Federal Energy Regulatory Commission

Office of Energy Projects

March 2019

Corpus Christi Liquefaction Stage III, LLC
Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.

Docket No. CP18-512-000
Docket No. CP18-513-000

Stage 3 Project
Environmental Assessment

Cooperating Agencies:

Washington, DC 20426

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas 2
Corpus Christi Liquefaction Stage III, LLC
Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Docket No. CP18-512-000
Docket No. CP18-513-000

TO THE INTERESTED PARTIES:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Stage 3 Project (Project) proposed by Corpus Christi Liquefaction Stage III, LLC, Corpus Christi Liquefaction, LLC, and Cheniere Corpus Christi Pipeline, L.P. (collectively referred to as Cheniere) in the above referenced dockets. Cheniere requests authorization to expand the liquefied natural gas (LNG) liquefaction and storage capacity of the previously approved Corpus Christi Liquefaction Project (Liquefaction Project) (Docket No. CP12-507-000 and CP12508000), as well as to construct and operate a new interstate natural gas pipeline and associated facilities in San Patricio County, Texas.

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

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

The Stage 3 Project would consist of the following facilities in San Patricio County, Texas:

- addition of seven mid-scale liquefaction trains capable of producing up to 11.45 million tons per annum of LNG;

- one new 160,000-cubic meter LNG storage tank;
- 21 miles of new 42-inch-diameter natural gas pipeline;
- addition of two natural gas compressor units at the existing Sinton Compressor Station; and
- appurtenant facilities including, meter and regulator stations, launcher and receiver facilities, and mainline valves.

The FERC staff 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 Environmental Documents page (https://www.ferc.gov/industries/gas/enviro/eis.asp). In addition, the EA may be accessed by using the eLibrary link on the FERC's website. Click on the eLibrary link (https://www.ferc.gov/docs-filing/elibrary.asp), click on General Search, and enter the docket number in the "Docket Number" field, excluding the last three digits (i.e. CP18-512). 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.

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 would be. To ensure that your comments are properly recorded and considered prior to a Commission decision on the proposal, it is important that the FERC receives your comments in Washington, DC on or before 5:00 pm Eastern Time on **April 29, 2019**.

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

(1) You can file your comments electronically using the eComment feature on the Commission's website (www.ferc.gov) under the link to Documents and Filings. 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 Documents and Filings. 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 following address. Be sure to reference the project docket numbers (CP18-512-000 and CP18-513-000) with your submission: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Room 1A, Washington, DC 20426 NE, Room 1A, Washington, DC 20426

Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214). Motions to intervene are more fully described at http://www.ferc.gov/resources/guides/how-to/intervene.asp. Only intervenors have the right to seek rehearing or judicial review of the Commission's decision. The Commission may grant affected landowners and others with environmental concerns intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which no other party can adequately represent. **Simply filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered.**

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 formal documents issued by the Commission, such as orders, notices, and rulemakings.

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 www.ferc.gov/docs-filing/esubscription.asp.

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Technical Abbreviations and Acronyms

AAQS	ambient air quality standards
ACHP	Advisory Council on Historic Preservation
AGRU	acid gas removal unit
AIChE	American Institute of Chemical Engineers
APE	Area of Potential Effect
API	American Petroleum Standard
AQCR	Air Quality Control Regions
ASME	American Society of Mechanical Engineers
ATWS	additional temporary workspace
BA	Biological Assessment
BACT	best available control technology
BCC	Birds of Conservation Concern
Bcf/d	billion standard cubic feet per day
BCR	Bird Conservation Region
BGEPA	*Bald and Golden Eagle Protection Act*
bhp	brake-horsepower
BLEVE	boiling liquid expanding vapor explosion
BMP	best management practice
BOG	boil-off gas
BPVC	Boiler and Pressure Vessel Code
Btu/ft^2-hr	British thermal units per square foot per hour
CAA	*Clean Air Act*
CAAA	*Clean Air Act* Amendments
CCL Stage III	Corpus Christi Liquefaction Stage III, LLC
CCPL	Cheniere Corpus Christi Pipeline, L.P.
CCPS	Center for Chemical Process Safety
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfu	colony forming unit
CH_4	methane
Cheniere	Cheniere, Inc.
CMC	Controlled Modulus Column
Coast Guard	U.S Coast Guard
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
COTP	Captain of the Port
CWA	*Clean Water Act*
CZM	Coastal Zone Management
dBA	A-weighted decibels

DHS	U.S. Department of Homeland Security
DMPA	Dredged Material Placement Area
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOE/FE	DOE's Office of Fossil Energy
DPS	distinct population segment
EA	environmental assessment
EDR	Environmental Data Resources, Inc.
EI	Environmental Inspector
EIS	environmental impact statement
EFH	Essential Fish Habitat
EPA	U.S. Environmental Protection Agency
ESA	*Endangered Species Act*
F	Fahrenheit
FAA	Federal Aviation Administration
FDCP	*Fugitive Dust Control Plan*
FEED	front-end-engineering-design
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
FSA	Facility Security Assessment
FSP	Facility Security Plan
FTA	free trade agreement
FWS	U.S. Fish and Wildlife Service
g	gravity
GHG	greenhouse gases
GIWW	Gulf Intracoastal Waterway
GMD	geomagnetic disturbance
GWP	global warming potential
HAPs	hazardous air pollutants
HAZOP	hazard and operability review
HCA	high consequence area
HDD	horizontal directional drill
HGB	Houston-Galveston-Brazoria
HMB	heat and material balance
HP	horsepower
HUC	Hydrologic Unit Code
IBC	International Building Code
IMO	International Marine Organization
ISA	International Society for Automation
ISD	Independent School District
kPA	kilopascals
kW	kilowatts
kW/m^2	kilowatts per square meter
lb	pound

lb/hr	pounds per hour
LDAR	Leak Detection and Repair
L_{dn}	day-night equivalent sound level
L_{eq}	equivalent sound level
Liquefaction Project	Corpus Christi Liquefaction Project
LNG	liquefied natural gas
LNGC	liquefied natural gas carriers
LOD	Letter of Determination
LOR	Letter of Recommendation
LPG	liquefied petroleum gas
MAOP	maximum allowable operating pressure
M&R	meter and regulator
MACT	Maximum Available Control Technology
MBTA	*Migratory Bird Treaty Act*
MEOW	maximum envelope of water
MLV	mainline valve
MMBtu/hr	million British thermal units per hour
MOU	memorandum of understanding
MP	milepost
mph	miles per hour
MSS	maintenance, start-up, and shutdown
MTPA	million tons per annum
MTSA	*Maritime Transportation Security Act*
NAQQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NEPA	*National Environmental Policy Act*
NFPA	National Fire Protection Association
NGA	*Natural Gas Act*
NHTSA	National Highway Traffic Safety Administration
NMFS	National Marine Fisheries Service
N_2O	nitrous oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NOI	*Notice of Intent to Prepare an Environmental Assessment for the Proposed Stage 3 Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Session*
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NSA	noise sensitive areas
NSPS	New Source Performance Standards
NSR	New Source Review
NWI	National Wetlands Inventory

O_3	ozone
OBE	operating basis earthquake
OEP	Office of Energy Projects
P&ID	piping and instrumentation diagram
PEM	palustrine emergent
PFD	process flow diagram
PGA	peak ground acceleration
PHMSA	Pipeline and Hazardous Materials Safety Administration
Plan	*Upland Erosion Control, Revegetation, and Maintenance Plan*
Procedures	*Wetland and Waterbody Construction and Mitigation Procedures*
Project	Stage 3 Project
PSD	Prevention of Significant Deterioration
psgi	pounds per square inch gauge
$PM_{2.5}$	particulate matter sized 2.5 microns or smaller
PM_{10}	particulate matter sized 10 microns or smaller
PTE	potential to emit
RHA	*Rivers and Harbors Act*
RMP	risk management plan
RRC	Railroad Commission of Texas
SHPO	State Historic Preservation Officer
SIPs	state implementation plans
SLOSH	Sea, Lake, and Overland Surge from Hurricanes
SO_2	sulfur dioxide
SPCC Plan	*Spill Prevention, Containment, and Countermeasures Plan*
SSE	safe shutdown earthquake
SSURGO	Soil Survey Geographic Database
SWEL	stillwater elevation
SWPPP	*Stormwater Pollution Prevention Plan*
TAC	Texas Administration Code
T&E	threatened and endangered
TCEQ	Texas Commission on Environmental Quality
TPWD	Texas Parks and Wildlife Department
tpy	tons per year
TWEI	Tolunay-Wong Engineers, Inc.
TWIC	Transportation Worker Identification Credential
TXDOT	Texas Department of Transportation
USC	United States Code
USDA	U.S. Department of Agriculture
USDOT	U.S. Department of Transportation
USGS	U.S. Geological Survey
VOC	volatile organic compound
WSA	Waterway Suitability Assessment

SECTION A – PROPOSED ACTION

1.0 INTRODUCTION

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared this environmental assessment (EA) to assess the potential environmental impacts of the construction and operation of an expansion of the previously authorized and currently under construction Corpus Christi Liquefaction Project (Liquefaction Project) and Corpus Christi Pipeline (Docket Nos. CP12-507-000 and CP12-508-000, respectively) in San Patricio County, Texas. Corpus Christi Liquefaction Stage III, LLC (CCL Stage III) along with Corpus Christi Liquefaction, LLC requests authorization to expand the liquefied natural gas (LNG) liquefaction and storage capacity of the previously approved Liquefaction Project (Docket No. CP12-507-000). Cheniere Corpus Christi Pipeline, L.P. (CCPL) requests authorization to construct and operate a new bi-directional interstate natural gas pipeline and associated facilities, all of which are located within San Patricio County, Texas. The location and a general overview of the proposed facilities are provided on figure A.1.0-1.

The FERC is the lead federal agency for authorizing interstate natural gas transmission facilities under the *Natural Gas Act* (NGA), and is the lead federal agency for preparation of the EA. We[1] prepared this EA in compliance with the requirements of the National Environmental Policy Act (NEPA) (Title 40 of the Code of Federal Regulations [CFR] Parts 1500-1508 [40 CFR 1500-1508]) and the Commission's implementing regulations under 18 CFR 380.

On June 28, 2018, CCL Stage III and CCPL, collectively Cheniere, Inc. (Cheniere), filed an application with the Commission in Docket Nos. CP18-512-000 and CP18-513-000 for authorization under Sections 3 and 7 of the NGA and Part 157 of the Commission's regulations. The application requested authorization to construct and operate a new liquefaction and storage facility located immediately adjacent to the previously authorized Liquefaction Project, which would include seven midscale liquefaction trains and one LNG storage tank (collectively, the Stage 3 LNG Facilities). The application requested authorization to construct a new bi-directional interstate natural gas pipeline and associated facilities (Stage 3 Pipeline) in order to deliver feed gas to the Stage 3 LNG Facilities. The Stage 3 Pipeline would include a new 21-mile-long, 42-inch-diameter pipeline that would be 99 percent collocated with CCPL's 48-inch-diameter pipeline approved by the Commission in Docket No. CP12-508-000 (Corpus Christi Pipeline). The Stage 3 LNG Facilities and Stage 3 Pipeline are collectively referred to as the Stage 3 Project or Project (Project). On June 9, 2015, Commission staff approved Cheniere to commence the pre-filing process under Docket No. PF15-26-000. During pre-filing, Commission staff reviewed the Project prior to its formal application. The main purposes of pre-filing are to encourage early involvement of interested stakeholders, facilitate interagency cooperation, and identify and resolve environmental issues before an application is filed with FERC.

[1] The pronouns "we," "us," and "our" refers to environmental and engineering staff of the Office of Energy Projects.

Figure A.1.0-1 Stage 3 Project General Location Map

2.0 PURPOSE AND NEED

Cheniere states in its applications that the purpose of the Project is to expand the Liquefaction Project's production capabilities and diversify delivery platforms to meet the future needs of the global LNG market. Cheniere states that the Stage 3 Project is consistent with ongoing development of U.S. natural gas resources and expanding access to these resources in global markets. The ability to export domestic natural gas as LNG greatly increases the market scope and access for domestic natural gas producers.

Under Section 3 of the NGA, the Commission considers all factors bearing on the public interest as part of its decision to authorize natural gas facilities. Specifically, regarding whether or not to authorize natural gas facilities used for importation or exportation, the Commission shall authorize the proposal unless it finds that the proposed facilities will not be consistent with the public interest.

Under Section 7(c) of the NGA, the Commission determines whether interstate natural gas transportation facilities are in the public convenience and necessary and, if so, grants a Certificate to construct and operate the facilities. The Commission bases its decision on technical competence, financing, rates, market demand, gas supply, environmental impact, long-term feasibility, and other issues concerning a proposed project.

3.0 SCOPE OF THIS ENVIRONMENTAL ASSESSMENT

Our principal objectives in preparing this EA are to:

- identify and assess potential impacts on the natural and human environment that would result from implementation of the proposed action;
- describe and evaluate reasonable alternatives to the proposed actions that would avoid or minimize adverse effects on the environment;
- identify and recommend specific mitigation measures, as necessary, to minimize the environmental impacts; and
- facilitate public involvement in identifying the significant environmental impacts.

The topics addressed in this EA include: geology; soils; groundwater; surface waters; wetlands; vegetation; wildlife and aquatic resources; special status species; land use, recreation, special interest areas, and visual resources; socioeconomics (including transportation and traffic); cultural resources; air quality and noise; reliability and safety; and cumulative impacts. The EA describes the affected environment as it currently exists, discusses the environmental consequences of the Project, and compares the Project's potential impact with that of various alternatives. The EA also presents our recommended mitigation measures.

The EA will be used by the Commission in its decision-making process to determine whether to authorize Cheniere's proposal. Approval would be granted if, after consideration of both environmental and non-environmental issues, the Commission finds that the Project is in the public convenience and necessity.

4.0 COOPERATING AGENCIES

The U.S. Army Corps of Engineers (COE), U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Transportation (USDOT), U.S. Coast Guard (Coast Guard), and U.S. Fish and Wildlife Service (FWS) 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. The roles of the COE, EPA, DOE, USDOT, Coast Guard, and FWS in the Project review process are described below. The EA provides a basis for coordinated federal decision making in a single document, avoiding duplication among federal agencies (or state agencies with federal delegation authority) in the NEPA environmental review process. In addition to the lead and cooperating agencies, other federal, state, and local agencies may use this EA in approving or issuing permits for all or part of the Project. Federal, state, and local permits, approvals, and consultations for the Project are discussed in section A.10.0.

4.1 U.S. Army Corps of Engineers

The COE has jurisdictional authority pursuant to Section 404 of the *Clean Water Act* (CWA) (33 United States Code [USC] 1344), which governs the discharge of dredged or fill material into waters of the U.S. and Section 10 of the *Rivers and Harbors Act* (RHA) (33 USC 403), which regulates any work or structures that potentially affect the navigable capacity of a waterbody. Construction of the Stage 3 Project would impact waters of the U.S.; however, it would qualify for coverage under a Nationwide Permit without notification to the COE. Nevertheless, due to Project's impacts on waters of the U.S., the COE is participating as a cooperating agency in the development of this EA.

4.2 U.S. Environmental Protection Agency

The EPA has delegated water quality certification, under Section 401 of the CWA, to the jurisdiction of individual state agencies. The EPA also oversees the issuance of a National Pollutant Discharge Elimination System (NPDES) permit by the state agency, under Section 402 of the CWA, for point-source discharge into waterbodies. In addition to its authority under the CWA, the EPA has jurisdictional authority under the *Clean Air Act* of 1970 (CAA) to control air pollution by developing and enforcing rules and regulations for all entities that emit toxic substances into the air. Under this authority, the EPA has developed regulations for major sources of air pollution and has delegated the authority to implement these regulations to state and local agencies. State and local agencies also develop and implement their own regulations for nonmajor sources of air pollutants.

4.3 U.S. Department of Energy

The DOE's Office of Fossil Energy (DOE/FE) must meet its obligation under Section 3 of the NGA to authorize the import and/or export of natural gas, including LNG, unless it finds that the proposed import or export is not consistent with the public interest. By law, under Section 3(c) of the NGA, applications to export natural gas to countries with which the United States has free trade agreements (FTA) that require national treatment for trade in natural gas are deemed to be consistent with the public interest and the Secretary of Energy must grant authorization without modification or delay. In the case of applications to export LNG to non-FTA countries, Section 3(a) of the NGA requires DOE to conduct a public interest review and to grant applications unless the DOE finds that the proposed exports would not be consistent with the public interest. Additionally, NEPA requires the DOE to consider the environmental impacts of its decisions regarding applications to export natural gas to non-FTA nations. In this regard, the DOE acts as a cooperating agency, with the FERC as the lead agency, pursuant to the requirements of NEPA.

