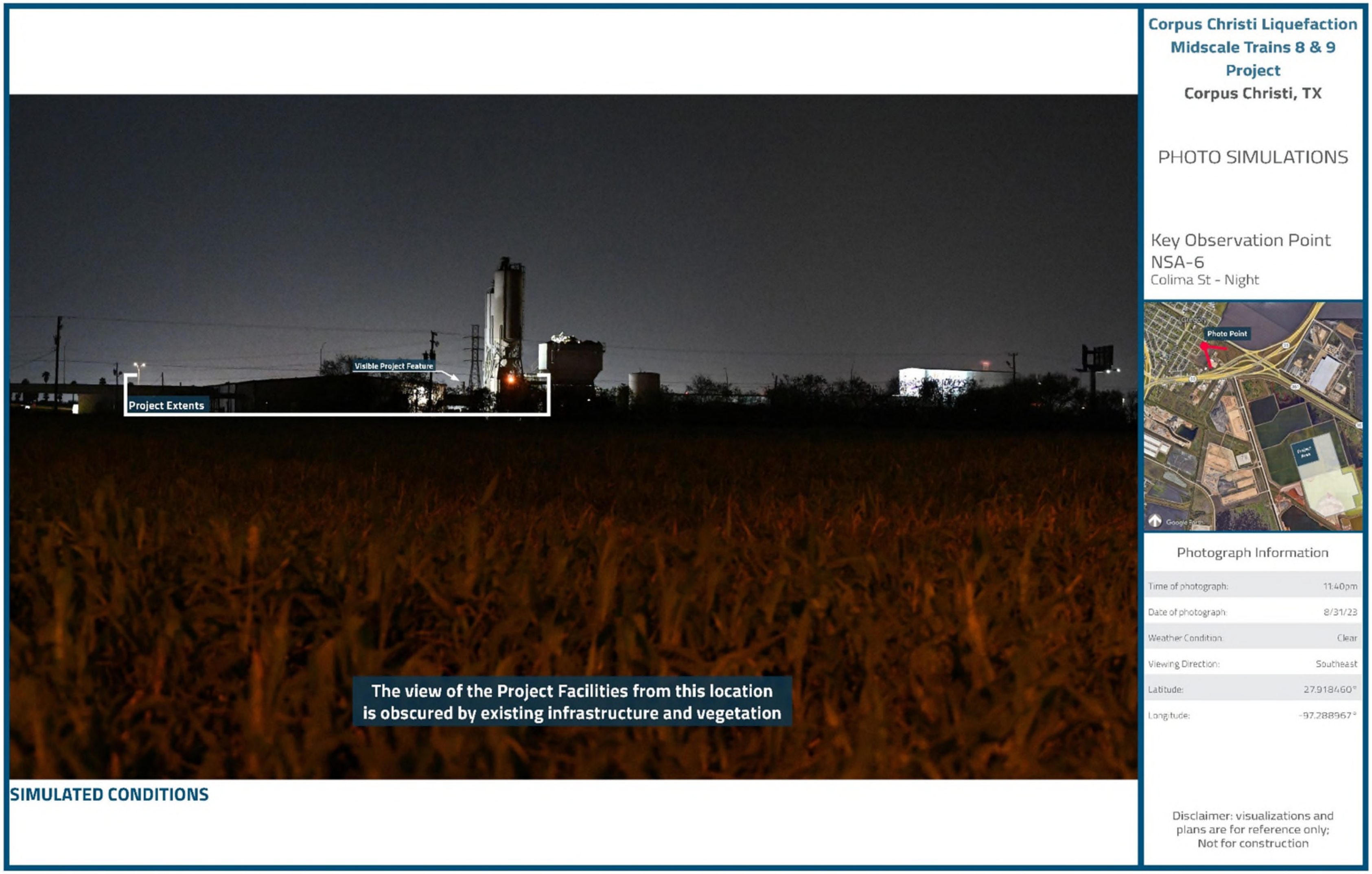

Figure D4 Key Observation Point NSA-6: Nighttime Simulated Conditions

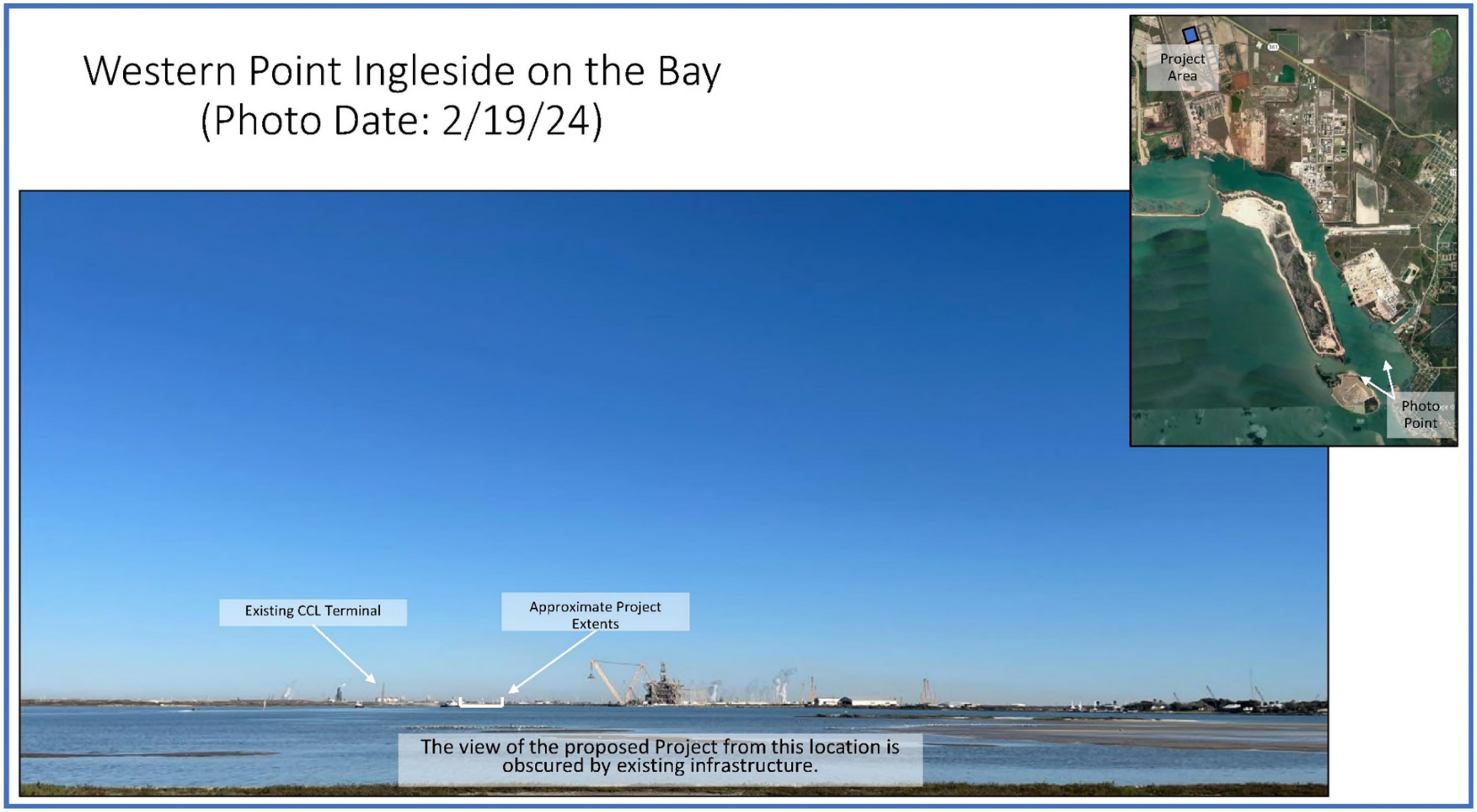

Figure D5 **Existing Daytime Conditions at Western Point Ingleside on the Bay**

Figure D6 Existing Daytime Conditions at NSA 1

NSA 4
(Photo date: 2/18/24)

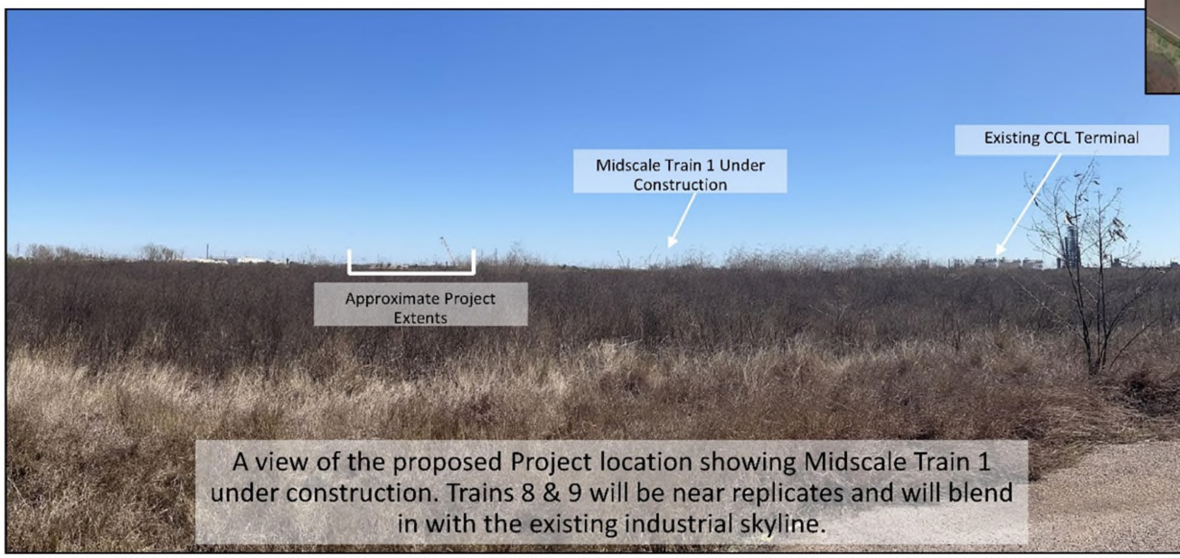

Figure D7 Existing Daytime Conditions at NSA 4

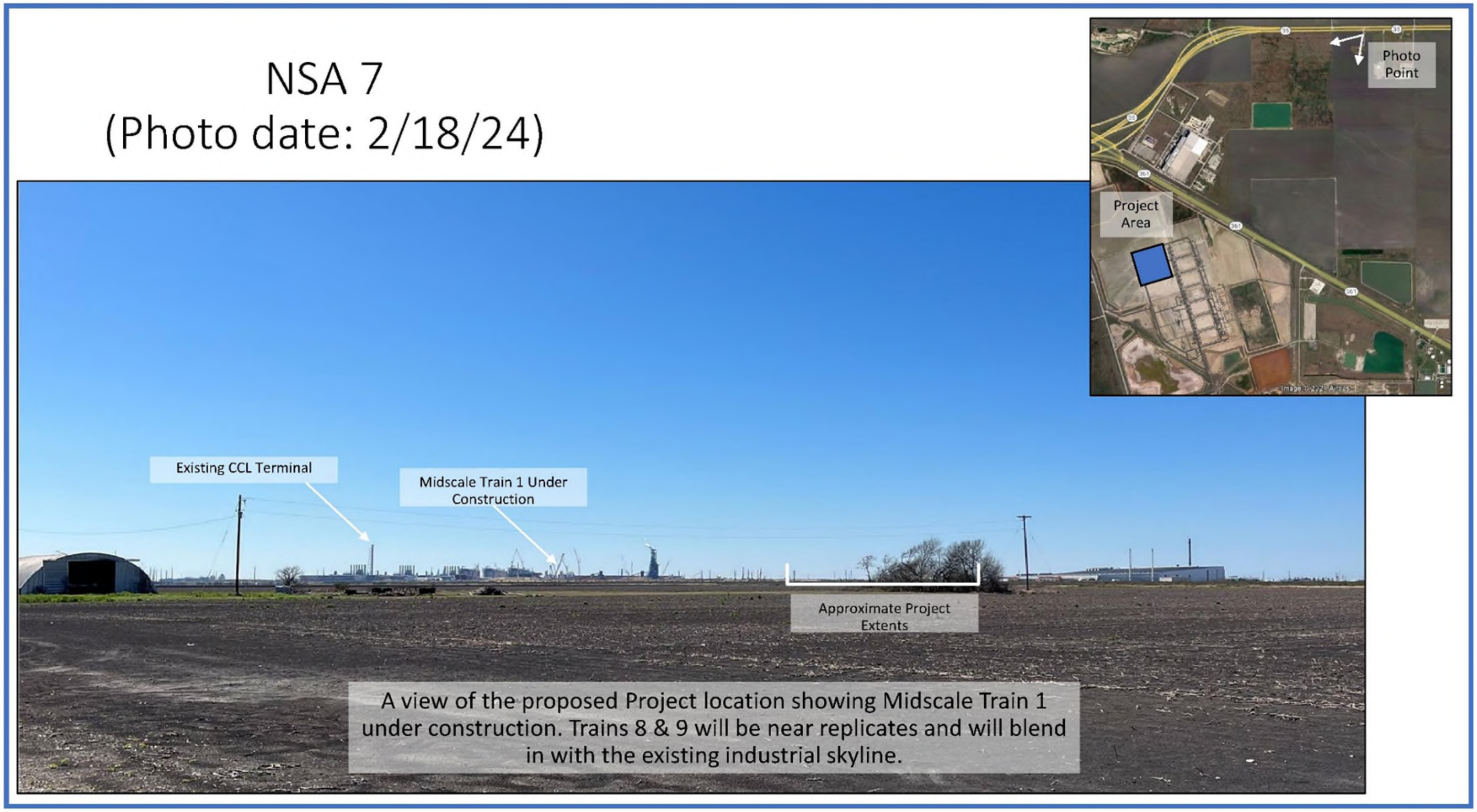

Figure D8 **Existing Daytime Conditions at NSA 7**

NSA 9
(Photo date: 2/18/24)

Figure D9 **Existing Daytime Conditions at NSA 9**

Appendix E

Tables and Maps of Environmental Justice Communities

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
State of Texas	28,862,581	40.7	11.8	0.2	5.0	0.1	0.3	2.3	39.8	59.3	13.3
Calhoun County	20,367	40.8	2.2	0.2	4.3	0.0	0.0	2.7	49.8	59.2	9.6
CT 5.02 BG 1	724	61.0	0.0	0.0	1.5	0.0	0.0	3.5	34.0	39.0	0.0
Nueces County	353,594	28.4	3.5	0.1	2.1	0.0	0.2	1.0	64.6	71.6	17.3
CT 5 BG 1	465	0.0	26.9	0.0	0.0	0.0	0.0	0.0	73.1	**100.0**	7.8
CT 5 BG 2	475	3.4	34.5	0.0	0.0	0.0	0.0	0.0	62.1	**96.6**	**37.2**
CT 6.01 BG 1	1,066	4.0	20.4	0.0	0.0	0.0	0.0	0.0	75.6	**96.0**	**27.9**
CT 6.01 BG 2	439	14.4	0.0	0.0	0.0	0.0	0.0	0.0	85.6	**85.6**	**34.7**
CT 6.01 BG 3	583	6.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0	**94.0**	9.6
CT 6.01 BG 4	1,273	9.5	0.0	0.0	0.0	0.0	0.0	0.0	90.5	**90.5**	3.5
CT 6.01 BG 5	342	24.0	11.4	0.0	0.0	0.0	0.0	0.0	64.6	**76.0**	0.0
CT 6.02 BG 1	815	2.2	11.8	0.0	0.0	0.0	0.0	0.0	86.0	**97.8**	16.3
CT 6.02 BG 2	1,488	4.5	19.6	0.9	1.7	0.0	0.0	0.0	73.3	**95.5**	**20.6**
CT 7 BG 1	1,279	11.9	1.5	0.0	0.0	0.0	0.0	0.5	86.1	**88.1**	5.4
CT 7 BG 2	1,468	10.6	1.4	0.0	1.9	0.0	0.0	2.4	83.7	**89.4**	**35.6**
CT 7 BG 3	1,371	10.5	9.9	0.0	0.0	0.0	0.0	0.0	79.6	**89.5**	**34.0**
CT 8 BG 1	2,380	18.4	10.4	0.0	0.0	0.0	0.0	0.0	71.2	**81.6**	12.2
CT 8 BG 2	662	30.4	0.0	0.0	0.0	0.0	0.0	0.0	69.6	**69.6**	8.3

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 8 BG 3	1,757	8.0	5.2	0.0	0.3	0.0	0.0	0.0	86.5	**92.0**	**51.6**
CT 9 BG 1	518	5.4	6.0	0.0	0.0	0.0	0.0	2.5	86.1	**94.6**	**26.7**
CT 9 BG 2	1,294	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	**17.8**
CT 9 BG 3	935	0.0	1.7	0.0	0.0	0.0	0.0	0.0	98.3	**100.0**	**27.6**
CT 9 BG 4	706	2.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	**98.0**	**24.4**
CT 10 BG 1	876	4.6	0.0	0.0	0.0	0.0	0.0	0.0	95.4	**95.4**	**44.2**
CT 10 BG 2	675	17.2	1.5	0.0	0.1	0.0	0.0	0.0	81.2	**82.8**	**44.5**
CT 10 BG 3	625	4.3	10.2	0.0	0.0	0.0	0.0	0.0	85.4	**95.7**	**54.2**
CT 10 BG 4	1,047	10.7	21.1	0.0	0.0	0.0	0.0	0.0	68.2	**89.3**	**28.2**
CT 11 BG 1	1,153	7.6	9.5	0.0	0.0	0.0	0.0	0.0	82.9	**92.4**	**47.0**
CT 11 BG 2	847	32.1	4.3	1.4	0.0	0.0	0.0	1.4	60.8	**67.9**	**36.8**
CT 12.01 BG 1	660	25.8	0.0	0.0	0.0	0.0	0.0	0.0	74.2	**74.2**	**35.6**
CT 12.01 BG 2	587	35.1	37.1	0.0	4.4	0.0	0.0	0.0	23.0	**64.9**	**22.4**
CT 12.02 BG 1	1,007	16.4	0.9	0.0	0.2	0.0	0.0	0.2	82.3	**83.6**	**19.1**
CT 12.02 BG 2	969	38.7	5.0	0.0	2.0	0.0	0.0	0.0	54.4	**61.3**	5.1
CT 13 BG 1	918	1.4	5.4	0.0	0.0	0.0	0.0	0.0	93.1	**98.6**	**29.0**
CT 13 BG 2	719	1.1	0.0	0.0	0.0	0.0	0.0	0.0	98.9	**98.9**	17.1
CT 13 BG 3	850	7.8	0.0	0.0	0.0	0.0	0.0	0.0	92.2	**92.2**	**24.3**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 13 BG 4	791	6.7	0.0	0.0	0.0	0.0	0.0	0.0	93.3	**93.3**	11.4
CT 14 BG 1	1,516	48.1	0.0	0.0	0.0	0.0	0.0	0.0	51.9	**51.9**	10.1
CT 14 BG 2	787	57.4	5.1	0.0	0.0	0.0	1.4	0.0	36.1	42.6	0.0
CT 14 BG 3	1,730	14.3	0.0	0.0	0.0	0.0	0.0	1.0	84.7	**85.7**	5.6
CT 14 BG 4	1,055	48.0	0.0	0.0	0.1	0.0	0.0	1.3	50.6	**52.0**	**22.0**
CT 15 BG 1	2,427	4.9	1.4	0.0	0.0	0.0	0.0	0.0	93.7	**95.1**	**79.7**
CT 15 BG 2	2,000	8.2	3.9	0.0	0.0	0.0	0.0	0.0	87.9	**91.8**	**31.1**
CT 15 BG 3	977	13.0	0.6	0.0	0.0	0.0	0.0	0.0	86.4	**87.0**	**36.4**
CT 16.01 BG 1	746	2.1	0.0	0.0	0.0	0.0	0.0	0.0	97.9	**97.9**	**17.5**
CT 16.01 BG 2	1,656	0.0	3.0	0.0	0.0	0.0	0.0	0.0	97.0	**100.0**	**20.9**
CT 16.01 BG 3	1,367	1.6	2.9	0.0	0.0	0.0	0.0	0.0	95.5	**98.4**	**43.9**
CT 16.01 BG 4	766	2.9	18.7	0.0	0.0	0.0	0.0	0.0	78.5	**97.1**	**20.1**
CT 16.02 BG 1	778	1.3	0.0	0.0	0.0	0.0	0.0	3.6	95.1	**98.7**	**20.7**
CT 16.02 BG 2	1,032	1.3	0.0	0.0	0.0	0.0	0.0	0.0	98.7	**98.7**	5.2
CT 16.02 BG 3	2,371	1.1	0.0	0.0	0.0	0.0	0.0	6.0	92.9	**98.9**	**20.4**
CT 17.02 BG 1	707	8.1	0.0	0.0	0.0	0.0	0.0	0.0	91.9	**91.9**	1.0
CT 17.02 BG 2	1,210	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	12.6
CT 17.03 BG 1	1,226	2.6	39.3	0.0	0.0	0.0	0.0	0.0	58.1	**97.4**	**28.1**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 17.03 BG 2	1,277	4.1	10.9	0.0	0.0	0.0	0.0	3.8	81.2	**95.9**	**34.0**
CT 17.03 BG 3	750	0.0	49.9	0.0	0.0	0.0	0.0	2.9	47.2	**100.0**	**54.9**
CT 17.04 BG 1	664	1.5	0.0	0.0	0.0	0.0	0.0	1.4	97.1	**98.5**	0.0
CT 17.04 BG 2	1,338	0.0	14.1	0.0	0.0	0.0	0.0	0.0	85.9	**100.0**	3.2
CT 17.04 BG 3	1,218	11.1	3.0	0.0	0.0	0.0	0.0	0.0	86.0	**88.9**	**28.0**
CT 18.01 BG 1	582	8.6	0.0	0.0	7.0	0.0	0.0	0.0	84.4	**91.4**	**24.8**
CT 18.01 BG 2	1,067	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	16.0
CT 18.01 BG 3	1,316	4.3	1.1	0.0	0.0	0.0	0.0	0.5	94.1	**95.7**	**24.0**
CT 18.01 BG 4	1,569	4.3	28.2	0.0	0.0	0.0	0.0	0.0	67.5	**88.6**	**18.5**
CT 18.01 BG 5	728	11.4	0.0	0.0	0.0	0.0	0.0	0.0	88.6	**88.6**	**35.4**
CT 18.02 BG 1	1,494	1.2	2.5	0.0	0.7	0.0	0.0	0.0	95.5	**98.8**	5.1
CT 18.02 BG 2	989	7.1	5.4	0.0	0.0	0.0	0.0	0.0	87.6	**92.9**	8.4
CT 19.03 BG 1	946	7.4	0.0	0.0	0.0	0.0	0.0	0.0	92.6	**92.6**	9.8
CT 19.03 BG 2	918	8.1	0.0	0.0	0.0	0.0	0.0	0.0	91.9	**91.9**	**41.0**
CT 19.03 BG 3	1,943	8.2	0.0	0.0	0.0	0.0	0.0	0.0	91.8	**91.8**	13.2
CT 19.04 BG 1	990	2.0	10.7	0.0	1.7	0.0	0.0	0.0	85.6	**98.0**	4.6
CT 19.04 BG 2	1,530	6.1	3.3	0.0	0.0	0.0	0.0	0.0	90.6	**93.9**	**22.8**
CT 19.04 BG 3	1,347	9.9	0.0	0.0	0.0	0.0	0.0	0.0	90.9	**90.1**	**27.4**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 19.05 BG 1	1,426	4.3	14.1	0.0	4.6	0.0	0.0	0.0	77.1	**95.7**	**27.4**
CT 19.05 BG 2	1,610	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	**22.2**
CT 19.06 BG 1	1,826	9.8	5.3	0.0	4.9	0.0	0.0	0.0	80.0	**90.2**	9.2
CT 19.06 BG 2	2,329	16.6	7.5	0.0	0.0	0.0	0.0	0.0	75.9	**83.4**	**34.5**
CT 19.06 BG 3	1,238	4.2	0.0	0.0	0.0	0.0	0.0	0.0	95.8	**95.8**	14.8
CT 20.01 BG 1	1,046	9.1	0.0	0.0	0.7	0.0	0.0	0.0	90.2	**90.9**	8.4
CT 20.01 BG 2	1,191	11.9	0.0	0.0	0.0	0.0	0.0	0.0	88.1	**88.1**	**17.3**
CT 20.01 BG 3	1,231	10.2	0.9	0.0	0.0	0.0	0.0	0.0	88.9	**89.8**	**25.4**
CT 20.01 BG 4	891	11.8	0.0	0.0	0.0	0.0	0.0	0.0	88.2	**88.2**	8.4
CT 20.02 BG 1	1,792	15.1	3.0	0.0	0.0	0.0	0.0	0.0	81.9	**84.9**	**25.7**
CT 20.02 BG 2	1,147	8.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	**92.0**	7.4
CT 20.02 BG 3	841	11.3	0.0	0.0	0.0	0.0	0.0	0.0	88.7	**88.7**	**34.8**
CT 21.01 BG 1	722	21.7	11.2	0.0	2.1	0.0	0.0	0.0	65.0	**78.3**	9.9
CT 21.01 BG 2	950	25.1	0.0	0.0	0.0	0.0	0.0	0.0	74.9	**74.9**	0.0
CT 21.01 BG 3	578	46.9	0.0	0.0	0.0	0.0	0.0	1.2	51.9	**53.1**	6.0
CT 21.01 BG 4	1,273	12.6	9.1	0.0	2.8	0.0	0.0	8.6	66.8	**87.4**	**28.3**
CT 21.02 BG 1	777	55.2	0.0	1.0	26.4	0.0	0.0	0.0	17.4	44.8	10.1
CT 21.02 BG 2	837	61.3	0.0	0.0	4.9	0.0	0.0	0.1	33.7	38.7	8.9

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 21.02 BG 3	1,367	58.0	9.0	0.0	2.2	0.0	0.0	0.1	30.7	42.0	11.3
CT 22 BG 1	1,325	14.7	0.0	0.0	0.0	0.0	0.0	1.7	83.5	**85.3**	**38.5**
CT 22 BG 2	606	20.5	0.0	0.0	0.0	0.0	0.0	0.0	79.5	**79.5**	**26.5**
CT 22 BG 3	1,112	25.3	0.0	0.0	0.0	0.0	0.0	0.0	74.7	**74.7**	**21.8**
CT 22 BG 4	1,421	15.6	4.2	0.0	0.1	0.0	0.0	0.0	80.2	**84.4**	**33.2**
CT 22 BG 5	1,144	5.1	0.0	0.0	0.0	0.0	0.0	0.0	94.9	**94.9**	**20.2**
CT 23.01 BG 1	626	17.9	0.0	0.0	0.0	0.0	0.0	0.0	82.1	**82.1**	6.0
CT 23.01 BG 2	1,356	11.9	0.0	0.0	1.3	0.0	0.0	0.0	86.7	**88.1**	15.8
CT 23.01 BG 3	1,730	19.5	3.9	0.0	0.0	0.0	0.0	0.0	75.9	**80.5**	**18.5**
CT 23.03 BG 1	2,447	16.5	2.4	0.6	0.0	0.0	0.0	0.0	77.6	**83.5**	**22.7**
CT 23.03 BG 2	813	11.4	0.0	0.0	0.0	0.0	0.0	4.1	84.5	**88.6**	**30.0**
CT 23.03 BG 3	1,626	21.0	1.9	0.0	0.0	0.0	0.0	0.0	77.1	**79.0**	7.5
CT 23.04 BG 1	1,370	4.9	1.0	0.0	0.0	0.0	0.0	0.0	94.1	**95.1**	4.7
CT 23.04 BG 2	927	21.1	11.5	0.0	6.0	0.0	0.0	2.9	58.4	**78.9**	**20.9**
CT 23.04 BG 3	568	17.6	1.4	3.5	4.8	0.0	0.0	2.6	70.1	**82.4**	11.7
CT 23.04 BG 4	2,598	12.7	1.8	0.0	0.1	0.0	0.0	0.0	85.4	**87.3**	8.2
CT 24 BG 1	724	32.6	2.1	0.0	0.0	0.0	0.0	2.2	63.1	**67.4**	**21.8**
CT 24 BG 2	973	28.3	5.3	0.0	0.0	0.0	0.0	0.0	66.4	**71.7**	4.5

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 24 BG 3	1,081	51.9	16.5	0.0	0.0	0.0	0.0	0.0	31.6	48.1	**24.6**
CT 24 BG 4	1,573	27.1	3.8	0.0	0.0	0.0	0.0	0.0	69.0	**72.9**	**17.6**
CT 24 BG 5	871	35.1	0.0	0.0	0.0	0.0	0.0	0.0	64.9	**64.9**	16.8
CT 25 BG 1	416	46.9	0.0	0.0	14.9	0.0	0.0	0.0	38.2	**53.1**	5.2
CT 25 BG 2	1,205	87.5	0.0	0.0	0.0	0.0	0.0	0.0	12.5	12.5	1.7
CT 25 BG 3	1,815	37.6	0.0	0.0	0.0	0.0	0.0	0.0	62.4	**62.4**	14.5
CT 25 BG 4	841	24.6	0.7	0.0	2.3	0.0	0.0	0.8	71.6	**75.4**	0.0
CT 26.01 BG 1	1,758	53.5	2.1	0.0	1.2	0.0	0.0	1.1	42.1	46.5	**25.6**
CT 26.01 BG 2	971	43.6	2.1	0.0	0.0	0.0	0.0	0.0	54.4	**56.4**	6.0
CT 26.02 BG 1	689	38.6	14.5	0.0	0.0	0.0	0.0	1.2	45.7	**61.4**	**20.7**
CT 26.02 BG 2	1,315	15.8	0.0	0.0	3.0	0.0	0.0	2.0	79.2	**84.2**	**18.5**
CT 26.03 BG 1	1,139	26.5	2.3	0.0	0.0	0.0	0.0	1.2	70.0	**73.5**	**21.5**
CT 26.03 BG 2	1,092	34.5	1.6	0.0	0.0	0.0	0.0	0.0	63.8	**65.5**	10.6
CT 26.03 BG 3	1,127	53.8	0.6	2.3	2.8	0.0	0.0	7.5	32.9	46.2	16.8
CT 27.03 BG 1	1,171	31.6	3.7	0.0	0.0	0.0	0.0	0.0	64.7	**68.4**	**27.6**
CT 27.03 BG 2	1,290	14.6	5.9	0.0	0.0	0.0	0.0	0.0	79.5	**85.4**	**22.7**
CT 27.03 BG 3	1,768	29.8	2.5	0.0	3.7	0.0	0.0	0.0	64.0	**70.2**	3.1
CT 27.03 BG 4	1,261	27.4	0.0	0.0	7.3	0.0	0.0	0.0	65.3	**72.6**	15.1

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 27.03 BG 5	494	50.8	3.2	0.0	0.0	0.0	0.0	4.3	41.7	49.2	0.0
CT 27.05 BG 1	1,621	50.2	0.0	0.0	13.8	0.0	0.0	0.0	36.0	49.8	13.8
CT 27.05 BG 2	615	15.1	0.0	0.0	0.0	0.0	0.0	0.0	84.9	**84.9**	**18.7**
CT 27.05 BG 3	1,219	84.0	0.0	0.0	2.8	0.0	0.0	5.3	7.9	16.0	2.8
CT 27.05 BG 4	1,788	23.8	1.1	0.0	0.0	0.0	0.0	0.0	75.1	**76.2**	11.3
CT 27.06 BG 1	3,409	49.9	8.2	0.0	1.4	0.0	0.0	0.0	40.5	**50.1**	0.0
CT 27.07 BG 1	1,386	34.0	9.7	0.0	15.1	0.0	0.0	0.9	40.3	**66.0**	**19.6**
CT 27.08 BG 1	1,423	51.4	7.1	0.0	9.3	0.0	0.0	3.6	28.6	48.6	**18.2**
CT 27.08 BG 2	1,891	53.6	0.0	0.0	9.6	1.5	0.0	0.0	35.3	46.4	**31.1**
CT 27.08 BG 3	951	59.4	0.0	0.0	2.3	0.0	0.0	3.5	34.8	40.6	**28.2**
CT 29 BG 1	950	67.1	16.7	0.0	2.5	0.0	0.0	8.6	5.1	33.0	3.8
CT 30.02 BG 1	913	61.2	0.7	0.0	9.4	0.0	0.0	2.3	26.4	38.8	15.5
CT 30.02 BG 2	936	55.9	0.7	2.5	1.8	0.0	1.7	2.0	35.4	44.1	**17.3**
CT 30.02 BG 3	990	55.8	2.8	0.0	5.8	0.0	0.0	7.5	28.2	44.2	**24.5**
CT 30.02 BG 4	949	59.3	1.2	0.9	1.9	0.0	0.0	5.6	31.1	40.7	**25.0**
CT 30.03 BG 1	2,355	31.3	11.7	0.0	6.2	0.0	0.0	0.0	50.8	**68.7**	8.0
CT 30.04 BG 1	1,201	49.6	14.1	0.0	21.6	0.0	0.0	0.0	14.7	**50.4**	**25.2**
CT 30.04 BG 2	868	17.1	20.2	0.0	6.2	0.0	3.9	0.0	52.6	**82.9**	**40.1**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 30.04 BG 3	1,031	50.6	0.6	0.0	3.8	0.0	0.0	0.0	45.0	49.4	**50.1**
CT 31.01 BG 1	1,140	74.1	0.0	0.0	0.0	0.0	0.0	0.0	25.9	25.9	5.8
CT 31.01 BG 2	1,207	66.8	0.0	0.0	0.0	0.0	0.0	0.0	33.2	33.2	13.9
CT 31.01 BG 3	901	78.5	0.0	1.2	0.0	0.0	0.0	0.0	20.3	21.5	8.1
CT 31.01 BG 4	577	62.4	8.8	0.0	0.0	0.0	0.0	17.5	11.3	37.6	0.0
CT 31.01 BG 5	588	67.4	0.0	3.0	0.0	0.0	0.0	0.0	29.7	32.6	22.7
CT 31.02 BG 1	1,914	54.5	0.0	0.0	6.1	0.0	0.0	0.8	38.6	45.5	20.8
CT 31.02 BG 2	2,182	63.1	0.0	0.0	8.0	0.0	0.7	1.9	26.4	36.9	14.5
CT 31.02 BG 3	1,063	70.4	16.4	0.9	0.0	0.0	1.0	0.8	10.4	29.6	2.0
CT 32.02 BG 1	926	34.9	2.7	0.0	1.4	0.0	4.0	0.0	57.0	**65.1**	**73.1**
CT 32.02 BG 2	1,135	17.6	11.9	0.0	0.0	0.0	0.0	0.0	70.5	**82.4**	**22.4**
CT 32.02 BG 3	1,860	28.5	0.0	0.0	7.4	0.0	0.0	0.0	64.0	**71.5**	0.0
CT 32.02 BG 4	4,023	34.8	2.4	0.0	4.9	0.0	2.0	2.0	53.8	**65.2**	3.0
CT 32.04 BG 1	1,329	38.6	0.0	0.8	0.0	0.0	0.0	5.1	55.5	**61.4**	2.4
CT 32.04 BG 2	1,985	29.8	2.4	0.0	2.3	0.0	0.0	4.7	60.8	**70.2**	7.3
CT 32.04 BG 3	944	41.7	0.0	0.0	0.0	0.0	0.0	0.0	58.3	**58.3**	5.3
CT 32.05 BG 1	1,784	32.2	0.0	0.0	4.1	0.0	0.0	1.2	62.4	**67.8**	**41.8**
CT 32.06 BG 1	1,368	30.4	0.0	0.0	1.5	0.0	0.0	5.0	63.1	**69.6**	**39.8**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 32.06 BG 2	3,043	17.4	7.7	0.0	6.8	0.0	0.0	0.9	67.2	**82.6**	**32.1**
CT 33.03 BG 1	414	41.1	0.7	0.0	0.0	0.0	0.0	0.0	58.2	**58.9**	9.4
CT 33.03 BG 2	699	14.2	0.0	0.0	0.0	0.0	0.0	0.0	85.8	**85.8**	**40.6**
CT 33.04 BG 1	3,054	33.4	3.9	0.0	1.3	0.0	0.0	1.9	59.5	**66.6**	12.3
CT 33.04 BG 2	1,637	39.2	0.0	0.0	0.0	0.0	0.0	0.9	59.9	**60.8**	7.8
CT 33.04 BG 3	1,490	34.4	11.3	0.0	0.0	0.0	0.0	0.8	53.4	**65.6**	0.0
CT 33.05 BG 1	2,391	15.8	4.9	0.4	5.4	0.0	0.0	0.0	73.5	**84.2**	**31.4**
CT 33.05 BG 2	2,124	13.3	1.3	0.0	6.7	0.0	0.0	0.0	78.7	**86.7**	**41.2**
CT 33.06 BG 1	2,129	33.0	3.8	0.0	2.8	0.0	0.0	0.5	60.0	**67.0**	14.5
CT 33.06 BG 2	691	40.5	0.6	0.0	0.7	0.0	0.0	0.0	58.2	**59.5**	13.3
CT 33.06 BG 3	2,395	16.2	0.0	0.0	0.0	0.0	0.0	0.0	83.8	**83.8**	6.0
CT 34.01 BG 1	934	24.5	4.6	0.0	12.1	0.0	0.0	3.0	55.8	**75.5**	**31.6**
CT 34.01 BG 2	1,515	24.7	1.3	1.7	0.0	0.0	0.0	0.0	72.4	**75.3**	**26.3**
CT 34.01 BG 3	1,477	15.8	2.4	0.0	1.4	0.0	0.0	3.2	77.3	**84.2**	**18.7**
CT 34.02 BG 1	1,126	24.7	0.1	0.0	0.0	0.0	0.0	0.0	75.2	**75.3**	**20.3**
CT 34.02 BG 2	1,269	34.0	6.9	0.0	0.0	0.0	0.0	0.0	59.0	**66.0**	**26.1**
CT 34.02 BG 3	2,118	15.3	0.0	0.0	0.0	0.0	0.0	0.0	84.7	**84.7**	**50.9**
CT 34.02 BG 4	625	8.5	0.0	0.0	0.0	0.0	0.0	0.0	91.5	**91.5**	14.3

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 34.02 BG 5	801	64.8	0.0	0.0	3.1	0.0	0.0	0.0	32.1	35.2	3.7
CT 35 BG 1	601	24.6	0.0	0.0	0.0	3.5	0.0	0.0	71.9	**75.4**	4.0
CT 35 BG 2	1,381	19.3	0.0	0.0	0.0	0.0	0.0	0.0	0.5	**80.7**	**20.1**
CT 36.01 BG 1	224	19.6	0.0	0.0	0.0	0.0	0.0	0.0	80.4	**80.4**	13.6
CT 36.01 BG 2	707	31.0	3.5	0.0	0.0	0.0	0.0	1.8	63.6	**69.0**	**20.1**
CT 36.01 BG 3	2,115	35.6	27.0	0.0	0.0	0.0	0.0	2.4	59.3	**64.4**	**27.3**
CT 36.01 BG 4	3,129	48.5	2.9	0.0	0.0	0.0	0.0	0.0	48.5	**51.5**	16.4
CT 36.02 BG 1	1,380	35.4	3.6	0.0	0.0	0.0	0.0	2.2	58.8	**64.6**	9.9
CT 36.02 BG 2	2,382	20.7	0.0	0.0	0.0	0.0	0.0	0.0	78.8	**79.3**	2.1
CT 36.02 BG 3	862	34.9	0.2	0.0	0.0	0.0	0.0	0.0	64.8	**65.1**	3.2
CT 36.02 BG 4	1,137	18.6	0.0	0.0	0.0	0.0	0.0	3.0	78.4	**81.4**	8.4
CT 36.03 BG 1	36.6	0.4	0.0	0.0	0.0	0.0	0.0	0.3	62.7	**63.4**	4.0
CT 36.03 BG 2	2,462	28.9	6.0	0.0	0.0	0.0	0.0	0.5	64.6	**71.1**	6.0
CT 37 BG 1	2,281	22.3	0.0	0.0	0.0	0.0	0.0	0.2	77.5	**77.7**	9.1
CT 37 BG 2	477	18.7	0.0	0.0	0.0	0.0	0.0	1.3	80.0	**81.3**	14.3
CT 37 BG 3	531	52.5	0.0	0.0	0.0	0.0	0.0	0.0	47.5	47.5	**20.3**
CT 51.03 BG 1 [f]	2,076	80.3	0.0	0.3	0.0	0.0	0.0	2.1	17.3	20.8	13.6
CT 51.04 BG 1 [f]	861	95.9	0.0	0.0	0.0	0.0	0.0	0.0	4.1	4.1	**24.0**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 54.04 BG 1	3,689	33.7	1.9	0.0	0.4	0.0	0.0	0.9	63.1	**66.3**	4.5
CT 54.04 BG 2	1,381	42.4	3.7	0.0	4.1	0.0	0.0	2.0	47.9	**57.6**	12.0
CT 54.06 BG 1	1,001	49.4	0.2	0.0	5.0	0.0	0.0	0.0	45.5	**50.6**	0.0
CT 54.06 BG 2	961	27.2	0.0	0.0	0.0	0.0	0.0	1.8	71.1	**72.8**	9.0
CT 54.06 BG 3	2,269	47.6	1.0	0.0	13.8	0.0	0.0	4.0	33.6	**52.4**	1.8
CT 54.07 BG 1	1,965	31.9	0.0	0.0	4.5	0.0	0.0	0.0	63.6	**68.1**	13.8
CT 54.07 BG 2	733	47.2	0.7	0.0	2.5	0.0	0.0	0.5	49.1	**52.8**	7.3
CT 54.08 BG 1	1,605	15.7	12.7	0.0	5.4	0.0	0.0	1.4	64.9	**84.3**	**24.5**
CT 54.08 BG 2	1,679	19.5	0.0	3.4	5.6	0.0	0.0	1.5	69.9	**80.5**	15.1
CT 54.08 BG 3	1,009	27.0	0.0	0.0	9.9	0.0	0.0	2.1	61.1	**73.0**	3.7
CT 54.09 BG 1	2,316	27.3	3.9	0.0	8.8	0.0	0.3	0.3	59.4	**72.7**	5.5
CT 54.09 BG 2	1,303	33.0	1.5	0.0	2.5	0.0	1.4	0.7	60.9	**67.0**	2.9
CT 54.10 BG 1	1,329	31.9	2.2	0.0	0.0	0.0	0.0	0.0	65.9	**68.1**	**22.1**
CT 54.10 BG 2	2,755	23.1	3.8	0.0	0.0	0.0	0.0	0.0	73.1	**76.9**	7.9
CT 54.11 BG 1	1,948	34.9	3.1	0.0	0.8	0.0	0.0	0.8	60.4	**65.1**	4.6
CT 54.11 BG 2	799	29.4	0.0	0.0	7.6	0.0	0.0	10.3	52.7	**70.6**	11.7
CT 54.11 BG 3	835	34.3	3.4	0.0	0.0	0.0	0.0	2.9	59.5	**65.7**	9.7
CT 54.12 BG 1	1,281	37.6	2.0	4.8	2.8	0.0	0.0	2.4	50.4	**62.4**	2.7

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 54.12 BG 2	1,793	36.0	11.5	0.0	0.6	0.0	0.0	0.9	50.9	**64.0**	1.7
CT 54.12 BG 3	1,751	32.2	15.9	0.0	0.0	0.0	0.0	1.2	50.7	**67.8**	3.2
CT 54.13 BG 1	1,826	38.3	6.0	0.0	14.1	0.0	0.0	2.0	39.6	**61.7**	16.5
CT 54.13 BG 2	761	41.8	0.0	0.0	12.6	0.0	0.0	2.8	42.8	**58.2**	15.9
CT 54.14 BG 1	3,019	27.0	2.4	1.4	3.0	0.0	0.0	0.7	65.6	**73.0**	10.1
CT 54.14 BG 2	1,348	30.0	4.8	0.8	8.8	0.0	0.0	0.0	55.6	**70.0**	1.4
CT 54.15 BG 1	3,627	30.3	3.8	0.0	3.0	1.2	4.3	3.6	53.8	**69.7**	5.9
CT 54.15 BG 2	2,824	27.4	0.0	0.0	9.2	0.0	1.8	2.7	58.9	**72.6**	0.0
CT 54.16 BG 1	1928	58.3	0.0	0.0	10.9	0.0	0.0	0.0	30.8	41.7	8.2
CT 54.16 BG 2	1,761	39.5	2.4	0.0	3.4	0.0	0.0	1.4	53.3	**60.5**	3.8
CT 54.17 BG 1	2,606	18.5	9.1	0.0	10.9	0.0	0.0	0.7	60.9	**81.5**	7.3
CT 54.17 BG 2	4,559	39.9	0.3	0.0	3.4	0.0	1.0	0.6	54.7	**60.1**	1.6
CT 56.03 BG 1	2,585	9.6	0.0	0.0	0.0	0.0	0.0	0.0	90.4	**90.4**	**35.0**
CT 56.03 BG 2	928	3.2	0.1	0.0	0.0	0.0	0.0	0.0	96.7	**96.8**	**39.5**
CT 56.04 BG 1	1,040	3.3	0.0	0.0	0.3	0.0	2.6	0.0	93.8	**96.7**	8.0
CT 56.04 BG 2	292	12.7	2.0	0.0	0.0	0.0	0.0	0.0	85.3	**87.3**	**28.0**
CT 56.04 BG 3	615	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	**46.8**
CT 56.05 BG 1	964	2.9	0.0	0.0	0.0	0.0	0.0	0.0	97.1	**97.1**	**27.4**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 56.05 BG 2	923	3.1	0.0	0.0	0.0	0.0	0.0	0.0	96.9	**96.9**	14.0
CT 56.05 BG 3	1,860	5.8	0.0	0.0	0.0	0.0	0.0	0.0	94.2	**94.2**	**28.2**
CT 56.05 BG 4	1,373	7.2	0.0	0.0	0.0	0.0	0.0	0.0	92.8	**92.8**	**53.8**
CT 56.06 BG 1	1,160	8.4	0.0	0.0	0.0	0.0	0.0	0.0	91.6	**91.6**	**33.2**
CT 58.01 BG 1	3,286	69.1	1.0	0.0	0.0	0.0	0.0	0.0	29.9	30.9	2.4
CT 58.01 BG 2	4,433	57.5	0.1	0.0	0.5	0.0	0.0	0.0	41.8	42.5	2.6
CT 58.03 BG 2	1,430	44.7	1.9	0.0	2.3	0.0	0.0	0.0	51.1	**55.3**	**21.3**
CT 58.03 BG 3	1,603	36.5	0.0	0.0	0.0	0.0	0.0	0.0	63.5	**63.5**	10.2
CT 58.03 BG 4	1,286	21.5	0.0	0.0	0.0	0.0	0.0	0.0	78.5	**78.5**	2.1
CT 58.04 BG 1	1,069	36.7	2.3	5.3	0.0	0.0	0.0	3.3	52.4	**63.3**	13.6
CT 58.04 BG 2	1,163	28.9	0.0	0.0	4.2	0.0	0.0	3.5	63.4	**71.1**	0.0
CT 59 BG 1	450	22.9	0.0	0.0	0.0	0.0	0.0	0.0	77.1	**77.1**	**40.2**
CT 59 BG 2	1,142	8.1	0.0	0.0	0.0	0.0	0.0	0.0	91.9	**91.9**	**43.6**
CT 59 BG 3	1,417	15.9	0.0	0.0	2.6	0.0	0.0	0.0	81.5	**84.1**	**37.4**
CT 60 BG 1	752	3.7	0.0	0.0	0.0	0.0	0.0	0.0	96.3	**96.3**	**32.8**
CT 60 BG 2	922	20.5	0.0	0.0	0.0	0.0	0.0	0.0	79.5	**79.5**	9.9
CT 60 BG 3	812	26.2	0.0	0.0	0.0	0.0	0.0	0.0	73.8	**73.8**	11.1
CT 62.01 BG 1	1,046	58.0	0.0	0.0	0.0	0.0	0.0	0.0	42.0	42.0	6.6

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent)** [a]									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White** [c]	**Black/African American** [c]	**American Indian/Alaska Native** [c]	**Asian** [c]	**Native Hawaiian & Other Pacific Islander** [c]	**Some other Race** [c]	**Two or more Races** [c]	**Hispanic or Latino**	**Total Minority** [d, e]	**Households at or below the poverty line** [e]
CT 62.01 BG 2	339	88.8	0.0	0.0	0.0	0.0	0.0	0.0	11.2	11.2	0.0
CT 62.01 BG 3	1,046	67.8	0.0	0.0	4.7	0.0	0.0	0.0	27.5	32.2	8.9
CT 62.02 BG 1	488	87.9	0.0	0.0	0.0	0.0	0.0	5.1	7.0	12.1	9.6
CT 62.02 BG 2	383	41.1	0.0	0.0	0.0	0.0	0.0	32.0	26.9	**58.9**	5.9
CT 62.02 BG 1	643	89.4	0.0	4.5	0.0	0.0	0.0	0.0	6.1	10.6	9.6
CT 62.02 BG 2	931	41.1	0.0	0.0	0.0	0.0	0.0	32.0	26.9	**58.9**	5.9
CT 62.02 BG 3	282	76.6	0.0	0.0	13.1	0.0	0.0	0.0	10.3	23.4	16.9
CT 62.03 BG 1	643	89.4	0.0	4.5	0.0	0.0	0.0	0.0	6.1	10.6	0.0
CT 62.03 BG 2	1,041	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5
CT 62.04 BG 1	1,353	81.0	0.0	0.0	9.3	0.0	0.0	1.9	7.8	19.0	0.0
CT 62.04 BG 2	388	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT 62.04 BG 3	1,101	13.5	0.0	0.0	0.0	0.0	0.0	0.0	86.5	**86.5**	0.0
CT 62.05 BG 1 [f]	1,526	86.1	0.0	0.0	2.4	0.0	0.0	0.0	11.5	13.9	12.4
CT 63 BG 1	329	60.2	10.9	0.0	0.0	0.0	0.0	6.7	22.2	39.8	10.3
CT 63 BG 2	2,210	18.7	4.0	0.0	0.5	0.0	0.6	0.0	76.3	**81.3**	**40.3**
CT 64 BG 1	19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	**100.0**	0.0
CT 64 BG 2	156	0.0	51.9	0.0	0.0	0.0	0.0	0.0	48.1	**100.0**	**93.1**
CT 64 BG 3	1,859	38.3	7.3	0.1	0.5	0.0	0.0	0.8	52.9	**61.7**	15.6

Table E1
Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels

Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 64 BG 4	464	55.2	0.0	0.0	0.0	0.0	2.6	1.5	40.7	44.8	10.5
CT 9800 BG 1	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
San Patricio County	68,600	37.2	1.9	0.0	0.9	0.2	0.2	1.1	58.5	62.8	16.4
CT 102.01 BG 1	1,733	53.7	6.0	0.1	0.0	0.0	0.0	0.2	40.1	46.3	**17.1**
CT 102.01 BG 2	626	58.8	0.0	0.0	0.0	0.0	0.0	0.0	41.2	41.2	6.0
CT 102.01 BG 3	1,009	43.2	4.8	0.0	0.4	0.0	0.0	0.4	51.2	**56.8**	**32.6**
CT 102.02 BG 1	865	15.7	14.8	0.0	0.0	0.0	0.0	0.6	68.9	**84.3**	**44.3**
CT 102.02 BG 2	1,697	43.3	9.5	0.0	3.7	0.0	0.0	8.2	35.3	**56.7**	10.5
CT 102.02 BG 3	1,087	31.7	0.0	0.0	0.0	0.0	0.0	0.0	68.3	**68.3**	0.0
CT 102.02 BG 4	744	40.9	1.7	0.0	13.7	0.0	4.7	0.0	39.0	**59.1**	**19.6**
CT 103.01 BG 1	2,282	53.0	0.0	0.0	1.1	0.0	0.0	0.0	45.9	47.0	5.5
CT 103.01 BG 2	854	97.1	0.0	0.0	0.0	0.0	0.0	1.0	31.9	32.9	7.0
CT 103.01 BG 3	1,867	43.0	4.2	0.0	0.0	0.0	0.0	0.0	0.0	**57.0**	10.9
CT 103.02 BG 1 [f]	1,429	64.9	3.3	0.1	1.5	0.0	0.0	1.3	28.8	35.0	5.5
CT 103.02 BG 2 [f]	548	21.9	0.0	0.0	0.0	9.3	0.0	0.0	68.8	**78.1**	**17.4**
CT 103.02 BG 3 [f]	1,825	34.7	6.1	0.0	0.0	0.0	0.0	0.0	59.2	**65.3**	9.0
CT 103.02 BG 4	1,696	37.1	1.4	0.0	0.2	0.0	0.4	2.8	58.1	**62.9**	11.6
CT 105 BG 1	1,247	9.5	0.0	0.0	0.0	0.0	0.8	0.0	89.7	**90.5**	**38.7**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 105 BG 2	984	9.5	0.4	0.0	0.0	0.0	0.0	0.0	90.1	**90.5**	16.4
CT 106.01 BG 1	1,511	34.8	0.0	0.0	2.8	0.0	0.0	9.7	52.7	**65.2**	2.7
CT 106.01 BG 2	2,420	37.0	3.1	0.0	7.6	0.0	0.0	0.0	52.2	**63.0**	**22.4**
CT 106.01 BG 3	1,526	31.7	0.4	0.0	0.0	0.0	0.0	0.0	67.9	**68.3**	5.6
CT 106.01 BG 4	724	51.5	2.9	0.0	0.0	0.0	0.0	0.3	45.3	48.5	**18.1**
CT 106.02 BG 1	2,378	60.7	1.6	0.0	2.1	0.0	0.0	0.9	34.7	39.3	5.6
CT 106.02 BG 2	2,202	51.4	0.0	0.0	0.7	0.0	0.0	0.0	47.9	48.6	2.0
CT 106.03 BG 1 [f]	1,630	73.3	0.0	0.3	1.3	0.0	0.0	0.4	24.7	26.7	4.1
CT 106.03 BG 2	1,550	61.9	3.9	0.0	1.5	4.1	0.0	7.9	20.6	38.1	5.3
CT 106.04 BG 1	1,051	67.0	7.7	0.0	1.2	0.0	0.0	0.5	23.5	32.9	0.0
CT 106.04 BG 2	1,650	67.8	0.0	0.0	2.7	0.0	0.0	0.0	29.5	32.2	9.4
CT 107 BG 1	762	33.7	0.5	0.0	0.0	0.0	0.0	0.0	65.7	**66.3**	12.4
CT 107 BG 2 [f, g]	4,015	43.5	3.6	0.0	0.0	0.2	0.2	2.2	50.2	**56.5**	3.6
CT 108 BG 1	973	9.6	0.0	0.0	0.0	0.0	0.0	0.0	90.4	**90.4**	**24.8**
CT 108 BG 2	1,305	34.1	0.0	0.0	0.0	0.0	0.0	0.0	65.9	**65.9**	**20.7**
CT 108 BG 3	968	4.4	0.0	0.0	0.0	0.0	1.1	0.0	94.4	**95.6**	**52.1**
CT 108 BG 4	1,300	2.8	0.0	0.0	0.0	0.0	0.0	0.0	97.2	**97.2**	**19.4**
CT 109 BG 1	2,404	43.7	0.0	0.0	0.0	0.0	0.0	0.0	56.3	**56.3**	**30.1**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 109 BG 2	1,198	51.4	0.0	0.0	0.0	0.0	0.0	0.0	48.3	48.6	15.9
CT 109 BG 3	2,047	24.8	0.0	0.0	0.0	0.0	0.6	0.0	74.6	**75.2**	15.7
CT 110 BG 1	1,950	26.6	0.0	0.0	0.0	0.0	0.0	0.0	73.4	**73.4**	**20.1**
CT 110 BG 2	1,316	18.5	3.7	0.0	1.4	0.0	0.0	4.2	72.1	**81.5**	**19.2**
CT 110 BG 3	1,308	34.2	3.2	0.0	0.5	0.0	0.0	1.5	60.6	**65.8**	**30.8**
CT 110 BG 4	1,958	9.9	0.0	0.0	0.0	0.0	0.0	0.0	90.1	**90.1**	**51.4**
CT 111 BG 1	614	3.4	0.0	0.0	0.0	0.0	0.0	0.0	96.6	**96.6**	**25.6**
CT 111 BG 2	647	37.1	0.0	0.0	0.0	0.0	0.0	0.0	62.9	**62.9**	5.7
CT 111 BG 3	1,225	9.5	0.0	0.0	0.0	0.0	0.0	0.3	90.2	**90.5**	16.0
CT 112 BG 1	782	49.7	0.0	0.0	0.0	0.0	0.0	0.0	50.3	**50.3**	9.5
CT 112 BG 3	569	53.3	0.0	0.0	0.0	0.0	0.0	0.0	46.7	46.7	**21.7**
Bee County	31,191	30.4	6.8	0.4	0.2	0.0	0.0	2.7	59.5	69.6	18.9
CT 9502.01 BG 3	1,152	37.8	0.2	0.0	0.2	0.0	0.0	4.3	57.6	**62.2**	17.0
CT 9506 BG 1	1,217	20.9	0.5	0.0	0.0	0.0	0.0	0.0	78.6	**79.1**	11.7
CT 9506 BG 2	948	53.2	0.0	0.0	0.0	0.0	0.0	0.0	46.8	46.8	3.9
Kleberg County	31,015	19.8	3.0	0.2	1.6	0.0	0.4	1.5	73.5	80.2	27.8
CT 201.01 BG 3	746	62.9	0.1	0.0	2.4	0.0	1.7	1.5	31.4	37.1	10.1
Jim Wells County	39,203	17.6	0.6	0.2	0.1	0.4	0.1	0.6	80.5	82.4	20.3
CT 9501.02 BG 2	2,965	32.1	5.1	0.0	0.0	0.0	0.0	3.1	59.7	**67.9**	2.5

Table E1
Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels

Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
Aransas County	24,149	66.3	0.2	0.3	1.4	0.0	0.0	3.3	28.6	33.7	18.8
CT 9501.01 BG 1	631	91.0	0.0	4.6	0.2	0.0	0.0	0.0	4.3	9.0	**17.9**
CT 9501.01 BG 2 [f]	1,050	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**45.3**
CT 9501.02 BG 1	721	73.4	0.0	1.9	3.7	0.0	0.0	10.1	10.8	26.6	17.6
CT 9501.02 BG 2	1,142	88.4	0.0	0.0	0.0	0.0	0.0	0.0	11.6	11.6	1.3
CT 9501.02 BG 3	1,139	54.1	0.0	0.2	20.4	0.0	0.0	4.3	21.1	45.9	**18.9**
CT 9501.03 BG 1	239	65.3	0.0	0.0	34.7	0.0	0.0	0.0	0.0	34.7	13.0
CT 9501.03 BG 2	567	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT 9502 BG 1	990	75.9	0.0	0.0	0.0	0.0	0.0	0.0	24.1	24.1	10.4
CT 9503.01 BG 1	1,000	67.2	2.4	0.0	0.0	0.0	0.0	5.3	25.1	32.8	13.7
CT 9503.01 BG 2	2,053	35.6	0.0	0.0	0.0	0.0	0.0	0.0	64.4	**64.4**	**28.4**
CT 9503.01 BG 3	964	23.5	0.0	0.0	0.0	0.0	0.0	0.0	76.5	**76.5**	**31.4**
CT 9503.02 BG 1	1,480	70.1	0.5	0.0	0.0	0.0	0.0	0.0	29.3	29.9	0.0
CT 9503.02 BG 2	1,677	86.8	0.0	0.0	0.0	0.0	0.0	0.0	13.2	13.2	7.7
CT 9504 BG 1	1,261	32.4	0.0	0.0	0.0	0.0	0.0	2.9	64.8	**67.6**	**38.1**
CT 9504 BG 2	1,046	72.2	0.0	0.0	0.0	0.0	0.0	0.0	27.8	27.8	10.7
CT 9504 BG 3	381	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
CT 9504 BG 4	728	40.1	0.8	2.6	0.0	0.0	0.0	0.0	56.5	**59.9**	**45.7**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		Race and Ethnicity (percent) [a]									Low-Income
State/ County/CT/BG [b]	Total Population	White [c]	Black/African American [c]	American Indian/Alaska Native [c]	Asian [c]	Native Hawaiian & Other Pacific Islander [c]	Some other Race [c]	Two or more Races [c]	Hispanic or Latino	Total Minority [d, e]	Households at or below the poverty line [e]
CT 9505.01 BG 1	1,101	73.9	0.0	0.0	0.0	0.0	0.0	0.0	26.1	26.1	**36.0**
CT 9505.01 BG 2	942	85.9	0.0	0.0	0.0	0.0	0.0	9.9	4.2	14.1	4.0
CT 9505.02 BG 1	1,518	39.1	0.0	0.0	0.0	0.0	0.0	1.4	59.6	**60.9**	**53.3**
CT 9505.02 BG 2	1,772	58.2	0.1	0.0	0.0	0.0	0.0	25.7	15.9	41.8	16.9
CT 9505.03 BG 1	668	69.9	0.0	0.0	0.0	0.0	0.0	3.1	26.9	30.1	7.0
CT 9505.03 BG 2	322	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT 9505.03 BG 3	583	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
CT 9505.01 BG 1	1,101	73.9	0.0	0.0	0.0	0.0	0.0	0.0	26.1	26.1	**36.0**
CT 9505.01 BG 2	942	85.9	0.0	0.0	0.0	0.0	0.0	9.9	4.2	14.1	4.0
CT 9505.02 BG 1	1,518	39.1	0.0	0.0	0.0	0.0	0.0	1.4	59.6	**60.9**	**53.3**
Refugio County	6,822	40.4	6.6	0.0	0.2	0.0	0.2	1.3	51.2	59.6	15.5
CT 9502 BG 1	586	53.8	0.0	0.0	0.0	0.0	0.0	0.0	46.2	46.2	13.7
CT 9502 BG 2	1,148	31.9	11.1	0.1	0.0	0.0	0.0	1.0	55.9	**68.1**	12.7
CT 9502 BG 3	821	24.4	12.5	0.0	0.4	0.0	0.0	7.4	55.3	**75.6**	10.2
CT 9502 BG 4	726	20.7	24.9	0.0	0.0	0.0	0.0	0.6	53.9	**79.3**	**55.9**
CT 9504 BG 1	1,154	66.8	0.6	0.0	0.0	0.0	1.4	0.8	30.4	33.2	10.6
CT 9504 BG 2	964	42.4	1.7	0.0	1.0	0.0	0.0	0.0	54.9	**57.6**	9.1
CT 9504 BG 3	889	32.4	0.0	0.0	0.0	0.0	0.0	0.0	67.6	**67.6**	**16.9**

Table E1 Minority and Low-Income Populations within 50 Kilometers of the Project Workspace and 1 mile from the La Quinta and Corpus Christi Ship Channels											
Geographic Area and Population		**Race and Ethnicity (percent) [a]**									**Low-Income**
State/ County/CT/BG [b]	**Total Population**	**White [c]**	**Black/African American [c]**	**American Indian/Alaska Native [c]**	**Asian [c]**	**Native Hawaiian & Other Pacific Islander [c]**	**Some other Race [c]**	**Two or more Races [c]**	**Hispanic or Latino**	**Total Minority [d, e]**	**Households at or below the poverty line [e]**
CT 9504 BG 4	534	48.7	2.2	0.0	0.2	0.0	0.0	0.7	48.1	**51.3**	5.8

Source: U.S. Census Bureau, 2022d, 2022e

Due to rounding differences in the dataset, the totals may not reflect the sum of the addends.

CT – Census Tract

BG – Block Group

[a] Estimates are annual totals developed as part of the 2017-2021 American Community Service ("ACS") 5-Year Estimates.

[b] All block groups presented are within 50 kilometers of the Project workspace.

[c] Non-Hispanic only. The federal government considers race and Hispanic/Latino origin to be two separate and distinct concepts. People identifying as Hispanic or Latino origin may be of any race. The data summarized in this table present Hispanic/Latino as a separate category.

[d] "Minority" refers to people who reported their ethnicity and race as something other than non-Hispanic White. The percent minority levels are calculated using the ACS 5-Year Estimates File # B03002.

[e] Low-income or minority populations exceeding the established thresholds for an environmental justice community are indicated in red bold type and blue shading. The threshold for the minority population is greater than 50 percent of the population or meaningfully greater than the reference community (10 percent greater than minority population in the county); threshold for low-income is equal to or greater than the reference community (county) for each associated section.

[f] This block group is within 1 mile of the La Quinta and Corpus Christi Ship Channels.

[g] The direct footprint of the Project is within this block group.