The purpose and need for DOE/FE action are to enable DOE's public interest evaluation and NEPA review of CCL Stage III's application for authority to export LNG to non-FTA countries from the Stage 3 LNG Facilities. CCL Stage III seeks to export the LNG to any country: (1) with which the United States has an FTA requiring national treatment for trade in natural gas, including LNG, or with which the United States does not have an FTA requiring national treatment for trade in natural gas, including LNG; (2) that has, or in the future develops, the capacity to import LNG; and (3) with which trade is not prohibited by U.S. law or policy. On November 9, 2018, in FE Docket No. 18-78-LNG, the DOE issued DOE/FE Order

No. 4277 granting CCL Stage III authorization to export the equivalent of approximately 582.14 Bcf per year of natural gas, in the form of LNG, by vessel from the Corpus Christi Liquefaction Terminal to FTA countries.

The DOE will not make decisions on applications to export LNG to non-FTA countries until the DOE has met all of its statutory responsibilities. In accordance with 40 CFR 1506.3, after an independent review of this EA, the DOE may adopt it prior to making a decision relating to CCL Stage III's application for authority to export LNG to non-FTA countries.

4.4 U.S. Department of Transportation

Under 49 USC 60101, the USDOT has prescribed the minimum federal safety standards for LNG facilities. Those standards are codified in 49 CFR Part 193 *Liquefied Natural Gas Facilities: Federal Safety Standards* and apply to the siting, design, construction, operation, maintenance, and security of LNG facilities. A portion of 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 2004 Interagency Agreement on the safety and security review of waterfront import/export LNG facilities, the USDOT participates as a cooperating agency and assists in assessing any mitigation measures that may become conditions of approval for any project. On August 31, 2018, FERC and USDOT signed a Memorandum of Understanding (MOU) to improve agency coordination on LNG project reviews and eliminate duplicative efforts. [1]

The USDOT would issue a Letter of Determination (LOD) to FERC on the 49 CFR 193, Subpart B, regulatory requirements. The LOD would provide the Pipeline and Hazardous Materials Safety Administration's (PHMSA) analysis and conclusions on the Subpart B regulatory requirements. The USDOT's conclusion on the siting and hazard analysis required by Part 193 would be based on preliminary design information, which may be revised as the engineering design progresses to final design. USDOT regulations also contain requirements for the design, construction, installation, inspection, testing, operation and maintenance, and contingency plans for LNG facilities, which would be completed during later stages of the project. If the facilities are approved and constructed, final compliance with the requirements of 49 CFR Part 193 would be subject to USDOT's inspection and enforcement programs.

The USDOT also has authority to enforce safety regulations and standards related to the design, construction, and operation of natural gas pipelines, under the federal pipeline safety statutes codified in 49 USC 60101 *et seq*, and under 49 CFR 192, Transportation of Natural or Other Gas by Pipeline: Minimum Federal Safety Standards.

4.5 U.S. Coast Guard

The Coast Guard is the principal federal agency responsible for maritime safety, security, and environmental stewardship in U.S. ports and waterways. As such, the Coast Guard is the federal agency responsible for assessing the suitability of the Project Waterways (defined as the waterways that begin at the outer boundary of the navigable waters of the U.S.) for LNG marine traffic. The Coast Guard exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the *Magnuson Act* (50 USC 191); the *Ports and Waterways Safety Act* of 1972, as amended (33 USC 1221 et seq.); and the *Maritime Transportation Security Act* (MTSA) of 2002 (46 USC 701). If the Project is approved, constructed, and operated, the Coast Guard would continue

[1] https://www.ferc.gov/legal/mou/2018/FERC-PHMSA-MOU.pdf

to exercise regulatory oversight of the safety and security of the LNG terminal facilities (includes Stage 3 LNG Facilities and previously authorized Liquefaction Project facilities) in compliance with 33 CFR 127.

As required by its regulations, the Coast Guard is responsible for issuing a Letter of Recommendation (LOR) as to the suitability of the waterway for LNG marine traffic following a Waterway Suitability Assessment (WSA). The process of preparing the LOR begins when an applicant submits a Letter of Intent to the Captain of the Port (COTP). As required by 33 CFR 127.007, CCL Stage III submitted its Follow-on WSA to the Coast Guard in February 2016. In a letter dated August 15, 2018, the Coast Guard issued the LOR for the Project, which stated that the La Quinta Channel is considered suitable for the increased LNG carrier (LNGC) traffic associated with the Project in accordance with the guidance in the Coast Guard Navigation and Vessel Inspection Circular 01-2011.

4.6 U.S. Fish and Wildlife Service

The FWS is responsible for ensuring compliance with the *Endangered Species Act* (ESA). Section 7 of the ESA, as amended, states that any project authorized, funded, or conducted by any federal agencies should not "…jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined…to be critical…" (16 USC 1536(a)(2)). The FWS also reviews project plans and provides comments regarding protection of fish and wildlife resources under the provisions of the *Fish and Wildlife Coordination Act* (16 USC 661 et seq.). The FWS is also responsible for the implementation of the provisions of the *Migratory Bird Treaty Act* (MBTA) (16 USC 703) and the *Bald and Golden Eagle Protection Act* (BGEPA) (16 USC 688).

The ultimate responsibility for compliance with Section 7 remains with the lead federal agency (i.e., FERC for this Project). As the lead federal agency for the Project, FERC consulted with the FWS, a cooperating agency, pursuant to Section 7 of the ESA to determine whether federally listed endangered or threatened species or designated critical habitat under the FWS jurisdiction are found in the vicinity of the Project, and to evaluate the proposed action's potential effects on those species or critical habitats. For the purposes of compliance with Section 7 of the ESA, this EA serves as our Biological Assessment (BA) for the Project. Furthermore, we are requesting concurrence from the FWS with our determinations of effect for the federally listed species presented in this EA and further discussed in section B.4.0.

5.0 PUBLIC REVIEW AND COMMENT

On June 1, 2015, Cheniere filed a request to utilize our pre-filing process, and we approved and initiated the pre-filing process on June 9, 2015, in Docket No. PF15-26-000. We participated in one public open house sponsored by Cheniere near the Project site on July 1, 2015, to explain our environmental review process to interested stakeholders. FERC staff also participated in a site visit on that same day to examine the existing facilities and the proposed site for the new liquefaction and pipeline facilities.

On August 17, 2015, the Commission issued a *Notice of Intent to Prepare an Environmental Assessment for the Proposed Stage 3 Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Session* (NOI). The NOI was published in the Federal Register and mailed to over 530 entities, including federal, state, and local government, representatives and agencies; elected officials; Native American tribes; environmental and public interest groups, newspapers and libraries in the Project area; and affected landowners and interested parties.[3] Comments received during the scoping process are part of the public record for the Project and are available for viewing on the FERC Internet website

[3] The NOI was published in 80 Federal Register No. 162 on August 21, 2015.

(http://www.ferc.gov).[4] Table A.5.0-1 summarizes the environmental issues identified during the scoping process. Substantive environmental issues raised by commenters are addressed in the applicable sections of the EA. Agencies that commented on the NOI included the Federal Emergency Management Agency, Texas Parks and Wildlife Department (TPWD), EPA, and FWS. No comments were filed after Cheniere filed its application.

Table A.5.0-1

Issues Identified During the Scoping Period

Issue	Comments	EA Section(s) Where Comments are Addressed
Alternatives	Recommend the EA describe how each alternative was developed, how it addresses each project objective, and how it would be implemented; clearly describe the rationale used to determine whether impacts of an alternative are significant or not; and describe the methodology and criteria used for determining project siting.	C
Water Use and Quality	Effects on water quality and supply during project construction and operation.	B.3.0
Surface Waters	Effects on surface waters during pipeline construction and operation.	B.3.2
Wetlands	Effects on wetlands during pipeline construction; loss of wetlands.	B.3.3
Vegetation	Effects on vegetation during construction and operation of the pipeline.	B.4.1
Fish and Wildlife	Effects on wildlife during pipeline construction; loss of habitat.	B.4.2
Threatened, Endangered, and Special-Status Species	Effects on threatened and endangered species and their habitats.	B.4.4
Migratory Birds	Effects on migratory bird species and their habitats during construction.	B.4.3
Land Use, Recreation, and Visual Resources	Effects on land use plans.	B.6.0
Floodplains	Effects of construction on floodplains.	B.1.2.2
Socioeconomics	Effects of project construction and operation on quality of life for nearby residents/environmental justice issues; adequacy of local gas supplies for industry.	B.7.0
Cultural Resources	Effects on cultural and tribal resources during construction.	B.5.0

[4] Using the “eLibrary” link, select “General Search” from the eLibrary menu and enter the docket number excluding the last three digits in the “Docket Number” field (i.e., PF15-26 and/or CP18-512 and CP18-513). Select an appropriate date range.

Table A.5.0-1 Issues Identified During the Scoping Period		
Issue	**Comments**	**EA Section(s) Where Comments are Addressed**
Air Quality and Noise	Air pollution during construction and operation; air emissions from LNGC; air pollution impacts on nearby residents; increased gas production/climate change issues.	B.8.1

6.0 PROPOSED FACILITIES

Cheniere's Stage 3 Project would involve the installation of new facilities and modification of existing facilities to meet the purpose and need of the Project. The Project would consist of the Stage 3 LNG Facilities and the Stage 3 Pipeline, as described in the sections below.

6.1 LNG Facilities

The Stage 3 LNG Facilities would include natural gas liquefaction facilities, LNG storage facilities, and other associated infrastructure. In addition, the Stage 3 LNG Facilities would utilize the marine facilities currently authorized for the Liquefaction Project. The Stage 3 LNG Facilities are described in greater detail in the sections below. Figure A.6.1-1 depicts an artist's rendering of the proposed Stage 3 LNG Facilities.

Figure A.6.1-1 Artist Rendition of the Stage 3 LNG Facilities (view to the north)

6.1.1 Liquefaction Facilities

The Stage 3 LNG Facilities would consist of seven midscale liquefaction trains each with a LNG nameplate capacity of 1.36 million tons per annum (MTPA) and a maximum capacity of 1.64 MTPA.[5] The Project would produce up to 11.45 MTPA of LNG for export under optimal conditions. Each liquefaction train would contain the following:

- two liquefaction units with a capacity of 0.681 MTPA;
- facilities to remove carbon dioxide, hydrogen sulfide, and other sulfur compounds from the feed gas;
- facilities to remove water, mercury, and heavy hydrocarbons from the feed gas;
- a thermal oxidizer for combusting waste gas;
- electric motor driven refrigerant compressors and associated cold boxes;
- induced draft air coolers;
- associated fire and gas safety systems; and
- associated control systems and electrical infrastructure.

Impurities removed from the natural gas stream prior to liquefaction would pass through a triazine scavenger bed to absorb hydrogen sulfide. The remaining waste gas (with carbon dioxide [CO_2]) would be mixed with a small amount of fuel gas and sent to a thermal oxidizer. There would be no operational solvent wastes to be disposed of offsite.

Mercury is typically absent from the feed gas. However, as a precaution, mercury removal beds would be provided and spent mercury removal catalysts would be periodically returned to the supplier or a licensed third-party contractor for metals removal and recovery.

6.1.2 LNG Storage

LNG storage facilities would consist of one full containment storage tank and would be designed to store a nominal volume of 160,000 cubic meters (approximately 42 million gallons) of LNG. The LNG storage tank would store the LNG between -260 degrees Fahrenheit (F) to -270 degrees F and with a normal operating pressure of 1.5 pounds per square inch gauge (psig) to a maximum internal pressure of 4.2 psig. The LNG storage tank would be supported on a reinforced concrete foundation. The tank would be 258 feet in diameter and a total of 225 feet in height from the foundation base to the top. The tank would feature a 9 percent nickel steel inner container, designed to withstand the hydrostatic pressures and cryogenic temperatures of the LNG, as well as the predicted seismic, insulation, and thermal gradient loads. The outer tank would be compromised of reinforced concrete with a domed concrete roof. An insulated aluminum deck would be suspended from the roof over the inner container, which would be insulated with fiberglass blankets so that the vapor space would essentially be at ambient temperature. The vapor pressure from the LNG would be equalized through ports in the suspended deck and would be contained by the outer container. The space between the inner container and the outer container would be insulated with expanded

[5] Capacity is based on CCL Stage III's June 29, 2018 *Application Requesting Long-term Multi-Contract Authorization to Export Domestically Produced Natural Gas in the Form of LNG to FTA/NFTAns*. https://www.energy.gov/fe/corpus-christi-liquefaction-stage-iii-llc-fe-dkt-no-18-78-lng.

perlite to maintain the outer container at near ambient temperature. Electric base heating would be installed in the concrete foundation to prevent frost heave.

Cheniere states the tank system would meet the requirements of the NFPA 59A, American Society of Mechanical Engineers (ASME) B31.3, 49 CFR 193, and American Petroleum Institute (API) Standard 620 Appendix Q. In compliance with USDOT's requirement that any potential LNG spill must be contained within the facility's property limits, a tertiary containment system would be provided. The tertiary containment system would be primarily defined by the roads that encircle the seven trains and the LNG Storage Tank. A typical full containment LNG storage tank is shown in figure A.6.1-2.

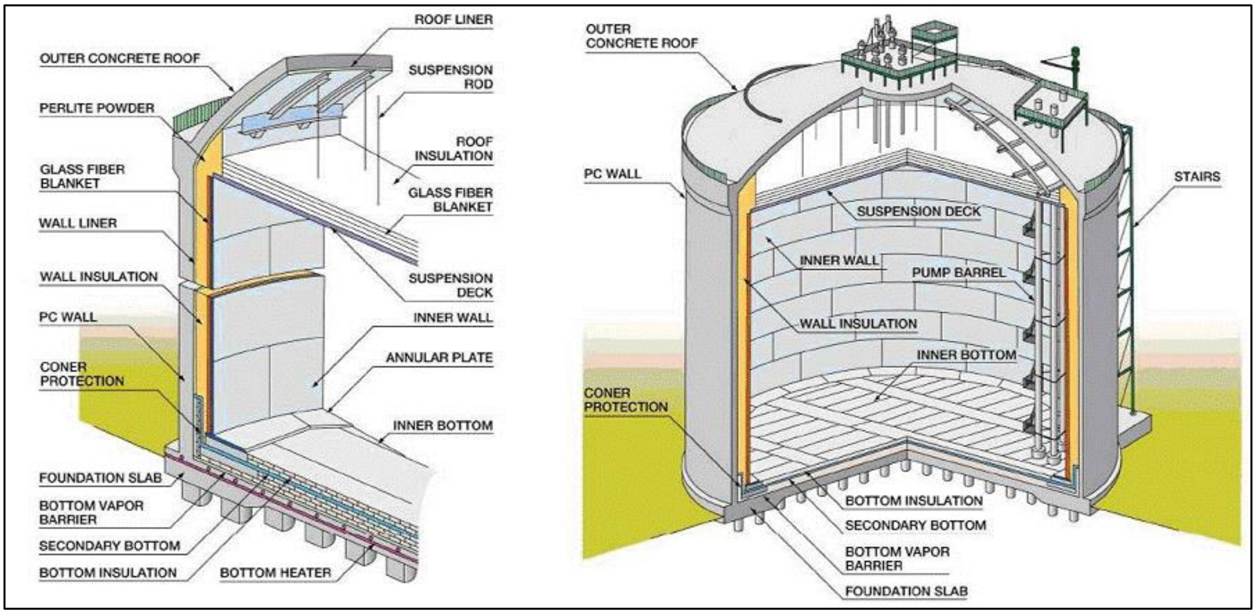

Figure A.6.1-2 Full Containment LNG Storage Tank

6.1.3 Other Terminal Infrastructure

In addition to the facilities listed above, the Project would require the following additional facilities and infrastructure:

- expansion of the Liquefaction Project control building to accommodate the Stage 3 LNG Facilities;
- miscellaneous buildings and other structures to accommodate employees, equipment, utilities and support services infrastructure;
- remote input/output buildings and substations;
- spill containment facilities;
- emergency shutdown systems and firewater system;
- three elevated wet flares (approximately 197 feet in height each);
- three elevated dry flares (approximately 197 feet in height each);
- three ground flares (approximately 50 feet in height each);

- instrument air compressor packages;
- security and perimeter control systems including telecoms, information technology, closed circuit television, and other systems;
- potable water, utility water, and demineralized water systems;
- pipeline gas compressor;
- pipeline interconnects for the receipt of natural gas from the Corpus Christi Liquefaction, LLC Terminal Custody Meter Station as well as transfer of LNG to the Corpus Christi Liquefaction, LLC marine facilities;
- electric facilities, switchgear, transformers, and other electrical accessories;
- LNG transfer line to Liquefaction Project storage tanks; and
- various interconnects to the Liquefaction Project.