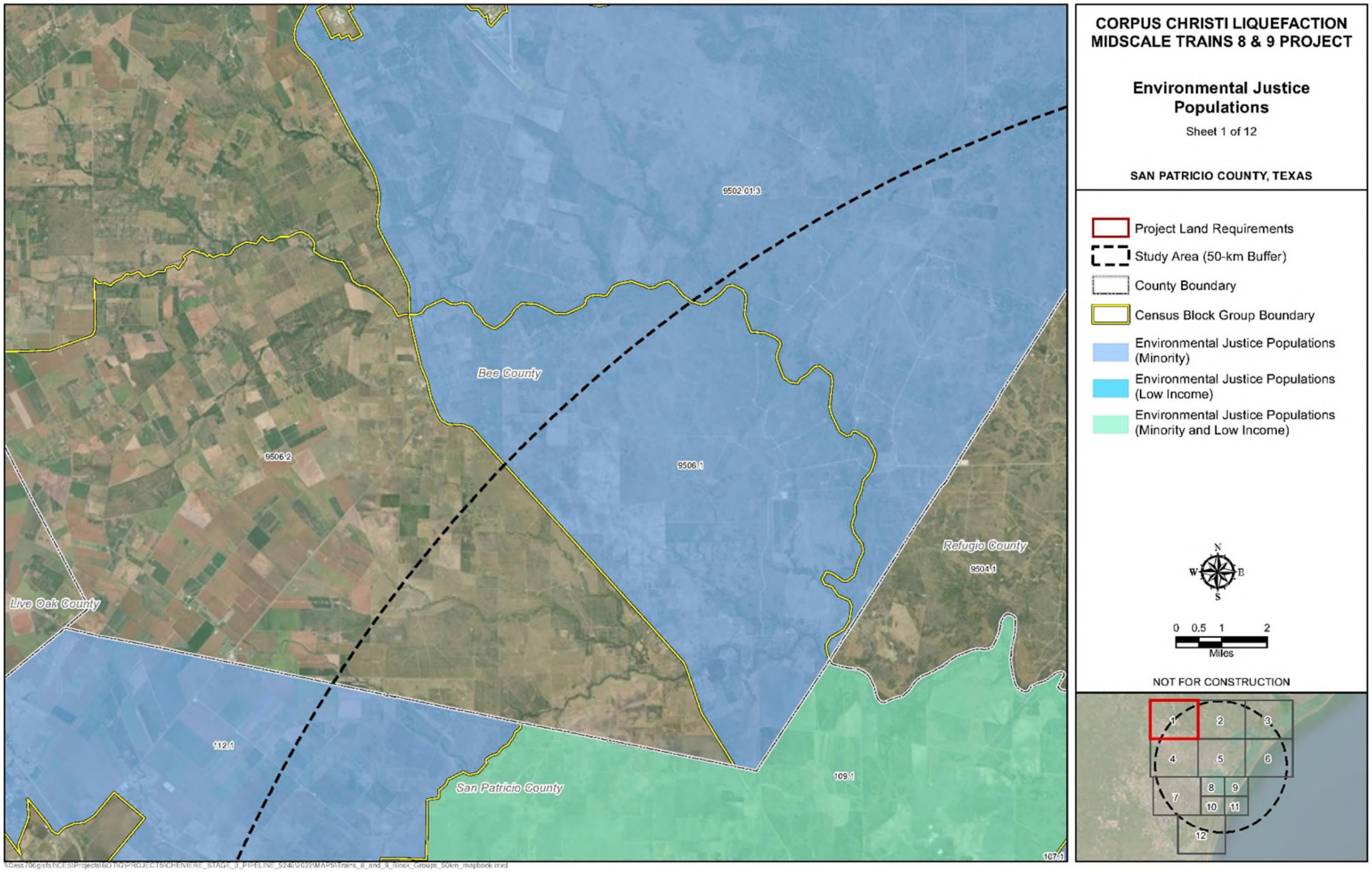

Figure E1-1 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

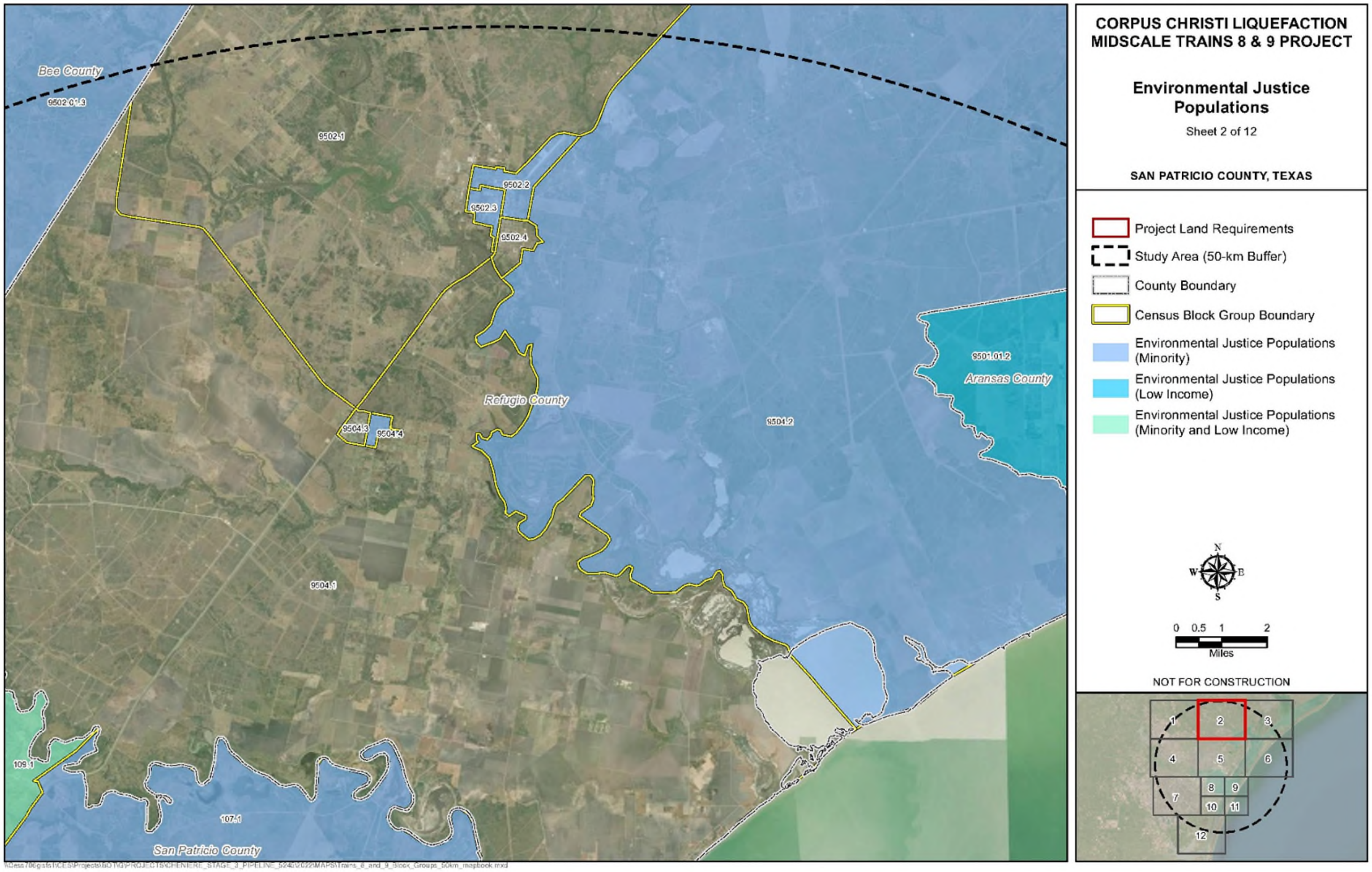

Figure E1-2 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

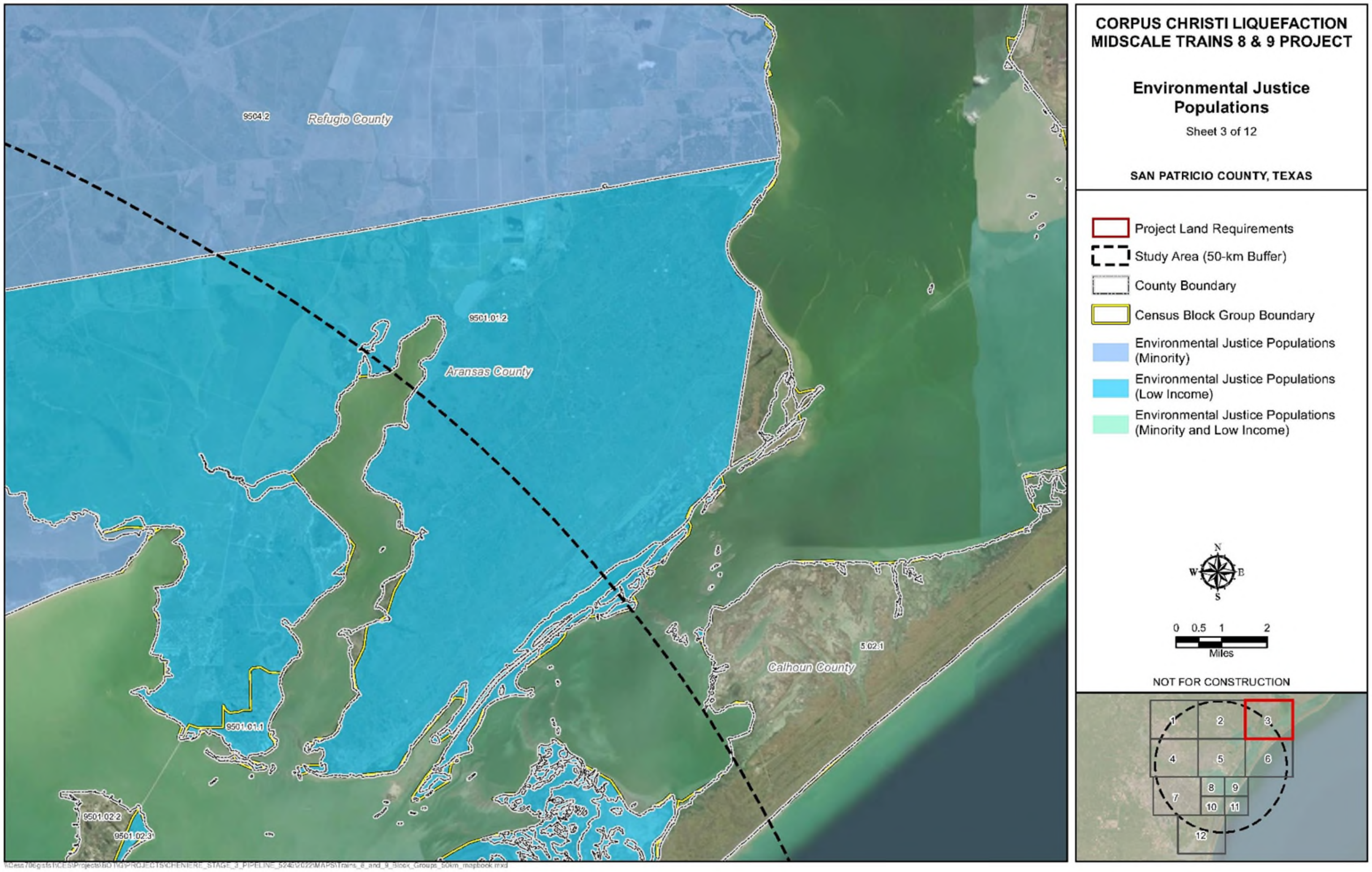

Figure E1-3 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

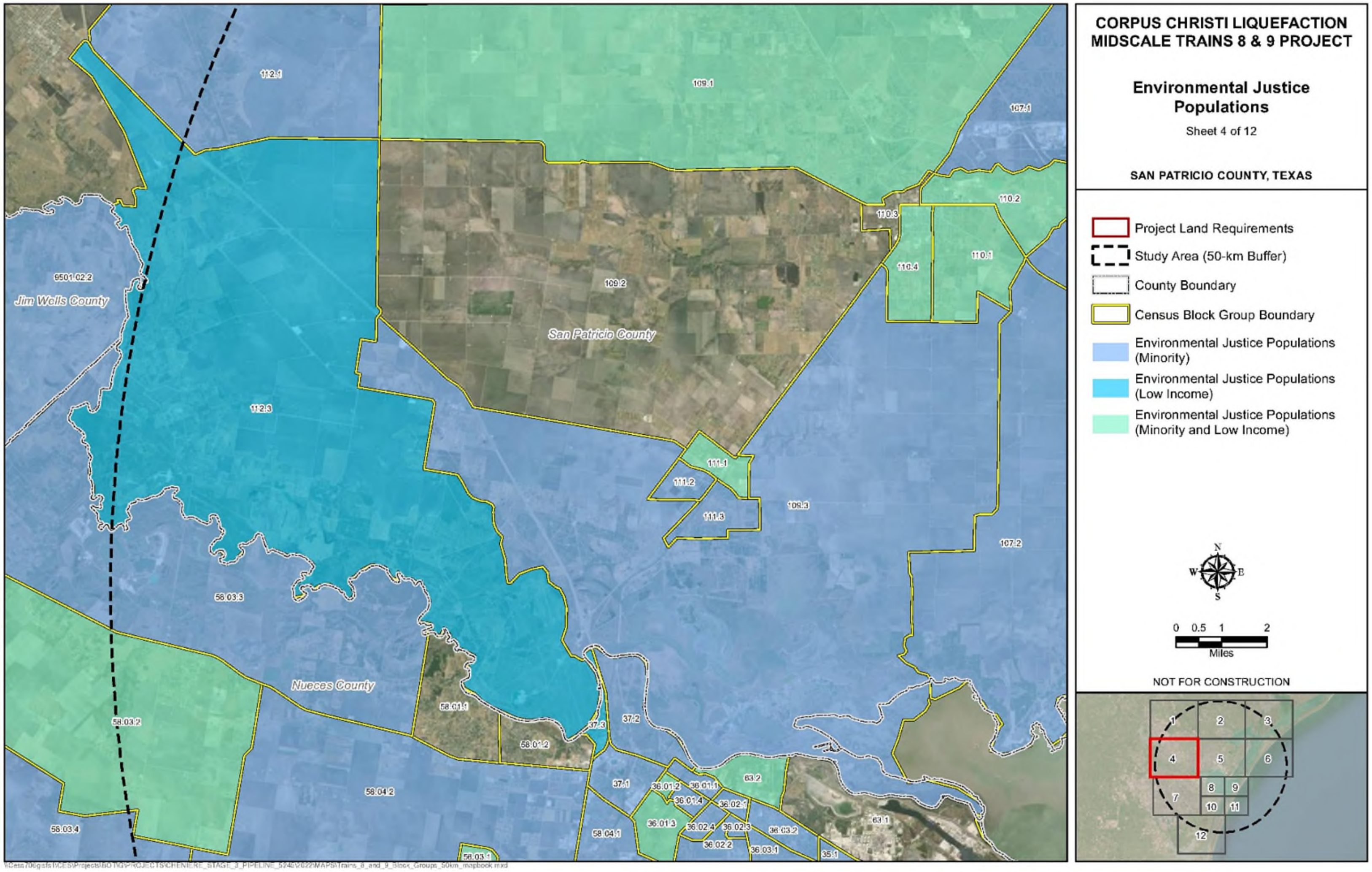

Figure E1-4 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

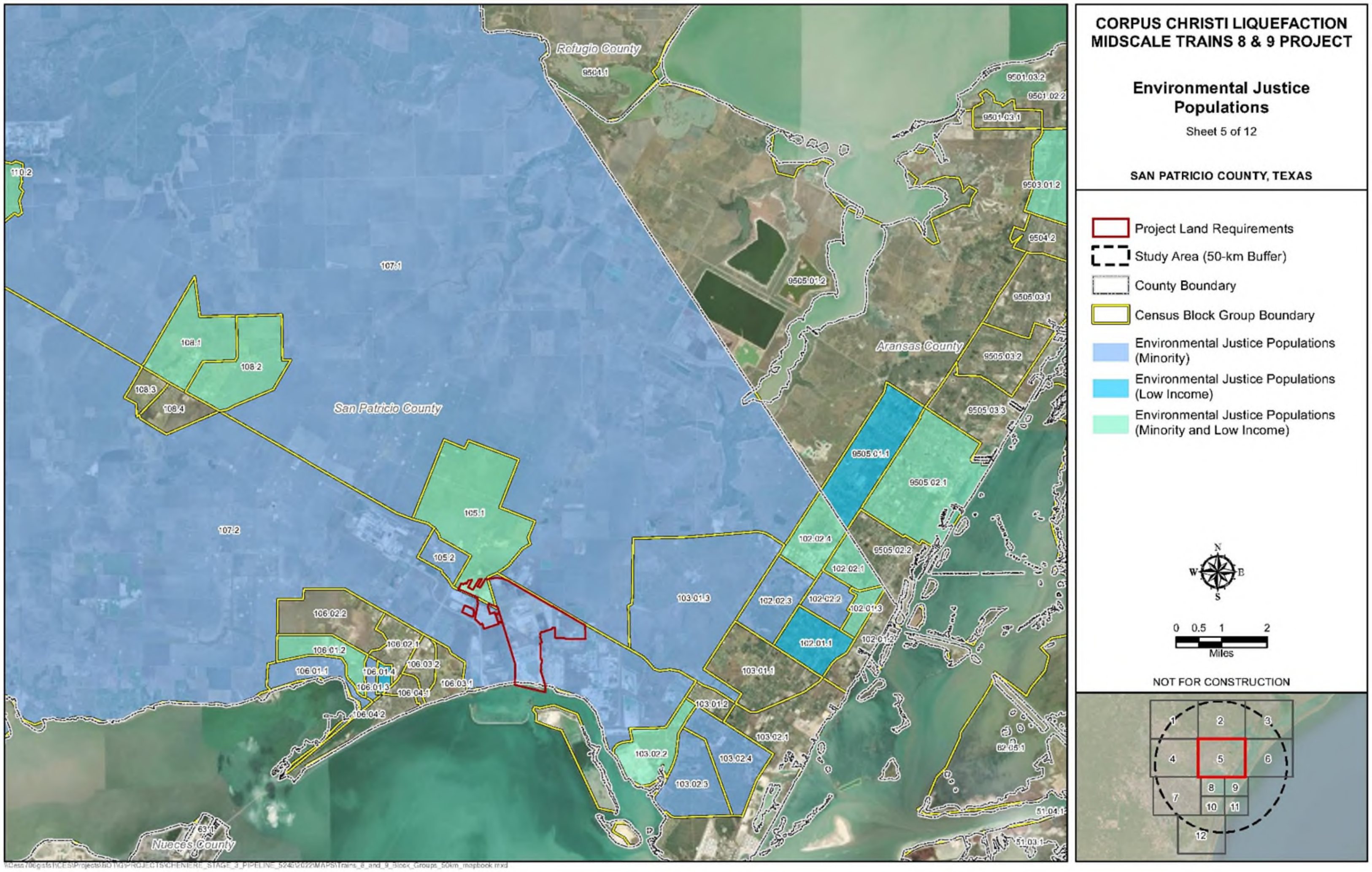

Figure E1-5 **Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace**

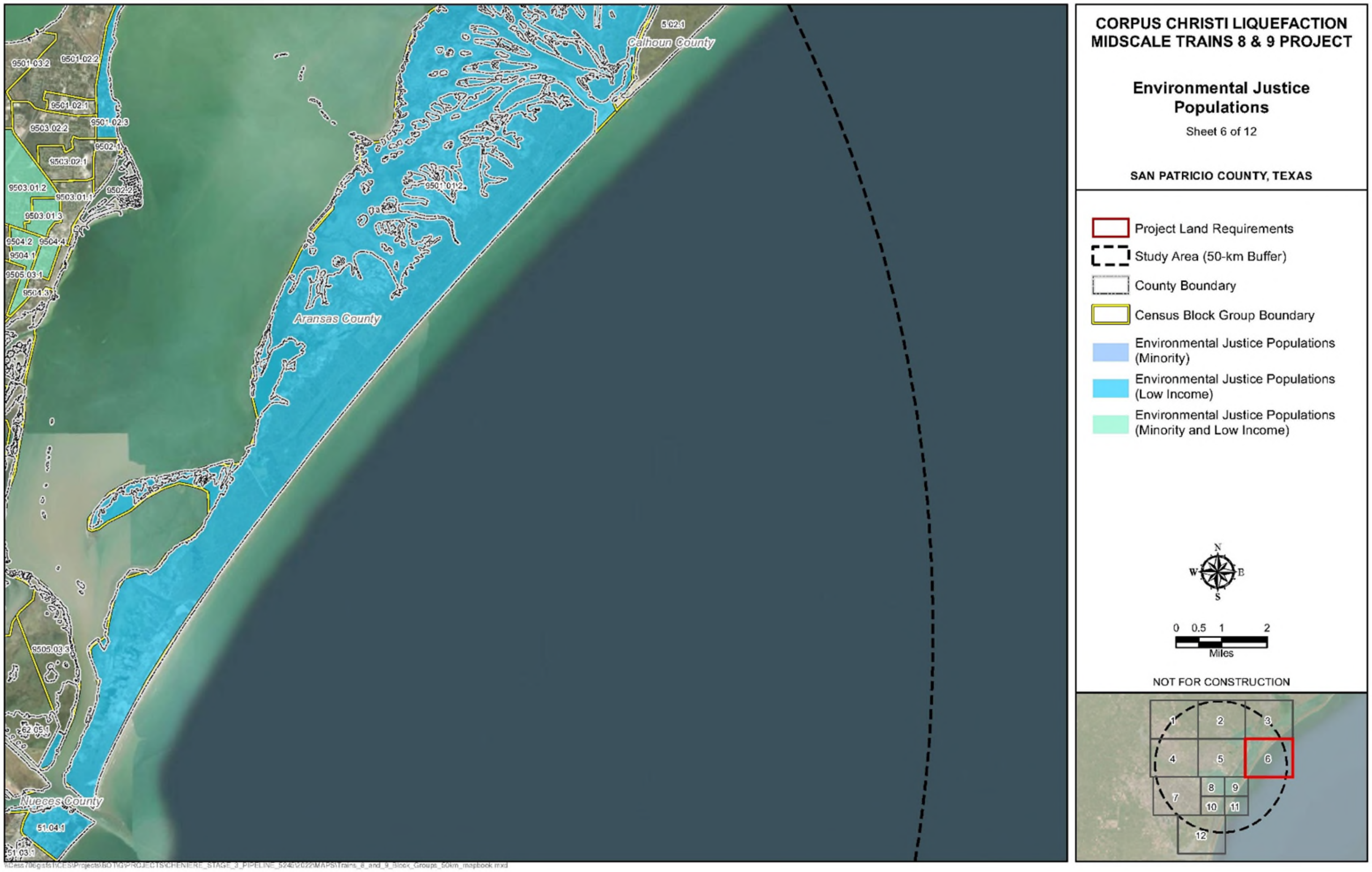

Figure E1-6 **Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace**

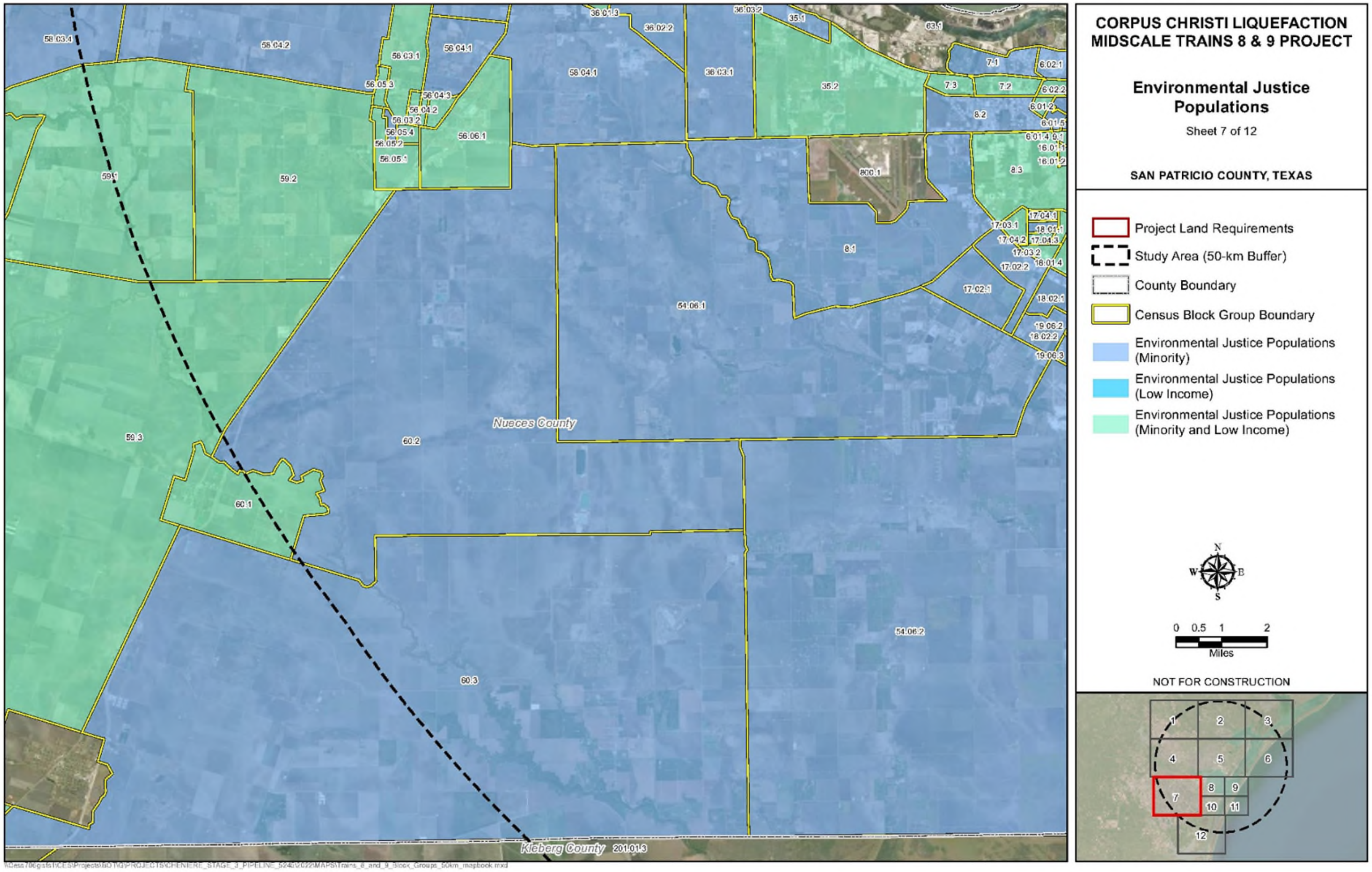

Figure E1-7 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

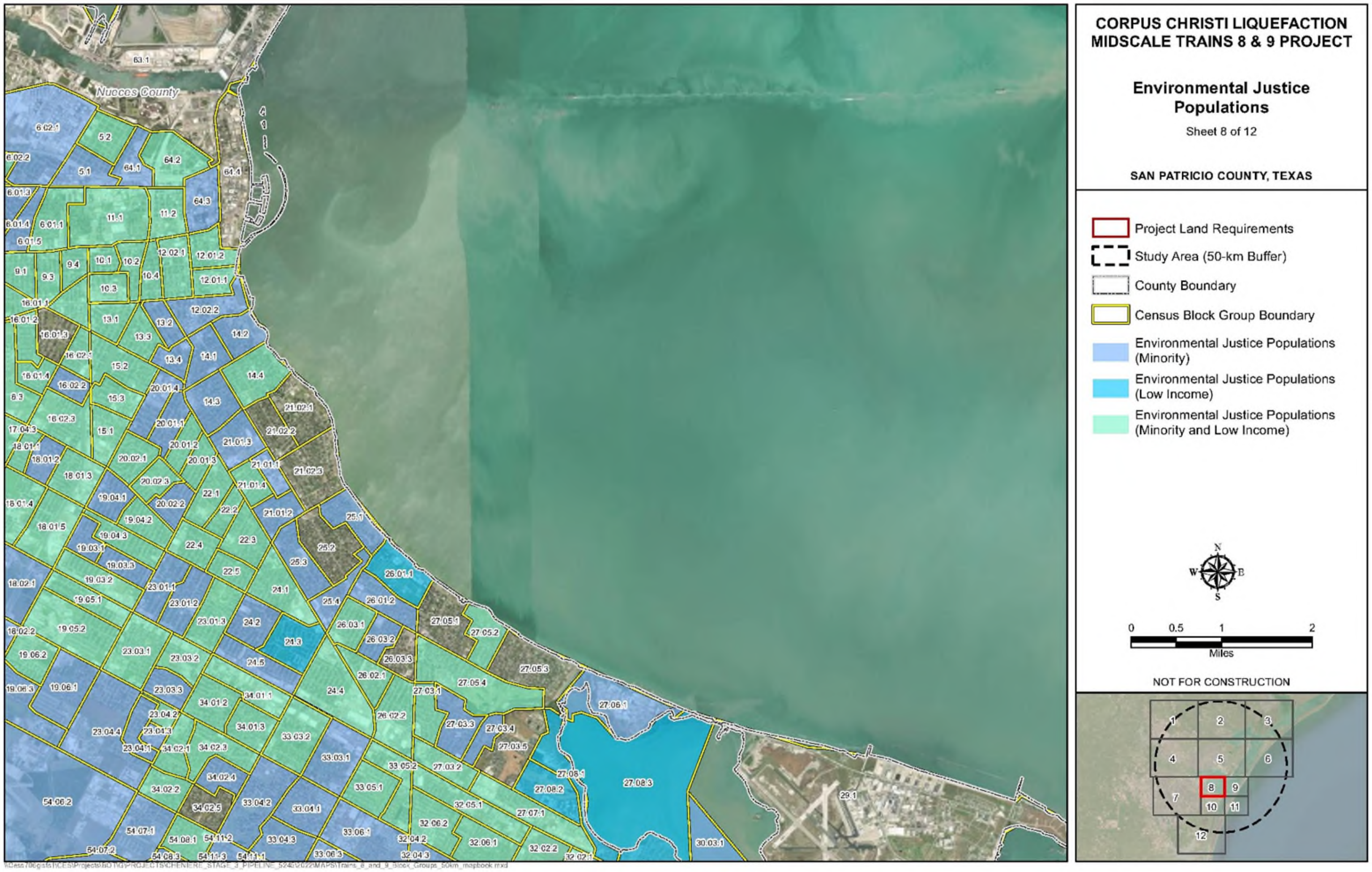

Figure E1-8 **Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace**

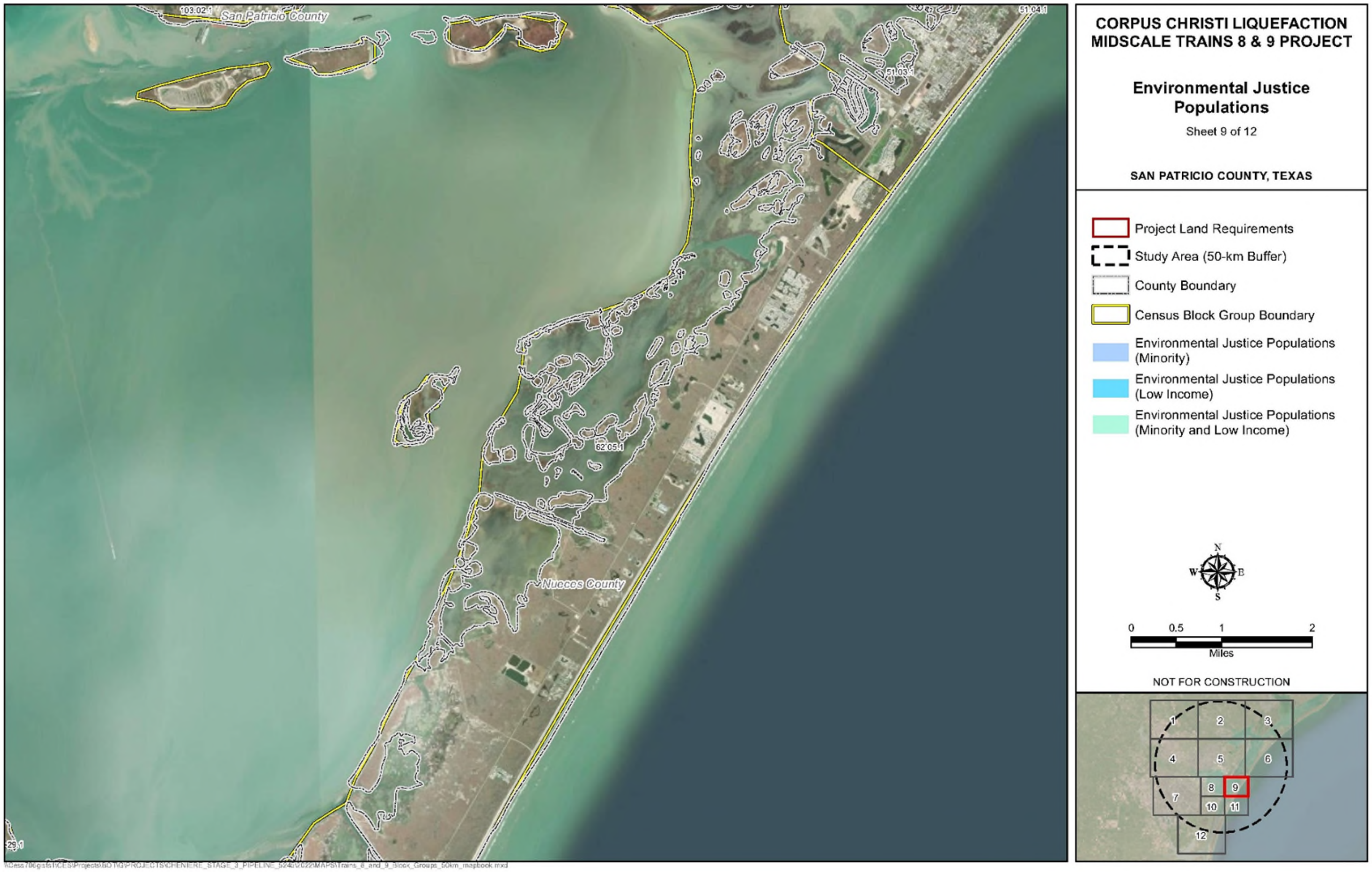

Figure E1-9 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

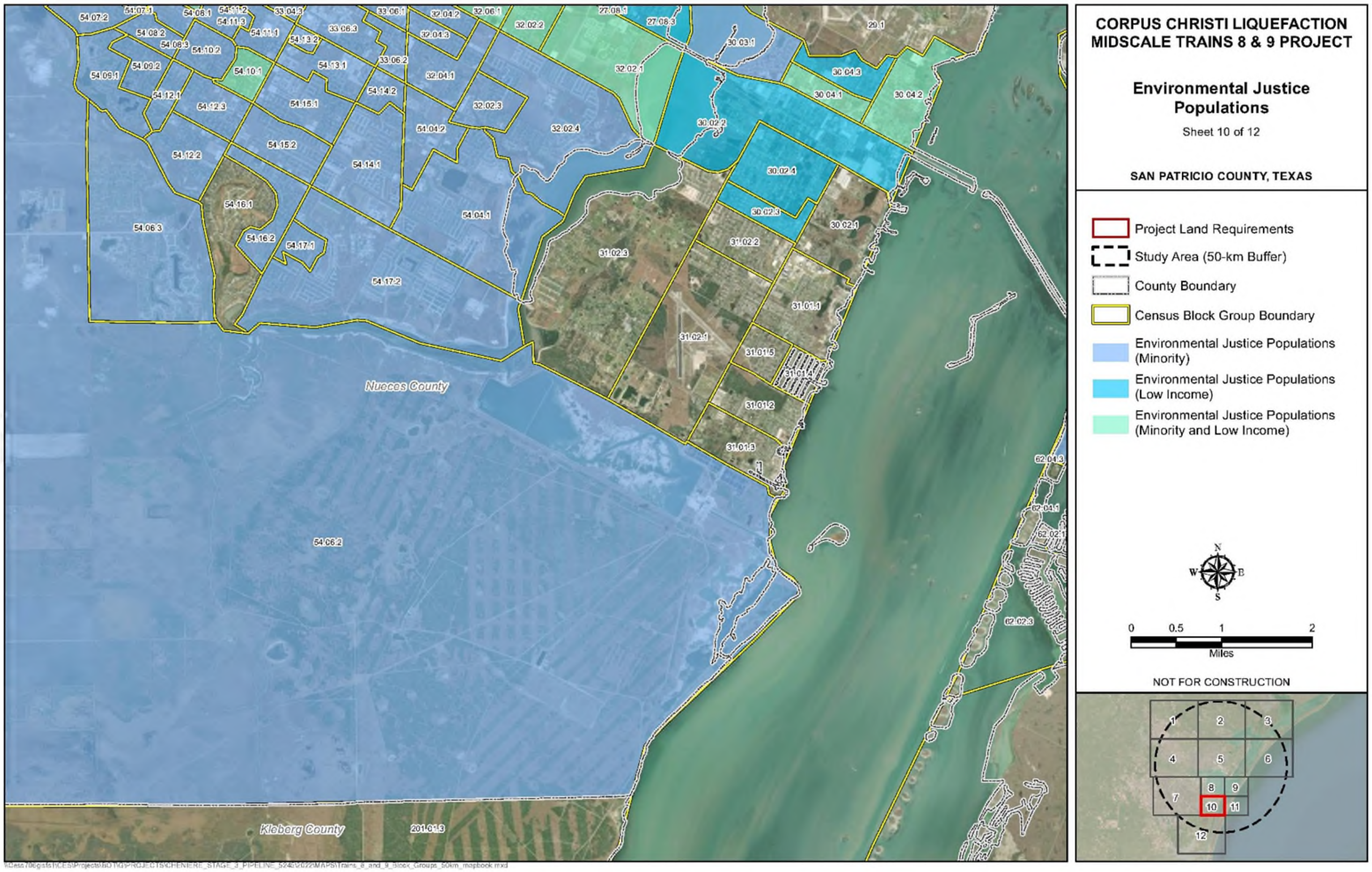

Figure E1-10 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

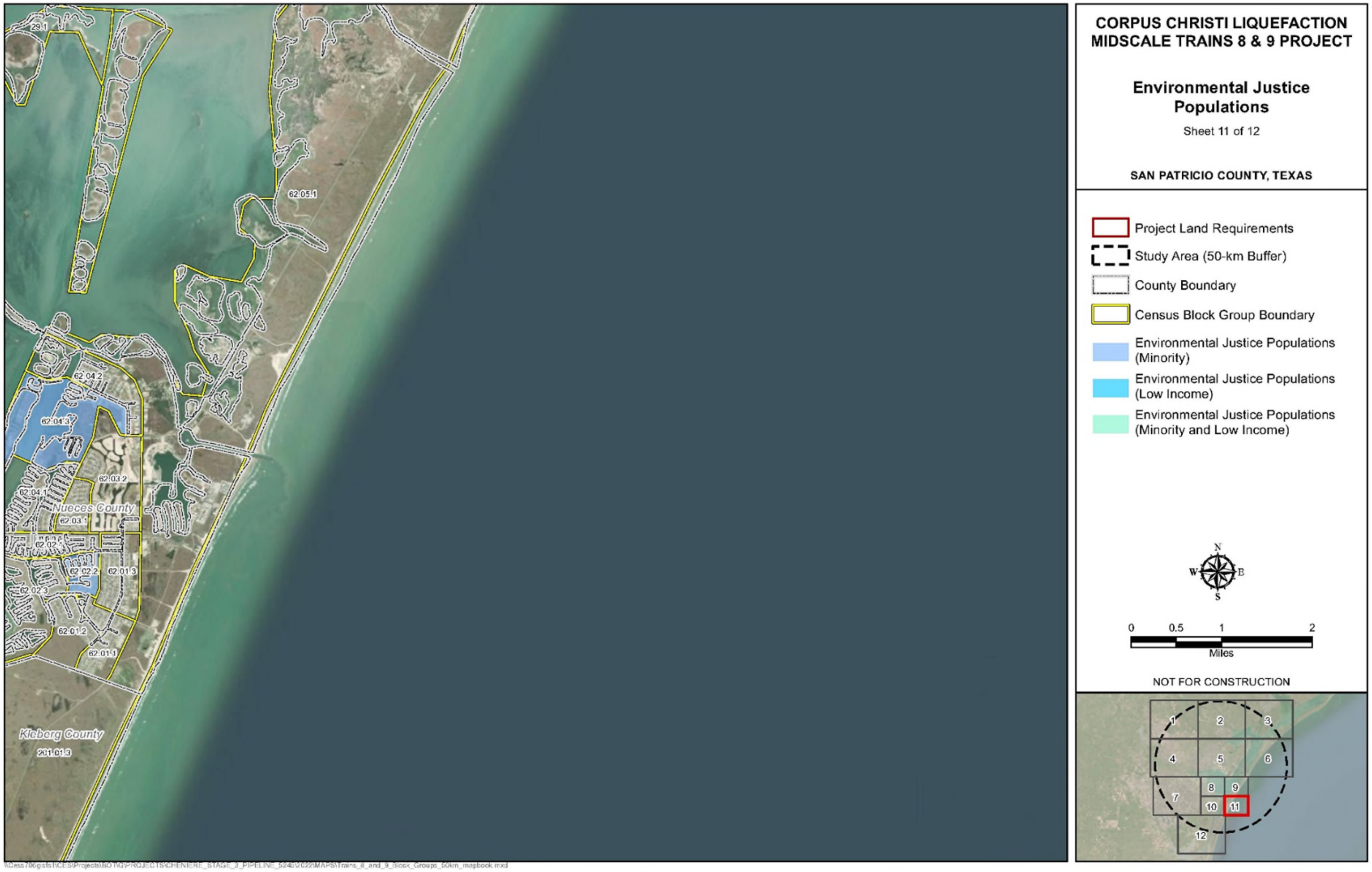

Figure E1-11 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

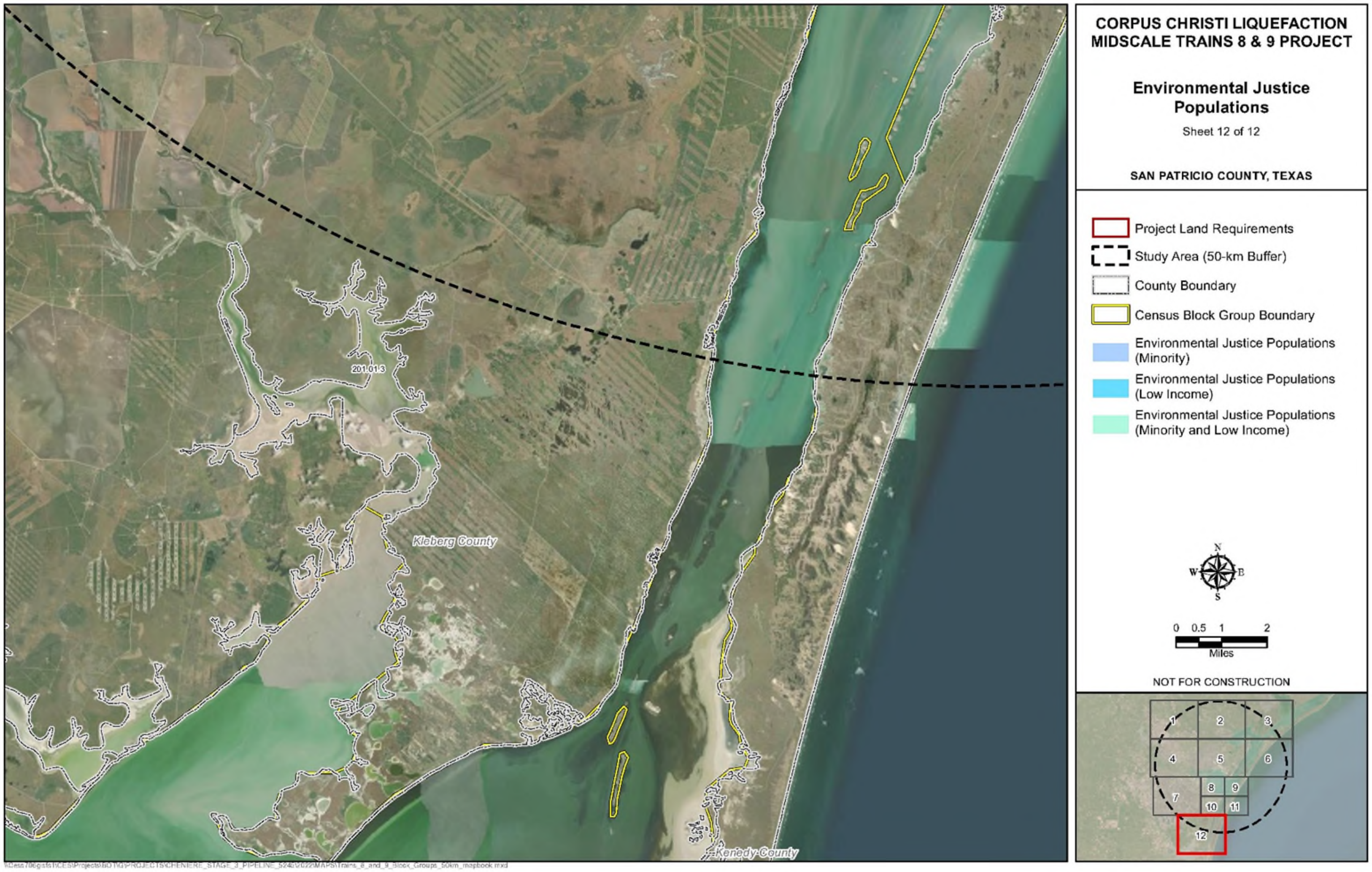

Figure E1-12 Minority and Low Income Environmental Justice Populations within 50 km of the Project Workspace

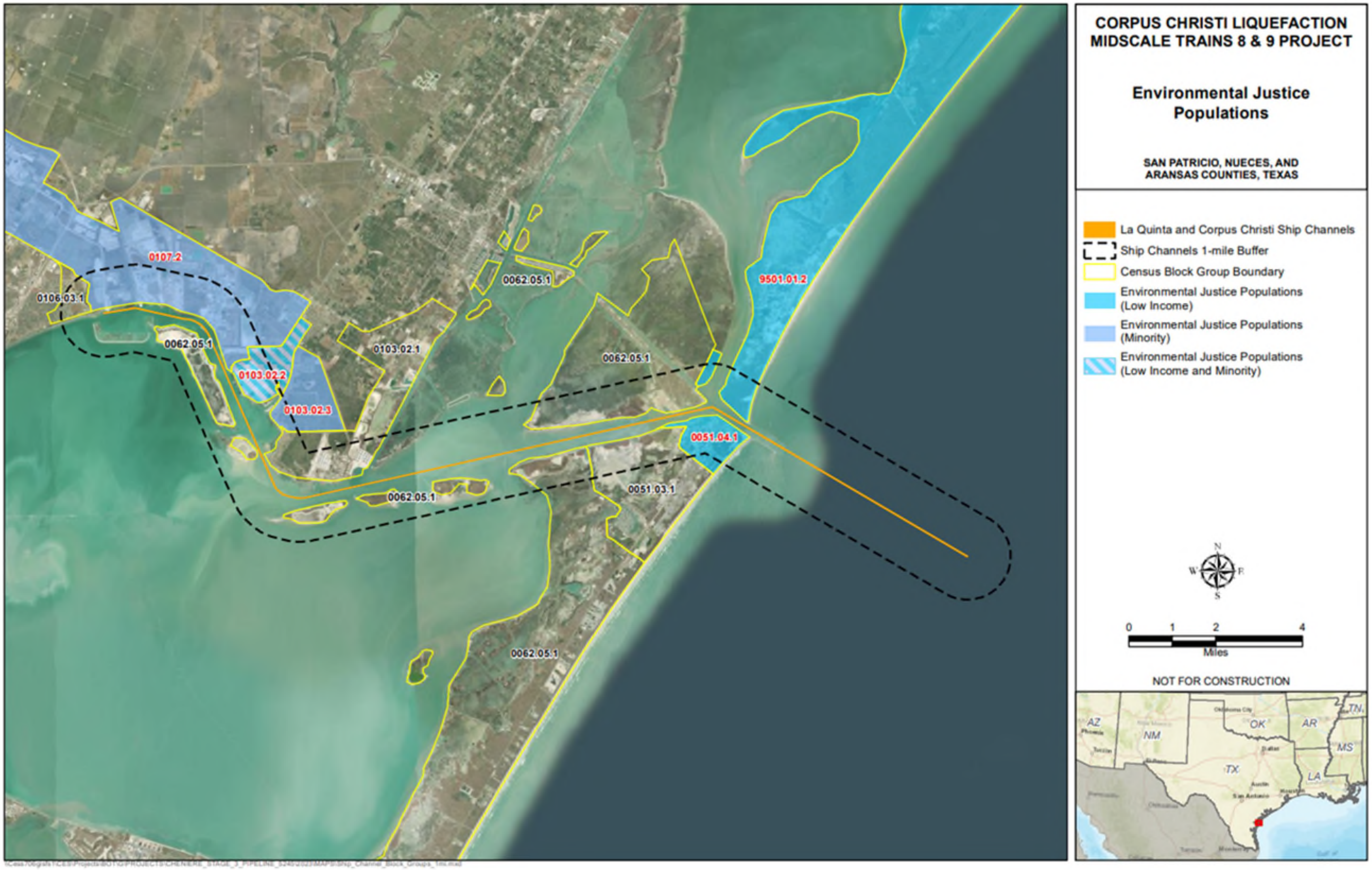

Figure E2 Environmental Justice Populations Within 1 Mile of Vessel Traffic Route

Appendix F

Human Health Risk Assessment

Cheniere LNG Terminal Human Health Risk Assessment (HHRA)

March 4, 2024

Prepared For
POWER Engineers, Inc.

Prepared by

Lucy Fraiser, PhD, DABT
Principal

Lucy Fraiser Toxicology Consulting LLC
Fayetteville, Arkansas

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Section 1
Background

Corpus Christi Liquefaction, LLC (CCL), a subsidiary of Cheniere Energy, Inc. filed an application for authorization for modifications to the existing liquefied natural gas (LNG) Terminal near Gregory, in San Patricio and Nueces Counties, Texas (collectively, the "Project") with the Federal Energy Regulatory Commission ("FERC"). Three existing liquefaction trains, Trains 1, 2, and 3, are authorized to operate at the LNG Terminal. CCL is also authorized to construct seven additional liquefaction trains, as well as the equipment needed to support the new trains (also known as the Stage 3 Project). CCL is seeking to expand the Stage 3 Project by adding 2 additional trains (Trains 8 and 9) and update representations to reflect final design of the entire Stage 3 project.

This report responds to a request from the FERC for an inhalation risk assessment of the hazardous air pollutants (HAPs) potentially emitted from the proposed CCL LNG Terminal and associated marine vessels (LNG carriers, tugs, and pilot vessels).

The National Environmental Policy Act (NEPA) requires federal agencies, such as FERC, to assess the environmental effects of proposed actions prior to making decisions. Specifically, federal agencies are required to prepare assessments of the environmental impact of proposed actions with the potential to significantly affect the environment. These assessments are commonly referred to as either an Environmental Assessment (EA) or an Environmental Impact Statement (EIS), with the EA being a less comprehensive document than the EIS.

This Human Health Risk Assessment (HHRA) was prepared in support of the EA for the Project.

Section 2
Air Quality Modeling Analysis

2.1 HAP Emissions

Facility-wide maximum hourly (pounds per hour or lb/hr) and annual emission rates (pounds per year or lb/yr) for each HAP, as well as sources of the emissions, were provided in ATTACHMENT 1, Air Quality Impact Analysis For HAPS, Corpus Christi Liquefaction, LLC, FERC Docket No. CP23-129-000 Midscale Trains 8 & 9 Project (*"CCL Air Modeling Report"*).

Facility-wide HAP emissions included:[1]

- CCL LNG Terminal stationary sources; and
- Mobile marine sources (LNG carriers, tugs, and pilot vessels).

The CCL LNG Terminal stationary sources included emissions from turbines, thermal oxidizers, heaters, engines, storage tanks, Stages 1, 2 and 3 piping, and flares. The mobile marine sources included emissions from in-port LNG carrier engines, tugboat engines and pilot vessel engines. The most recently authorized or pending emission rates have been used in the air dispersion modeling (emission calculation tables are provided in Appendix E of the CCL Air Modeling Report) and a summary of the total CCL HAP emission rates are shown in Table 4-1 of the CCL Air Modeling Report.

2.2 Modeling of HAPs

FERC requested that the Applicants provide the maximum off-property air quality impacts of HAPs within a 50-kilometer (km) radius of the CCL LNG Terminal due to emissions from the Terminal stationary and associated marine vessel sources.

The maximum modeled 1-hour and annual off-property ground-level concentrations (GLCs) of HAPs that serve as the bases of the HHRA were obtained from **Table 5-1** of the CCL Air Modeling Report.[2] The CCL Air Modeling Report provided modeled GLCs for 24 HAPs, including 15 organic compounds and nine metals.

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[1] Corpus Christi Liquefaction, LLC, CCL Midscale 8-9, LLC. Accession No. 20231124-5009, ATTACHMENT 1, Air Quality Impact Analysis For HAPs, Corpus Christi Liquefaction, LLC, FERC Docket No. CP23-129-000, Midscale Trains 8 & 9 Project. November 24, 2023.

[2] Corpus Christi Liquefaction, LLC, CCL Midscale 8-9, LLC. Accession No. 20231124-5009, ATTACHMENT 1, Air Quality Impact Analysis For HAPs, Corpus Christi Liquefaction, LLC, FERC Docket No. CP23-129-000, Midscale Trains 8 & 9 Project. November 24, 2023.

2.2.1 Polycyclic Aromatic Hydrocarbons (PAHs)

Total polycyclic organic matter (POM), a broad class of compounds consisting of all organic compounds with two or more fused aromatic rings and a boiling point greater than or equal to 212°F (100°C), are amongst the organic HAPs modeled. Epidemiologic studies have reported increases in lung cancer in humans exposed to coke oven emissions, roofing tar emissions, and cigarette smoke, each of which contain POM compounds.[3] Polycyclic aromatic hydrocarbons (PAHs) are a subset of the constituents comprising POM. PAHs often consist of three or more fused benzene rings and are generally considered to be the constituents responsible for the carcinogenic properties of POM. Although there are more than 100 PAHs, there is a much smaller group of PAHs for which exposure potential is higher, that are more harmful than many other PAHs, and that exhibit effects that are representative of the PAHs as a group. The U.S. Environmental Protection Agency (EPA) has compiled Relative Potency Factors (RPFs) to assist in evaluating the cancer risk potentially associated with exposure to these seven PAHs. Therefore, maximum modeled off-property GLCs for these PAHs are needed for the HHRA.

A review of CCL's HAPs analysis model output for POM (or PAH) impacts from CCL LNG facility emissions showed that the sources responsible for nearly 100% of the maximum 1-hour GLCs for PAH are the stationary diesel engines and the sources responsible for nearly 100% of the maximum annual GLCs for PAH are marine vessels (operating within the "safety zone"). This finding enabled the use of existing commonly used EPA emission factors to estimate the contributions of the individual PAH species to the total 1-hour and annual PAH impacts.

The individual PAH species emission rates associated with the maximum annual PAH impact (in micrograms per cubic meter or $\mu g/m^3$) (0.00114 $\mu g/m^3$) were calculated using the EPA-specified fraction (based on VOC or PM2.5 categorization of each individual PAH, per Table D.1 of EPA's 2020 Port Emissions Inventory Guidance)[4] applied to that maximum annual PAH impact. (Note that the assumed set of individual compounds contributing to the total PAH impact for marine vessels was provided by CCL[5]. The resulting annual emission rate~~s~~ for each individual PAH species was divided by the total annual PAH emission rate, with that emission-based fraction, then applied to the maximum annual PAH impact (0.00114 $\mu g/m^3$) to calculate the maximum annual impact for each individual PAH species.

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[3] Polycyclic organic matter (POM). https://www.epa.gov/sites/production/files/2016-09/documents/polycyclic-organic-matter.pdf.

[4] EPA. 2022. Port Emissions Inventory Guidance: Methodologies for Estimating Port-Related and Goods Movement Mobile Source Emissions. Office of Transportation and Air Quality, U.S. Environmental Protection Agency. April 2022. EPA-420-B-22-011.

[5] Corpus Christi Liquefaction, LLC, CCL Midscale 8-9, LLC. Accession No. 20231124-5009, Response to Question 5.d. November 24, 2023.

The individual PAH species emission rates associated with the maximum 1-hour PAH impact (0.235 μg/m^3) were calculated using the established emission factors for EPA-listed individual PAH species for stationary diesel engines, per EPA's AP-42: Compilation of Air Emissions Factors from Stationary Sources document ("AP-42").[6] The fraction of each individual PAH species emission rate relative to the total PAH emission rate based on the AP-42 emission factors was applied to the maximum 1-hour PAH impact (0.235 μg/m^3) to estimate the individual PAH compound concentration contribution to that impact.

2.2.2 Lead (Pb)

The rolling 3-month average lead (Pb) GLCs from all CCL sources for each receptor were calculated from Cheniere's model-predicted hourly Pb GLCs using the EPA's LEADPOST (Version 12114) post-processing tool[7]. The calculated maximum rolling 3-month average Pb GLC, after application of EPA's LEADPOST post-processor, is 0.00023 μg/m^3.

2.2.3 Maximum Modeled Off-Property Concentrations

The air dispersion modeling methodologies used were consistent with U.S. EPA guidelines.[8] A detailed description of the air dispersion modeling methodology can be found in **Sections 3** and **4** of the CCL Air Modeling Report.[9]

The maximum modeled 1-hour and annual GLCs for each HAP that provide the bases for this HHRA are provided in **Table 1**. A 3-month rolling average of 0.00023 μg/m^3 provided the basis for the Pb risk assessment instead of maximum modeled 1-hour and annual GLCs, as discussed in **Sections 3.1.2** and **3.1.3**.

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[6] EPA. 1996. AP-42: Compilation of Air Emissions Factors from Stationary Sources, Fifth Ed., Volume I, Section 3.4 – Large Stationary Diesel and All Stationary Duel-Fuel Engines. U.S. Environmental Protection Agency (EPA), Research Triangle Park, NC. October 1996.

[7] EPA. 2012. User Instructions for LEADPOST (Version 12114) Program. https://www.epa.gov/scram/air-quality-dispersion-modeling-preferred-and-recommended-models. Accessed January 2024.

[8] Code of Federal Regulations, Title 40-Protection of the Environment, Part 51, Appendix W, Guideline on Air Quality Models, January 2017 at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/appendix-Appendix%20W%20to%20Part%2051.

[9] Corpus Christi Liquefaction, LLC, CCL Midscale 8-9, LLC. Accession No. 20231124-5009, ATTACHMENT 1, Air Quality Impact Analysis For HAPs, Corpus Christi Liquefaction, LLC, FERC Docket No. CP23-129-000, Midscale Trains 8 & 9 Project. November 24, 2023.

Table 1
Maximum Modeled Off-Property Concentrations

Pollutant	Annual Concentration (µg/m³)	Hourly Concentration (µg/m³)
1,3-Butadiene	5.00E-04	6.00E-02
2,2,4-Trimethylpentane	4.00E-03	4.00E-01
Acetaldehyde	5.00E-03	5.00E-01
Acrolein	1.00E-03	1.00E-01
Benzene	6.00E-01	5.52E+01
Ethylbenzene	1.10E-01	1.10E+01
Formaldehyde	6.00E-02	2.30E+00
Hexane	1.30E+00	1.28E+02
Acenaphthene	2.71E-05	5.21E-03
Acenaphthylene	6.29E-05	1.03E-02
Anthracene	1.83E-04	1.37E-03
Benz[a]Anthracene	1.58E-06	6.92E-04
Benzo[a]Pyrene	7.48E-07	2.86E-04
Benzo[b]Fluoranthene	1.49E-06	1.24E-03
Benzo[k]Fluoranthene	7.48E-07	2.43E-04
Benzo[g,h,i]Fluoranthene	2.36E-05	6.19E-04
Chrysene	2.92E-06	1.70E-03
Dibenzo[a,h]Anthracene	1.55E-06	3.85E-04
Fluoranthene	1.61E-05	4.48E-03
Flourene	8.74E-05	1.42E-02
Indeno[1,2,3-cd]Pyrene	1.49E-06	4.61E-04
Naphthalene	1.60E-02	1.72E+00
Phenanthrene	7.23E-04	4.54E-02
Pyrene	6.03E-06	4.13E-03
Polychlorinated Biphenyl (PCB)	0.00E+00	1.00E-05
Propionaldehyde	8.00E-04	8.00E-02
Propylene Oxide	2.00E-03	3.00E-02
Toluene	4.50E-01	4.45E+01
Xylenes	1.40E-01	1.39E+01
Antimony	1.00E-04	1.00E-02
Arsenic	0.00E+00	4.00E-04
Cadmium	4.00E-05	4.00E-03
Chromium	0.00E+00	0.00E+00
Lead (Pb)	2.00E-05	2.00E-03
Manganese	0.00E+00	1.00E-04
Mercury	0.00E+00	0.00E+00
Nickel	1.10E-04	1.00E-02
Selenium	0.00E+00	0.00E+00

Note that HAPs for which a maximum 1-hour or annual GLCs of less than 1E-06 µg/m³ was modeled by Cheniere were reported to have a concentration of zero in the CCL Air Modeling Report. All HAPs evaluated have acceptable chronic and acute concentrations above 1E-06 µg/m³.

Section 3
Human Health Risk Assessment

Due to the level of concern regarding potential health effects associated with HAPs emissions from the CCL LNG Terminal, as well as potential impacts on environmental justice communities, FERC requested that an inhalation HHRA be conducted to evaluate the potential for short- (acute) and long-term (chronic) health effects from inhalation of HAPs potentially emitted from the Terminal, including the Project, using nationally recognized methods.

3.1 Methodology for Characterizing Human Health Risk

This HHRA was conducted in accordance with methods outlined in EPA's 2005 "Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities" (HHRAP).[10] The HHRAP provides a standardized methodology for conducting combustion risk assessments and was, therefore, chosen as appropriate guidance for this HHRA.

3.1.1 Exposure Assessment

Exposure Setting

The CCL LNG Terminal is located in a highly industrial area on the northern shore of Corpus Christi Bay in San Patricio and Nueces Counties. Undeveloped land, the Voestalpine Texas industrial facility (pre-reduced iron ore production), and Vopak Terminal Corpus Christi industrial facility (plastics manufacturing) are located immediately to the west of the Terminal (across LaQuinta Rd.), State Highways (SH)-361, SH-35, and MnI Diesel (diesel engine service, manufacturing, and fabrication) are to the north, and SH-361, TEDA TPCO America (steel pipe manufacturing) and undeveloped land are located to the east. Residential areas in the vicinity of the Terminal include Gregory (0.08 mile north, Portland (0.2 mile southwest), and Ingleside (2.1 miles southeast). According to the San Patricio County Economic Development Corporation,[11]there are no planned residential areas within 0.25 mile of the Project (and the City of Corpus Christi[12] has announced plans to construct the La Quinta Desalinization project along the La Quinta Ship Channel, about 0.6 mile east of the CCL LNG Terminal). No additional commercial

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[10] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. https://archive.epa.gov/epawaste/hazard/tsd/td/web/html/risk.html.

[11] San Patricio Economic Development Corporation. 2002. https://sanpatricioedc.com/key-data/housing. Accessed July 2023.

[12] City of Corpus Christi. 2022. Seawater Desalination. https://www.desal.cctexas.com. Accessed July 2023.

developments were identified by FERC in the Draft EA as being planned or under construction in the immediate Project area.

Exposure Pathways

An exposure "pathway" is the course a chemical takes from its source to the person potentially exposed and consists of:

1. A source (e.g., combustion turbine, engine, flare, etc.) and mechanism of HAP release (i.e., stack or fugitive emissions);

2. A receiving medium (e.g., air);

3. A point of potential human contact (e.g., property boundary, residential areas); and

4. An exposure route (e.g., inhalation).

This HHRA estimated chronic (long-term) cancer risk and non-cancer hazard, as well as acute (short-term) hazard via inhalation of compounds potentially emitted from stationary combustion sources, marine mobile sources, and fugitive emissions from CCL LNG Terminal equipment.

Exposure Scenario and Location

This HHRA evaluated inhalation exposure of hypothetical Adult and Child Residents for which Reasonable Maximum Exposure (RME) was assumed.

RME means that the hypothetical resident is conservatively assumed to be exposed 24 hours/day, 350 days/year (two weeks assumed for travel) for 30 years for the Adult Resident and six years for the Child Resident.[13] To further ensure maximum exposure, the Adult and Child Resident are assumed to live at the off-property location where HAP concentrations are highest. However, the highest concentration for different HAPs occur at different locations, making this location purely hypothetical. These highly conservative exposure assumptions are intended to evaluate potential risk/hazard with a level of protectiveness to address the possibility of exposures not directly evaluated in the HHRA. For example, of potential fishing/boating receptors in the area, commercial fishing boat operators are expected to have the greatest exposures assuming they work full-time and year-round (this is unlikely due to weather). Even a commercial fishing boat operator that is assumed to work 5 days/week year-round (minus 25 days for vacation and time spent away from work) would have considerably lower exposures than the hypothetical RME resident because he/she would be exposed fewer days (i.e., a maximum of 225 days vs 350

[13] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 6 – 20.

days/year), for fewer hours (i.e., a maximum of 8 hours vs 24 hours/day), for a shorter duration (25 years[14] vs 30 years) and they would not be exposed at maximally-impacted off-property locations that occur on land, as assumed for the hypothetical resident.

Exposure Assumptions

The 30-year exposure duration assumed for the Adult Resident is the recommended exposure duration for the Adult Resident in the HHRAP and is routinely used in HHRAs.[15] This exposure duration approximates the 95th percentile residency time for the entire U.S. populations.[16] This means that only approximately 5% of the U.S. adult population would be expected to reside in the same home for longer than 30 years, making this a highly conservative assumption. The 6-year exposure duration for the Child Resident is recommended in the HHRAP and is also an assumption routinely made in EPA HHRAs.[17] The National Research Council has recommended that EPA "…assess risks to infants and children whenever it appears that their risks might be greater than those of adults."[18] This is because adjusting exposure for body weight can cause risks estimated for child receptors to be higher than adult exposures, depending on whether the combination of child body weight and intake rate cause childhood exposures to be higher than adult exposures (this is the case for incidental soil ingestion and milk ingestion). However, for the inhalation pathway, exposure is not adjusted for bodyweight, nor is it adjusted for differences in breathing rates because EPA's methodology for developing inhalation toxicity values accounts for these.[19] Therefore, the only difference between the Adult and Child Resident inhalation exposure in this HHRA is the duration of exposure. Although an exposure duration greater than 6 years (e.g., 12 years or 18 years)

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[14] Approximately equal to the median occupational tenure for men 65 – 70 years or older, as indicated in EPA. 2011. United States Environmental Protection Agency. "Exposure Factors Handbook: 2011 Edition". EPA/600/R-090/052F. Table 16-3. September.

[15] EPA Regional Screening Levels at https://www.epa.gov/risk/regional-screening-levels-rsls; EPA. 1991. Risk Assessment Guidance for Superfund: Volume 1-Human Health Evaluation Manual (Part B, Development of Risk-based Preliminary Remediation Goals). Publication 9285.7-01 B. https://www.epa.gov/risk/risk-assessment-guidance-superfund-rags-part-b.

[16] EPA. 2011. United States Environmental Protection Agency. "Exposure Factors Handbook: 2011 Edition". EPA/600/R-090/052F. Tables 16-108. September.

[17] EPA Regional Screening Levels at https://www.epa.gov/risk/regional-screening-levels-rsls; EPA. 1991. Risk Assessment Guidance for Superfund: Volume 1-Human Health Evaluation Manual (Part B, Development of Risk-based Preliminary Remediation Goals). Publication 9285.7-01 B. https://www.epa.gov/risk/risk-assessment-guidance-superfund-rags-part-b.

[18] EPA. 2005. Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens. https://www.epa.gov/risk/supplemental-guidance-assessing-susceptibility-early-life-exposure-carcinogens.

[19] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 6-2; EPA EpoBox. Exposure Assessment Tools by Routes – Inhalation. https://19january2021snapshot.epa.gov/expobox/exposure-assessment-tools-routes-inhalation_.html.

would cause the estimated cancer risk for the Child Resident to be higher, the cancer risk would under no circumstances be greater than the Adult Resident cancer risk.[20] More importantly, 6 years is the most reasonable exposure duration for the Child Resident given the other assumptions made for the RME scenario (i.e., exposure for 24 hours/day, 350 days/year).

Children generally spend more time outdoors than do adults. According to EPA's Exposure Factors Handbook:[21]

- children 1 – 2 years old spend 36 minutes/day outdoors;
- children 2 – 3 years old spend 76 minutes/day outdoors;
- children 3 – 6 years old spend 107 minutes/day outdoors;
- children 6 – 11 spend 132 minutes/day outdoors;
- children 11 – 16 spend 100 minutes/day outdoors; and
- children 16 – 21 spend approximately 102 minutes/day outdoors.

Even though children 6 – 11 years old spend more total time outdoors, and children 11 – 16 and 16 – 21 years old spend similar amounts of time outdoors, children less than 6 years old generally spend more time at the home because they are not yet in school. Therefore, much of the time older children spend outside would occur at school and elsewhere away from the home. Therefore, evaluating childhood inhalation exposure over a period of 6 years comports with focusing the exposure assessment on the life stage with behavioral characteristics that may lead to higher levels of exposure[22].

It is important to acknowledge that few if any residents would be homebound 24 hours/day, much less spend all of their time outdoors, every day. Therefore, the combination of exposure factors utilized in this HHRA for the Adult and Child Resident make it highly unlikely that risks will be underestimated.

Exposure Concentrations

Chronic exposures occur over time. To calculate an average inhalation exposure per unit of time (Exposure Concentration, or EC), the maximum modeled annual GLC or air concentration was multiplied by the Exposure Frequency (EF) and Exposure Duration (ED) and divided by the time over which exposure is averaged, which differs for carcinogens (70 years) and non-carcinogens (30 years or 6 years). Estimating

[20] Changing the exposure duration in the non-cancer exposure equation does not change the overall estimate of exposure or hazard quotient because the same exposure duration is used in the averaging time in denominator.
[21] EPA. 2011. U.S. Environmental Protection Agency. Exposure Factors Handbook: 2011 Edition. EPA/600/R-09/052F. Table 16-1. https://www.epa.gov/expobox/about-exposure-factors-handbook.
[22] EPA. 2012. U.S. Environmental Protection Agency. Standard Operating Procedures for Residential Pesticide Exposure Assessment. https://www.epa.gov/pesticide-science-and-assessing-pesticide-risks/standard-operating-procedures-residential-pesticide#.

ECs in air does not involve or require adjustment for differences in respiration rates for adults and children, as those are inherent to inhalation toxicity factors.[23] The equation for calculating chronic ECs is provided below.

$$EC = \frac{CA\ x\ EF\ x\ ED}{AT_c\ or\ AT_{nc}}$$

Where:

			Value
EC	=	Exposure concentration (µg/m³)	*Calc*
CA	=	Air concentration (µg/m³)	*Model*
EF	=	Exposure frequency (days/year)	350
ED_{adult}	=	Exposure duration (years)	30
ED_{child}	=	Exposure duration (years)	6
AT_c	=	Carcinogen (70 years x 365 days/year) averaging time (days)	25550
$AT_{nc\ adult}$	=	Carcinogen (30 years x 365 days/year) averaging time (days)	10950
$AT_{nc\ child}$	=	Carcinogen (6 years x 365 days/year) averaging time (days)	2190

For acute exposures, the maximum modeled 1-hour concentration is used without any adjustment since acute exposures occur intermittently.

The ECs calculated for use in this HHRA are provided in **Table 2**. Note that HAPs for which a maximum 1-hour or annual off-property concentration of less than 1E-06 µg/m³ was modeled by Cheniere (See CCL Air Modeling Report) are reported to have a concentration of zero and, therefore, are dropped from further consideration in the HHRA. All air concentrations corresponding to EPA's lower-bound target cancer risk, Reference Concentrations (RfCs), Minimal Risk Levels (MRLs) or acute toxicity factors for modeled HAPs were considerably higher than 1E-06 µg/m³.

3.1.2 Toxicity Assessment

Toxicity factors used to estimate chronic (long-term) cancer risk are Inhalation Unit Risk Factors (IURFs) developed by U.S. EPA. Toxicity factors used to estimate chronic non-cancer hazards for all HAPs except for lead (Pb), include EPA RfCs or MRLs developed by the Agency for Toxic Substances and Disease Registry (ATSDR). For Pb, the National Ambient Air Quality Standard (NAAQS) is compared to the maximum 3-month rolling average air concentration (not an estimated EC). Toxicity factors for estimating acute (short-term) inhalation hazards are comprised of California EPA Acute (1-hour) Reference Exposure Levels (RELs) and EPA 1-Hour Acute Exposure Guideline Levels (AEGLs).

[23] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 6-2.

Table 2
Maximum Modeled Off-Property Exposure Concentrations (ECs)

Pollutant	Exposure Concentrations (µg/m^3)				
	Chronic				Acute
	Carcinogen		Non-Carcinogen		
	Adult	Child	Adult	Child	
1,3-Butadiene	2.05E-04	4.11E-05	4.79E-04	4.79E-04	6.00E-02
2,2,4-Trimethylpentane	1.64E-03	3.29E-04	3.84E-03	3.84E-03	4.00E-01
Acetaldehyde	2.05E-03	4.11E-04	4.79E-03	4.79E-03	5.00E-01
Acrolein	4.11E-04	8.22E-05	9.59E-04	9.59E-04	1.00E-01
Benzene	2.47E-01	4.93E-02	5.75E-01	5.75E-01	5.52E+01
Ethylbenzene	4.52E-02	9.04E-03	1.05E-01	1.05E-01	1.10E+01
Formaldehyde	2.47E-02	4.93E-03	5.75E-02	5.75E-02	2.30E+00
Hexane	5.34E-01	1.07E-01	1.25E+00	1.25E+00	1.28E+02
Acenaphthene	1.12E-05	2.23E-06	2.60E-05	2.60E-05	5.21E-03
Acenaphthylene	2.59E-05	5.17E-06	6.03E-05	6.03E-05	1.03E-02
Anthracene	7.54E-05	1.51E-05	1.76E-04	1.76E-04	1.37E-03
Benz[a]Anthracene	6.49E-07	1.30E-07	1.51E-06	1.51E-06	6.92E-04
Benzo[a]Pyrene	3.08E-07	6.15E-08	7.18E-07	7.18E-07	2.86E-04
Benzo[b]Fluoranthene	6.14E-07	1.23E-07	1.43E-06	1.43E-06	1.24E-03
Benzo[k]Fluoranthene	3.08E-07	6.15E-08	7.18E-07	7.18E-07	2.43E-04
Benzo[g,h,i]Fluoranthene	9.71E-06	1.94E-06	2.27E-05	2.27E-05	6.19E-04
Chrysene	1.20E-06	2.40E-07	2.80E-06	2.80E-06	1.70E-03
Dibenzo[a,h]Anthracene	6.36E-07	1.27E-07	1.48E-06	1.48E-06	3.85E-04
Fluoranthene	6.60E-06	1.32E-06	1.54E-05	1.54E-05	4.48E-03
Flourene	3.59E-05	7.19E-06	8.38E-05	8.38E-05	1.42E-02
Indeno[1,2,3-cd]Pyrene	6.14E-07	1.23E-07	1.43E-06	1.43E-06	4.61E-04
Naphthalene	6.58E-03	1.32E-03	1.53E-02	1.53E-02	1.72E+00
Phenanthrene	2.97E-04	5.94E-05	6.93E-04	6.93E-04	4.54E-02
Pyrene	2.97E-04	5.94E-05	5.79E-06	5.79E-06	4.13E-03
Polychlorinated Biphenyl (PCB)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.00E-05
Propionaldehyde	3.29E-04	6.58E-05	7.67E-04	7.67E-04	8.00E-02
Propylene Oxide	8.22E-04	1.64E-04	1.92E-03	1.92E-03	3.00E-02
Toluene	1.85E-01	3.70E-02	4.32E-01	4.32E-01	4.45E+01
Xylenes	5.75E-02	1.15E-02	1.34E-01	1.34E-01	1.39E+01
Antimony	4.11E-05	8.22E-06	9.59E-05	9.59E-05	1.00E-02
Arsenic	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.00E-04
Cadmium	1.64E-05	3.29E-06	3.84E-05	3.84E-05	4.00E-03
Lead (Pb)	NA	NA	NA	NA	2.00E-03
Manganese	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.00E-04
Nickel	4.52E-05	9.04E-06	1.05E-04	1.05E-04	1.00E-02

Chronic (Long-Term) Toxicity Factors

A hierarchical approach was used to select the appropriate toxicity criteria for use in estimating chronic (long-term) cancer risk and non-cancer hazards. Chronic toxicity criteria for the HAPs were selected from the following sources, in order of preference:

1. Cancer IURFs (Inhalation Unit Risk Factors) and non-cancer RfCs (Reference Concentrations) from EPA's Integrated Risk Information System (IRIS) at https://www.epa.gov/iris.

2. Cancer IURFs and non-cancer RfCs from EPA's Provisional Peer Reviewed Toxicity Values (PPRTVs) at https://www.epa.gov/pprtv/provisional-peer-reviewed-toxicity-values-pprtvs-assessments.

3. Chronic MRLs (Minimal Risk Levels) provided in Toxicological Profiles published by the ATSDR at https://www.atsdr.cdc.gov/toxprofiledocs/index.html or the MRL list at https://wwwn.cdc.gov/TSP/MRLS/mrlsListing.aspx.

Carcinogen IURFs are expressed in terms of risk per concentration for inhalation exposures (i.e., risk per $\mu g/m^3$ or $(\mu g/m^3)^{-1}$). Non-cancer RfCs and MRLs are expressed as air concentrations and have been converted from their original units of mg/m^3 to $\mu g/m^3$ for ease of use with the modeled air concentrations, which are expressed in units of $\mu g/m^3$.

EPA defines the IURF as an estimate of the increased cancer risk from inhalation exposure to a concentration of 1 $\mu g/m^3$ for a lifetime. RfCs are defined as an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.[24] The ATSDR defines an MRL as an estimate of the daily human exposure to a hazardous substance that is likely to be without appreciable risk of adverse non-cancer health effects over a specified duration of exposure.[25]

Benzene

EPA's IRIS lists a range for the benzene IURFs, each having equal scientific plausibility, to reflect the inherent uncertainties in the risk assessment of benzene and the limitations of the epidemiologic studies in determining dose-response and exposure data. The EPA-recommended IURFs range from 2.2×10^{-6}

[24] EPA website. "Basic Information about the Integrated Risk Information System". https://www.epa.gov/iris/basic-information-about-integrated-risk-information-system. Visited on June 6, 2023.

[25] ATSDR website. "Minimal Risk Levels (MRLs) – For Professionals". https://www.atsdr.cdc.gov/mrls/index.html#:~:text=An%20MRL%20is%20an%20estimate,a%20specified%20duration%20of%20exposure. Visited on June 7, 2023.

$(\mu g/m^3)^{-1}$ (2.2E-06 $(\mu g/m^3)^{-1}$) to 7.8×10^{-6} $(\mu g/m^3)^{-1}$ (7.8E-06 $(\mu g/m^3)^{-1}$).[26] This IURF range is based on two different exposure estimates by two different researchers (Paustenbach et al.,1993[27] and Crump and Allen,1984[28]) for the benzene worker cohort. To ensure conservatism in this HHRA, the upper-bound IURF (7.8×10^{-6} or 7.8E-06 $(\mu g/m^3)^{-1}$) was used to estimate benzene cancer risk in this HHRA. However, as noted in the IRIS summary, each of the IURFs have equal scientific plausibility. The air concentrations corresponding to a 1-in-1,000,000 cancer risk (EPA's most stringent target level) based on the range of IURFs recommended for benzene by EPA is 0.13 to 0.45 $\mu g/m^3$.

Lead (Pb)

Pb (lead) is unique among HAPs in several ways. Infants and children are particularly susceptible to the health effects of Pb and Pb risk assessment is based on blood Pb levels in children. The primary contribution of Pb in ambient air to young children's blood Pb concentrations is generally due to ingestion of Pb following its deposition onto soil/dust rather than directly from inhaling Pb in ambient air. Therefore, any air benchmark used in a Pb risk assessment must consider the complex relationship between the concentration of Pb in air and blood Pb concentration.

EPA's IRIS database does not list an inhalation RfC or an IURF for Pb. However, EPA has established a NAAQS that is based on the relationship between Pb in air and blood Pb levels. Therefore, the Pb NAAQS is used as the health benchmark for evaluating non-cancer effects associated with exposure to Pb in this HHRA.

Polycyclic Aromatic Hydrocarbons (PAHs)

PAHs are members of the same family and exhibit similar toxicological properties. However, they differ in degree of toxicity. Relative potency factors (RPFs) have been developed by U.S. EPA for seven individual PAH species with carcinogenic properties that are representative of the group of PAHs.[29] These RPFs are based on the carcinogenic potency of each PAH species relative to that of benzo[a]pyrene. In deriving the

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[2626] EPA, 2004. Integrated Risk Information System (IRIS), U.S. Environmental Protection Agency Chemical Assessment Summary for Benzene CASRN 71-43-2. https://19january2021snapshot.epa.gov/iris_.html.

[27] Paustenbach, D; Bass, R; Price, P. (1993) Benzene toxicity and risk assessment, 1972-1992: implications for future regulation. Environ Health Perspect 101 (Suppl 6):177-200.

[28] Crump, KS; Allen, BC. (1984) Quantitative estimates of risk of leukemia from occupational exposure to benzene. Prepared for the Occupational Safety and Health Administration by Science Research Systems, Inc., Ruston, LA. Unpublished.

[29] EPA. 1993. Provisional Guidance for Quantitative Risk Assessment of Polycyclic Aromatic Hydrocarbons. EPA/600/R-93/089. Table 8, p. 17. https://www.epa.gov/risk/regional-screening-levels-rsls-users-guide#toxicity.

RPFs, it was assumed that the PAHs have similar dose-response curves, but that it takes a proportionally larger concentration of non-benzo[a]pyrene PAHs to induce an equivalent tumor response. Since they are specific to carcinogenic potency, RPFs are not used to estimate non-cancer toxicity factors. Consistent with the approach used by EPA in developing its regional screening levels,[30] the RPFs have been applied to the IURF for benzo[a]pyrene to calculate IURFs for each carcinogenic PAH, as shown in **Table 3.**

Table 3
Carcinogenic Polycyclic Aromatic Hydrocarbon (PAH)
Inhalation Unit Risk Factors (IURFs)

Calculation of IURFs for Carcinogenic PAHs			
PAH	**RPF**	**Benzo[a]Pyrene IURF $(\mu g/m^3)^{-1}$**	**Calculated IURF $(\mu g/m^3)^{-1}$**
Benzo(a)pyrene	1	6.00E-04	6.00E-04
Benz(a)anthracene	0.1		6.00E-05
Benzo(b)fluoranthene	0.1		6.00E-05
Benzo(k)fluoranthene	0.01		6.00E-06
Chrysene	0.001		6.00E-07
Dibenz(a,h)anthracene	1		6.00E-04
Indeno(1,2,3-	0.1		6.00E-05

Source: Table 8 of EPA's *Provisional Guidance for Quantitative Risk Assessment of Polycyclic Aromatic Hydrocarbons*.[31]

Chronic toxicity factors used in this HHRA and their sources are provided in **Table 4**. Also provided in **Table 4** are the critical effects on which non-cancer toxicity factors are based.

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[30] EPA website. Regional Screening Levels (RSLs) - User's Guide. https://www.epa.gov/risk/regional-screening-levels-rsls-users-guide#toxicity. Visited on June 23, 2023.

[31] EPA. 1993. Provisional Guidance for Quantitative Risk Assessment of Polycyclic Aromatic Hydrocarbons. EPA/600/R-93/089. Table 8, p. 17. https://www.epa.gov/risk/regional-screening-levels-rsls-users-guide#toxicity.

Table 4
Chronic Toxicity Factors

Pollutant	Cancer IURF $(\mu g/m^3)^{-1}$	Ref.	Non-Cancer RfC, MRL or NAAQS $(\mu g/m^3)$	Non-Cancer Effect	Ref.
1,3-Butadiene	3.00E-05	IRIS	2.00E+00	ovarian atrophy	IRIS
2,2,4-Trimethylpentane	NA	NA	NA	NA	NA
Acetaldehyde	2.20E-06	IRIS	9.00E+00	olfactory epithelium degen	IRIS
Acrolein	NA	NA	2.00E-02	nasal lesions	IRIS
Benzene	7.80E-06 2.2E-06	IRIS	3.00E+01	decreased lymphocyte	IRIS
Ethylbenzene	NA	NA	1.00E+03	developmental	IRIS
Formaldehyde	1.30E-05	IRIS	9.80E+00	histological changes in nasal	ATSDR
Hexane	NA	NA	7.00E+02	peripheral neuropathy	IRIS
Acenaphthene	NA	NA	NA	NA	NA
Acenaphthylene	NA	NA	NA	NA	NA
Anthracene	NA	NA	NA	NA	NA
Benz[a]Anthracene	6.00E-05	RPF	NA	NA	NA
Benzo[a]Pyrene	6.00E-04	IRIS	2.00E-03	developmental	IRIS
Benzo[b]Fluoranthene	6.00E-05	RPF	NA	NA	NA
Benzo[k]Fluoranthene	6.00E-06	RPF	NA	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA	NA	NA
Chrysene	6.00E-07	RPF	NA	NA	NA
Dibenzo[a,h]Anthracene	6.00E-04	RPF	NA	NA	NA
Fluoranthene	NA	NA	NA	NA	NA
Flourene	NA	NA	NA	NA	IRIS
Indeno[1,2,3-cd]Pyrene	6.00E-05	RPF	NA	NA	IRIS
Naphthalene	NA	NA	3.00E+00	hyperplasia resp/nasal	IRIS
Phenanthrene	NA	NA	NA	NA	NA
Pyrene	NA	NA	NA	NA	NA
Propionaldehyde	NA	NA	8.00E+00	olfactory epithelium atrophy	IRIS
Propylene Oxide	3.70E-06	IRIS	3.00E+01	nasal epithelial infolds	IRIS
Toluene	NA	NA	5.00E+03	CNS	IRIS
Xylenes	NA	NA	1.00E+02	CNS	IRIS
Antimony	NA	NA	2.00E-01	pulm tox/interstitial inflam	IRIS
Cadmium	1.80E-03	IRIS	1.00E-02	NA	ATSDR
Lead	NA	NA	1.5E-01	neurodevelopmental, CNS	NAAQS
Nickel	4.80E-04	IRIS	1.00E-02	lung inflammation	ATSDR

ATSDR – Agency for Toxic Substances and Disease Registry
CNS – Central Nervous System
IRIS – Integrated Risk Information System
IURF – Inhalation Unit Risk Factor
NAAQS – National Ambient Air Quality Standard
RfC – Reference Concentration
RPF – PAH Relative Potency Factor

Acute Toxicity Factors (ATFs)

To ensure consistency with other FERC HHRAs, the following sources were searched for 1-hour toxicity criteria, in order of preference.

1. California EPA Acute Reference Exposure Levels (RELs) at https://oehha.ca.gov/air/general-info/oehha-acute-8-hour-and-chronic-reference-exposure-level-rel-summary.
2. Level 1 EPA 1-hour Acute Exposure Guideline values (AEGL-1) https://www.epa.gov/aegl/access-acute-exposure-guideline-levels-aegls-values.
3. Level 2 EPA 1-hour AEGL-2 values at https://www.epa.gov/aegl/access-acute-exposure-guideline-levels-aegls-values.

California EPA Acute RELs are defined as the concentration in air at or below which no adverse health effects are anticipated in the general population, including sensitive individuals, for a specified exposure period (i.e., 1-hour) on an intermittent basis.[32] EPA AEGL-1 values are the concentration of a substance in air above which the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure. AEGL-2 values are the airborne concentration of a substance above which it is anticipated that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.[33] AEGL-2 values were only selected if an AEGL-1 value was not available.

Acute toxicity factors used in this HHRA and their sources are provided in **Table 5**.

[32] OEHHA. 2015. California Environmental Protection Agency Office of Environmental Health Hazard Assessment. Air Toxics Hot Spots Program. Risk Assessment Guidelines. February 2015. p. 6-3.
[33] EPA website. "About Acute Exposure Guideline Levels (AEGLs)". https://www.epa.gov/aegl/about-acute-exposure-guideline-levels-aegls. Visited on June 6, 2023.

Table 5
Acute Toxicity Factors

Pollutant	Acute Toxicity Factor (µg/m³)	Effect	Ref.
1,3-Butadiene	6.60E+02	developmental	Ca REL
2,2,4-Trimethylpentane	NA	NA	NA
Acetaldehyde	4.70E+02	eye/resp irritation	Ca REL
Acrolein	2.50E+00	eye/resp irritation	Ca REL
Benzene	2.70E+01	developmental, immune system, hematological effects	Ca REL
Ethylbenzene	1.43E+05	CNS	AEGL-1 (Interim)
Formaldehyde	5.50E+01	eye irritation	Ca REL
Hexane	1.00E+04	CNS	AEGL-2
Acenaphthene	NA	NA	NA
Acenaphthylene	NA	NA	NA
Anthracene	NA	NA	NA
Benz[a]Anthracene	NA	NA	NA
Benzo[a]Pyrene	NA	NA	NA
Benzo[b]Fluoranthene	NA	NA	NA
Benzo[k]Fluoranthene	NA	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA
Chrysene	NA	NA	NA
Dibenzo[a,h]Anthracene	NA	NA	NA
Fluoranthene	NA	NA	NA
Flourene	NA	NA	NA
Indeno[1,2,3-cd]Pyrene	NA	NA	NA
Naphthalene	NA	NA	NA
Phenanthrene	NA	NA	NA
Pyrene	NA	NA	NA
Polychlorinated Biphenyl (PCB)	NA	NA	NA
Propionaldehyde	1.10E+05	nasal irritation	AEGL-1 (Interim)
Propylene Oxide	3.10E+03	eye/resp irritation, developmental effects	Ca REL
Toluene	5.00E+03	eye/resp irritation, CNS	Ca REL
Xylenes	2.20E+04	eye/resp irritation, CNS	Ca REL
Antimony	NA	NA	NA
Arsenic	2.00E-01	developmental, cardiovascular, CNS	Ca REL
Cadmium	4.60E+02	resp irritation	AEGL-1 (Interim)
Manganese	1.70E-01	CNS	Ca REL (8-hr)
Nickel	2.00E-01	immune system	Ca REL

AEGL – Acute Exposure Guideline Levels
Ca REL – California EPA Acute Reference Exposure Levels
CNS – Central Nervous System effects
NOAEL – No Observed Adverse Effect Level

3.1.3 Risk Characterization

Chronic cancer risks and non-cancer hazards as well as acute hazards associated with inhalation exposure are estimated using ECs (provided in **Table 2**) with the appropriate inhalation toxicity factors (chronic toxicity factors are provided in **Table 4**, while acute toxicity factors are provided in **Table 5**).

Chronic Cancer Risk

Cancer risk estimates represent the incremental probability that an individual will develop cancer over a lifetime due to exposure to a carcinogenic HAP. HAP-specific cancer risks were estimated by multiplying the chronic carcinogen EC for the HAP (EC_c provided in **Table 2**) by the IURF (provided in **Table 4**) for the HAP, as shown in the equation below.

$$Cancer\ Risk = EC_c\ x\ IURF$$

Where:			**Value**
Cancer Risk	=	Probability of developing cancer over a lifetime (unitless)	*Calculated*
EC_C	=	Chronic carcinogen exposure concentration ($\mu g/m^3$)	*Table 2*
IURF	=	Inhalation Unit Risk Factor $(\mu g/m^3)^{-1}$	*Table 4*

Although different carcinogenic PAHs have different potencies, they produce similar tumor responses.[34] Therefore, the total cancer risk associated with inhaling all carcinogenic PAHs was estimated as follows.

$$Cancer\ Risk_{TPAH} = \sum_{PAHi}^{n} Cancer\ Risk_{PAHi}$$

Where:			**Value**
Cancer $Risk_{TPAH}$	=	Total PAH cancer risk across all carcinogenic PAHs (unitless)	*Calculated*
Cancer $Risk_{PAHi}$	=	Cancer risk for individual PAH_i (unitless)	*Calculated*

In addition, because it is possible for receptors (i.e., Residents) to be exposed to multiple carcinogenic HAPs via a single exposure pathway (i.e., inhalation), the total cancer risk associated with inhaling all carcinogenic HAPs was estimated as follows.

$$Cancer\ Risk_{THAP} = \sum_{HAPi}^{n} Cancer\ Risk_{HAPi}$$

[34] EPA. 1993. Provisional Guidance for Quantitative Risk Assessment of Polycyclic Aromatic Hydrocarbons. EPA/600/R-93/089. Table 8, p. 17. https://www.epa.gov/risk/regional-screening-levels-rsls-users-guide#toxicity.

Where: **Value**

Cancer $Risk_{THAP}$ =	Total cancer risk across all carcinogenic HAPs (unitless)	*Calculated*
Cancer $Risk_{HAPi}$ =	Cancer risk for individual HAP_i (unitless)	*Calculated*

Although it is a common procedure used in HHRAs, it should be noted that summing cancer risk across all carcinogenic HAPs is an extremely conservative approach (i.e., health protective) and in all likelihood substantially overestimates total risk from a particular source because: 1) maximum modeled annual concentrations for different HAPs occur at different locations (i.e., exposure to them does not occur simultaneously; and 2) cancers that occur at different sites within the body, or with different cellular origin, likely have independent mechanisms of causation and are, therefore, not necessarily additive.[35]

Chronic Non-Cancer Hazard

Standard risk assessment methodology is to assume that, for most chemicals that cause adverse health effects other than cancer, there is a level of exposure below which no adverse effects will be observed. Therefore, estimating non-cancer hazard typically involves comparing an estimated chronic exposure concentration in air or the EC_{nc} (provided in **Table 2**) to the RfC (provided in **Table 4**), which is an estimate of the continuous inhalation exposure that is likely to be without an appreciable risk of deleterious effects. In some instances, HAP-specific RfCs were not available and a MRL was used instead. The comparisons of inhalation exposure estimates to RfCs (or MRLs) are known as chronic hazard quotients (HQ), which are calculated as follows:

$$HQ_{chronic} = \frac{EC_{nc}}{RfC\ or\ MRL}$$

Where: **Value**

$HQ_{chronic}$ =	Chronic Hazard Quotient (unitless)	*Calculated*
EC_{nc} =	Chronic Non-Cancer Exposure Concentration (µg/m^3)	*Table 2*
RfC =	Reference Concentration (µg/m^3)	*Table 4*
MRL =	Minimal Risk Level (µg/m^3)	*Table 4*

As with carcinogenic HAPs, a receptor (i.e., a Resident) might be exposed to multiple HAPs associated with non-cancer health effects by the same pathway. Therefore, the total chronic hazard for the exposure pathway (i.e., inhalation) is estimated by summing the individual HAP HQs that have similar effects (e.g., eye irritation, developmental effects, etc.) or affect the same target organ (e.g., CNS, nasal epithelium) to obtain a total pathway Hazard Index (HI). Summing only the HQs for HAPs that have similar health effects is referred to as segregating the HI.

[35] Salmon, A. G., & Roth, L. A. 2010. Cancer risk based on an individual tumor type or summing of tumors. Cancer Risk Assessment: Chemical Carcinogenesis, Hazard Evaluation, and Risk Quantification, 716-735.

$$HI_{chronic} = \sum_{i}^{n} HQ_i$$

Where:			**Value**
$HI_{chronic}$	=	Chronic Hazard Index across all HAPs with similar effects (unitless)	*Calculated*
HQ_i	=	Hazard Quotients for individual HAP_i (unitless)	*Calculated*

As shown in **Table 4**, chronic health effects that are associated with more than one HAP include: 1) effects on nasal epithelium/septum (acetaldehyde, acrolein, formaldehyde, naphthalene, propionaldehyde, and propylene oxide); 2) respiratory effects (naphthalene, antimony, and nickel); 3) developmental toxicity (benzo[a]pyrene and ethylbenzene); and 4) CNS effects (toluene, xylenes, and lead). Therefore, non-cancer HIs are estimated for these endpoints by summing individual HQs for all HAPs (except Pb) that cause these effects. The respiratory and nasal effects HQs are combined to provide an overall respiratory HI. For Pb, the NAAQS is compared to a 3-month rolling average (the specified form of the lead NAAQS) calculated from the modeled maximum off-property Pb concentration, as described in **Section 2.2.2**.

However, it should be noted that summing chronic HQs across HAPs, even those that have similar effects or affect the same target organ, is a conservative (i.e., health protective) approach that likely overestimates non-cancer hazard because: 1) maximum modeled annual concentrations for different HAPs occur at different locations (i.e., simultaneous exposure does not necessarily occur); and 2) different toxicity endpoints have different cellular origins, and likely have independent mechanisms of action, which means that they are not necessarily additive.

Acute Hazard

The potential for adverse health effects from acute inhalation exposure to HAP emissions were estimated by comparing the EC_{acute} (**Table 2**) to the HAP-specific Acute Toxicity Factors (ATFs) provided in **Table 5**. This comparison is known as the acute hazard quotient (HQ_{acute}) and is calculated as follows.

$$HQ_{acute} = \frac{EC_{acute}}{ATF}$$

Where:			**Value**
HQ_{acute}	=	Acute Hazard Quotient (unitless)	*Calculated*
EC_{acute}	=	Acute Exposure Concentration (µg/m^3)	*Table 2*
ATF	=	Acute Toxicity Factor (µg/m^3)	*Table 5*

Acute HQs (HQ_{acute}) from individual HAPs are summed for HAPs that have similar effects (e.g., eye irritation, CNS effects, etc.) to obtain an acute Hazard Index (HI_{acute}), as shown below.

$$HI_{acute} = \sum_{i}^{n} HQ_i$$

Where:		**Value**
HI_{acute} =	Acute Hazard Index across all HAPs with similar acute effects (unitless)	*Calculated*
HQ_i =	Acute Hazard Quotients for individual HAP_i (unitless)	*Calculated*

As shown in **Table 5**, adverse acute effects that are common across HAPs include: 1) eye irritation/toxicity (acetaldehyde, acrolein, formaldehyde, propionaldehyde, propylene oxide, and toluene); 2) respiratory/nasal effects (acetaldehyde, acrolein, formaldehyde, propionaldehyde, propylene oxide, toluene, xylenes, manganese, and nickel); 3) developmental effects (1,3-butadiene, benzene, propylene oxide, and arsenic); 4) CNS (central nervous system) effects (ethylbenzene, hexane, toluene, xylenes, arsenic, and manganese); and 5) immune system effects (benzene and nickel). Therefore, acute HIs are estimated for these endpoints by summing individual HAP HQs based on these effects.

3.1.4 Context for Interpreting Risk Assessment Results

EPA has established a target cancer risk range of 1-in-1,000,000 (1E-06) to 1-in-10,000 (1E-04) within which it strives to manage long-term risk from environmental exposures.[36] EPA often strives to manage risk from environmental exposure by limiting the cancer risk from individual HAPs to 1-in-1,000,000 (1E-06) and limiting total risk (i.e., risk summed across multiple HAPs from a single facility) and risk from multiple sources combined to 1-in-10,000 (1E-04). The EPA Region 6 Risk Management Addendum,[37] a companion document to the HHRAP, recommends reducing the upper-bound target risk for total risk (summed across all HAPs from a facility) of 1-in-10,000 (1E-04) to 1-in-100,000 (1E-05) to account for exposure to background levels of air contaminants from other sources. Therefore, per the EPA Region 6 Risk Management Addendum, the RME risk associated with exposures to potential carcinogens released from a single facility should not exceed 1-in-100,000 (1E-05). This 1-in-100,000 risk level is ten times more stringent than the highest level that EPA deems acceptable (i.e., 1E-04) and, therefore, represents a highly conservative risk management objective.

A risk of 1E-05 indicates a 1-in-100,000 chance of developing cancer due to lifetime exposure to a substance or group of substances. According to the American Cancer Society, the overall risk of developing cancer over a lifetime in the U.S. is approximately 50%, or a 1-in-2 chance for men (or a 50,000-in-100,000

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[36] EPA. 1990. U.S. Environmental Protection Agency. National Contingency Plan. Federal Register Volume 55, Number 46. March 8.

[37] EPA. 1998. Region 6 Risk Management Addendum – Draft Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA-R6-98-002. p. ADD-3. https://archive.epa.gov/region6/6pd/rcra_c/pd-o/web/pdf/r6add.pdf.

chance), and 33% or a 1-in-3 (or 33,333-in-100,000) chance for women.[38] Therefore, the range within which EPA manages risks posed by environmental exposures from a single facility is very small by comparison to a person's background risk of developing cancer. Said another way, a lifetime cancer risk of 1-in-1,000,000 to 1-in-100,000 has the potential to increase a person's existing cancer risk range from 33% - 50% to 33.0001% - 50.001%. In other words, by managing cancer risks within this range, EPA limits the potential for increased cancer risk due to environmental exposures from a facility to between 0.0001% and 0.001%.

With regard to potential hazards posed by long-term exposure to non-carcinogenic HAPs, a HQ (HQ = EC/RfC or MRL) of less than or equal to 1 is generally considered protective of health.[39] Because they represent exposures that are likely to be without an appreciable risk of deleterious effects during a lifetime, if the EC_{nc} (non-cancer exposure concentration) is less than the RfC or MRL, no adverse health effects are expected. It is important to recognize, however, that an EC_{nc} that exceeds the RfC or MRL does not indicate that adverse health effects will occur, or that they should be expected. This is because RfCs and MRLs do not represent threshold exposures above which illness or disease is expected. They instead represent exposures below which such effects are NOT expected.[40] In developing toxicity factors for non-carcinogenic effects, the upper bound tolerance range is identified. Because variability exists in the human population, attempts are made to identify a sub-threshold level protective of sensitive individuals in the population. One way in which sub-threshold levels are established is through the application of uncertainty factors to the underlying toxicity data. Therefore, a chronic non-cancer HQ above one is not necessarily indicative of health impacts because of the application of these uncertainty factors in deriving the RfCs.[41] Similar logic applies to short-term exposures. Ca RELs are concentrations in air at or below

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[38] American Cancer Society website. "Lifetime Risk of Developing or Dying From Cancer". https://www.cancer.org/cancer/risk-prevention/understanding-cancer-risk/lifetime-probability-of-developing-or-dying-from-cancer.html.

[39] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 7-6. https://archive.epa.gov/epawaste/hazard/tsd/td/web/html/risk.html; ATSDR website. Calculating Hazard Quotients and Cancer Risk Estimates. https://www.atsdr.cdc.gov/pha-guidance/conducting_scientific_evaluations/epcs_and_exposure_calculations/hazardquotients_cancerrisk.html#:~:text=HQs%20less%20than%201%20indicate,in%2Ddepth%20toxicological%20effects%20analysis. Visited on June 20, 2023.

[40] EPA website. Basic Information about the Integrated Risk Information System. https://www.epa.gov/iris/basic-information-about-integrated-risk-information-system. Visited on June 20, 2023; EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 7-6. https://archive.epa.gov/epawaste/hazard/tsd/td/web/html/risk.html.

[41] EPA. 1989. Risk Assessment Guidance for Superfund Volume I: Human Health Evaluation Manual (Part A). EPA/540/1-89/002. p. 7-6. https://www.epa.gov/risk/risk-assessment-guidance-superfund-rags-part.

which no serious adverse health effects are anticipated in the general population from intermittent (i.e., 1-hour) exposures[42] Therefore, if an EC_{acute} exceeds the CA REL, it does not necessarily mean that there is cause for concern. However, AEGL-1 and AEGL-2 values represent air concentrations at which effects may occur.[43] Therefore, if an EC_{acute} exceeds an AEGL value, adverse effects could occur.

Because the agencies tasked with setting these limits (e.g., US and California EPA, ATSDR) are tasked with protecting human health and the environment, these toxicity factors are generally set at very conservative (highly health protective) levels. Therefore, a risk or hazard estimate that exceeds a target value should, in most cases, trigger more careful consideration of the underlying scientific basis for the estimate. It does not automatically mean that it is not safe or that it presents an unacceptable risk.[44] An exception to this general rule is the Pb NAAQS. The Pb NAAQS represents an air concentration that is not to be exceeded on a 3-month rolling average basis.

3.2 Human Health Risk Assessment Results

3.2.1 Chronic Cancer Risks

Estimated cancer risks are provided in **Table 6**. As shown in **Table 6**, the only individual HAP with an estimated cancer risk above EPA's lower-bound target risk of 1-in-1,000,000 (1E-06) is the Maximum Off-Property Adult Resident, with a cancer risk of 2E-06. This hypothetical residential cancer risk is only slightly above EPA's most stringent target cancer risk of 1E-06. There are no residences in this location. The maximum estimated annual benzene concentration occurs in a highly industrialized area near the CCL LNG Terminal property line, west of the LNG storage tanks and LaQuinta Rd. This area is adjacent to undeveloped land immediately east of the Voestalpine industrial facility (see **Figure 5-2** of the CCL Air Modeling Report). The closest residences are north of the CCL LNG Terminal in Gregory and the maximum annual benzene concentrations in Gregory (and other nearby residential areas) are at least an order of magnitude lower (maximum GLC in a residential area of Gregory = 0.047 $\mu g/m^3$), with estimated exposure concentrations and cancer risks that are also at least an order of magnitude lower (Maximum Off-Property Adult Resident = 1.5E-07 or 1.5-in-10,000,000) and well below EPA's target cancer risk level of 1E-06, as shown in **Table 6**.

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[42] OEHHA. 2015. California Environmental Protection Agency Office of Environmental Health Hazard Assessment. Air Toxics Hot Spots Program. Risk Assessment Guidelines. February 2015. p. 6-3.
[43] EPA website. About Acute Exposure Guideline Levels (AEGLs). https://www.epa.gov/aegl/about-acute-exposure-guideline-levels-aegls. Visited on June 20, 2023.
[44] EPA. 2005. U.S. Environmental Protection Agency. Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA530-R-05-006. p. 7-10. https://archive.epa.gov/epawaste/hazard/tsd/td/web/html/risk.html.

Table 6
Estimated Chronic Cancer Risks

Pollutant	Maximum Off-Property Adult Resident Cancer Risk	Maximum Off-Property Child Resident Cancer Risk	Maximum Gregory Adult Resident Cancer Risk	Maximum Gregory Child Resident Cancer Risk
1,3-Butadiene	6.16E-09	1.23E-09	6.16E-09	1.23E-09
2,2,4-Trimethylpentane	NA	NA	NA	NA
Acetaldehyde	4.52E-09	9.04E-10	4.52E-09	9.04E-10
Acrolein	NA	NA	NA	NA
Benzene	1.92E-06	3.85E-07	***1.50E-07***	***3.00E-08***
Ethylbenzene	NA	NA	NA	NA
Formaldehyde	3.21E-07	6.41E-08	3.21E-07	6.41E-08
Hexane	NA	NA	NA	NA
Acenaphthene	NA	NA	NA	NA
Acenaphthylene	NA	NA	NA	NA
Anthracene	NA	NA	NA	NA
Benz[a]Anthracene	3.89E-11	7.79E-12	3.89E-11	7.79E-12
Benzo[a]Pyrene	1.85E-10	3.69E-11	1.85E-10	3.69E-11
Benzo[b]Fluoranthene	3.69E-11	7.37E-12	3.69E-11	7.37E-12
Benzo[k]Fluoranthene	1.85E-12	3.69E-13	1.85E-12	3.69E-13
Benzo[g,h,i]Fluoranthene	NA	NA	NA	NA
Chrysene	7.20E-13	1.44E-13	7.20E-13	1.44E-13
Dibenzo[a,h]Anthracene	3.82E-10	7.64E-11	3.82E-10	7.64E-11
Fluoranthene	NA	NA	NA	NA
Flourene	NA	NA	NA	NA
Indeno[1,2,3-cd]Pyrene	3.69E-11	7.37E-12	3.69E-11	7.37E-12
Naphthalene	NA	NA	NA	NA
Phenanthrene	NA	NA	NA	NA
Pyrene	NA	NA	NA	NA
Propionaldehyde	NA	NA	NA	NA
Propylene Oxide	3.04E-09	6.08E-10	3.04E-09	6.08E-10
Toluene	NA	NA	NA	NA
Xylenes	NA	NA	NA	NA
Antimony	NA	NA	NA	NA
Cadmium	2.96E-08	5.92E-09	2.96E-08	5.92E-09
Lead	NA	NA	NA	NA
Nickel	2.17E-08	4.34E-09	2.17E-08	4.34E-09
Total PAH Cancer Risk	**6.8E-10**	**1.4E-10**	**6.8E-10**	**1.4E-10**
Total Cancer Risk	**2.3E-06**	**4.6E-07**	**5.4E-07**	**1.1E-07**

IURF – Inhalation Unit Risk Factor
Total Cancer Risk – Cancer risk obtained by summing cancer risk for each individual HAP.
Note: Only the maximum Gregory residential benzene cancer risks are shown in Table 6 (shown in bold italics). The cancer risks for other constituents are the maximum modeled off-property cancer risks, making the total Gregory Adult and Child Resident cancer risks presented highly conservative (i.e., overestimated).

It is also important to recognize that the benzene cancer risk for the hypothetical Maximum Off-Property Adult Resident (and all other resident receptors) was estimated using the upper-bound (most stringent) IURF from the range of IURFs recommended by EPA. Had the lower-bound benzene IURF (2.2E-06 $(\mu g/m^3)^{-1}$), which is considered to have equal plausibility as the higher IURF (7.8E-06 $(\mu g/m^3)^{-1}$), been used instead, the estimated Maximum Off-Property Adult Resident cancer risk would have been 5.4E-07, and below EPA's most stringent target cancer risk (1E-06). The Maximum Off-Property Child Resident benzene cancer risk estimate is below EPA's target cancer risk. All other HAPs, including total PAHs (summed across all carcinogenic PAHs from the CCL Terminal) have cancer risk estimates that are well below EPA's target cancer risk of 1E-06.

The total cancer risks summed across all carcinogenic HAPs from the CCL Terminal (Maximum Off-Property Adult Resident = 2.3E-06, Child Resident = 4.6E-07) are below the EPA's[45] target of 1-in-100,000 (1E-05) for a single facility.[46] As previously discussed, this 1-in-100,000 individual facility risk management objective is ten times more stringent than the highest cancer risk that EPA deems acceptable to account for potential exposure to background levels of air contaminants (i.e., from other sources besides the CCL terminal) and, therefore, represents a highly conservative target risk. Moreover, summing cancer risk across all carcinogenic HAPs is an extremely conservative approach (i.e., health protective) and in all likelihood substantially overestimates total risk from a particular facility because maximum modeled annual concentrations for different HAPs occur at different locations (i.e., exposure to them does not occur simultaneously) and cancers that occur at different sites within the body, or with different cellular origin, likely have independent mechanisms of causation and are, therefore, not necessarily additive.[47]

3.2.2 Chronic Non-Cancer Hazards

Estimated HAP-specific chronic HQ ($HQ_{chronic}$) values and total chronic HIs or $HI_{chronic}$ values (summed across HAPs with similar chronic effects) are provided in **Table 7**.

As shown in **Table 7**, no $HQ_{chronic}$ value for any HAP is greater than 1. In addition, all segregated $HI_{chronic}$ values (derived by summing $HQ_{chronic}$ values for all HAPs with similar chronic effects) are also well below 1 (by more than 10-fold). Summing chronic HQs across HAPs, even those with similar effects or that affect

[45] EPA. 1998. Region 6 Risk Management Addendum – Draft Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA-R6-98-002. p. ADD-3. https://archive.epa.gov/region6/6pd/rcra_c/pd-o/web/pdf/r6add.pdf.
[46] EPA. 1998. Region 6 Risk Management Addendum – Draft Human Health Risk Assessment Protocol for Hazardous Waste Combustion Facilities. EPA-R6-98-002. p. ADD-3. https://archive.epa.gov/region6/6pd/rcra_c/pd-o/web/pdf/r6add.pdf.
[47] Salmon, A. G., & Roth, L. A. 2010. Cancer risk based on an individual tumor type or summing of tumors. Cancer Risk Assessment: Chemical Carcinogenesis, Hazard Evaluation, and Risk Quantification, 716-735.

Table 7
Estimated Chronic Non-Cancer Hazards

Pollutant	Maximum Off-Property Adult Resident Non-Cancer $HQ_{chronic}$	Maximum Off-Property Child Resident Non-Cancer $HQ_{chronic}$	Maximum Gregory Adult Resident Non-Cancer $HQ_{chronic}$	Maximum Gregory Child Resident Non-Cancer $HQ_{chronic}$
1,3-Butadiene	2.40E-04	2.40E-04	2.40E-04	2.40E-04
2,2,4-Trimethylpentane	NA	NA	NA	NA
Acetaldehyde	5.33E-04	5.33E-04	5.33E-04	5.33E-04
Acrolein	4.79E-02	4.79E-02	4.79E-02	4.79E-02
Benzene	1.92E-02	1.92E-02	***1.50E-03***	***1.50E-03***
Ethylbenzene	1.05E-04	1.05E-04	1.05E-04	1.05E-04
Formaldehyde	5.87E-03	5.87E-03	5.87E-03	5.87E-03
Hexane	1.78E-03	1.78E-03	1.78E-03	1.78E-03
Acenaphthene	NA	NA	NA	NA
Acenaphthylene	NA	NA	NA	NA
Anthracene	NA	NA	NA	NA
Benz[a]Anthracene	NA	NA	NA	NA
Benzo[a]Pyrene	3.59E-04	3.59E-04	3.59E-04	3.59E-04
Benzo[b]Fluoranthene	NA	NA	NA	NA
Benzo[k]Fluoranthene	NA	NA	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA	NA
Chrysene	NA	NA	NA	NA
Dibenzo[a,h]Anthracene	NA	NA	NA	NA
Fluoranthene	NA	NA	NA	NA
Flourene	NA	NA	NA	NA
Indeno[1,2,3-cd]Pyrene	NA	NA	NA	NA
Naphthalene	5.11E-03	5.11E-03	5.11E-03	5.11E-03
Phenanthrene	NA	NA	NA	NA
Pyrene	NA	NA	NA	NA
Propionaldehyde	9.59E-05	9.59E-05	9.59E-05	9.59E-05
Propylene Oxide	6.39E-05	6.39E-05	6.39E-05	6.39E-05
Toluene	8.63E-05	8.63E-05	8.63E-05	8.63E-05
Xylenes	1.34E-03	1.34E-03	1.34E-03	1.34E-03
Antimony	4.79E-04	4.79E-04	4.79E-04	4.79E-04
Cadmium	3.84E-03	3.84E-03	3.84E-03	3.84E-03
Lead	1.56E-03	1.56E-03	1.56E-03	1.56E-03
Nickel	1.05E-02	1.05E-02	1.05E-02	1.05E-02
Respiratory/Nasal HI	**7.07E-02**	**7.07E-02**	**7.07E-02**	**7.07E-02**
Developmental HI	**4.64E-04**	**4.64E-04**	**4.64E-04**	**4.64E-04**
CNS HI	**1.43E-03**	**1.43E-03**	**1.43E-03**	**1.43E-03**

CNS HI – –Segregated Hazard Index obtained by summing HQs for all HAPs that affect the Central Nervous System(toluene and xylenes).
Developmental HI – – Segregated Hazard Index obtained by summing HQs for all HAPs that cause developmental toxicity (benzo(a)pyrene and ethylbenzene).
MRL – Minimal Risk Level
Nasal HI – Segregated Hazard Index obtained by summing HQs for all HAPs that affect the nasal epithelium/septum (acetaldehyde, acrolein, formaldehyde, naphthalene, propionaldehyde, propylene oxide, and chromium.
RfC – Reference Concentration
Note: Only the maximum Gregory Adult and Child Resident benzene HQs are shown in Table 7 (shown in bold italics). The HQs for other constituents are the maximum modeled off-property HQs, making the total Gregory HIs presented highly conservative (i.e., overestimated).

the same target organ, is a conservative (i.e., health protective) approach that likely overestimates non-cancer hazard because: 1) maximum modeled annual concentrations for different HAPs occur at different locations (i.e., simultaneous exposure does not necessarily occur); and 2) non-cancer toxicity endpoints have different cellular origins, and likely have independent mechanisms of action, which means that they are not necessarily additive.

3.2.3 Acute Hazards

Estimated HAP-specific acute HQs and total HI (summed across HAPs with similar effects) are provided in **Table 8**.

As shown in **Table 8**, the only individual HAP acute HQ (HQ_{acute}) above one (1) is benzene (HQ = 2.04) at the maximum modeled off-property location. This HQ is only twice EPA's target HQ of one (1). Segregated acute HIs (HI_{acute}), which are derived by summing HQs for all HAPs with similar acute effects, for developmental (2.05) and immune system effects (2.09) are also above the target value of one (1) but are driven by benzene. The maximum off-property hourly benzene concentrations on which the Maximum Off-Property Adult and Child Resident HQ_{acute} and HI_{acute} values are based occur in an uninhabited area (adjacent to undeveloped land immediately east of the Voestalpine industrial facility) near the CCL LNG Terminal property line, west of the LNG storage tanks and LaQuinta Rd. (see **Figure 5-1** of the CCL Air Modeling Report). As previously discussed, the closest residences are north of the CCL LNG Terminal in Gregory and the maximum hourly benzene concentrations in Gregory residential areas (and other nearby residential areas) are at least an order of magnitude lower (maximum hourly benzene concentration in a Gregory residential area = 3.86 µg/m^3), with HQ_{acute} and HI_{acute} values that are also at least an order of magnitude lower (Maximum Gregory Resident benzene HQ_{acute} = 0.14, Maximum Gregory HI_{acute} = 0.19) and well below one (1), as shown in **Table 8**.

Summing acute HQs across HAPs, even those that have similar effects, is a conservative (i.e., health protective) approach that likely overestimates acute hazard because maximum modeled hourly concentrations for different HAPs occur at different locations (i.e., simultaneous exposure does not necessarily occur).

Table 8
Estimated Acute Hazards

Pollutant	Maximum Off-Property Adult/Child Resident HQ_{acute}	Maximum Gregory Adult/Child Resident HQ_{acute}
1,3-Butadiene	9.09E-05	9.09E-05
2,2,4-Trimethylpentane	NA	NA
Acetaldehyde	1.06E-03	1.06E-03
Acrolein	4.00E-02	4.00E-02
Benzene	2.04E+00	***1.43E-01***
Ethylbenzene	7.68E-05	7.68E-05
Formaldehyde	4.18E-02	4.18E-02
Hexane	1.28E-02	1.28E-02
Acenaphthene	NA	NA
Acenaphthylene	NA	NA
Anthracene	NA	NA
Benz[a]Anthracene	NA	NA
Benzo[a]Pyrene	NA	NA
Benzo[b]Fluoranthene	NA	NA
Benzo[k]Fluoranthene	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA
Chrysene	NA	NA
Dibenzo[a,h]Anthracene	NA	NA
Fluoranthene	NA	NA
Flourene	NA	NA
Indeno[1,2,3-cd]Pyrene	NA	NA
Naphthalene	NA	NA
Phenanthrene	NA	NA
Pyrene	NA	NA
Polychlorinated Biphenyl (PCB)	NA	NA
Propionaldehyde	1.60E-04	1.60E-04
Propylene Oxide	9.68E-06	9.68E-06
Toluene	8.90E-03	8.90E-03
Xylenes	6.32E-04	6.32E-04
Antimony	NA	NA
Arsenic	2.00E-03	2.00E-03
Cadmium	8.70E-06	8.70E-06
Lead	NA	NA
Manganese	5.88E-04	5.88E-04
Nickel	5.00E-02	5.00E-02
Eye Irritation/Toxicity HI	**9.27E-02**	**9.27E-02**
Respiratory/Nasal Irritation HI	**5.09E-02**	**5.09E-02**
Developmental HI	**2.05E+00**	**1.45E-01**
CNS HI	**2.50E-02**	**2.50E-02**
Immune System HI	**2.09E+00**	**1.93E-01**

Developmental HI – Hazard Index obtained by summing HQs for all HAPs that cause developmental toxicity (1,3-butadiene, propylene oxide, and arsenic).
Eye Irritation/toxicity HI – Hazard Index obtained by summing HQs for all HAPs that cause eye irritation or toxicity (acetaldehyde, acrolein, formaldehyde, propylene oxide, and toluene).
Respiratory Irritation/Toxicity HI – Hazard Index obtained by summing HQs for all HAPs that cause respiratory irritation or toxicity (acetaldehyde, acrolein, formaldehyde, propionaldehyde, propylene oxide, toluene, xylenes, cadmium, chromium, manganese, and nickel)
Note: Only the maximum Gregory Resident benzene HQs are shown in Table 8 (shown in bold italics). The HQs for other constituents are the maximum modeled off-property HQs, making the total Gregory HIs presented highly conservative (i.e., overestimated).
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Section 4
Summary and Conclusions

4.1 Summary

Chronic cancer risks and non-cancer hazards, as well as acute hazards estimated in this HHRA are summarized in **Table 9**.

As shown in **Table 9,** the Maximum Off-Property Adult Resident cancer risk for benzene is slightly above EPA's lower-bound target risk of 1E-06. The Maximum Off-Property Adult Resident cancer risk was estimated based on the maximum modeled off-property annual benzene concentration. This maximum modeled off-property annual benzene concentration occurs in a highly industrialized area, where no residences are located. The modeled annual benzene concentrations at the closest residences, which are located north of the CCL Terminal in Gregory, are at least an order of magnitude lower, with estimated cancer risks that are also at least an order of magnitude lower than the hypothetical Maximum Off-Property Adult Resident and well below EPA's lower-bound (most stringent) target cancer risk level. It is also important to recognize that the benzene cancer risk for this hypothetical Maximum Off-Property Adult Resident (and all other receptors) was estimated using the upper-bound (most stringent) IURF from the range of benzene IURFs recommended by EPA. Had the lower-bound benzene IURF (2.2E-06 $(\mu g/m^3)^{-1}$) been used, which is considered to have equal plausibility as the higher IURF (7.8E-06 $(\mu g/m^3)^{-1}$), the estimated Maximum Off-Property Adult Resident cancer risk would be 5.4E-07, and below EPA's most stringent target cancer risk (1E-06), even at the maximum modeled impact location (i.e., in the uninhabited industrial area).

All other individual HAP cancer risks are below EPA's most stringent target cancer risk level. The total cancer risk (summed across all carcinogenic HAPs from the CCL Terminal) is below the EPA target cancer risk for individual facilities of 1E-05. As previously discussed, this 1E-05 individual facility risk management objective is ten times more stringent than the highest cancer risk that EPA deems acceptable (1E-04) and is intended to account for the potential for background risk from other sources and environmental factors in the surrounding area.

Table 9 also indicates that no $HQ_{chronic}$ value for any HAP is greater than the non-cancer risk management objective of one (1) for individual HAPs. In addition, all segregated $HI_{chronic}$ values (derived by summing $HQ_{chronic}$ values for all HAPs with similar chronic effects) are below one (1) by a factor of more than 10.

As shown in **Table 9**, the only individual HAP HQ_{acute} value above one (1) is benzene (HQ = 2.04) at the maximum modeled off-property location. This HQ value is only twice EPA's target HQ of one (1).

Table 9
Risk and Hazard Summary

Pollutant	Maximum Hypothetical Off-Property Resident				Maximum Gregory Resident			
	Adult Cancer Risks	Child Cancer Risks	Adult/Child Non-Cancer $HQ_{chronic}$	Adult/Child HQ_{acute}	Adult Cancer Risks	Child Cancer Risks	Adult/Child Non-Cancer $HQ_{chronic}$	Adult/Child HQ_{acute}
1,3-Butadiene	6.2E-09	1.2E-09	2.4E-04	9.1E-05	6.2E-09	1.2E-09	2.4E-04	9.1E-05
2,2,4-Trimethylpentane	NA	NA	NA	NA	NA	NA	NA	NA
Acetaldehyde	4.5E-09	9.0E-10	5.3E-04	1.1E-03	4.5E-09	9.0E-10	5.3E-04	1.1E-03
Acrolein	NA	NA	4.8E-02	4.0E-02	NA	NA	4.8E-02	4.0E-02
Benzene	1.9E-06	3.8E-07	1.9E-02	2.0E+00	***1.5E-07***	***3.0E-08***	***1.5E-03***	***1.4E-01***
Ethylbenzene	NA	NA	1.1E-04	7.7E-05	NA	NA	1.1E-04	7.7E-05
Formaldehyde	3.2E-07	6.4E-08	5.9E-03	4.2E-02	3.2E-07	6.4E-08	5.9E-03	4.2E-02
Hexane	NA	NA	1.8E-03	1.3E-02	NA	NA	1.8E-03	1.3E-02
Acenaphthene	NA	NA	NA	NA	NA	NA	NA	NA
Acenaphthylene	NA	NA	NA	NA	NA	NA	NA	NA
Anthracene	NA	NA	NA	NA	NA	NA	NA	NA
Benz[a]Anthracene	3.9E-11	7.8E-12	NA	NA	3.9E-11	7.8E-12	NA	NA
Benzo[a]Pyrene	1.8E-10	3.7E-11	3.6E-04	NA	1.8E-10	3.7E-11	3.6E-04	NA
Benzo[b]Fluoranthene	3.7E-11	7.4E-12	NA	NA	3.7E-11	7.4E-12	NA	NA
Benzo[k]Fluoranthene	1.8E-12	3.7E-13	NA	NA	1.8E-12	3.7E-13	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA	NA	NA	NA	NA	NA
Chrysene	7.2E-13	1.4E-13	NA	NA	7.2E-13	1.4E-13	NA	NA
Dibenzo[a,h]Anthracene	3.8E-10	7.6E-11	NA	NA	3.8E-10	7.6E-11	NA	NA
Fluoranthene	NA	NA	NA	NA	NA	NA	NA	NA
Flourene	NA	NA	NA	NA	NA	NA	NA	NA
Indeno[1,2,3-cd]Pyrene	3.7E-11	7.4E-12	NA	NA	3.7E-11	7.4E-12	NA	NA
Naphthalene	NA	NA	5.1E-03	NA	NA	NA	5.1E-03	NA
Phenanthrene	NA	NA	NA	NA	NA	NA	NA	NA
Pyrene	NA	NA	NA	NA	NA	NA	NA	NA
Propionaldehyde	NA	NA	9.6E-05	1.6E-04	NA	NA	9.6E-05	1.6E-04
Propylene Oxide	3.0E-09	6.1E-10	6.4E-05	9.7E-06	3.0E-09	6.1E-10	6.4E-05	9.7E-06
Toluene	NA	NA	8.6E-05	8.9E-03	NA	NA	8.6E-05	8.9E-03
Xylenes	NA	NA	1.3E-03	6.3E-04	NA	NA	1.3E-03	6.3E-04
Antimony	NA	NA	4.8E-04	NA	NA	NA	4.8E-04	NA
Arsenic	0.0E+00	0.0E+00	NA	2.0E-03	0.0E+00	0.0E+00	NA	2.0E-03
Cadmium	3.0E-08	5.9E-09	3.8E-03	8.7E-06	3.0E-08	5.9E-09	3.8E-03	8.7E-06
Lead	NA	NA	1.6E-03	NA	NA	NA	1.6E-03	NA
Manganese	NA	NA	0.0E+00	5.9E-04	NA	NA	0.0E+00	5.9E-04
Nickel	2.2E-08	4.3E-09	1.1E-02	5.0E-02	2.2E-08	4.3E-09	1.1E-02	5.0E-02
TOTAL CANCER RISK	**2.3E-06**	**4.6E-07**			**5.4E-07**	**1.1E-07**		
Eye Irritation/Toxicity HI				**9.2E-02**				**9.2E-02**
Respiratory/Nasal HI			**7.1E-02**	**5.1E-02**			**7.1E-02**	**5.1E-02**
Developmental HI			**4.6E-04**	**2.0E+00**			**4.6E-04**	**1.5E-01**
CNS HI			**1.4E-03**	**2.5E-02**			**1.4E-03**	**2.5E-02**
Immune Systems HI				**2.1E+00**				**1.9E-01**

Eye Irritation/Toxicity HI – Hazard Index obtained by summing HQs for all HAPs that cause eye irritation or toxicity.
Respiratory/Nasal HI – Hazard Index obtained by summing HQs for all HAPs that cause respiratory system or nasal toxicity.
Developmental HI – Hazard Index obtained by summing HQs for all HAPs that cause developmental toxicity.
CNS HI – Hazard Index obtained by summing HQs for all HAPs that affect the Central Nervous System.
Immune System HI – Hazard Index obtained by summing HQs for all HAPs that cause immune system toxicity.

Note: Only the Maximum Gregory Resident cancer risk, $HQ_{chronic}$, and HQ_{acute} for benzene are shown in Table 9 (shown in bold italics). The cancer risks and HQs for other constituents are the Maximum Off-Property Resident cancer risks and HQs, making the total Gregory Resident cancer risks and HIs presented highly conservative (i.e., overestimated).

Segregated acute HIs (HI_{acute}) values for developmental (2.05) and immune system effects (2.09) are also above the target value of one (1) but are dominated by benzene. The maximum off-property hourly benzene concentrations on which the Maximum Off-Property Adult/Child HQ_{acute} and HI_{acute} values are based occurs in an uninhabited area adjacent to undeveloped land immediately east of the Voestalpine industrial facility and west of the CCL LNG Terminal property line. As previously discussed, the closest residences are north of the CCL LNG Terminal in Gregory and the maximum hourly benzene concentrations in Gregory residential areas (and other nearby residential areas) are at least an order of magnitude lower, with HQ_{acute} and HI_{acute} values that are also at least an order of magnitude lower than those estimated at the maximum impacted location (Maximum Gregory Resident benzene HQ_{acute} = 0.14, Maximum Gregory Resident HI_{acute} = 0.19) and well below one (1).

It is important to recognize that the Maximum Off-Property Adult and Child Residents evaluated in this HHRA are purely hypothetical receptors. The maximum off-property cancer risks and the Maximum Off-Property $HQ_{chronic}$ and HQ_{acute} values in this HHRA were estimated at the maximum impacted off-property location for each HAP, not at occupied residences. Estimated cancer risks, as well as $HQ_{chronic}$, $HI_{chronic}$, HQ_{acute} and HI_{acute} values for residential areas are much lower (by at least 10-fold). In addition, summing cancer risk across all carcinogenic HAPs is an extremely conservative approach (i.e., health protective) that is likely to substantially overestimate the total cancer risk from a particular source.[48] Likewise, summing $HQ_{chronic}$ values or HQ_{acute} values across HAPs, even those that have similar effects, is highly conservative and likely overestimates chronic and acute hazard.

4.2 Conclusions

This HHRA demonstrates that the highest estimated benzene cancer risk for the Maximum Off-Property Adult Resident is very slightly above EPA's most stringent target cancer risk level (1E-06). However, this hypothetical Maximum Off-Property Resident was assumed to live at the off-property location of the highest modeled annual benzene concentration, which occurred in a highly industrial (uninhabited) area. Moreover, the benzene cancer risk for this hypothetical Maximum Off-Property Adult Resident (as well as all other receptors) was estimated using the upper-bound (most stringent) IURF from a range of IURFs recommended by EPA, even though the lower-bound (less stringent) benzene IURF has equal plausibility. The benzene cancer risk for the Maximum Off-Property Child Resident, as well as all other individual HAP cancer risks (for both adult and child residents) and all chronic non-cancer hazards at the maximum modeled impact location(s) are below EPA target levels. In addition, the total cancer risk and chronic non-

[48] Salmon, A. G., & Roth, L. A. 2010. Cancer risk based on an individual tumor type or summing of tumors. Cancer Risk Assessment: Chemical Carcinogenesis, Hazard Evaluation, and Risk Quantification, 716-735.

cancer and acute hazards (summed across all carcinogenic HAPs and HAPs with similar chronic non-cancer and acute health effects from the CCL Terminal) are below EPA's target levels. The estimated benzene acute hazard for the Maximum Off-Property Adult/Child Resident is twice the target value of one (1). However, as previously discussed, the maximum off-property hourly benzene concentration on which the acute hazard estimate is based occurs in an uninhabited area adjacent to undeveloped land in a highly industrialized where no one is expected to remain for any length of time. Based on this information, it is concluded that there is no need for concern about health effects potentially associated with exposures to emissions from the CCL Terminal for the following reasons:

- Chronic cancer risks, chronic non-cancer hazards, and acute hazards for the Maximum Off-Property Adult and Child Resident in this HHRA were estimated at the maximum impacted off-property location for each HAP (even though they are not necessarily co-located), not at occupied residences.
    - The maximum impacted off-property locations for each HAP, including benzene, occurred in uninhabited areas where no actual residences are located and no one is expected to remain for any length of time;
    - Annual HAP concentrations, including those for benzene, in residential areas are estimated to be much lower (at least 10-fold), with corresponding estimated cancer risks, chronic non-cancer hazards and acute hazards that are much lower than those estimated at the most impacted location and well below EPA target levels.
- The benzene cancer risks for all receptors evaluated in this HHRA were estimated using the upper-bound (most stringent) IURF from a range of IURFs recommended by EPA.
    - Had the lower-bound benzene IURF (2.2E-06 $(\mu g/m^3)^{-1}$), which is considered to have equal plausibility as the higher IURF (7.8E-06 $(\mu g/m^3)^{-1}$), been used instead, the estimated cancer risk for the hypothetical Maximum Off-Property Adult Resident would have been 5.4E-07 (at the maximum impacted off-property location in a highly industrialized area), and below EPA's most stringent target cancer risk (1E-06).
- The Adult and Child Residents evaluated in this HHRA were assumed to be continuously exposed to outdoor air (24-hours/day, 7 days/week) for six (child) or 30 (adult) years when estimating chronic cancer risk and non-cancer hazard.
    - These exposure assumptions grossly exaggerate residential exposures because people:
        - Spend 85 to 90% of their time indoors and the modeled concentrations that serve as the basis for this HHRA are in outdoor air (indoor concentrations of HAPs associated with the CCL LNG Terminal emissions will be considerably less);

    - Do not spend 24 hours/day, 7 days/week at home; and
    - Few families live in the same residence for 30 years.

- All estimated total cancer risks (summed across all HAPs emitted by the CCL Terminal) are below the individual facility risk management objective (1E-05) and at least 40-fold lower than EPA's upper-bound target cancer risk (1E-04).

    - Summing cancer risks across individual HAPs overstates risk because maximum modeled annual concentrations for different HAPs occur at different locations and cancers that occur at different sites within the body, or with different cellular origins, likely have independent mechanisms of causation and are, therefore, not necessarily additive.

- All chronic hazard quotients for individual HAPs are more than an order of magnitude (i.e., > 10x) below EPA's non-cancer risk management objective.

- All chronic non-cancer

- segregated hazard indices (derived by summing hazard quotients for all HAPs with similar chronic effects) are also below EPA's non-cancer risk management objective by more than an order of magnitude (i.e., > 10x).
    - Summing chronic non-cancer hazard quotients for individual HAPs overestimates chronic hazard because maximum modeled annual concentrations for different HAPs occur at different locations, and different toxicity endpoints have different cellular origins and likely have independent mechanisms of action, which means that they are not necessarily additive.

- Although the acute hazard quotient for benzene and the acute segregated hazard indices for developmental and immune system effects estimated at the maximum modeled off-site location were above the target value of one (1):

    - The maximum impacted off-property locations for each HAP, including benzene, occurred in uninhabited locations where no one is expected to remain for any length of time;

    - 1-hour HAP concentrations, including those for benzene, in nearby residential areas are much lower (at least 10-fold), with corresponding estimated acute hazard quotients and hazard indices that are much lower than those estimated at the most impacted location and well below the target value of one (1).
    - Summing acute hazard quotients for individual HAPs, even for those with similar effects, overestimates acute hazard indices because maximum modeled hourly concentrations

for different HAPs occur at different locations (i.e., exposure does not necessarily occur simultaneously).

APPENDICES

Appendix A
Risk Assessment Input Values

Risk Assessment Input Values

Pollutant	Annual Concentration (µg/m^3)	Hourly Concentration (µg/m^3)	3-Month Rolling Average (µg/m3)	Cancer IURF (µg/m^3)$^{-1}$	Ref.	Non-Cancer RfC (mg/m^3)	Effect	Ref.
1,3-Butadiene	5.00E-04	6.00E-02	NA	3.00E-05	IRIS	2.00E-03	ovarian atrophy	IRIS
2,2,4-Trimethylpentane	4.00E-03	4.00E-01	NA	NA	NA	NA	NA	NA
Acetaldehyde	5.00E-03	5.00E-01	NA	2.20E-06	IRIS	9.00E-03	olfactory epithelium degen	IRIS
Acrolein	1.00E-03	1.00E-01	NA	NA	NA	2.00E-05	nasal lesions	IRIS
Benzene	6.00E-01	5.52E+01	NA	7.80E-06	IRIS	3.00E-02	decreased lymphocyte	IRIS
Ethylbenzene	1.10E-01	1.10E+01	NA	NA	NA	1.00E+00	developmental	IRIS
Formaldehyde	6.00E-02	2.30E+00	NA	1.30E-05	IRIS	9.80E-03	histological changes in nasal epithelium	ATSDR
Hexane	1.30E+00	1.28E+02	NA	NA	NA	7.00E-01	peripheral neuropathy	IRIS
Acenaphthene	2.71E-05	5.21E-03	NA	NA	NA	NA	NA	NA
Acenaphthylene	6.29E-05	1.03E-02	NA	NA	NA	NA	NA	NA
Anthracene	1.83E-04	1.37E-03	NA	NA	NA	NA	NA	NA
Benz[a]Anthracene	1.58E-06	6.92E-04	NA	6.00E-05	RPF	NA	NA	NA
Benzo[a]Pyrene	7.48E-07	2.86E-04	NA	6.00E-04	IRIS	2.00E-06	developmental	IRIS
Benzo[b]Fluoranthene	1.49E-06	1.24E-03	NA	6.00E-05	RPF	NA	NA	NA
Benzo[k]Fluoranthene	7.48E-07	2.43E-04	NA	6.00E-06	RPF	NA	NA	NA
Benzo[g,h,i]Fluoranthene	2.36E-05	6.19E-04	NA	NA	NA	NA	NA	NA
Chrysene	2.92E-06	1.70E-03	NA	6.00E-07	RPF	NA	NA	NA
Dibenzo[a,h]Anthracene	1.55E-06	3.85E-04	NA	6.00E-04	RPF	NA	NA	NA
Fluoranthene	1.61E-05	4.48E-03	NA	NA	NA	NA	NA	NA
Flourene	8.74E-05	1.42E-02	NA	NA	NA	NA	NA	IRIS
Indeno[1,2,3-cd]Pyrene	1.49E-06	4.61E-04	NA	6.00E-05	RPF	NA	NA	IRIS
Naphthalene	1.60E-02	1.72E+00	NA	NA	NA	3.00E-03	hyperplasia resp/nasal epithelium	IRIS
Phenanthrene	7.23E-04	4.54E-02	NA	NA	NA	NA	NA	NA
Pyrene	6.03E-06	4.13E-03	NA	NA	NA	NA	NA	NA

Risk Assessment Input Values

Pollutant	Annual Concentration ($\mu g/m^3$)	Hourly Concentration ($\mu g/m^3$)	3-Month Rolling Average (µg/m3)	Cancer IURF $(\mu g/m^3)^{-1}$	Ref.	Non-Cancer RfC (mg/m^3)	Effect	Ref.
Propionaldehyde	8.00E-04	8.00E-02	NA	NA	NA	8.00E-03	olfactory epithelium atrophy	IRIS
Propylene Oxide	2.00E-03	3.00E-02	NA	3.70E-06	IRIS	3.00E-02	nasal epithelial infolds	IRIS
Toluene	4.50E-01	4.45E+01	NA	NA	NA	5.00E+00	CNS	IRIS
Xylenes	1.40E-01	1.39E+01	NA	NA	NA	1.00E-01	CNS	IRIS
Antimony	1.00E-04	1.00E-02	NA	NA	NA	2.00E-04	pulm tox/interstitial inflam	IRIS
Arsenic	0.00E+00	4.00E-04	NA	4.30E-03	IRIS	NA	NA	IRIS
Cadmium	4.00E-05	4.00E-03	NA	1.80E-03	IRIS	1.00E-05	NA	ATSDR
Chromium	0.00E+00	0.00E+00	NA	1.20E-02	IRIS	8.00E-06	nasal septum atrophy	IRIS
Lead	2.00E-05	2.00E-03	2.33E-04	NA	NA	NA	neurodevelopmental, CNS	NAAQS
Manganese	0.00E+00	1.00E-04	NA	NA	NA	5.00E-05	neurobehavioral	IRIS
Mercury	0.00E+00	0.00E+00	NA	NA	NA	3.00E-04	CNS (tremor, memory disturb, autonomic dysfunction)	IRIS
Nickel	1.10E-04	1.00E-02	NA	4.80E-04	IRIS	1.00E-05	lung inflammation	ATSDR

Pollutant	Acute Toxicity Criterion (µg/m^3)	Effect	Ref.
1,3-Butadiene	6.60E+02	developmental	Ca REL
2,2,4-Trimethylpentane	NA	NA	NA
Acetaldehyde	4.70E+02	eye/resp irritation	Ca REL
Acrolein	2.50E+00	eye/resp irritation	Ca REL
Benzene	2.70E+01	developmental, immune system, hematological effects	Ca REL
Ethylbenzene	1.43E+05	CNS	AEGL-1 (Interim)
Formaldehyde	5.50E+01	eye irritation	Ca REL
Hexane	1.00E+04	CNS	AEGL-2
Acenaphthene	NA	NA	NA
Acenaphthylene	NA	NA	NA
Anthracene	NA	NA	NA
Benz[a]Anthracene	NA	NA	NA
Benzo[a]Pyrene	NA	NA	NA
Benzo[b]Fluoranthene	NA	NA	NA
Benzo[k]Fluoranthene	NA	NA	NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA
Chrysene	NA	NA	NA
Dibenzo[a,h]Anthracene	NA	NA	NA
Fluoranthene	NA	NA	NA
Flourene	NA	NA	NA
Indeno[1,2,3-cd]Pyrene	NA	NA	NA
Naphthalene	NA	NA	NA
Phenanthrene	NA	NA	NA
Pyrene	NA	NA	NA

Pollutant	Acute Toxicity Criterion (µg/m^3)	Effect	Ref.
Propionaldehyde	1.10E+05	nasal irritation	AEGL-1 (Interim)
Propylene Oxide	3.10E+03	eye/resp irritation, developmental	Ca REL
Toluene	5.00E+03	eye/resp irritation, CNS	Ca REL
Xylenes	2.20E+04	eye/resp irritation, CNS	Ca REL
Antimony	NA	NA	NA
Arsenic	2.00E-01	developmental, cardiovascular, CNS	Ca REL
Cadmium	4.60E+02	resp irritation	AEGL-1 (Interim)
Chromium	2.00E-01	resp irritation	Ca REL
Lead	NA	NA	NA
Manganese	1.70E-01	CNS	Ca REL (8-hr)
Mercury	1.70E+03	developmental NOAEL	AEGLE-2 (interim)
Nickel	2.00E-01	immune system	Ca REL

Appendix B

Cancer Risk Backup Calculations

Cancer Risk Estimates

Pollutant	Maximum Off-Property Annual Concentration (µg/m^3)	Maximum Gregory Residential Annual Concentration (µg/m^3)	Maximum LaQuinta Channel Annual Concentration (Excluding Safety Zone) (µg/m3)	Maximum Off-Property Adult Chronic Carcinogen Exposure Concentration (µg/m^3)	Maximum Off-Property Child Chronic Carcinogen Exposure Concentration (µg/m^3)	Maximum Gregory Adult Chronic Carcinogen Exposure Concentration (µg/m^3)	Maximum Gregory Child Chronic Carcinogen Exposure Concentration (µg/m^3)	Commercial Fishing Boat Operator Exposure Concentration (µg/m^3)	IURF (µg/m^3)$^{-1}$	Maximum Off-Property Adult Cancer Risk	Maximum Off-Property Child Cancer Risk
1,3-Butadiene	5.00E-04			2.05E-04	4.11E-05			0.00E+00	3.00E-05	6.16E-09	1.23E-09
2,2,4-Trimethylpentane	4.00E-03			1.64E-03	3.29E-04				NA	NA	NA
Acetaldehyde	5.00E-03			2.05E-03	4.11E-04				2.20E-06	4.52E-09	9.04E-10
Acrolein	1.00E-03			4.11E-04	8.22E-05				NA	NA	NA
Benzene	6.00E-01	**4.68E-02**	**1.43E-01**	2.47E-01	4.93E-02	**1.92E-02**	**3.85E-03**	**1.05E-02**	7.80E-06	1.92E-06	3.85E-07
									2.20E-06	5.42E-07	1.08E-07
Ethylbenzene	1.10E-01			4.52E-02	9.04E-03				NA	NA	NA
Formaldehyde	6.00E-02			2.47E-02	4.93E-03				1.30E-05	3.21E-07	6.41E-08
Hexane	1.30E+00			5.34E-01	1.07E-01				NA	NA	NA
Acenaphthene	2.71E-05			1.12E-05	2.23E-06				NA	NA	NA
Acenaphthylene	6.29E-05			2.59E-05	5.17E-06				NA	NA	NA
Anthracene	1.83E-04			7.54E-05	1.51E-05				NA	NA	NA
Benz[a]Anthracene	1.58E-06			6.49E-07	1.30E-07				6.00E-05	3.89E-11	7.79E-12
Benzo[a]Pyrene	7.48E-07			3.08E-07	6.15E-08				6.00E-04	1.85E-10	3.69E-11
Benzo[b]Fluoranthene	1.49E-06			6.14E-07	1.23E-07				6.00E-05	3.69E-11	7.37E-12
Benzo[k]Fluoranthene	7.48E-07			3.08E-07	6.15E-08				6.00E-06	1.85E-12	3.69E-13
Benzo[g,h,i]Fluoranthene	2.36E-05			9.71E-06	1.94E-06				NA	NA	NA
Chrysene	2.92E-06			1.20E-06	2.40E-07				6.00E-07	7.20E-13	1.44E-13
Dibenzo[a,h]Anthracene	1.55E-06			6.36E-07	1.27E-07				6.00E-04	3.82E-10	7.64E-11
Fluoranthene	1.61E-05			6.60E-06	1.32E-06				NA	NA	NA
Flourene	8.74E-05			3.59E-05	7.19E-06				NA	NA	NA
Indeno[1,2,3-cd]Pyrene	1.49E-06			6.14E-07	1.23E-07				6.00E-05	3.69E-11	7.37E-12
Naphthalene	1.60E-02			6.58E-03	1.32E-03				NA	NA	NA
Phenanthrene	7.23E-04			2.97E-04	5.94E-05				NA	NA	NA
Pyrene	7.23E-04			2.97E-04	5.94E-05				NA	NA	NA
Polychlorinated Biphenyl (PCB)	0.00E+00			0.00E+00	0.00E+00				1.00E-04	0.00E+00	0.00E+00
Propionaldehyde	8.00E-04			3.29E-04	6.58E-05				NA	NA	NA
Propylene Oxide	2.00E-03			8.22E-04	1.64E-04				3.70E-06	3.04E-09	6.08E-10
Toluene	4.50E-01			1.85E-01	3.70E-02				NA	NA	NA
Xylenes	1.40E-01			5.75E-02	1.15E-02				NA	NA	NA
Antimony	1.00E-04			4.11E-05	8.22E-06				NA	NA	NA
Arsenic	0.00E+00			0.00E+00	0.00E+00				4.30E-03	0.00E+00	0.00E+00
Cadmium	4.00E-05			1.64E-05	3.29E-06				1.80E-03	2.96E-08	5.92E-09
Chromium	0.00E+00			0.00E+00	0.00E+00				1.20E-02	0.00E+00	0.00E+00
Lead	2.00E-05			NA	NA				NA	NA	NA
Manganese	0.00E+00			0.00E+00	0.00E+00				NA	NA	NA
Mercury	0.00E+00			0.00E+00	0.00E+00				NA	NA	NA
Nickel	1.10E-04			4.52E-05	9.04E-06				4.80E-04	2.17E-08	4.34E-09
Selenium	0.00E+00			0.00E+00	0.00E+00				NA	NA	NA
Total Cancer Risk										**2.85E-06**	**5.70E-07**

Cancer Risk Estimates

Pollutant	Maximum Gregory Adult Cancer Risk	Maximum Gregory Child Cancer Risk	Commercial Fishing Boat Operator Cancer Risk
1,3-Butadiene	6.16E-09	1.23E-09	
2,2,4-Trimethylpentane	NA	NA	
Acetaldehyde	4.52E-09	9.04E-10	
Acrolein	NA	NA	
Benzene	**1.50E-07**	**3.00E-08**	**8.19E-08**
	4.23E-08	**8.47E-09**	**2.31E-08**
Ethylbenzene	NA	NA	
Formaldehyde	3.21E-07	6.41E-08	
Hexane	NA	NA	
Acenaphthene	NA	NA	
Acenaphthylene	NA	NA	
Anthracene	NA	NA	
Benz[a]Anthracene	3.89E-11	7.79E-12	
Benzo[a]Pyrene	1.85E-10	3.69E-11	
Benzo[b]Fluoranthene	3.69E-11	7.37E-12	
Benzo[k]Fluoranthene	1.85E-12	3.69E-13	
Benzo[g,h,i]Fluoranthene	NA	NA	
Chrysene	7.20E-13	1.44E-13	
Dibenzo[a,h]Anthracene	3.82E-10	7.64E-11	
Fluoranthene	NA	NA	
Flourene	NA	NA	
Indeno[1,2,3-cd]Pyrene	3.69E-11	7.37E-12	
Naphthalene	NA	NA	
Phenanthrene	NA	NA	
Pyrene	NA	NA	
Polychlorinated Biphenyl (PCB)	0.00E+00	0.00E+00	
Propionaldehyde	NA	NA	
Propylene Oxide	3.04E-09	6.08E-10	
Toluene	NA	NA	
Xylenes	NA	NA	
Antimony	NA	NA	
Arsenic	0.00E+00	0.00E+00	
Cadmium	2.96E-08	5.92E-09	
Chromium	0.00E+00	0.00E+00	
Lead	NA	NA	
Manganese	NA	NA	
Mercury	NA	NA	
Nickel	2.17E-08	4.34E-09	
Selenium	NA	NA	
Total Cancer Risk	**5.79E-07**	**1.16E-07**	

Cancer Risk Estimates

Equations

Resident

$$EC = \frac{CA \times EF \times ED}{AT}$$

Commercial Fisherman

$$EC = \frac{CA \times EF \times ET \times ED}{AT}$$

$$Risk = EC \times IURF$$

Definitions		**Value**	**Commercial Fishing Boat**
EC	Exposure concentration ($\mu g/m^3$)	*Calculated*	*Calculated*
CA	Maximum modeled annual air concentration ($\mu g/m^3$)	*Calculated*	*Calculated*
EF	Exposure frequency (days/year)	350	225
ET	Exposure Time (hours/24 hours-day)	24	8
ED_{child}	Exposure duration (years)	6	NA
ED	Exposure duration (years)	30	25
AT	Carcinogen (70 years x 365 days/year) averaging time (days)	25550	25550

Appendix C
Non-Cancer Hazard Backup Calculations

Non-Cancer Hazard Estimates

Pollutant	Annual Concentration ($\mu g/m^3$)	Maximum Residential Annual Concentration ($\mu g/m^3$)	Maximum LaQuinta Channel Annual Concentration (Excluding Safety Zone) (µg/m3)	3-Month Rolling Average ($\mu g/m^3$)	Maximum Off-Property Adult Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Maximum Off_Property Child Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Maximum Gregory Adult/Child Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Commercial Fishing Boat Operator Exposure Concentration ($\mu g/m^3$)
1,3-Butadiene	5.00E-04			NA	4.79E-04	4.79E-04		
2,2,4-Trimethylpentane	4.00E-03			NA	3.84E-03	3.84E-03		
Acetaldehyde	5.00E-03			NA	4.79E-03	4.79E-03		
Acrolein	1.00E-03			NA	9.59E-04	9.59E-04		
Benzene	6.00E-01	**4.68E-02**	**1.43E-01**	NA	5.75E-01	5.75E-01	**4.49E-02**	**2.94E-02**
Ethylbenzene	1.10E-01			NA	1.05E-01	1.05E-01		
Formaldehyde	6.00E-02			NA	5.75E-02	5.75E-02		
Hexane	1.30E+00			NA	1.25E+00	1.25E+00		
Acenaphthene	2.71E-05			NA	2.60E-05	2.60E-05		
Acenaphthylene	6.29E-05			NA	6.03E-05	6.03E-05		
Anthracene	1.83E-04			NA	1.76E-04	1.76E-04		
Benz[a]Anthracene	1.58E-06			NA	1.51E-06	1.51E-06		
Benzo[a]Pyrene	7.48E-07			NA	7.18E-07	7.18E-07		
Benzo[b]Fluoranthene	1.49E-06			NA	1.43E-06	1.43E-06		
Benzo[k]Fluoranthene	7.48E-07			NA	7.18E-07	7.18E-07		
Benzo[g,h,i]Fluoranthene	2.36E-05			NA	2.27E-05	2.27E-05		
Chrysene	2.92E-06			NA	2.80E-06	2.80E-06		
Dibenzo[a,h]Anthracene	1.55E-06			NA	1.48E-06	1.48E-06		
Fluoranthene	1.61E-05			NA	1.54E-05	1.54E-05		
Flourene	8.74E-05			NA	8.38E-05	8.38E-05		
Indeno[1,2,3-cd]Pyrene	1.49E-06			NA	1.43E-06	1.43E-06		
Naphthalene	1.60E-02			NA	1.53E-02	1.53E-02		
Phenanthrene	7.23E-04			NA	6.93E-04	6.93E-04		
Pyrene	6.03E-06			NA	5.79E-06	5.79E-06		
Polychlorinated Biphenyl (PCB)	0.00E+00			NA	0.00E+00	0.00E+00		
Propionaldehyde	8.00E-04			NA	7.67E-04	7.67E-04		
Propylene Oxide	2.00E-03			NA	1.92E-03	1.92E-03		
Toluene	4.50E-01			NA	4.32E-01	4.32E-01		
Xylenes	1.40E-01			NA	1.34E-01	1.34E-01		

Non-Cancer Hazard Estimates

Pollutant	Annual Concentration ($\mu g/m^3$)	Maximum Residential Annual Concentration ($\mu g/m^3$)	Maximum LaQuinta Channel Annual Concentration (Excluding Safety Zone) (μg/m3)	3-Month Rolling Average ($\mu g/m^3$)	Maximum Off-Property Adult Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Maximum Off_Property Child Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Maximum Gregory Adult/Child Chronic Non-Cancer Exposure Concentration ($\mu g/m^3$)	Commercial Fishing Boat Operator Exposure Concentration ($\mu g/m^3$)
Antimony	1.00E-04			NA	9.59E-05	9.59E-05		
Arsenic	0.00E+00			NA	0.00E+00	0.00E+00		
Cadmium	4.00E-05			NA	3.84E-05	3.84E-05		
Chromium	0.00E+00			NA	0.00E+00	0.00E+00		
Lead	2.00E-05			2.33E-04	NA	NA		
Manganese	0.00E+00			NA	0.00E+00	0.00E+00		
Mercury	0.00E+00			NA	0.00E+00	0.00E+00		
Nickel	1.10E-04			NA	1.05E-04	1.05E-04		
Selenium	0.00E+00			0.00E+00	0.00E+00	0.00E+00		
Nasal HI								
Pulmonary HI								
Developmental HI								
CNS HI								

Non-Cancer Hazard Estimates

Pollutant	RfC, MRL or NAAQS ($\mu g/m^3$)	Maximum Off-Property Adult Non-Cancer HQ	Maximum Off-Property Child Non-Cancer HQ	Maximum Gregory Adult/Child Chronic Non-Cancer HQ	Commercial Fishing Boat Operator HQ	Effect
1,3-Butadiene	2.00E+00	2.40E-04	2.40E-04	2.40E-04		ovarian atrophy
2,2,4-Trimethylpentane	NA	NA	NA	NA		NA
Acetaldehyde	9.00E+00	5.33E-04	5.33E-04	5.33E-04		olfactory epithelium degen
Acrolein	2.00E-02	4.79E-02	4.79E-02	4.79E-02		nasal lesions
Benzene	3.00E+01	1.92E-02	1.92E-02	**1.50E-03**	**9.79E-04**	decreased lymphocyte
Ethylbenzene	1.00E+03	1.05E-04	1.05E-04	1.05E-04		developmental
Formaldehyde	9.80E+00	5.87E-03	5.87E-03	5.87E-03		histological changes in nasal epithelium
Hexane	7.00E+02	1.78E-03	1.78E-03	1.78E-03		peripheral neuropathy
Acenaphthene	NA	NA	NA	NA		NA
Acenaphthylene	NA	NA	NA	NA		NA
Anthracene	NA	NA	NA	NA		NA
Benz[a]Anthracene	NA	NA	NA	NA		NA
Benzo[a]Pyrene	2.00E-03	3.59E-04	3.59E-04	3.59E-04		developmental
Benzo[b]Fluoranthene	NA	NA	NA	NA		NA
Benzo[k]Fluoranthene	NA	NA	NA	NA		NA
Benzo[g,h,i]Fluoranthene	NA	NA	NA	NA		NA
Chrysene	NA	NA	NA	NA		NA
Dibenzo[a,h]Anthracene	NA	NA	NA	NA		NA
Fluoranthene	NA	NA	NA	NA		NA
Flourene	NA	NA	NA	NA		NA
Indeno[1,2,3-cd]Pyrene	NA	NA	NA	NA		NA
Naphthalene	3.00E+00	5.11E-03	5.11E-03	5.11E-03		hyperplasia resp/nasal epithelium
Phenanthrene	NA	NA	NA	NA		NA
Pyrene	NA	NA	NA	NA		NA
Polychlorinated Biphenyl (PCB)	NA	NA	NA	NA		NA
Propionaldehyde	8.00E+00	9.59E-05	9.59E-05	9.59E-05		olfactory epithelium atrophy
Propylene Oxide	3.00E+01	6.39E-05	6.39E-05	6.39E-05		nasal epithelial infolds
Toluene	5.00E+03	8.63E-05	8.63E-05	8.63E-05		CNS
Xylenes	1.00E+02	1.34E-03	1.34E-03	1.34E-03		CNS

Non-Cancer Hazard Estimates

Pollutant	RfC, MRL or NAAQS ($\mu g/m^3$)	Maximum Off-Property Adult Non-Cancer HQ	Maximum Off-Property Child Non-Cancer HQ	Maximum Gregory Adult/Child Chronic Non-Cancer HQ	Commercial Fishing Boat Operator HQ	Effect
Antimony	2.00E-01	4.79E-04	4.79E-04	4.79E-04		pulm tox/interstitial inflam
Arsenic	NA	NA	NA	NA		NA
Cadmium	1.00E-02	3.84E-03	3.84E-03	3.84E-03		NA
Chromium	8.00E-03	0.00E+00	0.00E+00	0.00E+00		nasal septum atrophy
Lead	1.50E-01	1.56E-03	1.56E-03	1.56E-03		neurodevelopmental, CNS
Manganese	5.00E-02	0.00E+00	0.00E+00	0.00E+00		neurobehavioral
Mercury	3.00E-01	0.00E+00	0.00E+00	0.00E+00		CNS (tremor, memory
Nickel	1.00E-02	1.05E-02	1.05E-02	1.05E-02		lung inflammation
Selenium	NA	NA	NA	NA		NA
Nasal HI			**5.96E-02**	**5.96E-02**		
Pulmonary HI			**1.61E-02**	**1.61E-02**		
Developmental HI			**4.64E-04**	**4.64E-04**		
CNS HI			**1.43E-03**	**1.43E-03**		