6.1.4 Marine Facilities

The Stage 3 Project would utilize the same marine terminal facilities for mooring and loading LNGCs as the currently authorized Liquefaction Project. Additionally, the same tugs used for the Liquefaction Project would be available to facilitate maneuvering of LNGCs for the Stage 3 Project. Figure A.6.1-3 depicts the marine terminal facilities and the Liquefaction Project in relation to the Stage 3 Project.

The same access route that was analyzed by the Coast Guard for the currently authorized Liquefaction Project would be used to provide deepwater access from the Gulf of Mexico to the Stage 3 Project. The route is shown in figure A.6.1-4.

The Stage 3 Project would provide an increase in the maximum marine vessel traffic for the currently-authorized 300 LNGCs per year up to 400 LNGCs per year, which equates to approximately two additional LNGCs per week. CCL Stage III prepared a Follow-on WSA and submitted it to the Coast Guard in February 2016 seeking a LOR confirming that the increase of up to 100 LNGCs per year would not significantly impact the waterway. A LOR was issued on August 15, 2018 by the Coast Guard recommending that the Corpus Christi Ship Channel from the entrance approach at Port Aransas to the La Quinta Junction, and the entire length of the La Quinta Channel be considered suitable for the additional LNG marine traffic anticipated as a result of the Stage 3 Project.

Figure A.6.1-3 Artist Rendition of the Stage 3 Project and Liquefaction Project

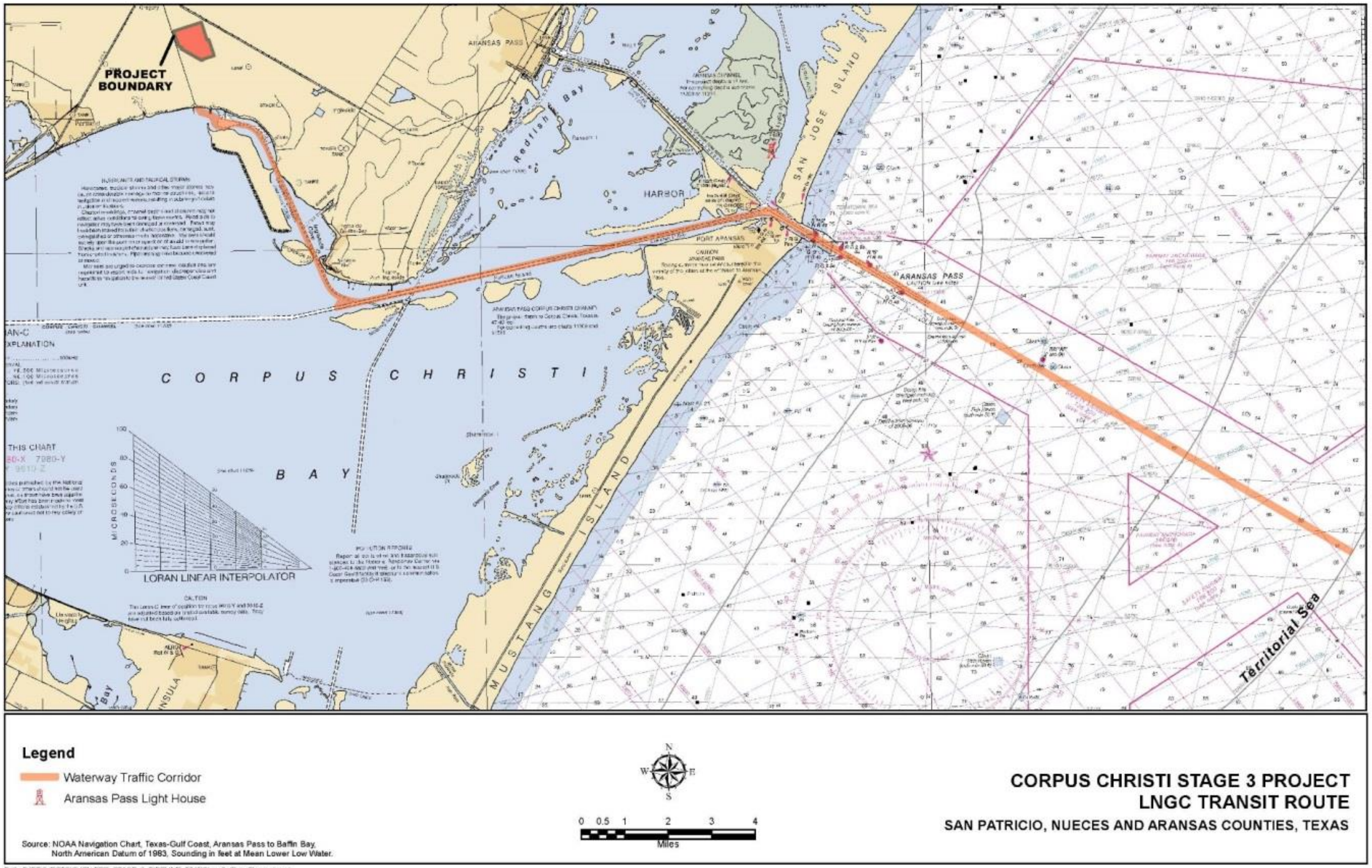

Figure A.6.1-4 Stage 3 Project LNGC Transit Route

6.2 Pipeline Facilities

The Stage 3 Pipeline Facilities would be designed for a maximum allowable operating pressure of 1,440 psig and a capacity of approximately 1.5 billion standard cubic feet per day (Bcf/d). The Stage 3 Pipeline Facilities would be located entirely within San Patricio County, Texas and are summarized in table A.6.2-1 and depicted in figure A.6.2-1 below.

Table A.6.2-1

Summary of the Stage 3 Pipeline

Facility	Length (miles)	Diameter (inches)	Location (milepost)	Horsepower	Description
PIPELINE					
Pipeline	21.0	42	0.0 – 21.0	N/A	New pipeline to connect the Stage 3 LNG Facilities to natural gas pipeline supply points
COMPRESSOR STATION					
Sinton Compressor Station Expansion	N/A	N/A	21.0	44,000 (22,000 x 2)	Two Titan 130E gas-fired compressors
METER AND REGULATOR (M&R) STATIONS					
Stage 3 LNG Facilities M&R Station	N/A	N/A	0.00	N/A	Install M&R station to feed gas into the Stage 3 LNG Facilities
M&R Stations	N/A	N/A	21.0	N/A	Two meters totaling 1.5 Bcf/d inside the Sinton Compressor Station Expansion
APPURTENANT FACILITIES					
Pig Receiver and Mainline Valve (MLV)	N/A	42	0.00	N/A	Pig receiver and MLV at Stage 3 LNG Facilities M&R Station
Pig Launcher and MLV	N/A	42	21.0	N/A	Pig launcher and MLV at Sinton Compressor Station
MLV 1	N/A	42	7.3	N/A	MLV on Stage 3 Pipeline
MLV 2	N/A	42	12.8	N/A	MLV on Stage 3 Pipeline
N/A – not applicable					

6.2.1 Pipeline

CCPL would construct approximately 21 miles of new 42-inch-diameter natural gas pipeline, originating at the currently-authorized and recently constructed Sinton Compressor Station and generally routed parallel to the currently authorized and recently constructed 48-inch-diameter Corpus Christi Pipeline (the Stage 3 Pipeline would be approximately 99% collocated with the Corpus Christi Pipeline). The Stage 3 Pipeline would deviate from the CCPL between mileposts (MP) 0.0 and 0.2 to accommodate the horizontal directional drill (HDD) under La Quinta Road. The Stage 3 Pipeline would terminate at the

Stage 3 LNG Facilities. While the origin and terminus of the Stage 3 Pipeline are the Sinton Compressor Station and Stage 3 LNG Facilities, respectively, MPs for the Stage 3 Pipeline begin at the Stage 3 LNG Facilities and end at the Sinton Compressor Station.

6.2.2 Compressor Station

The Stage 3 Pipeline would require additional compression at the authorized Sinton Compressor Station, which would consist of the addition of approximately 44,000 horsepower (HP) via two (2) Titan 130E gas compressor units (22,000 HP each). The Sinton Compressor Station, including facilities added for the Stage 3 Pipeline, would be remotely operated.

6.2.3 Meter and Regulation Stations

One meter and regulator (M&R) station would be installed within the Stage 3 LNG Facilities (at MP 0.0) and two M&R stations would be installed within the Sinton Compressor Station (at MP 21.0).

6.2.4 Appurtenant Facilities

Mainline valves (MLV) would be installed at the origin and terminus of the pipeline, as well as along the route at MP 7.3 and 12.8. A pig receiver would be installed at the pipeline origin within the Stage 3 LNG Facilities M&R Station and a pig launcher would be installed as the pipeline terminus within the Sinton Compressor Station.

Figure A.6.2-1 Stage 3 Pipeline Route

7.0 NON-JURISDICTIONAL FACILITIES

Under Section 7(c) of the NGA, the Commission is required to consider, as part of its decision to approve facilities under Commission jurisdiction, all factors bearing on the public convenience and necessity. Occasionally, proposed projects have associated facilities that do not come under the jurisdiction of FERC. These "non-jurisdictional" facilities may be integral to the needs of a project (e.g., a new or expanded power plant at the end of a pipeline that is not under the jurisdiction of FERC) or may be merely associated as minor, non-integral components of the jurisdictional facilities that would be constructed and operated as part of a project.

Powerline connections and an electrical substation would be utilized in support of the Stage 3 LNG Facilities, and are considered non-jurisdictional facilities. To provide power to the Project area during construction, American Electric Power, Inc. (AEP) would design, build, own, and operate approximately 3,000 feet of a new powerline within a 100-foot-wide corridor resulting in 6.89 acres of impacts. This construction powerline would extend from SH 361 to a construction distribution panel in the Project area. Cheniere stated that while the location of the powerlines has not been determined, all impacts would occur within areas identified for construction workspace.

For operation power, Cheniere would design, build, own, and operate a new powerline that would extend 0.25 mile from a new 10-acre substation to be constructed by AEP within the Project site (see figure A.9.1-1) to a connection at SH 361. All impacts associated with operation power is reflected in the Project impacts presented throughout this EA.

8.0 CONSTRUCTION, OPERATION, AND MAINTENANCE PROCEDURES

The Project facilities would be designed, constructed, tested, operated, and maintained in accordance with the USDOT regulations at 49 CFR 193, *Liquefied Natural Gas Facilities: Federal Safety Standards*, and the NFPA 59A, *Standard for the Production, Storage, and Handling of LNG* (as incorporated by reference in 49 CFR 193.2013, under Subpart A). The pipeline facilities would comply with USDOT regulations at 49 CFR 192, *Transportation of Natural or Other Gas by Pipeline: Minimum Federal Safety Standards*. These regulations specify material selection, design criteria, corrosion protection, and qualifications for welders and operation personnel. Additionally, CCPL would comply with the Commission's regulations at 18 CFR 380.15 regarding the siting and maintenance of pipeline rights-of-way. These regulations ensure adequate protection for the public and prevent natural gas facility accidents and failures.

Pending receipt of all necessary approvals and authorizations, Cheniere plans to begin construction of the Stage 3 LNG Facilities in 3rd quarter 2019 with an anticipated in-service date in 2023. Construction of the Stage 3 Pipeline would begin in 2020 with an in-service date in 2023. Cheniere adopted FERC staff's *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures). Cheniere would also implement its *Spill Prevention, Containment, and Countermeasures Plan* (SPCC Plan) to help ensure a favorable environment for the successful re-establishment of vegetation and proper handling of lubricants, fuel, or other potentially toxic materials and prevention of spills, respectively, prior to construction. Cheniere would also revegetate temporarily disturbed areas in accordance with the FERC Plan and Procedures and would incorporate recommendations from the National Resources Conservation Service, such as seed mixes to be used during Project restoration. The SPCC Plan would be implemented in compliance with the FERC and Texas Commission on Environmental Quality (TCEQ). In addition, Cheniere would develop a *Stormwater Pollution Prevention Plan* (SWPPP) for managing stormwater runoff during construction and operation of the Stage 3 Project.

Typical construction drawings would be available to guide construction crews as to the approved methods to employ at appropriate locations when, and if, any of the conditions are observed. Construction crews would be familiar with the plans and assessing actual conditions before employing the guidelines.

For purposes of quality assurance and compliance with mitigation measures, other applicable regulatory requirements, and Project specifications, the Stage 3 Project would be represented on site by a Chief Inspector. One or more craft inspectors and one or more Environmental Inspectors (EI) assisting the Chief Inspector. To ensure that the environmental conditions associated with other permits or authorizations are satisfied, the EI's duties would be fully consistent with those contained in paragraph II.B of the Plan. The EI(s) would have authority to stop work or require other corrective actions to achieve environmental compliance. In addition to monitoring compliance, the EI's duties would include training Project personnel about environmental requirements and reporting compliance status to the contractors, Stage 3 Project management, FERC, and other agencies, as required.

FERC staff would conduct field and engineering inspections during construction. Other federal and state agencies may also conduct oversight of inspection to the extent determined necessary by the individual agency. After construction is completed, the FERC staff would continue to conduct oversight inspection and monitoring during operation of the Project to ensure successful restoration. Additionally, the FERC staff would conduct annual engineering safety inspections of the Stage 3 facilities operations.

The sections below describe the general procedures proposed by Cheniere for construction and operation activities within the Project site including restoration and maintenance following the completion of Project construction.

8.1 Stage 3 LNG Facilities

The modularized construction of the Stage 3 LNG Facilities would allow for individual trains and associated facilities to be constructed and brought on line in a phased approach in response to market demand. However, CCL Stage III's expectation, based on current indications of market demand, is that the entirety of the Stage 3 LNG Facilities would be built in a single phase. The duration of construction of all seven trains is approximately 48 months.

There are two areas within the existing Liquefaction Project facility that would be used during construction of the Stage 3 LNG Facilities. These are the existing Construction Dock and the existing roadway between the Construction Dock and Stage 3 LNG Facilities site. In addition, space inside the Liquefaction Project Operation and Maintenance Building (Control Room) would be utilized for operations of the Stage 3 LNG Facilities.

8.1.1 Temporary Construction Facilities

The Project would utilize areas that have been authorized for temporary work areas and are currently being utilized for the Liquefaction Project. The scheduled use of these areas for the two projects would overlap. Temporary work areas would be restored in compliance with our Plan and Procedures. Additional temporary facilities, required solely for the Stage 3 LNG Facilities, primarily laydown areas and parking, would be located on site or in close proximity to the site in areas approved by the Commission for construction use. The main construction offices would be located either on-site or in a nearby construction laydown or parking area. Support/satellite offices, warehousing, lunchrooms, temporary access roads, parking lots, and material laydown storage would be erected as necessary to support craft labor.

8.1.2 LNG Trains

The Stage 3 LNG Facilities would include the addition of seven midscale liquefaction trains and the construction of the full containment tank. Pipe installation on the pipe racks would be implemented from multiple directions after installation of the pipe racks. Pipe spool fabrication would be conducted in a covered area, either on or off-site. Structural steel members would be prefabricated off-site and erected upon arrival.

The majority of the straight run pipe would be field fabricated prior to placement on the pipe racks. Pipe expansion loops would be pre-fabricated in a shop, transported to position, and then erected with the straight run piping. Pipe would also be painted to the maximum extent at the shops, after shop welds have been tested in accordance with the applicable codes. Pipe spool size would be as large as can be practicably trucked to site, in order to minimize site work and the quantity of site deliveries.

Wherever practical, large equipment would arrive at the site in preassembled packages to 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 existing Liquefaction Project construction dock on multi-wheel transport crawlers, and transported to their foundations. Approximately 10 waterborne deliveries per train, or a total of 70 deliveries by marine vessels, would be required to facilitate construction deliveries. Other material and equipment would be delivered to site by truck.

The system completion and turnover packages would be defined and scoped by engineering, and assembled by the construction team when the civil and structural work is substantially complete, the equipment set, and most of the large bore piping installed.

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

Construction of other necessary facilities and other buildings, as well as foundations and major utility equipment, would be constructed simultaneously with the liquefaction facilities, and major equipment would be placed on foundations upon arrival.