Non-Cancer Hazard Estimates

Equations

Resident

$$EC = \frac{CA \times EF \times ED}{AT}$$

Commercial Fisherman

$$EC = \frac{CA \times EF \times ET \times ED}{AT}$$

$$HQ = \frac{EC}{RfC}$$

Definitions		**Resident**	**Commercial Fishing Boat**
EC	Exposure concentration (µg/m^3)	*Calculated*	*Calculated*
CA	Maximum modeled annual air concentration (µg/m^3)	*Calculated*	*Calculated*
EF	Exposure frequency (days/year)	350	225
ET	Exposure Time (hours/24 hours	24	8
ED_{child}	Exposure duration (years)	6	NA
ED	Exposure duration (years)	30	25
AT_{CHILD}	Residential (6 years x 365 days/year) averaging time (days)	2190	NA
AT	Residential (30 years x 365 days/year) averaging time (days)	10950	9125

Non-Cancer Hazard Estimates

Equations

Resident

$$EC = \frac{CA \times EF \times ED}{AT}$$

Commercial Fisherman

$$EC = \frac{CA \times EF \times ET \times ED}{AT}$$

$$HQ = \frac{EC}{RfC}$$

Definitions		**Resident**	**Commercial Fishing Boat**
EC	Exposure concentration (µg/m^3)	*Calculated*	*Calculated*
CA	Maximum modeled annual air concentration (µg/m^3)	*Calculated*	*Calculated*
EF	Exposure frequency (days/year)	350	225
ET	Exposure Time (hours/24 hours	24	8
ED_{child}	Exposure duration (years)	6	NA
ED	Exposure duration (years)	30	25
AT_{CHILD}	Residential (6 years x 365 days/year) averaging time (days)	2190	NA
AT	Residential (30 years x 365 days/year) averaging time (days)	10950	9125

Appendix D

Acute Hazard Backup Calculations

Acute Hazard Estimates

Pollutant	Maximum Off-Property Hourly Concentration (µg/m3)	Maximum Gregory Hourly Concentration ($\mu g/m^3$)	Maximum LaQuinta Channel Hourly Concentration (Excluding Safety Zone) (µg/m3)	Acute Toxicity Factor (µg/m3)	Ref.
1,3-Butadiene	6.00E-02	6.00E-02		6.60E+02	Ca REL
2,2,4-Trimethylpentane	4.00E-01	4.00E-01		NA	NA
Acetaldehyde	5.00E-01	5.00E-01		4.70E+02	Ca REL
Acrolein	1.00E-01	1.00E-01		2.50E+00	Ca REL
Benzene	5.52E+01	**3.86E+00**	**2.13E+01**	2.70E+01	Ca REL
Ethylbenzene	1.10E+01	1.10E+01		1.43E+05	AEGL-1
Formaldehyde	2.30E+00	2.30E+00		5.50E+01	Ca REL
Hexane	1.28E+02	1.28E+02		1.00E+04	AEGL-2
Acenaphthene	5.21E-03	5.21E-03		NA	NA
Acenaphthylene	1.03E-02	1.03E-02		NA	NA
Anthracene	1.37E-03	1.37E-03		NA	NA
Benz[a]Anthracene	6.92E-04	6.92E-04		NA	NA
Benzo[a]Pyrene	2.86E-04	2.86E-04		NA	NA
Benzo[b]Fluoranthene	1.24E-03	1.24E-03		NA	NA
Benzo[k]Fluoranthene	2.43E-04	2.43E-04		NA	NA
Benzo[g,h,i]Fluoranthene	6.19E-04	6.19E-04		NA	NA
Chrysene	1.70E-03	1.70E-03		NA	NA
Dibenzo[a,h]Anthracene	3.85E-04	3.85E-04		NA	NA
Fluoranthene	4.48E-03	4.48E-03		NA	NA
Flourene	1.42E-02	1.42E-02		NA	NA
Indeno[1,2,3-cd]Pyrene	4.61E-04	4.61E-04		NA	NA
Naphthalene	1.72E+00	1.72E+00		NA	NA
Phenanthrene	4.54E-02	4.54E-02		NA	NA
Pyrene	4.13E-03	4.13E-03		NA	NA
Polychlorinated Biphenyl (PCB	1.00E-05	1.00E-05		NA	NA
Propionaldehyde	8.00E-02	8.00E-02		5.00E+02	AEGL-1 (Interim)
Propylene Oxide	3.00E-02	3.00E-02		3.10E+03	Ca REL
Toluene	4.45E+01	4.45E+01		5.00E+03	Ca REL
Xylenes	1.39E+01	1.39E+01		2.20E+04	Ca REL
Antimony	1.00E-02	1.00E-02		NA	NA
Arsenic	4.00E-04	4.00E-04		2.00E-01	Ca REL
Cadmium	4.00E-03	4.00E-03		4.60E+02	AEGL-1
Chromium	0.00E+00	0.00E+00		2.00E-01	Ca REL
Lead	2.00E-03	2.00E-03		NA	NA
Manganese	1.00E-04	1.00E-04		1.70E-01	Ca REL (8-hr)
Mercury	0.00E+00	0.00E+00		1.70E+03	AEGLE-2
Nickel	1.00E-02	1.00E-02		2.00E-01	Ca REL

Acute Hazard Estimates

Pollutant	Maximum Off-Property Hourly Concentration (µg/m3)	Maximum Gregory Hourly Concentration (µg/m^3)	Maximum LaQuinta Channel Hourly Concentration (Excluding Safety Zone) (µg/m3)	Acute Toxicity Factor (µg/m3)	Ref.
Selenium	0.00E+00	0.00E+00		NA	NA
Eye Irritation/Toxicity HI					
Repiratory/Nasal Effects HI					
Developmental HI					
CNS HI					
Immune System HI					

Acute Hazard Estimates

Pollutant	Maximum Off-Property Acute HQ	Maximum Gregory Acute HQ	Maximum Commercial Fishing Boat Operator Acute HQ	Effect
1,3-Butadiene	9.09E-05	9.09E-05		developmental
2,2,4-Trimethylpentane	NA	NA		NA
Acetaldehyde	1.06E-03	1.06E-03		eye/resp irritation
Acrolein	4.00E-02	4.00E-02		eye/resp irritation
Benzene	2.04E+00	**1.43E-01**	**7.90E-01**	developmental, immune system, hematological effects
Ethylbenzene	7.68E-05	7.68E-05		CNS
Formaldehyde	4.18E-02	4.18E-02		eye irritation
Hexane	1.28E-02	1.28E-02		CNS
Acenaphthene	NA	NA		NA
Acenaphthylene	NA	NA		NA
Anthracene	NA	NA		NA
Benz[a]Anthracene	NA	NA		NA
Benzo[a]Pyrene	NA	NA		NA
Benzo[b]Fluoranthene	NA	NA		NA
Benzo[k]Fluoranthene	NA	NA		NA
Benzo[g,h,i]Fluoranthene	NA	NA		NA
Chrysene	NA	NA		NA
Dibenzo[a,h]Anthracene	NA	NA		NA
Fluoranthene	NA	NA		NA
Flourene	NA	NA		NA
Indeno[1,2,3-cd]Pyrene	NA	NA		NA
Naphthalene	NA	NA		NA
Phenanthrene	NA	NA		NA
Pyrene	NA	NA		NA
Polychlorinated Biphenyl (PCB	NA	NA		NA
Propionaldehyde	1.60E-04	1.60E-04		nose, eye, mucous membrane irritation
Propylene Oxide	9.68E-06	9.68E-06		eye/resp irritation, developmental effects
Toluene	8.90E-03	8.90E-03		eye/resp irritation, CNS
Xylenes	6.32E-04	6.32E-04		eye/resp irritation, CNS
Antimony	NA	NA		NA
Arsenic	2.00E-03	2.00E-03		developmental, cardiovascular, CNS
Cadmium	8.70E-06	8.70E-06		resp irritation
Chromium	0.00E+00	0.00E+00		resp irritation
Lead	NA	NA		NA
Manganese	5.88E-04	5.88E-04		CNS
Mercury	0.00E+00	0.00E+00		developmental NOAEL
Nickel	5.00E-02	5.00E-02		immune system

Acute Hazard Estimates

Pollutant	Maximum Off-Property Acute HQ	Maximum Gregory Acute HQ	Maximum Commercial Fishing Boat Operator Acute HQ	Effect
Selenium	NA	NA		NA
Eye Irritation/Toxicity HI	**9.26E-02**	**9.26E-02**		
Repiratory/Nasal Effects HI	**5.08E-02**	**5.08E-02**		
Developmental HI	**2.05E+00**	**1.45E-01**		
CNS HI	**2.50E-02**	**2.50E-02**		
Immune System HI	**2.09E+00**	**1.93E-01**		

Equation

$$HQ = \frac{\text{1-Hour Conc}}{\text{ATF}}$$

Appendix G

State and Federal Air Quality Requirements

Table G1 Ambient Air Quality Standards				
Pollutant	**Averaging Period**	**Primary NAAQS ($\mu g/m^3$)**	**Secondary NAAQS ($\mu g/m^3$)**	**Texas NGLC ($\mu g/m^3$)**
PM_{10}	24-hr [a]	150	150	-
$PM_{2.5}$	Annual [b]	9	15	-
	24-hr [c]	35	35	-
NO_2	Annual [d]	100 (53 ppb)	100 (53 ppb)	-
	1-hr [e]	188 (100 ppb)	N/A	-
CO	8-hr [f]	10,000	N/A	-
	1-hr [f]	40,000	N/A	-
Ozone [g,h]	8-hr [i]	137 (0.070 ppm)	137 (0.070 ppm)	-
Lead	Rolling 3-month average [j]	0.15	0.15	-
SO_2	3-hr [f]	N/A	1,300 (0.5 ppm)	-
	1-hr [k]	196 (75 ppb)	N/A	-
	30-min			1,021[l]
H_2S	30-min			108/162[m]

$\mu g/m^3$ = micrograms per cubic meter
ppm = parts per million
ppb = parts per billion
a Not to be exceeded more than once pear year on average over three years.
b 3-year average of annual mean $PM_{2.5}$ concentrations.
c 98th percentile of the 24-hr concentrations, averaged over three years.
d Not to be exceeded.
e 98th percentile of the 1-hr daily maximum concentrations, averaged over three years.
f Not to be exceeded more than once per year.
g Although EPA revoked the 1-hr ozone standard (235 $\mu g/m^3$ or 0.12 ppm) in 2005 for all areas, some areas (excluding the Project area) have continuing obligations to adhere to the standard.
h The previous (2008) 8-hr ozone standard – 0.075 ppm – is not revoked and remains in effect for designated areas (LAC 33:III.711.A. and B. shows the ozone ambient air quality standard - primary and secondary - as 0.075 ppm).
I Annual 4th-highest daily maximum 8-hr concentration, averaged over three years.
j The standard is met when the maximum arithmetic 3-month average concentration for a 3-year period, as determined in accordance with Appendix R of 40 CFR Part 50, is less than or equal to 0.15 $\mu g/m^3$.
k 99th percentile of the 1-hr daily maximum concentrations, averaged over three years.
l Net ground-level concentration (NGLC) not to be exceeded at the property boundary (30 TAC §112.3).
m NGLC of 108 $\mu g/m^3$ not to be exceeded on property normally occupied by people (30 TAC §112.31) and NGLC of 162 $\mu g/m^3$ not to be exceeded on property not normally occupied by people (30 TAC §112.32).

Air Quality Monitoring and Background Concentrations

Air quality monitors maintained by the TCEQ are located throughout the state to determine existing levels of various air pollutants. Air quality monitoring data for the period were reviewed by CCL to characterize ambient air quality for regulated criteria pollutants in the vicinity of the Project site. Measured concentrations ($\mu g/m^3$) from representative air quality monitors are summarized by year in table G1. The assessment included the following pollutants: O_3, CO, NO_2, $PM_{2.5}$, PM_{10}, SO_2, and lead. For each pollutant, table G1 gives the available concentrations in terms of annual mean concentration values for each year and/or short-term concentrations. The short-term concentrations shown in table G1 are maximum or near maximum values, as defined by EPA, for the identified monitors, which are limited in number and location. As such, the concentrations are not necessarily representative of current actual air quality in the immediate vicinity of the Project sites.

Each of the measured ambient pollutant concentrations shown in table G2 is below the associated NAAQS for each applicable averaging period, thus indicating continued, on-going attainment of the standards.

Table G2
Ambient Air Quality Concentrations in the Vicinity of the CCL Midscale Trains 8 & 9 Project

Pollutant	Averaging Period	Concentration ($\mu g/m^3$) by Year			Monitor Information	
		2022	2021	2020	Location	ID No.
CO	8-hour [a]	1,830	3,090	2,180	Harris County, TX	48-201-1052
	1-hour [a]	2,060	3,320	2,630		
NO_2	Annual [b]	3.4 (1.8 ppb)	4.7 (2.5 ppb)	4.5 (2.4 ppb)	Lake Jackson, TX	48-039-1016
	1-hour [c]	32.1 (17.1 ppb)	36.7 (19.5 ppb)	32.0 (17.0 ppb)		
O_3	8-hour [d]	122 (0.062 ppm)	128 (0.065 ppm)	120 (0.061 ppm)	Nueces County, TX	48-355-0025
$PM_{2.5}$	Annual [b]	8.3	7.9	8.0	Nueces County, TX	48-355-0032 (POC 3)
	24-hour [c]	22	21	27		
PM_{10}	24-hour [a]	39	43	84	Nueces County, TX	48-355-0034
SO_2	3-hour [a]	11 (4.1 ppb)	20 (7.5 ppb)	7.6 (2.9 ppb)	Nueces County, TX	48-355-0032
	1-hour [e]	21 (7.9 ppb)	31 (12 ppb)	10 (3.7 ppb)		
Lead	3-month [f]	0.01	0.02	0.01	Collin County, TX	48-085-0029

$\mu g/m^3$ = micrograms per cubic meter
ppm = parts per million
ppb = parts per billion
a 2nd highest measurement recorded for each year.
b Annual average measurement recorded for each year.
c 98th percentile measurement recorded for each year.
d 4th highest 8-hour average measurement recorded for each year.
e 99th percentile measurement recorded for each year.
f Maximum 3-month measurement recorded for each year.

Air Quality Permitting Requirements

The Project would be subject to a variety of federal and state regulations pertaining to the construction and operation of air emission sources. The TCEQ has the primary jurisdiction over air emissions produced by stationary sources associated with the Project. The TCEQ is delegated by the EPA to implement Federal air quality programs. The TCEQ's air quality regulations are codified in 30 TAC Chapters 101, 106, 111-118, and 122. New sources of emissions, such as those associated with the Project, are required to obtain an air quality permit before initiating construction. Air permit applications were submitted by CCL for the Terminal Facilities to the TCEQ on March 28, 2023, and filed in the FERC docket on March 30, 2023. The following sections summarize the applicability of various state and federal regulations.

Federal Air Quality Requirements

The CAA, Title 42 of the U.S.C, Section 7401 *et seq.*, as amended in 1977 and 1990, and 40 CFR Parts 50 through 99 are the basic federal statutes and regulations governing air pollution in the U.S. The following federal requirements have been reviewed for applicability to the Project.

- New Source Review (NSR)/ PSD;
- Part 70 Operating Permit;
- New Source Performance Standards;
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Greenhouse Gas Reporting;
- Chemical Accident Prevention Provisions;
- Stratospheric Ozone Protection; and
- General Conformity.

No air quality or visibility impacts to any Class I Federal Areas identified in 40 CFR Part 81, Subpart D are expected. The closest Class I Federal Area (Big Bend National Park) is located approximately 600 kilometers (373 miles) from the Project site. Based on these distances and the magnitude of Project emissions, an analysis of impacts to this area is not required.

New Source Review/ Prevention of Significant Deterioration

Separate preconstruction review procedures for major new sources of air pollution (and major modifications to major sources) have been established for projects that are proposed to be built in attainment areas versus nonattainment areas. The preconstruction permit program for new or modified major sources proposed in attainment areas is known as the PSD program. This review process is intended to keep new air emission sources from causing existing air quality to deteriorate beyond acceptable levels codified in the federal regulations. Because all the stationary emission sources for the Project would be located within an attainment area for all criteria pollutants, nonattainment NSR does not apply. Rather, the Project emissions must be reviewed to determine the applicability of the PSD program.

The PSD rule defines a major stationary source as any source with a potential to emit 100 tpy or more of any NSR-regulated pollutant for source categories listed in 40 CFR 52.21(b)(1)(i) or 250 tpy or more of any NSR-regulated pollutant for source categories that are not listed. If a new source is determined to be a major source for any regulated pollutant, then other remaining regulated pollutants, including GHG (CO_2e), would be subject to PSD review if those pollutants are emitted at rates that exceed their respective significant emission rates. A stationary source with annual emissions that exceed the major source threshold for one or more regulated pollutants is subject to a PSD review. The PSD regulations, particularly those that apply to major modifications, are outlined in the state regulations in 30 TAC Chapter 116, Subchapter B, Division 6.

The TCEQ originally issued an NSR-PSD permit for the Stage 3 Project on February 14, 2017 (Permit Nos. 139479/PSD-TX-1496/GHG PSD-TX-157). The original 2017 permit for the Stage 3 Project, which was based on a project design that included gas-fired combustion turbines to drive refrigeration compressors, showed criteria pollutant emissions exceeding the 250 tpy major source threshold. Therefore, the Stage 3 Project originally was subject to PSD review. Because of that major source classification, the emission rates for the Project are compared to the PSD significant emission rate thresholds to determine PSD applicability of the Project. (Note that an amended permit for the Stage 3 Project was issued October 22, 2019, when the project design was revised to the currently authorized midscale design with seven trains but no gas-fired combustion turbines. The revised design for the Stage

3 Project resulted in a decrease in emission rates; therefore, PSD review was not required for the revised permit in 2019.)

The emission rates shown in table G3 represent emissions from the Project design as well as the associated changes being made concurrently to the Stage 3 Project permit. As shown in table G3, annual emission rates for NSR-regulated pollutants exceed their respective significant emission rates; thus, the Project is subject to PSD review. The Project emission increases for NO_x, CO, VOC and CO_2e exceed the PSD significant emission rate thresholds. PSD review also is required for PM_{10} and $PM_{2.5}$ because the air permit amendment application includes a revised PSD applicability analysis for all pollutants that previously triggered PSD, including PM_{10} and $PM_{2.5}$, to accommodate retrospective updates to the Stage 3 Project permit unrelated to the Project.

Table G3
New Source Review-Prevention of Significant Deterioration (NSR-PSD) Applicability Analysis for the CCL Midscale Trains 8 & 9 Project

Pollutant	Project Emission Rate Increase [a] (tpy)	Significant Emission Rate for Major Modification (tpy)	PSD Review Triggered?
PM	17.6	25	No
PM_{10}	17.6	15	Yes
$PM_{2.5}$	17.6	10	Yes
NO_x	317.9	40	Yes
CO	1,802.6	100	Yes
VOC	255.2	40	Yes
SO_2	15.3	40	No
H_2S	0.2	10	No
Sulfuric Acid Mist	0.0	7	No
CO_2e	1,475,357	75,000	Yes

[a] Includes emission rate increases from sources (e.g., marine flare, condensate storage) in Corpus Christi Liquefaction Project TCEQ Permit No. 105710 not included in Stage 3 Project TCEQ Permit No. 139479

Part 70 Operating Permit

Title V of the CAA requires states to establish an air quality operating permit program. The requirements of Title V are outlined in the federal regulations in 40 CFR 70 and in 30 TAC 122. The operating permits required by these regulations are often referred to as Part 70 or Title V operating permits.

A major source is required to obtain a Part 70 operating permit. Under 40 CFR 70, a major source is defined as a source that could emit at or above at least one of the following levels: 100 tpy for any regulated air pollutant; 10 tpy for an individual HAP; or 25 tpy for any combination of HAPs.

The Liquefaction Project LNG Terminal is subject to the Title V program because it is a major stationary source, and a Title V operating permit has been obtained for the terminal. CCL would need to apply for a revision to the existing Title V operating permit to address the Project modifications to the terminal before beginning operation of the Project, per 30 TAC 122.130.

New Source Performance Standards

NSPS regulations (40 CFR Part 60) establish pollutant emission limits and monitoring, reporting, and recordkeeping requirements for various emission sources based on source type and size. These regulations apply to new, modified, or reconstructed sources. The following NSPS requirements were identified as potentially applicable to the specified Project sources of emissions.

Subpart A of 40 CFR 60, General Provisions, includes broader definitions of applicability and various methods for maintaining compliance with requirements listed in subsequent subparts of 40 CFR 60. This subpart also provides visible emissions requirements for flares, per 40 CFR 60.18. This subpart also specifies the state agencies to which the EPA has delegated authority to implement and enforce standards of performance. The EPA has given delegated authority to the TCEQ for all relevant 40 CFR 60 standards. Equipment at the Project facilities that is subject to any of the NSPS subparts listed below would be subject to Subpart A.

Subpart Db of 40 CFR 60, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, that has a maximum heat input capacity of greater than 100 million British Thermal Units per hour (MMBtu/hr). Given that the gas-fired hot oil furnaces for Trains 8 & 9 meet the definition of a steam generating unit but have a maximum heat input of 66 MMBtu/hr, the furnaces are not subject to the requirements of Subpart Db.

Subpart Dc of 40 CFR 60, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to each steam generating unit constructed after June 9, 1989, that has a maximum heat input capacity of between 10 and 100 MMBtu/hr. The hot oil furnaces for Trains 8 & 9 are affected sources under this subpart; however, no requirements apply as the furnaces fire only fuel gas.

Subpart GG of 40 CFR 60, Standards of Performance for Stationary Gas Turbines, applies to each stationary gas turbine with a heat input at peak load equal to or greater than 10 MMBtu/hr. For the Project, the refrigeration compressors for Trains 8 & 9 would be powered by electric motor drives; therefore, the requirements of Subpart GG do not apply.

Subpart Kb of 40 CFR Part 60, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, applies to certain vessels storing volatile organic liquids. In addition to the construction date, regulatory applicability is dependent on the size, vapor pressure, and contents of the storage vessel. Unless otherwise exempted, Subpart Kb applies to tanks that have a storage capacity between 75 m^3 (19,813 gallons) and 151 m^3 (39,890 gallons) and contain VOCs with a maximum true vapor pressure greater than or equal to 15.0 kilopascals. Subpart Kb also applies to tanks that have a storage capacity greater than or equal to 151 m^3 and contain VOCs with a maximum true vapor pressure greater than or equal to 3.5 potential to emit. Pressure tanks are exempt from the requirements of Subpart Kb. The Project would rely on an existing condensate storage tank (i.e., permitted under the Liquefaction Project) when processing condensate. The tank has a capacity greater than 75 m^3 and stores VOCs with a maximum true vapor pressure of approximately 15 potential to emit. The tank is currently subject to the requirements of 40 CFR Part 63, Subpart EEEE, but is allowed to demonstrate compliance with this rule by following the requirements of Subpart Kb. No new volatile organic liquid storage tanks are proposed for the Project.

Subpart IIII of 40 CFR 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to diesel-fueled stationary compression ignition internal combustion engines of any size that are constructed, modified, or reconstructed after July 11, 2005. The rule requires manufacturers of these engines to meet emission standards based on engine size, model year, and end use and to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer. These requirements of Subpart IIII, as well as recordkeeping and reporting requirements, would apply to the diesel-fired standby emergency generators proposed for the Project.

Subpart KKKK of 40 CFR 60, Standards of Performance for Stationary Combustion Turbines, applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu/hr. For the Project, the refrigeration compressors for Trains 8 and 9 would be powered by electric motor drives; therefore, the requirements of Subpart KKKK do not apply.

Subpart OOOOb of 40 CFR 60, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After December 6, 2022, applies to emissions of GHG (methane), VOC, and SO_2 from affected facilities listed in §60.5365b(a) through (i) that are located within the Crude Oil and Natural Gas source category, as defined in §60.5430b. The Project does not involve construction of the types of operations included in the Crude Oil and Natural Gas source category; therefore, the requirements of Subpart OOOOb do not apply to the Project.

National Emissions Standards for Hazardous Air Pollutants

National Emissions Standards for Hazardous Air Pollutants (NESHAP), codified in 40 CFR Parts 61 and 63, regulates HAP emissions. Part 61 was promulgated prior to the 1990 CAA Amendments and regulates specific HAPs, such as asbestos, benzene, beryllium, inorganic arsenic, mercury, radionuclides, and vinyl chloride. Federal NESHAP requirements presented in 40 CFR 61 are incorporated by reference under the state regulations per 30 TAC Chapter 113, Subchapter B.

The 1990 CAA Amendments established a list of 189 HAPs, while directing EPA to publish categories of major sources and area sources of these HAPs, for which emission standards were to be promulgated according to a schedule outlined in the CAA Amendments. These standards, also known as the Maximum Achievable Control Technology Standards, were communicated under Part 63. The 1990 CAA Amendments defines a major source of HAPs as any source that has a potential to emit of 10 tpy for any single HAP or 25 tpy for all HAPs in aggregate. Area sources are stationary sources that do not exceed the thresholds for major source designation. Federal NESHAP requirements presented in 40 CFR 63 are incorporated by reference under the state regulations per 30 TAC Chapter 113, Subchapter C.

The existing CCL Terminal is classified as a major source of HAP emissions. The NESHAP described in the following paragraphs has been identified as applicable to specific emission sources related to the Project.

Subpart A of 40 CFR Part 63, General Provisions, includes broader definitions of applicability and various methods for maintaining compliance with requirements listed in subsequent subparts of 40 CFR 63. This subpart specifies the state agencies to which the EPA has delegated authority to implement and enforce NESHAP. The TCEQ has been delegated authority for all relevant 40 CFR 63 standards promulgated by the EPA.

Subpart EEEE of 40 CFR 63, NESHAP for Organics Liquid Distribution (Non-Gasoline), applies to owners and operators of organic liquid distribution operations located at a major source of HAP emissions. The storage and loading of condensate for the Project would occur at existing facilities for the CCL Terminal, which is subject to the requirements of this rule.

Subpart YYYY of 40 CFR 63, NESHAP for Stationary Combustion Turbines, applies to each stationary combustion turbine at a major source of HAP emissions. For the Project, the refrigeration compressors for Trains 8 & 9 would be powered by electric motor drives; therefore, the requirements of Subpart YYYY do not apply.

Subpart ZZZZ of 40 CFR 63, NESHAP for Stationary Reciprocating Internal Combustion Engines, applies to reciprocating internal combustion engines of all sizes located at major and area sources of HAPs. The proposed diesel-fueled standby generators, rated at greater than 500 brake-horsepower, are considered new emergency reciprocating internal combustion engines subject to 40 CFR Part 63 Subpart ZZZZ. As such, per 40 CFR 63.6590(b)(1), the generators would be subject only to the initial notification requirement of 40 CFR 63.6645(f).

Subpart DDDDD of 40 CFR 63, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to each existing, new, or reconstructed boiler or process heater at a major source of HAP emissions, and includes the requirement for an annual tune-up. The hot oil furnaces for Trains 8 & 9 meet the definition of a process heater; therefore, the furnaces are subject to the requirements of Subpart DDDDD.

Greenhouse Gas Reporting Rule

Subpart W under 40 CFR 98, the Mandatory GHG Reporting Rule, requires petroleum and natural gas systems that emit 25,000 metric tons or more of CO2e per year to report annual emissions of GHG and other relevant information (e.g., emissions monitoring and calculation methods, data quality assurance information) to the EPA.

A review of the Project emission sources and associated potential GHG emissions indicates that Subpart W (petroleum and natural gas systems) of Part 98 would be applicable. LNG storage and LNG import and export equipment are industry segments included in the source category definition for Subpart W. GHG emissions from operation of the Project are projected to exceed the 25,000-metric ton threshold; therefore, the Project emissions for the affected equipment would be subject to the reporting requirements of 40 CFR Part 98.

In April 2022, the EPA proposed revisions to 40 CFR 98, including Subpart W, that could alter how emissions are calculated and reported, beginning with reporting year 2023. CCL should analyze changes to this subpart, when finalized, to identify all revised requirements that apply to the Project.

Chemical Accident Prevention Provisions

The chemical accident prevention provisions, codified in 40 CFR 68, are federal regulations designed to prevent the release of hazardous materials in the event of an accident and minimize potential impacts if a release does occur. The regulations contain a list of substances (including methane, propane, and ethylene) and threshold quantities for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more substances on this list in a quantity equal to or greater than that specified in the regulation, the facility must prepare and submit a risk management plan.

If a facility does not have a listed substance on-site, or the quantity of a listed substance is below the applicability threshold, the facility does not have to prepare a risk management plan. However, if there is any regulated substance or other extremely hazardous substance onsite, the facility still must comply with the requirements of the General Duty Clause in Section 112(r)(1) of the 1990 CAA Amendments. The General Duty Clause is as follows:

"The owners and operators of stationary sources producing, processing, handling and storing such substances have a general duty to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility, taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."

Stationary sources are defined in 40 CFR 68 as any buildings, structures, equipment, installations, or substance-emitting stationary activities which belong to the same industrial group, that are on one or more contiguous properties, are under control of the same person (or persons under common control) and are from which an accidental release may occur. The Project facilities would handle and store significant quantities of methane (as LNG) and refrigerants, such as propane, which are regulated substances under 40 CFR 68. However, the definition also states that the term stationary source does not apply to transportation, including storage incidental to transportation, of any regulated substance or any other extremely hazardous substance. The term transportation includes transportation subject to oversight or regulation under 49 CFR Parts 192, 193, or 195. Based on these definitions, the Project facilities are subject to 49 CFR Part 193 and would not be required to prepare a risk management plan.

Stratospheric Ozone Protection

The implementation regulations for the stratospheric ozone protection provisions of the CAA are codified under 40 CFR 82. A condition would be included in the Part 70 operating permit for the CCL Terminal that requires CCL to comply with the standards for recycling and emissions reduction pursuant to Subpart F of 40 CFR 82 (as well as the standards for motor vehicle air conditioners pursuant to Subpart B, as applicable) across the entire facility.

General Conformity

A general conformity analysis must be conducted by the lead federal agency if a federal action would result in the generation of emissions that would exceed the general conformity applicability threshold levels of the pollutants(s) for which an AQCR is in nonattainment. According to Section 176(c)(1) of the CAA (40 CFR 51.853), a federal agency cannot approve or support any activity that does not conform to an approved SIP. Conforming activities or actions should not, through additional air pollutant emissions:

- cause or contribute to new violations of the NAAQS in any area;
- increase the frequency or severity of an existing violation of any NAAQS; or
- delay timely attainment of any NAAQS or interim emission reductions.

General Conformity assessments must be completed when the total direct and indirect emissions of a planned project would equal or exceed the specified pollutant applicability emission thresholds per year in each nonattainment area.

As previously discussed, operating emission sources for the Project would be entirely within designated unclassifiable/attainment areas for all criteria air pollutants and would be subject to evaluation under the NSR PSD permitting program; therefore, these emissions are not subject to General Conformity regulations. However, during the construction phase of the Project, barges carrying equipment and materials would travel periodically from the Port of Houston to the Project construction dock via the GIWW. The Port of Houston is in the HGB "marginal" ozone nonattainment area (2015 8-hour NAAQS); therefore, each barge would spend part of its trip within the HGB ozone nonattainment area. The construction barge traffic emissions associated with travel in the HGB ozone nonattainment area would be subject to evaluation under General Conformity regulations.

The relevant general conformity pollutant thresholds for the HGB ozone nonattainment area are 25 tpy of NO_x and VOC (ozone precursors) for the portion of the Project construction-related tug/barge emissions located in the nonattainment area (which is classified as "severe" for the 1997 8-hour ozone standard).

CCL estimated emissions from tug vessels that push the barges using EPA-sponsored marine vessel emissions estimation guidance. The emissions were apportioned between the HGB ozone nonattainment area and the adjacent unclassifiable/attainment area, Corpus Christi-Victoria Intrastate AQCR, based on the emissions generated during the time spent traveling through each of these areas.

CCL estimated that the total potential NOx and VOC emissions from the Project tug/barge construction equipment and material transport trips (i.e., construction tug/barge travel in HGB ozone nonattainment area and Corpus Christi-Victoria Intrastate AQCR) would be less than 25 tpy for each year of the construction period. Based on these projected emissions, a General Conformity Determination is not required for the Project.

Applicable State Air Quality Requirements

In addition to the federal regulations identified above, the TCEQ requires compliance with its air quality regulations, codified in 30 TAC. The state requirements potentially applicable to the Project are as follows:

- 30 TAC Chapter 101, Subchapter A – *General Rules*. This chapter includes provisions related to circumvention, nuisance, traffic hazards, sampling and sampling ports, emissions inventory requirements, sampling procedures and terminology, compliance with EPA standards, inspection and emission fees, and emission events and scheduled maintenance, startup, and shutdown activities.
- 30 TAC Chapter 111 – *Control of Air Pollution from Visible Emissions and Particulate Matter*. This chapter outlines the allowable visible emission (i.e., opacity) requirements and total suspended particulate emission limits based on calculated emission rates.
- 30 TAC Chapter 112 – *Control of Air Pollution from Sulfur Compounds*. This chapter outlines emission limits and monitoring, reporting, and recordkeeping requirements. This chapter also lists net ground-level concentration standards at the property line for certain sulfur compounds (SO_2 and H_2S).
- 30 TAC Chapter 113 – *Control of Air Pollution from Toxic Materials*. Chapter 113 incorporates by reference the NESHAP source categories (40 CFR Part 63).
- 30 TAC Chapter 115 – *Control of Air Pollution from Volatile Organic Compounds*. This chapter outlines requirements for storage tanks and VOC loading/unloading operations.
- 30 TAC Chapter 116, Subchapter B – *Control of Air Pollution by Permits for New Construction or Modification*. This chapter outlines the permitting requirements for the construction of new sources.
- 30 TAC Chapter 118 – *Control of Air Pollution Episodes*. This chapter outlines the requirements relating to generalized and localized air pollution episodes.
- 30 TAC Chapter 122 – *Federal Operating Permits*. This chapter outlines the requirements for complying with the Federal operating permits program. The requirements for the Project are discussed in the Title V Operating Permit section of this document.

Mitigation Measures

The dust reduction procedures and techniques outlined in the Fugitive Dust Control Plan includes:

- application of dust suppressant (e.g., water), on an as-needed basis, to the following areas of the construction site:
  - access roads;
  - staging and laydown areas;
  - parking areas; and
  - material storage piles;
- directing traffic to designated roads (keeping vehicles from tracking “off-road”);
- stabilizing material stockpiles to minimize wind and water erosion;
- covering of beds of open-bodied trucks hauling materials with excessive dust generation;

- limiting vehicle speeds on unsurfaced roads within construction site to 15 mph or less, with the posting of speed limit signs on designated access roads;
- using rock construction pads at the junction between unpaved access roads and paved roads to reduce track-out of material at construction site entrances; and
- conducting earthmoving activities in stages to minimize the amount of disturbed surface area.

Under the Fugitive Dust Control Plan, the EI and other staff (both CCL staff and construction contractor employees) would have the authority to determine if/when water needs to be re-applied for dust control, determine if or when palliative action should be used, and stop activities that are not in compliance with plan measures.

In addition, CCL would implement the following measures to enhance the effectiveness of the measures outlined in the Fugitive Dust Control Plan:

- Include the dust control measures outlined in the Fugitive Dust Control Plan in the environmental training for all onsite personnel, including more detailed training for foreman and senior construction contractor personnel.
- Prior to construction, publish in a local newspaper and the Project website the phone number (888-371-3607) and email address (community@cheniere.com) to report construction complaints regarding fugitive dust to the EI (or designee) for local residences to express concerns.
- The EI keeps a daily log where they document the following:
    - weather conditions, including noting the occurrence of precipitation or windy conditions;
    - condition of rock/gravel-construction track-out pads;
    - if water was or was not applied for dust control during the day;
    - any incidences where special dust abatement measures were needed, the measures employed (e.g., more frequent watering, application of chemical suppressant, etc.), and the reason for those measures; and
    - any stop-work order issued for excessive dust generation incidences.
- Make this daily logbook available to FERC or its designated representative for review upon request.
- If a dust-related complaint is received by TCEQ and communicated to CCL, provide a record of this complaint to FERC and the measure taken to address the complaint.

CCL would minimize vehicular exhaust and crankcase emissions from gasoline- and diesel-fired engines by the following measures:

- Verification that construction equipment being used on-site have engines manufactured to comply with applicable EPA mobile source emission standards.
- Implementation of measures to verify that contractors maintain construction equipment in accordance with manufacturers' recommendations.
- Minimization of engine idling to the extent practicable. CCL would instruct Project construction personnel to minimize the idle time of equipment to five minutes or less when not in active use. CCL's expectations concerning minimizing on-site idling would be communicated to construction personnel during safety/environmental training sessions and

enforced by construction supervisors and inspectors. Also, consistent with industry practice, unmanned equipment would be turned off and would not be left idling.

Appendix H

Air Quality Tables

Table H1 Annual Emissions (tpy) of Criteria Air Pollutants and HAPs for CCL Midscale Trains 8 & 9 Project Construction								
Year	**Emission Source**	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAPs**
2025	Fugitive Dust	-	-	-	58.90	6.30	-	-
	Non-Road Equipment	16.00	0.90	6.00	0.70	0.70	0.02	0.26
	Commuting and On-Road Vehicles	5.70	2.20	44.40	0.13	0.11	0.03	0.70
	2025 Total	***21.70***	***3.10***	***50.40***	***59.73***	***7.11***	***0.05***	***0.96***
2026	Fugitive Dust	-	-	-	58.90	6.30	-	-
	Non-Road Equipment	27.00	1.70	13.00	1.60	1.60	0.03	0.52
	Commuting and On-Road Vehicles	11.80	4.00	75.10	0.40	0.36	0.05	1.05
	Barges [a]	5.82	0.20	4.51	0.57	0.53	0.46	-
	2026 Total	***44.62***	***5.90***	***92.61***	***61.47***	***8.79***	***0.54***	***1.57***
2027	Fugitive Dust	-	-	-	58.90	6.30	-	-
	Non-Road Equipment	74.00	5.20	42.00	5.60	5.40	0.10	0.55
	Commuting and On-Road Vehicles	11.90	4.00	75.10	0.41	0.37	0.05	1.05
	Barges [a]	4.19	0.15	3.29	0.42	0.39	0.33	-
	2027 Total	***90.09***	***9.35***	***120.39***	***65.33***	***12.46***	***0.48***	***1.60***
2028	Fugitive Dust	-	-	-	58.90	6.30	-	-
	Non-Road Equipment	88.00	6.60	55.00	7.20	7.00	0.12	2.10
	Commuting and On-Road Vehicles	5.70	2.20	44.50	0.13	0.12	0.03	0.60
	2028 Total	***93.70***	***8.80***	***99.50***	***66.23***	***13.42***	***0.15***	***2.70***
	Total Construction Period Emissions	***250.1***	***27.2***	***362.9***	***252.8***	***41.8***	***1.2***	***6.8***
[a]	Inclusive of all barge-related emissions associated with Project construction, as all such barge traffic occurs in Texas state waters via the Gulf Intercoastal Waterway.							

Table H2
Annual Emissions (tpy) of Greenhouse Gases for CCL Midscale Trains 8 & 9 Project Construction Year

	Emission Source	**CO_2**	**CH_4**	**N_2O**	**CO_2e [a]**
2025	Non-Road Equipment	3,002	0.00	0.10	3,026
	Commuting and On-Road Vehicles	4,214	0.07	0.15	4,260
	2025 Total	***7,216***	***0.07***	***0.25***	***7,286***
2026	Non-Road Equipment	5,579	0.10	0.10	5,624
	Commuting and On-Road Vehicles	7,755	0.13	0.25	7,833
	Barges [b]	283	0.00	0.02	287
	2026 Total	***13,617***	***0.23***	***0.37***	***13,744***
2027	Non-Road Equipment	17,460	0.30	0.40	17,603
	Commuting and On-Road Vehicles	7,778	0.13	0.25	7,856
	Barges [b]	204	0.00	0.01	206
	2027 Total	***25,442***	***0.43***	***0.66***	***25,665***
2028	Non-Road Equipment	20,263	0.30	0.50	20,430
	Commuting and On-Road Vehicles	4,240	0.07	0.15	4,286
	2028 Total	***24,503***	***0.37***	***0.65***	***24,716***
	Total Construction Period Emissions	***70,778***	***1.1***	***1.9***	***71,411***

[a] CO_2e emissions based on GWPs of 1 for CO_2, 25 for CH_4, and 298 for N_2O.
[b] Inclusive of all barge-related emissions associated with Project construction, as all such barge traffic occurs in Texas state waters via the Gulf Intercoastal Waterway.

Table H3
Emissions (tons) of Criteria Air Pollutants and HAPs for CCL Midscale Trains 8 & 9 Project Commissioning [a]

Emission Source	NO_x	VOC	CO	PM_{10}	$PM_{2.5}$	SO_2	Total HAPs
Flares	141	1,052	87.0	--	--	1.5	0.02

[a] All commissioning emissions are assumed to occur in 2028.

Table H4
Emissions (tons) of Greenhouse Gases for CCL Midscale Trains 8 & 9 Project Commissioning [a]

Emission Source	CO_2	CH_4	N_2O	CO_2e[b]
Flares	362,280	904	0.5	385,029

[a] All commissioning emissions are assumed to occur in 2028.
[b] CO_2e emissions based on GWPs of 1 for CO_2, 25 for CH_4, and 298 for N_2O.

Table H5 Annual Emissions (tpy) of Criteria Air Pollutant and HAPs for CCL Midscale Trains 8 & 9 Project Operations							
Emission Source	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAPs**
Hot Oil Furnaces (2)	10.2	1.8	13.7	2.5	2.5	1.04	0.6
Thermal Oxidizers (2)	10.0	0.2	14.1	1.2	1.2	1.9	0.0
Flares - Multi-point Ground - normal operations (3)	3.5	5.5	13.9	0.0	0.0	0.0	0.0
Flares - Planned MSS	4.0	0.9	34.1	0.0	0.0	0.4	0.04
Marine Flare [a]	28.7	7.3	188.0	0.0	0.0	0.0	0.0
Condensate Storage/Loading [a]	7.6	1.2	4.4	0.4	0.4	0.03	0.08
Standby generator diesel engines (2)	1.5	0.2	0.8	0.0	0.0	0.0	0.0
Diesel Storage Tanks (2)	-	0.002	-	-	-	-	0.0
Amine Storage Tanks (2)	-	0.00001	-	-	-	-	0.0
Fugitive emissions	-	40.9	-	-	-	-	1.7
Miscellaneous MSS	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Total Annual Emissions	***65.4***	***57.8***	***268.9***	***4.2***	***4.2***	***3.4***	***2.5***
[a] The marine flare and condensate storage/loading operations will be shared with the existing Corpus Christi Liquefaction Project; emissions shown represent the Project emissions only.							

Table H6 Annual Emissions (tpy) of Greenhouse Gases for CCL Midscale Trains 8 & 9 Project Operations				
Emission Source	**CO_2**	**CH_4**	**N_2O**	**CO_2e[a]**
Hot Oil Furnaces (2)	41,938	2.3	0.5	42,132
Thermal Oxidizers (2)	170,426	14.2	0.1	170,806
Multi-point Ground Flare (3)	3,408	0.01	7.2	3,588
Flares - Planned MSS	158,439	448	0	169,715
Marine Flare [b,c]	43,280	333	0.1	51,622
Condensate Storage/Loading [b]	7,413	0.4	0.07	7,443
Standby generator diesel engines (2)	166	0.01	0.002	166
Fugitive Emissions	85	143	-	3,657
Nitrogen Removal Unit [d]	-	17	-	425
BOG Compressor MSS	-	0.1	-	1.6
Total Annual Emissions	***425,155***	***958.0***	***8.0***	***449,556***

a CO_2e emissions based on GWPs of 1 for CO_2, 25 for CH_4, and 298 for N_2O.
b. The marine flare and condensate storage/loading operations will be shared with the existing Corpus Christi Liquefaction Project; emissions shown represent the Project emissions only.
c CO_2 emissions from the marine flare include inert gas contribution from LNG carriers.
d Nitrogen Removal Unit is included in the air permit application but will be permitted separately.

Table H7 Maximum Short-Term Emissions (lb/hr) of Criteria Air Pollutant and HAPs for CCL Midscale Trains 8 & 9 Project Operations							
Emission Source	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAPs**
Hot Oil Furnaces (2)	4.60	0.82	5.88	1.12	1.12	0.46	0.28
Thermal Oxidizers (2)	2.8	0.0	3.9	0.3	0.3	0.6	0.004
Multi-point Ground Flare (3)	2.2	3.9	8.8	0.0	0.0	0.00	0.01
Flares - Planned MSS	-[a]	-[a]	-[a]	-	-	-[a]	-[a]
Marine Flare	-[b]	-[b]	-[b]	-	-	-[b]	-[b]
Condensate Storage/Loading	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]
Standby generator diesel engines (2)	31.0	3.7	17.0	1.0	1.0	0.04	0.03
Diesel Storage Tanks (2)	-	0.2	-	-	-	-	0.0
Amine Storage Tanks (2)	-	0.0003	-	-	-	-	0.0
Fugitive emissions	-	9.3	-	-	-	-	0.4
Miscellaneous MSS	-	0.00002	-	-	-	-	0.0
Total Short-Term Emissions	***40.6***	***17.9***	***35.6***	***2.4***	***2.4***	***1.1***	***0.7***

[a] The maximum short-term emission rates (NO_x - 558 lb/hr; CO - 3,138 lb/hr; VOC - 1,758 lb/hr; SO_2 - 0.6 lb/hr; total HAPs - 9.0 lb/hr) for the existing authorized multi-point ground flares will not increase from operation of the Project.

[b] The maximum short-term emission rates (NO_x - 389.7 lb/hr; CO - 1,552 lb/hr; VOC - 394 lb/hr; SO_2 - <0.01 lb/hr; total HAPs - 1.1 lb/hr) for the existing authorized marine flare will not increase from operation of the Project.

[c] The maximum short-term emission rates (NO_x - 5.1 lb/hr; CO - 3.0 lb/hr; VOC - 2.4 lb/hr; PM_{10} - 0.3 lb/hr; $PM_{2.5}$ - 0.3 lb/hr; SO_2 - 0.02 lb/hr; total HAPs - 0 lb/hr) for the existing authorized condensate storage/loading operations will not increase from operation of the Project.

Table H8 Annual Emissions (tpy) of Criteria Air Pollutants for Project Marine Vessels						
Emission Source	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**
LNG Carriers	15.86	1.39	6.85	1.10	1.01	0.12
Pilot Boats	0.28	0.0	0.09	0.005	0.005	0.0
Tugboats	4.12	0.44	11.45	0.09	0.09	0.02
Total Annual Emissions	***20.3***	***1.8***	***18.4***	***1.2***	***1.1***	***0.1***

Table H9 Annual Emissions (tpy) of Greenhouse Gases for Project Marine Vessels				
Emission Source	**CO_2**	**CH_4**	**N_2O**	**CO_2e [a]**
LNG Carriers	2,333	0.13	0.03	2,374
Pilot Boats	32	0.002	0.0001	32
Tugboats	1,505	0.02	0.07	1,526
Total Annual Emissions	***3,870***	***0.15***	***0.10***	***3,932***

[a] CO_2e emissions based on GWPs of 1 for CO_2, 25 for CH_4, and 298 for N_2O.

Table H10 Short-Term Emissions (lb/hr) of Criteria Air Pollutants for Project Marine Vessels						
Emission Source	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**
LNG Carriers [a]	95.0	7.4	14.3	7.3	6.7	0.6
Pilot Boats	7.01	0.09	2.35	0.13	0.13	0.01
Tugboats	12.7	1.3	35.4	0.3	0.3	0.1
Total Short-Term Emissions	***114.7***	***8.8***	***52.1***	***7.7***	***7.1***	***0.7***

[a] The LNG carrier emission rate is the maximum emission rate between the transit and in-port operations because both operations would not occur concurrently.

Table H11 Summary of Annual Emissions (tpy) of Criteria Air Pollutants and HAPs for the 2025-2028 Period								
Year	**Project Phase**	**NO_x**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Total HAPs**
2025	Construction	21.7	3.1	50.4	59.7	7.1	0.1	1.0
	Commissioning	0	0	0	0	0	0	0
	Operation	0	0	0	0	0	0	0
	2025 Total	***21.7***	***3.1***	***50.4***	***59.7***	***7.1***	***0.1***	***1.0***
2026	Construction [a]	44.6	5.9	92.6	61.5	8.8	1	1.6
	Commissioning	0	0	0	0	0	0	0
	Operation	0	0	0	0	0	0	0
	2026 Total	***44.6***	***5.9***	***92.6***	***61.5***	***8.8***	***0.5***	***1.6***
2027	Construction [a]	90.1	9.4	120.4	65.3	12.5	0.5	1.6
	Commissioning	0	0	0	0	0	0	0
	Operation	0	0	0	0	0	0	0
	2027 Total	***90.1***	***9.4***	***120.4***	***65.3***	***12.5***	***0.5***	***1.6***
2028	Construction	93.7	8.8	99.5	66.2	13.4	0.2	2.7
	Commissioning	141.0	87.0	1,052.0	-	-	1.5	0.02
	Operation [b]	67.0	36.0	167.0	3.4	2.9	2.6	1.5
	2028 Total	***301.7***	***131.8***	***1,318.5***	***69.7***	***16.3***	***4.3***	***4.2***

[a] Inclusive of all barge-related emissions associated with Project construction, as all such barge traffic occurs in Texas state waters via the Gulf Intercoastal Waterway.

[b] The operation emissions are estimated by applying a ratio of 0.58 (representing Train 8 operating 4 months and Train 9 operating 3 months of the year) to the emission rates, including the marine vessel emission rates assuming operation of an equivalent number of trains/months.

Table H12
Summary of Annual Emissions (tpy) of Greenhouse Gases for the 2025-2028 Period

Year	Emission Source	CO_2	CH_4	N_2O	CO_2e [a]
2025	Construction	7,216	0.1	0.3	7,286
	Commissioning	0	0	0	0
	Operation	0	0	0	0
	2025 Total	***7,216***	***0.1***	***0.3***	***7,286***
2026	Construction [b]	13,617	0.2	0.4	13,744
	Commissioning	0	0	0	0
	Operation	0	0	0	0
	2026 Total	***13,617***	***0.2***	***0.4***	***13,744***
2027	Construction [b]	25,442	0.4	0.7	25,665
	Commissioning	0	0	0	0
	Operation	0	0	0	0
	2027 Total	***25,442***	***0.4***	***0.7***	***25,665***
2028	Construction	24,503	0.4	0.7	24,716
	Commissioning	339,527	904	0.5	362,276
	Operation [c]	257,152	559	4.9	272,587
	2028 Total	***621,182***	***1,463***	***6.1***	***659,579***

[a] CO_2e emissions based on GWPs of 1 for CO_2, 25 for CH_4, and 298 for N_2O.

[b] Inclusive of all barge-related emissions associated with Project construction, as all such barge traffic occurs in Texas state waters via the Gulf Intercoastal Waterway.

[c] The operation emissions are estimated by applying a ratio of 0.58 (representing Train 8 operating 4 months and Train 9 operating 3 months of the year) to the emission rates, including the marine vessel emission rates assuming operation of an equivalent number of trains/months.

Table H13 Significance Analysis Results for the CCL Stage 3 Emission Sources, Including Midscale Trains 8 & 9 Project				
Pollutant	**Averaging Period**	**Highest Model-Predicted GLC [a] (μg/m^3)**	**Significant Impact Level (μg/m^3)**	**Model-Predicted GLC Greater than SIL?**
NO_2	1-hour	10.2 (0.5)	7.5	Yes
	Annual	0.85 (0.1)	1.0	No
CO	1-hour	167.8	2,000	No
	8-hour	91.0	500	No
PM_{10}	24-hour	1.0 (0.03)	5.0	No
$PM_{2.5}$	24-hour	1.08[b] (0.03)	1.2	No
	Annual	0.12[c] (0.02)	0.3	No
SO_2	1-hour	1.09 (0.04)	7.8	No
	3-hour	1.05 (0.01)	25	No

GLC = Ground-level concentration
SIL = Significant Impact Level
[a] Model-predicted impacts associated with the Midscale Trains 8 & 9 Project alone are shown in parentheses.
[b] Includes an estimated secondary $PM_{2.5}$ concentration of 0.16 μg/m^3.
[c] Includes an estimated secondary $PM_{2.5}$ concentration of 0.009 μg/m^3.

Table H14 NAAQS Analysis Results for the CCL Midscale Trains 8 & 9 Project [a]						
Pollutant	**Averaging Period**	**Highest Model-Predicted GLC (μg/m³)**	**Background Concentration [b] (μg/m³)**	**Total GLC (μg/m³)**	**NAAQS (μg/m³)**	**Total GLC Greater than NAAQS?**
NO_2	1-hour	139.9	33.4	173.3	188	No
	Annual	8.8	2.2	11.0	100	No
CO	1-hour	528.2	2,514	3,042	40,000	No
	8-hour	156.6	1,444	1,601	10,000	No
PM_{10}	24-hour	2.0	38.0	40.0	150	No
$PM_{2.5}$	24-hour	1.2	22.0	24.4[c]	35	No
	Annual	0.26	8.3	8.6[d]	9	No
SO_2	1-hour	35.9	19.9	55.8	196	No
	3-hour	3.1	9.1	12.2	1,300	No

GLC = Ground-level concentration
NAAQS = National Ambient Air Quality Standard
[a] NAAQS analysis is based on stationary source and marine vessel emissions associated with the entire CCL LNG Terminal, i.e., Stages 1/2 and 3 including Midscale Trains 8 & 9.
[b] Accounts for 2023 ambient monitoring data
[c] Includes an estimated secondary $PM_{2.5}$ concentration of 1.15 μg/m³.
[d] Includes an estimated secondary $PM_{2.5}$ concentration of 0.08 μg/m³.

Appendix I

Noise Tables and NSA Figure

Table I1
Sound Levels and Relative Loudness

Description of Sound	Sound Level (dBA)	Loudness Perception Relative to Baseline
Threshold of pain	140	256
Jet taking off (200-foot distance)	130	128
Operating heavy equipment	120	64
Night club with music	110	32
Construction site	100	16
Boiler room	90	8
Freight train (100-foot distance)	80	4
Classroom chatter	70	2
Conversation (3-foot distance)	60	1 (Baseline)
Urban residence	50	1/2
Soft whisper (5-foot distance)	40	1/4
North rim of Grand Canyon	30	1/8
Silent study room	20	1/16
Threshold of hearing (1,000 hertz)	0	1/64

Source: Adapted from U.S. Department of Labor (2016) Occupational Health and Safety Administration Technical Manual https://www.osha.gov/dts/osta/otm/new_noise/index.html

Table I2 Ambient Sound Levels at NSAs			
NSA	**Distance and Direction from Project**	**Description**	**Ambient Sound Level, L_{dn} (dBA) [a, b]**
1	2.1 miles SW	328 County Club Drive, Portland, TX	53
2	2.2 miles SW	Northshore County Club, Portland, TX	52
3	1.7 miles W	Residential deployment, Portland, TX	50
4	1.6 miles W	Residential deployment, Portland, TX	50
5	1.6 miles NW	Residential deployment, Gregory, TX	61
6	1.6 miles NW	Alamo St & Lee Ave. Gregory, TX	54
7	1.9 miles N	4735 Texas Rt. 35 Isolated Residence	62
8	2.5 miles NE	McCampbell Rd isolated Residence	50
9	2.1 miles SW	Ingleside High School Ingleside, TX	51

[a] NSAs 1, 2, 3, 4, 6, and 9 reference the post-construction Liquefaction Project survey conducted May 4, 2021. NSAs 5, 7, and 8 Liquefaction Project levels were derived based on modeling using 2018 on-site surveys (three large scale trains, OSBL, equipment, and auxiliary facilities running under normal full load operation) and ambient levels from the 2019 Stage 3 Project EA.

[b] Ambient approached or exceeded 55 dBA L_{dn} in some locations, due to non-Liquefaction Project sound (e.g., traffic, insects, other industrial facilities, etc.)

Table I3
Construction Noise Analysis

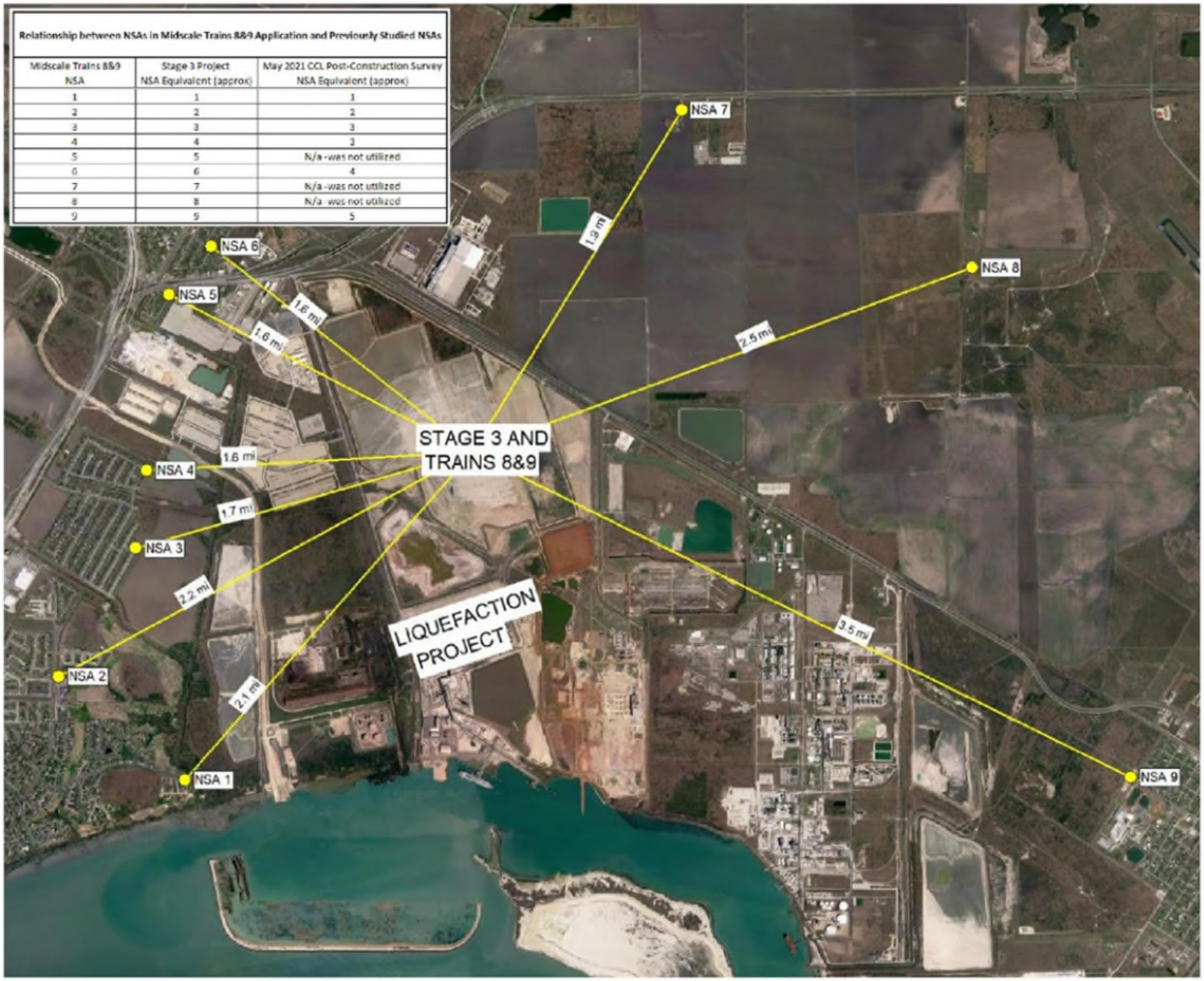
Construction Phase/Activity	NSA 4 (1.6 miles, W)			NSA 5 (1.6 miles, NW)			NSA 6 (1.6 miles, NW)		
	Existing Ambient with Liquefaction Project, L_{dn} (dBA)	Construction Noise Contribution, L_{dn} (dBA)	Cumulative (Ambient + Construction), L_{dn} (dBA)	Existing Ambient with Liquefaction Project, L_{dn} (dBA)	Construction Noise Contribution, L_{dn} (dBA)	Cumulative (Ambient + Construction), L_{dn} (dBA)	Existing Ambient with Liquefaction Project, L_{dn} (dBA)	Construction Noise Contribution, L_{dn} (dBA)	Cumulative (Ambient + Construction), L_{dn} (dBA)
Site Preparation	54	48	55	61	48	61	54	48	55
Excavation	54	45	55	61	45	61	54	45	55
Foundation Placement	54	47	55	61	47	61	54	47	55
Installation of Mechanical Equipment	54	44	54	61	44	61	54	44	54
Building Construction	54	53	57	61	53	62	54	53	57
Finishing and Site Cleanup	54	39	54	61	39	61	54	39	54

Table I4
Cumulative Noise Impact for the CCL Terminal at Normal Full Load Operation

NSA	Distance & Direction from Stage 3 Project and Proposed Project	Ambient (non LNG sound) + Liquefaction Project	Liquefaction Project Only	Stage 3 Project Only	Proposed Project Only	Total Stage 3 Project + Proposed Project Combined	Total CCL Terminal Contribution Without Ambient (2+3+4)	Total CCL Terminal Combined plus Ambient (1+5)	Increase Above Existing Ambient
		L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*
1	2.1 miles SW	53	48	40	36	41	49	53	-
2	2.2 miles SW	52	48	41	38	43	49	53	1
3	1.7 miles W	50	47	45	41	46	50	52	2
4	1.6 miles W	50	46	45	42	47	50	52	2
5	1.6 miles NW	61	44	44	43	47	49	61	-
6	1.6 miles NW	54	44	45	43	47	49	55	1
7	1.9 miles N	62	42	44	38	45	46	62	-
8	2.5 miles NE	50	40	37	31	38	42	50	-
9	2.1 miles SW	51	39	34	29	35	41	51	-

Table I5 Estimate of the Total CCL Facility with a Single Midscale Startup Flaring									
NSA	**Distance & Direction from Stage 3 Project and Proposed Project**	**Ambient (non LNG Sound) + Liquefaction Project**	**Liquefaction Project Only**	**Eight Midscale Trains in Operation, 9th in Commissioning**	**Stage 3 Ground Flare Only**	**Total Stage 3 Project + Trains 8&9 During Startup Flaring**	**Total CCL Terminal During Startup Flaring without Ambient**	**Total CCL Terminal During Startup Flaring plus Ambient**	**Increase Above Existing Ambient**
		L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)	L_{dn} (dBA)
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*
1	2.1 miles SW	53	48	41	45	47	50	54	1
2	2.2 miles SW	52	48	43	48	49	51	54	2
3	1.7 miles W	50	47	46	50	52	53	54	4
4	1.6 miles W	50	46	47	50	52	53	54	4
5	1.6 miles NW	61	44	47	50	51	52	62	1
6	1.6 miles NW	54	44	47	50	52	52	56	2
7	1.9 miles N	62	42	45	49	51	51	62	0
8	2.5 miles NE	50	40	38	45	46	47	51	1
9	2.1 miles SW	51	39	35	44	44	46	52	1

Table I6 C-Weighted Sound Levels from Total CCL Facility					
NSA	**Distance and Direction from Project**	**Liquefaction Project Only (dBC)**	**Stage 3 Project Trains 1-7 Only (dBC)**	**Project Only (dBC)**	**Total CCL Terminal Combined (dBC)**
1	2.1 miles SW	62	52	48	62
2	2.2 miles SW	64	54	51	65
3	1.7 miles W	61	56	53	63
4	1.6 miles W	61	55	52	62
5	1.6 miles NW	59	55	54	62
6	1.6 miles NW	59	55	55	62
7	1.9 miles N	57	56	50	60
8	2.5 miles NE	56	50	44	57
9	2.1 miles SW	56	48	42	56



Relationship between NSAs in Midscale Trains 8&9 Application and Previously Studied NSAs

Midscale Trains 8&9 NSA	Stage 3 Project NSA Equivalent (approx)	May 2021 CCL Post-Construction Survey NSA Equivalent (approx)
1	1	1
2	2	2
3	3	3
4	4	3
5	5	N/a -was not utilized
6	6	4
7	7	N/a -was not utilized
8	8	N/a -was not utilized
9	9	5

Figure I1 NSAs Closest to the Project

Appendix J

Reliability and Safety Discussion

Terminal Facilities

LNG Facilities 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 and/or operating 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 Project would be regulated by the DOT 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 U.S.C. § 1671 et seq.). PHMSA's LNG safety regulations are codified in 49 CFR Part 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 U.S.C. § 60101 et seq.), and 49 CFR Part 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 a 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 Part 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 Part 193, would be subject to PHMSA's inspection and enforcement programs to ensure compliance with the requirements of 49 CFR Part 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 Part 105 and 33 CFR Part 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 Part 105 and 33 CFR Part 127. If the facilities are constructed and become operational as designed, the facilities would be subject to the Coast Guard inspection program to ensure compliance with the requirements of 33 CFR Part 105 and 33 CFR Part 127.

The 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 the DOT PHMSA requirements in 49 CFR Part 193[1]. In addition, FERC's *Guidance Manual for Environmental Report Preparation*[2] (2017 Guidance Manual) for applications filed under the Natural Gas Act, Volume II, issued February 2017, provides further guidance on the type and level of information that should be provided for our evaluation of the hazards associated with proposed LNG facilities per 18 CFR § 380.12 (m) and (o). As suggested in our Guidance Manual, the level of detail recommended for the reliability, safety, and engineering information reflects a completed front-end engineering design (FEED) of a project. The design information should 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. 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 Department of Defense (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.[3] On March 16, 2023, the FERC received a response letter from the DOD Military Aviation and Installation Assurance Siting Clearinghouse indicating that the CCL Midscale Trains 8 & 9 Project would have a minimal impact on military operations conducted in the area.

PHMSA Siting Requirements and 49 CFR Part 193 Subpart B Determination

Siting LNG facilities, as defined in 49 CFR Part 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 Part 193, Subpart B. The Commission's regulations under 18 CFR § 380.12(o)(14) require CCL to identify how the proposed design complies with applicable federal siting requirements, including PHMSA's regulations under 49 CFR Part 193, Subpart B. The scope of PHMSA's siting authority under 49 CFR Part 193 applies to LNG facilities used in the transportation of gas by pipeline subject to the federal pipeline safety laws and 49 CFR Part 192.[4]

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1 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 Part 193 will still be the applicable federal regulation that applies the LNG facility. Furthermore, 18 CFR §380.12 (o) (15) was updated to codify existing practice for geotechnical investigations and for evaluating seismic and other natural hazards.

2 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.

3 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.

4 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.

The regulations in 49 CFR Part 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 Part 193, Subpart B, with regulatory preemption in the event of conflict. The following sections of 49 CFR Part 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 thermal exclusion zones 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 miles per hour (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 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 includes but 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.[5]

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:

- 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;[6]
- 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;[7] and
- 10,000 Btu/ft^2-hr - This level cannot extend beyond the plant property line that can be built upon.[8]

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 provided guidance on the determination of single accidental leakage sources on their website of frequently asked questions, which indicates 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.[9]

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

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5 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. Approved alternate models are available via https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-exclusion-zones.

6 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.

7 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.

8 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.

9 PHMSA, LNG Plant Requirements: Frequently Asked Questions | PHMSA (dot.gov), https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions#ds1ntRequirements:, accessed January 2024.

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 49 CFR Part 193 Subpart B.[10]

In accordance with the August 31, 2018 MOU, PHMSA issued an LOD on February 14, 2024[11] to the Commission on the 49 CFR Part 193 Subpart B siting requirements. The LOD provided PHMSA's analysis and conclusions regarding the proposed Project's compliance with 49 CFR Part 193, Subpart B for the Commission to consider in its decision to authorize, with or without modification or conditions, or deny an application.

Coast Guard Safety Regulatory Requirements and Letter of Recommendation

LNG Marine Vessel Historical Record

Since 1959, marine vessels have transported LNG without a major release of cargo or a major accident involving an LNG marine vessel. There are approximately 795 LNG marine vessels in operation routinely transporting LNG to approximately 220 import/export terminals currently in operation worldwide.[12,13] Since U.S. LNG terminals first began operating under FERC jurisdiction in the 1970s, there have been thousands of individual LNG marine vessel arrivals at terminals in the U.S. For more than 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways.

A review of the history of LNG maritime transportation indicates that there has not been a serious accident at sea or in a port which resulted in a spill due to rupturing of the cargo tanks. However, insurance records, industry sources, and public websites identify a number of incidents involving LNG marine vessels, including minor collisions with other marine vessels of all sizes, groundings, minor LNG releases during cargo unloading operations, and mechanical/equipment failures typical of large vessels. Some of the more significant occurrences, representing the range of incidents experienced by the worldwide LNG marine vessel fleet, are described below:

- **El Paso Paul Kayser** grounded on a rock in June 1979 in the Straits of Gibraltar during a loaded voyage from Algeria to the United States. Extensive bottom damage to the ballast tanks resulted; however, no cargo was released because no damage was done to the cargo tanks. The entire cargo of LNG was subsequently transferred to another LNG marine vessel and delivered to its U.S. destination.
- **Tellier** was blown by severe winds from its docking berth at Skikda, Algeria in February 1989 causing damage to the loading arms and the LNG marine vessel and shore piping. The cargo loading had been secured just before the wind struck, but the loading arms had not been drained. Consequently, the LNG remaining in the loading arms spilled onto the deck, causing fracture of some plating.
- **Mostefa Ben Boulaid** had an electrical fire in the engine control room during unloading at Everett, Massachusetts on February 5, 1996. The LNG marine vessel crew extinguished the fire and the ship completed unloading.

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10 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.

11 USDOT PHMSA Letter of Determination, dated February 14, 2024, filed on eLibrary under Accession Number 20240214-3053.

12 Vessel Finder, Vessel Database, LNG Tankers, https://www.vesselfinder.com/vessels?type=604, accessed February 2024.

13 International Group of Liquefied Natural Gas Importers (GIIGNL), Annual Report, 2023 Edition, World LNG Maps, https://giignl.org/wp-content/uploads/2023/07/GIIGNL_2023_Annual_Report_July14.pdf, accessed February 2024.

- **Khannur** had a cargo tank overfill into the LNG marine vessel's vapor handling system on September 10, 2001, during unloading at Everett, Massachusetts. Approximately 100 gallons of LNG were vented and sprayed onto the protective decking over the cargo tank dome, resulting in several cracks. After inspection by the Coast Guard, the Khannur was allowed to discharge its LNG cargo.
- **Mostefa Ben Boulaid** had LNG spill onto its deck during loading operations in Algeria in 2002. The spill, which is believed to have been caused by overflow rather than a mechanical failure, caused significant brittle fracturing of the steelwork. The LNG marine vessel was required to discharge its cargo, after which it proceeded to dock for repair.
- **Norman Lady** was struck by the USS Oklahoma City nuclear submarine while the submarine was rising to periscope depth near the Strait of Gibraltar in November 2002. The 87,000 m^3 LNG marine vessel, which had just unloaded its cargo at Barcelona, Spain, sustained only minor damage to the outer layer of its double hull but no damage to its cargo tanks.
- **Tenaga Lima** grounded on rocks while proceeding to open sea east of Mopko, South Korea due to strong current in November 2004. The shell plating was torn open and fractured over an approximate area of 20 by 80 feet, and internal breaches allowed water to enter the insulation space between the primary and secondary membranes. The LNG marine vessel was refloated, repaired, and returned to service.
- **Golar Freeze** moved away from its docking berth during unloading on March 14, 2006, in Savannah, Georgia. The powered emergency release couplings on the unloading arms activated as designed, and transfer operations were shut down.
- **Catalunya Spirit** lost propulsion and became adrift 35 miles east of Chatham, Massachusetts on February 11, 2008. Four tugs towed the LNG marine vessel to a safe anchorage for repairs. The Catalunya Spirit was repaired and taken to port to discharge its cargo.
- **Al Gharrafa** collided with a container ship, Hanjin Italy, in the Malacca Strait off Singapore on December 19, 2013. The bow of the Al Gharrafa and the middle of the starboard side of the Hanjin were damaged. Both ships were safely anchored after the incident. No loss of LNG was reported.
- **Al Oraiq** collided with a freight carrier, Flinterstar, near Zeebrugge, Belgium on October 6, 2015. The freight carrier sank, but the Al Oraiq was reported to have sustained only minor damage to its bow and no damage to the LNG cargo tanks. According to reports, the Al Oraiq took on a little water but was towed to the Zeebrugge LNG terminal where its cargo was unloaded using normal procedures. No loss of LNG was reported.
- **Al Khattiya** suffered damage after a collision with an oil tanker off the Port of Fujairah on February 23, 2017. Al Khattiya had discharged its cargo and was anchored at the time of the incident. A small amount of LNG was retained within the LNG marine vessel to keep the cargo tanks cool. The collision damaged the hull and two ballast tanks on the Al Khattiya, but did not cause any injury or water pollution. No loss of LNG was reported.
- **Assem** collided with a very large crude carrier Shinyo Ocean off the Port of Fujairah on March 26, 2019. The Shinyo Ocean suffered severe portside hull height breach and the Assem had damage to its bow. Both marine vessels were unloaded at the time of the collision and subsequently no LNG or oil was released. Aseem was moved to port for anchorage and Shinyo Ocean was relocated to another point of anchorage.

- **Adam LNG** was struck while anchored by a bulk carrier off Gibraltar on August 29, 2022. The bulk carrier sustained a hull breach and was intentionally grounded to avoid sinking. The Adam had unloaded its cargo prior to the allision. The allision resulted in a superficial dent on the Adam's bow and did not result in water ingress.

LNG Marine Vessel Safety Regulatory Oversight

The Coast Guard exercises regulatory authority over LNG marine vessels under 46 CFR Part 154, which contains the U.S. safety standards for self-propelled LNG marine vessels transporting bulk liquefied gases. The LNG marine vessels visiting the proposed facility would also be constructed and operated in accordance with the International Marine Organization (IMO), *International Convention for the Safety of Life at Sea*. Since 1986, the *International Convention for the Safety of Life at Sea* Chapter VII requires LNG marine vessels to meet IMO, *International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk.* LNG marine vessels built from October 31, 1976 to July 1, 1986 would have to comply with IMO, *Code for Construction and Equipment of Ships Carrying Liquefied Gases in Bulk* and LNG marine vessels in built and in operation before then would have to meet IMO, *Code for Existing Ships Carrying Liquefied Gas in Bulk.* Under 46 CFR Part 154, no ship entering U.S. waters may carry a cargo of bulk liquid hazardous material without possessing a valid IMO Certificate of Fitness and either a Coast Guard Certificate of Inspection (for U.S. flag vessels) or a Coast Guard Certificate of Compliance (for foreign flag vessels). These documents 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.

Pilotage is compulsory for foreign marine vessels and U.S. marine vessels under registry in foreign trade when in U.S. waters. All deep draft marine vessels currently entering the shared waterway would employ a U.S. pilot. The National Vessel Movement Center in the U.S. would require a 96-hour advance notice of arrival for deep draft marine vessels calling on U.S. ports. During transit, LNG marine vessels would be required to maintain voice contact with controllers and check in on designated frequencies at established way points.

The LNG marine vessels that would deliver or receive LNG to or from a facility would also need to comply with various U.S. and international security requirements. The IMO adopted the *International Ship and Port Facility Security Code* in 2002. This code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships; improve security aboard ships and ashore; and reduce the risk to passengers, crew, and port personnel on board ships and in port areas. All LNG marine vessels, as well as other cargo vessels (e.g., 500 gross tons and larger), and ports servicing those regulated vessels, must adhere to the IMO standards. Some of the IMO requirements for ships are as follows:

- marine vessels must develop security plans and have a Vessel Security Officer;
- marine vessels must have a ship security alert system to transmit ship-to-shore security alerts identifying the ship, its location, and indication that the security of the ship is under threat or has been compromised;
- marine vessels must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with ships; and
- marine vessels may have equipment onboard to help maintain or enhance the physical security of the ship.

In 2002, the Maritime Transportation Security Act (MTSA) was enacted by the U.S. Congress and aligned domestic regulations with the maritime security standards of the IMO, *International Ship and Port Facility Security Code;* IMO, *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk;* and IMO, *International Convention for the Safety of Life at Sea*. The Coast

Guard's regulations in 33 CFR Part 104 require marine vessels to conduct a vessel security assessment and develop a vessel security plan that addresses each vulnerability identified in the vessel security assessments. All LNG marine vessels servicing the facility would have to comply with the MTSA requirements and associated regulations while in U.S. waters.

The Coast Guard 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 MTSA of 2002 (46 U.S.C. section 701). The Coast Guard 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 Coast Guard also has authority for LNG facility security plan review, approval, and compliance verification as provided in 33 CFR Part 105.

The Coast Guard 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 includes 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, CCL would be required to submit copies of its Operations and Emergency Manuals to the COTP for examination.

CCL Midscale Trains 8 & 9 Project's Waterway Suitability Assessment

An LNG marine vessel's transit to and from the LNG terminal would enter or exit at Port Aransas and pass by Harbor Island and Pelican Island, before turning at Ingleside at the Bay near Cooks Island. The LNG marine vessel would head north by Quinta Island before reaching its final destination at the LNG terminal of the CCL Midscale Trains 8 & 9 facility. Pilotage is compulsory for foreign vessels and U.S. marine vessels under registry in foreign trade when in U.S. waters. All deep draft marine vessels currently entering the shared waterway would employ a U.S. pilot. The National Vessel Movement Center in the U.S. would require a 96-hour advance notice of arrival for deep draft vessels calling on U.S. ports. An LNG marine vessel's port time with pilotage would be approximately 3 to 4 hours for inbound and outbound transits with transit speeds of approximately 4 to 16 knots depending on the location, weather, sea state, and vessel traffic in the area. During transit, vessels would be required to maintain voice contact with controllers and check in on designated frequencies at established way points.

Both the Coast Guard regulations under 33 CFR Part 127 and FERC regulations under 18 CFR § 157.21, require an applicant who intends to build an LNG terminal to submit a LOI to the Coast Guard no later than the date that the owner/operator initiates pre-filing with FERC, but, in all cases, at least 1 year prior to the start of construction. In addition, the applicant must submit a Preliminary WSA to the COTP with the LOI.

The Preliminary WSA provides an initial explanation of the port community and the proposed facility and transit routes. It provides an overview of the expected impacts LNG operations may have on the port and the waterway. Generally, the Preliminary WSA does not contain detailed studies or conclusions. This document is used by the COTP to begin his or her evaluation of the suitability of the waterway for LNG marine traffic. The Preliminary WSA must provide an initial explanation of the following:

- port characterization;

- characterization of the LNG facility and the LNG marine vessel route;
- risk assessment for maritime safety and security;
- risk management strategies; and
- resource needs for maritime safety, security, and response.

A Follow-On WSA must be provided no later than the date the owner/operator files an application with FERC, but in all cases at least 180 days prior to transferring LNG. The Follow-on WSA must provide a detailed and accurate characterization of the waterfront facilities handling LNG, the LNG marine vessel route, and the port area. The Follow-on WSA provides a complete analysis of the topics outlined in the Preliminary WSA. It should identify credible security threats and navigational safety hazards for the LNG marine vessel traffic, along with appropriate risk management measures and the resources (i.e., federal, state, local, and private sector) needed to carry out those measures. Until a facility begins operation, applicants must also annually review their WSAs and submit a report to the COTP as to whether changes are required. This document is reviewed and validated by the Coast Guard and forms the basis for the agency's LOR to the FERC.

In order to provide the Coast Guard COTPs/Federal Maritime Security Coordinators, members of the LNG industry, and port stakeholders with guidance on assessing the suitability of a waterway for LNG marine traffic, the Coast Guard has published a Navigation and Vessel Inspection Circular – *Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas Marine Traffic* (NVIC 01-11).

NVIC 01-11 directs the use of the three concentric Zones of Concern, based on LNG marine vessels with a cargo carrying capacity up to 265,000 m^3, used to assess the maritime safety and security risks of LNG marine traffic. The Zones of Concern are:

- Zone 1 – impacts on structures and organisms are expected to be significant within 500 meters (1,640 feet). The outer perimeter of Zone 1 is approximately the distance to thermal hazards of 37.5 kilowatts per square meter (kW/m^2) (approximately 12,000 Btu/ft^2-hr) from a pool fire;[14]
- Zone 2 – impacts would be significant but reduced, and damage from radiant heat levels are expected to transition from severe to minimal between 500 and 1,600 meters (1,640 and 5,250 feet). The outer perimeter of Zone 2 is approximately the distance to thermal hazards of 5 kilowatts per square meter (kW/m^2) (1,600 Btu/ft^2-hr) from a pool fire;[15] and
- Zone 3 – impacts on people and property from a pool fire or an unignited LNG spill are expected to be minimal between 1,600 meters (5,250 feet) and a conservative maximum distance of 3,500 meters (11,500 feet or 2.2 miles). The outer perimeter of Zone 3 should be considered the vapor cloud dispersion distance to the lower flammability limit from a

[14] The 37.5 kW/m^2 (approximately 12,000 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 less than 10 seconds, and 100 percent mortality in approximately 30 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.

[15] The 5 kW/m^2 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 an average 10-minute exposure.

credible worst-case unignited release. Impacts to people and property could be significant if the vapor cloud reaches an ignition source and burns back to the source.

Like the Coast Guard, FERC staff also uses characteristics of the structures and population within the Zones of Concern for accidental and intentional events to identify challenges to evacuating or sheltering in place to inform its review of emergency response plans and corresponding cost-sharing plans, which are described in more detail in the Onsite and Offsite Emergency Response Plans Section.

On August 15, 2022, CCL submitted an LOI to the COTP, Sector Corpus Christi, to notify the Coast Guard of the increased ship traffic related to the proposed CCL Midscale Trains 8 & 9 Project. On August 18, 2022, the COTP accepted CCL's previous WSA dated February 29, 2016 as the preliminary WSA for this expansion project. CCL submitted the Follow-on WSA to the Coast Guard on February 9, 2023 and requested a LOR to confirm that the waterway is suitable to accommodate the proposed increase in the maximum marine vessel traffic from the 400 LNG carriers per year that was authorized as part of the Stage 3 Project to 480 LNG carriers per year. On January 25, 2024, the FERC received a response letter from the Coast Guard indicating that the CCL Midscale Trains 8 & 9 Project would have a minimal impact on the waterway.

U.S. Coast Guard Letter of Recommendation and Analysis

Once the applicant submits a complete Follow-On WSA, the Coast Guard reviews the document to determine if it presents a realistic and credible analysis of the public safety and security implications from LNG marine traffic both in the waterway and when in port. As required by its regulations (33 CFR § 127.009), the Coast Guard is responsible for issuing a LOR to the FERC regarding the suitability of the waterway for LNG marine traffic with respect to the following items:

- physical location and description of the facility;
- the LNG marine vessel's characteristics and the frequency of LNG shipments to or from the facility;
- waterway channels and commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by LNG marine vessels en route to the facility, within 25 kilometers (15.5 miles) of the facility;
- density and character of marine traffic in the waterway;
- locks, bridges, or other manmade obstructions in the waterway;
- depth of water;
- tidal range;
- protection from high seas;
- natural hazards, including reefs, rocks, and sandbars;
- underwater pipes and cables; and
- distance of berthed LNG marine vessels from the channel and the width of the channel.

The Coast Guard may also prepare an LOR Analysis, which serves as a record of review of the LOR and contains detailed information along with the rationale used in assessing the suitability of the waterway for LNG marine traffic.

In a letter dated January 25, 2024, the Coast Guard issued an LOR and LOR Analysis to FERC stating that the Corpus Christi and La Quinta Ship Channels would be considered suitable for accommodating the type and frequency of LNG marine traffic associated with this Project. As part of its assessment of the safety and security aspects of this Project, the COTP Sector Corpus Christi consulted a variety of stakeholders including the Port of Corpus Christi, local facility security representatives, the Aransas-Corpus Christi Pilots Association, and maritime stakeholders. The LOR was based on a comprehensive review of the applicant's WSA, including an assessment of the risks posed by these transits and validation of the risk management measures proposed by the applicant in the WSA.

The Coast Guard regulations in 33 CFR Part 127 require that applicants annually review WSAs until a facility begins operation and submit a report to the Coast Guard identifying any changes in conditions, such as changes to the port environment, the LNG facility, or the LNG marine vessel route, that would affect the suitability of the waterway for LNG marine traffic.

The Coast Guard's LOR is a recommendation, regarding the current status of the waterway, to the FERC, the lead agency responsible for siting the on-shore LNG facility. Neither the Coast Guard nor the FERC has authority to require waterway resources of anyone other than the applicant under any statutory authority or under the Emergency Response Plan (ERP) or the Cost-Sharing Plan. As stated in the LOR, the Coast Guard would assess each transit on a case-by-case basis to identify what, if any, safety and security measures would be necessary to safeguard the public health and welfare, critical marine infrastructure and key resources, the port, the marine environment, and vessels. Under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA, and the Security and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG marine vessel movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port, or marine environment. If this Project is approved and if appropriate resources are not in place prior to LNG marine vessel movement along the waterway, then the COTP would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address navigational safety and maritime security considerations.

LNG Facility Security Regulatory Requirements

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 13.32 covers security plans and should reference any security specifications in 13.F.4, security threat and vulnerability analyses in 13.G.8, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D. While regulatory requirements and general review and recommendations are included, details of these systems are not described in order to protect Critical Energy Infrastructure Information under 18 CFR § 388.113 and Security Sensitive Information protected under 49 CFR Part 1520.

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 Coast Guard for review and approval before commencement of operations of the proposed Project facilities. Some responsibilities of the owner/operator include, but are not limited to:

- designating a Facility Security Officer (FSO) 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.

Similarly, FERC staff recognize that one of the first steps in defining security requirements is understanding the security threats, vulnerabilities, and risks. However, the FSA is not required to be conducted until after a FERC application that establishes siting. Therefore, the 2017 Guidance Manual suggest applicants provide sufficient information to demonstrate that the facilities would be designed, installed, and operated to meet federal regulations and that the level of security and safety is consistent with the security threats and vulnerabilities at the project location. Similarly, NFPA 59A (2019 edition) added language in section 5.2.1 that requires a security threat and vulnerability analysis as part of a written plant and site evaluation that identifies safety and security measures incorporated in the design and operation of the plant. The approach of development of preliminary design based on preliminary risk analyses is also consistent with other codes, standards, and recommended and generally accepted good engineering practices, such as Unified Facilities Criteria (UFC) 4-020-01, *DoD Security Engineering Facilities Planning Manual*, which indicates the procedures includes the development of preliminary design criteria based on consideration of the assets associated with a facility in terms of their value to their users and the likelihoods that different aggressors will target them, and that preliminary design criteria are evaluated using a preliminary risk analysis. The 2017 Guidance Manual also suggests the FSA prepared for or submitted to Coast Guard in accordance with 33 CFR §105.305 may satisfy the Security threat, vulnerability, and risk assessment (TVRA) in Appendix 13.G.8. FERC staff also recognize that the Security TVRA may reference applicable codes and standards that can provide a more consistent basis, definition, and quantification of threats, vulnerabilities, and risks, including, but not limited to, the following:

- American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS), *Guidelines for Analyzing and Managing the Security Vulnerabilities of Fixed Chemical Sites*;

- AIChE CCPS, *Guidelines for Chemical Transportation Safety, Security, and Risk Management*;
- American Petroleum Institute (API), *Security Vulnerability Assessment Methodology for the Petroleum and Petrochemical Industries*;
- API, *Security Guidelines for the Petroleum Industry*;
- American Society for Industrial Security (ASIS) RA.1, *Risk Assessment Standard*;
- ASIS, *General Security Risk Assessment Guideline*;
- International Organization for Standardization (ISO) 31000, *Risk Management, Principles and Guidelines*; and
- ISO 31010, *Risk Management, Risk Assessment Techniques.*

The Security TVRA then informs commensurate security requirements to be included in the FSP, which may be beyond the security requirements under 33 CFR 105, 33 CFR 127, and 49 CFR 193 described in more detail in sub-sections. If the Project is authorized, constructed, and operated, it would be subject to the security requirements of 33 CFR Part 105, 33 CFR 127, and 49 CFR Part 193, Subpart J and the respective Coast Guard and PHMSA inspection and enforcement programs.

We also recognize that the CCL facility is currently operating with a Coast Guard-approved FSA and FSP. Furthermore, if the CCL Terminal FSP is amended, CCL stated in the application that any updates to the FSP will be shared with the Coast Guard in accordance with 33 CFR Part 105 and the updated FSP would be coordinated with them. However, FERC staff recommendations and conclusions are based upon, in part, the security risks and security design of the proposed Project. Therefore, we recommend in section D of the EA that prior to commencement of service, CCL should file, for review and approval, any proposed revisions to the security plan and physical security of the plant.

Lighting

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 13.32 covers security plans, including lighting, and should reference any security specifications in 13.F.4, security threat and vulnerability analyses in 13.G.8, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D. While regulatory requirements and general review and recommendations are included, details of these systems are not described in order to protect Critical Energy Infrastructure Information under 18 CFR § 388.113 and Security Sensitive Information protected under 49 CFR Part 1520.

Title 33 CFR § 105.275(a) requires the waterfront facility owner or operator ensure implementation of security measures and have the capability to continuously monitor, through a combination of lighting, security guards, waterborne patrols, automatic intrusion detection devices, or surveillance equipment as specified in the approved FSP. Title 33 CFR § 105.305(a) requires the waterfront facility owner or operator ensure that background information, including lighting, is provided to the person(s) who will conduct the FSA, and 33 CFR § 105.305(d) requires that the written FSA report is prepared and included as part of the FSP and must contain a description of existing security measures, including lighting. Similarly, 33 CFR § 105.400 requires the FSO ensure the FSP is developed and implemented for each facility for which he or she is designated as FSO and it must address each vulnerability identified in the FSA, it must be submitted for approval to the cognizant COTP in a written or electronic format, and it must be protected in accordance with 49 CFR 1520.

In addition, 33 CFR § 127.109 requires (a) the marine transfer area for LNG have a lighting system and separate emergency lighting; (b) all outdoor lighting be located or shielded so that it is not confused with any aids to navigation and does not interfere with navigation on the adjacent waterways; and (c) the lighting system provide an average illumination on a horizontal plane one meter (3.3 feet) above the deck that is (1) 54 lux (five foot-candles) at any loading flange; and (2) 11 lux (one foot-candle) at each work area. In addition, 33 CFR § 127.109 (d) requires the emergency lighting provide lighting for the operation of the (1) ESD system; (2) communications equipment; and (3) firefighting equipment.

Title 49 CFR § 193.2911 requires where security warning systems are not provided for security monitoring under § 193.2913, the area around the facilities listed under § 193.2905(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 foot-candles) between sunset and sunrise.

Similarly, FERC staff generally look for multiple layers of protection in terms of security to minimize potential impacts to the safety of the public, including lighting. Therefore, although it is unclear as to whether lighting is required under 33 CFR § 105.275 in all cases and 49 CFR § 193.2911 seems to allow for lighting to be less than 2.2 lux if there are security monitoring systems provided, we recognize that lighting assists in deterring intruders through increasing the likelihood of visually detecting potential physical breaches. FERC staff also recognize IESNA G-1-03, *Guideline for Security Lighting for People, Property, and Public Spaces*, and may also provide additional guidance for security lighting.

FERC staff also recognize higher lighting illuminance is often recommended in standards or required in other regulations of similar facilities to reduce human error and safeguard personnel during operation and construction, such as Occupational Safety and Health Administration's (OSHA) 29 CFR Parts 1910 and 1926, respectively. For example, 29 CFR § 1910.120 specify a minimum of 3 foot candles (30 lux) for access ways, storage areas, loading platforms, refueling areas, and field maintenance areas as well as where concrete placement and excavation occurs, 5 foot candles (50 lux) in most other indoor and outdoor areas, 10 foot candles (100 lux) in mechanical and electrical equipment rooms, storage rooms, living quarters and lavatories, and 30 foot candles (320 lux) in areas of first aid stations, infirmaries, and offices. In addition, 29 CFR § 1915.82 for shipyards has similar requirements of 3- to 30-foot candles (30 to 320 lux) for similar areas. Other OSHA illumination and lighting requirement exist, but generally use broad performance based language to provide adequate illumination as needed to permit safe performance of the required task (e.g., 29 § CFR 1910.268(b) for telecommunications, 29 CFR 1910.269(w)(4) for electric power generation, transmission, and distribution, 29 CFR 1910.303 for switchboards, panelboards motor control centers installed indoors, etc.) or pertain to electrical wiring or of lighting (e.g., 29 CFR 1915.82(b)(1) for protecting non-recessed temporary light bulbs with guards, 29 CFR 1915.82(d) for use of explosion proof, self-contained lights approved by a nationally recognized testing laboratory for areas at or above 10% LEL, etc.). OSHA illumination requirements under 29 CFR 1910.219, 29 CFR 1910.261, 29 CFR 1910.262, and 29 CFR 1910.265 for various other similar industries, such as power-transmission apparatus; pulp, paper, and paperboard mills; textiles; sawmills; and shipyards, respectively, also incorporate by reference Illuminating Engineering Society (IES) A11.1, *Practice for Industrial Lighting*, 1965 (revised 1970), for recommended values of illumination. In a letter of interpretation issued June 17, 1996 (and corrected on October 20, 2008) OSHA stated "OSHA accepts employers' use of the current revision to national consensus standards in place of earlier revisions incorporated by reference or adopted into OSHA standards." We note that the current version of the incorporated IES standard is IES of North America (IESNA) 7, *Recommended Practice for Lighting Industrial Facilities*, 2021 edition.

In addition, API 540, *Electrical Installations in Petroleum Processing Plants*, is the most commonly referenced code, standard, and recommended and generally accepted good engineering practice listed and specified in applications of LNG facilities under FERC jurisdiction and provides lighting levels for over 85 different areas more specific to petrochemical facilities to aid in operation and provide minimum levels for safety and security. API 540, 4th (1999) edition, Table 4, *Illuminances Currently Recommended for Petroleum, Chemical, and Petrochemical Plants*, recommends maintained horizontal illuminance ranging from 1 lux to 1,000 lux with most outdoor work areas between 10 and 50 lux and most indoor work areas between 100 and 500 lux, including, but not limited to: plant road that involves frequent use be at least 4 lux (or 0.4 foot-candles) at ground level and infrequently used road lighting at least 2 lux (or 0.2 foot-candles), general process units, buildings, and non-process units, including, but not limited to general process areas (10 lux or 1 foot-candle at ground); storage tank gauges (10 lux or 1 foot-candle at ground); heat exchangers (30 lux or 3 foot-candles at ground); separators (50 lux or 5 foot-candles at top of bay); process pumps, valves, manifolds (50 lux or 5 foot-candles at ground); compressor shelters (200 lux or 20 foot-candles at floor); tanker truck loading (100 lux or 10 foot-candles at point of loading); maintenance platforms (10 lux or 1 foot-candles at floor); operating platforms (50 lux or 5 foot-candles at floor); instruments (50 lux or 5 foot-candles at eye level); control rooms (300 lux or 30 foot-candles at floor), instrument panels (500 lux or 50 foot-candles at 66 inches elevation). These are generally above the 2.2 lux (0.2 foot-candle) required by 49 CFR § 193.2911 with the exception of infrequently used road lighting that is approximately the same and parking lots that are generally less (1 lux or 0.1 foot-candles at ground level). API 540 also defers to Coast Guard regulations for dock facilities, where 33 CFR § 127.109(c)(1) for marine transfer flange (54 lux or 5 foot-candles at 1 meter) is similar to API 540 recommendations for general loading racks (50 lux or 5 foot-candles at ground) and § 127.109(c)(2) for work areas (11 lux or 1 foot-candle) is similar to API 540 recommendations for general process areas (10 lux or 1 foot-candle at ground). These illumination levels can be achieved by a variety of designs for lighting, depending on the light fixture, elevation, location, etc. and is often designed by conducting photometric analyses or equivalent of the proposed light fixtures, their locations, and elevations.

For the CCL proposed Project facilities, CCL would have illuminance approximately equal or greater than those specified in API 540 (1999 edition). However, these drawings did not provide lux levels within certain areas and CCL reported that the perimeter street and security lighting plan drawings were the only ones currently developed, but that the complete lighting layout plans and lux level studies for the process areas would be developed during detailed engineering. We also note that the lighting drawings should also include the proposed Refrigerant Storage area. All lighting drawings would need to be updated to show the proposed new facilities. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, photometric analyses or equivalent and associated lighting drawings. The lighting drawings should show the location, elevation, type of light fixture, and lux levels of the lighting system and should depict illumination coverage along the perimeter of the terminal, process equipment, and along paths/roads of access and egress to facilitate security monitoring and emergency response operations in accordance with federal regulations (e.g., 49 CFR Part 193, 33 CFR 127, 29 CFR Part 1910, and 29 CFR Part 1926) and API 540 or approved equivalent. If the Project is authorized and recommendations are adopted as conditions of the authorization, FERC staff would ensure that the lighting meets API 540 (1999 edition) or approved equivalent while compliance with federal regulations would be subject to DOT PHMSA and Coast Guard requirements. In addition, while FERC staff would not have the authority to check or opine as to whether the lighting meets other agency's federal regulations, FERC staff would coordinate with DOT PHMSA and Coast Guard if it identified any areas that it thought may not meet those agency's federal regulations. We have also proposed NFPA 59A (2026 edition) incorporate similar requirements.

Physical Barriers, Protective Enclosures, and Access 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. 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 13.32 covers security plans, including physical barriers and access controls, and should reference any security specifications in 13.F.4, security threat and vulnerability analyses in 13.G.8, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D. While regulatory requirements and general recommendations for review and approval are included, details of these systems are not described in order to protect Critical Energy Infrastructure Information under 18 CFR § 388.113 and Security Sensitive Information protected under 49 CFP Part 1520.

Title 49 CFR § 193.2905(a) under Subpart J Security requires the following facilities to be surrounded by a protective enclosure: (1) storage tanks; (2) impounding systems; (3) vapor barriers; (4) cargo transfer systems; (5) process, liquefaction, and vaporization equipment; (6) control rooms and stations; (7) control systems; (8) fire control equipment; (9) security communication systems; and (10) alternative power sources. In addition, the protective enclosure may be one or more separate enclosures surrounding a single facility or multiples facilities. Title 49 CFR § 193.2905(b) also requires ground elevations outside a protective enclosure to be graded in a manner that does not impair the effectiveness of the enclosures and 49 CFR § 193.2905(c) requires that protective enclosures not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security. Title 49 CFR § 193.2905(d) requires at least two accesses to be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency, and 49 CFR § 193.2905(e) requires each access be locked, unless it is continuously guarded, and during normal operations, an access may be unlocked only by persons designated in writing by the operator and during an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access. Further, 49 CFR § 193.2907(a) requires each protective enclosure have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed and 49 CFR § 193.2907(b) requires openings in or under protective enclosures be secured by grates, doors or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening.

Title 49 CFR § 193.2917(a) also requires warning signs be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30 m (100 feet) from any way that could reasonably be used to approach the enclosure, and 49 CFR § 193.2917(b) requires signs be marked with at least the following on a background of sharply contrasting color: The words "NO TRESPASSING," or words of comparable meaning.

Title 33 CFR § 105.305(a) requires the waterfront facility owner or operator ensure that background information, including a general layout of security doors, barriers, restricted areas, and access points, is provided to the person(s) who will conduct the FSA, and 33 CFR § 105.305(d) requires that the written FSA report is prepared and included as part of the FSP and must contain a description of existing security measures, including access control, describe physical security, and discuss and evaluate controlling access to the facility. Similarly, 33 CFR § 105.400 requires the FSO ensure the FSP is developed and implemented for each facility for which he or she is designated as FSO and it must address each vulnerability identified in the FSA, it must be submitted for approval to the cognizant COTP in a written or electronic format, and it must be protected in accordance with 49 CFR 1520.

In addition, when Coast Guard updated its regulations in 33 CFR Part 127 in 87 FR 5691 it removed minimum requirements for protective enclosures, but 33 CFR § 127.113 requires the marine transfer area for LNG have warning signs that meet can be seen from the shore and the water and have the following text with each black letters on a white background written in block style and 3 inches high:

Warning

Dangerous Cargo

No Visitors

No Smoking

No Open Lights

In addition, an LNG facility regulated under 33 CFR Part 105 would be subject to the TWIC Reader Requirements Rule issued by the Coast Guard on August 23, 2016. This rule requires owners and operators of certain vessels and facilities regulated by the Coast Guard 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 Coast Guard's June 22, 2018 notice initially delayed the effective date to implement this rule to August 23, 2021. Subsequently, Coast Guard'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, Coast Guard'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.

We also note that NFPA 59A (2019 edition) added language in section 16.8.3 that has similar requirements as § 49 CFR 193.2905(a) and added language in section 16.8.3.1(3) through (6) to mirror the performance -based requirements as 49 CFR § 193.2905(b) through (e) for protective enclosures. Similarly, NFPA 59A (2019 edition) has added similar performance requirements in section 16.8.3.1(1) and (2) as those in 49 CFR 193.2907(a) and (b). We also note that, from 1980 to 1995, 49 CFR § 193.2907 used to contain additional prescriptive-based requirements on the design of protective enclosures, including that the protective enclosures had to be fences or walls; fences had to be chain-link security fences constructed of No. 11 American wire gauge or heavier metal wire; and walls had to be vertical and constructed of stone, brick, cinder block, concrete, steel, or comparable materials and must be noncombustible. Title 49 CFR § 193.2907 used to also require that the protective enclosures be topped by three or more strands of barbed wire or similar materials on brackets angled outward between 30 degrees and 45 degrees from the vertical, with a height of at least 8 ft, including approximately one foot of barbed topping. As explained in 61 FR 27791, the predecessor to PHMSA concluded that such prescriptive requirements were unnecessary and overly burdensome in view of the performance standard that requires that each protective enclosure have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed, and, therefore, repealed the prescriptive requirements to rely solely on the performance standard. While we agree that prescriptive requirements can be limiting and generally prefer performance- and risk-based approaches, the subjectivity to the performance-based language of "sufficient strength and configuration to obstruct unauthorized access" does not define the performance-based objective or requirement constituting sufficient strength and FERC staff has observed correspondingly broad interpretation of this requirement and others within regulations. Performance-based and risk-based standards, such as American Society of Testing and Materials (ASTM) F2656, *Standard Test Method for Vehicle Crash Testing of Perimeter Barriers* and ASTM F2781, *Standard Practice for Testing Forced Entry, Ballistic* *and Low Impact Resistance of Security Fence Systems* would provide better standardization and definition of what may constitute sufficient strength for various design threats based on potential threats stemming from FSAs or security TVRA, but would still be subjective if the security TVRA is not defined or regulated on a consistent basis.

Similarly, FERC staff generally looks for multiple layers of protection for security to minimize potential impacts to the safety of the public and FERC staff generally evaluates these security mitigation measures, including physical barriers, protective enclosures, and access controls, based on a mixture of prescriptive, performance, and risk-based methods. Therefore, although it is unclear as to whether physical barriers are required under 33 CFR 105 in all cases and it is unclear what protective enclosures constitutes "sufficient physical strength" and whether there are other minimum requirements on the design of the physical barriers, protective enclosures, and access controls, we recognize that physical barriers, protective enclosures, and access controls assists in deterring intruders through increasing the likelihood of preventing or delaying potential physical breaches. We also recognize there are codes, standards, and recommended and generally accepted good engineering practices that may provide more guidance on physical barriers, protective enclosures, and access control, including, but not limited to:

- ASTM F567, *Standard Practice for Installation of Chain-Link Fence*;
- ASTM F900, *Standard Specification for Industrial and Commercial Steel Swing Gates*;
- ASTM F1043, *Standard Specification for Strength and Protective Coatings on Steel Industrial Fence Framework*;
- ASTM F1184, *Standard Specification for Industrial and Commercial Horizontal Slide Gates*;
- ASTM F1553, *Standard Guide for Specifying Chain Link Fence*;
- ASTM F2548, *Standard Specification for Expanded Metal Fence Systems for Security Purposes*;
- ASTM F2611, *Standard Guide for Design and Construction of Chain Link Security Fencing*;
- ASTM F2656, *Standard Test Method for Vehicle Crash Testing of Perimeter Barriers*;
- ASTM F2780, *Standard Guide for Design and Construction of Expanded Metal Security Fences and Barriers*;
- ASTM F2781, *Standard Practice for Testing Forced Entry, Ballistic and Low Impact Resistance of Security Fence Systems*;
- ASTM F3204, *Standard Guide for Design and Construction of Welded Wire Fence Systems for Security Purposes*;
- ASTM F3342, *Standard Guide for Temporary Fence Applications for Construction Sites*;
- ASTM F3455, *Standard Practice for Establishing the Minimum- and Maximum-Width Configurations for Crash Testing of Exceptionally Long Variable-Width Vehicle Barriers*;
- Chain Link Fence Manufacturers Institute (CLFMI) CLF-TP0211, *Tested and Proven Performance of Security Grade Chain Link Fencing Systems*;
- DHS, *Dam Sector Active and Passive Vehicle Barriers Guidance*;

- ISO 22343-1, *Security and Resilience - Vehicle Security Barriers, Part 1: Performance Requirement, Vehicle Impact Test Method and Performance Rating*;
- ISO 22343-2, *Security and Resilience - Vehicle Security Barriers, Part 2: Application*;
- NUREG/CR-6190, *Protection Against Malevolent Use of Vehicles at Nuclear Power Plant*;
- UFC 4-021-02, *Electronic Security Systems*;
- UFC 4-022-01, *Security Engineering: Entry Control Facilities/Access Control Points*;
- UFC 4-022-02, *Security Engineering: Selection and Application of Vehicle Barriers*;
- UFC 4-022-03, *Security Engineering: Design of Security Fencing, Gates, Barriers, and Guard Facilities*;
- UFC 4-025-01, *Security Engineering: Waterfront Security*;
- Underwriters Laboratories (UL) 294, *Access Control Systems;* and
- UL 752, *Bullet-Resisting Equipment*.

CCL has an existing protective enclosure that have been subject to previous FERC staff reviews for which the proposed Project facilities would be within. Additionally, the Stage 3 Order dated November 22, 2019, contains a condition on crash rated vehicle barriers that CCL plans to satisfy for the already approved CCL Stage 3 Project. This condition would address concerns with crash rated vehicular protection at the CCL Terminal since the CCL Midscale Trains 8 & 9 Project would be constructed within the existing CCL Terminal and Stage 3 Project site. However, all drawings should be updated to show the proposed new facilities. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, updated drawings of the security enclosure that show the new Project facilities. The security enclosure drawings should provide details of the enclosure that demonstrate it is in accordance with NFPA 59A (2019 edition) or approved equivalent 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 enclosure to be overcome. If the project is authorized and if our recommendations are adopted as conditions, FERC staff would evaluate the protective enclosure designs in coordination with DOT PHMSA, Coast Guard, and any other federal agencies with LNG facility security requirements to ensure they are commensurate with the security TVRA and so that they are also consistent with the other codes, standards, and recommended and generally accepted good engineering practices referenced.

There should also be security plans and systems implemented during construction. CCL already has indicated that they would implement a Construction Security Plan that would address security during construction of the proposed Project. We would want to review finalization of these prior to implementation. Therefore, we recommend in section D of the EA that prior to initial site preparation, CCL 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.

Intrusion Monitoring and Detection

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 13.32 covers security plans, including intrusion monitoring and detection, and should reference any security specifications in 13.F.4, security threat and vulnerability analyses in 13.G.8, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D. While regulatory requirements and general recommendations for review and approval are included, details of these systems are not described in order to protect Critical Energy Infrastructure Information under 18 CFR § 388.113 and Security Sensitive Information protected under 49 CFR Part 1520.

Title 33 CFR § 105.275(a) requires the waterfront facility owner or operator ensure implementation of security measures and have the capability to continuously monitor, through a combination of lighting, security guards, waterborne patrols, automatic intrusion detection devices, or surveillance equipment as specified in the approved FSP. Title 33 CFR § 105.305(a) requires the waterfront facility owner or operator ensure that background information, including security personnel and procedures for monitoring, is provided to the person(s) who will conduct the FSA, and 33 CFR § 105.305(d) requires that the written FSA report is prepared and included as part of the FSP and must contain a description of existing security measures, including monitoring restricted areas to ensure only authorized persons have access and monitoring the facility and areas adjacent to the pier. Similarly, 33 CFR § 105.400 requires the FSO ensure the FSP is developed and implemented for each facility for which he or she is designated as FSO and it must: address each vulnerability identified in the FSA, be submitted for approval to the cognizant COTP in a written or electronic format, and be protected in accordance with 49 CFR 1520.

Title 49 CFR § 193.2913 requires each protective enclosure and the area around each facility listed in 49 CFR § 193.2905(a), discussed above, to be monitored for the presence of unauthorized persons, and that this monitoring must be by visual observation in accordance with the schedule in the security procedures under § 193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m^3 (250,000 bbl) of storage capacity, 49 CFR § 193.2913 requires only the protective enclosure be monitored.

Similarly, FERC staff generally looks for multiple layers of protection for security to minimize potential impacts to the safety of the public and FERC staff generally evaluates these security mitigation measures, including continuous intrusion monitoring and detection, based on a mixture of prescriptive, performance, and risk-based methods. NFPA 59A (2023 edition) section 16.8.5 and subsection 16.8.5.1 contains the same broad general security monitoring requirements as 49 CFR § 193.2913 that would seem to be consistent with the even broader general security monitoring requirements in 6 CFR § 27.230(2). Therefore, although it is unclear as to whether both visual detection by security patrols and automatic detection are required under 33 CFR 105 or 49 CFR 193 and whether there are any minimum requirements on the design of the intrusion monitoring and detection systems, we recognize that intrusion monitoring and detection assists in deterring intruders through increasing the likelihood of deterring, and more quickly detecting potential physical breaches and responding to neutralize the threat. We also recognize there are codes, standards, and recommended and generally accepted good engineering practices that may provide more guidance on intrusion monitoring and detection, including, but not limited to:

- NFPA 730, *Guide for Premises Security*;
- NFPA 731, *Standard for the Installation of Premises Security Systems*;
- Telecommunication International Association 568.3-D, *Optical Fiber Cabling and Components Standard*,
- ASIS CP-01, *Control Panel Standard, Features for False Alarm Reduction*;

- ASIS PIR-01, *Passive Infrared Motion Detector Standard, Features for Enhancing False Alarm Immunity Standard*;
- UFC 4-021-02, *Electronic Security Systems*;
- UFC 4-025-01, *Security Engineering: Waterfront Security*;
- UL 636, *Standard for Holdup Alarm Units and Systems*;
- UL 639, *Standard for Intrusion Detection Units*;
- UL 827, *Central-Station Alarm Services*;
- UL 2044, *Standard for Commercial Closed-Circuit Television Equipment*;
- UL 2610, *Commercial Premises Security Alarm Units and Systems*;
- UL 2802, *Performance Testing of Camera Image Quality;*
- UL/International Electrotechnical Commission (IEC) 60065, *Standard for Audio, Video and Similar Electronic Apparatus*; and
- UL/IEC 62368, *Audio/Video, Information and Communication Technology Equipment*.

CCL has an existing intrusion monitoring and detection systems that have been subject to previous FERC staff reviews. However, the new proposed facilities would also have new safety and security monitoring. Therefore, we recommend in section D of the EA that prior to initial construction of final design, CCL should file, for review and approval, updated closed-circuit television (CCTV) and intrusion detection drawings. The CCTV drawings should show the locations, mounting elevation, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, etc.) and should provide camera coverage at access points and along the entire perimeter of the terminal with redundancies and CCTV coverage interior of the facility to enable rapid monitoring of the terminal, including coverage within new Project areas and buildings. The drawings should show or note the location and type of the intrusion detection and should demonstrate coverage of the entire perimeter surrounding the Project facilities. If the project is authorized and if our recommendations are adopted as conditions, FERC staff would evaluate the security designs in coordination with DOT PHMSA and Coast Guard to ensure they are commensurate with the security TVRA and so that they are also consistent with the other security codes, standards, and recommended and generally accepted good engineering practices referenced.

Cybersecurity

CCL has the responsibility for establishing policy, procedures, and controls to guard against cybersecurity threats to energy system architectures in accordance with regulatory requirements.

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 13.32 covers security plans, including cybersecurity, and should reference any security specifications in 13.F.4, security threat and vulnerability analyses in 13.G.8, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D. While regulatory requirements and general recommendations for review and approval are included, details of these systems are not described in order to protect Critical Energy Infrastructure Information under 18 CFR § 388.113 and Security Sensitive Information protected under 49 CFR Part 1520.

Title 33 CFR § 105.300 requires those involved in an FSA to draw upon expert assistance in computer systems and networks, and 33 CFR § 105.305(c) requires the waterfront facility owner or operator ensure that the FSO analyzes the facility background information for establishing and prioritizing security measures included in the FSP, including measures to protect computer systems and networks. Similarly, 33 CFR § 105.305(d) requires that the written FSA report is prepared and included as part of the FSP and must describe computer systems and networks. Title 33 CFR § 105.400 also requires the FSO ensure the FSP is developed and implemented for each facility for which he or she is designated as FSO and it must: address each vulnerability identified in the FSA, be submitted for approval to the cognizant COTP in a written or electronic format, and be protected in accordance with 49 CFR 1520.

Analogously to physical security threats and actors, multiple layers of protection for cybersecurity better minimize potential impacts to the safety of the public, including barriers to cybersecurity threats, physical access to control systems and computer and network access controls, intrusion monitoring and detection, and cybersecurity response capabilities, and cybersecurity training, consistent with codes, standards, and recommended and generally accepted good engineering practices. We recognize there are a number of relevant codes, standards, and recommended and generally accepted good engineering practices developed on cybersecurity that may be applicable. 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) has legal authorities for researching and developing cybersecurity standards, guidelines, and best practices. As part of an interagency agreement with NIST, the DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) and NIST agreed to research and develop tools and practices that will strengthen the cybersecurity of maritime transportation systems within the Nation's energy sector, focusing on LNG facilities. As such, NIST published, in collaboration with LNG industry stakeholders and FERC, Interagency Report 8406, *Cybersecurity Framework for LNG*.[16]

In addition, FERC staff participates in the LNG committee of NFPA that is responsible for NFPA 59A. FERC staff worked with the committee, including LNG industry and other stakeholders, to help develop NFPA 59A (2019 edition) section 11.7.2, which stipulates a cybersecurity vulnerability assessment of the process control systems and safety instrumented systems (SIS) shall be conducted and reviewed every 2 years not to exceed 27 months or at intervals determined by the authority having jurisdiction, and revised as necessary. NFPA 59A A.11.7.2 provides the following references in the annex for such assessments:

- International Society for Automation (ISA) TR 99.00.01, *Security Technologies for Industrial Automation and Control Systems*;
- ANSI/ISA 99.01.01 (ISA/IEC 62443-1-1), *Security for Industrial Automation and Control Systems, Part 1-1: Terminology, Concepts, and Models*;
- ISA/IEC TR 62443-1-2, *Security for Industrial Automation and Control Systems (IACS), Part 1- 2 Master Glossary of Terms and Abbreviations*;
- ISA/IEC TR 62443-1-3, *Security for Industrial Automation and Control Systems, Part 1-3 System Security Compliance Metrics*;
- ISA/IEC TR 62443-1-4, *Security for Industrial Automation and Control Systems, Part 1-4 Security Life Cycle and Use Cases*;

16 NIST Interagency Report 8406, *Cybersecurity Framework Profile for Liquefied Natural Gas*, https://csrc.nist.gov/pubs/ir/8406/final, Accessed March 2024.

- ISA/IEC TR 62443-3-2, *Security for Industrial Automation and Control Systems, Part 3-2 Security Risk Assessment and System Design*;
- ANSI/ISA 99.03.03 (ISA/IEC 62443-3-3), *Security for Industrial Automation and Control Systems, Part 3-3: System Security Requirements and Security Levels*;
- ISA/IEC TR 62443-4-1, *Security for Industrial Automation and Control Systems, Part 4-1 Product Development Requirements*;
- ISA/IEC TR 62443-4-2, *Security for Industrial Automation and Control Systems, Part 4-2 Technical Security Requirements for IACS Components*;
- ANSI/ISA 99.02.01 (ISA/IEC 62443-2-1), *Security for Industrial Automation and Control Systems, Part 2-1: Establishing an Industrial Automation and Control Systems Security Program*;
- ISA/IEC TR 62443-2-2, *Security for Industrial Automation and Control Systems, Part 2-2 Implementation Guidance for an Industrial Automation and Control Systems Security Program*;
- ISA/IEC TR 62443-2-3, *Security for Industrial Automation and Control Systems, Part 2-3 Patch Management in the IACS Environment*;
- ISA/IEC TR 62443-2-4, *Security for Industrial Automation and Control Systems, Part 2-4 Requirements for IACS Solution Suppliers*; and
- ISA/IEC TR 62443-3-1, *Security for Industrial Automation and Control Systems, Part 3-1 Security Technologies for IACS*.

Similarly, FERC staff have proposed in NFPA 59A (2026 edition) that a cybersecurity plan and procedures be developed, documented, implemented, and periodically updated every 2 years, not to exceed 27 months, or at intervals determined by the authority having jurisdiction, and revised, as necessary, in accordance with the following or approved equivalents:

- NIST Interagency Report 8406, *Cybersecurity Framework for LNG*;
- ISA TR84.00.09, *Cybersecurity Related to the Functional Safety Lifecycle*;
- ISA TR 99.00.01, *Security Technologies for IACS*;
- ANSI/ISA 99.01.01 (ISA/IEC 62443-1-1), *Security for IACS, Part 1-1: Terminology, Concepts, and Models*;
- ISA 62443-2-1, *Security for IACS, Part 2-1: Establishing an IACS security program*;
- ISA TR62443-2-3, *Security for IACS, Part 2-3: Patch management in the IACS environment*;
- ISA TR62443-2-4, *Security for IACS, Part 2-4: Security program requirements for IACS service providers*;
- ISA TR62443-3-1, *Security for IACS, Part 3-1: Security technologies for IACS*;
- ISA TR62443-3-2, *Security for IACS, Part 3-2: Security Risk Assessment for System Design*;
- ISA 62443-3-3, *Security for IACS, Part 3-3: System Security Requirements and Security Levels*;

- ISA 62443-4-1, *Security for IACS, Part 4-1: Secure Product Development Lifecycle Requirements*; and
- ISA 62443-4-2, *Security for IACS, Part 4-2: Technical Security Requirements for IACS Components*.

Nearly all of the government agencies authorized for overseeing 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. In addition, under the Maritime Transportation Security Act of 2002, 46 U.S.C. § 2101, the Coast Guard 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 Coast Guard 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 FSA 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. On February 22, 2023, TSA entered a pre-rule stage on the proposed rulemaking, however a Notice of Proposed Rulemaking has not been published. Also, the DOE, Federal Bureau of Investigations under the Department of Justice, Central Intelligence Agency, National Security Agency/Central Security Service, and 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 Coast Guard, FERC staff would collaborate with the Coast Guard and PHMSA on the Project's security provisions, including but not limited to any cybersecurity vulnerabilities identified by FERC staff and potential provisions to mitigate such vulnerabilities.

FERC Engineering and Technical Review of the Preliminary Engineering Designs

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 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 ESD 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.

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.[17] 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, in the Mechanical sections, we evaluated and made recommendations on the specifications, including materials of construction. In

[17] 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.

addition, in the Spill Containment section, we evaluated and made recommendations on the spill containment systems to 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, in the Ignition Controls section, we evaluated and made recommendations on the electrical seal design interface between flammable fluids and the electrical conduit or wiring systems; the electrical seal leak detection systems; and the venting of flammable vapors in the electrical wiring and conduit systems 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 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. In addition, in the Hazard Detection section, we evaluated the preliminary hazard detection design and layout and made recommendations on 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.[18] 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, in the Commissioning Schedule, Plans, and Procedures section below, we evaluated and made recommendations on purging procedures, which should reduce the risk of projectiles from pressure vessel bursts (PVBs). Similarly, in the Spacing and Layout section, we evaluated and made recommendations on reducing the risk of other sources of PVBs and boiling liquid expanding vapor explosions (BLEVEs). In addition, the Overpressures section below discusses

[18] For a description of the incident and the findings of the investigation, see Root Cause Failure Analysis, Plymouth LNG Plant Incident Investigation under CP14-515.

cascading events that could result in BLEVEs and the extent of resulting projectiles. Furthermore, to prevent sources of projectiles from affecting occupied buildings, in the Hurricanes, Tornadoes, and other Meteorological Events section below, we discuss a recommendation for an assessment of projectiles on buildings and equipment.

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, the piping segment underwent a BLEVE and ruptured.[19] To address this potential hazard for the proposed facilities, in the Inspection, Testing, and Maintenance Plans and Procedures section below, we evaluated and made recommendations on the use and management of car seals and in the Operation Plans and Procedures section below, we made recommendations on contractor oversight. In the Personnel and Training section, we evaluated and made recommendations on training and discussed 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.

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 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, by 49 CFR Part 193, for them to be available upon request for review

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19 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 2024.

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 required by 49 CFR Part 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 LOI to notify the 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 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.

Coast Guard 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 Coast Guard, 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[20], and then manage changes from the application to final design and throughout construction and operation. Therefore, we recommend in section D of the EA that CCL 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. CCL should:

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 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.

Similarly, we recommend in section D of the EA, that prior to construction of final design, the CCL should file, for review and approval, change logs that list and explain any changes made from the FEED provided in CCL's application and filings. A list of all changes with an explanation for the design alteration should be filed and all changes should be clearly indicated on all diagrams and drawings. In addition, CCL committed to making certain changes in response to data requests to FERC staff. Therefore, we recommend in section D of the EA, that prior to construction of final design, CCL should file, for review and approval, information/revisions pertaining to CCL's response numbers 5, 13, 18, 40, 41, 42, 44, 45, 46, 47, 48, and 53 of their Sept 11, 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 went 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 AIChE Center for CCPS, *Guidelines for Management of Change for Process Safety*, or equivalents to ensure companies are managing changes safely.

Project Schedule

Title 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

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

engineering, procurement, construction, commissioning, and startup of the facilities. Phased construction and operation, tie-ins, and future plans should also be summarized and included in the project schedule. CCL provided a project schedule in the application that was a high level overview that provided general timelines for FERC approval, site preparation, construction, 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*;
- CII RS6-5, *Project Control for Construction*;
- CII RS6-6, *Work Packaging for Project Control*;
- CII RR272-11, *Enhanced Work Packaging: Design through Workface Execution*;
- CII RR272-12, *Advanced Work Packaging: Design, through Workface Execution*; and
- CII Implementation Resource 272-2, *Advanced Work Packaging: Design, through Workface Execution, Version 3.1*.

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 D of the EA that prior to initial site preparation, CCL 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 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 C Design and Subpart D Construction, covers the DOT PHMSA regulatory requirements for LNG facilities designed and constructed after March 31, 2000. Title 49 CFR Part 193, Subpart E Equipment, includes PHMSA regulatory requirements for the fabrication and installation of vaporization equipment, liquefaction equipment, and control systems.

Specifically, 49 CFR §§ 193.2101, 193.2301, and 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). Furthermore, 49 CFR § 193.2703 requires each operator to use, persons who have demonstrated competence by training or experience in the fabrication or design 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. If the Project is authorized, constructed, and operated, LNG facilities, as defined in 49 CFR Part 193, would be subject to PHMSA's inspection and enforcement programs to ensure compliance with the requirements of 49 CFR Part 193.

Title 33 CFR Part 127 Subpart B covers Coast Guard 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 NFPA 59A (2019 edition) Chapter 4, which has similar competence requirements for fabricator, constructor, installer, inspector, testers, and supervisors as 49 CFR §§ 193.2703 and 193.2705. Further, 33 CFR Part 127 does not incorporate NFPA 59A (2019 edition) Chapter 7, which has requirements for boilers, pressure vessels, and other process equipment.

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 Canadian Standards Association (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, 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.[21] CCL is proposing the use of pressure vessels and shell and tube heat exchangers as part of this Project, but are not proposing any boilers.

NFPA 59A (2001 edition) Chapter 4 provides requirements for stationary LNG storage containers and 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 pounds per square inch (psi) (100 kilopascals) 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

21 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).

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 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.

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.

We note that NFPA 59A (2001 edition) defines LNG[22] and defines container[23], but does not define storage, and 49 CFR § 193.2007 defines LNG[24], storage tank[25], and container[26], but does not define storage container. In addition, the definition for LNG and container in NFPA 59A (2001 edition) is different than the definition of LNG and container in 49 CFR § 193.2007 and therefore 49 CFR § 193.2007 definitions prevail per 49 CFR §193.2051 for siting, § 193.2101 for design, § 193.2301 for construction, and § 193.2401 for equipment. This can be confusing as container is defined based on a definition of component that includes container. Therefore, it is unclear as to whether the other components, such as undefined processing equipment, would be considered a container or not in 49 CFR Part 193.

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22 LNG is defined in NFPA 59A (2001 edition) as a fluid in the liquid state that is composed predominantly of methane and that can contain minor quantities of ethane, propane, nitrogen, or other components normally found in natural gas. We further note that "predominantly" and "minor quantities" are not defined quantitatively.

23 Container is defined in NFPA 59A (2001 edition) as a vessel for storing LNG. We note that this definition would limit any requirements of containers to just those storing LNG.

24 LNG is defined in 49 CFR § 193.2007 as natural gas or synthetic gas having methane as its major constituent which has been changed to a liquid. We further note that "major constituent" is not defined quantitatively.

25 Storage tank is defined in 49 CFR § 193.2007 as a container for storing a hazardous fluid. We further note that hazardous fluid is defined as a gas or hazardous liquid and that hazardous liquid is defined as LNG or a liquid that is flammable or toxic. This makes it not entirely clear if a container storing any gas would be considered a storage tank.

26 Container is defined in 49 CFR § 193.2007 as a component other than piping that contains a hazardous fluid. We further note that piping is defined in in 49 CFR § 193.2007 as pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids and component is defined in 49 CFR § 193.2007 as any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid. This makes it unclear whether processing equipment, such as pressure vessels, heat exchangers, columns, etc. would be considered as a container or not.

NFPA 59A (2019 and 2023 editions) provides more clarity on definitions for containers[27], ASME containers[28], pressure vessels[29], tanks[30], storage tanks[31], and tank systems[32], but also does not define storage containers. In addition, NFPA 59A (2001 edition) section 3.3 requires installation of storage tanks for flammable refrigerants and liquids to comply with section 2.2 or:

- 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; and
- API 2510, *Design and Construction of Liquefied Petroleum Gas (LPG) Installations*, 1989 edition.

However, it is unclear whether the installation includes the design, construction, or other requirements because while the above referenced codes and standards scopes cover such requirements, NFPA 59A (2001 edition) allows the installations to meet section 2.2 in lieu of these codes and standards and section 2.2 only covers major site provisions for spill and leak control (e.g., impoundment sizing and spacing) and does not speak to the design, construction, or other requirements of the tanks. In addition, FERC staff considers storage containers, which would include both storage tanks and storage vessels, as a container designed and/or used for storing a product and not designed and used for processing a product (e.g., phase separation or knock-out drums, surge drums, etc.). FERC generally considers and recommends containers be in accordance with applicable recognized standards including, but not limited to:

- pressure vessels (i.e., 15 pounds per square inch gauge [psig] and above) subject to ASME BPVC or other approved recognized standard(s) for pressure vessels;
- low-pressure tanks (i.e., above 0 psig and below 15 psig) subject to API 620 or other approved recognized standard(s) for low-pressure tanks,
- atmospheric tanks (i.e., 0 psig to 2.5 psig) subject to API 650, *Welded Tanks for Oil Storage*, API 12B, *Bolted Tanks for Storage of Production Liquids*, API 12D, *Field Welded Tanks for Storage of Production Liquids*, API 12F, *Shop Welded Tanks for Storage of Production Liquids*, API 650, *Welded Tanks for Oil Storage*, UL 58, *Steel Underground Tanks for Flammable and Combustible Liquids*, UL 80, *Steel Tanks for Oil-Burner Fuels and Other Combustible Liquids*, UL 142, *Steel Aboveground Tanks for Flammable and Combustible Liquids*, UL 1316, *Glass-Fiber Reinforced Plastic Underground Storage Tanks for Petroleum Products, Alcohols, and Alcohol-Gasoline Mixtures*, UL 2080, *Fire Resistant Tanks for Flammable and Combustible Liquids*, UL 2085, *Protected Aboveground Tanks for Flammable and Combustible Liquids*, UL 142A, *Safety for Special Purpose Aboveground Tanks for Specific Flammable or Combustible Liquids*, UL 2258,

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27 Container in NFPA 59A (2019 and 2023 editions) is defined as a vessel, tank, portable tank, or cargo tank used for or capable of holding, storing, or transporting liquid or gas. We note that the inclusion of capable and holding makes the definition also subjective and potentially very broad.

28 ASME container in NFPA 59A (2019 edition) refers to definition of pressure vessel.

29 Pressure vessel is defined in NFPA 59A (2019 edition) as a container designed and fabricated in accordance with the ASME BPVC, Section VIII or CSA B51.

30 Tank in NFPA 59A (2019 edition) refers to definition of storage tank.

31 Storage tank is defined in NFPA 59A (2019 edition) as a low-pressure container designed for an internal gas pressure of 15 psi or less, in accordance with API 620 or API 650.

32 Tank system is defined in NFPA 59A (2019 edition) as low-pressure (less than 15 psi) equipment designed for storing LNG or other hazardous liquids, consisting of one or more containers, together with various accessories, appurtenances, and insulation.

Aboveground Nonmetallic Tanks for Fuel Oil and Other Combustible Liquids, or other approved recognized standard(s) for atmospheric tanks;

- firewater tanks and vessels subject to NFPA 22, *Standard for Water Tanks for Private Fire Protection*, or other approved recognized standard for firewater tanks;
- water tanks subject to American Water Works Association (AWWA) D100, *Welded Carbon Steel Tanks for Water Storage*, AWWA D103, *Standard for Factory-Coated Bolted Carbon Steel Tanks for Water Storage*, AWWA D107, *Standard for Composite Elevated Tanks for Water Storage*, AWWA D110, *Wire- and Strand-Wound, Circular, Prestressed Concrete Water Tanks*, AWWA D115, *Tendon-Prestressed Concrete Water Tanks*, AWWA D120, *Thermosetting Fiberglass Reinforced Plastic Tanks*, AWWA D121, *Bolted Aboveground Thermosetting Fiberglass Reinforced Plastic Panel-Type Tanks for Water Storage*, or other approved recognized standard(s) for water tanks.

This would be consistent with the requirements of NFPA 30, NFPA 59, NFPA 59, API 2510, and other recommended and generally accepted good engineering practices.

CCL is proposing to install new refrigerant storage vessels, diesel storage tanks, amine storage tanks, and anti-foam storage tanks, but no other storage vessels or storage tanks. As such, FERC staff does not consider CCL as proposing any LNG storage containers as part of this Project. In addition, FERC staff does not consider CCL as proposing any LNG tanks as part of this Project either. However, FERC staff evaluated whether other containers (non-LNG and non-storage) were specified to follow the above-mentioned codes, standards, and recommended and generally accepted good engineering practices applicable to them and found no concerns. These are discussed under Mechanical Design.

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).

CCL 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 included in the elements discussed above. While CCL would need to meet the requirements of 49 CFR Part 193 and 33 Part CFR 127, 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 D of the EA that prior to initial site preparation, CCL should 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 ISO 9001, *Quality Management Systems*, and Project Management Institute, *Project Management Body of Knowledge*, 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 Coast Guard 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 CCL provided preliminary equipment lists, and datasheets and specifications for select equipment and no concerns were identified, any proposed specification would be subject to change when an EPC contractor is selected. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL 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 D of the EA that prior to construction of final design, CCL 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.

Construction Progress and Reporting

If the Project is authorized and proceeds, and if recommendations are adopted as conditions of the order, CCL final design and QAQC would be subject to FERC staff review and approval. CCL would then install equipment in accordance with final specifications, final designs, and QAQC program, which would typically include non-conformance report or deficiency logs consistent with ISO 9001, ISO 9002, Project Management Institute Project Management Body of Knowledge, and other QMS standards. As discussed in previous and later subsections, we recommended that these final specifications, final designs, and QAQC plans be filed for review and approval. We also recommend in section D of the EA that beginning with the filing of its Implementation Plan, CCL should 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 CCL'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 CCL from other federal, state, or local permitting agencies concerning instances of noncompliance, and the CCL's response.

In addition, FERC staff would conduct construction inspections including reviewing QAQC plans and resultant documentation, such as non-conformance report 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, codes, and standards. We would also conduct spot checks during our own inspections, such as piping and instrument diagram (P&ID) walkdowns, and equipment nameplate verifications to ensure installed equipment is consistent with the approved design.

Personnel and Training

If the Project is authorized, CCL 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 18 CFR 380.12(c)(7) and 18 CFR 380.12(g)(3) requires description of on-site manpower requirements during construction and operation. 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 13.1.3, companies should provide a description of the owner, principal contractors, and operator of the facilities, and section 13.29 recognizes operation and maintenance personnel training and training plans and procedures would typically become available after the application stage, but development of the operation and maintenance personnel training and training plans and procedures should be discussed in the application as part of the engineering planning approach to the construction of any new facilities. In addition, 13.29.1.4 suggests the description should include the operations and maintenance structure with reference to an Organizational Chart in Appendix 13.A.4 as part of the engineering planning approach to the construction of any new facilities, and also denotes the number of operation and maintenance personnel, and management procedures, such as shift procedures and fatigue management, would become available after the application stage. In addition, 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 § 193.2707, 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.

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 § 193.2709 also 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.

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. Title 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 the training plans and procedures to be submitted, reviewed, or demonstrated to be completed prior to commissioning, and it is not clear what constitutes some of the more subjective training requirements, such as what constitutes "characteristics and hazards of LNG and other flammable fluids used or handled at the facility" and whether toxic fluid characteristics and hazards also need to be included, and what distinguishes between "basic" and "advanced" firefighting procedures. In addition, there are no explicitly stated requirements on process safety. Therefore, we recommend in section D of the EA, that prior to commissioning, CCL should file, for review and approval, a plan to maintain a detailed training log to demonstrate that operating, maintenance, safety, security, and emergency response staff have completed the required training. In addition, CCL should file signed documentation that demonstrates training has been conducted, including emergency shutdown (ESD) and emergency response procedures, prior to the respective operation. We would evaluate these training logs in coordination with PHMSA and the Coast Guard, as applicable to the Project.

Furthermore, incidents have also indicated the importance of having sufficient number of staff to conduct and support operations, maintenance, security, and safety, including training and management of those personnel. Insufficient number of staff can lead to excess overtime and fatigue that can increase the risk of human error. In addition, as recognized in NFPA 59A (2019 and 2023 editions) A.19.6.2, incident history indicates many of the largest incidents occur during night due to an increase in probability for certain human errors as a result of fatigue, lower staffing/supervisory personnel, and potential for less visibility. This could suggest an increase in probability for releases occurring at night when environmental conditions can also be less favorable and result in an unequal distribution of risk in terms of higher likelihoods and larger consequences. Related industries, including pipelines regulated by DOT PHMSA under 49 CFR 192 require operators to address control room management and fatigue in 49 CFR § 192.631. In addition, API has published, API 1168, *Recommended Practice for Pipeline Control Room Management*, which covers shift turnover guidance and fatigue management and workload of operators. In addition, NFPA 59A (2019 and 2023 editions) section A.11.7.1 makes reference to API 770, *A Manager's Guide to Reducing Human Errors*, API 755, *Fatigue Risk Management Systems for Personnel in the Refining and Petrochemical Industries*. AIChE CCPS has also published *Guidelines for Preventing Human Error in Process Safety* and *Human Factors Methods for Improving Performance in the Process Industries*. AIChE and Energy Institute also jointly published *Human Factors Handbook for Process Plant Operations: Improving Process Safety and System Performance*. Collectively, the AIChE and Energy Institute publications cover various human error causes, factors, and techniques to identify and mitigate them. Currently, there are no requirements for LNG facilities under 49 CFR 193 or 33 CFR 127 for managing shift turnovers, fatigue, workload, or other common factors and sources of human error. However, root cause analyses of LNG incidents also indicate insufficient training, staffing, and resultant fatigue as a contributing cause. Therefore, we recommend in section D of the EA, that prior to commissioning, CCL should file, for review and approval, an Organizational Chart that denotes the operations and maintenance structure and number of operation and maintenance personnel, including support staff. CCL should also conduct periodic monitoring and assessments of the staffing levels that includes plans to reduce human error caused by periods of overtime, address any identified causes of fatigue, and any related lessons learned and deficiencies consistent with API 755 or approved equivalent.

Commissioning Schedule, Plans, and Procedures

If the Project is authorized and constructed, CCL would commission 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.

CCL 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, CCL 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 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 D of the EA that prior to commissioning, CCL should file, for review and approval, 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. CCL 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 D of the EA that prior to commissioning, CCL 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.

Additionally, we recommend in section D of the EA that prior to commissioning, CCL should file, for review and approval, a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Manual (2018 edition) or approved equivalent, and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing. As discussed in later subsections, we also recommend that specific commissioning plans and procedures be provided for review and approval, such as pressure/leak testing; and those associated with the distributed control system (DCS) and SIS. FERC staff would review the commissioning plans and procedures consistent with codes, standards, and recommended and generally accepted good engineering practices, such as aforementioned

American Gas Association's, Purging Manual (2018 edition), and 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 process hazard analysis (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 D of the EA that, prior to introduction of hazardous fluids, CCL should complete and document a PSSR to ensure that installed equipment meets the design and operating intent of the facility. The PSSR should include any 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 D of the EA that CCL 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.

During the commissioning process, CCL would conduct numerous commissioning and demonstration tests to verify the performance and reliability of the constructed facilities. FERC staff would utilize the test results to verify the safe and reliable operation of the facility prior to providing written authorization to place the facilities in service as discussed below. Therefore, we recommend in section D of the EA, that after production of first LNG, CCL should file weekly reports on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports should include a summary of activities, problems encountered, and remedial actions taken. The weekly reports should also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports should include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude should be reported to the FERC within 24 hours.

In addition, we recommend in section D of the EA that CCL should request and 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 D of the EA 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, should 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, including facility events that have taken place since the previously submitted semi-annual report, be submitted. As part of the regular inspections, FERC staff would coordinate its inspections with DOT PHMSA and Coast Guard. 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 reviews conducted, including a descriptive title or summary/sentence for each item and for identification and copies of any changes to management of change 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 PHAs, root cause analyses, 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 ESD test. Describe how the facility's ESD 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 prevent 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 D of the EA that throughout the life of the Project, CCL should 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 and recommended in the Incidents and Investigations section 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, Coast Guard, 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. Incident is 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 ESD of an LNG facility or a UNGSF. Activation of an ESD 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 other criteria in 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 be taken to minimize recurrence of the incident as a result of the investigation and 49 CFR § 193.2515(c) requires the operator involved to make available all relevant and provide reasonable assistance in conducting the investigation if the Administrator or relevant state agency under the pipeline safety laws (49 U.S.C. 60101 et seq.) investigates an incident. Section 193.2515(c) 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 § 191.2533 the existence of any of the following safety-related conditions involving LNG facilities in service with certain exceptions:

- Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the

[33] 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. *See* 49 C.F.R. § 191.25(a).

structural integrity or reliability of an 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 (MAWP) of an LNG facility that contains or processes gas or LNG.
- A leak in an 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-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, Coast Guard 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 D of the EA that throughout the life of the CCL Project, CCL 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 Coast Guard, 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 2023 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, requires the use of persons who have demonstrated competence by training or experience in the design of comparable components. Title 49 CFR §§ 193.2013 and 193.2101(a), under Subpart C, also incorporate NFPA 59A (2001). Like 49 CFR § 193.2703, 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 Part 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 CCL does not propose new facilities or modified facilities within the Project scope that would impact facilities regulated under 33 CFR Part 127.

While it is good that 49 CFR Part 193, 33 CFR Part 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 CCL is 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 Part 193, 33 CFR Part 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 an 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, H_2S, 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 PFD, HMBs, and P&IDs would be subject to changes in final design after additional detailed engineering is conducted. Therefore, as discussed in the Process Description section below, we have included a recommend in section D of the EA that CCL should file up-to-date PFDs, HMBs, and piping and instrument diagrams (P&IDs) including vendor P&IDs.

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 Coast Guard would be responsible for enforcing any of the minimum federal requirements in their respective regulations that would be applicable.

Process Description

The inlet feed gas would first pass through the existing Stage 3 gas gate which is comprised of pig receivers, gas meters, flow control valves, and pig launchers. The gas gate would be connected to the terminal's utility systems (e.g., flare, instrument air) through tie-in points. The inlet gas from the gas gate would flow into each train's high integrity pressure protection system (HIPPS). A HIPPS is specified at the inlet of the LNG terminal, near the feed gas pressure control system, to automatically close if the pipeline pressure exceeds the design pressure of the pipe and equipment downstream of the HIPPS. The pressure would be monitored by a set of pressure indicators that would trigger isolation valves to close and stop gas flow from the pipeline if at least two monitors measure a pressure that nears the design pressure of the downstream equipment. FERC staff has confirmed the set pressure of the HIPPS is lower than the design pressure of the downstream equipment. Next, the gas would flow to either the Feed Gas Heater or the Startup-Fuel Gas Electric Heater depending on the operation. The Startup-Fuel Gas Heater would only be used for startup conditions. Some inlet gas would be taken off as supplemental fuel gas for use in start-up operations and fuel gas. The Feed Gas Heaters would be used to control the gas temperature to prevent hydrate formation in downstream equipment. The inlet gas then passes to the mercury/H_2S removal system to reduce the mercury and H_2S concentration. Each mercury/H_2S Removal Unit would consist of two adsorbent beds in a lead-lag configuration. As noted above, mercury and H_2S removal is specified to prevent mercury embrittlement and corrosion of downstream brazed aluminum heat exchangers and minimize the absorption of H_2S in the Acid Gas Removal Unit.

After mercury and H_2S removal, the feed gas would contact a solvent solution in the Acid Gas Absorber Column to reduce the H_2S and CO_2 (i.e., acid gas) to a low concentration to prevent freezing in the liquefaction process. Freezing in the liquefaction process can lead to degraded performance, more frequent deriming (thawing and disposal of frozen components of the feed gas), or clogging of the downstream heat exchangers that, if not derimed, can lead to failure from over-pressurization. Acid gas can also increase corrosion rates in certain common materials of construction, depending on pressure and concentration, such as carbon steel, used to handle the relatively warmer natural gas prior to the refrigeration and liquefaction of the natural gas. To prevent backflow of amine into the piping and equipment upstream of the Absorber column, a check valve is sometimes specified; however, CCL proposes the use a loop seal. Therefore, we recommend in Section D that, prior to construction of final design, CCL should provide a check valve upstream of the Acid Gas Removal Column to prevent backflow or provide a dynamic simulation that shows that upon plant shutdown, the vertical piping segment would be sufficient for this purpose.

Once the acid gas components accumulate in the amine solution, the acid gas rich amine solution would be routed to an Amine Regenerator Distillation Column. The amine regenerator would essentially boil the acid gases out of the amine solution, leading to a lean, regenerated amine stream leaving the bottom of the column and an overhead vapor stream containing the acid gas components (H_2S and CO_2). The lean amine solution would be cycled back to the Acid Gas Absorber Column. The acid gas stream would then be routed to thermal oxidizers where trace amounts of H_2S not removed in the mercury/H_2S removal system and trace amounts of hydrocarbons would be incinerated and discharged to atmosphere, along with the CO_2 in the acid gas. Thermal oxidizers are commonly specified downstream of a Sulfur Removal Unit to further reduce emissions and decrease the hazard footprint over just venting the acid gas stream. In the event the thermal oxidizers would become out-of-service during operations, the acid gas would be routed to a dedicated acid gas flare.

Water in the treated feed gas from the Acid Gas Removal Unit would be removed by adsorption regenerative molecular sieve beds in the Dehydration Unit prior to the Liquefaction Unit. Each

Dehydration Unit would include three molecular sieve beds, any two of which would be in the adsorption mode with the third bed in regeneration or on stand-by mode. One Dehydration Unit would be provided for each liquefaction train. Molecular sieve beds would regenerate by passing a slipstream of dry feed gas, heated in the generation gas heater, in the reverse direction to the adsorption flow. The hot and moist regeneration gas would then pass through a cooler to remove bulk water which would circulate back to the Solvent Flash Drum between the Acid Gas Absorber Column and Amine Regeneration Column. Spent regeneration gas would be routed to a Regeneration Gas Compressor and injected back to the feed gas upstream of the Acid Gas Absorber column.

Each liquefaction train would contain a Heavy Hydrocarbon (HHC) Removal Unit comprised of two Heavies Removal Systems, and one Hydrocarbon Condensate Stabilization Unit. In these units, heavy hydrocarbons would be removed from the dry gas. The Heavies Removal Cold Box would house a Brazed Aluminum Heat Exchanger (BAHX), a Heavies Removal Column, and a Heavies Removal Reflux Drum. The feed gas would be precooled in the BAHX, using a slip stream of mixed refrigerant, and directed to the Heavies Removal Column where lighter components (e.g., methane, ethane, propane, etc.) rise, and heavier components (e.g., pentane, hexane, heptane, etc.) descend as liquid from the column's bottom. The lean gas would exit the Heavies Removal Cold Box and flow to the liquefaction system. The liquid product containing heavier components would be stripped using cooled vapor from the Heavies Removal Exchanger and sent to the Condensate Stabilization Unit. The Hydrocarbon Condensate Stabilization process would use a Refluxed Fractionation Column, the Condensate Stabilizer, a Reboiler heated by hot oil, and an Overhead Condenser. This process would result in an overhead liquefied petroleum gas (LPG) stream and a bottom stabilized condensate (e.g., pentane, hexane, heptane) stream. A portion of LPG would be recycled into the inlet of the Liquefaction Unit Cold Box, and the stabilized condensate would be sent to the existing condensate storage facilities.

In order to achieve the cryogenic temperatures needed to liquefy the treated natural gas stream from the HHC Removal Unit, the gas would be cooled by a thermal exchange process driven by a closed loop refrigeration system using a mixed refrigerant (MR). The MR Compressor would be electrically driven, and the MR would be comprised of a mixture of nitrogen, methane, ethylene, propane, n-butane, and iso-pentane. Methane would be provided from the feed gas stream entering the liquefaction process. Nitrogen makeup would be supplied from the on-site facility nitrogen utility header. The ethylene would be delivered by truck, stored on-site as a liquid and heated through an ambient vaporizer prior to being loaded onto the MR system. Propane, n-butane and iso-pentane fluids would be delivered by truck and stored onsite for initial filling of the refrigerant system and used, as needed, to restore refrigerant levels in the MR system. Truck unloading facilities would be installed as part of the already approved CCL Stage 3 Project to unload refrigerants into the refrigerant storage tanks. Four horizontal drums to store ethylene, propane, n-butane and iso-pentane refrigerants would be installed as part of this Project, and would serve all 9 midscale LNG trains. Individual molecular sieve dehydration vessels would also be provided for the propane, n-butane, and iso-pentane. Additionally, a MR Liquid Deinventory Drum would be installed in the Refrigerant Storage area. This MR recovery drum would allow mixed refrigerants to be recovered from the refrigerant loop during maintenance and planned shutdown instead of sending the MR to the flare.

The refrigeration for liquefying the feed gas would be provided by the heating and vaporization of MR streams fed to progressively colder points in the heat exchanger. High pressure MR would flow parallel with the feed gas initially, then would exit and reenter the exchanger and flow counter currently to the feed gas. The MR pressure is reduced progressively to cool the natural gas to its final desired temperature. As a result, all MR would exit the exchanger as vapor, where it would then be compressed, cooled, and sent back to the Liquefaction Unit Heat Exchanger. 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 3.3 million tonnes per annum for ideal conditions. FERC staff confirmed the HMBs support the application export capacity in terms of net maximum production during low ambient conditions. However, HMBs may be updated in final design in a way that could increase liquefaction production without increasing export capacity, therefore, as discussed below, we have included a recommend that CCL should provide updated PFDs and HMBs and any other engineering documentation that demonstrates the final design would be capable of liquefying natural gas and producing LNG for up to a 3.3 million tonnes per annum export capacity.

During liquefaction operations, LNG from Trains 8 & 9 would be sent to the three existing LNG Storage Tanks via an End Flash Gas (EFG) Unit. The EFG system would be constructed as part of the CCL Midscale Trains 8 & 9 project and would process LNG rundown for Midscale Trains 8 & 9 and the CCL Stage 3 trains approved under CP18-512. The EFG system would consist of a reboiler, a separation column, a flash gas exchanger, flash gas compressor and interstage coolers, and LNG forwarding pumps. LNG rundown from all 9 liquefaction trains would enter the Reboiler Heat Exchanger where the LNG rundown would be chilled with cold liquid from the bottom of the EFG Column. The chilled rundown would then be reduced in pressure and flashed in the EFG Column where the nitrogen rich gas would rise to the top of the column, and liquid LNG would fall to the bottom. LNG at the bottom of the column would circulate through the EFG Reboiler and enter the column again to further release nitrogen from the LNG stream. LNG at the bottom of the column would then be pumped to the existing LNG Storage Tanks. Nitrogen rich vapor at the top of the column would pass through an EFG Exchanger, warming in the process and cooling a methane stream from a potential Nitrogen Rejection Unit, which also enters the EFG Column. The warmed nitrogen rich gas exits the EFG Exchanger and would increase in pressure through several stages of compression with aftercoolers, and either be sent to a potential pipeline, or to the Nitrogen Rejection Unit for further processing. The LNG forwarding pumps in the EFG system would be sized for all 9 midscale LNG trains. A sudden trip of the LNG forwarding pumps would result in a sudden loss of flow to the LNG storage tanks. The sudden reduction in flow from the LNG forwarding pumps could cause pressure surge effects in the rundown line, which would result in increased pressure within the rundown line and increase reaction forces to the rundown line. To mitigate against dynamic surge effects from a sudden pump trip, we recommend in section D of the EA that prior to construction of final design, CCL 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 the design pressures or pipe support design loads.