8.1.3 LNG Storage

Construction of the LNG storage tank would begin with soil preparation and the foundation to support the tank would be constructed per the site-specific geotechnical study completed for the Stage 3 LNG Facilities. Next, a reinforced concrete base slab would be poured, followed by erection of the exterior concrete wall. As the walls rise, the tank top would be assembled inside and the suspended deck would be hung from the roof along with temporary guy wires to prepare for air lift of the roof (lifting of the roof with air pressure). Air pressure would be applied inside the tank to raise the roof to the top where it is attached to the tank compression ring and reinforced concrete would be poured on the roof. The inner metallic tank would be constructed inside the outer concrete structure on an insulated base. Next the inner tank pump columns, associated piping and electrical components would be installed, followed by the insulating perlite between the inner and outer tank. The tank would then be tested with the equivalent weight of water for the LNG to be contained. Following testing, the tank would be dried and purged with nitrogen, cooled down, further tested, commissioned, and filled with LNG to be placed into operation.

8.1.4 Operation and Maintenance

CCL Stage III would operate and maintain the Stage 3 LNG Facilities in accordance with applicable federal, state, and local regulations and guidelines, including the requirements of the USDOT minimum federal safety standards specified in 49 CFR 193. Appropriate personnel would meet the training requirements established under 49 CFR 193. Safety procedures are discussed further in section B.9.0.

Operating procedures for the Stage 3 LNG Facilities would be similar to those developed for the Liquefaction Project. Operational, maintenance and technical personnel would be trained extensively to gain familiarity with, and adhere to, the operating and safety procedures. Full-time staff would be on site 24 hours/day, and would conduct routine maintenance and minor overhauls. Major overhauls and other major maintenance would be led by full-time plant staff, the embedded general maintenance contract personnel and supplemented by services of trained contract and vendor personnel.

8.2 Stage 3 Pipeline

8.2.1 General Construction Procedures

In general, CCPL would use conventional construction techniques for buried pipelines and would follow our Plan and Procedures. Construction specifications would also require adherence to the SWPPP for construction stormwater discharges, SPCC Plan, best management practices (BMPs), and plans and procedures for unique construction techniques (e.g., HDD). General construction procedures for routine pipeline construction include:

- Right-of-Way Survey – Prior to the start of construction, the Stage 3 Pipeline centerline and boundaries of the construction workspace would be marked with stakes and land surveys would be conducted to locate existing utility lines and other sensitive resources.
- Clearing and Grading – The Stage 3 Pipeline right-of-way and the temporary construction workspace would be cleared of vegetation by mechanical means or hand cutting. Following clearing, the entire width of the construction right-of-way, including the temporary construction workspace may be rough graded, as necessary. Graded topsoil would be segregated in accordance with our Plan and Procedures.
- Trench Excavation – A trench would be excavated to the appropriate depth to allow for the burial of the pipe with a minimum of 3 feet of cover as required by 49 CFR Part 192 of the USDOT's regulations. Excavated material would be placed next to the trench within the construction right-of-way.
- Piping Techniques – Following trench excavation, stringing of the Stage 3 Pipeline along the trench would proceed. Stringing of the pipe involves hauling the pipe sections to the right-of-way via truck from the pipe storage yard and off-loading the pipe next to the trench. Following stringing, the pipe sections would be bent as necessary, using a hydraulic pipe bending machine, to fit the horizontal and vertical contours. Individual pipe sections would be welded in accordance with API Standard No. 1104. Each weld would subsequently be inspected to ensure structural integrity is consistent with 49 CFR Part 192 of the USDOT's regulations. With the exception of the pipe ends, the pipe would be coated (usually with a fusion bond epoxy) at a coating mill prior to being delivered to the Project site. After welds have been inspected and approved, the pipe ends would be field coated by a coating crew.

- Lowering-In – Once the pipe has been welded, coated, and inspected, the trench would be cleared of debris and any water would be pumped out of the trench and into well-vegetated upland areas or into an approved filter bag. Once the pipe strings have been lowered in with sideboom tractors, the ends of each pipe string would be welded together, inspected, and coated.
- Backfilling – All suitable material excavated from the trench would be replaced during the backfilling. In areas where excavated material is unsuitable for backfilling, additional fill may be brought in from off-site. The subsoil would be placed into the trench first and the topsoil would be spread over top. The soil would be inspected for compaction and scarified as necessary.
- Cleaning and Hydrostatic Testing – Following completion of the Stage 3 Pipeline tie-ins, the pipe would be internally cleaned with "pigs." The Stage 3 Pipeline would then be hydrostatically tested to ensure that the system is leak proof and to provide the necessary safety margin for high-pressure operation. Once in-place, the pipeline would be filled with water and pressurized. Pressure would be maintained throughout the test. Water for hydrostatic testing of the Stage 3 Pipeline would be obtained from the San Patricio Municipal Water District. CCPL stated that it does not anticipate that any chemical agents would be added to the test water, except for a biocide (i.e., sodium hypochlorite) to control microbial induced corrosion.

  After the completion of a satisfactory test, the water would be discharged over land into containment structures in accordance with state permit requirements and additional "drying" pig runs would be made, as necessary, to remove any residual water from the pipeline.
- Restoration and Revegetation – After the completion of backfilling and topsoil replacement across the construction workspace, all disturbed areas would be final graded and any remaining trash, debris, or unsuitable backfill would be properly disposed. The construction workspace would be restored using site-specific contouring and reseeding with an approved seed mix. If needed, permanent slope breakers or diversion berms would be constructed and maintained in accordance with our Plan and Procedures.

8.2.2 Specialized Construction Procedures

Wetland and waterbody crossings would be conducted in accordance with state and federal permits and our Procedures and completed as quickly and safely as possible. Operation of construction equipment in wetlands would be limited to that needed to clear the right-of-way, dig the trench, fabricate the pipe, backfill the trench, and restore the right-of-way. In unsaturated wetlands, topsoil over the pipe trench would be segregated from subsoils. In accordance with our Procedures, fuel would not be stored within 100 feet of wetlands or waterbodies. Wetlands and waterbodies would generally be crossed using the conventional excavator-type equipment and wet-crossing techniques, or by HDD. Proposed HDDs for the Stage 3 Pipeline are identified in table A.8.2-1.

Table A.8.2-1
Proposed HDDs for the Stage 3 Pipeline

HDD ID	Features Crossed	MP Location	Approximate HDD Length (feet) [a]	Entry and Exit Note
HDD-4	La Quinta Road, La Quinta Ditch, Green's Ditch	0.0 – 0.8	3,880	Entry MP 0.0; Exit MP 0.8
HDD-1	U.S. Highway 181, SH 35	1.2 – 1.6	2,200	Entry MP 1.6; Exit MP 1.2
HDD-2	Oliver Creek, SH 188	16.0 – 16.6	2,800	Entry MP 16.0; Exit MP 16.6

Table A.8.2-1 Proposed HDDs for the Stage 3 Pipeline				
HDD ID	**Features Crossed**	**MP Location**	**Approximate HDD Length (feet) [a]**	**Entry and Exit Note**
HDD-3	Chiltipin Creek	17.3 – 17.8	2,400	Entry MP 17.8; Exit MP 17.3
[a] Measured as surface length between entry and exit points.				

Road and utility crossings would be accomplished using open-cut, bore, or HDD crossing methods, depending upon site-specific conditions and state and local statutes. Prior to construction, the "Call Before You Dig" or "One Call" system would be contacted to verify and mark all utilities along the Project workspace areas. The proposed pipeline route does not cross any railroads. The minimum pipeline clearance for both unsurfaced and paved public roads would be 5 feet under the roadbed and 4 feet under any side borrow/drainage ditches. Pipeline warning signs/markers would be installed at each crossing location.

8.2.3 Aboveground Facilities

At the sites for the aboveground facilities, the principal sequential construction steps would be clearing and grading, placement of a concrete pad foundation, installation of equipment, erection of equipment housing, and surface clean-up, during which open areas would be covered with gravel, limestone or similar material. Where pigging equipment is installed, a concrete liquids containment area would be constructed below the barrel of the pig launcher or receiver.

8.2.4 Operation and Maintenance

The pipeline facilities would be operated and maintained in a manner such that the pipeline integrity is maintained in the interest of assuring that a safe, continuous supply of natural gas reaches its destination. Maintenance activities would include regularly scheduled gas leak surveys and measures necessary to repair any potential leaks. All fence posts, signs, markers, and decals would be painted or replaced to ensure visibility from the air or ground. The Stage 3 Pipeline would be patrolled on a routine basis and all valves would be periodically inspected and maintained. The Stage 3 Pipeline would be patrolled by air on a periodic basis to provide information on potential problems that may affect the safety and operation of the pipeline such as possible leaks, exposed pipe, erosion, construction activities, population density, or possible encroachment. Other maintenance functions would include the following:

- periodic seasonal mowing of the permanent easement in accordance with the vegetative maintenance restrictions outlined in our Plan and Procedures;
- terrace repair, backfill replacement; and
- periodic inspection of water crossings.

During pipeline easement maintenance, CCPL would not use herbicides or pesticides within 100 feet of a wetland or waterbody unless approved by appropriate state and local agencies. Routine maintenance between HDD entry and exit locations would be limited to keeping a 10-foot-wide corridor centered over the pipeline clear of trees; however, in accordance with the FERC Plan, CCPL indicated that no clearing would be conducted within riparian areas and wetlands. Cathodic protection systems would be installed at various points along the pipeline to prevent corrosion, by applying a low voltage current to offset natural soil and groundwater corrosion potential.

9.0 LAND REQUIREMENTS

9.1 LNG Facilities

Land requirements in terms of operational footprint and construction workspace for the Stage 3 LNG Facilities are depicted in figure A.9.1-1 and quantified in table A.9.1-1. Construction and operation of the Stage 3 LNG Facilities would require approximately 1,274.4 acres of which, approximately 932.4 acres of land would be utilized during operation. Approximately 1,261.5 acres (99 percent) are permitted for impacts associated with construction and operation of the Liquefaction Project. Of the 932.4 acres impacted by operation of the Stage 3 LNG Facilities, 919.5 acres overlap areas previously authorized for the Liquefaction Project (including 893.1 acres authorized for temporary impacts and 26.4 acres authorized for permanent impacts associated with the Liquefaction Project). A large portion of the Stage 3 LNG Facilities would be constructed within Dredged Material Placement Area (DMPA) 2, which was authorized for dredged material placement for construction of the marine berths for the Liquefaction Project. An additional 12.9 acres that were not previously impacted by the Liquefaction Project would be permanently impacted by the Stage 3 LNG Facilities.

Table A.9.1-1

Land Requirements for the Stage 3 LNG Facilities

Facility	Construction [a]			Operation		
	Land Impacted by Liquefaction Project (acres)	New Land Impacts (acres)	Total (acres)	Land Impacted by Liquefaction Project (acres)	New Land Impacts (acres)	Total (acres)
Stage 3 LNG Facilities	901.0	12.9	913.9	901.0	12.9	913.9
Private Access Roads	18.5	0.0	18.5	18.5	0.0	18.5
Temporary Construction Workspace	342.0	0.0	342.0	0.0	0.0	0.0
Total	**1,261.5**	**12.9**	**1,274.4**	**919.5**	**12.9**	**932.4**

[a] Construction impacts for the Stage 3 LNG Facilities are inclusive of operation impacts.

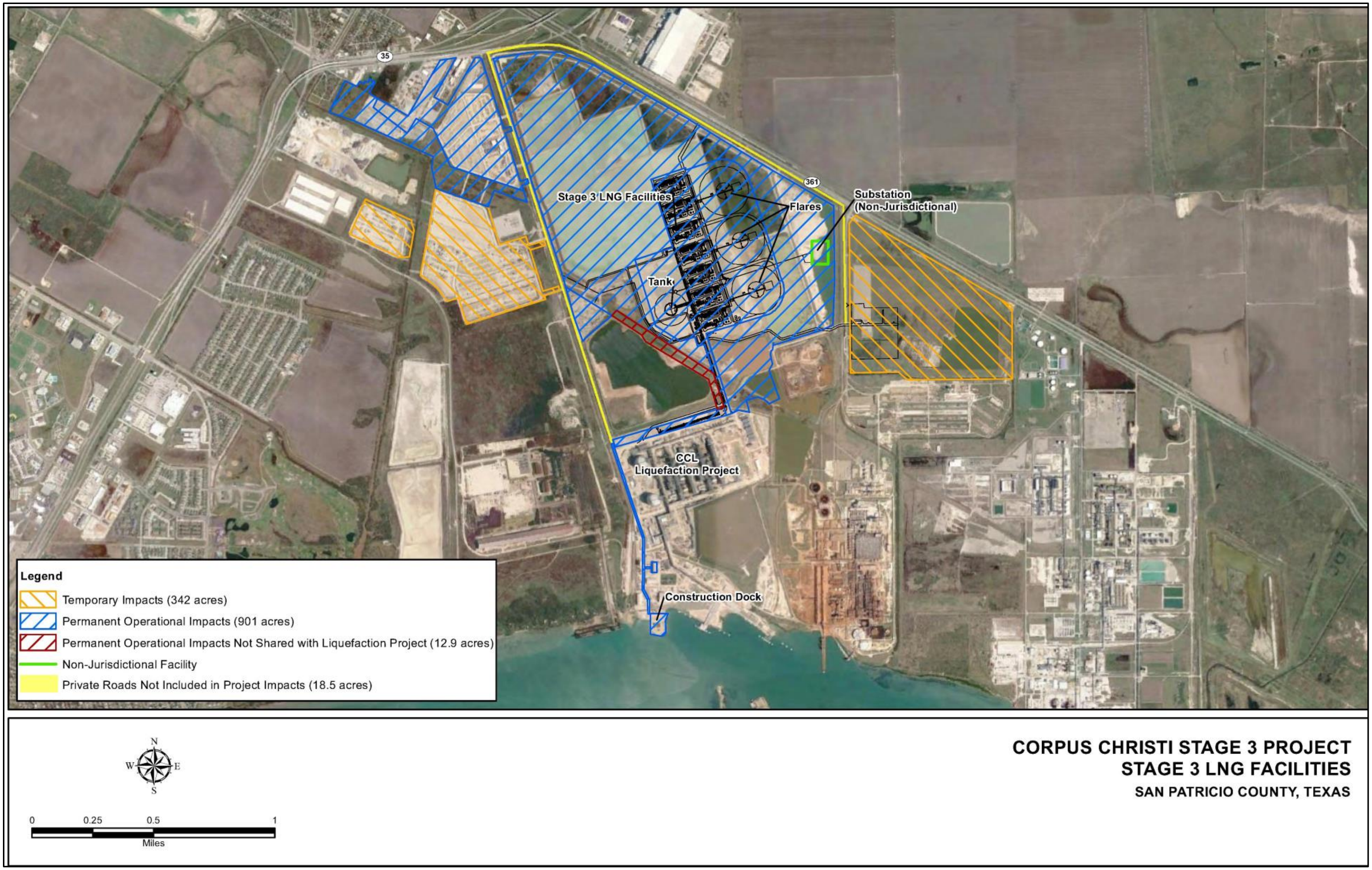

Figure A.9.1-1 Stage 3 LNG Facilities Operational Footprint and Construction Workspace

9.2 Pipeline Facilities

Land requirements in terms of operational footprint and construction workspace for the Stage 3 Pipeline Facilities are provided in table A.9.2-1 and depicted in the alignment sheets.[6]

9.2.1 Pipeline

The 42-inch-diameter Stage 3 Pipeline would be installed generally parallel to the 48-inch-diameter Corpus Christi Pipeline. The Stage 3 Pipeline would be constructed using a 120-foot-wide construction right-of-way and a permanent right-of-way width of 50 feet overlapping 25 feet with the Corpus Christi Pipeline right-of-way. In wetlands, the construction right-of-way would be reduced to 75-feet-wide.

CCPL stated that a 120-foot-wide construction corridor would be required to provide adequate area for temporary storage of soil on the spoil side of the pipeline trench and safe and efficient maneuvering within the working side of the trench. The recently constructed Corpus Christi Pipeline (FERC Docket No. CP12-508) utilized an approved 120-foot-wide construction corridor. Although a 105-foot-wide corridor was initially anticipated to be sufficient for the Stage 3 Pipeline, experience gained during construction of the Corpus Christi Pipeline supports CCPL's conclusion that the additional 15 feet is necessary to provide sufficient area for spoil stacking and safe travel lanes for large equipment operating within the construction workspace.

Additional temporary workspace (ATWS) would be needed at road, railroad, and pipeline crossings, including some wetland and waterbody crossings. ATWS would be located at least 50 feet away from wetlands and waterbodies, where practicable, except in active agricultural areas or other disturbed areas.

Table A.9.2-1

Land Requirements for the Stage 3 Pipeline and Associated Facilities

Facility	Construction			Operation		
	Overlapping 48" Corpus Christi Pipeline (acres)	New Stage 3 Pipeline Land Impacts (acres)	Total (acres) [a]	Overlapping 48" Corpus Christi Pipeline (acres)	New Stage 3 Pipeline Land Impacts (acres)	Total (acres)
Pipeline Right-of-Way						
Pipeline	209.2	81.0	290.2	59.6	71.8	131.4
Additional Temporary Workspace [b]	22.2	38.4	60.6	0.0	0.0	0.0
Compressor Station						
Sinton Compressor Station	28.6	14.0	42.6	26.6	0.0	26.6
M&R Stations [c]						
Stage 3 LNG Facilities M&R Station (MP 0.0)	0.0	0.0	0.0	0.0	0.0	0.0

[6] The Stage 3 Pipeline alignment sheets are available on the FERC eLibrary website at https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp under accession number 20181130-5214.

Table A.9.2-1

Land Requirements for the Stage 3 Pipeline and Associated Facilities

Facility	Construction			Operation		
	Overlapping 48" Corpus Christi Pipeline (acres)	New Stage 3 Pipeline Land Impacts (acres)	Total (acres) [a]	Overlapping 48" Corpus Christi Pipeline (acres)	New Stage 3 Pipeline Land Impacts (acres)	Total (acres)
M&R Station (MP 21.0)	0.0	0.0	0.0	0.0	0.0	0.0
M&R Station (MP 21.0)	0.0	0.0	0.0	0.0	0.0	0.0
Launchers/MLVs [d]						
Pig Receiver and MLV (MP 0.0)	0.0	0.0	0.0	0.0	0.0	0.0
MLV #1 (MP 7.3)	0.0 [e]	0.0	0.0	0.1	0.1	0.2
MLV #2 (MP 12.8)	0.0 [e]	0.0	0.0	0.1	0.1	0.2
Pig Launcher and MLV (MP 21.0)	0.0	0.0	0.0	0.0	0.0	0.0
Access Roads/Yards						
Access Roads	18.8	0.3	19.1	12.7	0.0	12.7
Contractor and Pipe Yard	71.7	0.0	71.7	0.0	0.0	0.0
Total	**350.5**	**133.7**	**484.2**	**99.1**	**72.0**	**171.1**

Note that the columns may not sum exactly due to rounding.

[a] Total construction impacts inclusive of impacts from operation.
[b] Includes impacts from the existing Tejas Interconnect and work area.
[c] The M&R Stations would be within the footprint of the Stage 3 LNG Facilities and the Sinton Compressor Station.
[d] The launcher/receiver would be within the Sinton Compressor Station, and the Stage 3 Facilities M&R station.
[e] The MLVs at MPs 7.3 and 12.8 would be entirely within the Stage 3 Pipeline construction right-of-way; therefore, impacts during construction are captured in the impacts for the pipeline right-of-way. MLVs at MPs 7.3 and 12.8 would each require approximately 0.5 acre during operation, of which approximately 0.3 acre would be located within the Stage 3 Pipeline permanent right-of-way, 0.1 acre would be within the existing Corpus Christi Pipeline permanent right-of-way, and 0.1 acre would result in new permanent impacts outside of the permanent pipeline rights-of-way.

9.2.2 Aboveground Facilities

The Stage 3 Pipeline Facilities at the Sinton Compressor Station would require 42.6 acres for construction. Operation of the Stage 3 Pipeline Facilities at the Sinton Compressor Station would require 26.6 acres, all of which would be within the existing facility, with no new permanent impacts. The three M&R Stations would be constructed within the Stage 3 LNG Facilities and the Sinton Compressor Station. The pig launcher and receiver, as well as the MLVs would be constructed within the Stage 3 LNG Facilities, the Sinton Compressor Station, as well as the Stage 3 Pipeline construction right-of-way. However, portions of the MLVs at MP 7.3 and 12.8 (0.2 acre) would be located outside of the Stage 3 Pipeline and Corpus Christi Pipeline permanent rights-of-way and would result in new permanent impacts.

9.2.3 Access Roads/Contractor and Pipe Yards

CCPL would utilize 29 access roads for construction of the Stage 3 Pipeline. All access roads, with the exception of Access Road 12.1, were permitted for use during construction of the Corpus Christi

Pipeline. However, 11 of those roads were restored following the completion of construction of the Corpus Christi Pipeline and would be temporarily impacted again for construction of the Stage 3 Pipeline. The remaining 18 roads are existing roads that would be utilized for construction and/or operation of the Stage 3 Pipeline. Roads would typically be 25 feet in width and extend from the boundary of the nearest public road to the construction workspace.

CCPL would utilize 71.7 acres for laydown area and pipe storage. This includes the Gregory Contractor Yard #1 (6.1 acres), Gregory Contractor Yard #3 (18.2 acres), Taft Pipe Storage Yard (30.0 acres), and a pipe storage yard at MP 6.1 (17.4 acres). Compacted fill material has been distributed across the whole of each of these areas, which would be maintained throughout construction of the Project. These areas have undergone FERC review and were previously utilized for the Corpus Christi Pipeline.

10.0 PERMITS, APPROVALS, AND REGULATORY CONSULTATIONS

Table A.10.0-1 lists the federal, state, and local regulatory agencies that have permit approval authority or consultation requirements and the status of that review for portions of the Stage 3 Project. Cheniere would be responsible for obtaining all necessary permits, licenses, and approvals required for the Stage 3 Project, regardless of whether or not they are listed in table A.10.0-1.

Table A.10.0-1

Permits, Approvals, and Consultations for the Stage 3 Project

Agency and Agency Contact	Permit/Approval/Consultation	Actual or Anticipated Submittal	Actual/Anticipated Issuance
FERC	Authorization pursuant to Section 3 and Section 7(c) of the Natural Gas Act	June 28, 2018	Pending
FWS	Section 7 Endangered Species Act Consultation/Clearance; Migratory Bird Consultation; Fish and Wildlife Coordination Act	Submitted May 27, 2015	2nd Quarter 2019
COE [a]	Clean Water Act Section 404 Permit	Submitted June 29, 2018	COE non-jurisdictional determination received June 15, 2016 for the Stage 3 LNG Facilities Stage 3 Pipeline qualifies for automatic authorization without preconstruction notification under Nationwide Permit 12
NMFS	Essential Fish Habitat; Endangered Species Act Aquatic Threatened and Endangered Species; Marine Mammal Protection Act; Fish and Wildlife Coordination Act	Submitted May 27 2015 (EFH Consultation). Submitted December 20, 2018 (Section 7 Consultation)	Issued May 28, 2015 (EFH Consultation) Anticipated 2nd Quarter 2019 (Section 7 Consultation)
Coast Guard	Waterway Suitability Assessment	February 29, 2016	Issued August 15, 2018

Table A.10.0-1

Permits, Approvals, and Consultations for the Stage 3 Project

EPA	National Pollutant Discharge Elimination Systems Industrial Water Discharge	Anticipated 2nd Quarter 2019	Anticipated 3rd Quarter 2019
	Hydrostatic Test Water Discharge	Anticipated 2nd Quarter 2019	Anticipated 3rd Quarter 2019
DOE	Natural Gas Act, Section 3 Applications for Authorization to Export LNG	Submitted June 29, 2018	Authorization granted November 9, 2018 for FTA nations; Decision for non-FTA nations is pending
Federal Aviation Administration	Determination of No Hazard to Air Navigation (14 CFR Part 77)	Anticipated 1st Quarter 2019	Anticipated 1st Quarter 2019
Railroad Commission of Texas	Water Quality Certification under Section 401 [b]	N/A (Stage 3 Facilities) Automatically authorized under Nationwide Permit 12 (Stage 3 Pipeline)	N/A (Stage 3 Facilities) Automatically authorized under Nationwide Permit 12 (Stage 3 Pipeline)
	Hydrostatic Test water Discharge Permit	Anticipated 2nd Quarter 2019	Anticipated 2nd Quarter 2019
	Coastal Management Plan Consistency Determination	Automatically authorized under Nationwide Permit 12 (Stage 3 Pipeline)	Automatically authorized under Nationwide Permit 12 (Stage 3 Pipeline)
Texas General Land Office	Coastal Management Plan Consistency Determination	Submitted January 23, 2019 (Stage 3 LNG Facilities)	Issued January 23, 2019 (Stage 3 LNG Facilities)
TCEQ	Stage 3 LNG Facilities Prevention of Significant Deterioration Permit Amendment	Submitted June 27, 2018	2nd Quarter 2019
	Stage 3 LNG Facilities Greenhouse Gas (GHG) Permit	Submitted June 27, 2018	2nd Quarter 2019
	Stage 3 LNG Facilities Title V Permit	Anticipated 2022	Anticipated 2022
	Sinton Compressor Station (minor permit)	Submitted July 5, 2018	Issued August 24, 2018
Texas Parks and Wildlife Department	State threatened and endangered species review	Submitted May 27, 2015	Issued September 24, 2018
Texas Historical Commission	Section 106 National Historic Preservation Act Consultation, Clearance	See Appendix A for the dates of correspondence with the Texas Historical Commission	See Appendix A for the dates of correspondence with the Texas Historical Commission

SECTION B – ENVIRONMENTAL ANALYSIS

In this section we discuss the affected environment, general construction and operation impacts, and proposed mitigation to minimize or avoid impacts on each resource. Cheniere, as part of its proposal agreed to implement certain measures to reduce impacts on environmental resources. We evaluated Cheniere's proposed mitigation measures to determine whether additional measures would be necessary to reduce impacts. Where we identify the need for additional mitigation, our recommended measures appear as bulleted, boldfaced paragraphs in the text. We will recommend that these measures be included as specific conditions to any authorization that the Commission may issue to Cheniere. Conclusions in this EA are based on our analysis of the environmental impact of Project construction as described in section A of this document, including implementation of the mitigation measures included in Cheniere's applications and supplemental filings to FERC.

1.0 GEOLOGY

The Stage 3 Project would be within the Coastal Prairie region of the Gulf Coastal Plain physiographic province of Texas (Bureau of Economic Geology, 1996). The topography of the Coastal Prairie region is nearly flat where subsurface sediments dip gently toward the Gulf and are dissected by highly sinuous streams (Bureau of Economic Geology, 1996). In this region, recent Holocene-age deposits generally consist of alluvial, deltaic, beach, bay-estuary, and marsh deposits, and are underlain by Pleistocene-age deltaic and alluvial deposits to a few thousand feet below ground level (Brown et al., 1976). Furthermore, these deposits are underlain by the Pleistocene-age Beaumont Formation in the Project vicinity. The upper layers of the Beaumont Formation are sands, silty sands, and clayey sands deposited in a tidally influenced back-bay environment, while the lower sections of the Beaumont Formation consist of interbedded sands and clays deposited in a barrier bar setting. Zones of weathering may contain calcium carbonate and iron oxide concretions. The formation is, on average, about 100 feet thick (Bureau of Economic Geology, 1975a; 1975b). Underlying the Beaumont Formation is the Pleistocene-age Lissie Formation, which is comprised of alluvial clay and lenticular sandstone deposits (Tolunay-Wong Engineers, Inc. [TWEI], 2012).

Geologic formations in the Project vicinity may contain mammoth, mastodon, and bison fossils (The Paleontology Portal, 2015). However, formations are not known for their paleontological resources in the Project area, and no sensitive fossil areas have been identified in the vicinity of the Stage 3 LNG Facilities and Stage 3 Pipeline (U.S. Fossil Sites, 2016; The Paleontology Portal, 2015; Texas A&M University, Kingsville, 2016). Therefore, the potential for impacting paleontological resources is considered minimal.

1.1 Mineral Resources

1.1.1 Stage 3 LNG Facilities

No active surface or subsurface mines (e.g., sand, gravel, and crushed stone) are within 0.25 mile of the Stage 3 LNG Facilities (U.S. Geological Survey [USGS], 2015a). The Stage 3 LNG Facilities lie within the Houston Diapir Province but the LouAnn Salt, which is the source for salt domes in the Gulf Coast, does not underlie the site (TWEI, 2012). The nearest salt dome to the Project area is the South Texas Salt Basin located more than 50 miles southwest of the Stage 3 LNG Facilities site (Beckman and Williamson, 1990). Based on a review of the oil and gas well database maintained by the Railroad Commission of Texas (RRC), 15 oil and gas wells would be within the Stage 3 LNG Facilities workspace, including 11 dry holes, 1 gas well, 1 plugged gas well, 1 oil well, and 1 permitted well (RRC, 2018). In addition, 20 oil and gas wells were identified outside of the Stage 3 LNG Facilities workspace but within 0.25 mile, including 10 dry holes, 1 gas well, 6 plugged gas wells, and 3 permitted wells (RRC, 2018).

However, locational information for the oil and gas well database is approximate and no oil and gas wells have been observed at the site during field studies.

CCL Stage III would conduct field verification surveys to confirm the locations of any wells prior to construction and would review the area in the vicinity of the reported well locations. In the event that a previously unidentified oil or gas well is encountered during construction, CCL Stage III would stop all work in the area, contain any spillage of the product, secure the area, and notify the environmental inspector. In addition, CCL Stage III would consult with the RRC to identify the well operator or owner of record, as RRC Statewide Rule 14 (Texas Administrative Code [TAC] Title 16, Part 1, Chapter 3) requires operators of record to plug abandoned oil and gas wells. CCL Stage III may utilize the RRC Oil Field Cleanup Fund to properly plug wells in the event that the well operator cannot be identified. Therefore, we conclude that the Stage 3 LNG Facilities construction and/or operational impacts on fuel and non-fuel mineral resources would not occur, given the distance to active mineral extraction and CCL Stage III's adherence to their proposed construction and mitigation measures.

1.1.2 Stage 3 Pipeline

The Stage 3 Pipeline would cross several oil fields, including the Midway Oil Field, Taft Oil and Gas Field, and Portilla Oil and Gas Field. Oil and gas deposits are at subsurface depths significantly below the proposed depth of the pipeline trench and HDD path, and would not be disturbed by construction or operation of the Stage 3 Pipeline (RRC, 2018; USGS, 2015a). Further, the Project would not affect future oil and gas exploration and production because the use of unconventional (directional) drilling techniques would allow for oil and gas wells to be drilled outside of the pipeline right-of-way. CCPL identified 20 oil and gas wells within 150 feet from the Stage 3 Pipeline centerline, 3 of which were permitted but have not been installed. CCPL stated that all identified oil and gas wells are over 100 feet from the Stage 3 Pipeline route (TelALL Corporation, 2018). Based on a review of RRC records for inactive, abandoned, or orphaned oil and wells, two dry holes and one plugged gas well would be within 500 feet of the Stage 3 Pipeline HDD drill paths (TelALL Corporation, 2018). Tables B.1.1-1 and B.1.1-2 list all oil and gas wells within 150 feet of the Stage 3 Pipeline and all inactive, abandoned, or orphaned within 500 feet of the HDD paths, respectively.

Table B.1.1-1

Oil and Gas Wells within 150 Feet of the Stage 3 Pipeline

Well Location (Milepost)	Direction from Pipeline [a]	Well Status
0.2	North	Dry Hole
4.2	North	Dry Hole
4.5	North	Dry Hole
5.6	North	Plugged Oil Well
5.8	North	Plugged Oil Well
5.8	North	Plugged Oil Well
5.9	North	Oil Well
5.9	North	Plugged Oil Well
5.9	South	Oil/Gas Well
6.1	North	Permitted Location
6.1	North	Oil Well
6.1	North	Plugged Oil Well
6.2	North	Dry Hole

Table B.1.1-1 Oil and Gas Wells within 150 Feet of the Stage 3 Pipeline		
Well Location (Milepost)	**Direction from Pipeline [a]**	**Well Status**
7.0	South	Permitted Location
7.1	North	Plugged Oil Well
7.7	North	Plugged Oil Well
8.5	South	Dry Hole
15.6	West	Cancelled Location
17.4	West	Permitted Location
20.7	West	Dry Hole
[a] All wells are greater than 100 feet from the pipeline centerline.		