CCL would be increasing their authorized ship loading rate from any single jetty from 12,000 m^3/hr to 14,000 m^3/hr. Dual ship loading would also be implemented under this Project at a combined rate of 22,500 m^3/hr. During export operations, LNG stored within the LNG Storage Tanks would be sent out through multiple in-tank pumps. The CCL Midscale Trains 8 & 9 project would add three additional in-tank pumps (one per tank) to allow for the increased ship loading rate. The existing pump discharge piping penetrates through the roof of the LNG Storage Tank and is then routed through a marine transfer line and multiple liquid marine transfer arms connected to an LNG marine vessel. The LNG marine transfer system is jurisdictional to the Coast Guard under 33 CFR Part 127, which incorporates NFPA 59A (2019) to provide requirements for piping system design, including secondary containment provisions. The marine transfer lines have emergency shutoff valves, and pressure relief capability is provided. Sudden closure of shutoff valves in the marine transfer line could cause pressure surges which would result in increased pressure within the transfer line, as well as increased reaction forces to the marine transfer line pipe supports. To mitigate against pressure surge effects from increased loading rates and dual loading, we recommend in section D of the EA that prior to construction of final design, CCL should 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.

To keep the marine transfer lines cold between LNG export cargoes and avoid a cooldown prior to every marine vessel loading operation, an LNG recirculation line maintains the marine transfer line temperature between ship loading operations. The LNG transferred to the LNG marine vessel displaces vapors from the marine vessel. Displaced vapors are routed through a vapor marine transfer arm, a vapor return line, and into the BOG header. Once loaded, the LNG marine carrier disconnects and departs for export.

Low pressure BOG generated from stored LNG and vapors returned during LNG marine carrier filling operations would be compressed and routed to the existing three large scale liquefaction trains for use as refrigerant. NFPA 59A (2001) section 3.4.5 requires a BOG and flash gas handling system separate from container pressure relief valves, designed so the BOG and flash gas discharge either safely into the atmosphere or into a closed system, and that the BOG venting system cannot normally inspirate air during operation. The closed BOG system prevents the release of BOG to the atmosphere and would be in accordance with NFPA 59A (2001). An additional electric motor driven BOG Compressor will be added to the existing facility, making a total of six BOG Compressors. This added BOG Compressor would increase operability and reliability of the facility. This is an inherently safer design when compared to allowing the BOG to vent to the atmosphere. To protect the LNG tank from vacuum conditions, pad gas for each LNG Storage Tank is pulled from the feed gas through a separate piping system and controlled via a pressure control valve. Should the vacuum conditions be significant, the LNG Storage Tank is equipped with vacuum relief valves. We recommend in section D of the EA that prior to construction of final design, CCL should 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. FERC staff would review the information on the LNG storage tank pressure vacuum relief devices, to confirm the existing LNG storage tank pressure and vacuum relief devices are adequate for the additional BOG compressor and dual ship loading.

The CCL Midscale Trains 8 & 9 Project would include many utilities and associated auxiliary equipment. The major auxiliary systems required for the operation of the liquefaction facility include fuel gas, flares, instrument and plant air, firewater, hot oil, nitrogen, diesel, and backup power.

Three existing flare systems at the Terminal Site would be used to handle and control the vent gases from all process areas including CCL Midscale Trains 8 & 9. One warm flare knock out drum, and one cold flare knock out drum would be installed and dedicated to Trains 8 & 9. The added knock out drums would be connected to the existing Stage 3 flares via the common flare header. The warm, cold, and acid gas flares would be routed to separate ground flares located in common areas. A Marine Vapor Control System Package (elevated low-pressure flare) would be utilized for the venting requirements in the marine area during a warm LNG ship cool down operation. The safety relief valves are designed to handle process upsets and thermal expansion. NFPA 59A (2001) sections 6.1.1 and 6.8.2 require thermal expansion relief valves be installed as required to prevent overpressure in any section of piping handling flammable liquids or gases with service temperatures below -20 degrees F that can be isolated by valves. A spare pressure relief valve is installed on most systems that are continuously used by all process trains to maintain those systems in operation during pressure safety valve (PSV) maintenance. FERC Staff notes that some common non-spared process vessels are proposed without redundant relief valves, such as refrigerant storage vessels. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should specify, for review and approval, redundant, full capacity relief valves for the Ethylene, Propane, Butane, and Pentane storage drums.

Electricity for the facility would be provided from the local electrical grid connection. Back-up power would be provided by Diesel Engine Generators, one for each train, to equipment essential for safe shutdown. Each generator would have its own day tank sized for 24-hour continuous operation.

The diesel would be supplied by ISO Containers or trucks. Additionally, 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 Condensate Stabilization Reboiler, the Regeneration Gas Heater, the Feed Gas Heater, and the Amine Regenerator Reboiler. The hot oil would be heated by a gas-fired Hot Oil Furnace. One Hot Oil Furnace would be installed per train.

New air compressors and air receiver would be installed to provide both instrument air and plant air to the proposed facilities. Each liquefaction train would have a pair of air compressors, one operating, one spare, powered by main power from the Stage 3 Project Main GIS Substation via AEP Texas. In the event of a power loss, each air compressor would be connected to receive power from the emergency generators. To provide intermittent higher loads of instrument air in the event of a safe plant shutdown, there would be one instrument air receiver per liquefaction train. Upon inquiry, CCL also indicated it would update its list of codes and standards in final design to include ISA 7.0.01, Quality Standard for Instrument Air.

High purity nitrogen would be supplied by an existing pipeline from Air Liquide via the CCL Stage 3 nitrogen system. Nitrogen for the sixth BOG Compressor would be supplied from the existing Liquefication Project.

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 D of the EA that prior to construction of final design, CCL should file, for review and approval, up-to-date PFDs, HMBs, and P&IDs including vendor P&IDs. The HMBs should demonstrate a peak export rate of 3.3 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 D of the EA that prior to construction of final design, CCL 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. CCL would install process control valves and instrumentation 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 (BPCSs), 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 system[34] 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 Part 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

34 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.

(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 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 BPCS (e.g., DCS) or by 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 ESD 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 ISA (ISA 84) series and 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 D of the EA that, prior to construction of final design, CCL should 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).

CCL indicated in their application that alarms would have visual and audible notification in the control room 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 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. Related industries, including pipelines regulated by DOT PHMSA under 49 CFR 192 now require operators to address control room management and fatigue in 49 CFR § 192.631 and incorporate API 1165, *Recommended Practice for Pipeline SCADA Displays.* CCL'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 5.1, Instrumentation Symbols and Identification;
- ISA 5.2, Binary Logic Diagrams for Process Operations;
- ISA 5.3, *Graphic Symbols for Distributed Control/Shared Display Instrumentation Logic and Computer Systems;*
- ISA 5.4, Instrument Loop Diagrams;
- ISA 5.5, *Graphic Symbols for Process Displays;*
- ISA 18.1, *Annunciator Sequences and Specifications;*
- 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 60.6, *Nameplates Labels and Tags for Control Centers;*
- ISA 71.04, *Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants; and*
- IEC 61131-3, *Programmable Controllers – Part 3: Programming Languages*.

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. Further guidance may also be found in ISA 71.01, *Environmental Conditions for Process Measurement and Control Systems: Temperature and Humidity*, which is now referenced in NFPA 59A (2019 and 2023 editions) A.11.7.1 and ISA 71.02, *Environmental Conditions for Process Measurement and Control Systems: Power*, and ISA 71.03, *Environmental Conditions for Process Measurement and Control Systems: Mechanical Influences*.

In order to ensure the functionality of the BPCSs, we also recommend in section D of the EA that prior to introduction of hazardous fluids, CCL should file, for review and approval, 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. Further guidance may be found in IEC 62381, *Automation Systems in the Process Industry- Factory Acceptance Test (FAT), Site Acceptance Test (SAT), and Site Integration Test (SIT)*, which is now referenced in NFPA 59A (2019 and 2023 editions) A.11.7.1.

CCL would implement an alarm management program and procedures for the control of equipment as part of the Stage 3 Project (Docket No. CP19-512) 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. CCL indicated the facilities being added as a part of the Project would be included in the alarm management program, but did not provide any further details. Therefore, we recommend in section D of the EA that prior to introduction of hazardous fluids, CCL should file, for review and approval, 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. If authorized and recommendations are adopted as conditions, FERC staff would evaluate whether CCL has 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. CCL 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 D of the EA that CCL should 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). We also recommend in section D of the EA that prior to commissioning, CCL 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 Coast Guard 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*, *American Gas Association's*, *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 be 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 D of the EA that prior to commissioning, CCL 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 in section D of the EA that prior to commencement of service, CCL 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 Part 68. Therefore, we recommend in section D of the EA that prior to commencement of service, CCL should file, for review and approval. procedures for offsite contractors' responsibilities, restrictions, monitoring, training, and limitations and for supervision of these contractors and their tasks by CCL 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; and

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).

While 49 CFR § 193.2017 requires each operator review and update the plans and procedures required in 49 CFR 193 and 49 CFR § 193.2707 requires each operator be qualified by training, experience and acceptable performance on a proficiency test, incidents and other inspection findings have also demonstrated that having procedures in place and training on them for both operating and maintenance personnel, including contractors, does not ensure that operators and contractors are following such procedures. As recognized in AIChE CCPS, *Guidelines for Writing Effective Operating and Maintenance Procedures*, procedures are best developed and periodically reviewed by operating and maintenance personnel conducting the operation and maintenance tasks within the procedures and as recognized in AIChE CCPS, *Conduct of Operations and Operational Discipline*, indicators of effective conduct of operations and operating discipline or excellence include not only that personnel are trained in normal and abnormal operations, trained on the basis for the procedures and operating limits, and assigned to tasks based on their qualifications to perform the specific task, but also include and are not limited to:

- personnel are involved in the development of procedures;
- supervisors are aware of who is qualified to perform each task;
- correct procedure use is enforced and rationale for exceptions or changes to established procedures are communicated by management so that workers understand the situations;
- structured methods for changing procedures are in place and widely used;
- personnel are always seeking to improve their performance and, as a result, there is extensive use of self-checking, peer-checking, audits, incident investigations, management reviews, and metrics to identify and eliminate deviations;
- personnel embrace feedback from personnel outside their group as opportunities to improve their systems and processes;
- management systems are developed based on the results of proactive analyses and industry best practices;
- organizational changes are assessed to determine impacts on existing management systems;
- leadership follow the same rules they preach for front-line personnel;
- leadership gather and consider input from front-line personnel when making changes to the organization or facilities.

Many of these characteristics are also reflected in the foundational blocks of risk based process safety management system and are nearly identical to some of the 21 elements in AIChE CCPS, *Guidelines for Risk Based Process Safety*, including the workforce involvement element in Committing to Process Safety foundational block, conduct of operations element in Managing Risk foundational block, and the incident investigation element, management and metrics element, auditing element, and management review and continuous improvement element in Learn from Experience foundational block. Not implementing, tracking, and striving to meet such indicators often are precursors to deviating from operating and maintenance procedures that have led to incidents within and outside the LNG industry. Therefore, we recommend in section D of the EA that prior to commencement of service, CCL should file, for review and approval, a written management system that it would implement to document and track process safety metrics consistent with API 754 or approved equivalent, including Tier 4 metrics that include, but are not limited to whether personnel are involved in the development of procedures they are assigned, whether supervisors are using only qualified personnel for carrying out procedures, whether personnel are adhering to procedures, whether deviations from procedures are investigated, whether procedural and organizational changes are subjected to management of change requirements.

<u>Safety Instrumented Systems and Emergency Shutdown Systems</u>

In the event of a process deviation, SISs and ESD valves would monitor, alarm, shutdown, and isolate equipment and piping during process upsets or emergency conditions. CCL would install SISs 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 ESD 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 BPCSs SISs, including the feed gas 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 ESD and fire and gas systems, 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[35] 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) section 9.2.1 requires each LNG facility to incorporate ESD system(s) 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.

[35] 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.

However, 49 CFR § 193.2401 provide limited requirements for where instrumentation and shutdowns must be installed, as discussed in Process Control Systems, 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.

CCL's 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, and design philosophies, 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; and*
- 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).

CCL's application indicated that the current version at the time of design would be used. Therefore, we recommend CCL in section D of the EA, as also discussed in Final Specifications and QMS, that prior to construction of final design CCL 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.

In their application, CCL 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, CCL 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 D of the EA that, prior to construction of final design, CCL should file, for review and approval, cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD 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 D of the EA that, prior to construction of final design, CCL should specify, for review and approval, that all ESD valves are to be equipped with open and closed position switches connected to the DCS/ SIS. The effectiveness of these valves is 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 D of the EA that prior to construction of final design, CCL should file, for review and approval, an evaluation of ESD valve closure times. The evaluation should account for the time to detect an upset or hazardous condition, notify plant personnel, and close the ESD 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 D of the EA that, prior to introduction of hazardous fluids, CCL should 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.

Process Hazard Analysis

In order to assess the process design, control systems, SISs, and ESD systems, companies will typically conduct a 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)(3) requires applicants to discuss operational measures to avoid or reduce risk. 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, CCL conducted a Hazard and Operability study (HAZOP) of the project's preliminary design based on the proposed process flow diagrams and the plot plans, including for such proposed facilities and changes as Trains 8 & 9 and its OSBL area as well as EFG Unit, refrigerant storage, and increased loading rate. This is consistent with NFPA 59A (2019) and later editions which requires consideration of a PHA for the plant and 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. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, information to verify how the EPC contractors has addressed all FEED HAZOP recommendations.

A detailed HAZOP analysis would be performed by CCL 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 to define the reliability through average probabilities of failure on demand ($PFD_{average}$) for the safeguards, or layers of protection. The safety integrity level is often specified as a safety integrity level 1, safety integrity level 2, or higher safety integrity level corresponding to a $PFD_{average}$ of 10%, 1%, or lower, or, in other words, a risk reduction factor of 10, 100, or higher. The estimated initiating event frequency and safety integrity levels of the safeguards, often SISs, are then specified until they would meet specified targeted risk tolerance criteria. The safety integrity level of a safeguard is then often verified through a safety integrity level verification study that evaluates historical failure frequencies of those safeguards. In some cases, companies will skip the LOPA and jump straight to defining a safety integrity level during the HAZOP and conduct a safety integrity level verification study. In any case, the HAZOP, and any LOPAs and safety integrity level 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 D of the EA that prior to construction of final design, CCL should file, for review and approval, a HAZOP study, and any LOPA or safety integrity level verification studies on the final design, a list of the resulting recommendations, and actions taken on the recommendations. The issued for construction P&IDs should incorporate the 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 constructed we would evaluate the HAZOP, and any LOPA and safety integrity level 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, *Guidelines for Hazard Evaluation Procedures*. In addition, FERC staff would monitor whether the resolutions of the recommendations generated by the HAZOP review 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.

Title 49 CFR Part 193, Subpart C Design includes regulations for the design of LNG facilities, and Subpart E Equipment includes regulations for the design and fabrication of vaporization equipment, liquefaction equipment, and control systems. 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 determine 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 D of the EA that prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and 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 D of the EA that prior to construction of final design, CCL 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[36] (e.g., threaded one end, threaded both ends, concentric and eccentric swage nipples, etc.), reducers[37], 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).

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36 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.

37 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.

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 Part 127 Subpart B covers Coast Guard 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*.

CCL listed NFPA 59A (2001 edition) as a mandatory code and standard it would comply, but then also listed ASME B31.3, *Process Piping*, ASME B31.5, *Refrigeration Piping and Heat Transfer Components*, ASME B31.8, *Gas Transmission and Distribution Piping Systems*, as non-mandatory code and standard. For all non-mandatory code and standards, CCL indicated it would comply with latest version as of June 17, 2017, which would be the 2016 edition for ASME B31.3, ASME B31.5, and ASME B31.8. However, CCL piping specifications indicate the Project would comply with NFPA 59A (2001 edition) and ASME B31.3 (2014 edition) or just ASME B31.3 (2014 edition). While FERC staff generally supports the use of more up to date 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 2016 editions) would be considered equivalent by DOT PHMSA for compliance with 49 CFR Part 193. Compliance with 49 CFR Part 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 would 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) 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. As aforementioned, materials of construction will depend primarily on the fluid service, process conditions, and external environment. Listed and unlisted materials must therefore conform to published specifications, such as those published by the 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. Non-potable water piping (e.g., utility water, wastewater, etc.) and potable water service piping is commonly specified in accordance with International Code Council, *International Building Code*, and International Code Council, *International Plumbing Code*, and is commonly specified as polyvinyl chloride or chlorinated PVC, respectively. Other common process piping materials of construction in LNG plants include aluminum. The piping materials of construction then typically have specified ASTM that standardized the chemical compositions and material properties, as described above, such as ASTM A106, *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service* or ASTM A312, *Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes*. For all piping, CCL proposed materials of construction that were 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 and 2016 editions) and consistent with those commonly specified and in operation at other LNG facilities under FERC jurisdiction.

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 that the fluid must travel through the piping. CCL 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 nominal pipe size (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). While CCL listed ASME B31.3, *Process Piping*, ASME B31.5, *Refrigeration Piping*, ASME B31.8 *Gas Transmission Piping*, ASME B36.10M, *Welded and Seamless Wrought Steel Pipe*, and ASME B36.19M, *Stainless Steel Pipe*, as non-mandatory codes and standards it shall use on the Project, the piping specifications for process piping utilized ASME B31.3 (2014 edition). However, CCL is not proposing any power generation or any new gas transmission lines with this Project and while there is liquefaction equipment that involves refrigeration, ASME B31.3, Process Piping (1996) 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. Therefore, FERC staff found the piping codes referenced to be suitable and would not pose any safety or reliability impacts. Further, CCL 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. ASME construction codes indicate that corrosion allowances should be considered (e.g., ASME Section VIII par UG-25 and ASME B31.3 par 302.4), however, no discrete values are prescribed. In addition, our 2017 Guidance suggests that material of construction and corrosivity potential be discussed. While CCL provided corrosion allowances for a host of piping systems and equipment, its application of corrosion allowances was inconsistent in as various systems and with similar service fluids, process conditions, and materials of construction, had varying corrosion allowances and no discussion was provided in support of its selections. It is unclear if the selection of corrosion allowances is consistent with ASME Section VIII par UG-25 and ASME B31.3 par 302.4. Further, it is unclear the absence of a corrosion allowance on systems subject to corrosion would be consistent the inspection criteria of API 510 or 570. Therefore, we recommend in Section D that prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications should include mechanical specifications for piping, valves, insulation, rotating equipment, heat exchanger, storage tank and vessel, other specialized equipment. In addition, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, documentation demonstrating that the corrosion allowances for piping and pressure vessels systems are consistent with ASME B31.3 (or appropriate ASME B31 code), ASME Section VIII, and the inspection intervals prescribed by the facility's preventative maintenance program governing the internal, external, corrosion under insulation, and metal thickness inspections (e.g., API 510, API 570).

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 of 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 CCL does not specify all hazardous fluid piping and piping nipples 2-inch and less as schedule 160 or thicker for carbon steel piping and does not specify 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, such as aluminum, 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 (2016 edition). Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a pipe stress analysis for critical or potential higher consequence lines that evaluates all loads in ASME B31.3 (2016 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. CCL should 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.

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 15.3, 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 flowrate in the rundown line from the CCL Stage 3 facilities to the LNG storage tank would increase with the additional production from trains 8 and 9. Additionally, CCL plans to increase the single berth ship loading rate from 12,000 m^3/hr to 14,000 m^3/hr, and implement simultaneous ship loading at a combined rate of 22,500 m^3/hr by installing one high capacity in-tank pump in each of the existing three LNG storage tanks. When the LNG rundown flowrates and ship loading rates 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 and ship loading rate, we recommend in section D of the EA that prior to construction of final design, CCL 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 or 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 under ASME B31.3 (1996 and 2016 editions) paragraph 319. However, the additional requirements differ between editions. For example, the 2016 edition accounts for axial stress in the computed displacement stress range in paragraph 319.4.4(a) whereas the 1996 edition does not account for axial stress. Conversely, the 1996 edition requires welds to be fully examined with paragraph 341.4.3 when the computed displacement stress range exceeds 80% of the allowable stress and the equivalent number of cycles exceeds 7,000, but the 2016 edition does not have any such weld quality assurance stipulations. In order to verify the adequacy of these analyses done typically in final design, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a pipe stress analysis for critical or potential higher consequence lines that evaluates all loads in ASME B31.3 (2016 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. CCL specifications indicated that all 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. CCL'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; and*
- 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.

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

- ASME B1.1, *Unified Screw Threads;*
- ASME B1.20.1, *Pipe Threads General Purpose (Inch);*
- ASME B16.5, *Pipe Flanges and Flanged Fitting;*
- ASME B16.9, *Buttwelding Fittings;*
- ASME B16.11, *Forged Fittings, Socket-Welding and Threaded;*
- ASME B16.20, *Metallic Gaskets for Pipe Flanges;*
- 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; and*
- ASME B16.48, *Steel Line Blanks.*

Although not listed in their application under codes and standards to be used in the project, CCL specifications referenced 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*. As discussed in Final Specifications and Quality Management Systems, we recommend in section D of the EA that prior to construction of final design, CCL 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. In addition, CCL valve specifications indicate the use of the latest edition as of June 17, 2017 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 Part 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. CCL has proposed flange facings consistent with fluid service, flange class ratings, and process pressures and temperatures. FERC staff also evaluated pipe 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. CCL 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 D of the EA that prior to commissioning, CCL should file, for review and approval, the procedures for pressure/leak tests of piping which address the requirements of ASME BPVC section VIII and ASME B31.3. In addition, CCL should file 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) section 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. As aforementioned, CCL listed NFPA 59A (2001 edition) as a mandatory standard and ASME B31.3, *Process Piping*, 2016 edition, as a non-mandatory standard. In addition, CCL listed ASME B31.5, *Refrigeration Piping*, and ASME B31.8 *Gas Transmission and Distribution Systems* as non-mandatory codes and 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[38]); 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

[38] 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).

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.

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 valves in ASME B31.3 (1996 edition), include:

- 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;* and
- 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.

CCL 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 Pressure-Relief Valves for Flanged Pressure Relief Valves 1 in or Larger;*
- API 527, *Seat Tightness of Safety Relief Valves*;
- API 594, *Check Valves: Wafer, Wafer Lug and Double Flanged Type*, 5th;
- API 600, *Bolted Bonnet Steel Gate Valves for Petroleum and Natural Gas Industrie*s;
- API 601, *Metallic Gaskets for Raised Face Pipe Flanges and Flanged Connections (Double Jacketed Corrugated and Spiral-Wound)*;
- API 602, *Compact Steel Gate Valves Flanged, Treaded Welding and Extended Body Ends*;
- API 608, *Metal Ball Valves-Flanged, threaded and Welding Ends*; and
- API 609, *Butterfly Valves: Double Flanged, Lug and Wafer Type,*

We note that API 601 is not a listed standard and has been superseded by ASME B16.20. In addition, although not listed in their application under codes and standards to be used in the project, CCL specifications referenced API 623, *Steel Globe Valves – Flanged and Buttwelding Ends, Bolted Bonnets*. API 623 is also not a listed standard, but generally has thicker walled construction and lower emission performance compared to ASME B16.34. As discussed in Final Specifications and Quality Management Systems, we recommend in section D of the EA that prior to construction of final design, CCL 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. In addition, CCL valve specifications indicate the use of the latest edition as of June 17, 2017 and addenda in effect at the time of purchase, while other specifications list earlier code versions. 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 Part 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 ASME BPVC, Section VIII, 1992 edition, including Addenda and applicable Code Interpretation Cases, or in accordance with 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[39], and coordinated on the development of frequently asked questions (FAQs) to address compliance.[40] 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

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

40 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#d5, Accessed March 2024.

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. CCL would need to pursue one of these options with PHMSA. At the time of application, CCL indicated in their application compliance with ASME BPVC Section VIII, 2021 edition. However, the latest edition is now the 2023 edition. 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 Part 193 would be subject to DOT PHMSA inspection and enforcement program.

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, FERC staff recommends in section D of the EA, as discussed in Final Specifications and Quality Management Systems section, that prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and final mechanical data sheets, and 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 D of the EA that prior to commissioning, CCL should file, for review and approval, procedures for pressure/leak tests of pressure vessels, which address the requirements of ASME BPVC Section VIII. In addition, CCL should file a list of pneumatic and hydrostatic test pressure. CCL should demonstrate that the test pressures consistent with ASME BPVC Section VIII (1992) do not exceed the yield strength of the pressure vessels.

<u>Heat Exchangers</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 13.24 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 ASME *Boiler and Pressure Vessel Code* (BPVC), Section VIII, 1992 edition, including Addenda and applicable Code Interpretation Cases, or in accordance with 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.

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, while NFPA 59A (2019 and 2023 editions) require shell and tube heat exchangers to still be designed and fabricated in accordance with ASME BPVC Section VIII or CSA B51, it no longer requires (since 2006 edition) shell and tube heat exchangers to meet Tubular Exchanger Manufacturers Association standards. However, NFPA 59A (2019 and 2023 editions) require brazed aluminum plate-fin heat exchangers to be designed and fabricated to ASME BPVC Section VIII and Aluminum Plate-Fin Heat Exchanger Manufacturers' Association (ALPEMA), *Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturers' Association*. In addition, NFPA 59A (2019 and 2023 editions) section 7.5.6 also stipulates heat exchangers be designed in accordance with recognized standards and A.7.5.6 lists the following:

- API 660, *Shell and Tube Heat Exchangers for General Refinery Services*;
- API 661 *Air Cooled Heat Exchangers for General Refinery Services*; and
- API 662, *Plate Heat Exchangers for General Refinery Services, Part 1 and Part 2*.

We also note API publishes other heat exchanger standards, such as API 664, *Spiral Plate Heat Exchangers*, and published in November 2018, the first edition of API 668, *Brazed Aluminum Plate-fin Heat Exchangers*. ALPEMA provided responses in February 2022 to requirements in API 668 that may be provide additional guidance, such as recommended use of 80 Tyler mesh (177 micron) filters and limiting mercury content to 0.1 micrograms per Normal cubic meter even for mercury tolerant designs[41]. As part of its FERC application, CCL 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:

- ASME BPVC Section VIII;
- API 660, *Shell and Tube Heat Exchangers for General Refinery Services*;
- API 661 *Air Cooled Heat Exchangers for General Refinery Services*.
- ALPEMA, *Standards of the Brazed Aluminum Plate-Fin Heat Exchanger Manufacturers' Association*; and
- Tubular Exchanger Manufacturers Association standards *Standards of the Tubular Exchanger Manufacturers Association*.

FERC staff agree the adherence to recognized standards in the design and fabrication would better ensure the heat exchangers are designed safely and reliably. However, final equipment lists, process and mechanical datasheets, and specifications would be subject to change until the design is finalized, so as discussed in Final Specifications and Quality Management Systems, we recommend in section D of the EA, that prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project.

Atmospheric and Low Pressure Containers

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 13.8.2 covers heavies/condensate storage design, 13.11.1 covers LNG storage tank design, section 13.16.1 covers heat transfer fluid storage design, section 13.22.1 covers utility water storage design, section 13.22.2 covers other utilities storage design,

41 ALPEMA, ALPEMA Responses to Requirements in API 668, https://www.alpema.org/ALPEMA_responses_to_Requirements_in_API_668_Feb2022.pdf, Accessed April 2024.

and section 13.38.1 covers firewater storage design, including references to any mechanical specifications in 13.F.2, such as Appendix 13.F.2.6 that covers storage tank specifications, federal regulatory requirements in 13.C, and codes and standards in Appendix 13.D.

Title 49 CFR § 193.2101 requires LNG facilities to comply with NFPA 59A (2001 edition) and each stationary LNG storage tank to comply with section 7.2.2 of NFPA 59A (2006 edition) for seismic design of field fabricated tanks and all other LNG storage tanks to comply with API 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*, 1990 edition, for seismic design.

CCL is not proposing any LNG storage tanks, therefore, only the requirements of NFPA 59A (2001 edition) would be applicable for atmospheric and low-pressure containers. As discussed in Final Specifications and Quality Management Systems, NFPA 59A (2001 edition) requires flammable refrigerant and flammable liquid storage installation to comply with NFPA 30 (2000 edition), NFPA 58 (2001 edition), NFPA 59 (2001 edition), API 2510 (1989 edition), or NFPA 59A (2001 edition) section 2.2, however, NFPA 59A (2001 edition) section 2.2 only provides requirements for site provisions for spill and leak control and not the design of atmospheric and low-pressure containers.

NFPA 30 (2000 edition) section 4.2.3.1.1 requires atmospheric tanks to be designed and constructed in accordance with recognized engineering standards or approved equivalent, and the following standards are deemed as meeting these requirements:

- API 12B, *Bolted Tanks for Storage of Production Liquids*;
- API 12D, *Field Welded Tanks for Storage of Production Liquids*;
- API 12F, *Shop Welded Tanks for Storage of Production Liquids*;
- API 650, *Welded Tanks for Oil Storage*;
- UL 58, *Steel Underground Tanks for Flammable and Combustible Liquids*;
- UL 80, *Steel Tanks for Oil-Burner Fuels and Other Combustible Liquids*;
- UL 142, *Steel Aboveground Tanks for Flammable and Combustible Liquids*;
- UL 1316, *Glass-Fiber Reinforced Plastic Underground Storage Tanks for Petroleum Products, Alcohols, and Alcohol-Gasoline Mixtures*;
- UL 2080, *Fire Resistant Tanks for Flammable and Combustible Liquids*; and
- UL 2085, *Protected Aboveground Tanks for Flammable and Combustible Liquids.*

The latest edition of NFPA 30 (2024 edition) section 21.4.2.1.1 has the same requirement except that it also stipulates the following as recognized engineering standards meeting these requirements:

- UL 142A, *Safety for Special Purpose Aboveground Tanks for Specific Flammable or Combustible Liquids*; and
- UL 2258, *Aboveground Nonmetallic Tanks for Fuel Oil and Other Combustible Liquids*.

NFPA 30 (2000 edition) section 4.2.3.2.1 require low-pressure tanks to be designed and constructed to API 620 or ASME BPVC Section VIII, Division 1. NFPA 30 (2000 edition) section 4.2.3.3.1 require containers above 15 psig to be designed and constructed with recognized engineering standards or approved equivalents and ASME BPVC Section I or Section VIII are deemed as meeting these requirements.

NFPA 58 (2001 edition) section 2.2.1.3 require containers to be designed, fabricated, tested, and marked or stamped in accordance with regulations of DOT[42], ASME BPVC Section VIII, except for UG-125 through UG-136, or API/ASME, *Code for Unfired Pressure Vessels for Petroleum Liquids and Gases*. NFPA 58 (2001 edition) section 9.1.1.1 require refrigerated containers designed to operate above 15 psig to meet ASME BPVC Section VIII, except that construction using joint efficiencies listed in Table UW12, Column C, are not permitted, and NFPA 58 (2001 edition) section 9.1.1.2 require refrigerated containers designed to operate at or below 15 psig to be in accordance with API 620, including Appendix R.

Similarly, NFPA 59 (2001 edition) section 5.1.1 require shop-fabricated non-refrigerated containers to be designed, constructed, and tested in accordance with ASME BPVC Section VIII, except UG-125 through UG-136, and NFPA 59 (2001 edition) section 5.2.2 require field-erected non-refrigerated containers to be built in accordance with ASME BPVC, except that construction using joint efficiencies listed in Table UW12, Column C, are not permitted. NFPA 59 (2001 edition) section 6.1.1.1 require refrigerated containers designed to operate greater than 15 psig to be designed and constructed in accordance with ASME BPVC Section VIII, except that construction using joint efficiencies listed in Table UW12, Column C, are not permitted. NFPA 59 (2001 edition) section 6.1.1.3 requires refrigerated containers designed to operate below 15 psig to be in accordance with API 620, including Appendix R.

API 2510 (2001 edition) section 4.1.1 requires vessels meet the requirements of ASME BPVC, Section VIII and API 2510 (2001 edition) section 11.2.1.1 requires refrigerated containers with design pressures of less than 15 psig to conform to API 620 and refrigerated containers with design pressures of at least 15 psig to be designed in accordance with ASME BPVC Section VIII.

NFPA 59A (2001 edition) sections 10.15.4.5 and 11.5.5.1 also stipulate fire protection systems shall be inspected and tested in accordance with NFPA 22 (1998 edition). While firewater tanks are not required, NFPA 59A (2001 edition) requires fire protection to be provided based on a fire protection evaluation that evaluates the type, quantity, and location of equipment necessary for the control of fires of LNG, flammable refrigerants, and flammable gases, and section A.9.1.2 references NFPA 22 among other standards for information on fire extinguishing systems. NFPA 22 (1998 edition) then makes reference in its requirements to AWWA D100, *Welded Carbon Steel Tanks for Water Storage;* AWWA D103, *Factory Coated Bolted Carbon Steel Tanks for Water Storage;* AWWA D110, *Wire- and Strand-Wound, Circular, Prestressed Concrete Water Tanks;* AWWA D115, *Tendon-Prestressed Concrete Water Tanks;* and AWWA D120, *Thermosetting Fiberglass Reinforced Plastic Tanks* for the various types of firewater tanks. NFPA 22 also makes reference to:

- for various types of firewater tanks:
  - AWWA D100, *Welded Carbon Steel Tanks for Water Storage;*
  - AWWA D103, *Factory Coated Bolted Carbon Steel Tanks for Water Storage;*
  - AWWA D110, *Wire- and Strand-Wound, Circular, Prestressed Concrete Water Tanks;*
  - AWWA D115, *Tendon-Prestressed Concrete Water Tanks;* and
  - AWWA D120, *Thermosetting Fiberglass Reinforced Plastic Tanks*.
- for foundations:
  - ACI 318, *Building Code Requirements for Structural Concrete and Commentary*;

42 NFPA 58 (2024 edition) specifically calls out DOT regulations in 49 CFR and DOT FAA regulations in 14 CFR while NFPA 58 (2001 edition) more broadly calls out just DOT regulations.

- for concrete tanks:
  - ACI 350R, *Environmental Engineering Concrete Structures*;
- for coating systems:
  - AWWA D102, *Coating Steel Water Storage Tanks*, for coating systems; and
- for gaskets and sealants resisting chlorination exposure:
  - AWWA C652, *Disinfection of Water-Storage Facilities*.

AWWA D107, *Composite Elevated Tanks*, and AWWA D121, *Bolted Aboveground Thermosetting Fiberglass Reinforced Plastic Panel Type Tanks for Water Storage*, are also referenced in NFPA 22 (2018 and 2023 editions). While it is unclear whether the federal regulations require the above-mentioned containers must meet the above-mentioned recognized engineering standards, as part of its FERC application, CCL included the following applicable atmospheric and low-pressure container codes, standards, and recommended and generally accepted good engineering practices among others in their list of non-mandatory codes and standards that they would use for the Project[43]:

- NFPA 58 (2004 edition);
- NFPA 59 (2015 edition);
- API 620 (11^{th} edition, Addendum 3, March 1, 2012);
- API 650 (12^{th} edition, March 1, 2013);
- API 653 (4^{th} edition, Addendum 3, November 1, 2013);
- ASME BPVC Section VIII (2017 edition);
- NFPA 22 (2013 edition); and
- AWWA D100 (2011 edition).

CCL also listed NFPA 30 (2021 edition) and ASME BPVC Section VIII (2021 edition) in their list of mandatory codes and standards that they would use for the Project.[44]

FERC staff agree the adherence to recognized standards in the design and fabrication of atmospheric and low-pressure containers would better ensure the materials of construction and design are suited to the pressure and temperature conditions of the process design. However, referenced ASME BPVC edition dates conflict, CCL indicated it will use its two existing firewater tanks and is not proposing any new firewater tanks where NFPA 22 would be applicable, CCL did not propose any new water tanks where AWWA D100 would be applicable, CCL did not propose any new low-pressure tanks where API 620 would be applicable, and final equipment lists, process and mechanical datasheets, and specifications would be subject to change until the design is finalized, so as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project. For similar reasons, as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL 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

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43 CCL indicated that the effective date of non-mandatory codes and standards is the latest version as of June 17, 2017, unless otherwise noted with a specific version or edition date.

44 CCL indicated that the effective date of non-mandatory codes and standards is the latest version as of October 21, 2022, unless otherwise noted with a specific version or edition date.

specifications and document numbers. FERC staff would review these final specifications and codes, standards, and recommended and generally accepted good engineering practices to ensure there are no gaps. For example, we note NFPA 59 (2001 edition) section 6.1.1.3 requires refrigerated containers designed to operate below 15 psig to be in accordance with API 620, including Appendix R. However, NFPA 59 (2024 edition) section 6.2.1.1 requires refrigerated containers designed to operate below 7 psig and above 5,000 barrels to be in accordance with API 625, *Tank Systems for Refrigerated Liquefied Gas Storage*, and NFPA 59 (2024 edition) section 6.2.1.2 require metal containers that are part of a refrigerated tank system to comply with API 620 and additional provisions of NFPA 59 (2024 edition) Chapter 6. Therefore, it is unclear if there are any requirements refrigerated containers designed to operate above 7 psig and below 15 psig for NFPA 59 (2024 edition).

<u>Rotating 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 13.25 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.

NFPA 59A (2001 edition) sections 10.15.4.5 and 11.5.5.1 also stipulate fire protection control systems shall be inspected and tested in accordance with NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*, 1999 edition. While firewater pumps are not required, NFPA 59A (2001 edition) requires fire protection to be provided based on a fire protection evaluation that evaluates the type, quantity, and location of equipment necessary for the control of fires of LNG, flammable refrigerants, and flammable gases, and section A.9.1.2 references NFPA 20 among other standards for information on fire extinguishing systems.

While federal regulations may not require rotating equipment to meet any recommended or generally accepted good engineering practices, as part of their application, CCL 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 546, *Brushless Synchronous Machines. 500 KVA and Larger*, 2008 edition;
- API 547, *General-purpose Form-wound Squirrel Cage Induction Motors 250*

Horsepower and Larger, 2005 edition;

- API 610, *Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries, Eleventh Edition*, September 2010;
- 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 672, *Packaged, Integrally Geared, Centrifugal Air Compressors for Petroleum, Chemical and Gas Industry Service*, Fourth Edition, 2004;
- API 675, *Positive Displacement Pumps – Controlled Volume*, 2005 edition;
- API 676, *Positive Displacement Pumps – Rotary*, 2009 edition;
- API 682, *Pumps—Shaft Sealing Systems for Centrifugal and Rotary Pumps*, 2006 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; and
- NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*, 2010 edition.

In addition, CCL referenced API 610, API 617, API 618, and API 661 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 recognized standards in the design and fabrication would better ensure the rotating equipment selections are suited for the proposed process design and process safety systems. However, CCL did not propose any new reciprocating compressors where API 619 would be applicable, and equipment lists, process and mechanical datasheets, and specifications would be subject to change until the design is finalized, so as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL should file, for review and approval, an up-to-date equipment list, process and mechanical data sheets, and specifications for the project. For similar reasons, as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL 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.

Fired 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 13.26 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). NFPA 59A (2019 edition) also requires fired heaters and burner management systems to be installed in accordance with recognized standards and provides examples in the annex, such as API 556, *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*, API 560, *Fired Heaters for General Refinery Service*, NFPA 85, *Boiler and Combustion Systems Hazards Code*, and ASME CSD-1, *Controls and Safety Devices for Automatically Fired Boilers*.

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.

CCL proposes to install one thermal oxidizer and one hot oil heater per train that would be considered fired equipment. While federal regulations do not require adherence to recommended and generally accepted good engineering conditions, as part of their application, CCL 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 and Control Systems for Gas Fired Heaters and Steam Generators*, 1997 edition;
- API 560. *Fired Heaters for General Refinery Service*, 2016 edition;
- ASME, *BPVC*;
- NFPA 54, National Fuel Gas Code, edition;
- NFPA 85B, Prevention of Furnace Explosion in Natural Gas Fired Multiple Burner Boiler Furnace, edition;
- NFPA 86, Standards for Ovens and Furnaces;

- NFPA 8501, Boiler Operation – Single burner, edition; and
- NFPA 8502, Furnace Explosions, Implosions in Multiple Burner Boilers, edition.

In addition, the datasheets for the thermal oxidizer indicates it would be designed to API 560, NFPA 86, *Standard for Ovens and Furnaces*. The mechanical datasheet for the hot oil furnace/heater indicates it would be designed to API 530, *Calculation of heater- tube Thickness in Petroleum Refineries*, 2008 edition, API 535, *Burners for Fired Heaters in General Refinery Services*, API 556, and API 560. Resource Report 13 also indicated the burner management system would be per NFPA 85. 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 recognized 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, equipment lists, process and mechanical datasheets, and specifications would be subject to change until the design is finalized, so as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL should file, for review and approval, final equipment lists, process and mechanical data sheets, and specifications for the project. In addition, as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL 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.

Pressure and Vacuum Relief Valves

Pressure and vacuum safety relief valves are installed to protect the storage containers, pressure vessels, process equipment, and piping from an unexpected or uncontrolled pressure excursion in the event an operator or SIS 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 Part 127 Subpart B covers Coast Guard 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, 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 MAWP 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 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, CCL is 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 edition;
- Phillips Petroleum Company, Bulletin E-2, *How to Size Safety Relief Devices; and*
- Phillips Petroleum Company, *A Study of Available Fire Test Data as Related to Tank Car Safety Device Relieving Capacity Formulas*, 1971 edition.

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; "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; and*
- 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.

CCL 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, CCL listed they would use the following applicable codes, standards, 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;*
- API 537, *Flare Details for General Refinery and Petrochemical Service;* and
- API 2000, *Venting Atmospheric and Low-Pressure Storage Tanks (Nonrefrigerated and Refrigerated).*

FERC staff agree the adherence to recognized standards would better ensure the safety and reliability of the pressure relief valves and effluent handling systems (e.g., vents, flares, etc.). However, pressure relief lists, sizing, process and mechanical datasheets, and specifications would be subject to change until the design is finalized, so as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL should file, for review and approval, final equipment lists, process and mechanical data sheets, and specifications for the project. In addition, as discussed and recommended in Final Specifications and Quality Management Systems, prior to construction of final design, CCL 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.

In addition, the Project would utilize the existing flare system for emergency, maintenance, and startup reliefs. As discussed in the Process Design section, CCL is proposing to add four horizontal drums to store ethylene, propane, n-butane, and iso-pentane refrigerants. During refrigerant filling operations, vapor displacement from the refrigerant storage drums would be routed back to the truck. During refrigerant deinventory operations, vapor generation would be routed either through pressure vents to the existing dry flare or to the EFG unit. FERC staff note CCL's relief system design basis, provided in Appendix B of the application, specifies both pressure and vacuum relief protection for pressure vessels which would include the refrigerant storage drums. Typically, vacuum relief protection is not provided for pressure vessels. FERC staff verified the data sheets and P&IDs include pressure relief protection for the refrigerant storage drums, however, vacuum relief protection does not appear to be included in the FEED. Therefore, it appears the relief design basis may have inadvertently included vacuum relief protection for pressure vessels. CCL would need to review the relief system design basis to ensure appropriate relief protection is included in the design. CCL also proposes to add an Amine Storage Tank which would have specifications for pressure/vacuum reliefs and vents. Equipment and piping systems for the process design would also include pressure relief devices for overpressure protection. Relief and vent sizing would be based on relief calculations which would be performed in final design.

CCL's application also included a list of pressure relief valves with most including set pressures, sizing, and capacities in Appendix M. In addition, CCL provided a flare load and venting sizing and capacities in Appendix R. However, some of the pressure relief valve devices included notes that sizes would be confirmed in final design and subsequent calculations that form the basis of these capacities demonstrating the pressure were within allowable limits were not provided. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should 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 tank.

In order to facilitate testing and maintenance of pressure relief valves such that more consequential vessels are continuously 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 D of the EA that prior to construction of final design, CCL should specify, for review and approval, 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 D of the EA that prior to construction of final design, CCL 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, CCL 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 Part 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; and
- 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 D of the EA that prior to commissioning, CCL 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. The operational maintenance and testing procedures for fire protection components should be in accordance with NFPA 59A (2019) or approved equivalent. In addition, we recommend in section D of the EA that prior to commencement of service, CCL should file, for review and approval, 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 Coast Guard. 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*; and
- 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 D of the EA that prior to construction of final design, CCL should file, for review and approval, 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 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 ESD 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, in evaluating the appropriateness and execution of a fire risk assessment, for a given fire safety problem. NFPA 551 (2022 edition) section 1.2 purpose is intended to assist with the evaluation of fire risk assessment 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, ESD 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.

CCL performed a preliminary fire protection evaluation to ensure that adequate mitigation would be in place, including spill containment and spacing, hazard detection, ESD and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response. We recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a final 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 should be filed. The evaluation should justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD 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 should 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 should take into account the set points, voting logic, wind speeds, and wind directions. 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.

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. As suggested in our 2017 Guidance Manual, section 13.34, this should include a description and drawings of the spill containment design.

Further, under NFPA 59A (2001 edition), 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 authority having jurisdiction. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR Part 193, must comply with the design requirements of 49 CFR Part 193, Subpart C and would be subject to PHMSA's inspection and enforcement programs. The impoundment system design for the marine facilities would be subject to the Coast Guard's 33 CFR Part 127, which does not specify a spill or duration for impoundment sizing. FERC staff evaluates the impoundment sizing based on the largest flow capacity from a single pipe for 10 minutes at pump runout flow rates 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. FERC staff performed an impoundment sizing analysis for all impoundments and further discussed below.

CCL indicated that all piping, hoses, and equipment that could produce a hazardous liquid spill would be provided with spill collection and/or spill conveyance systems. CCL proposes to install curbing, paving, and troughs to direct potential hazardous liquid spills, involving LNG, refrigerants, heavy hydrocarbons and other hazardous material releases to impoundment basins. Three new impoundments have been proposed for the Project, including an ISBL Impoundment Basin located in the pretreatment area for each of the two proposed trains and an impoundment basin located within the proposed Refrigerant Storage area. CCL also proposed to construct curbing around essential diesel generators and a dike around the amine storage tank area. CCL provided information indicating the size of the impoundment basins, dikes, and the local containment areas would be adequate for the spill scenarios considered.

Releases of hazardous liquids in the pretreatment area, consisting of hot oil and/or amine solvent would be trenched to the ISBL basin and preliminary information provided indicates the size of ISBL impoundment would be adequate to contain the spills in the ISBL area. The FERC impoundment sizing evaluation was based assessing the largest flow capacity from a single pipe for 10 minutes at pump runout flow rates, accounting for de-inventory and 10 minutes of firewater, or the liquid capacity of the largest vessel (or total of impounded vessels) served. The evaluation demonstrated that the sizing of the ISBL impoundment basin would be able to contain a spill of the hot oil system's inventory. However, detailed information would need to be provided to ensure the final designs of the ISBL impoundments would be adequately sized. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, spill containment system drawings with dimensions and slopes of curbing, trenches, impoundment, tertiary containment and capacity calculations considering any foundations and equipment within the impoundment. 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 and 10 minutes of firewater, 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.

Releases from the refrigerant area, consisting of ethylene, propane, n-butane, and iso-pentane would be trenched to the Refrigerant Storage Impoundment Basin and preliminary information provided indicates the size of the refrigerant impoundment would be adequate to contain the spills in the Refrigerant Storage area. The FERC impoundment sizing evaluation was based assessing the largest flow capacity from a single pipe for 10 minutes at pump runout flow rates, accounting for de-inventory and 10 minutes of firewater, or the liquid capacity of the largest vessel (or total of impounded vessels) served, therefore the sizing of the Refrigerant Storage Impoundment Basin was based on the total of impounded vessels. The refrigerant storage vessel spill volumes were calculated in accordance with API 2510 Section 5.4. However, detailed information would need to be provided to ensure the final design of the Refrigerant Storage area impoundment would be adequately sized. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, spill containment system drawings with dimensions and slopes of curbing, trenches, impoundment, tertiary containment and capacity calculations considering any foundations and equipment within the impoundment. 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 and 10 minutes of firewater, 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.

Hazardous liquid spills occurring at the diesel generator for each train would be contained within its diked area. The diesel sizing spill accounts for the entire contents of the diesel day tank which would be contained in the diked area. We recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, spill containment system drawings with dimensions and slopes of curbing, impoundment, tertiary containment and capacity calculations considering any foundations and equipment within this impoundment area. 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 and 10 minutes of firewater, 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.

Additionally, two previously approved impoundment basins that were part of the CCL Stage 3 facility are also being utilized for the Midscale Trains 8 & 9 Project facility. This includes the Process Impoundment Basin and Transfer Line Impoundment Basin. The Process Impoundment Basin would provide containment for hazardous liquid spills emanating from the liquefaction areas of all trains, proposed EFG Unit, as well as off the rundown line, whereas the Transfer Line Impoundment Basin would collect releases from this transfer line. These approved impoundments were sized for a larger release including pump runout of in-tank pumps for a single LNG tank in the midscale train area, however CCL filed a motion to vacate the originally authorized Stage 3 LNG Storage Tank on March 27, 2023, and FERC granted this motion in an Order Vacating Authorization in Part on May 18, 2023, but will keep the impoundments sized for the larger spill volume. CCL indicates that all containment areas would be paved, and the spill conveyance system would be constructed of concrete. Further, liquid releases off the piperack between the proposed Midscale 8 & 9 trains and existing trains and near the Refrigerant Storage area and EFG Unit would be directed to either the Process Area LNG Spill Impoundment Basin or the Transfer LNG Spill Impoundment Basin. Additionally, CCL provided sizing basis for the trenches leading to the impoundment basins. We recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments and capacity calculations considering any foundations and equipment within these 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 and 10 minutes of firewater, 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.

To achieve increased loading rate and simultaneous loading of both berths, CCL has proposed adding one additional high capacity in-tank pump to each of the existing three LNG storage tanks, for a total of five LNG pumps per tank with four at a high capacity and one at a lower capacity. Liquid releases from LNG tank top piping would be conveyed down from the tank top via a downcomer pipe to grade-level trenches. The increased loading rate would result in a larger worst-case spill. NFPA 59A-2001 Table 2.2.3.5 states that for containers with over-the-top fill, with no penetrations below the liquid level, the design spill is the largest flow from any single line that could be pumped into the impounding area with the container withdrawal pumps considered to be delivering at full rated capacity. CCL provided preliminary discussion and calculations on sizing for the tank downcomer. FERC staff performed a sizing analysis on the existing tank downcomers for a release from all in-tank pumps at the increased loading rate flow, including pump runout, and determined the downcomers would be adequately sized for the increased loading rate flow and associated vaporization within the downcomers. Further, CCL stated that there would be no changes to the existing downcomers for the increased loading rates; however, this is based on preliminary design and could be subjected to change; therefore, CCL should demonstrate the size of the existing down-comer is sufficient to convey the larger spill volume with the proposed additional pump in each LNG tank. Additionally, preliminary information provided to FERC staff indicates the trenches in the existing area could be inadequate because their demonstrated capacity of the exiting trenches did not consider pump runout for the maximum proposed ship loading rate. CCL indicated the loading lines would be isolated from each other during dual loading scenarios, which would reduce the maximum total spill rate from a single loading line. FERC staff inquired about the full dimensions including the slope of every trench segment that moves LNG spills to either the OSBL Impoundment Basin or the Jetty Impoundment Basin as well as the capacity of these trench segments match the expected maximum LNG spills from increased LNG loading rate at pump runout. CCL responded that they proposed the use of a Safety

Integrity Level (safety integrity level) 2 surveillance and shutdown system to ensure that the spill would be contained within the existing trench system, which would be provided during detailed engineering. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, final design drawings and spill sizing calculations for the existing LNG Storage Tank spill collection and conveyance system, considering vapor formation rates, that demonstrates the existing spill conveyance systems, including their downcomers, would be adequately sized to convey a spill with an additional LNG pump in each storage tank. Additionally, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, impoundment swale hydraulics analysis on the OSBL and Jetty Impoundment Basins that demonstrates the maximum sizing spill controlled by the proposed safety integrity level 2 rated system could be contained without overtopping each trench segment and provide the dimensions of the minimum, maximum trench height, and the slope and length of each section of their trench systems.

NFPA 59A (2001), section 2.2.2.2 as mentioned above requires 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. FERC staff evaluates the impoundment sizing based on the largest flow capacity from a single pipe for 10 minutes at pump runout flow rates accounting for de-inventory and 10 minutes of firewater, 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. FERC staff analyzed the impoundment sizing for the existing OSBL and Jetty Impoundment Basins and found that they are approximately half of the identified spill volume for the proposed increased single ship loading rate and simultaneous ship loading. However, to prevent potential LNG releases from exceeding the capacity of the existing OSBL and Jetty Impoundments, CCL would include in the final design several control system interlocks, and a safety integrity level 2 surveillance and shutdown system to limit the size and duration of potential LNG releases associated with their optimized loading plans. CCL would install one additional pump in each LNG storage tank for a total of fifteen (15) total in-tank pumps that could produce approximately 11,000 m^3/hr per LNG storage tank or a total of 33,000 m^3/hr for all three tanks. During single ship loading, CCL would use a control system interlocks to prevent no more than seven LNG loading pumps from operating simultaneously to ensure the proposed 14,000 m^3/hr ship loading rate is not exceeded in any piping segment. During dual ship loading, another interlock would prevent misdirected flow that would result in flowrates higher than the spill containment design basis. CCL provided preliminary spill sizing calculations and a preliminary safety integrity level 2 surveillance analysis in their application to determine: the maximum LNG spill that could occur at the higher loading rate; the time needed for the surveillance and shutdown system to react to the low temperature detectors near the existing impoundments, and; prevent hazardous liquid spills from possibly overfilling the impoundments and backing up into the LNG trenches. FERC staff reviewed the preliminary spill sizing calculations and the proposed safety integrity level 2 surveillance system. However, some of the preliminary input factors used in the analysis, such as maximum pump runout factor, longest total pipe length involved, valve closure time, etc. are not sufficiently conservative for the FEED level assessment. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a finalized sizing spill analysis and supporting documentation that considers the maximum LNG spill for the increased loading rate and demonstrate how the spill would be limited by a safety integrity level 2 rated system or equivalent. The analysis should include spill containment drawings and calculations and consider the maximum flowrates, largest piping deinventory, and a feasible instrument response time for the surveillance and shutdown system. Additionally, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, final details on the interlocks that specify the loading rate would not exceed 14,000 m^3/hr for both the East and West Jetties.

Furthermore, during our review of the existing OSBL and Jetty impoundments and their LNG trench conveyance system, the OSBL and Jetty Impoundment Basins appear to each have a concrete outlet channel that is connected to the stormwater drainage system. The bottom of these concrete outlets appears to be at the same elevation of the entrance point of the LNG conveyance trenches into these impoundment basins. And, as discussed above, the LNG release size due to the proposed increased single ship loading rate and simultaneous ship loading could result in a spill volume that is nearly twice the capacity of these impoundments, potentially result in an overflow of the impoundment and a release of hazardous liquids into the connected outlet channel and stormwater ditch. And while CCL plans to limit the maximum LNG spill volume for the proposed increased single ship loading rate and simultaneous ship loading with a safety integrity level 2 rated system, if this safety integrity level system did not function as designed or was inoperable, a maximum LNG release from the sendout line or loading line due to the higher capacity in-tank pumps could result in LNG flowing out of these potentially undersized impoundments and overflowing into the stormwater drainage system, which is not designed for or intended to control LNG spills, and could also discharge into the shipping channel. Even without a stormwater trench connected to the impoundments, a spill volume that is nearly twice the capacity of these impoundments would still potentially result in an overflow and have the potential to spill onto nearby ground and enter surrounding stormwater drainage systems. Therefore, the addition of impoundments and/or trench systems may be necessary to capture the volume from the largest flow capacity from a single pipe for 10 minutes at pump runout flow rates, accounting for de-inventory and 10 minutes of firewater. Additionally, portions of the stormwater drainage system contain ditches that are covered. PHMSA regulations in 49 CFR § 193.2167 prohibits covered impoundment systems. Further, 33 CFR § 127.321(a)(1) states that "operator of the waterfront facility handling LNG must ensure that no person releases LNG into the navigable waters of the United States". If the Project is authorized, constructed, and operated, it would be subject to 33 CFR Part 127 and 49 CFR Part 193, Subpart C and the respective Coast Guard and PHMSA inspection and enforcement programs. Therefore, as an additional layer of protection to prevent further conveyance downstream of these impoundments, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a plan, including mitigative measures or design modifications, to inhibit conveyance of an LNG spill downstream of the OSBL and Jetty Impoundment Basins into the stormwater conveyance system in the event of a safety system failure.

Rainwater collected within the impoundments would reduce their maximum capacity. Automatic pumps within these impoundments would remove the rainwater ensuring their maximum capacity is available. Low temperature interlocks would be provided to automatically shut off or prevent startup of the water removal pumps upon detection of a spill in the LNG impoundments. Stormwater removal pumps are also proposed for the impoundment basins and diked secondary containment systems. The curbed containment systems for hazardous fluids would also drain to an impoundment basin. As defined in 49 CFR § 193.2173, the water removal system of an impoundment system must have adequate capacity to remove water at a rate equal to 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes. CCL provided NOAA/ National Weather Service Atlas 14, Volume 11, Version 2, point precipitation frequency estimates for site location that indicated a 10 year mean recurrence interval for a 1 hour duration rainfall to be 3.12 inches.[45] Based on the surface area of the impounding system, including curbed areas, trenches, and impoundment, and the runoff coefficient, the sump pump withdrawal rate would be less than the 25% of the maximum predicted rainwater collection rate, which would not seem to meet the requirements of 49 CFR § 193.2173. Specifically, the P&IDs provided by CCL indicate that the stormwater pumping capacity for the ISBL Impoundment Basin's sump pumps in

45 National Oceanic and Atmospheric Administration (NOAA), National Weather Service (NWS), Atlas 14, Volume 11, Version 2, Point Precipitation Frequency Estimates, https://hdsc.nws.noaa.gov/pfds/pfds_map_cont.html?bkmrk=tx and https://www.weather.gov/owp/hdsc_currentpf, Accessed April 2024.

Trains 8 & 9 may be less than what is required to meet 49 CFR § 193.217, but it is unclear as federal regulations do not specify minimum values or criteria for runoff coefficients or other reduction factors that could be used. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, detailed calculations for sump pumps for all impoundments potentially impacted by proposed Project facilities demonstrating they can remove at least 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration using National Weather Service, Atlas 14, Volume 11, Version 2, or approved equivalent. FERC staff would coordinate this review with DOT PHMSA.

If the Project is authorized and constructed, CCL would install spill containment systems in accordance with its approved final 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, in the Operational Inspections section, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff to verify that impoundments are being properly maintained to ensure their effectiveness and reliability.

<u>Spacing and Plant Layout</u>

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 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 edition) section 2.2.4.1 requires that for LNG containers with storage capacity larger than 75,000 gallons, the edge of the impoundment or container drainage system must be at least 100 feet or a distance equivalent to 0.7 times the container diameter away from buildings and plant property lines. NFPA 59A (2001 edition) section 2.2.5.2 requires integral heated vaporizers must be located at least 100 feet from the property line and 50 feet away from the impounded LNG, LNG containers, unfired process equipment, loading and unloading connections, control buildings, offices, shops, and other occupied or important plant structures. 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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127. Title 33 CFR **§** 127.105(a) requires LNG impounding spaces to be located so that the heat flux from a fire over the impounding spaces does not cause structural damage to an LNG vessel moored or berthed at the waterfront facility handling LNG. Title 33 CFR **§** 127.105(a) also requires each LNG loading flange be located at least 300 meters (984.3 feet) from each bridge crossing a navigable waterway and each entrance to any tunnel under a navigable waterway primarily intended for the use of the general public or railways: Title 33 CFR **§** 127.101 also incorporates NFPA 59A (2019 edition) section 6.7. NFPA 59A (2019 edition) section 6.7.1 requires buildings or structural enclosures not covered by the design, fire and explosion control, and ventilation requirements of NFPA 59A (2019 edition), must be located, or provision otherwise be made, to minimize the possibility of entry of flammable gases or vapors and section 6.7.2 requires they be located no less than 50 ft from tanks, vessels, and gasketed or sealed connections to equipment containing LNG and other hazardous fluids. However, 33 CFR Part 127 no longer incorporates general spacing requirements in NFPA 59A (2019 edition) 6.2, process equipment spacing requirements in NFPA 59A (2019 edition) section 6.5, loading and unloading facilities spacing requirements from uncontrolled sources of ignition, process areas, storage containers, control buildings, offices, shops, and other occupied or important plant structures unless the equipment is directly associated with the transfer operation in NFPA 59A (2019 edition) section 6.6.3, or other impoundment spacing requirements in NFPA 59A (2019 edition) section 6.8. If authorized, constructed, and operated, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard inspection and enforcement programs.

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 CCL 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.

CCL listed NFPA 59A (2001 edition) and NFPA 30 (2021 edition) as “mandatory codes and standards” and CCL also listed NFPA 58 (2004 edition), NFPA 59 (2015 edition), API 2510, *Design and Construction of LPG Installations (LPG)*, 8th (2001) edition, API 752, *Management of Hazards Associated with Location of Process Plant Buildings*, 3rd (2009) edition, and API 753, *Management of Hazards Associated with Location of Process Plant Portable Buildings*, 1st (2007) edition, among other applicable standards as “non-mandatory codes and standards”.

To minimize the risk of cryogenic spills causing structural supports and equipment from cooling below their minimum design metal temperature, CCL would generally locate 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. In addition, CCL would protect equipment and structural members against cold shocks through the selection of suitable materials of construction or by the application of cold proofing or shielding, which is discussed further in the Passive Protection section along with recommendations.

To minimize risk for flammable or toxic vapor ingress into buildings and from reaching areas that could result in cascading damage from explosions, CCL would generally locate buildings, fired equipment, and ignition sources away from process areas. CCL would include flammable gas detection near all combustion and building ventilation air intakes within the facility such that upon activation, the gas detectors would alert operators and the associated equipment or air intake would shut down. Shutdown for HVAC systems would be based on detection from two gas detectors for that air intake. However, the specific installed locations of the detectors would need to be verified as appropriate during final design. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a technical review of the final design of the locations of buildings that shows their locations are consistent with API 752 (2009 edition) and API 753 (2007 edition), or approved equivalents. In addition, we recommend in section D of the EA that prior to construction of final design, CCL should also file, for review and approval, a technical review of the final design of the facility that identifies all combustion/ventilation air intake equipment, shows the detailed placement of detectors at those air intakes to detect flammable gas or toxic releases, and verifies 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 D of the EA 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, in the Operational Inspections section, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff 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. Vapor cloud explosions in process areas were evaluated by CCL using the Baker-Strehlow method to evaluate the extent of overpressures. The results demonstrate that process area explosions could generate overpressures greater than 1 pound per square inch (psi) within Trains 8 & 9 and could impact critical equipment, including the emergency power diesel generators. Additionally, CCL's analysis demonstrated an ethylene vapor cloud explosion occurring within the existing Train 1 due to a release from the nearby proposed Refrigerant Storage area could produce an overpressure greater than 1 psi upon the existing CCL Stage 3 firewater tanks and pumps. CCL noted that the overpressure hazards to the 1 psi threshold remain within the project property line but did not consider cascading impacts from the overpressures upon critical equipment and vessels, such as existing firewater tanks, firewater pumps, and proposed emergency power diesel generators. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, an evaluation that demonstrates overpressures would not cause failure of the firewater tanks and pumps, emergency diesel generators, and any other significant components or provide mitigation measures that would prevent the failure of these components. Alternatively, CCL should provide drawings and calculations for mitigation measures that would be installed to prevent failure of these components due to this overpressures concern.

To minimize the risk of pool fires from causing cascading damage, CCL generally located the spill impoundments such that the radiant heats would have a minimal impact on most areas of the plant or position in areas with low risk for cascading damage. As discussed in the spill containment section above, there are three new impoundments proposed for the Project including an impoundment basin located in the pretreatment area within each proposed new train and an impoundment basin located within the proposed Refrigerant Storage area. For the ISBL impoundments, there are equipment, vessels, and piperack situated in close proximity to them that could be exposed to high radiant heat levels in the case of an impoundment fire with the closest ones being the below grade and within a sump structure Amine Sump Drum and an above grade Amine Sump Pump and Amine Storage Tank as well as an adjacent piperack. Both the Amine Sump Drum and Amine Storage Tank contain an aqueous amine mixture. However, the nearby piperack carries hot oil, flare, amine, fuel gas, and water lines that if its support structure was weakened and destroyed by high radiant heats from a nearby impoundment fire then the lines carrying flammable and combustible material could break and result in a potential hazardous liquid release from the damaged fuel, flare, and hot oil lines that could result in cascading damage. Furthermore, also adjacent to this piperack on its other side, a diesel-powered generator is located along with its day tank that could be damaged or destroyed from a nearby cascading event resulting in additional damage to nearby equipment or buildings. More details on the adequacies or potential gaps in coverage for passive and active protection measures for the proposed Project are discussed in the Passive Protection and Firewater sections below. CCL also indicated that, based on LNGFIRE3 modeling, a fire in the Refrigerant Storage area basin would produce greater than 4,000 Btu/ft^2-hr heat flux over the MR Liquid Deinventory Drum, Iso-Pentane Storage Drum, and N-Butane Storage Drum. However, this would be the heat level for an LNG fire in those impoundments, and the use of a model that could account for the actual composition of the fluids would likely show less radiant heat for fires involving non-LNG refrigerants due to higher soot production and flame shielding from smoke. Additionally, the hazard modeling showed firefighting equipment located near the refrigerant impoundment that would be within or near 10,000 Btu/ft^2-hr flux level. FERC staff asked that this basin be relocated to a distance that the high radiant heat fluxes could not impact nearby firefighting equipment or refrigerant storage vessels. CCL responded that the location of the remote impoundment met API Standard 2510, being located at least 50 feet from the vessels draining to it and from any hydrocarbon piping or other equipment, but they did not address the cascading damage concerns from potential high radiant heat fluxes upon the firefighting equipment or refrigerant storage vessels. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, an evaluation to demonstrate a fire at the ISBL and refrigerant impoundments would not pose cascading damage risk to any of equipment, vessels, or building in the pretreatment area as well as the firefighting equipment and vessels in the refrigerant storage area using methods and/or models that would appropriately account for the composition of an ISBL and refrigerant impoundment fires. To further mitigate cascading impacts from impoundment fires, CCL proposed to install firewater hydrants and monitors throughout the proposed Project's site. We recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, supporting firewater demand calculations that demonstrate there would be adequate firewater supply and delivery devices to mitigate the consequences of radiant heats from impoundment fires. We also recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, drawings and specifications for the passive fire protection systems, demonstrating that structural supports and equipment would be adequately protected from fire scenarios (e.g., design spills) that may exacerbate the initial hazard.

To minimize the risk of jet fires from causing cascading damage that could exacerbate the initial hazard, CCL would generally locate flammable and combustible containing piping and equipment away from buildings and process areas that do not handle flammable and combustible materials. Heat impacts from jet fires in process areas could also reach pressure vessels, structural members, and other significant components. To mitigate these exposures, CCL would install ESD systems that would limit the duration of a jet fire event, depressurization systems that would reduce the pressure in equipment and would install firewater systems to cool equipment and structures as described in the Firewater Systems section. CCL provided updated thermal radiation modeling for jet fire scenarios involving LNG releases from the existing rundown and loading lines due to the increased ship loading rate with radiant heat isopleths for 1,600 Btu/ft^2-hr, 3,000 Btu/ft^2-hr, 4,000 Btu/ft^2-hr, and 10,000 Btu/ft^2-hr flux levels as well as their current active and/or passive protection for these already approved areas. FERC staff reviewed this updated hazard modeling for jet fires from the existing transfer and loading lines at the increased loading rate, and the current active and/or passive protection for these already approved areas could have adequate protection measures, including in locations containing existing occupied buildings, pressurized equipment, structural supports, and process equipment or machinery, but will be verified during final design. Additionally, CCL also provided thermal radiation modeling for jet fire scenarios associated with the proposed Project's facilities including LNG releases within the Trains 8 & 9, such as from the Cold box outlet and off the already approved CCL Stage 3 rundown line; non-LNG releases within the Trains 8 & 9, such as from the MR Accumulator, Heavies Removal Reflux Drum, Absorber, and from refrigerant storage vessels; as well as LNG and non-LNG releases within the EFG Unit system. The modeling included radiant heat isopleths for 1,600 Btu/ft^2-hr, 3,000 Btu/ft^2-hr, 4,000 Btu/ft^2-hr, and 10,000 Btu/ft^2-hr flux levels as well as the current active and/or passive protection for these areas. FERC staff reviewed the hazard modeling for jet fires within the proposed Project's facilities, and the proposed active and/or passive protection for these areas could have adequate protection measures in some areas, including in locations containing pressurized equipment, structural supports, and process equipment or machinery, but will be verified during final design. Additionally, more details on the adequacies or potential gaps in coverage for these protection measures for the proposed Project are discussed in the Passive Protection and Firewater sections below. Since modification to the existing facility and changes to its process conditions for the proposed Project could impact the existing terminal and its facilities, these active and passive protection measures for the existing and proposed Project's new facilities would need to be assessed for adequacy within final design. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, drawings and specifications for the passive fire protection systems, demonstrating that structural supports and equipment would be adequately protected from fire scenarios (e.g., design spills) that may exacerbate the initial hazard. In addition, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a detailed quantitative analysis demonstrating that adequate mitigation would be provided for each significant component (pressure vessels, hazardous fluid containing equipment, etc.) within the 4,000 Btu/ft^2-hr and structural steel within the 4,900 Btu/ft^2-hr zone from jet fires that could cause failure of the component.

In addition, FERC staff evaluated the spacing to determine if there could be cascading damage from fires to inform what fire protection measures may be necessary to reduce the risk of cascading damage. To mitigate against fires within the plant, CCL proposes thermal radiation mitigation measures to prevent cascading events in the design, including emergency depressurization, flame, combustible gas and low temperature detectors, fire proofing of structural steel columns supporting critical equipment, wheeled extinguishers, and firewater monitors and hydrants. However, details of these systems would be developed in final design. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, final design information on these thermal mitigation measures, for review and approval, to demonstrate cascading events would be mitigated.

If the Project is authorized, CCL would finalize the plot plan, and we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. If the facilities are constructed, CCL would install equipment in accordance with the spacing indicated on the plot plans. In addition, in Construction Progress and Reporting, we discussed that Project facilities be subject to periodic inspections during construction. This would enable FERC staff to inspect whether equipment is installed in appropriate locations and the spacing is met in the field. In the Operational Inspections section, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff to inspect and continue to verify that equipment setbacks from other equipment and ignition sources are being maintained during operations.

<u>Ignition Controls</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. 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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127. Title 33 CFR § 127.107 require electrical power systems to meet NFPA 70 (2020 edition). NFPA 70 (2020 edition) also contains figures for areas where electrical equipment should be classified for hazardous locations. If authorized, constructed, and operated, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 70 (2020 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 CCL proposed to use and whether the electrical area classification drawings for the proposed CCL Midscale Trains 8 & 9 facilities were consistent with those standards or other applicable codes and standards. CCL listed NFPA 59A (2001 edition) and NFPA 70 (2020 edition) as "mandatory codes and standards" and CCK listed the following among other applicable standards as "non-mandatory codes and standards":

- 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*, 2021 edition,
- API 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2,* 3rd (2012) edition,
- API 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class 1, Zone 0, 1, and 2*, 2nd (2018) edition,
- ISA 12.01.01, *Electrical Instruments in Hazardous Atmospheres*, 2009 edition,

- And ISA 12.06.01, *Recommended Practice for Wiring Methods for Hazardous (Classified) Locations Instrumentation Part 1: Intrinsic Safety*, 2003 edition.