Table B.1.1-2 Oil and Gas Wells within 500 Feet of HDD Paths for the Stage 3 Pipeline			
HDD Location (Milepost)	**Well Location (Milepost)**	**Distance and Direction from HDD [a]**	**Well Status**
0.0 - 0.8	0.2	150 ft north	Dry Hole
0.0 - 0.8	0.4	400 ft south	Dry Hole
1.2 - 1.6	1.4	420 ft north	Plugged Gas Well
[a] CCPL would verify locations of wells in the field prior to final pipeline design, and site-specific plans to prevent the communication/cross-contamination of HDD drilling fluids with the wells would be filed with FERC			

A majority of the oil and gas wells within 150 feet of the Stage 3 Pipeline centerline are abandoned and situated in agricultural fields; however, exact locations in relation to the Stage 3 Pipeline have not yet been field-verified. Prior to construction, CCPL would conduct field verification surveys to confirm the locations of oil and gas wells within 150 feet of the Stage 3 Pipeline and would field-verify the locations of inactive, abandoned, or orphaned oil and gas wells within 500 feet of each HDD drill path. At each of the reported well locations, CCPL would review the area within and adjacent to the construction right-of-way for evidence of the well and coordinate with the landowners and RRC to obtain additional information regarding the presence of oil and gas wells prior to construction. CCPL would prepare site-specific plans to prevent the communications/cross-contamination of HDD drilling fluids with wells and file them with the FERC as part of the Project implementation plan prior to construction. Should an unidentified oil/gas well be encountered during construction, CCPL would stop all work in the area, contain any spillage of product, secure the area, and notify the environmental inspector and the RRC. CCPL would consult with the RRC to determine the operator or owner on record for the subject well. If the well operator cannot be identified, the RRC maintains and administers and Oil Field Cleanup Fund which may be utilized to properly plug wells. If an oil or gas well is found near the pipeline centerline and requires a pipeline reroute to avoid, CCPL would request a variance from FERC.

In addition, three surface sand or clay quarries are within 0.25 mile of the Stage 3 Pipeline, including one active quarry located 0.2 mile north of MP 1.9 and two historic quarries located 0.2 mile south of MP 2.5 and less than 0.1 mile south of MP 5.7. No other mineral resources, including surface and subsurface mines or quarries, were identified within 0.25 mile of the Stage 3 Pipeline (USGS, 2015). If CCPL identifies previously unknown mineral operations during final design or construction, CCPL has committed to avoid impacts through coordination with the operator(s) to establish terms of agreement which allow adequate easement for the Stage 3 Pipeline. Therefore, we conclude that the Stage 3 Pipeline would not significantly impact availability of or access to mineral resources.

1.2 Geologic Hazards

1.2.1 Stage 3 LNG Facilities

Section B.9.1 provides a discussion of the engineering review completed for the proposed Stage 3 LNG Facilities site, including safeguards built into the engineering design to reduce the risk of an incident occurring and impacting the public and the results of a geotechnical and structural design review. The discussion in section B.9.1 focuses on the resilience of the liquefaction facilities against natural hazards, including extreme geological, meteorological, and hydrological events, such as earthquakes, tsunamis, seiches, hurricanes, tornadoes, floods, regional subsidence, sea level rise, landslides, wildfires, volcanic activity, and geomagnetism.

1.2.2 Stage 3 Pipeline

The shaking during an earthquake can be expressed in terms of the acceleration as a percent of gravity (g), and seismic risk can be quantified by the motions experienced at the ground surface or by structures during a given earthquake expressed in terms of g. USGS National Seismic Hazard Probability Mapping shows that for the Project area, within a 50-year period, there is a 2 percent probability of an earthquake with an effective peak ground acceleration (PGA) of 2 to 4 percent g; and a 10 percent probability of an earthquake with an effective PGA of less than 1 percent g being exceeded (USGS, 2014). For reference, PGA of 10 percent g (0.1 g) is generally considered the minimum threshold for damage to older structures or structures not constructed to resist earthquakes. Further, modern pipeline systems have not sustained damage during seismic events except due to permanent ground deformation, or traveling ground-wave propagation greater than or equal to a Modified Mercalli Intensity of VIII (similar to a Richter scale magnitude around 6.8 or 7.0 (O'Rourke and Palmer, 1996; USGS, 2018a). The USGS maintains a database of geologic faults and folds in the United States. The Project facilities would not cross any Quaternary-age faults identified in the database (USGS, 2018a).

The Project area is within the Gulf-margin normal fault system, a belt of poorly defined, mostly seaward-facing normal faults that trend parallel to the Gulf Coast in westernmost Florida, southwestern Alabama, southern Mississippi, all of Louisiana and southernmost Arkansas, and eastern and southern Texas (USGS, 2018a). Movement along active growth faults in the Coastal Plain physiographic province tends to be minimal and non-seismogenic occurring more as a gradual creep rather than a sudden break or displacement (Louisiana Geologic Survey, 2001). Project facilities are not anticipated to be affected by faults given the nature of fault movement (gradual creep) and the composition of sediments and rocks that underlie the fault system, which are likely unable to generate the energy required to produce significant seismic events (Crone and Wheeler, 2000). Given these conditions, we conclude that there is a low potential for damage due to prolonged ground shaking or ground rupture to occur within the Project area.

The Stage 3 Pipeline route has underlying sediment layers that are water saturated and that could be susceptible to liquefaction under sufficiently strong ground motion. However, due to the low levels of seismic activity and probable ground motion estimated for the area crossed by the Stage 3 Pipeline, there would be little risk for liquefaction of the underlying loose sand layers (Crone and Wheeler, 2000). Therefore, we do not consider soil liquefaction a potential hazard to the Stage 3 Pipeline.

Subsidence is the sudden sinking or gradual downward settling of land with little or no horizontal motion as a result of geologic or anthropogenic processes. Subsidence in the Gulf Coast is caused by groundwater extraction, oil and gas extraction, and slumping along growth faults (Ratzlaff, 1982).

Groundwater withdrawal in San Patricio County is primarily for irrigation, and the amount pumped varies by season and year. However, there are no public or private water supply wells within at least 150 feet of the Stage 3 Pipeline route and groundwater extraction would not be required for pipeline operations (Texas Water Development Board, 2018). In addition, although there are several oil and gas fields in San Patricio County, no significant petroleum extraction occurs within the Stage 3 Project area and the oil and gas resources are thousands of feet below ground (RRC, 2018). Various degrees of subsidence have been documented along the entire Texas coast, with the most significant subsidence occurring in the Houston-Galveston area as a result of groundwater withdrawals (Gibeaut and Tremblay, 2003; USGS, 2018b). In the Corpus Christi area, subsidence is greatest southwest of the Stage 3 LNG Facilities, northwest of the city of Corpus Christi. Other areas of San Patricio County do not experience the degree of subsidence found elsewhere along the Gulf Coast (Ratzlaff, 1982). Cheniere would construct all Project facilities in accordance with USDOT PHMSA design specifications to ensure the facilities are not affected by subsidence. Due to the regional and gradual nature of the subsidence in the Project area, impacts on the Project resulting from subsidence would not be significant.

Ground subsidence may also be caused by karst formation due to limestone or gypsum bedrock dissolution. The potential for karst formation is greatest where surficial deposits are less than 30 feet thick and underlying carbonate rocks occur at a depth at or just above the water table. These conditions do not exist within or in the vicinity of Stage 3 Pipeline workspaces, and we do not anticipate a risk of subsidence related to karst formation (Texas Speleological Survey, 2007).

The Stage 3 Pipeline would cross land that is relatively flat (slopes less than 10 percent), with elevation increasing gradually from 13 to 68 feet above mean sea level (Natural Resources Conservation Service [NRCS], 2017). Therefore, we do not consider slope instability to be a hazard for the Stage 3 Pipeline.

The Stage 3 Pipeline would cross several 100-year flood zones, but does not extend to 500-year flood zones (Federal Emergency Management Agency, 1985). These crossings occur from MP 0.2 to MP 2.1, MP 9.1 to MP 9.8, MP 16.1 to MP 16.5, and from MP 16.8 to MP 18.9, and are generally associated with major surface water drainages. Installation of the pipeline would not affect floodplain storage capacity as it would be installed subsurface and all contours would be restored following the completion of construction activities. At waterbody crossings and other areas subject to potential flooding, the Stage 3 Pipeline may be concrete coated or weighted using saddle bag-type weights to compensate for negative buoyancy and would be placed below the anticipated depth of scour. Discussion of crossing methods for surface waters is included in section B.3.2. No aboveground facilities associated with the Stage 3 Pipeline (including the Sinton Compressor Station, M&R stations, and appurtenant facilities) would be within 100-year or 500-year flood zones. Based on this analysis, we conclude that adverse impacts on floodplain storage or resulting from flood hazards are not anticipated during construction and operation of the Stage 3 Pipeline.

CCPL has proposed the use of the HDD construction method to cross U.S. Highway 181 and State Highway (SH) 35 (HDD-1); Oliver Creek and SH 188 (HDD-2); Chiltipin Creek (HDD-3); and La Quinta Road, La Quinta Ditch, and Green Ditch (HDD-4). Length of an HDD alignment, pipeline diameter, and subsurface material are factors in the technical feasibility of an HDD installation. Subsurface conditions that can affect feasibility of an HDD installation include excessive rock strength and abrasivity, poor rock quality, solution cavities, and artesian conditions. Furthermore, inadvertent returns of drilling fluid to the ground surface are more likely to occur in less permeable soils or via fractures or fissures in bedrock. Chances for an inadvertent return to occur are greatest near the drill entry and exit points where the drill path has the least amount of ground cover.

CCPL conducted geotechnical investigations at proposed crossings for HDD-1, HDD-2, and HDD-3, consisting of the installation of two geotechnical borings at each crossing, which were installed to depths between 120 feet and 160 feet below the ground surface. A detailed geotechnical investigation for HDD-4 would be conducted during final design, the results of which would be provided to FERC for our review and approval prior to construction. At the location of each boring, unconsolidated material consisting of interbedded sands and clays was encountered to the terminal depths of each boring.

Based on evaluation of the data collected, and an absence of subsurface conditions that may add risk for HDD complications, CCPL concluded that there would be a high likelihood of success for the crossings. To further minimize potential drilling complications, including inadvertent returns, CCPL would require their HDD contractor to utilize information obtained from geotechnical studies to establish downhole allowable drilling pressures for all HDDs and would follow various industry standard BMPs such as varying drilling fluid viscosity to best fit the soil conditions encountered, and conducting visual and pedestrian monitoring of alignments during HDD construction. CCPL would additionally follow its *Horizontal Directional Drill Procedures and Inadvertent Return Plan,*[7] which outlines specific procedures to minimize and address inadvertent returns during construction. CCPL stated that a final *Horizontal Directional Drill Procedures and Inadvertent Return Plan* would be provided in its Implementation Plan, for our review and approval, prior to construction and would incorporate the FERC's Draft *Guidance for Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Contingency Plans* (2018).[8]

Based on available soils and geological data for the Project area and geotechnical investigations conducted by CCPL, blasting is not proposed or anticipated for construction of the Project. Therefore, no Blasting Plan has been filed.

Overall, impacts on geologic resources resulting from the installation of the Stage 3 Pipeline would be minor and not significant. With the implementation of BMPs and our Plan and Procedures, impacts on geological resources would be adequately minimized during construction and operation of the Stage 3 Pipeline.

2.0 SOILS

Soil information for the Project was obtained from the U.S. Department of Agriculture (USDA) Soil Survey of San Patricio and Aransas Counties, Texas (USDA, 1979) and the USDA NRCS Soil Survey Geographic Database (SSURGO) (NRCS, 2017). The SSURGO is a digital version of the original county soil surveys developed by the NRCS for use with geographic information systems. This database provides a detailed level of soils information for natural resource planning and management. The SSURGO system is linked to an attribute database that gives the proportionate extent of the component soils and their properties for each soil map unit.

Construction activities such as clearing, grading, trench excavation, backfilling, heavy equipment traffic, and restoration within Project workspaces have the potential to cause adverse soil impacts such as erosion, compaction, rutting, and mixing of topsoil and subsoil layers. These impacts could in turn lead to disruption or alteration of natural soil characteristics such as water infiltration and storage, surface and subsurface drainage patterns, and nutrient fertility in a manner that reduces soil productivity and its ability to support a stabilizing vegetative cover. Certain soils have characteristics that contribute to difficult

[7] The *Horizontal Directional Drill Procedures and Inadvertent Return Plan* is available on the FERC eLibrary at www.ferc.gov under accession no. 20181001-5293.

[8] FERC's Draft *Guidance for Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Contingency Plans* is available on the FERC website at https://www.ferc.gov/industries/gas/enviro/guidelines/hdd/guidance.pdf?csrt=14733501056902424593.

construction conditions or are especially susceptible to adverse impacts. Other construction impacts such as spills of construction equipment fuels, oils and lubricants could result in contamination of soils.

Topsoil would be imported only if necessary. For example, imported topsoil may be utilized to mitigate areas where settlement of native material has occurred within the backfilled trench. The volume of imported topsoil to be utilized, if any, is unknown at this time. If required, topsoil to be imported would be sourced from borrow areas that either (1) are known to comprise primarily native seed stocks and are not contaminated, or (2) are known to be absent of contaminated fill material. CCPL does not anticipate encountering soils with native properties that would preclude their use as backfill; however, soils may be encountered (unanticipated discovery) with qualities unsuitable for use as backfill (e.g., unanticipated discovery of contamination). Backfilled, imported soil would be seeded as necessary in accordance with FERC's Plan and Procedures.

2.1 Stage 3 LNG Facilities

There are seven soil map units within the Project area for the Stage 3 LNG Facilities, as identified in table B.2.1-1, as well as areas that are classified as either "Wasteland" or "Urban Land." Soils belonging to the seven map units occupy a relatively small portion of the Stage 3 LNG Facilities site and would be generally classified as fine grained to loamy (clays and sandy clay loams), with drainage classes ranging from poorly-drained to well-drained depending on bauxite mineralization. However, the vast majority of the workspace required for construction and operation of the Stage 3 LNG Facilities is occupied by NRCS classified "Wasteland" soils, which were previously impacted by a DMPA during construction of the Liquefaction Project. The DMPA previous to the Liquefaction Project was used for bauxite residue and ore storage. Soils classified as "Urban Land," defined by the NRCS as covered by streets, parking lots, building and other structures typical of urban areas, are located in temporary workspaces east of the Stage 3 LNG Facilities. Soil limitations exhibited by the soils impacted by the Stage 3 LNG Facilities are also presented in table B.2.1-1.

Table B.2.1-1
Soils Impacted by the Stage 3 LNG Facilities

Soil Map Unit (Soil Map Unit Symbol)	Area Affected by Construction (acres) [a]	Area Affected by Operation (acres)	Prime Farmland [b]	Hydric [c]	Severe Erosion Hazard [d]	Severe Compaction Potential [e]	Poor Revegetation Potential [f]
Wasteland [g]	724.4	724.4	No	No	N/A	N/A	N/A
Banquete clay, 0 to 1 percent slopes (Ec)	69.0	15.0	No	Yes	No	Yes	Yes
Edroy clay, 0 to 1 percent slopes, occasionally flooded (Ed)	57.1	15.1	No	Yes	No	Yes	Yes
Orelia sandy clay loam (Os)	214.2	90.2	No	Yes	No	No	No
Papalote fine sandy load, 0 to 1 percent slopes (PaA)	27.0	27.0	Yes	Yes	No	No	No

Table B.2.1-1

Soils Impacted by the Stage 3 LNG Facilities

Soil Map Unit (Soil Map Unit Symbol)	Area Affected by Construction (acres) [a]	Area Affected by Operation (acres)	Prime Farmland [b]	Hydric [c]	Severe Erosion Hazard [d]	Severe Compaction Potential [e]	Poor Revegetation Potential [f]
Papalote fine sandy loam, 1 to 3 percent slopes (PaB)	5.0	3.0	Yes	No	No	No	No
Raymondville clay loam, 0 to 1 percent slopes (RaA)	94.0	29.0	Yes	Yes	No	No	No
Victoria clay, 0 to 1 percent slopes (VcA)	24.7	24.7	Yes	Yes	No	Yes	Yes
Urban land [g]	55.0	0.0	No	No	N/A	N/A	N/A
Total [h, I, j]	**1,270.4**	**928.4**					

Source: NRCS, 2017

a Construction impacts are inclusive of operation impacts.

b Includes land that is designated as prime farmland, unique farmland, farmland of statewide importance, and farmland of local importance.

c Includes soils classified as "partially hydric" by the NRCS.

d Soils that are classified as having Severe Erosion Hazard include soils ranked as "very severe" or "severe" for Erosion Hazard Criteria on SSURGO or gave a Wind Erodibility Index of 1 or 2, as ranked by SSURGO.

e Severe compaction potential includes soils with that are silt loam or finer based on particle size and ranked as having "somewhat poor," "poor," and "very poor" drainage by SSURGO.

f Soils identified as having poor revegetation potential are soils that have a Land Capability Class of 3 or greater, have low available water capacity, and/or slopes greater than 8 percent.

g "Wasteland" and "Urban land" are not soil map units and are, therefore, not ranked.

h Sum of addends may not equal total due to rounding.

i Totals do not include approximately 4 acres beneath the construction dock that is open water and not included in soil mapping.

j Soil impacts associated with the 18.5 acres of existing access roads were estimated through use of aerial imagery and map exhibits provided by Cheniere.

2.1.1 Prime Farmland

The NRCS defines prime farmland as land that has the best combination of physical and chemical characteristics for growing food, feed, forage, fiber, and oilseed crops. Unique farmland is land, other than prime farmland, that is used for production of specific high-value food and fiber crops. Soils that do not meet all of the requirements to be considered prime or unique farmland may be considered farmland of statewide or local importance if soils are capable of producing a high yield of crops when treated or managed according to accepted farming methods (NRCS, 2017).

Approximately 150.7 acres (12 percent) of the soils that would be affected by construction of the Stage 3 LNG Facilities are considered prime farmland or farmland of statewide importance. All of this area is currently being utilized as temporary work area for the Liquefaction Project. Approximately 83.7 acres of prime farmland soils would be impacted by operation of the Stage 3 LNG Facilities. While none of these areas are currently being used for agricultural purposes, some areas were in agricultural production prior to the start of the Corpus Christi Liquefaction Project (FERC Docket No. CP12-508-000) and thus would be permanently impacted by the Stage 3 LNG Facilities.

It is unlikely that the site could be used as future cropland, given prior industrial activities. However, CCL Stage III would implement the FERC Plan and Procedures and its *Project Erosion and Sedimentation Control Plan* as well as conduct tilling to restore compacted soils as necessary to promote revegetation.

2.1.2 Hydric Soils and Compaction

Hydric soils are defined as "soils that formed under conditions of saturation, flooding, or ponding long enough during the growing season to develop anaerobic conditions in the upper part" (COE, 1987). Generally, hydric soils are those that are poorly or very poorly drained. Due to extended periods of saturation, hydric soils can be prone to compaction and rutting. About 486.0 acres (38 percent) of the soils that would be affected by construction of the Stage 3 LNG Facilities are considered hydric. The areas characterized as hydric soils are currently being utilized as temporary work areas for the Liquefaction Project. Approximately 201.0 acres of hydric soils would be permanently impacted by operation of the Stage 3 LNG Facilities.

About 150.8 acres (12 percent) of the soils that would be affected by construction of the Stage 3 LNG Facilities have severe compaction potential. If construction activities, particularly the operation of heavy equipment, occur when soils are saturated, soil compaction and rutting could occur. CCL Stage III would minimize rutting and compaction by paying particular attention to areas identified as having hydric soils that are vulnerable to these types of impacts and to areas that are saturated due to recent rainfall. In general, rutting and compaction of soils would be avoided or minimized through the use of timber mats, as deemed necessary during construction. Other methods, such as using low-ground pressure equipment, may also be used as conditions dictate. In addition, the permanent compaction of soils beneath aboveground facilities and access roads would have permanent hydrological impacts on the area, but impacts would be highly localized and minor.

Compaction impacts would be minimal due to the highly disturbed nature of the Stage 3 LNG Facilities site from prior industrial activities. There would be a potential for increased runoff of stormwater as a result of compacted soils. To facilitate stormwater drainage, CCL Stage III would install a system of drainage features within the Stage 3 LNG Facilities site to convey stormwater to the La Quinta Ditch, which runs along the western edge of the site and flows into Corpus Christi Bay. Measures that would be implemented to minimize impacts on soils from stormwater runoff include use of silt fence, hay bale dikes, rock check dams, filter bags for dewatering activities, vegetated filter strips, and diffuser devices.

2.1.3 Erosion

None of the soils crossed are typically highly susceptible to erosion by water or wind. However, clearing, grading, and equipment movement can accelerate the erosion process and, without adequate protection, result in discharge of sediment to waterbodies and wetlands. CCL Stage III would adopt our Plan and implement its *Project Erosion and Sedimentation Control Plan* to limit the effects of erosion. Appropriate erosion and sedimentation control measures, such as silt fencing, would be implemented and maintained at all times during construction of the Stage 3 LNG Facilities. In addition, CCL Stage III would minimize wind erosion by implementing dust control measures (wetting of construction areas) and revegetating temporarily disturbed areas after the completion of construction activities. Following restoration and clean up, the disturbed areas would be monitored to maintain erosion control structures and repair any eroded areas.

2.1.4 Soil Contamination

The Stage 3 LNG Facilities site has been used to store bauxite ore since the 1950s. Arsenic contamination of groundwater resulting from leached bauxite is discussed further in section B.3.1. Some degree of bauxite mineralization has occurred and an overall negative effect on vegetative growth is evident within the Stage 3 LNG Facilities site. Metals present in bauxite residue can inhibit microbial activity necessary for vegetative growth, thus reducing soil fertility (Lee et al., 2017). No other sources of historic contamination are present on the Stage 3 LNG Facilities site. Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment can adversely affect soils. The effects of contamination would typically be minor because of the low frequency and volumes of potential spills and leaks. Cheniere developed a SPCC Plan for construction that specifies cleanup procedures in the event of soil contamination from spills or leaks of fuel, lubricants, coolants, or solvents. Implementation of the measures in the SPCC Plan, revised to include certain Project-specific measures, would minimize the potential for soil contamination. In addition, Cheniere stated it would provide procedures for unanticipated discoveries of contaminated material for review and approval by FERC prior to construction.

2.1.5 Conclusion

Based on adherence to measures contained in our Plan and Procedures and Cheniere's *Project Erosion and Sedimentation Control Plan* and implementation of impact minimization and mitigation measures identified by CCL Stage III and described above, we conclude that impacts on soils due to construction and operation of the Stage 3 LNG Facilities would be permanent but minor.

2.2 Stage 3 Pipeline

The Stage 3 Pipeline would be constructed adjacent to the currently authorized Corpus Christi Pipeline. Table B.2.2-1 summarizes the soils that would be affected by construction and operation of the Stage 3 Pipeline.

Table B.2.2-1

Soils Impacted by the Stage 3 Pipeline

Soil Map Unit	Soil Map Unit Symbol	Crossing Length (miles)	Area Affected by Construction (acres)	Area Affected by Operation (acres) [a]	Prime Farmland [b]	Hydric [c]	Severe Erosion Hazard [d]	Severe Compaction Potential [e]	Poor Revegetation Potential [f]
Orelia sandy clay loam	Os	2.0	37.9	21.3	No	Yes	No	No	No
Wasteland [g]	Wa	0.1	5.6	0.5	No	No	No	No	No
Willacy fine sandy loam, 0 to 1 percent slopes	WfA	0.1	0.7	0.1	Yes	No	No	No	No
Banquete clay, 0 to 1 percent slopes	Ec	1.5	27.2	11.6	No	Yes	No	Yes	Yes
Papalote fine sandy load, 0 to 1 percent slopes	PaA	2.6	91.6	46.6	Yes	Yes	No	No	No
Papalote fine sandy loam, 1 to 3 percent slopes	PaB	0.8	12.2	4.8	Yes	No	No	No	No
Victory clay, depressional	Vd	1.0	17.0	5.8	No	Yes	No	Yes	Yes
Victoria clay, 0 to 1 percent slopes	VcA	9.8	233.0	59.9	Yes	Yes	No	Yes	Yes
Victoria clay, 1 to 3 percent sloeps	VcB	0.1	0.4	0.4	Yes	Yes	No	Yes	Yes
Raymondville clay loam, 0 to 1 percent slopes	RaA	1.6	29.5	10.7	Yes	Yes	No	No	No
Raymondville clay loam, 1 to 3 percent slopes	RaB	<0.1	1.8	0.3	Yes	No	No	No	No
Sinton loam	Sn	0.1	1.3	0.7	Yes	Yes	No	No	No
Delfina loamy fine sand	Dn	0.6	15.4	3.8	No	Yes	Yes	No	No

Table B.2.2-1

Soils Impacted by the Stage 3 Pipeline

Soil Map Unit	Soil Map Unit Symbol	Crossing Length (miles)	Area Affected by Construction (acres)	Area Affected by Operation (acres) [a]	Prime Farmland [b]	Hydric [c]	Severe Erosion Hazard [d]	Severe Compaction Potential [e]	Poor Revegetation Potential [f]
Orelia fine sandy loam	Or	0.7	10.7	4.6	No	Yes	No	No	No
Total [h]		**21.0**	**484.2**	**171.1**					

Source: NRCS, 2017

[a] Temporary facilities such as the laydown areas would only be affected during construction.

[b] Includes land that is designated as prime farmland, unique farmland, farmland of statewide importance, and farmland of local importance.

[c] Includes soils classified as "partially hydric" by the NRCS.

[d] Soils that are classified as having Severe Erosion Hazard include soils ranked as "very severe" or "severe" for Erosion Hazard Criteria on SSURGO or gave a Wind Erodibility Index of 1 or 2, as ranked by SSURGO.

[e] Severe compaction potential includes soils with that are silt loam or finer based on particle size and ranked as having "somewhat poor," "poor," and "very poor" drainage by SSURGO.

[f] Soils identified as having poor revegetation potential are soils that have a Land Capability Class of 3 or greater, have low available water capacity, and/or slopes greater than 8 percent.

[g] "Wasteland" is not a soil series and is therefore not ranked.

[h] Sum of addends may not equal total due to rounding.

The majority of the Stage 3 Pipeline would be constructed on previously disturbed soils. There would be no residential areas crossed by the Stage 3 Pipeline. CCPL would avoid or minimize impacts to existing soils and limitations posed by soil properties through the use of our Plan and Procedures and its *Project Erosion and Sedimentation Control Plan*.

2.2.1 Prime Farmland and Agricultural Land

A total of 370.5 acres of designated prime farmland soils would be disturbed during construction of the Stage 3 Pipeline Facilities, 369.5 acres of which would be restored to pre-construction conditions following construction. Construction and mitigation measures contained within our Plan and Cheniere's *Project Erosion and Sedimentation Control Plan*, such as topsoil conservation, would be used in soils under active agricultural use but not in prime farmland in which agricultural or residential use is absent. Stage 3 Pipeline operation would not affect the aforementioned prime farmland acreage or preclude it from being used for agricultural purposes.

No new permanent impacts would occur as a result of Project activities at the Sinton Compressor Station, and no permanent loss of prime farmland would occur, as no expansion of the existing fence line is anticipated. Approximately 1.0 acre of mapped prime farmland soils would be removed from agricultural use as a result of operation of the MLVs at MPs 7.3 and 12.8. Due to the small amount of prime farmland that would be removed from production as a result of the Project relative to available farmland in the region, the Stage 3 Pipeline Facilities would not result in significant impacts on prime farmland.

2.2.2 Hydric Soils and Compaction

A total of 464.0 acres of hydric soils would not be impacted by construction of the Stage 3 Pipeline Facilities, of which 165.4 acres would be impacted during operation. Construction of the Stage 3 Pipeline would also impact approximately 277.6 acres of soils with high potential for compaction, including approximately 77.7 acres associated with operation. The movement back and forth along the construction right-of-way and access roads, especially in saturated working conditions, could result in rutting and/or soil compaction. To reduce soil compaction and soil horizon mixing in residential land, active agricultural areas, or other areas at the landowner's request crossed by the Stage 3 Pipeline, CCPL would segregate topsoil from subsoil and utilize harrow, para-plow, para-till, or other equipment to de-compact subsoils prior to the replacement of topsoil. CCPL would avoid and minimize rutting and compaction impacts in saturated soils by: 1) restricting work to areas where conditions are not prohibitive; 2) using low ground weight or wide-track equipment or other low impact construction techniques; 3) limiting work to areas that have adequately drained soils or have a sufficient cover of vegetation such as sod, crops or crop residues; and 4) installing geotextile material or construction mats in problem areas.

2.2.3 Erosion

One soil crossed by the Stage 3 Pipeline (Delfina loamy fine sand), representing approximately 15.4 acres of impacts associated with the Stage 3 Pipeline Facilities, is considered highly erodible. However, even soils that are not highly erodible are more susceptible to erosion when subjected to accelerating influences such as construction-related clearing, grading, and equipment movement. During construction of the pipeline, CCPL would implement the erosion control measures presented in our Plan and its *Project Erosion and Sedimentation Control Plan*. These measures would include use of temporary slope breakers if slopes are encountered and silt fence or staked hay or straw bales to reduce the runoff velocity and divert water off the construction right-of-way. In addition, CCPL would use sediment barriers to stop the flow of sediments and prevent the deposition of sediments beyond approved workspaces or into sensitive resources.

2.2.4 Soil Contamination

A search was conducted along the Stage 3 Pipeline and did not reveal any indication of contaminated soils within 1 mile of the Stage 3 Pipeline Facilities (Environmental Data Resources, Inc. [EDR], 2016). However, a relatively small area of hydrocarbon-impacted soils is known to be within approximately 200 feet of the Stage 3 Pipeline at approximate MP 0.3. This contamination is thought to be a relic of a historic crude oil pipeline release. If contaminated soils are encountered, CCPL would contain, characterize, and properly dispose of impacted soils. CCPL would utilize BMPs, such as the use of visqueen plastic to separate excavated impacted soils from unimpacted topsoil layers and to shield impacted soil from rainfall. Further, CCPL stated it would provide procedures for unanticipated discoveries of contaminated material for review and approval by FERC prior to construction.

CCPL indicated that they would not be utilizing coal ash for soil stabilization purposes. Handling and disposal of topsoil that is to be replaced would be conducted in accordance with applicable permits, laws, and regulations. Topsoil that is to be replaced would be disposed of at a licensed or otherwise authorized location. Cheniere would dispose of topsoil removed from the pipeline right-of-way by disposing it in either a licensed disposal facility such as the City of Corpus Christi Cefe Valenzuela Landfill, or in an authorized facility such as the El Centro landfill in Robstown, Texas. The ultimate disposition would depend on the volume and character of the topsoil in question, which wouldn’t be determined at this time.

3.0 WATER RESOURCES AND WETLANDS

3.1 Groundwater

The Project is underlain by the Coastal Lowlands aquifer system, which extends along the Gulf Coast of the United States and, in Texas, is commonly referred to as the Gulf Coast aquifer. It is characterized as an unconfined aquifer with unconsolidated sand and clay deposits. In Texas, the Coastal Lowlands aquifer system underlies about 35,000 square miles of level, low-lying coastal plain. The aquifer system extends eastward into parts of the Coastal Plain of Louisiana, Mississippi, Alabama, and the western edge of the Florida panhandle, and consists mostly of Miocene and younger unconsolidated deposits that lie above and coastward of the Vicksburg-Jackson confining unit (Ryder, 1996). The deposits extend to the land surface and recharge occurs through infiltration of rainfall in outcrop areas. The coastward-dipping sediments reach a thickness of several thousand feet and contain waters that range from freshwater to brine. The Coastal Lowlands aquifer system yields large amounts of water for public, agricultural, and industrial uses (Ryder, 1996).

The Gulf Coast aquifer has been separated into five permeability zones and two confining units (Ryder, 1996). Along the Gulf Coast and within the Project area, the upper part of the aquifer system is unconfined. The Chicot and Evangeline aquifers are commonly used hydrogeologic-unit designations for subdivisions of the upper, mostly sandy part of the aquifer system and the lower permeable zones make up the Jasper aquifer (Ryder, 1996). In San Patricio County, the Chicot aquifer is the primary source for groundwater withdrawals. Long-term groundwater levels in most of San Patricio County are fairly stable; however, levels fluctuate seasonally as water is primarily drawn for irrigation. Groundwater levels have declined in areas where significant municipal or industrial pumping has occurred within the Project area near the town of Sinton, approximately 2 miles from the Stage 3 Pipeline and 15 miles from the Stage 3 LNG Facilities (Shafer, 1968).

Groundwater withdrawals would not be required for the Project, except as necessary for trench dewatering during construction. Due to the shallow nature of the perched groundwater table, groundwater could sustain minor impacts immediately adjacent to Project areas from temporary changes in overland water flow and recharge from trenching, backfilling, trench dewatering, clearing and grading; however, this effect would be temporary and flow patterns would return to pre-construction conditions once activities cease. All water necessary for construction and operation would be obtained from surface water resources or municipal water (which is sourced for surface waterbodies [San Patricio Water District, 2018]) as discussed in section B.3.2.

3.1.1 Stage 3 LNG Facilities

Groundwater in much of San Patricio County has high concentrations of chloride, salinity, and alkalinity. The chloride and total dissolved solids in most of the area's wells exceed the standards for drinking water, and the concentrations increase towards Corpus Christi Bay (Shafer, 1968). There are no freshwater-bearing sands within the Stage 3 LNG Facilities site. Saltwater intrusion in the sands extends further inland along the northern shore of Corpus Christi Bay. The nearest freshwater sands are approximately 3 miles east of the Stage 3 LNG Facilities site, in the vicinity of Aransas Pass and Ingleside, where a lens of freshwater sands extends down to Corpus Christi Bay (Wood et al., 1963).