CCL provided a set of figures for the area classification philosophies that also includes a note incorporating the codes mentioned above. Based upon the electrical area classification drawings and area classification philosophies, FERC staff determined that CCL utilized appropriate hazardous area classification methods for most areas. CCL in most locations appropriately applied API 500 figures 20 and 21 for near grade and above grade potential flammable gas and liquid leakage points within the pretreatment and liquefaction areas of the midscale trains and Refrigerant Storage area and in certain locations within the EFG Unit. However, as a whole for the EFG Unit area, CCL specified only a 50 ft classified distance for near grade and above grade potential flammable gas and liquid releases from its equipment, vessels, and piping, even though API 500 requires a 100 ft classified distance for Division 2 areas where releases of highly volatile liquids (HVLs) or large releases of volatile products may occur. FERC staff informed CCL that there are large quantities of cold methane exiting the EFG exchanger to the EFG column as well as significant amounts of LNG leaving the EFG column via the LNG pumps. CCL responded that the additional 50 ft horizontal extent with 2 ft vertical classified distance is typical for refinery installations and there are no process streams that contain HVL within the EFG process. API 500 stipulates include liquids such as butane, ethane, ethylene, propane, propylene, *liquefied natural gas*, natural gas liquids, and mixtures of such. API 500 notes vapor pressures of these liquids exceed 276 kilopascals (40 psia) at 37.8°C (100°F). Furthermore, from a performance-based perspective, NFPA 497, *Recommended Practice for Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*, bases Class 1 Division 2 distances based on dispersion of flammable vapors to 25% lower flammable limit (LFL) from a 1 lb-mol/min release. FERC staff modeled the dispersion distances in PHAST version 8.11 to the 25% LFL for 1 lb-mol/min under same 100 psig pressure for LNG at -260°F through a 1/8 inch (3.2 millimeter [mm]) diameter hole to equate to 16 pounds per minute (lb/min), ethylene at -74°F through a 5/32 inch (4.0 mm) diameter hole to equate to 28 lb/min, ethane at -39° F through a 11/64 inch (4.4 mm) diameter hole to equate to 30 lb/min, and propane at 64° F through a 13/64 inch (3.175 mm) diameter hole to equate to 44 lb/min. The results show they would all extend approximately 100 ft in 1.5 m/s (3.3 mph) wind and D and F stabilities and extend to approximately 50 ft in 5 m/s (11 mph) wind and D stability despite LNG being stipulated with a smaller release size and lower mass flow rate to get to the same 1 lb-mol/min release rate. As such, FERC staff believe the area surrounding the EFG Unit was not classified correctly because of the large quantities of LNG, defined as a HVL in API 500, leaving the EFG Column via the LNG pumps should invoke the API 500 HVL prescriptive distances of 100 ft and the NFPA 497 performance based option also yields 100 ft for LNG. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL 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). FERC staff also recognizes risk-based methods for electrical area classification found in Energy Institute 15, *Model Code of Safe Practice Part 15: Area Classification for Installations Handling Flammable Fluids*, 4th (2015) edition, subject also to PHMSA and Coast Guard approval as they can be less than the prescriptive- and performance-based requirements incorporated by reference in federal regulations. Energy Institute 15 also uses 25% LFL for its flammable concentrations and provides hazard radii for 1 mm (0.04 inch), 2 mm (0.08 inch), 5 mm (0.2 inch), 10 mm (0.40 inch), and 30 mm (1.2 inch) equivalent hole diameters and LNG release pressures of 1.5 bar absolute (7.1 psig), 5 bar absolute (60 psig), and 10 bar (130 psig). The distances for hazard radius 1 range from 2.2 meters (7.2 feet) to 20.4 meters (66.9 feet) and hazard radius 2 range from 1.8 meters (5.9 feet) to 40.1 meters

(132 feet) dependent on the hole diameter and release pressure. The hole diameters are stipulated based on the risk range level. For example, a risk range level of 1e-3 to 1e-4 per release-source-year, flanges are stipulated as a 5mm (0.2 inch) hole diameter and range from 6.2 meters (20 feet) to 12.6 meters (41.3 feet) and valves are stipulated as 10mm hole diameter and range from 9.8 meters (32 feet) to 40.1 meters (132 feet) depending on release pressure. By contrast, a risk range level of greater than 1e-2 per release-source-year, flanges and valves are stipulated as a 1mm hole diameter and range from 2.2 meters (7.2 feet) to 2.9 meters (9.5 feet) depending on release pressure. Depending on where in the system, LNG pressures may fall within the Energy Institute 15 ranges or may exceed the pressures listed in Energy Institute 15 that form the LNG hazard radii distances. FERC staff also modeled in PHAST version 8.11 with these release hole diameters within the Energy Institute 15 listed LNG release pressures and in exceedance of the maximum listed LNG release pressure of 10 bar absolute (130 psig) and found distances to 25% LFL of approximately 10-15 feet for 1 mm (0.04 inch), 20-50 ft for 2 mm (0.08 inch)), 90-170 feet for 5 mm (0.2 inch), and 220-350 feet for 10 mm (0.40 inch) for 1.5 m/s (3.3 mph) and 5 m/s (11 mph) wind speeds and D and F stabilities. Alternatively, CCL could potentially request a modification and demonstrate equivalency using risk-based methods and standards subject to written approval.

If our recommendations are adopted and facilities are constructed, CCL would install appropriately classed electrical equipment, and we recommend in section D of the EA 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, in Operational Inspections we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facility. This would allow FERC staff to inspect whether electrical equipment is being 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). CCL provided process seal design for submerged pumps that show nitrogen purge between primary and secondary seals that would be vented. Potential leaks from these seals would be detected by pressure indicators. However, these details were not provided for the LNG rundown pumps. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, final design drawings and details that show process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system that meet the requirements of NFPA 59A (2001) and NFPA 70 (1999 or 2020, as applicable). In addition, we recommend in section D of the EA that prior to construction of final design, CCL 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. 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, CCL should file details on a system providing equivalent protection, in accordance with NFPA 59A (2023 edition) or approved equivalent, from the migration of flammable fluid through the electrical conduit or wiring. In addition, in Operational Inspections, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would allow FERC staff to inspect whether 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.

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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127. Title 33 CFR **§** 127.201 requires fixed sensors that continuously monitor for LNG vapors be in each enclosed area where vapor or gas may accumulate; and meet Section 16.4 of NFPA 59A (2019 edition); fixed sensors that continuously monitor for flame, heat, or products of combustion be in each enclosed or covered Class I, Division 1, hazardous location defined in Section 500.5(B)(1) of NFPA 70 (2020 edition) and each area in which flammable or combustible material is stored; and meet Section 16.4 of NFPA 59A (2019 edition); and requires fixed sensors have audio and visual alarms in the control room and audio alarms nearby. NFPA 59A (2019 edition) section 16.4 requires areas, including enclosed buildings and enclosed drainage channels, that can have the present of LNG or other hazardous fluids be monitored as required by the fire protection evaluation required in NFPA 59A (2019 edition) section 16.2.1, which has near identical requirements as NFPA 59A (2001 edition) section 9.2.1. Section 16.4 also provides requirements for first and second alarm setpoints, including potential of different flammable gases and vapors, for flammable gas detection, toxic gas detection, low oxygen detection, and fire detection; allowance for activation of portions of the ESD system; and adherence to NFPA 72 (2019 edition). If authorized, constructed, and operated, LNG facilities, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2019 edition), which references NFPA 72 (2019 edition) for installation of hazard detectors.

However, 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 CCL proposed to use and whether the engineering design of the hazard detection system for the proposed CCL Midscale Trains 8 & 9 facilities were consistent with those standards or other applicable codes and standards. CCL 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. CCL listed NFPA 59A (2001 edition) and NFPA 72, *National Fire Alarm and Signaling Code*, 2022 edition, as "mandatory codes and standards" and CCL also listed ISA 12.13[.3], *Guide for Combustible Gas Detection as a Method of Protection*, 2009 edition, among other applicable codes and standards as "non-mandatory codes and standards".

FERC staff also evaluated the adequacy of the general hazard detection type, location, and layout to evaluate the coverage to detect cryogenic spills, flammable and toxic vapors, and fires near potential release sources (i.e., pumps, compressors, sumps, trenches, flanges, and instrument and valve connections) across a range of consequences and likelihoods. The proposed hazard detection design utilizes an array of point gas, open path, flame, and low temperature detectors to provide coverage of process equipment containing flammable fluids. CCL stated the alarm and shutdown set points would be provided during detailed design. FERC staff evaluated the hazard detection layout and noted a lack of hazard detection in several areas of the proposed plant, including the Hot Oil, Diesel Generator, Regenerator Gas Compressor areas, among others. FERC staff also noticed multiple locations on the hazard detection drawings that indicated a lack of fire detection coverage. CCL stated that for these hazard detection drawings, specifically for uncovered areas with a lack of fire detector coverage would be evaluated during detailed engineering design and updated drawings and specifications should be provided with the final design. Additionally, as discussed in Spill Containment section, CCL plans to place low temperature detectors in the LNG trenches near the existing undersized OSBL and Jetty Impoundment basins due to increased loading rate and simultaneous loading that will be safety integrity level 2 interlocked to initiate an ESD of all in-tank pumps and prevent LNG from potentially backup into the LNG trenches and overflowing the impoundments. FERC staff also noted that the hazard detection device coverage plan did not include tag numbers. CCL stated that tag numbers that correspond to those on the hazard detection matrix would be provided on the drawings during detailed design. FERC staff noted the NFPA 59A Preliminary Fire Protection Evaluation did not contain any recommendations. CCL stated an additional NFPA 59A evaluation would be conducted during detailed design contemporaneous with the development of hazard detection measures. CCL has also stated the final design would comply with NFPA 72 and that smoke detectors would be installed in all buildings, including substations, however, the smoke detector locations were not indicated on hazard detection drawings for these buildings. We recommend in section D of the EA that CCL should file, for review and approval, a final 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 should be filed. The evaluation should justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD 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 should be 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 HVLs. 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 D of the EA, that, prior to construction of final design, CCL 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, CCL would install an ESD system in accordance with NFPA 59A (2001 edition). The ESD shutdown would include failsafe, or fireproof, valves within 50 feet of the equipment they protect. FERC Staff noted that the hazard detection drawings did not depict the location of ESD manual push buttons. CCL indicated the ESD layout plans along with the location of ESD activation switches would be developed during detailed engineering. Additionally, as discussed in the Process section and from the 2019 EA, CCL decided not to install a site-wide or project-wide ESD button that would shut each unit down sequentially depending on the incident impacts. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, the details of the ESD system, including a Project-wide ESD button with proper sequencing and reliability or another system that is demonstrated through a human reliability analysis to provide a means to quickly and reliably shutdown the entire CCL Midscale Trains 8 & 9 Project. We also recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, drawings showing the locations of all ESD buttons, including, but not limited to, the Refrigerant Storage area/unit emergency isolation and equipment shutdown. ESD 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 D of the EA that prior to construction of final design, CCL should file, for review and approval, up-to-date security and fire safety specifications, including hazard detection systems.

CCL indicated that the batteries for the uninterruptible power supply would consist of valve-regulated lead-acid batteries. However, CCL did not specify whether hydrogen detection would be provided in the vicinity of battery installations. FERC staff asked if CCL would provide hydrogen detectors that alarm and initiate mitigative actions or alarms in the event the ventilation equipment is not operating or functioning as designed in the vicinity of battery installations. CCL responded that in the event that the building HVAC fails a building alarm would be triggered when the ventilation equipment is not operating or functioning as designed and would provide final design details. While this would alert operators to whether the ventilation equipment that is there to mitigate the development of flammable vapors within the enclosed area is operating, it would not provide an indication to the operators as to whether a flammable atmosphere exists in the enclosed space or not, which could include the development of flammable vapors when equipment is operating, but not functioning as designed. In the absence of such devices, an operator may enter the enclosed space with a flammable concentration that could result in ignition. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, an analysis of the buildings containing hazardous fluids and the ventilation calculations that limit concentrations below the LFLs, including an analysis of off gassing of hydrogen in battery rooms, and should also provide hydrogen detectors that alarm (e.g., 20- to 25-percent LFL) and initiate mitigative actions (e.g., 40- to 50-percent LFL) or alarms in the event the ventilation is not functioning as designed, in accordance with NFPA 59A and NFPA 70, or approved equivalents. Additionally, CCL stated the final design would comply with NFPA 72 which includes requirements for spacing smoke detectors at 30 feet or less. However, the design would be finalized during detailed design. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, a design that includes hazard detection suitable to detect high temperatures and smoldering combustion products in electrical buildings.

FERC staff also reviewed the cause-and-effect matrices provided. The hazard detection devices that were included did specify the hazard detector device type, device tag number, voting logic, and set points that would initiate any type of action. However, these are not finalized. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, the final cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD system. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points. In addition, we recommend in section D of the EA that prior to construction of final design, CCL 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. 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 D of the EA that, prior to construction of final design, CCL should file, for review and approval, 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 D of the EA, that, prior to construction of final design, CCL 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 for toxic components such as condensate and hydrogen sulfide. In addition, in section D of the EA, we recommend, that, prior to construction of final design, CCL 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 lower flammable limit set points for methane, ethylene, propane, iso-pentane, and condensate.

If the Project is authorized and constructed, CCL would install hazard detectors according to its final specifications and drawings. If the project is authorized and this recommendation is adopted as a condition of the order, FERC staff would spot check during construction inspections that the hazard detection selection, locations, orientations and ESD buttons match final design information. In addition, the Operational Inspections section above discusses a recommendation for regular inspections throughout the life of the facility. FERC staff would ensure that hazard detection equipment and ESD buttons are properly installed, functional, and maintained; and are 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. In addition, NFPA 59A (2001 edition) section 9.5.1 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. NFPA 59A (2001 edition) section 9.5.1 also requires 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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127. Title 33 CFR § 127.603 similarly requires each marine transfer area for LNG to have portable fire extinguishers that meet section 16.6.1 of NFPA 59A (2019 edition) and Chapter 6 of NFPA 10 (2018 edition). NFPA 59A (2019 edition) section 16.6.1 only requires portable or wheeled fire extinguishers be recommended for gas fires by their manufacturer. Title 33 CFR § 127.603 also requires at least one portable fire extinguisher in each designated parking area. If authorized, constructed, and operated, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard 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 CCL proposed to use and whether the engineering design of the hazard control system for the proposed CCL Midscale Trains 8 & 9 facilities were consistent with those standards or other applicable codes and standards.

CCL proposed the installation of hazard control systems to extinguish various types of incipient fires that could occur within the Project. CCL listed NFPA 59A (2001 edition), NFPA 10 (2022 edition), and NFPA 2001 (2022 edition) as "mandatory codes and standards" and CCL also listed

NFPA 12 (2015 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 codes and standards as "non-mandatory codes and standards".

We also recognize that the agent type and capacities were later prescribed by NFPA 59A (2009 edition) to ensure their effectiveness. FERC staff evaluated whether the agent type and capacities would meet these requirements in NFPA 59A (2009 and later editions) and whether the spacing of the fire extinguishers would meet NFPA 10 (2022 edition). NFPA 59A (2023 edition) section 16.6.1.4 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 20lb or greater and have a minimum 1 pound per second agent discharge rate and wheeled portable dry chemical extinguishers contain a nominal agent capacities of 125 lb or greater and have a minimum 2 pounds per second agent discharge rate. CCL 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 and wheeled extinguishers of 125 lb agent capacity or larger should not exceed 100 ft unless otherwise specified. The available FEED hazard control plans appeared to meet NFPA 10 travel distances to most components containing flammable or combustible fluids (Class B) for handheld fire extinguishers (30 to 50 feet) and wheeled extinguishers (100 feet). However, some components, such as certain locations on the elevated platform of the MR condenser rack as well as at the pressure building coils in the Refrigerant Storage area were not shown with extinguishers meeting the above distances. Regarding the MR condenser rack, CCL stated that section 6.3.2 of NFPA 10 (2022 edition) does not apply to its elevated platform because this platform is grated and does not provide an area where liquid pooling could collect. However, NFPA 10 (2022 edition) Class B fires, defined in section 5.2.2 includes fires involving flammable gases, section 5.5.3.1 requires fire extinguishers to be selected based on Class B fire hazard present or anticipated to be present, section 5.5.4.1 contains requirements for selection of extinguishers for pressurized liquid and pressurized gas fires, and section 6.3.3 contains requirements for where hand portable and wheel fire extinguishers be installed for Class B pressure fire hazards, which would include pressurized gaseous fires. Given that pressurized jet fires could occur from the piping, valving, or flanges carrying mixed refrigerant vapor or two-phase mixed refrigerant along this elevated platform, we believe that the MR condenser rack would need additional portable handheld fire extinguishers to meet NFPA 10 (2022 edition) or approved equivalent. In addition, no hazard control drawings were available for buildings and substations with CCL reporting that hazard control systems inside buildings and electrical substations would be developed during detailed engineering. Therefore, the NFPA 10 (2022 edition) agent type, storage capacity, and flow rate and maximum travel distance for handheld extinguishers (75 feet) located within these buildings and substations involving ordinary combustible hazard (Class A) or associated electrical (Class C) hazard would need to be assessed when these drawings are available. Therefore, we recommend in section D of the EA, that prior to construction of final design, CCL 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.

In addition, CCL indicated that they would install clean agent fire suppression systems in accordance with NFPA 2001 (2022 edition) in enclosed spaces containing electronic circuits that do not tolerate the use of water as an extinguishing agent, including the electrical substations. However, CCL indicated that specific information regarding the clean agent systems and their location drawings would be developed during detailed engineering. We recommend in section D of the EA that prior to introduction of hazardous fluids, CCL should file, for review and approval, documentation demonstrating they have completed clean agent acceptance tests in accordance with NFPA 2001 (2022 edition) or approved equivalent.

If the Project is authorized and constructed, CCL would install hazard control equipment. If the project is authorized and this recommendation is adopted as a condition of the order, FERC staff would spot check during construction inspections that the selection and location of hazard control equipment matches final design information. In addition, the Operational Inspections section above discusses a recommendation for regular inspections throughout the life of the facility. If the project is authorized and this recommendation is adopted as a condition of the order, FERC staff would ensure that hazard control equipment is properly installed, functional, and maintained. We made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities.

<u>Passive Protection from Fires and Releases Below Minimum Design Metal Temperatures</u>

If cold fluid 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, section 13.35, this should include engineering plans for passive protection systems. In addition, 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, 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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127, which incorporate sections of NFPA 59A (2019 edition), including Chapter 10. NFPA 59A (2019 edition) sections 10.3.1.2 and 10.3.1.3 contain requirements for piping materials or insulation to withstand exposure to low temperature or ignited releases that could fail the piping and increase the emergency. Also, similar to the requirement for PHMSA jurisdictional facilities above, section 10.6.1 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. In addition, section 10.6.1 requires fire protection for such piping supports be designed in accordance with recognized standards. Annex A indicates an example of a recognized standard is API 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*, 3rd (2013) edition. Similarly, section 15.5.2.3.3 requires for valves that do not automatically fail closed on loss of power that the valve actuator and its power supply within 50 feet of the valve shall be protected against operational failure due to a fire exposure of at least a 10-minute duration. If authorized, constructed, and operated, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard inspection and enforcement programs, which require compliance with the structural passive protection from low temperatures and fires discussed above.

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 the aforementioned 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 provides 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 through 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 a vertical vessel supported by a skirt fireproofing be provided on the exterior of the skirt. In addition, section 10.8.5 stipulates fireproofing be provided on all pipe supports within 50 feet 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 API 2218 is listed in a non-mandatory annex and only covers fire protection with subjective language on where to apply passive protection, there is not clear guidance on protection of piping supports from escaping cold liquid, fire, or both fire and cold liquid. Therefore, FERC staff evaluated the proposed passive protection systems based on a mixture of prescriptive-, performance-, and risk-based approaches 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*. In addition, 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[46] and that the passive protection is specified in accordance with recommended and generally accepted good engineering practices with cold protection or a fire protection rating commensurate to the exposure. As part of our review, we evaluated the codes and standards that CCL proposed to use and whether the engineering design of the passive protection systems for the proposed CCL Midscale Trains 8 & 9 facilities were consistent with elements of those standards or other applicable codes, standards, and recommended and generally accepted good engineering practices, as described in this section.

CCL listed NFPA 59A (2001 edition) and NFPA 70, *National Electric Code*, under "mandatory codes and standards," and CCL also listed the following, among other applicable standards as "non-mandatory codes and standards":

- API 607, *Fire Test for Soft-Seated Quarter Turn Valves*;
- API 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*, 3rd (2013) edition;
- 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*, 2nd (1996) edition.

In addition, the following standards are referenced in CCL specifications and, upon inquiry, CCL indicated they would update the list of codes and standards in final design to include these applicable standards:

- API 6FA, *Fire Test for Valves*;
- ASTM E605, *Test Methods for Thickness and Density of Sprayed Fire Resistive Material Applied to Structural Members*;
- ASTM E761, *Standard Test Method for Compressive Strength of Sprayed Fire-Resistive Material Applied to Structural Members*;
- ISO 22899-1, *Determination of the Resistance to Jet Fires of Passive Fire Protection Materials - Part 1: General Requirements*; and
- UL 1709, *Rapid Rise Fire Test of Protection Materials for Structural Steel.*

To minimize the risk of cold spills causing structural supports and equipment from cooling below their minimum design metal temperatures, CCL would protect equipment and structural steel against cold shocks through the selection of suitable materials of construction or by the application of cold proofing or shielding. In addition, CCL would have spill containment systems surrounding cryogenic equipment to direct releases to an impoundment and would generally locate cryogenic equipment away from other areas that do not handle cryogenic materials. Passive cold protection would need to comply with NFPA 59A (2001 edition) and other recommended and generally accepted good engineering practices. However, CCL did not indicate if the cold proofing material would comply with any codes, standards, or recommended and generally accepted good engineering practices for cryogenic releases, such as ISO 20088. In addition, the passive protection philosophies and layout drawings

[46] 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.

provided by CCL did not appear to consider the impacts of potential cold release scenarios, i.e., design spills, that could have a significant jetting liquid component extending beyond the protected zone, such as to areas surrounding LNG pumps and cold boxes. In addition, the passive cold protection drawings did not clarify the passive protection plan for each specific support component and equipment item in the protected area. Therefore, we recommend in section D of the EA that, prior to construction of final design, CCL should file, for review and approval, drawings and specifications for the structural passive cold protection systems, demonstrating that equipment and supports would be adequately protected from low temperature releases (e.g., design spills) below minimum design metal temperatures that may exacerbate the initial hazard. In addition, we recommend in section D of the EA that, prior to construction of final design, CCL should file, for review and approval, calculations and/or test results, per ISO 20088 or approved equivalent, for the structural passive protection systems to protect equipment and supports from low temperature releases below minimum design metal temperatures.

To minimize the risk of a pool or jet fire from causing cascading damage, CCL 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. The structural fire protection design would comply with NFPA 59A (2001); API RP 2218; ISO 22899; UL 1709; and other recommended and generally accepted good engineering practices. CCL indicates that fireproofing rated for two hours of the fire-resistant rating in UL 1709 test conditions. CCL also specified that fireproofing would be applied to structures and equipment supports within the fire scenario envelope of the high fire potential equipment, considering the guidance in API 2218. However, the CCL fire hazard analyses identified multiple fire potential equipment items that are not considered in the fire-proofing strategy. Also, the drawings depicting the areas proposed for fireproofing do not appear to include all areas where jet fires or pool fires could impact structural supports, such as the EFG area condensing units. The drawings show that the 4,000 Btu/ft^2-hr heat flux from a fire in the ISBL Impoundment Basin would extend beyond an adjacent pipe rack leading to a flare and also beyond an amine sump drum within a sump, without further justification, and the passive fire protection zone from the impoundment would not reach these areas. In addition, as discussed in the Spacing and Plant Layout section, according to LNGFIRE3 modeling provided by CCL, multiple refrigerant storage vessels would be exposed to over 4,000 Btu/ft^2-hr radiant heat from an impoundment pool fire. Passive protection layout drawings show that the vessel supports would be within a passive fire protection zone, while no pipe racks would be within this radiant heat zone. The passive protection philosophy and mechanical datasheets for the vessels do not appear to show the vessels would be protected by passive protection. Further, as discussed in the Spacing and Plant Layout section above, the proposed increased ship loading rate and pressures could result in increased radiant heat flux levels from jet fires impacting areas containing existing or authorized occupied buildings, pressurized equipment, structural supports, and process equipment or machinery. CCL provided a list of active and/or passive protection for these previously approved areas. As discussed above, FERC staff reviewed the current protection measures and determined that they could be adequate, however, additional details would be needed to confirm, and other existing plant areas may be reached by project jet fires as well. Therefore, we recommend in section D of the EA that, prior to construction of the final design, CCL should file, for review and approval, drawings and specifications for the 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. Further, we recommend in section D of the EA that, prior to construction of the final design, CCL should file, for review and approval, a detailed quantitative analysis, for project facility areas and relevant existing and authorized facility areas, demonstrating that adequate mitigation would be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from a pool or jet fire; 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; and each occupied building that could expose unprotected personnel within the 1,600 BTU/ft^2-hr zone from a pool or jet fire. Trucks at truck transfer stations should be included in the analysis of potential pressure vessel failures.

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.

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.

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 feet (15 meters) 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. API 2218 describes UL 1709 as the recommended 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).[47] 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.[48] 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.[49] 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.[50,51,52] 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 (CAROLFIRE)”, 2007. The direct current testing methods and results are

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47 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.

48 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.

49 Luketa, A., Hightower, M., *Guidance on Hazard and Safety Analyses of LPG Spills on Water*, Sandia Report, SAND2018-10338, April 2018

50 Chamberlain, G., *Developments in Design Methods for Predicting Thermal Radiation from Flares,* Chemical Engineering Res. Des., Vol 65, pp 299-309, July 1987.

51 Bennett, J., Cowley, L., Davenport, J., Rowson, J., *Large Scale Natural Gas and LPG Jet Fires Final Report to the CEC*, Shell Research, Thornton Research Centre, 1991.

52 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.

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. 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 would expect the design to withstand a minimum of a 20-minute fire exposure.

CCL indicated that the control wiring used to activate emergency systems during a fire that could be exposed to the fire would be fire resistant to a 20-minute fire exposure equivalent to UL 1709. Fire resistant cable specifications for cables involved with electrical, instrument, and control systems that may activate emergency systems, and if failed would directly cause or contribute to a fire or explosion, resulting in loss of life, or adverse impact upon property or the environment, would be verified during final design. Therefore, in section D of the EA, we recommend that, prior to construction of final design, CCL should file, for review and approval, fire resistant cable specifications for 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.

FERC staff also evaluated whether the design would include blast or firewalls for transformers per NFPA 70 and 850. CCL does not propose to install firewalls in transformer areas. CCL indicated the transformers would be installed to provide for safe operation per NFPA 70. CCL also indicates the transformers would utilize a high fire point, less flammable fluid which can justify reduced separation distances per NFPA 850. However, detailed information on the transformer insulation fluid and an analysis justifying the transformer physical separation were not available. Therefore, it is unclear if the transformers would be spaced adequately per NFPA 850 or equivalent industry standards to nearby structures. Therefore, we recommend in section D of the EA that, prior to construction of final design, CCL provide, for review and approval, an evaluation and associated specifications, drawings, and datasheets for the transformers and transformer fluid demonstrating prevention of cascading damage of transformers (e.g., fire walls or spacing) in accordance with NFPA 850 or approved equivalent.

If the Project is authorized, constructed, and operated, CCL would install passive structural cold and fire protection according to its final design. In the Construction Progress and Reporting section, we discussed that the Project facilities would be subject to periodic inspections during construction to verify passive structural cold and fire protection is properly installed in the field as designed prior to introduction of hazardous fluids. In addition, in Operational Inspections section, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff to continue to verify that passive protection is being properly maintained.

<u>Firewater Systems</u>

If ignition of flammable vapors occurred, hazard control devices would be installed to extinguish or control incipient fires and releases and firewater systems would be installed to cool equipment and structures during fires. 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, 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 § 193.2801 under Subpart I Fire Protection, incorporates by reference 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 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, CCL 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.

The marine facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before an LNG storage tank would not be subject to PHMSA regulations under 49 CFR Part 193, but would fall under the Coast Guard regulations in 33 CFR Part 127. Title 33 CFR § 127.601 requires fire equipment to bear the approval of Underwriters Laboratories, Inc., the Factory Mutual Research Corp., or the Coast Guard and all hydrants and standpipes, hose stations, portable fire extinguishers, and fire monitors must be red or some other conspicuous color and be in locations that are readily accessible. In addition, 33 CFR Part 127.607 requires each marine transfer area for LNG to have a fire main system that provides at least two water streams to each part of the LNG transfer piping and connections, one of which must be from a firewater monitor or from a single length of hose on a hose rack or reel connected at all times to each fire hydrant or standpipe having at least one length of hose of sufficient length. In addition, the hose must be 100 feet or less in length and be 1 ½ inches or more in diameter with a Coast Guard approved combination solid stream and water spray fire hose nozzle. In addition, the fire main must have at least one isolation valve at each branch connection and at least one isolation valve downstream of each branch connection to isolate damaged sections. The fire main system must have the capacity to supply simultaneously all fire hydrants, standpipes, and fire monitors in the system, and at a pitot tube pressure of 75 psi, the two outlets having the greatest pressure drop between the source of water and the hose or monitor nozzle, when only those two outlets are open. If the source of water for the fire main system is capable of supplying a pressure greater than the system's design working pressure, the system must have at least one pressure relief device. Title 33 CFR Part 127 also requires the marine transfer area for LNG to have an international shore connection that is in accordance with ASTM F1121–87 (2019), a 2 ½ inch fire hydrant, and 2 ½ inch fire hose of sufficient length to connect the fire hydrant to the international shore connection on the vessel. If authorized, constructed, and operated, CCL must comply with the requirements of 33 CFR Part 127 and would be subject to Coast Guard inspection and enforcement programs, which require compliance with the firewater system requirements discussed above.

FERC staff evaluated the proposed firewater systems based on a mixture of prescriptive, performance-, and risk-based approaches 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 codes and standards that CCL proposed to use and whether the engineering design of the firewater systems for the proposed CCL Midscale Trains 8 & 9 facilities were consistent with those standards or other applicable codes and standards.

CCL listed NFPA 59A (2001 edition) and NFPA 24, *Standard for the Installation of Private Fire Service Mains and Their Appurtenances*, 2022 edition, as "non-mandatory codes and standards" among other applicable standards. CCL CCL also listed the following as non-mandatory codes and standards among other applicable standards:

- API 2510, *Design and Construction of LPG Installations (LPG)*, 8th (2001) edition;
- API 2510A, *Fire Protection Considerations for the Design and Operation of Liquefied Petroleum Gas (LPG) Storage Facilities*, 2nd (1996) edition;
- NFPA 15, *Standard for Water Spray Fixed Systems for Fire Protection*, 2012 edition;
- NFPA 20, *Standard for the Installation of Stationary Pumps for Fire Protection*, 2016 edition; and
- NFPA 22, *Standard for Water Tanks for Private Fire Protection*, 2013 edition.

In addition, upon inquiry, CCL indicated they would update the list of codes and standards in final design to include NFPA 13, *Standard for the Installation of Sprinklers*, NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*, and NFPA 1961, *Standard on Fire Hose*. With the exception of editions referenced, these codes and standards are consistent with those required in NFPA 59A (2023 edition). 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. In addition, consistent with requirements in NFPA 59A (2001) section 9.1.2 (9), CCL confirmed it would ensure that qualified plant personnel would be trained and provided with firefighting equipment for the firefighting duties as specified by NFPA 600.

CCL would provide firewater systems, including fixed manually operated firewater monitors, self-oscillating monitors, and firewater hydrants and hoses for use during an emergency to cool the surface of storage vessels, piping, and equipment exposed to heat from a fire. The firewater facilities in Trains 8 & 9, EFG Unit, and Refrigerant Storage area would be in loop style and connected to the CCL Stage 3 firewater supply system to supply firewater to a user from multiple flow paths. Post indicator valves would be installed as sectional valves to isolate portions of the firewater loops out of service for maintenance. NFPA 24 (2022 edition) section 6.6 requires sectional valves to be provided on looped systems at locations within piping sections such that the number of fire protection connections between sectional valves does not exceed six. CCL indicated that no more than six fire protection devices would be out of service when one section of firewater piping is removed from service. FERC staff evaluated the adequacy of the firewater loops and found more than six fire protection devices between sectional valves in two areas. CCL indicates that the sectional valves at these locations would be corrected in during the detailed design phase. Therefore, we recommend in section D of the EA that, prior to construction of final design, CCL 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. The drawings should also demonstrate that firewater coverage is provided by at least two monitors or hydrants with sufficient firewater flow to cool exposed surfaces subjected to a fire, with obstructions to firewater flow path and throw distance taken into account. The drawings should also demonstrate firewater coverage in areas inaccessible or difficult to access in the event of an emergency by automatic or remotely operated monitors, or fixed fire suppression systems. The drawings should also include piping and instrumentation diagrams of the firewater systems. Drawings of the sprinkler system design should show coverage in applicable buildings per NFPA 850 and in applicable closed roofed buildings around the site, per NFPA 13.

CCL provided preliminary firewater demand calculations and fire hazard analysis reports detailing the firewater system design and demonstrating the firewater demand is within the capacities of the existing firewater pumps and firewater storage. CCL also provided firewater coverage drawings for the firewater monitors. FERC staff evaluated the firewater demand design cases and found that the firewater demand calculation does not represent the latest firewater equipment layout. FERC staff also noted that certain areas or equipment that may contain hydrocarbons may not have sufficient firewater coverage or other mitigation, e.g., the discharge coolers in EFG area. CCL indicated that calculations for all zones would be updated during the final design phase. In addition, CCL provided pool fire radiant heat isopleths for the Refrigerant Storage Impoundment Basin using LNGFIRE3, which shows that multiple refrigerant storage vessels would be impacted by radiant heat exceeding 4,000 Btu/ft^2-hr. However, CCL indicated there would be no deluge water spray fire protection systems anticipated for this Project, and the proposed areas would only be protected with firewater by monitors and hydrants. FERC staff notes that the protection effectiveness from monitors and hydrants would be highly dependent on the operator actions, monitor maneuverability, and potential high wind. FERC staff also noted that where firewater monitor coverage circles intersect pipe racks, large vessels, or process equipment, which could obstruct the firewater coverage, the coverage circles did not appear to be modified to account for obstructions. CCL's firewater layout shows that certain fire hydrants would be supplied with fire hose houses. CCL indicates the hose houses would contain two 100-foot hoses, which could be connected in series.

Further, as discussed in the Spacing and Plant Layout section above, the proposed increased ship loading rate could result in high radiant heat flux levels from jet fires impacting areas containing existing occupied buildings, pressurized equipment, structural supports, and process equipment or machinery. CCL provided a list of active and passive protection for these previously approved areas. As discussed above, FERC staff reviewed the current active and passive protection list and determined that these measures could be adequate to mitigate jet fires from the loading lines at the proposed ship loading rate, however additional details would be needed to confirm. Similar details may be needed for other existing plant areas as well. In the Passive Protection from Fires and Releases Below Minimum Design Metal Temperatures section, we made a recommendation that CCL should file a detailed quantitative analysis to demonstrate the effectiveness of both passive and active protection for pool and jet fires. We also recommend in section D of the EA that, prior to construction of final design, CCL should file, for review and approval, calculations to confirm the existing firewater pumps and firewater storage are hydraulically adequate for supporting the firewater demands. In addition, where coverage circles intersect pipe racks, large vessels or process equipment, where the firewater coverage could be blocked, the coverage circles should be modified to account for obstructions during the final design. We also recommend in section D of the EA that, prior to introduction of hazardous fluids, CCL should complete and document a firewater monitor and hydrant coverage tests. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s).

If the Project is authorized, constructed, and operated, CCL would install the firewater systems as designed. FERC staff would spot check during construction inspections that the firewater system is consistent with the final design information. We also recommend in section D of the EA that, prior to commissioning, CCL should file the operational maintenance and testing procedures for fire protection components prepared in accordance with NFPA 59A (2019 edition) or approved equivalents. In addition, in Operational Inspections section, we recommended that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff to ensure firewater systems are being properly maintained and tested that better ensure their effectiveness and reliability.

Geotechnical and Structural Design

CCL 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 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.

Geotechnical Evaluation

FERC regulations under 18 CFR § 380.12 (h) (3) require geotechnical investigations to be provided.[53] In addition, FERC regulations under 18 CFR § 380.12 (o) (14) require an applicant to demonstrate compliance with applicable federal regulations and requirements including 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 PHMSA's inspection and enforcement programs. 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 the facility. However, no additional requirements 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 to ensure they are adequate for the LNG facilities as described below.

The proposed Project is a planned expansion of the existing CCL Terminal along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio County, Texas. On November 22, 2019, FERC approved the Stage 3 Project under Docket No. CP18-512-000. Two additional proposed midscale trains (Trains 8 & 9) would be located northwest alongside the existing approved Trains 6 and 7 entirely within the previously approved Stage 3 Project Terminal fenceline. The CCL Midscale Trains 8 & 9 and supporting infrastructure would be interconnected and operated, on an integrated basis, with the existing LNG storage tanks, control buildings, marine facilities, and other ancillary facilities. FERC staff have reviewed the previously filed Stage 3 Project geotechnical report and new geotechnical investigation report to determine whether the geotechnical investigations would be sufficient for the proposed expansion project.

CCL contracted Bechtel Energy, Inc. (Bechtel) as an EPC contractor for the proposed project. Fugro USA Land, Inc. (Fugro) was contracted to conduct the geotechnical site investigation and laboratory tests to collect geotechnical data to support Bechtel during the FEED phase of new Trains 8 and 9. Lettis Consultants International (LCI) was contracted to conduct a supplemental seismic and geologic hazards report for the proposed Project site.

As presented in Fugro geotechnical study report, the existing ground elevation at Trains 8 and 9 is currently 44 to 45 feet above the NAVD 88 Datum. The soil conditions at Trains 8 and 9 are similar to those at approved Trains 6 and 7 area within the existing LNG Terminal. Fugro indicated that the field explorations were scattered among Trains 8 and 9 areas. Twenty-four soil borings were drilled and sampled at the Trains 8 and 9 area, including four borings to 150 ft each and twenty borings to

[53] 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).

100 ft each below exiting grade, to explore the subsurface soil and groundwater condition and to obtain soil samples for laboratory testing. Fugro performed twenty-three cone penetration test (CPT) soundings to depths of 100 feet each below exiting grade, and the probe was advanced until one of multiple refusal criteria was met during CPT soundings. Four seismic cone penetration test (SCPT) soundings were performed at the proposed project location; installed two piezometers to depths of 20 feet each and two piezometers to depths of 40 feet each to determine long term groundwater levels; performed field and laboratory tests on selected soil samples to evaluate the geotechnical engineering properties of the subsurface soil for the proposed project location area. Shear wave velocities were determined in each SCPT test by measuring the travel time of a shear wave generated by a source (metal block) located at the ground surface. A pseudo-interval shear wave velocity is determined between subsequent measurement depths. The test is repeated at pre-determined intervals down to the completion depth establishing a shear wave velocity (Vs) versus depth profile. In addition to shear wave velocity measurement, continuous measurements of penetration resistance at the cone tip, friction on the friction sleeve, and pore pressures were recorded during the penetration. Four piezometers were installed at the site, to depths of about 20 feet to 40 feet below the existing grade with an approximate stick-up of 3 feet for long-term depth-to-water measurements. FERC staff agree with the number and type of field explorations, and they are well within our 2017 Guidance Manual suggested 200-300 feet spacing for borings and CPTS for liquefaction and other process areas.

Fugro indicated that the free water was initially encountered at depths ranging from approximately 5.3 feet to 15 feet below the existing grade. Four temporary piezometers were installed at the proposed project site to collect readings over the period of four weeks. The piezometer readings observed groundwater depths ranging from approximately 10.4 feet to 11.8 feet below the existing grade. CCL stated that the project site would be raised to about El. +49 feet from existing ground elevations (i.e., El. +44 to +45 feet). Several soil improvement concepts would be evaluated for the proposed project including shallow soil stabilization of existing subgrade prior to raising the site; installation of wick drains to expedite the consolidation settlement of underlying strata and surcharge the site. The finished grade elevations would be between El. +49 feet and El. +49.5 feet. The foundations for the proposed project site would generally be 1 ft above local grade and maximum elevation would be either 49 ft or 50 ft, including process areas foundation, utilities foundation. The crown elevation of roads within the Trains 8 & 9 area would be around 50.3 feet.

Based on Fugro provided geotechnical study report, CCL determined that the proposed Project site is categorized as Seismic Site Class E[54] per ASCE/SEI 7-05 based on the results of soil strata and shear wave velocities measurements from SCPTs by measuring the travel time of a shear wave generated by a source (metal block) located at the ground surface. The determination of Site Class for the proposed project site is consistent with the existing approved LNG Terminal, which was determined as a Site Class E. As aforementioned, the soil conditions at Trains 8 and 9 are similar to those at approved Trains 6 and 7 area within the existing LNG Terminal. FERC staff agree with the determination of Site Class E for the proposed project site.

Fugro properly collected soil samples for laboratory testing. Storage, preservation and transportation of soil samples were carefully handled and were stated to be in general accordance with ASTM D4220, *Standard Practices for Preserving and Transporting Soil Samples*. Laboratory-testing program carried out on selected disturbed and undisturbed soil samples recovered during the execution of the geotechnical borings associated with the proposed project. The Fugro's laboratory testing program included evaluating the classification properties, undrained shear strength, compressibility

54 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).

characteristics, soil corrosion potential, and electrical resistivity of the subsurface soils at the proposed project location.

Fugro performed laboratory soil corrosion tests for the proposed project. On the basis of the pH, sulfate ion concentration, and chloride ion concentration, the laboratory tests results show that the dredge soil and underlying bauxite residue at the proposed project site have very high potential to attack unprotected steel and mild to severe potential for attacking concrete. Steel and concrete elements in contact with soil, whether part of a foundation or part of the supported structure, are subject to degradation due to corrosion or chemical attack. Per a FERC staff review engineering information request, CCL provided supplemental support documents to mitigate the potential issues. CCL indicated that an overall mitigation plan was not produced for the Project, but measures to protect against corrosion are included in the design of and operational procedures for the Project. CCL provided Coating In-Plant, Buried Pipe specifications to confirm all underground metallic piping would be coated to prevent corrosion and includes the types of coating and products to be utilized. The Specification for Cathodic Protection notes that all carbon steel and stainless-steel underground piping are further protected with either a sacrificial anode or impressed current cathodic protection system. CCL states that drilled displacement concrete piles for the foundation support system would be selected for the Project. The concrete mix design for these piles and the foundation elements considered the presence of soil corrosion potential following recommendations to mitigate corrosion. Furthermore, the Specification for Furnishing and Delivering of Concrete requires that concrete mixtures would contain at least 25% fly ash and a maximum water cement ratio of 0.40. These limits reduce the permeability of concrete to increase its durability in aggressive environmental exposure conditions.

CCL also states that the proposed project would incorporate corrosion allowances for carbon steel applications. This includes both equipment and piping. Consideration for corrosion allowance includes installation location, process fluid type and velocities, equipment life requirements, etc. Allowances are included on the equipment datasheets or pipe material class specs. For ASME code stamped equipment, corrosion allowances would be included in the design thickness calculations. Therefore, as discussed below in the Structural and Natural Hazard Evaluation, to address the potential corrosion, we recommend in section D of the EA that prior to construction of final design, CCL should file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in the State of Texas: finalized corrosion control and prevention plan for any underground piping, structure, foundations, equipment, and components; and the finalized foundation design criteria for the project, and the associated quality assurance and quality control procedures for the project.

Settlement is also considered in the proposed project. As mentioned above, the soil condition at the proposed Trains 8 and 9 area is similar to the pre-approved Trains 6 and 7 subsurface soil condition within the existing LNG terminal. CCL states that all permanent plant equipment and structures would be supported on deep foundations. In conjunction with soil stabilization, shallow foundations (concrete spread footings) would be used to support lightly loaded miscellaneous equipment and temporary structures. The existing approved measurement of settlement would be implemented into the proposed project design. Per a FERC staff request, CCL provided a table summarizing the areas and supporting foundation types to ensure facility foundation designs are appropriate designed for the proposed project. If authorized with recommendations adopted as conditions of the order, FERC staff would continue its review of the settlement to ensure facility foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

FERC staff also reviewed subsidence for the proposed project. 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. CCL states that regional subsidence was evaluated as part of the project’s seismic and geologic hazards study. Typical contributors to regional subsidence can include subsurface flow of salt deposits, extraction of subsurface fluids (oil, gas, groundwater), and compaction of unconsolidated sediments. These potential contributors were determined to be absent and therefore not anticipated for the design life of the facilities. Local subsidence in other places could occur from sinkholes, collapsed caves, karst, collapse of abandoned underground mines, or salt domes. The sedimentary deposits of the Project area are deep and do not lend themselves to any natural formation of sinkholes, caves or karst and there are no underground mines or salt domes at the Project area or in the vicinity. There are no other features known that would cause local subsidence. Therefore, further analysis on local subsidence was determined unnecessary and not included in the report. In addition, the proposed Project is within the existing LNG terminal. We do not expect significant concerns of the subsidence for the proposed Project site. If authorized and constructed, FERC staff would continue its review of the subsidence to ensure facility foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

FERC staff evaluated the geotechnical investigation to ensure the adequacy in the number, coverage, and types of the geotechnical borings, CPTs, seismic CPTs, and other tests for the proposed Project. The results of CCL Midscale Trains 8 & 9 Project geotechnical investigation at the proposed project site indicate that subsurface conditions are generally suitable for the proposed facilities, if proposed site preparation, foundation design, and construction methods are implemented appropriately in addition to the satisfaction of proposed recommendations. The CCL Midscale Trains 8 & 9 Project would be consistent with the geotechnical evaluation described in the Stage 3 Project under Docket Nos. CP18-512-000 and CP18-513-000. If authorized and constructed, FERC staff would continue its review of the project civil engineering design 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 the public 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 applicable federal regulations and requirements including 49 CFR Part 193 and NFPA 59A.[55]

Title 49 CFR Part 193, Subpart B Siting and Subpart C Design, include PHMSA regulatory requirements for protection against natural hazards. Specifically, 49 CFR § 193.2067 requires LNG facilities be designed to withstand without loss of structural or functional integrity the direct effect of wind forces based on an assumed sustained wind velocity of not less than 150 mph or the most critical combination of wind velocity and duration having a probability of exceedance in a 50-year period of 0.5 percent or less. Title 49 CFR § 193.2067(b)(1) incorporates by reference ASCE/SEI 7 (2005) for applicable wind load data for shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons. Title 49 CFR § 193.2101 incorporates by reference Section 7.2.2 of NFPA 59A (2006) for seismic design of field fabricated LNG storage tanks and API 620 (11th, 2008, edition and addendums) for seismic design of all other LNG storage tanks. Title 49 CFR § 193.2155(a) requires 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 imposed loading from LNG spills, erosive action from a spill, the effect of temperature, exposure to fire, and applicable impact due to collapse of components and collision or explosion of a train, tank car, or tank truck from adjoining highway or railroad. NFPA 59A (2001) section 2.1.1 (c)

55 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.

also requires CCL 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. Title 49 CFR §§ 193.2051, 193.2101, 193.2301 and 193.2401 incorporate by reference NFPA 59A (2001) for siting, design, construction, design, fabrication, and installation of all other LNG facilities and equipment. Section 2.1.1(c) in NFPA 59A (2001) requires considering the degree that the plant can be protected against forces of nature in the selection of plant site locations, and section 6.1.2 provides requirements for the seismic ground motion used in the piping design. DOT PHMSA's LOD on 49 CFR Part 193 Subpart B discusses CCL's proposed wind speed design and studies of site-specific natural hazards. 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 DOT PHMSA's inspection and enforcement programs.

Furthermore, we evaluated the basis of design for the Project facilities for all natural hazards under FERC jurisdiction, including those under DOT PHMSA and Coast Guard jurisdiction. CCL indicated that the Project facilities would be constructed to satisfy the FERC and NFPA 59A requirements in accordance with 2015 International Building Code and ASCE/SEI 7-05. The federal 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. CCL clearly states that this Expansion Project does not include any marine infrastructure or dredging activities. In addition, if there were changes to marine infrastructure, CCL must meet NFPA 59A (2019) as incorporated by 33 CFR Part 127.

CCL states that all permanent plant equipment and structures would be supported on deep foundations. This includes all plant equipment and structures within each train, and the Refrigerant Storage area. The type of deep foundation is the drilled, large displacement, cast-in-place concrete piles (DD Pile). In conjunction with soil stabilization, shallow foundations (concrete spread footings) would be used to support lightly loaded miscellaneous equipment and temporary structures, includes underground duct backs, cable trenches, and stormwater drainage ditches.

If the proposed project is authorized, constructed, and operated, CCL would install equipment in accordance with its final design. In addition, there is an existing condition of the Stage 3 Project under Docket Nos. CP18-512-000 order authorizing that prior to construction of the final design, CCL should file with the Secretary the final design package. Similarly, we recommend in section D of the EA that, prior to construction of final design, CCL should file with Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in the State of Texas:

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 foundations 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, CCL should file, in its Implementation Plan, the schedule for producing this information.

Earthquakes, Tsunamis, and Seiche

FERC regulations under 18 CFR § 380.12 (h) (5) requires evaluation of earthquake hazards based on whether there is potential seismicity, surface faulting, or liquefaction.[56] Earthquakes and tsunamis have the potential to cause damage from shaking ground motion and fault ruptures. Earthquakes and tsunamis often result 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 Expansion Project would be constructed entirely within the approved existing LNG Terminal.

To assess the potential impact from earthquakes and tsunamis, CCL contracted LCI to perform a supplemental seismic and geologic hazard report for the proposed project. LCI analysis was to evaluate whether the recent shear wave velocity (Vs) data were consistent with the data used in the 2020 site response analysis performed and if not, would this require a revision to the 2020 seismic design ground motion performed for the Stage 3 Project under Docket Nos. CP18-512-000 and CP18-513-000. To assess the impact of the newer Vs data, LCI performed a site responses sensitivity analysis to compute the amplification factors from the lognormal mean Vs profile from the newer SCPT data. LCI concluded that the 2020 design ground motions are conservative with respect to the ground motions that would be computed using the newer SCPT data and concluded that the 2020 design ground motions are still appropriate for the proposed CCL project.

LCI also evaluated growth faults for the proposed project area. A literature review was performed in order to identify and map previously reported growth faults in the Corpus Christi area and evaluate the potential for surface deformation at the site. Aerial photography and high-resolution LiDAR topographic data in the vicinity of the site also were examined to identify any geomorphic features that may be the topographic expression of growth fault surface deformation. LCI stated that the potential growth fault near the site would only deform the ground surface by warping and/or tilting distributed over a horizontal distance of several hundred feet. No discrete surface offset along a growth fault is expected. If it is assumed that the fault moves continuously at depth at the long-term average rate estimated from geologic and geomorphic data, then the predicated tilting during the lifetime of the facility would not produce detectable changes in the ground surface elevation. Therefore, LCI believes that the proposed project site does not need to incorporate the surface deformation due to growth faulting in the design of the facilities. In addition, the proposed CCL project is located within the existing approved LNG Terminal.

Based on CCL's evaluation, FERC staff agree that the proposed Expansion Project would not alter the hazard of Earthquake, Tsunami, and Seiche to the facility. CCL indicates the proposed project would apply similar seismic design basis as used on existing approved Stage 3 Project. For further

[56] Effective December 29, 2023, 18 CFR §380.12 was updated and information that applicants should provide for natural hazards (including seismic, tsunami, flood, hurricane, tornado, precipitation (rain, ice, snow, etc.), and other natural hazards such as landslides, wildfires, volcanic activity, and geomagnetism) is included in 18 CFR §380.12(o)(15)(iii).

discussion on these hazards, refer to section 9.1.5 "*Earthquakes, Tsunamis, and Seiche*" of the 2019 EA filed under Docket No. CP18-512-000. To ensure the final design of the proposed Project facilities are adequate, we included a recommendation in the above Structural Section and section D of the EA. If authorized and constructed, FERC staff would continue its review of the seismic design basis, tsunamis, and seiche for the proposed project site prior to construction of final design and throughout the life of the facilities.

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, CCL 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. CCL states that all LNG facilities would be designed to withstand a sustained wind velocity of not less than 150 mph per 49 CFR § 193.2067. A sustained wind speed of 150 mph is equivalent to a 183 mph 3-second gust wind speed at 33 feet (10 meters) above ground for Exposure C category, using the Durst Curve in ASCE/SEI 7-05 or using a 1.23 gust factor recommended for offshore winds at a coastline in World Meteorological Organization, *Guidelines for Converting between Various Wind Averaging Periods in Tropical Cyclone Conditions*. These 3-second gust wind speeds are greater than a 10,000-year mean return interval 3-second gust wind speeds of 178 mph per ASCE/SEI 7-22 for the site (ASCE 7 Hazard Tool). Per ASCE/SEI 7-05, the 183 mph 3-second gust wind speed equates to a strong Category 4 Hurricane using the Saffir-Simpson Hurricane Wind Scale (131-155 mph sustained wind speed). CCL must meet 49 CFR § 193.2067 wind load requirements. In accordance with the 2018 MOU, PHMSA issued an LOD on February 14, 2024[57], to the Commission on the 49 CFR Part 193, Subpart B siting requirements. The LOD provided PHMSA's analysis and conclusions regarding the wind speed design for the proposed Project. If the Project is constructed and becomes operational, the facilities would be subject to the DOT PHMSA's inspection and enforcement programs. Final determination of whether the facilities are in compliance with the requirements of 49 CFR Part 193 would be made by the DOT PHMSA staff. In addition, the proposed Project is located within the existing Stage 3 Project terminal under Docket No. CP18-512-000. Therefore, we do not consider that construction or operation of the proposed Expansion Project would be significantly impacted by wind speed.

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. The Project site is in the tornado-prone region as indicated in ASCE/SEI 7-22. Per ASCE/SEI 7-22, the design tornado loads for buildings and other structures, including the Main Wind Force Resisting System and Components and Cladding elements thereof, should be determined using one of the procedures as specified in section 32.1.2 and subject to the applicable limitations of Chapters 26 through 32, excluding Chapter 28 of ASCE/SEI 7-22.

FERC staff independently evaluated the potential of tornados hazard for the proposed project site, using ASCE Hazard Tool along with ASCE/SEI 7-22. Per ASCE/SEI 7-22 Chapter 32, the tornado loads are based on tornado speeds using 1,700- and 3,000 return periods for Risk Category III and IV, respectively. However, 49 CFR § 193.2067, under Subpart B for wind load requirements is based on an MRI of 10,000 years. With the maximum effective plan area of 1,000,000 square feet and

57 DOT PHMSA Letter of Determination, dated February 14, 2024, filed on eLibrary under Accession Number 20240214-3053.

MRI of 10,000 years, the tornado speed corresponds to a 3-second gust speed at 33 feet (10 meters) above the ground would be V_T = 130 mph at the proposed Project location. As noted above, CCL proposed would design their Project facilities to withstand a 150 mph sustained wind speed equivalent to approximately a 183 mph 3-second gust wind speed. A 183 mph 3-second gust wind speed at 33 feet (10 meters) above the ground for all LNG facilities design is above the tornado speed V_T = 1 30 mph at 1,000,000 ft^2 effective plan area per ASCE/SEI 7-22 tornado hazard map. Per ASCE/SEI 7-22 Chapter 32, linear interpolation of tornado speed between maps using the logarithm of the effective plan area size is permitted. FERC Staff estimated that the tornado wind speed for the effective plan area of 1.263 million square feet (i.e., direct project footprint of 29 acres for the Trains 8&9) corresponds to a 3-second gust wind speed at 33 feet (10 meters) above the ground would be approximately equal to V_T = 132 mph. Also, a 183 mph 3-second gust wind speed at 33 feet (10 meters) above the ground for the facility design, which is above the tornado speed V_T = 132 mph at 1.263 million square feet effective plan area.

However, the overall process to determine the tornado loads differs from the process to determine the wind loads per ASCE/SEI 7-22. For an MRI of 10,000 years (that is equivalent to the MRI for wind speed in 49 CFR § 193.2067, the calculated tornado loads of V_T = 131.68 mph would be greater than the threshold speeds specified in ASCE/SEI 7-22 (i.e., wind speed of 183 mph * 0.6 = 109.8 mph) and the tornado loads would need to be considered in the design. For an MRI of 3,000 years (as discussed in Chapter 32 of ASCE/SEI 7-22 for Exposure Category C with Risk Category IV), FERC staff calculated a tornado load of V_T = 106 mph (using a linear interpolation method) that would be less than the thresholds specified in ASCE/SEI 7-22 (i.e., 110 mph) and design for tornado loads is not needed. As a result, FERC staff believe the use of a 150 mph sustained wind speed, which is equivalent to a 183 mph 3-second gust wind speed at 33 feet (10 meters) above ground for the LNG facility design, is adequate for the project, if, at a minimum, the design meets the procedures in ASCE/SEI 7-22 during final design and construction. 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 B and would be subject to PHMSA's inspection and enforcement programs.

In addition, FERC staff re-evaluated historical tropical storm, hurricane, and tornado tracks in the vicinity of the Project facilities using data from the DHS Homeland Infrastructure Foundation Level Data and NOAA Historical Hurricane Tracker.[58,59] Based on CCL's evaluation, the proposed Expansion Project would not alter the hazard of Hurricanes and Tornadoes to the facility. For further discussion on these hazards, refer to section 9.1.5 "*Hurricanes, Tornadoes, and other Meteorological Events*" of the 2019 EA filed under Docket No. CP18-512-000.

Potential flood levels may also be informed from the Federal Emergency Management Agency (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 Viewer[60], the Project site would be outside 1% and 0.2% annual chance floodplain boundaries (100-year and 500-year) flood event. CCL states the proposed project site is on a plateau at elevations 49 to 50 feet above NAVD88 and the site is approximately 20 to 25 feet above adjacent natural ground, there are no streams flowing onto or through the site. The Base Flood Elevation landward of the coastal water line according to FEMA flood maps is 11.4 feet above NAVD88. Another indicator of potential storm surge elevations in the vicinity is the Sea, Lake and Overland Surge from Hurricanes ("SLOSH") model

58 Department of Homeland Security. Homeland Infrastructure Foundation Level Data: https://hifld-geoplatform.opendata.arcgis.com/, accessed January 2024.

59 NOAA. Historical Hurricane Tracker: https://coast.noaa.gov/hurricanes/, accessed January 2024.

60 FEMA National Flood Hazard Layer Viewer: https://hazards-fema.maps.arcgis.com/apps/webappviewer, accessed January 2024.

developed by the National Weather Service. SLOSH is divided into 32 regions or basins from Maine down through southern Texas. SLOSH can simulate the Maximum Envelope of High Water and the Maximum of Maximum Envelope of High Water ("MOM") for all hurricane categories (1-5). The most conservative result of a Category 5 storm from four nearby locations was a MOM elevation at high tide of 19.6 feet above NAVD88. The elevation of 19.6 is well below the site elevation of 49 ft NAVD88. The Project site would be located within existing CCL Terminal at the elevation +49 to 50 feet above NAVD88.

Also, we would expect an intermediate projected sea level rise and subsidence of approximate1.3 feet between 2025 and 2055, as provided by NOAA (2017)[61]. The proposed Project area is located just north of the existing Liquefaction Project, and it is approximately 8,000 feet from the shoreline in the south. The swell should not affect the Project site; therefore, the wave height is not required at the Project site. Given the current proposed site elevation at El. +49 to 50 ft, there would be adequate protection from storm surge and flood hazard for the proposed Project site, even when including relative sea level rise, settlement, etc. over the life of the facilities.

The Texas and Louisiana Gulf Coast area is experiencing the highest rates of coastal erosion and wetland loss in the United States (Ruple, 1993). The average coastal erosion rate is 1.2 meters per year between 2000 and 2012 along the Texas coastal shoreline, with the area between Sabine Pass and Rollover Pass experiencing a shoreline loss rate of -4.7 meters per year between 2000 and 2012 (McKenna, 2014). However, CCL Midscale Trains 8 & 9 Project would be constructed within the existing approved Stage 3 site and would be located northwest alongside the existing approved Trains 6 and 7 within the existing LNG terminal approximately 8,000 feet away from the shoreline in the south. Therefore, coastal erosion would not occur at the proposed project site during the Project life cycle.

Landslides and other Natural Hazards

Landslides involve the downslope movement of earth materials under force of gravity due to natural or human causes. Landslides in the United States occur in all 50 states. CCL states that there is little likelihood that landslides or slope movement at the site would be a realistic hazard as the low relief across the project site. FERC staff also independently evaluated the potential landslide at the proposed project site, using USGS Landslide Inventory and Interactive Map[62]. The proposed project is located outside the possible 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 northwest alongside the existing approved Trains 6 and 7 within the existing LNG terminal. There is low evidence of vegetation around the proposed project site to cause potential wildfires. FERC staff also independently evaluated the potential for wildfire at the proposed project site using USGS[63] and FEMA[64] mapping tools. While differing in values, the various maps show relatively low probabilities of wildfire occurrence. U.S. Department of Agriculture National Burn Probability Map[65] shows less than 1 per 10,000 years and San Patricio County has an expected wildfire frequency of 0.063% per year with a "Very Low" risk index for Wildfire as indicated

61 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.

62 United States Geological Survey, U.S. Landslide Inventory: https://www.usgs.gov/programs/landslide-hazards/maps, accessed February 2024.

63 United States Geological Survey, SGS Wildfire Hazard and Risk Assessment Clearinghouse, https://apps.usgs.gov/wildfire_hazard_and_risk_assessment_clearinghouse/, accessed February 2024.

64 Federal Emergency Management Administration, National Risk Index, Wildfire, https://hazards.fema.gov/nri/map, accessed February 2024.

65 U.S. Department of Agriculture National Burn Probability Map, https://www.arcgis.com/apps/mapviewer/index.html?layers=1fb27ff2aada4a68ac8078bca4fc6480, accessed February 2024.

in the FEMA National Risk Index. Therefore, we conclude that it is unlikely that a wildfire would occur at the Project site.

Volcanic activity is primarily a concern along plate boundaries on the West Coast and in Alaska and Hawaii. Based on FERC staff review of maps from USGS[66] and DHS[67] 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 565 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 intensities with an estimated 100-year mean return interval.[68] The map indicates the CCL Midscale Trains 8 & 9 site could experience geomagnetic disturbances intensities of 250-400 nano-Tesla with a 100-year mean return interval. However, CCL Midscale Trains 8 & 9 would be designed such that if a loss of power were to occur the valves would move into a fail-safe position. In addition, CCL Midscale Trains 8 & 9 would be constructed within the existing approved Stage 3 site, 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 Risk Management Program (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 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

[66] United States Geological Survey, U.S. Volcanoes and Current Activity Alerts, https://volcanoes.usgs.gov/index.html, accessed January 2024.

[67] Department of Homeland Security, Homeland Infrastructure. Foundation-Level data (HIFLD). Natural Hazards, https://hifld-geoplatform.opendata.arcgis.com/, accessed January 2024.

[68] United States Geological Survey. Magnetic Anomaly Maps and Data for North America, https://mrdata.usgs.gov/magnetic/map-us.html, accessed January 2024.

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), 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) 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 [69], DOT National Highway Traffic Safety Administration[70], PHMSA[71], EPA, NOAA[72], and other reports[73,74,75], 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 Federal Highway Administration 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 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.

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69 FHWA, Office of Highway Policy Information, Highway Statistics 2020, https://www.fhwa.dot.gov/policyinformation/statistics/2020/, accessed January 2024.

70 National Highway Traffic Safety Administration, Traffic Safety Facts Annual Report Tables, https://cdan.nhtsa.gov/tsftables/tsfar.htm, accessed January 2024.

71 PHMSA, Office of Hazardous Material Safety, Incident Reports Database Search, https://www.phmsa.dot.gov/hazmat-program-management-data-and-statistics/data-operations/incident-statistics, accessed February 2024.

72 U.S. Environmental Protection Agency, National Oceanic and Atmospheric Administration, ALOHA®, User's Manual, The CAMEO® Software System, February 2007.

73 Birk, A.M., BLEVE Response and Prevention Technical Documentation, 1995.

74 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.

75 Lees, F.P, Lees' Loss Prevention in the Process Industries: Hazard Identification, Assessment, and Control, Volume 2, Second Edition, 1996.

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 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 radius. These values are also close to the distances provided by the DOT Federal Highway Administration for designating hazardous material trucking routes[76] (0.5 mile for flammable gases and flammable and combustible liquids for potential impact area) and PHMSA for emergency response[77] (330 ft 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, CCL estimates up to 12 refrigerant make-up trucks, 4 amine trucks, 4 hot oil trucks, as well as up to 4 diesel trucks would be needed at the site annually. The most frequent truck deliveries would occur during commissioning and startup activity at the site and would deliver refrigerants to load the liquefaction trains. During construction and commissioning, CCL estimates up to 28 refrigerant trucks, 4 amine trucks, 3 hot oil trucks, 93 nitrogen trucks, and 4 diesel trucks at the facility. CCL does not plan to utilize any trucks to deliver LNG.

Physical barriers, including bollards and concrete barriers, would be installed to protect critical plant equipment areas from damage caused by vehicular traffic. Further, as discussed above in Physical Barriers, Protective Enclosures, and Access Controls section, CCL plans to meet the condition on crash rated vehicle barriers for the already approved CCL Stage 3 Project. Additionally, CCL stated they would install bollards and guards for fire protection equipment installed near the roadways for impact protection, and firewater post indicators and other plant equipment would be protected against mechanical damage where needed. Therefore, we recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, drawings of vehicle protections internal to the plant, such as guard rails, barriers, and bollards to protect transfer piping, pumps, compressors, hydrants, monitors, firewater post indicator valves per NFPA 24 section 6.3, 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.

State Highway 361 and State Highway 35 Frontage Road run along the eastern and northern property line, respectively, at the Terminal Site and feed to private road 87A, La Quinta Road. La Quinta Road runs along the western property line at the Terminal Site and would be used to access the CCL Project site as well as the existing CCL facilities. La Quinta Road is a two-lane bi-directional route with a 25 mph speed limit. CCL provided a Road Safety and Reliability Impact Study. The Road Safety and Reliability Impact Study assessed the potential risks of the in-plant and exterior road traffic safety and reliability impacts and as a result of the HAZID, no recommendations were generated for the CCL Midscale Trains 8 & 9 LNG Project Site.

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76 U.S. Department of Transportation, Federal Highway Administration, Office of Highway Safety, 1994,

77 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.

The separation distance between La Quinta Road or Highways 361/35 and the Terminal Site facilities that would contain hazardous fluids would be greater than 1,500 feet, which would exceed the impact distances estimated for the following unmitigated consequences from a catastrophic truck failure: radiant heat from jet fires, overpressure from a BLEVE, and radiant heat from a fireball from a BLEVE. However, unmitigated flammable vapors and projectiles could potentially reach onsite, but a vapor barrier for the site installed North-West of the Midscale Trains 8 &9 would likely mitigate flammable vapors that disperse from an incident from reaching onsite such that the risk is not significant. In addition, a catastrophic failure that would result in projectiles from a road incident that could reach the Project facilities are also highly infrequent and would not present a significant risk to the Project facilities and subsequently would not present a significant risk to the public. FERC staff did not identify any major highways or roads within close enough proximity to piping or equipment containing hazardous materials at the site that would raise concerns of direct impacts from a vehicle impacting the site.

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, and proposed mitigation by CCL.

Rail

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 CCL 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 CCL Midscale Train 8 & 9.

FERC staff evaluated the risk of the rail operations based on the consequences from a release, incident data from PHMSA[78], and rail miles from DOT Bureau of Transportation Statistics [79]. Incident data from PHMSA and rail miles from DOT Bureau of Transportation Statistics 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

[78] 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 2024.

[79] DOT Bureau of Transportation Statistics, System Milage Within the United States, https://www.bts.gov/content/system-mileage-within-united-states, 2000-2021, accessed March 2024.

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 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 transports hazardous natural gas liquids and is located immediately adjacent to the Project site's northern and eastern property boundary, with the closest CCL Midscale Train 8 & 9 being approximately 1,900 feet from the rail line. These distances are farther than the hazard distances from the smaller 1,000-gallon or less releases constituting approximately 95 percent of all hazardous material incidents and farther than the worst-case jet fires from the 30,000-gallon or more releases constituting 1 percent of the hazardous material incidents described above.

There are several rail lines within 1 mile of the Project's 932,000 square foot (ft^2) footprint with approximately 770,000 ft^2 constituting the liquefaction and process areas, approximately 116,000 ft^2 of EFG Unit area and approximately 46,000 ft^2 of the Refrigerant Storage area. The fireballs could burn workers onsite, but there would not be any cascading failures that would impact the public. Similarly, vapor dispersion could impact workers onsite, but there would not likely be any cascading failures that would impact the public because of the high ignition probability and low probability of wind direction and speed that would be needed to reach the Project site. In addition, the closest Project facilities are approximately 2,000 feet away and would constitute approximately 1 percent of the potential impact area of the projectiles that could reach that far. Therefore, the risk we calculated would not be significant. CCL has also committed to include coordination with local emergency responders with regard to potential rail incidents.

Due to the low risk of a rail incident occurring that could directly impact the site, the low risk of a hazardous material rail incident impacting the site that would cause cascading damage that could impact the public, FERC staff concludes 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 Federal Aviation Administration (FAA) requirements. In addition, FERC staff evaluated the risk of an aircraft impact from nearby airports.

There is one on-site heliport situated 1.10 miles south of the proposed Project location and eight airports located within 22 miles of the proposed Project site as follows:

- Three general aviation airports are Mustang Beach Airport located 12.2 miles south-southeast, and San Patricio County Airport located 18.3 miles north-northwest of the proposed Project site.
- Two general and military aviation airports with helicopter operations are McCampbell Airport located 3.73 miles northeast and Aransas County Airport located 18.5 miles north-northeast of the proposed Project site.
- One mixed-use airport (commercial, military, and general aviation) with helicopter operations is Corpus Christi International Airport located 15.9 miles south-southwest of the proposed Project site.
- Two Navy airfields and one naval air station are Cabaniss Field Navy Landing Airfield located 16.5 miles south-southwest, Waldron Field Navy Landing Airfield located 17.8 miles south-southwest and Naval Air Station Corpus Christi located 13.6 miles south-southwest of the proposed Project site, respectively.

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 CCL to provide a notice to the FAA of its proposed construction and mobile objects. This notification should identify all equipment, including temporary (construction) structurers 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). The closest airport to the proposed Project site is the McCampbell Airport at a distance of 3.73 miles or 19,694 feet and its only runway is 4,975 feet. Since its runway is more than 3,200 ft, the notification should identify all equipment that are more than 197 feet above ground level (based on the 100:1 ratio stipulation). The tallest equipment proposed for the Project includes the EFG Column Cold Box and Solvent Regenerator, which are both below the 197 feet requirement. Further, since there are no permanent structures greater than 197 feet above ground level, an aeronautical obstruction study wound not be required for permanent structures. CCL has reported that they received a determination of no hazard to air navigation from the FAA for temporary construction cranes, 300 feet above ground level regarding the Stage 3 Project and that these permits will be renewed or resubmitted for the Project prior to construction. Therefore, CCL would seek a no hazard to air navigation determination letter from FAA for any structures, whether temporary or permanent.

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. CCL does not anticipate utilizing the on-site heliport for construction or normal operations and would only be made available for emergency medical evacuations, annual exercises, and executive travel. Further, CCL has reported that so far this helicopter pad use has been infrequent with no emergencies to date, drills occurring once every three years, and minimal executive travel; therefore, the impact risk due to heliport operations is considered insignificant for facility or area-associated flights. 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. In addition, pipelines associated with this Project must meet the PHMSA regulations under 49 CFR Parts 192 and 195 as discussed in section 9.1.1. 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 CCL Midscale Train 8 & 9.

For existing pipelines, FERC staff identified several active buried natural gas and hydrocarbon pipelines located within close proximity to the Project site. These pipelines are all within established pipeline corridors, and no CCL Midscale Train 8 & 9 LNG Facilities are situated on top of the buried pipelines. However, based on the location of the existing pipelines, traffic that would enter and exit the project site would need to drive over the buried pipelines. Therefore, we recommend in section D of the EA that prior to initial site preparation, CCL should file, for review and approval, an analysis demonstrating that the anticipated traffic loads on buried pipelines and utilities at temporary and permanent crossings will be adequately distributed during construction and operation of the project. The analysis should consider anticipated traffic loads along the facility entrance/exit roads during construction and operation to determine whether provisions are needed to dissipate the loads on the active buried natural gas and hydrocarbon pipelines situated along the facility entrance/exit roads. If provisions are required, the analysis should demonstrate the effectiveness of such provisions. The analysis shall be based on API RP 1102 or other approved methodology.

Based on the potential likelihood of pipeline incidents and potential consequences from a pipeline incident and with the implementation of our recommendation, 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 two power generation facilities within a 5-mile radius of the proposed Project site. The Gregory Power and Ingleside Cogeneration facility are located 0.69 and 1.71 miles away from the proposed Project boundary, respectively. The closest nuclear plants, South Texas Project Units 1 and 2, are located approximately 100 miles northeast of the site. There are multiple facilities located immediately adjacent to the proposed Project site including the Voestalpine Steel Manufacturing Facility and Vopak Petrochemical Terminal which are situated approximately 1,000 feet west of the CCL site boundary. Additional industrial facilities within a 5-mile radius of the proposed Project site include the Occidental Chemical Corporation Chemical plant 1.55 miles away, the Oxychem Chemical plant 1.80 miles away, and the Gulf Coast Growth Ventures Chemical Plant 3.15 miles away. CCL indicated that an ERP would be finalized prior to operation that would include emergency response coordination and notification plans. As discussed in the Emergency Response Plans and Mitigation section below, we have included a recommendation for an Emergency Response Plan to be coordinated with nearby facilities. If the project is authorized and our recommendations are adopted as conditions of the order, FERC staff would confirm that the Emergency Response Plan would be coordinated with nearby infrastructure that handle hazardous materials in the event of an incident at the CCL Facility or neighboring facility that handles hazardous materials.

Given the distances, locations, and risk management plan requirements of the facilities relative to the populated areas near the proposed site, FERC staff does not believe the proposed Project would 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, CCL indicated that the existing CCL Terminal ERP would be updated to include the CCL Midscale Trains 8 & 9 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. CCL 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 CCL 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, CCL would need to prepare updated 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 in the vicinity of the LNG plant; and c) coordination and cooperation with appropriate local officials in preparation of and in the event of an emergency. Specifically, 49 CFR § 193.2509(b)(3) requires emergency procedures to include provisions for "[c]oordinating 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) require at least two access points in each protective enclosure to be located to minimize the escape distance in the event of emergency. CCL indicates that the proposed project facilities, including Trains 8 and 9, EFG Unit, and Refrigerant Storage area, would be located entirely within the existing protective enclosure. In the prior CCL Stage 3 Project, this fencing enclosure was approved with multiple access points in the vicinity of the proposed project facilities.

Title 33 CFR § 127.307 also requires the development of an emergency manual that incorporates additional material, including LNG release response and ESD 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 CCL marine transfer areas were previously approved, and there are no new transfer areas or modifications to these approved facilities in this Project.

This Project would increase the number of LNG marine vessels transiting to the existing LNG terminal by 20 percent. In accordance with the EPAct 2005, FERC must approve an ERP covering the terminal and ship transit 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 Coast Guard 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 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 LNG marine vessel, 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*[80]

[80] Freely and publicly accessible to view in English and Spanish at NFPA, https://www.nfpa.org/codes-and-standards/1/6/6/1660, accessed January 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*;[81]
- NFPA 475, *Recommended Practice for Organizing, Managing, and Sustaining a Hazardous Materials and Weapons of Mass Destruction Response Program*.[82]

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.

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.[83]

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81 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 January 2024.

82 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 January 2024.

83 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.

- 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 cover organizing, planning, implementing, and evaluating a program for mass evacuation, sheltering, and re-entry, which states:

- 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 environmental 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 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 DHS 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 for in emergency response plans in accordance with 49 CFR § 193.2509(b)(3), and along the LNG carrier route using the Zones of Concern referenced in Coast Guard NVIC 01-11. In addition, FERC staff identified potential emergency response needs based on the potential impacts to and characteristics of the population and infrastructure for potential intentional and accidental incidents along the LNG marine vessel route and at the LNG terminal. 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:

a. daycares;

b. elementary, middle, and high schools and other educational facilities;

c. elderly centers and nursing homes and other boarding and care facilities;

d. detention and correctional facilities;

e. stadiums, concert halls, religious facilities, and other areas of assembly;

f. densely populated commercial and residential areas, including high rise buildings, apartments, and hotels;

g. hospitals and other health care facilities;

h. police departments, stations, and substations;

i. fire departments and stations;

j. military or governmental installations and facilities;

k. major transportation infrastructure, including evacuation routes, major highways, airports, rail, and other mass transit facilities as identified in external impacts section; and

l. 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 response plans. NFPA 101 is currently used by every U.S. state and adopted statewide in 43 of the 50 states.[84] Texas currently adopts NFPA 101 (various editions) without amendments.[85,86] These areas are also similar to "identified sites" defined in 49 CFR Part 192 that

84 NFPA, NFPA 101 Fact Sheet, https://docinfofiles.nfpa.org/files/AboutTheCodes/101/NFPA101FactSheet0809.pdf, accessed February 2024.

85 Up Codes, Texas Building Codes, https://up.codes/codes/texas, accessed February 2024.

86 Life Safety Codes, Texas State Law Library, https://www.sll.texas.gov/law-legislation/texas/building-codes/life-safety-codes/, accessed February 2024.

define high consequence areas and those identified within Pipelines and Informed Planning Alliance for special land use planning considerations near pipelines.[87]

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 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 on-site 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 kg 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, an 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

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87 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.

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 weather 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 2023 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 Coast Guard 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 Coast Guard 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, CCL would take measures to mitigate the vapor dispersion and ignition into confined areas, such as buildings. CCL 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 LNG facilities

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.[88]

The preceding Reliability and Safety sections assessed potential impacts to the public and whether the CCL 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, CCL evaluated potential impacts from incidents identified at the LNG Terminal, including potential impacts

88 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.

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 PVB), weather conditions, and surrounding terrain. Distances to radiant heats of 5kW/m^2 (or approximately 1,600 BTU/ft^2-hr) from fires produced by accidental and intentional acts could impact onsite personnel or offsite public. 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 great than 6-inch 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 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.

The infrastructure and communities that could be impacted by a fire with 10,000 BTU/ft^2-hr or greater radiant heats extending offsite due to a pool fire over an LNG release and from large piping jet fires if not mitigated by the barrier wall on the North side of Terminal Site, include industrial land owned or controlled by CCL, Cheniere Land Holdings, LLC, the Port of Corpus Christi Authority (site office and laydown area), or TPCO America Corporation (steel pipe manufacturing factory), and a portion of Highway TX-361. The infrastructure and communities that could be impacted by a fire between 1,600 BTU/ft^2-hr to 10,000 BTU/ft^2-hr radiant heats extending offsite, include two industrial facilities with potential hazardous material, additional Highway TX-361, and industrial lands which are owned by the previously mentioned companies within the 10,000 BTU/ft^2-hr radiant heats. The unignited vapor dispersion is extremely unlikely but, if it occurred, could extend farther offsite and could impact the following communities and infrastructure: 15 government facilities, 15 hospitals/polyclinics, 37 places of worships, 30 educational facilities (including libraries and museums), 4 emergency response facilities, 2 detention centers, 2 youth centers/daycares, 6 assisted care and elderly facilities, 8 other areas of assemblies, 2 military facilities, 19 hotels/lodging facilities, 22 apartments, and 2 significant transportation centers. There are also seven industrial facilities within the potential hazardous materials.

Potential Infrastructure Impacts Along LNG Marine Vessel Route

As LNG marine vessels proceed along the intended transit route, the estimated impacts would extend onto populated areas and infrastructure. These distances are provided as Zones of Concern in the publicly available guidance document NVIC 01-11[89] used by the Coast Guard and correspond to 37.5 kW/m^2 (approximately 12,000 BTU/ft^2-hr) radiant heats from fires for Zone 1, 5 kW/m^2 (approximately 1,600 BTU/ft^2-hr) radiant heats from fires for Zone 2, and flammable vapor dispersion

[89] NVIC 01-11, https://www.dco.uscg.mil/Portals/9/DCO%20Documents/5p/5ps/NVIC/2011/NVIC%2001-2011%20Final.pdf, accessed January 2024.

distances for Zone 3. The areas impacted by the three different hazard zones are illustrated for accidental and intentional events in figures J1 and J2, respectively.

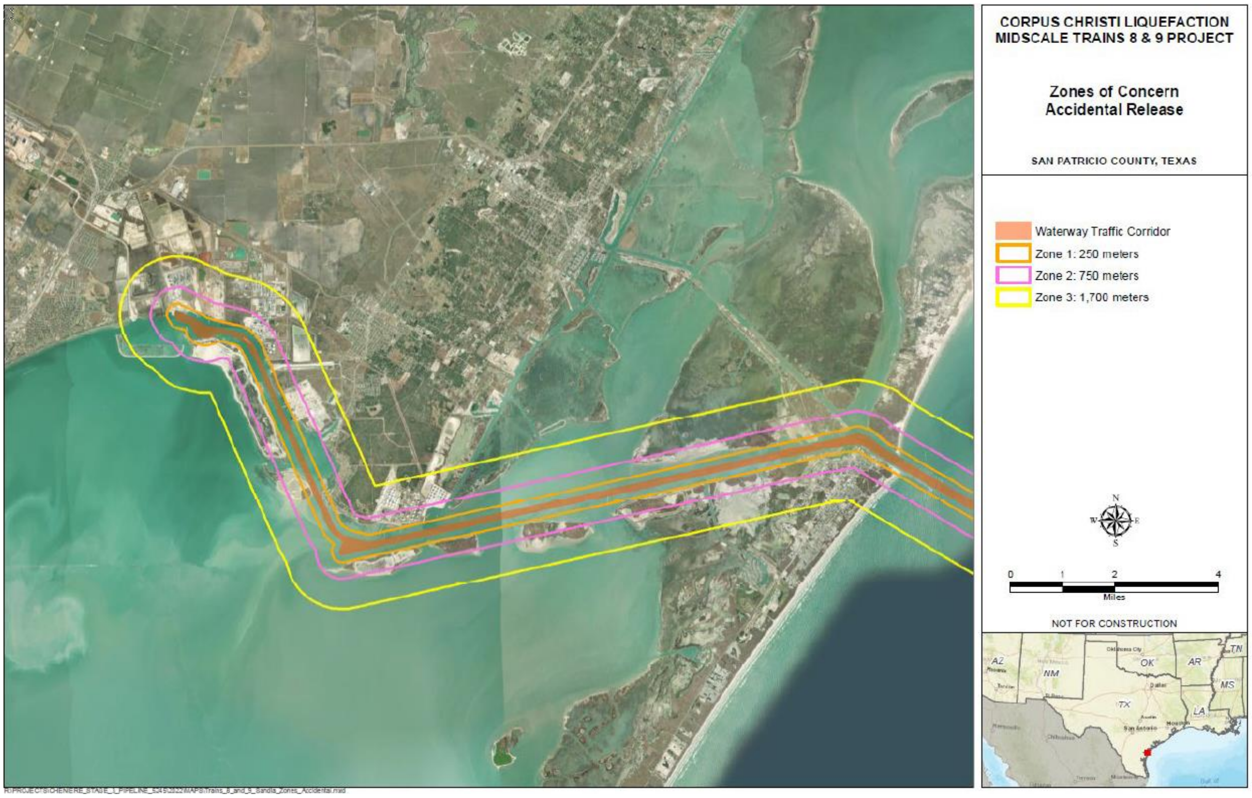

Figure J1

Distances to radiant heats of 5 kW/m^2 (or approximately 1,600 BTU/ft^2-hr) from fires demarked by Zone 1 for accidental events would remain mostly over the water and any coastal infrastructures along the waterway, which would encompass one transportation center and three apartments/condos complexes. This zone also includes any commercial and recreational vessels if they would be allowed within 830 feet (250 meters) of the LNG marine vessel. Zone 2 for accidental events would encompass the waterway and coastal residential and recreational areas in Ingleside on the Bay and Port Aransas, which includes, in addition to Zone 1 facilities, two government facilities, two educational facilities, one **Accidental Hazard Zones along LNG Marine Vessel Route** transportation center, two emergency response facilities, one military facility, one assembly area, eight hotels/lodging facilities, and three apartment/condos complexes. This zone also includes some industrial marine terminals along the waterway, including Chemours Ingleside Plant, EMR Facility, Enbridge Energy Dock, and a portion of the CCL Terminal facility. Any commercial and recreational vessels if they would be allowed with 1,660 feet (500 meters) of the LNG marine vessel would also be subjected to this zone. Zone 3 for accidental events would encompass a wider swath of coastal areas along the waterway, including larger part of Ingleside on the Bay and Port Aransas. The zone also encompasses more industrial compounds, including NRG Gregory Power Plant, Vopak Terminal, and Voestalpine Steel Manufacturing Facility. In addition to the residential and recreational facilities listed in Zones 1 and 2 for accidental events, Zone 3 encompassed an additional one government facility, six places of worships, five educational facilities, one emergency response facility, one area of assembly, 25 hotels/lodging facilities, and four apartment/condos complexes.

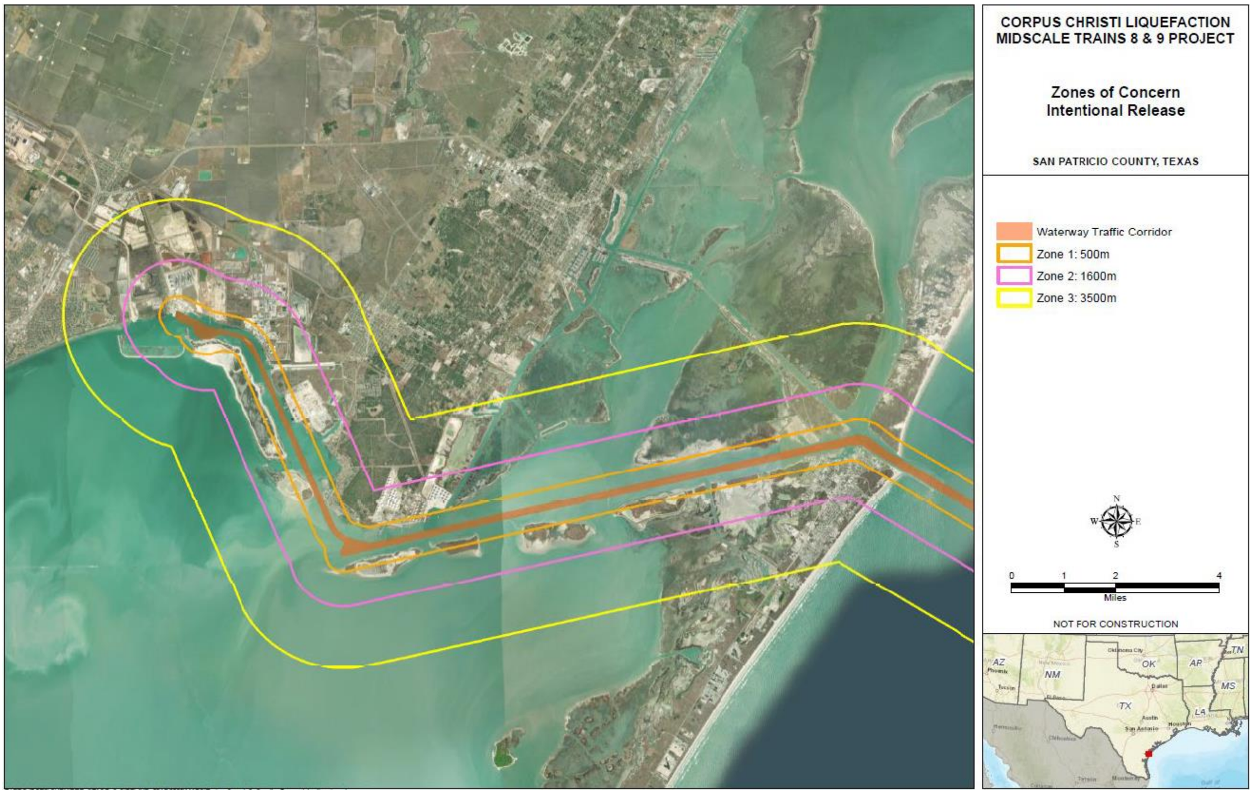

Figure J2 Intentional Hazard Zones along LNG Marine Vessel Route

Distances to radiant heats of 37.5 kW/m^2 (or approximately 10,000 BTU/ft^2-hr) from fires demarked by Zone 1 for intentional acts would remain mostly over the water and any marine structures along the waterway. It would encompass the coastal residential and commercial areas in Ingleside on the Bay and multi-level apartments in Port Aransas, which includes one educational facility, one transportation center, one military facility, two hotel/lodging facilities, and five apartments/condo complexes. Any commercial and recreational vessels if they would be allowed within 1,640 feet (500 meters) of the LNG marine vessel would also be encompassed within Zone 1 for intentional acts. Zone 2 for intentional acts would encompass the waterway and multiple industrial facilities, including Vopak Petrochemical Terminal, Voestalpine Steel Manufacturing Facility, NRG Gregory Power Plant, Chemours Ingleside Plant, EMR Facility (if constructed), Enbridge Energy Dock, Aransas Terminal, etc., multiple boat works, recreational marina, and a portion of the CCL Terminal facility. It also encompasses additional areas of Ingleside on the Bay and Port Aransas, including, in additional to Zone 1, three government facilities, six places of worships, 6 educational facilities, one transportation center, three emergency response facilities, two areas of assemblies, 29 hotels/lodging facilities, and five apartments/condos complexes. Any commercial and recreational vessels if they would be allowed with 5,250 feet (1,600 meters) of the LNG marine vessel would also be encompassed within Zone 2 for intentional acts. Zone 3 for intentional acts would also encompass a wider swath of coastal areas along the waterway, including part of Portland and Ingleside, and majority portion of Port Aransas, which would include additional places of residents and municipal facilities, including five government facilities, four places of worships, six educational facilities, two youth centers, one emergency response facility, one military facility, six area of assemblies, 67 hotels/lodging facilities, 19 apartments/condos complexes, and 1 polyclinics.

Potential Impacts to People with Access and Functional Needs and Environmental Justice Communities

FERC staff used NEPAssist[90] and EJScreen[91] as an initial screening tool to identify the potential impacts from incidents identified along the LNG marine vessel transit route and 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 in addition to a pool fire from an LNG tank failure. Table J1 shows the resultant percentages of people with potential access and functional needs within all potential impact areas[92] combined for that category, which may not be representative of a single event, based on 2017-2021 U.S. Census Bureau, American Community Survey as follows:[93]

Table J1
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]
Zone 1 (accidental)	486	85	106	2%	21%	0%
Zone 2 (accidental)	449	327	803	1%	23%	0.3%
Zone 3 (accidental)	246	802	2,138	2%	24%	0.2%
Zone 1 (intentional)	282	196	457	2%	22%	0%
Zone 2 (intentional)	238	757	1,973	2%	24%	0.3%
Zone 3 (intentional)	407	3,564	6,003	7%	16%	2%
10,000 BTU/ft^2-hr (LNG Terminal)	0	0	0	0%	0%	0%

90 EPA, NEPAssist, https://nepassisttool.epa.gov/nepassist/nepamap.aspx, accessed Feb 2024

91 EPA, EJScreen, https://ejscreen.epa.gov/mapper/, accessed Feb 2024. EJScreen information is part of NEPAssist output.

92 LNG terminal hazard 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. The LNG marine vessel zones of concerns are based on Sandia Reports SAND2004-6258 and SAND2008-3153. 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.

93 Based on EPA, EJScreen User Guide, Version 2.2, 2023, the impact area will 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 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.

Table J1 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]**
1,600 BTU/ft^2-hr (LNG Terminal)	0	1	1	0%	0%	0%
Flammable Vapor Cloud (LNG Terminal)	426	9,711	11,337	7%	13%	1.3%

[a] 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.

The worst-case distances from these potential incidents would potentially impact 25 block groups, 14 of which are considered environmental justice communities, as defined in section B.7.2 of the EA. The block groups located with environmental justice communities that exceed the thresholds for minority and low income identified in section B.7.2 would include CT 103.01, BG 3, CT 103.02, BG 3, CT 103.02, BG 4, CT 106.01, BG 1, CT 106.01, BG 3, CT 107, BG 1, CT 107, BG 2 (based on the minority threshold); CT 106.01, BG 4, CT 51.04, BG 1, CT 9501.01, BG 2 (based on the low-income threshold); and CT 103.02, BG 2, CT 105, BG 1, CT 105, BG 2, CT 106.01, BG 2 (based on both low-income and minority thresholds). Minority and low-income population percent for these Census Tract Block Groups are provided in detail in Table E1 in Appendix E.

Should a catastrophic incident or other more likely emergency occur at the CCL facilities or at the LNG marine vessel along its route, people with access and functional needs and environmental justice communities could experience significant public safety impacts and impacts on environmental justice communities would be disproportionately high and adverse as the impacts of such an accident would be predominately borne by environmental justice communities. However, 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 and Coast Guard regulations under 33 CFR Part 127 and 33 CFR Part 105, and those required for the LNG marine vessel by Coast Guard regulations under 33 CFR Part 104 and 46 CFR Part 154, 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.

Emergency Response Plans and Mitigation

In order to mitigate these potential offsite risks, 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 Coast Guard regulations under 33 CFR Part 127 and 33 CFR Part 105.

As stated in Sandia National Laboratories Report, Guidance on Risk Analysis and Safety Implications of a Large LNG Spill Over Water, SAND2004-6258, which was the basis for the Zones of Concern and referenced in NVIC 01-011, Zone 1 represents "risks and consequences of an LNG spill could be significant and have severe negative impacts" and radiant heat demarked by this zone "poses a severe public safety and property hazard, and can damage or significantly disrupt critical infrastructure." Subsequently, the Sandia report concludes that for accidental Zone 1 impacts, "risk management strategies for LNG operations should address both vapor dispersion and fire hazards" and the most rigorous deterrent measures, such as vessel security zones, waterway traffic management, and establishment of positive control over vessels are options to be considered as elements of the risk management process." Zone 1 is based upon a 37.5 kW/m^2 radiant heat from a fire, which would cause significant damage to equipment and structures that are located within 1,640 feet as described more fully in footnote describing impacts of radiant heat corresponding to Zone 1. Sandia recommends that "incident management and emergency response measures should be carefully evaluated to ensure adequate resources (i.e., firefighting, salvage, etc.) are available for consequence and risk mitigation."

Sandia indicates Zone 2 represents where radiant heat "transitions to less severe hazard levels to public safety and property" and the consequence of an accidental LNG spill are reduced and risk reduction and mitigation approaches and strategies can be less extensive." Zone 2 is based upon a 5 kW/m^2 radiant heat, which would cause significant impacts to individuals, but would not be expected to significantly impact most structures as described more fully in footnote describing impacts of radiant heat corresponding to Zone 2. Sandia concludes that for accidental Zone 2 impacts, "risk management strategies for LNG operations should focus on approaches dealing with both vapor dispersion and fire hazards" and "should include incident management and emergency management and emergency response measures, such as ensuring areas of refuge (e.g., enclosed areas, buildings) are available, development of community warning signals, and community education programs to ensure persons know what precautions to take."

Sandia indicates Zone 3 represents "risks and consequences to people and property of an accidental LNG spill over water are minimal" and radiant heat "poses minimal risks to public safety and property". Zone 3 is based upon the dispersion distance to flammable vapors under worst-case wind conditions. In the rare circumstance that the flammable vapors are not ignited until later, there could be flash fires or explosions depending on congestion, confinement, and ignition strength and location. Subsequent pool fires that would be demarked from the Zone 1 and 2 fire hazard distances, Sandia concludes that for accidental Zone 3 impacts, "risk reduction and mitigation strategies can be significantly less complicated or extensive" and "should concentrate on incident management and emergency response measures that are focused on dealing with vapor cloud dispersion...", such as ensuring "areas of refuge are available, and community education programs...to ensure that persons know what to do in the unlikely event of a vapor cloud." Sandia makes similar recommendations for the Zones of Concern for intentional acts. We recommend the Sandia recommendations be incorporated into Emergency Response Plans 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 occurring 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 Coast Guard regulations under 33 CFR Parts 127 and 105, and those required for the LNG marine vessel by Coast Guard regulations under 33 CFR Part 104 and 46 CFR Part 154. Furthermore, EPAct 2005 requires that an LNG terminal operator's ERP be developed in consultation with the Coast Guard and State and local agencies and be approved by the Commission prior to final approval to begin construction. To satisfy this requirement, FERC staff recommend in section D of the EA that prior to initial site preparation, CCL should file, for review and approval, 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 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 along the LNG marine vessel route and potential impacts and onset of hazards from accidental and intentional events at the LNG terminal, including but not limited to a catastrophic failure of the largest LNG tank. The plan should also address any special considerations and pre-incident planning for infrastructure and public with access and functional needs and should include at a minimum:

a. 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/or shelter in place of the public within any transient hazard areas along the marine vessel route and within LNG terminal hazard areas in the event of an incident;

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 transient hazard areas along the marine vessel route and within hazard areas from LNG terminal;

d. designated contacts with federal, state and local emergency response agencies responsible for emergency management and response within any transient hazard areas along the marine vessel route and 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 and/or shelter public within transient hazard areas along the marine vessel route and 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 any transient hazard areas along the LNG marine vessel route and within hazard areas from the LNG terminal;

h. 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 the public within any transient hazard areas along the LNG marine transit route and 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 public prior to onset of debilitating hazards within transient hazard areas that may better benefit from sheltering in place (i.e., those within Zones of Concern 1 and 2), along the route of the LNG marine vessel and within hazard areas of the LNG terminal that may benefit from sheltering in place (i.e., those within areas of 1,600 BTU/ft^2-hr and 10,000 BTU/ft^2-hr radiant heats from fires with farthest impacts, including from a catastrophic failure of largest LNG tank).

FERC staff recommends CCL notify FERC staff of all planning meetings in advance and should report progress on the development of its updated 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. The facility currently contracts to Refinery Terminal Fire Company personnel and equipment to provide immediate response and deployment in the event of a wide range of site emergencies, 24 hours a day, 7 days a week, 52 weeks a year. If additional support is needed, CCL would request assistance from local emergency responders. CCL is engaged with and currently provides annual funding to both the Coastal Plain Local Emergency Planning Committee and the City of Corpus Christi-Nueces County Local Emergency Planning Committee to help ensure coordinated emergency response efforts in the region. We recommend in section D of the EA that, prior to initial site preparation, CCL should file, for review and approval, a 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 should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. This plan should 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. CCL should notify FERC staff of all planning meetings in advance and should report progress on the development of its Cost-Sharing Plan at 3-month intervals. Once submitted by CCL, we would evaluate the revised ERP and the 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.

If this Project is authorized, constructed, and operated, CCL would coordinate with local, state, and federal agencies on the development of an updated emergency response plan and a cost-sharing plan. As discussed above, we recommend that CCL should provide periodic updates on the development of these plans. In addition, the final ERP would be in place prior to introduction of hazardous fluids. We also recommend in section D of the EA that prior to construction of final design, CCL should file, for review and approval, three-dimensional drawings to confirm plant layout for maintenance, access, egress, and the extent and density of congested areas used in overpressure modeling. In addition, in Operational Inspections section, we made a recommendation that Project facilities be subject to regular inspections throughout the life of the facilities. This would enable FERC staff to continue to evaluate changes and updates to the ERP.

Recommendations from FERC Preliminary Engineering and Technical Review

Based on our preliminary engineering and technical review of the reliability and safety of the CCL Midscale Trains 8 & 9 Project, we recommend the mitigation measures listed in section D 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.

Appendix K

Cumulative Impacts Analysis Discussion, Tables, and Figure

Table K1 Resource-Specific Geographic Scope for the Cumulative Impact Assessment		
Environmental Resource	**Geographic Scope for Cumulative Impacts**	**Justification for Geographic Scope**
Soils and surficial geology	Construction workspaces and adjacent areas	Impacts on soils and surficial geology would be highly localized and would not be expected to extend beyond the area of direct disturbance associated with the Project.
Water resources (groundwater, surface water, aquatic resources)	HUC-12 subwatershed	Impacts on groundwater and surface water resources could reasonably extend throughout a HUC-12 subwatershed (i.e., a detailed hydrologic unit that can accept surface water directly from upstream drainage areas and indirectly from associated surface areas such as remnant, noncontributing, and diversions to form a drainage area with single or multiple outlet points), as could the related impacts on aquatic resources and fisheries.
Wildlife, including threatened and endangered species	HUC-12 subwatershed	Impacts within a HUC-12 subwatershed sufficiently accounts for impacts on wildlife that would be directly affected by construction activities and for indirect impacts such as changes in habitat availability and displacement of transient species.
Recreation	5.0 miles	Impacts on recreation are assessed withihn 5.0 miles from the Project.
Visual Resources	The tallest Project feature would be visible approximately 6.0 miles from the Project.	Assessing the impact based on the viewshed allows for the impact to be considered with any other feature that could have an effect on visual resources.
Socioeconomics	San Patricio and Nueces counties; La Quinta Ship Channel	Affected counties would experience the greatest impacts associated with employment, housing, public services, transportation, traffic, property values, economy and taxes, and environmental justice.
Environmental Justice	Affected environmental justice block groups	The geographic scope of potential impacts for environmental justice includes all environmental justice block groups affected by the Project.
Marine transportation	La Quinta Ship Channel	Affected navigable waterways would experience the greatest impact downstream from the Project.
Air quality – construction	Within 1.0 mile of the Project	Air emissions produced during construction would be limited to vehicle and construction equipment emissions and dust and localized to the Project construction area.
Air quality – operation	Within 31.1-miles (50-kilometers) of the Project	The distance used by the EPA for cumulative modeling of major sources (40 CFR 51, appendix W) for the PSD permitting of the Project.
Noise – construction	NSAs within 0.25 mile of any construction and within 1.0 mile of pile driving activities	Areas in the immediate proximity of construction activities (within 0.25 mile) would have the potential to be affected by construction noise. NSAs within 1.0 mile of pile driving could be cumulatively affected if other projects had a concurrent impact on the NSA.
Noise - operation	NSAs within 1.0 mile of a noise-emitting permanent aboveground facility	Noise from the proposed Project's permanent aboveground facilities could result in cumulative impacts on NSAs within 1 mile.
[a] We note that GHGs do not have a localized geographic scope. GHG emissions from the Project combined with projects all over the planet lead to increased CO2, methane, and other GHG concentrations in the atmosphere.		

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
Stage 3 Project – LNG Terminal and Pipeline (1)	Adjacent	C: 2022-2027 O: 2027	LNG liquefaction and export terminal and natural gas pipeline	C: 2,306 O: 246	12.9 acres (terminal) 110 acres (pipeline)	12.10	19	Geology, Soils, Groundwater, Vegetation and Wildlife, Land Use, Visual Resources, Socioeconomics, Environmental Justice, Marine Transportation, Air (construction and operations), Noise (construction and operations)
Liquefaction Project (2)	Adjacent	Past Project [b] C: 2015-2019 O: 2019	LNG liquefaction and export terminal	C: Past Project [b] O: 300	1,000 acres	27.45	10	Environmental Justice, Noise (operation), Air (construction and operations)
Cheniere Sinton Compressor Station (3)	17.8	Past Project [b] C: 2017-2019 O: 2019	Existing natural gas compressor station	C: Past Project [b] O: 0	27 acres	IU	IU	Air (operations)
Tennessee Gas Pipeline Compressor Station 3A (4)	21.0	Past Project [b] C: 2018-2020 O: 2020	Existing natural gas compressor station	C: Past Project [b] O: 6	13.4 acres	0.00	0	Air (operations)
Buckeye Partners - South Texas Gateway Terminal (5)	6.5	C: 2019-2021 O: 2021	Crude Oil Marine Terminal	C: Past Project [b] O: Unknown	Unknown	IU	IU	Air (operations)
Enbridge Ingleside Energy Center Expansion (6)	6.7	C: 2018-2020 O: 2020	Crude oil storage and export terminal	C: Past Project [b] O: 75	900 acres	IU	IU	Air (operations)
Enbridge Ingleside Energy Center Solar Project (6)	6.7	Unknown	Solar energy project	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
Enbridge and Humble Midstream Hydrogen and Ammonia Production and Export Facilities (6)	6.7	Unknown	Blue hydrogen and ammonia production and export	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
ExxonMobil/SABIC Plastics Manufacturing Facility - Gulf Coast Growth Ventures Project (7)	3.6	C: 2019-2022 O: 2022	Construction of a 1.8-million-ton ethane steam cracker.	C: 6,000 O: 600	1,300 acres	IU	IU	Air (operations), Land Use, Visual Resources, Socioeconomics

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
Corpus Christi Polymers Manufacturing Complex and Desalination Plant (8)	14.4	C: 2023-2025 operation: 2025	Terephthalic acid and polyethylene terephthalate manufacturing facility	C: 2,400 O: 250	412 acres	IU	IU	Air (operations), Socioeconomics
Corpus Christi Ship Channel Improvement Project – Phases 2 and 3 (9)	Approx. 5 to 15	C: 2018-2023 O: 2023	Various improvements to the Port of Corpus Christi waterway system including increasing the channel depth and widening	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
City of Portland: Citywide Hike and Bike Trail (10)	3.0	C: Unknown O: Post 2023	Construction of proposed trail facilities	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics, Environmental Justice
City of Portland: Railroad Right-of-Way Linear Park (11)	2.7	C: 2021-2022 O: 2022	New scenic linear park development	C: Unknown O: Unknown	2.75 acres	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics, Environmental Justice
City of Portland: Hunt Airport Drainage Outfall (12)	5.5	C: 2021-2022 O: 2022	The project would improve drainage west of Hunt Airport	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics
City of Portland: Bay Ridge/Green Lake Linear Park (13)	3.3	C: Unknown O: Post 2023	New linear park along pipeline corridor bisecting Bay Ridge subdivision	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics
City of Portland: Akins Drive Hike and Bike Trail (14)	3.0	Past Project [b] C: 2018-2019 O: 2019	New bike trail connecting roadways in Portland	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics, Environmental Justice

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
City Sidewalk Improvements, Phases 1 and 2 (15)	4.2	Phase 1 C: 2019-2020 O: 2020 Phase 2: C: 2021-2022 O: 2022	Repair, replace, and/or construct sidewalks citywide	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics
City of Portland: Utility Line Replacement Phases 2 and 3 (16)	2.0	Phase 2: C: 2019-2020 O: 2020 Phase 3: C: 2022-2023 O: 2023	Replacement of aging pipes in several areas of Portland	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Socioeconomics, Environmental Justice
City of Portland: New Fire Station (17)	Unknown – Location TBD	Unknown	Construction of new fire station on the south side of the city.	C: Unknown O: Unknown	Unknown	IU	IU	Groundwater, Surface Water, Wetlands, Vegetation, Wildlife, Land Use, Visual Resources, Socioeconomics
TXDOT: US 181 Harbor Bridge Project (18)	9.0	C: 2018-2023 O: 2023	Replacement of the existing Harbor Bridge and reconstruction of portions of US 181, I-37, and the Crosstown Expressway	C: Unknown O: Unknown	50.4 acres	IU	IU	Socioeconomics
TXDOT: Upgrade to Freeway Standards on US 77 (19)	10.4	C: 2027-2032 O: 2032	Upgrade to freeway standards	C: Unknown O: Unknown	2.91 miles of roadway	IU	IU	Socioeconomics
TXDOT: Upgrade Freeway and Upgrade Interchange on IH 37 and Interchange (20)	12.8	C: 2027-2032 O: 2032	Upgrade Freeway and upgrade Interchange on IH 37 and Interchange	C: Unknown O: Unknown	4.26 miles of roadway	IU	IU	Socioeconomics

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
TXDOT: Construct Auxiliary Lanes and Ramp Reversal to Exist 4-Ln Freeway on US 181 (21)	2.1	C: 2022 O: 2022	Construct auxiliary lanes and ramp reversal to existing 4-lane Freeway	C: Unknown O: Unknown	1.8 miles of roadway	IU	IU	Land Use, Visual Resources, Socioeconomics, Environmental Justice
TXDOT: New Location Roadway SH 200 (22)	3.1	C: 2027-2031 O: 2031	New Location Roadway SH 200	C: Unknown O: Unknown	4.8 miles of roadway	IU	IU	Socioeconomics, Land Use
TXDOT: Upgrade To 5-Lane Urban Roadway by Constructing 2 new Lanes (23)	4.5	C: 2022-2026 O: 2026	Upgrade to 5-lane urban roadway by constructing additional 2 lanes and centerline	C: Unknown O: Unknown	1.41 miles of roadway	IU	IU	Socioeconomics, Land Use
TXDOT: Upgrade/add Direct Connectors on SH 361 (24)	0.6	C: 2027-2032 O: 2032	Upgrade/add direct connectors	C: Unknown O: Unknown	0.6 miles of roadway	IU	IU	Socioeconomics, Environmental Justice, Land Use, Noise (construction), Air (construction)
The Port of Corpus Christi and Stabilis Solutions Inc. LNG Marine Fueling Project (25)	10.5	Unknown	LNG marine fueling facility	C: Unknown O: Unknown	Unknown	IU	IU	Air (operations)
Port of Corpus Christi - Harbor Island Desalination Project (26)	13.5	Unknown	Desalinization Plant	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
Harbor Island Oil Terminals (27)	Approx. 13	Unknown, but presumed cancelled	Oil export terminals	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics, Air (operations)
Port of Corpus Christi – La Quinta Channel Desalination Project (28)	1.5	Unknown	Desalinization Plant	C: Unknown O: Unknown	Unknown	IU	IU	Visual, Socioeconomics, Environmental Justice
City of Corpus Christi – La Quinta Channel Desalination Project (29)	2.2	Unknown	Desalinization Plant	C: Unknown O: Unknown	Unknown	IU	IU	Visual, Socioeconomics, Environmental Justice
City of Corpus Christi – Inner Harbor Desalination Project (30)	10.5	Unknown	Desalinization Plant	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
Pin Oak Taft Terminal (31)	8.5	C: 2019-2021 O: 2021	Crude oil storage	C: Unknown O: Unknown	63 acres	IU	IU	Air (operations)
ADCC Pipeline (32)	0-43	C: 2023-2024 O: 2024	Intrastate natural gas pipeline between Agua Dulce, TX and CCL Terminal	C: 400 O: 6	520 acres (construction)	IU	IU	Geology, Soils, Groundwater, Vegetation and Wildlife, Land Use, Visual Impacts, Socioeconomics, Environmental Justice, Marine Transportation, Air Quality (construction and operations), Noise (construction and operations)
City of Portland: Wildcat Drive Waterline (33)	1.5	C: 2018-2019 O: 2019	The City's water system currently had a deadend segment along Kestrel Lane and CR 1612 that provides lower than typical water pressure. The City would loop the existing line on CR 1612 to the existing line on Wildcat Drive north of the high school.	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
City of Portland: Street Improvements (Sealcoat, Rehabs, and Overlays) [c]	Various	C: 2019-2020; 2021-2022 O: 2020; 2022	The project is divided into two parts: Rehab and Overlay, which includes streets or street segments with severe damage requiring major repair, and Sealcoat, which includes streets for which a sealcoat is sufficient to revitalize the street and add 7- 10 years to its life.	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**
Enbridge and OLCV CO2 Hub [c]	Unknown	Unknown	CO2 pipeline transportation and sequestration hub	C: Unknown O: Unknown	Unknown	IU	IU	Socioeconomics
Flint Hills Ingleside Marine Terminal and various expansions (34)	6.8	Past Project [b] C: 2009-2018 O: 2010-2018	Bulk oil storage	C: Past Project [b] O: Unknown	115 acres	IU	IU	Air (operations)
Kiewit Offshore Fabrication Yard (35)	3.5	Past Project [b] C: 1998-2001 O: 2001	Fabrication of offshore infrastructure	C: Past Project [b] O: Unknown	248 acres	IU	IU	Air (operations)
Occidental Chemical Ingleside Plant (36)	2.0	Past Project [b] C: 1974-1977 O: 1977	Chemical manufacturing and on-site electrical co-generation	C: Past Project [b] O: 375	590 acres	IU	IU	Air (operations)
ArcelorMittal (Voestalpine) La Quinta Plant (37)	0.7	Past Project [b] C: 2013-2016 O: 2016	Steel plant	C: Past Project [b] O: 150	160 acres	IU	IU	Air (operations)
Steel Dynamics Southwest, Sinton Steel Mill (38)	15.2	C: 2022, and 2023 Expansion O: 2022 and 2023 Expansion	Steel mill	C: 1,500 O: 700	142 acres	IU	IU	Air (operations)
Buckeye Texas Hub Terminal Modifications (39)	14.8	C: 2020 O: 2020	Modifications to existing crude marine terminal	C: Past Project [b] O: Unknown	48 acres	IU	IU	Air (operations)
Nustar Logistics Terminal Modifications (40)	10.6	C: 2020 O: 2020	Modifications to existing crude marine terminal	C: Unknown O: Unknown	Unknown	IU	IU	Air (operations)
Valero Refining-Texas, L.P. West Plant Modifications (41)	14.5	Unknown	Modifications to existing petroleum fuels refinery	C: Unknown O: Unknown	170 acres	IU	IU	Air (operations)

Table K2 Past, Present, and Reasonably Foreseeable Activities Considered in the Cumulative Impact Analysis								
Project Name (Map Number)	**Distance from the Proposed Project (miles)**	**Anticipated Construction (C) and Operation (O) Start Dates**	**Project Description [a]**	**Workforce**	**Approximate Size of Project [a]**	**Impacts on Wetlands (acres)**	**Impacts on Waterbodies (# crossed)**	**Resources Potentially Affected**

IU – information unavailable

[a] Estimated acreage is based on publicly available project information.

[b] Past Project refers to completed projects that have a continued presence in the area for operating air emissions.

[c] Location not identified or multiple locations.

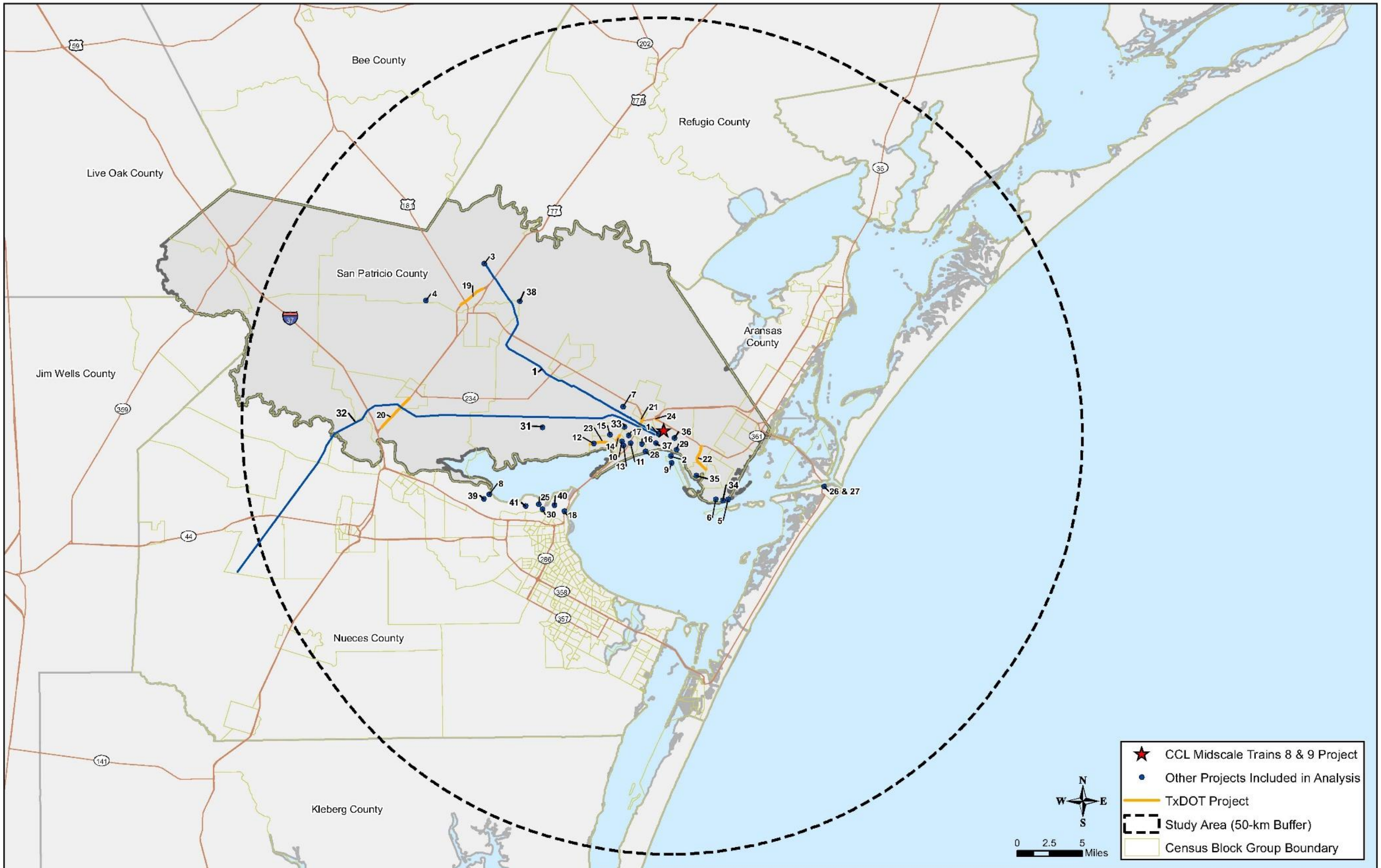

Figure K1 **Projects Potentially Contributing to Cumulative Impacts**

PROJECTS IDENTIFIED WITHIN THE GEOGRAPHIC SCOPE

The past, present, proposed, and reasonably foreseeable actions presented in table K2 were identified by CCL and by a general literature review of publicly available sources including, but not limited to the FERC eLibrary, COE Regulatory Public Notices, Texas state agencies, county agencies, local government websites, media outlets, and company websites.

We received comments during the pre-filing comment period requesting the analysis of additional industrial projects in the vicinity of the Project. All identified projects that have the potential for cumulative impacts because of their location and timing are included in this appendix, which includes a summary table and a figure of the projects. Of the 45 total actions identified, not including the Project, there are 4 FERC jurisdictional LNG and pipeline projects; 1 FERC non-jurisdictional pipeline project; 22 industrial projects; 12 transportation, road, and port improvement projects; 6 other municipal improvement projects.

In addition to the projects identified above in table K2, there is existing shipping traffic within the La Quinta Ship Channel, which when combined with the Project's additional 80 LNGC trips per year, may have cumulative impacts on resources within or adjacent to the channel. Facilities that contribute to the existing vessel traffic within the La Quinta Channel are described in the Project's WSA and summarized below.

- Flint Hills Ingleside Terminal has 3 berths that are capable of berthing vessels up to Aframax sized class tankers, with an estimated capacity of about 55 tankers annually.
- Enbridge Ingleside Energy Center is a crude and liquefied petroleum gas export terminal at the former Naval Station Ingleside site that consists of three ship docks capable of handling vessels up to very large crude carriers, and an estimated capacity of about 299 tankers annually.
- Ingleside on the Bay is a small residential community near Ingleside Point and includes a small marina on the east side of the channel, and small craft often enter and cross the channel in this area.
- Kiewit Offshore operates a fabrication yard along the east side of the channel that supports fabrication and integration of large, complex offshore projects. No regular traffic projections are made for the yard, however when structures are moved in or out of the yard it requires careful coordination with the marine LNG traffic in the area.
- Subsea 7, formerly EMAS AMS, Inc., is a pipe spooling and outload facility at Ingleside that has operated at about the same output level for the past several years and that is not expected to change in the foreseeable future. Vessel traffic varies at this facility, which can accommodate various sized pipelay vessels, but is not high volume.
- OxyChem has a single ship dock with about 155 vessel calls annually.
- Signet Maritime operates a fleet of tugs which berth at their facility on the Jewell Fulton Canal and service primarily marine terminals along the La Quinta Ship Channel, with about 200 vessel calls (barges) annually.
- ArcelorMittal Texas HBI LLC (formerly Voestalpine), is a steel plant just west of the CCL LNG terminal. ArcelorMittal leases waterfront property from the PCCA sufficient for two berths, with one berth currently constructed and no known plans for an expansion. The facility currently receives both barges and dry bulk carriers that reach the facility via the La Quinta Ship Channel.

- Gulf Coast Growth Ventures, an ExxonMobil and SABIC joint venture, operates an ethylene cracker plant just northwest of Portland, Texas to support production of plastics at the same facility. To support construction of the plant a dock was constructed on PCCA property at the end of the La Quinta Ship Channel to receive construction materials and plant production modules, and the dock has since been converted to a bulk liquids receipt and storage dock to support operation of the plastics plant. Inland and ocean-going barges and liquid bulk carriers are used to transport cargos from the dock.
- Buckeye South Texas Gateway is a crude export terminal that consists of two berths each capable of handling very large crude carriers

POTENTIAL CUMULATIVE IMPACTS BY RESOURCE

The potential cumulative impacts associated with the Project in conjunction with the other past, present, and reasonably foreseeable actions identified in this appendix are discussed below.

Geological Resources and Soils

The geographic scope for geologic resources and soils was defined as the area that would be affected by, or directly adjacent to the Project. Projects that would be constructed in close proximity to one another, and require excavation or considerable grading, would generally have greater impacts on geological resources and soils than projects with limited ground disturbance or those projects that are separated by time and space. Of the other projects identified, only the Liquefaction Project, Stage 3 Project, and ADCC pipeline would occur within the geographic scope for geologic resources and soils. Impacts on soils and surficial geology would be highly localized and would not be expected to extend beyond the area of direct disturbance associated with the Project.

Geology

As described in appendix J, the potential for impacts on or by the Project related to geologic hazards is low. Hurricanes and/or storm surge are the geologic hazards with the greatest potential to affect the Project. The Liquefaction Project and Stage 3 Project, occurring at the CCL Terminal, and the proposed Project have designed facilities to withstand predicted maximum hurricane force winds and storm surge. The non-jurisdictional ADCC pipeline is not anticipated to exacerbate potential impacts associated with a hurricane or storm surge, as the pipeline would be buried underground and contours would be restored along the right-of-way. Therefore, no cumulative impacts on geologic hazards are anticipated to occur.

The Project would include up to an additional 80 LNGCs to the LNG terminal per year. This increase, when combined with existing vessel traffic within the La Quinta Ship Channel would have some cumulative impacts on shoreline erosion as a result of wakes and water displacement during vessel passage. CCL would work with Ingleside on the Bay property owners along the channel and the PCCA to evaluate potential solutions that would mitigate the impacts.

Soils

The eastern terminus of the ADCC Pipeline and approximately 1,636 acres of workspace previously reviewed for construction and/or operation of the CCL Terminal would overlap with the Project workspace. While Project impacts and the impacts of the ADCC Pipeline and Stage 3 Project could contribute to cumulative impacts on soil resources within the overlapping construction areas during construction and restoration, these impacts would be individually and collectively temporary and localized given that CCL would implement measures in the FERC Plan to prevent erosion and stabilize disturbed areas, and the ADCC Pipeline would implement similar soil conservation and restoration. Therefore, construction of the Project and other projects identified would not result in a significant cumulative impact on soils. Further, soil disturbances would largely take place in industrial corridors and the Project's industrial nature would remain consistent with the land uses of the surrounding area.

Water Resources

The geographic scope established for water resources, including wetlands, is considered as the HUC-12 subwatershed affected by the Project. Projects identified within this geographic scope include the Stage 3 Project, Liquefaction Project, eight municipal and transportation development projects, and the ADCC Pipeline.

Groundwater

Cumulative impacts on groundwater may occur through construction activities, including clearing and grading; dewatering; contamination through fuel and other hazardous material spills; and groundwater withdrawal. As discussed in section B.3.1 of the EA, potential impacts on groundwater resources associated with the Project would be short-term and localized, with groundwater effects limited to water table elevations in the immediate vicinity of the Project. The majority of the other projects considered for cumulative impacts on groundwater would involve similar ground disturbing activities that could temporarily affect groundwater levels should project construction occur simultaneously.

There are two areas of contaminated groundwater that are present within the Project workspace (see section B.3.1 of the EA). Construction of the Project and other projects occurring within the area, including the Stage 3 Project, could contribute to the further spread of groundwater contamination. However, CCL maintains a groundwater monitoring program and a management plan for arsenic affected groundwater was coordinated with the TCEQ and was filed with FERC to meet the conditions of the Stage 3 Project Order.

Shallow groundwater areas could be vulnerable to contamination caused by inadvertent surface spills of hazardous materials (e.g., fuels, lubricants, and coolants) used during construction and operation of the Project and other projects within HUC-12 subwatershed. All FERC-regulated projects, including the Liquefaction Project, Stage 3 Project, and the proposed Project, would mitigate for potential contamination of wells and shallow groundwater areas due to accidental spills or leaks of hazardous materials associated with vehicle refueling, vehicle maintenance, and storage of construction materials by adhering to the FERC Plan and Procedures and/or project-specific plans, which include spill prevention and containment measures to minimize potential impacts on groundwater resources. Therefore, cumulative impacts on groundwater quality and availability would be minor.

Surface Waters

Other projects within the temporal scope and HUC-12 subwatershed (see table K2) involving clearing, grading, or other earthwork would have similar impacts on surface waterbodies if constructed concurrent with the Project. All project proponents would be required to adhere to state and federal regulations regarding hydrostatic, construction, and industrial stormwater and wastewater discharges. Through compliance with these regulations, and with the implementation of BMPs, including the Plan for FERC-regulated projects, and other project plans, potential cumulative impacts on surface water resources from stormwater runoff and wastewater discharges would be minimized.

Similarly, it can be reasonably assumed that all projects considered in the cumulative impacts analysis for surface water resources would be utilizing equipment and or materials that could be hazardous to the environment in the event of a spill. However, it is anticipated that all of these projects would prepare and follow a SPCC Plan or similar plan to prevent spills of hazardous materials from reaching surface water resources, as well as the measures to be implemented if such a spill occurs. Therefore, cumulative impacts resulting from the construction of the Project and other projects in the HUC-12 subwatershed are anticipated to be short-term and minor.

The Project's increase of 80 LNGCs annually would result in impacts on surface water quality within the La Quinta Ship Channel from water discharge, cooling water discharge, and increased potential for fuel spills. Although existing vessel traffic exists within the La Quinta Ship Channel, with the exception of the Stage 3 Project, none of the other projects considered for cumulative impacts on surface water quality are anticipated to result in increased vessel traffic. As discussed above, CCL and other project proponents, including vessels calling to the La Quinta Ship Channel would be required to adhere to federal and state regulations to minimize impacts on surface water resources. Therefore, cumulative impacts as a result of operation of the Project are anticipated to be minor.

Special Status Species

The geographic scope established for special status species is the HUC-12 subwatershed crossed by the Project. The Project would be constructed entirely within previously disturbed industrial lands that provide very limited, if any, habitat value for special status species (migratory birds and threatened and endangered species) and other wildlife. The Project, and all projects listed in table K2, would be required to comply with the ESA and all projects requiring federal permits would be required to adhere to Section 7 of the ESA. As part of the Section 7 consultation process, FWS and NMFS would review each project's potential impacts on federally listed species. Because the Project would have no effect on or be not likely to adversely affect threatened, endangered, and other special status species, and because the other projects would also be required to comply with the ESA, we conclude that the Project, when considered with the other projects in the HUC-12 subwatershed, would not contribute to significant cumulative impacts on threatened, endangered, and other special status species.

Recreation, and Visual Resources

The geographic scope considered for impacts on recreation and visual resources was determined to be 5 and 6 miles from the Project, respectively. The Project would not result in significant impacts on recreational areas as no recreational areas are present in the vicinity of the Project construction workspaces. Therefore, no cumulative impacts on recreational areas from construction of the Project are anticipated.

Recreational fishing and boating occurs in Corpus Christi Bay, the La Quinta Ship Channel, and CCSC, and fishing takes place off piers along the shoreline in the Ingleside and Port Aransas areas. Several charter fishing boats from Corpus Christi, Ingleside, Port Aransas, Aransas Pass, and Rockport operate in Corpus Christi Bay. Common species sought by recreational anglers in the bay are speckled trout, redfish, black drum, flounder, and sheepshead (Corpus Christi Convention & Visitors Bureau, 2022). The increase of 80 LNGCs to the CCL Terminal annually, when combined with existing vessel traffic within the La Quinta Ship Channel and CCSC, would result in cumulative impacts on recreational boating. Recreational activity outside the channel itself is not likely to be affected by large ship transit; LNGCs and other existing deep draft vessels are restricted to the existing deep draft navigation channels. CCL has submitted a follow-on WSA to the Coast Guard and received a LOR confirming that the LNGC increase would not materially impact the waterway. Therefore, we conclude that the Project would contribute negligibly to overall minor cumulative impacts on recreation.

Cumulative impacts on visual resources would be minor, as construction would occur within and adjacent to the CCL Terminal and would generally be consistent with the surrounding industrial area. From the north, views of the Project would be set against the backdrop of the CCL Terminal and ArcelorMittal (formerly Voestalpine) industrial facility located south of the Project site. From the northwest (Gregory), views of the Project would be screened by the elevated Highway 35 and elevated sections of U.S 181 that run between Gregory and the Project site and would also be set against the existing Oxychem complex southwest of the Project site. From the west (Portland), views of the Project would be set against the backdrop of the Stage 3 Project east of the Project site, and partially screened by warehouses along U.S 181. From the southwest (Portland), views of the Project would be partially screened by the visual berm installed along the western boundary of the PCCA property west of the Project site. From the south and southeast (Corpus Christi Bay, La Quinta Ship Channel, and Ingleside), views of the Project would be partially screened by the bluff along the shoreline and would be partially screened by and set in the background of the CCL Terminal, ArcelorMittal, and Oxychem facilities south and southeast of the site. From the east and northeast (open land) the Project would be partially screened by and set in the background of the Stage 3 Project. Concurrent construction of the Stage 3 Project and other projects identified, would result in short-term cumulative impacts as a result of increased construction equipment; however, these impacts would be localized, minor, and not significant. During operation, the Project's incremental increase in flaring would contribute to a cumulative impact on visual resources when combined with the Stage 3 Project and Liquefaction Project; however, the cumulative impact on visual resources due to flaring would not be significant, as the Project would utilize the existing previously authorized flares at the CCL Terminal. Permanent impacts on visual resources as a result of the Project are not anticipated to be significant, as the permanent facilities would be constructed within the existing CCL Terminal.

Socioeconomics

The geographic scope for the assessment of cumulative impacts for the Project on socioeconomic resources includes San Patricio and Nueces Counties, where the majority of the Project workforce is anticipated to reside, and the La Quinta Ship Channel. As proposed, the Project alone would have no significant impacts during construction or operation on population, employment, regional, or local services. While many of the other projects identified have the potential to contribute to cumulative impacts on socioeconomic resources within the geographic scope, these impacts would be greatest during concurrent construction of projects with large construction workforces. For this analysis, the review of cumulative impacts focused on projects that are anticipated to be constructed concurrently with the Project, when socioeconomic cumulative impacts would be greatest.

Economy and Employment

Construction of the Project would generate an average of 1,500 jobs for a period of about 4 years. The estimated construction workforces for the Stage 3 Project (2,306 workers), Corpus Christi Polymers Manufacturing Complex and Desalination Plant (2,400 workers), and ADCC Pipeline (400 workers) could also occur during the same time period. The peak construction workforces of Project construction totals approximately 2,100 workers and could occur with one or more of these projects. Some construction schedules and workforces for the other projects identified are unknown. The cumulative effect from this increase in construction positions may be a minor reduction in unemployment in the area, although it should be noted that these projects include modular construction methods, so several of the generated construction jobs may occur outside of San Patricio and Nueces counties, and even outside of the U.S. Therefore, although construction of the Project, in addition to the other proposed actions identified, would generate jobs over a period of about 4 years, the overall effect on local unemployment would likely not be significant. Operation of the Project and other projects would result in a minor, permanent impact on the local economy and construction workforce.

The Project along with the other projects would contribute to the local, regional, and state economy in terms of direct payroll expenditures, purchase of supplies and materials, indirect employment in the service sector, and taxes. With the increase in local taxes and government revenue associated with the Project as well as the other projects, the overall cumulative impact on taxes and revenue during construction and operation of the Project would result in a cumulative positive, short-term, and permanent impact on the local economy.

Housing

CCL anticipates that 40 percent of the Project workforce (840 workers at peak construction) would consist of local individuals. However, the concurrent construction of other large industrial projects could limit the availability of local workers. Based on the number of available rental units and motels/hotels in the Project area (see table B.7-3 of the EA), it is anticipated that there would be sufficient housing available, even if additional non-local workers were needed. For these reasons, we conclude that cumulative impacts on housing during construction would be short-term and minor. Operation workforces would be much smaller than construction workforces and are not anticipated to result in significant cumulative impacts.

Public Services

The construction and operation workforces required for major industrial projects in San Patricio and Nueces counties could result in increased demand for housing and public services such as schools, health care facilities, social services, utilities, and emergency services if non-local workers relocate to the area with their families. Further, if more non-local construction workers relocate to the area with their families, including school age children, than are anticipated, this would increase the population in some schools where the non-local workers reside. However, it is likely that those families would be housed throughout many school districts in various counties and the increase in school population would be distributed through many schools. As stated in section B.7.1 of the EA, the existing CCL Terminal contracts the Refinery Terminal Fire Company to provide firefighting and emergency services. Further, CCL and other large industrial projects would work directly with local law enforcement, fire departments, and emergency medical services to coordinate for effective emergency response during construction of the projects. For these reasons, we conclude that cumulative impacts on public services during construction would be short-term and minor. Operation workforces would be much smaller than construction workforces and are not anticipated to result in significant cumulative impacts.

Traffic

Land Transportation

During construction of the Project and other projects identified, roadways in the area would experience an increase in daily vehicle trips as a result of material and equipment deliveries and commuting of construction personnel to and from the Project site. Where other projects are constructed at the same time as the proposed Project, the potential for additional traffic congestion exists, particularly where the projects share routes for workers and/or site deliveries. An increase in traffic on roads would be expected but impacts are anticipated to be minor (ranging from approximately 2 to 4 percent at major roadways in the Project area; see section B.7.1 of the EA) and lasting the duration of construction.

Traffic associated with operation of the Project would be related to the 45 permanent employees that would commute to the Project site; however, this would only result in an approximate 0.1 to 0.2 percent increase on traffic of major roadways in the Project vicinity. Other projects identified within the geographic scope for cumulative impacts on land transportation would total approximately 1,402 operational workers, not inclusive of operational workforces not publicly available. These workers would commute to projects ranging from adjacent (Stage 3 Project and Liquefaction Project) to 43 miles (ADCC pipeline) from the Project. Based on the daily traffic counts on major roads/highways in the vicinity of the Project (see table B.7-4 in the EA) this would account for a minor increase in existing traffic.

Based on the minimal anticipated impacts of the Project on traffic in the area and anticipated project schedules, cumulative impacts on traffic are anticipated to be localized and minor.

Marine Transportation

If the other projects along the La Quinta Ship Channel that are listed in appendix K were to be constructed at the same time as the Project, a cumulative impact on vessel traffic in the waterway, primarily by increasing congestion and vessel travel times could occur. However, these impacts would be temporary, and the extent of the impacts would depend on the frequency and number of deliveries being made for various projects at any given time during the respective construction periods. Additionally, the projects identified are anticipated to begin construction and operations at a staggered pace, which would allow for a gradual increase in the associated ship traffic.

Throughout construction of the Project, CCL anticipates approximately 8 barges in 2026 from the Port of Corpus Christi and approximately 18 barges total in 2026 and 2027 from the Port of Houston to arrive at the existing CCL Terminal construction dock for material and equipment deliveries. For comparison, in 2022 and 2023, the Port of Corpus Christi received over 7,000 ships and barges annually (The Waterways Journal, Inc., 2022; Port of Corpus Christi, 2021).

The Project would include up to an additional 80 LNGCs to the CCL Terminal per year. The Stage 3 Project received authorization for an additional 100 LNGCs annually and other industrial facilities contributing to existing traffic within the La Quinta Channel for which information is available account for approximately 709 vessels annually. The proposed Project's increase, when combined with proposed and existing vessel traffic within the La Quinta Ship Channel, would have some cumulative impacts on the shoreline, including docks and infrastructure associated with residences along the channel. CCL states they would work with Ingleside on the Bay property owners along the channel and the PCCA to evaluate potential solutions that would mitigate the impacts. Further, the Liquefaction Project, Stage 3 Project, and the proposed Project have received a LOR from the Coast Guard concluding that the La Quinta Ship Channel is suitable for the anticipated increase in vessel traffic; therefore, cumulative impacts on marine traffic would not be significant.

Environmental Justice

The geographic scope established for environmental justice is the affected environmental justice block groups. There are several other projects that have been proposed or approved that could have overlapping construction schedules with the Project. These include the Stage 3 Project, Corpus Christi Polymers Manufacturing Complex and Desalination Plant, City of Portland: Citywide Hike and Bike Trail, City of Portland: Bay Ridge/Green Lake Linear Park, and multiple Texas Department of Transportation (TxDOT) projects.

Based on the scope of the Project and our analysis of the Project's impacts on the environment as described throughout the EA, we have determined Project-related impacts on socioeconomics, water resources, transportation and traffic, fishing and boating, visual resources, air quality, and noise may adversely but not significantly affect the identified environmental justice communities (see section B.8.2 of the EA). Therefore, cumulative impacts on environmental justice communities could occur for these resources. Cumulative impacts on environmental justice communities are not present for other resource areas such as geology, soils, wildlife, wetlands, land use, or cultural resources due to the minimal overall impact the Project would have on these resources and will not be discussed further.

Socioeconomics

Project impacts on environmental justice populations may include impacts on socioeconomic factors. Constructing the Project would require, at its peak, about 2,100 workers.

Construction workforce information is not available for many of the projects; however, the Stage 3 Project's peak workforce is approximately 2,306 workers. Combined, the Project and the Stage 3 Project would employ 4,406 workers during construction and could contribute to a maximum, approximate 1 percent increase to the combined population of San Patricio and Nueces counties. However, CCL anticipates that 40 percent of the proposed Project workforce (840 workers at peak construction) would consist of local individuals. While the temporary flux of workers/contractors into the area could increase the demand for housing, impacts are anticipated to be less than significant. Available short- and long-term housing would be limited within the two affected counties and associated environmental justice communities. Should the other LNG and industrial projects identified be constructed at the same time as the Project, sufficient housing is presumably available for the additional residents made up of the non-local workforce for these projects in the Project area (see table B.7-3 in the EA). This cumulative increased demand for housing could drive costs up, increase property taxes, and adversely impact low-income individuals. However, given the volume of existing housing available in the Project area, we conclude that cumulative impacts on housing within environmental justice communities would be less than significant.

The population increase, as well as various construction projects, may also increase the need for police, fire, and emergency medical services. Because environmental justice and smaller communities could have fewer public service resources available, any increased need due to these projects could negatively affect the availability of these services to the public. However, because applicants would be required to assess the capabilities of local public services and develop appropriate mitigation measures, such as training of internal staff to respond to emergencies, providing training, equipment, or funds to local departments, we have determined that cumulative impacts on police, fire, and emergency medical service within environmental justice communities would be less than significant.

Water Resources

Construction and operation of the Project could impact surface water resources as a result of stormwater runoff and hydrostatic testing water withdrawal and discharge. Further, construction and operation of the Project, as well as marine traffic to and from the CCL Terminal, have the potential to adversely impact water quality in the event of an accidental release of hazardous substance such as fuel, lubricants, coolants, or other material. Construction of multiple projects during the same time period, and the associated vessel traffic, may increase this risk. However, CCL and proponents of the other FERC-regulated projects, such as the Stage 3 Project, would implement the measures outlined in the FERC Plan and Procedures, respectively to minimize the likelihood of a spill and would implement its respective SPCC Plans. Additionally, LNGCs are required to develop and implement an emergency plan, which includes measures to be taken when an oil pollution incident has occurred, or a ship is at risk of one. If an accidental release were to occur, environmental justice communities along the ship channel, as well as individuals from these communities that use the channel, could be affected. However, given the mitigation measures that would be in place, we conclude that environmental justice communities would not be significantly impacted by an accidental release. Water resource impacts are more fully addressed in section B.3 of the EA and cumulative water resources impacts are discussed above.

Marine Traffic, Recreational Fishing, and Boating

Recreational fishing and boating could be impacted by construction and operational vessel traffic related to the Project and other projects and existing vessel traffic listed above. An increase in marine traffic could result in delays to other large vessels as well as recreational fisherman and boaters, including those from environmental justice communities. If the other identified projects along the La Quinta Ship Channel were to be constructed at the same time, a cumulative impact on vessel traffic in the waterway, primarily by increasing congestion and vessel travel times could occur. Construction barge traffic would be temporary, and the extent of the impacts would depend on the frequency and number of deliveries being made for various projects at any given time during the respective construction periods. Operation of multiple industrial facilities along the ship channel would result in an increase in marine vessels using the ship channel. Recreational activity outside the channel itself is not likely to be affected by large ship transit; LNGCs and other existing deep draft vessels are restricted to the existing deep draft navigation channels. CCL has submitted a follow-on WSA to the Coast Guard and received a LOR confirming that the LNGC increase would not materially impact the waterway. Therefore, we conclude that the Project would not have a significant contribution to overall cumulative impacts on marine transportation, including recreational fishing and boating, in the La Quinta Ship Channel. Marine traffic impacts are more fully addressed in section B.7.1 of the EA and cumulative marine traffic impacts are discussed in this section.

Land Traffic

Area residents may be affected by traffic delays during construction of the Project. There would be a temporary increase in use of area roads by commuter vehicles, heavy construction equipment, and associated trucks and vehicles. Increased use of these roads would result in a higher volume of traffic, increased commute times, and greater risk of vehicle accidents. These impacts would most likely affect those environmental justice communities that are in proximity to several large projects, as well as those communities in San Patricio and Nueces counties where workers may find housing. Given the temporary duration of construction activities, overall cumulative impacts on traffic within environmental justice communities would be less than significant.

Visual Resources

Cumulative impacts on visual resources would be less than significant. Based on visual simulations from NSA 6 and existing conditions at NSAs 4, 7, and 9, the proposed Project facilities would either be obscured by vegetation and/or existing infrastructure or would be consistent with the current industrial use and viewshed of the area (see appendix D of the EA). Concurrent construction of the Stage 3 Project and other projects identified, would result in short-term cumulative impacts on environmental justice communities as a result of increased construction equipment; however, these impacts would be localized and less than significant. Permanent impacts on visual resources as a result of the Project are not anticipated to be significant, as the permanent facilities would be constructed within the existing CCL Terminal.

Air Quality

As discussed in section B.8.1 of the EA, construction and operation of the Project would result in impacts on air quality. Emissions during construction of the Project would generally be associated with onshore construction activities conducted using on-road and off-road mobile equipment and marine vessels such as tugboats or barges for delivery of equipment and materials. Construction equipment exhaust emissions would be minimized by using construction equipment and vehicles that are maintained in accordance with manufacturers' maintenance schedules; comply with EPA vehicle and non-road engine emissions regulations; and use commercial fuels (e.g., diesel) that meet specifications of applicable federal and state air pollution control regulations. Fugitive dust emissions from earth-moving/material handling and equipment/vehicle traffic during construction, and gaseous emissions from fuel combustion in construction equipment would result in short-term, localized impacts in the immediate vicinity of construction work areas. Fugitive dust generation would be minimized, in part, by applying water in active construction areas (e.g., unpaved roads, material storage piles) and imposing speed limits for on-site vehicles in accordance with CCL's FDCP. These use of such mitigation measures in conjunction with an awareness of conditions (e.g., weather) and knowledge of specific construction activities at the site, would minimize the potential for excessive fugitive dust/particulate matter levels (see section B.8.1 for additional detail).

We did not identify any off-property projects that would cumulatively contribute to construction impacts in the geographic scope for air quality. Therefore, with implementation of the above-described mitigation measures for the Project (and potential overlapping construction activities for the Stage 3

Project), we conclude that the construction-related impacts on environmental justice communities during the temporary construction period for the Project would not be significant.

There are numerous projects located within the geographic scope for air quality for the Project operation (see table K2). As a means of assessing potential cumulative impacts, CCL conducted detailed air quality impact assessments for emissions of criteria pollutants (subject to PSD review) from the Project operation to show compliance with the relevant NAAQS. CCL also conducted a detailed impact assessment for emissions from the Stage 3 Project that included Midscale Trains 8 and 9. The results of these assessments showed the furthest distance that the model-predicted impacts would make a significant contribution to the cumulative impacts for the NAAQS compliance assessment beyond the Cheniere-controlled property boundary. The assessment results for the Project emissions alone showed no model-predicted impacts greater than SILs. The assessment results for the Project emissions combined with the Stage 3 Project emissions showed that operational emissions would result in 1-hour average NO_2 impacts that exceed the relevant EPA-defined SILs over a very limited area adjacent to and within 0.4 mile of property boundary. These impacts would occur primarily within CTs 107.1, 107.2, and 105.1 and to a lesser extent in CTs 105.2 and 103.02.2, which show the presence of environmental justice populations.

Overall, we conclude the construction and operational emissions from the Project would not have significant cumulative adverse air quality impacts on the minority and low-income populations in the Project area. The air quality impacts analyses are discussed in more detail in section B.8.1 of the EA.

Noise

Noise levels resulting from construction activities of the Project and the other projects in the geographic scope would vary over time and would depend on the nature of the construction activity, the number and type of equipment operating, and the distance between sources and receptors. The level of cumulative impacts would depend on the overlap in construction periods for the other projects identified within the geographic scope. Construction for the Stage 3 Project and multiple transportation projects (see table K2) could occur at the same time as construction of the Project and would contribute to cumulative noise impacts for environmental justice communities. A cumulative noise study completed for the CCL Terminal and the Project concluded the noise level during Project operation is expected to be below the FERC L_{dn} noise limit of 55 dBA at any of the nearest noise sensitive areas (see appendix I and section B.8.2 of the EA). The transportation projects identified within the geographic scope and ADCC pipeline are not anticipated to produce significant noise. Noise modeling is not available for the Port of Corpus Christi – La Quinta Channel Desalination Project or the City of Corpus Christi – La Quinta Channel Desalination Project; however, these are not anticipated to produce significant, cumulative noise impacts due to distance from the Project (1.5 to 2.2 miles, respectively). Based on the projected noise levels and CCL's proposed noise mitigation measures, the Project would not result in significant cumulative noise impacts on noise for environmental justice communities.

Air Quality

Construction

As mentioned in section B.8.1 of the EA, air emissions during construction would be limited to vehicle and construction equipment emissions and fugitive dust and other projects that could occur within the geographic scope (1.0 mile) for analysis of the cumulative impact on air quality during Project construction include construction of the Stage 3 Project. Construction of the Project would result in increases in emissions of criteria pollutants, HAPs, GHG primarily from combustion of fuel in vehicle and equipment engines; dust (particulate matter) generated from excavation and grading activities and driving on unpaved roads; and general construction activities. Generally, construction projects within the geographic scope for construction air quality with multiple-year overlapping construction schedules or single-year projects that occur in the same timeframe could cumulatively contribute to air quality impacts.

Construction impacts vary based on factors such as timing of the construction projects, intensity, and type of construction activity underway at any given time, quantity, and size of emission-producing equipment in operation, distance separating the projects, soil silt content, quantity of dust-producing material being handled, and dry or windy conditions. Specifically, other projects that could occur within the geographic scope (1.0 mile) for analysis of the cumulative impact on air quality during Project construction include construction of the Stage 3 Project.

As discussed in section B.8.1 of the EA, CCL would minimize impacts on air quality during construction of the Project by implementing the measures outlined in its FDCP and the additional measures outlined in appendix G. Additionally, CCL would require vehicular and/or barge exhaust and crankcase emissions from gasoline and diesel engines to comply with applicable EPA mobile source emission regulations (40 CFR 85) by using equipment manufactured to meet these specifications.

The combustion and fugitive dust emissions that would occur during construction would be largely limited to the immediate vicinity of the Project construction sites. These emissions would subside once construction has been completed. Given CCL's commitment to implementation of mitigation measures identified in section B.8.1 of the EA and the temporary timeframe of construction activities, we conclude that the Project would not contribute significantly to cumulative impacts on local air quality during the construction phase.

Operations

Under state and federal PSD regulations, the emission increases for the Project make it a major modification to an existing major source, and these emissions would contribute to cumulative impacts on air quality within the Project's cumulative impact area. The potential for other projects to cumulatively interact with Project emissions depends on the type of project, its stage of development, and the location (direction and distance) of the other projects relative to the Project site. Other projects that could occur within the geographic scope (31 miles or 50 km) for analysis of the cumulative impact on air quality during Project operation should be included in this assessment. Impacts on air quality from projects beyond the geographic scope are not expected to significantly contribute to a cumulative impact that includes Project impacts.

The actions identified within the Project's geographic scope for operational air quality impacts include four FERC-jurisdictional projects (including the CCL Liquefaction Project and Stage 3 Project) and 15 industrial projects, with several of the industrial projects being located within 5 miles of the Project site. Numerous industrial projects are completed projects with facilities in operation; therefore, we expect that the contribution from these sources to cumulative impacts in the region would be accounted for in the background concentrations discussed in section B.8.1 of the EA.

We note that some foreseeable future actions, particularly those actions that would be required to obtain an air quality permit at some point in the future, are not included in the NAAQS compliance demonstration analyses conducted by CCL (consistent with EPA and TCEQ requirements). Such projects (that are planned but unpermitted) would be required to conduct air quality impact analyses to demonstrate compliance with the NAAQS, per federal and state permitting requirements and comply with the TCEQ air permit conditions for construction and operation. Should operational emissions for a proposed future project demonstrate an adverse impact to air quality, the TCEQ would enforce operational limitations and/or require emissions controls that would ensure compliance with the NAAQS and other applicable air quality standards (e.g., TCEQ state property line standards).

As discussed in section B.8.1 of the EA, the results of the Significance Analysis demonstrate that the Project would not make a significant contribution to cumulative air impacts within the geographic scope of this analysis.

Noise

The geographic scope for construction noise was estimated to be NSAs within 0.25 mile of any construction and within 1.0 mile of pile driving activities. There could be cumulative construction noise impacts if construction schedules for the various projects overlap. Construction for the TxDOT: Upgrade/add Direct Connectors on SH 361 project could overlap with Project construction; however, due to the linear nature of roadway construction and the typically staggered schedule, it is unlikely that construction noise impacts from this TxDOT project and the Project would have a significant cumulative impact on nearby NSAs.

Construction for the Stage 3 Project is scheduled to be complete in 2027 and would overlap with construction of the Project. Cumulative noise impacts would occur to the combined construction activities at the CCL Terminal. Cumulative noise impacts at the CCL Terminal have been included in the noise assessment and analysis presented in section B.8.2 of the EA. We conclude that the construction noise impact of the projects would result in a minor cumulative noise impact.

The geographic scope for operation noise was estimated to be the area within a 1-mile radius around aboveground facilities. Sound levels from the Liquefaction Project and the Stage 3 Project have been included in the noise assessment and analysis in section B.8.2 of the EA. The Stage 3 Pipeline would not have any noise impacts during operations of the pipeline, so while the pipeline is adjacent/within the CCL Terminal and the Project, it would not have any long-term noise impact on nearby NSAs. Calculated sound levels attributable to the total CCL Terminal are below FERC's requirement of 55 dBA L_{dn} at the existing NSAs, and the calculated ambient noise increases associated with the addition of the Stage 3 and proposed Project are 0 to 2 dBA at nearby NSAs. Therefore, we conclude that cumulative operational noise impacts from the identified reasonably foreseeable future actions in the area of the Project are likely to be minor.