According to Texas Water Development Board data there are no public or private water supply wells located within 150 feet of the Stage 3 LNG Facilities (Texas Water Development Board, 2018). The nearest public and private supply wells are approximately 3 miles and 2 miles from the Stage 3 LNG Facilities site, respectively (Texas Water Development Board, 2018; Corpus Christi Aquifer Storage and Recovery Conservation District, 2018).

A sole source aquifer is an aquifer designated by the EPA as the "sole or principal source" of drinking water for a given service area. This designation is given to aquifers that supply 50 percent or more of the drinking water for an area and for which there are no reasonably available sources should the aquifer become contaminated (EPA, 2016). The Stage 3 LNG Facilities would not overlie a sole source aquifer, as designated by the EPA, and there are no locally zoned aquifer protection areas within the Stage 3 LNG Facilities site (TCEQ, 2018; San Patricio County Groundwater Conservation District, 2017; Corpus Christi Aquifer Storage and Recovery Conservation District, 2018; EPA, 2017a). No water supply springs would be impacted by the Stage 3 LNG Facilities.

The Stage 3 LNG Facilities site was used for several decades starting in the mid-1950's for bauxite residue storage associated with the adjacent and recently decommissioned Sherwin Alumina plant. Cheniere stated that, per a letter from the TCEQ, previous investigations in the area south of the Stage 3 LNG Facilities site 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. Cheniere also stated that 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. However, a copy of this letter was not filed with FERC. There is no other known groundwater contamination within 0.25 mile of the Stage 3 LNG Facilities (EDR, 2016).

Groundwater monitoring wells and borings associated with past and adjacent ongoing industrial activities and the previous geotechnical study performed for the Liquefaction Project occur within the vicinity of the Stage 3 LNG Facilities site. Six of the 25 holes are documented as being plugged. Well and borehole depths range from 5 to 52 feet. To protect groundwater monitoring wells during construction and operation of the Stage 3 LNG Facilities, CCL Stage III would locate and flag wells prior to construction to ensure avoidance.

Construction impacts on groundwater associated with the Stage 3 LNG Facilities are expected to be temporary and minor. The groundwater beneath the Stage 3 LNG Facilities site occurs at an elevation of 15 feet (approximate). The majority of Stage 3 LNG Facilities would be constructed atop an elevated (approximate elevation 48 feet above natural ground surface) dredged material placement area, which was recently utilized for the Liquefaction Project. If shallow groundwater is encountered during excavations, free water would be pumped out of excavations using pumps. Dewatering structures would be located to avoid deposition of sediments directly into wetlands or waterbodies.

Construction activities (including the installation of ground improvement columns and dewatering) within areas of known groundwater contamination could further the spread of the contamination if special construction and material handling methods are not utilized. Cheniere has not provided the measures that would be implemented during construction in areas of known groundwater contamination to ensure that the contamination does not spread. Therefore, **we recommend that**:

- **<u>Prior to construction of the Stage 3 LNG Facilities</u>, CCL Stage III should file with the Secretary of the Commission (Secretary), for review and written approval by the Director of the Office of Energy Projects (OEP), groundwater containment and disposal guidelines and practices that will be implemented during construction in areas of known groundwater contamination. CCL Stage III should develop the groundwater containment and disposal guidelines and practices in consultation with the TCEQ, and its filing should include documentation of its consultation with TCEQ.**

The greatest potential for an impact on groundwater would be an accidental release of hazardous substances, such as fuels, lubricants, and coolants, while constructing and operating the Stage 3 LNG Facilities. If an accidental leak or spill of hazardous materials occurs during construction, there may be short-term and/or long-term impacts on groundwater quality. If spilled hazardous substances (e.g., fuels, lubricants, or coolants) are carried by surface water, storm water runoff, or groundwater, then waters outside of the work area may be affected. Cheniere filed a SPCC Plan that provides measures to minimize the potential impacts of spills of hazardous materials. Cheniere's SPCC Plan describes general preventative BMPs, including personnel training, equipment inspection, and refueling procedures to reduce the likelihood of a spill. It also describes the mitigation measures, including containment and cleanup, to minimize potential impacts should a spill occur.

Due to the non-potable saline groundwater conditions that naturally occurs at the site, lack of water supply wells in the area, surficial mitigation measures that would be implemented by CCL Stage III in the event of a hazardous material spill, and our recommendation regarding contaminated groundwater, we conclude impacts on the groundwater resources underlying the Stage 3 LNG Facilities would be minor and not significant.

3.1.2 Stage 3 Pipeline

The proposed Stage 3 Pipeline is underlain by the Coastal Lowlands aquifer system. Groundwater resources for the area crossed by the Stage 3 Pipeline would be the same as those described for the Stage 3 LNG Facilities presented in section B.3.1.1; however, the salinity of the groundwater decreases towards the western portion of the pipeline (Wood et al., 1963).

There are no public or private water supply wells within 150 feet of any Stage 3 Pipeline work area (Texas Water Development Board, 2018). The Stage 3 Pipeline would not overlie a sole source aquifer as designated by the EPA, and there are no locally zoned aquifer or wellhead protection areas crossed by the Stage 3 Pipeline (TCEQ, 2018; San Patricio County Groundwater Conservation District, 2017; Corpus Christi Aquifer Storage and Recovery Conservation District, 2018). No water supply springs would be impacted by the Stage 3 Pipeline. There are no existing areas of groundwater contamination within 0.25 mile of the proposed Stage 3 Pipeline with the exception of the previously discussed arsenic contamination near the Stage 3 LNG Facilities (EDR, 2016).

If shallow groundwater is encountered during construction, free water would be pumped out of excavations using pumps. Dewatering structures would be located to avoid deposition of sediments directly into wetlands or waterbodies.

Surface drainage and groundwater recharge patterns could be temporarily altered by clearing, grading, trenching, and soil stockpiling activities, potentially causing minor fluctuations in groundwater levels and/or increased turbidity, particularly in shallow surficial aquifers. We expect the resulting changes in water levels and/or turbidity in these aquifers to be localized and temporary because water levels quickly re-establish equilibrium and turbidity levels rapidly subside. Furthermore, CCPL would limit the amount of time trenches and bore pits remain open to allow local water tables to return to original elevations as quickly as possible. Upon completion of construction, CCPL would restore the ground surface to original contours, to the extent practicable, and would revegetate disturbed areas, excluding areas within permanent aboveground facility fence lines and access roads, with the goal of restoring preconstruction overland flow and recharge patterns. We conclude no significant or long-term impacts from construction of the Stage 3 Pipeline would occur on groundwater resources with implementation of proposed mitigation measures and our Plan and Procedures. The addition of impervious surfaces at aboveground facilities may affect overland flow patterns and subsurface hydrology. However, these effects would be highly localized and minor and would not impact the underlying aquifer.

Spills of fuels, lubricants, or solvents during Project activities could result in groundwater contamination. However, CCPL would implement proper storage, containment, and handling procedures and other measures outlined in the SPCC Plan to prevent or control inadvertent spills of hazardous materials and groundwater contamination. In addition, CCPL stated it would provide procedures for unanticipated discoveries of contaminated material, including groundwater, for review and approval by FERC prior to construction.

The HDD-4 is near (0.25 mile) an area of known arsenic contaminated groundwater (see section B.3.1.1); however, the drill path is located outside of the contamination. To ensure that Project activities do not further the spread of groundwater contamination, CCPL would test drilling mud from HDD No. 4 for contaminants (see section B.3.2.2) prior to placement within upland areas. HDD Nos. 1-3 would not be located in the vicinity of known contaminated soil or groundwater. Thus, CCPL does not plan to test drilling mud from these locations. Per the FERC Plan at section III.E, disposal of materials for beneficial reuse must not result in adverse environmental impact. In order to adhere to the FERC Plan at section III.E, **we recommend that:**

- **<u>Prior to construction of the Stage 3 Pipeline</u>, CCPL should file with the Secretary, for review and written approval by the Director of the OEP, an updated *Horizontal Directional Drill Procedures and Inadvertent Return Plan* that includes procedures for environmental testing of drilling mud prior to any placement in upland areas or other beneficial reuse, including a list of testing parameters.**

If an unanticipated discovery of contamination were to occur within the drilling mud utilized for the HDDs, CCPL would stop work in the area of suspected contamination until the type and extent of the contamination is identified and notify applicable agencies of the discovery. Representative samples of drilling fluid would be collected for laboratory analysis for any drilling fluid scheduled for off-site disposal, and prior to reuse of HDD fluid transported from one drill site to another. In these cases, samples would be collected by a trained technician or EI and delivered to a certified laboratory for analysis. Laboratory analysis would include total metals (i.e., lead, silver, barite, beryllium, cadmium, chromium, nickel, mercury, selenium, arsenic, and antimony) and total petroleum hydrocarbons. CCPL would dispose drilling mud determined to be contaminated at a licensed disposal facility.

We conclude that the mitigation measures proposed by CCPL and our recommendation would adequately avoid or minimize potential impacts on groundwater resources, and that long-term operational impacts on groundwater are negligible. Therefore, we do not anticipate any significant impacts on groundwater resources as a result of construction or operation of the Project.

3.2 Surface Water

3.2.1 Stage 3 LNG Facilities

The Stage 3 Project would be located within the North Corpus Christi Bay watershed (Hydrologic Unit Code [HUC] 12110201). No COE-jurisdictional waterbodies would be impacted by the Project. However, several small, ephemeral ditches and ponds occur within the Stage 3 LNG Facilities. These waterbodies were determined by the COE to be non-jurisdictional under the CWA on June 15, 2016, as they were excavated from uplands. Impacts on these waterbodies are presented in table B.3.2-1.

Table B.3.2-1

COE Non-jurisdictional Waterbodies Impacted by the Stage 3 LNG Facilities

Waterbody ID	Description	Temporary Impact (acres)	Permanent Impact (acres)
3E	Ephemeral ditch excavated from uplands	0.55	0.00
7E	Ephemeral ditch excavated from uplands	0.29	0.00
10E	Ephemeral ditch excavated from uplands	0.20	0.00
12E	Ephemeral ditch excavated from uplands	0.09	0.00
17E	Stormwater control feature excavated from uplands	0.63	0.00
19E	Stormwater control feature excavated from uplands	0.06	0.00
2E	Stormwater control pond excavated from uplands	7.66	0.00
16E	Isolated pond created from excavation of a fill material borrow pit in an upland	31.88	0.00
3W	Artificial constructed bauxite settling pond in uplands	0.00	10.02
6W	Artificial constructed bauxite settling pond in uplands	0.00	708.66
7W	Isolated pond created from excavation of a fill material borrow pit in an upland	0.00	50.26

The only major surface waterbody within proximity to the Stage 3 LNG Facilities is Corpus Christi Bay, which is designated in the National Estuary Program as an estuary of "national significance" (EPA, 1999). Corpus Christi Bay is approximately 1 mile south of the Stage 3 LNG Facilities.

Corpus Christi Bay is considered a sensitive surface waterbody, as identified by the State of Texas for criteria pertaining to water quality and important ecological and habitat elements. It 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, 2010). Corpus Christi Bay is considered a warmwater, saline fishery. As described below, construction and operation of the Stage 3 LNG Facilities would temporarily impact Corpus Christi Bay, but no permanent impacts on Corpus Christi Bay would result from construction and operation of the Stage 3 LNG Facilities.

Stormwater Runoff

Stormwater discharges from construction and operation of the Stage 3 LNG Facilities would be exempt from industrial stormwater permitting, which is consistent with EPA's *Policy Act* of 2005, Final Rule: Amendments to the Storm Water Regulations for Discharges Associated with Oil and Gas Construction Activities (EPA, 2006); and as granted by Section 402(I)(2) of the CWA; 33 USC § 1342(l)(2). A system of drainage features would be constructed within the Stage 3 LNG Facilities site which would convey stormwater to Corpus Christi Bay via La Quinta Ditch. Based on the topography at the site, the stormwater would pass through existing outfalls permitted by the Texas Pollutant Discharge Elimination System for an affiliate of CCL Stage III. Routine sampling of this outfall would continue, as required by the existing permit.

Stormwater removal from within the LNG storage tank dikes would conform to 49 CFR 193.2173, under Subpart C, requiring water to be pumped out at 25 percent of the maximum predictable collection rate from a storm of ten-year frequency and 1-hour duration. In addition, Cheniere would develop a SWPPP for managing stormwater runoff during construction and operation of the Stage 3 Project.

Water Use

The proposed Stage 3 LNG Facilities site is not within a source water protection area. However, two public water supply surface water intakes are located within 1 mile of the proposed site (Miller, 2015). These intakes are associated with the Jim Naismith Reservoir for Raw Water Blending and Storage (adjacent to the Stage 3 LNG Facilities to the east on the north side of Highway 361) and the San Patricio Municipal Water District 3-Plant Water Treatment Complex (adjacent to the Stage 3 LNG Facilities to the southeast). These lined ponds/reservoirs are used for temporary storage of water from outside sources, and are protected from adjacent drainage areas. The Stage 3 LNG Facilities site would not impact these intake reservoirs.

Municipal water supplies in San Patricio County currently come from the Nueces, Navidad, and Colorado Rivers, upgradient of the proposed Stage 3 LNG Facilities site (TCEQ, 2014). Therefore, there are no public watershed areas in the vicinity of the Stage 3 LNG Facilities site.

During operation, treated and potable water supplies would be obtained from the San Patricio Municipal Water District. Initial fill requirements would be limited to filling the two 480,000-gallon Stage 3 Facility Fire Water Tanks for a total of 980,000 gallons. Approximately 8,100,000 gallons of continuous water would be required for the demineralizer water makeup in the acid gas removal units (AGRUs). The demineralizer water would be supplied from imported International Organization for Standardization containers. All other potential operation water consumption would be periodic or intermittent and would be associated with operation of safety showers, eye wash stations, utility and hose stations, and sample coolers, as well as the makeup to the fire water system. CCL Stage III estimates that 73,000 gallons per year of water would be necessary for sanitary use during operation of the Project. There would be no on-site storage for utility water, as the utility water would be supplied as micro-filtered water directly from San Patricio Municipal Water District.

The only normal operational periodic or intermittent water requirement would be makeup to the fire water system to account for water used during annual testing of the fire water deluge systems. With an average testing period of 10 minutes per systems, the total amount of water that would be used for annual testing of the deluge spray systems would be 450,000 gallons per year. Firewater pumps would undergo annual flow testing using a recirculation system; therefore, there would be no consumption of water for the testing.

Water discharged during operations (other than stormwater, as discussed above) would occur via outfalls permitted in accordance with the NPDES programs. This program requires routine sampling and reporting. Other than during startup and periodic maintenance, the volume of discharged process water is expected to be negligible.

Hydrostatic Testing

Prior to being placed into service, the LNG storage tank, piping, and equipment would be tested to ensure structural integrity. The inner tank of the LNG storage tank would be tested hydrostatically, in accordance with API Standard 620, Q.8.3. Hydrostatic testing would involve filling the inner tank with fresh water obtained from the San Patricio Municipal Water District, and discharged into La Quinta Ditch to the west of the site, using pumps to control the discharge rate of the test water from the LNG storage tank. Energy dissipation devices, such as a splash plate or hay bale structures, would be used to dissipate energy during discharge of the hydrostatic test water to prevent scouring and erosion. No chemical additives, except for a biocide (i.e., sodium hypochlorite) to control microbial induced corrosion, would be used in the water during hydrostatic testing. A total of 30 million gallons of water would be used to hydrostatically test the LNG storage tank, piping, and other equipment associated with the Stage 3 LNG Facilities. CCL Stage III would adhere to the testing requirements of the EPA and RRC hydrostatic test water permits.

Ship and Boat Traffic

During operation of the Stage 3 Project, there would be an anticipated increase in the maximum marine vessel traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year. The facilities required for mooring and loading LNGCs for the Stage 3 Project would be the same facilities currently under construction in association with the currently-authorized Liquefaction Project. No new marine facilities would be required for the Stage 3 Project. However, the additional 100 LNGCs arriving at the Liquefaction Project berth would discharge ballast water, and would intake and discharge cooling water, while at the berth. Discharge of ballast and cooling water could have potential impacts on surface water quality, including changes in pH, salinity, and water temperature, as discussed below. Permits and authorities covering the discharge of ballast water are described in section B.4.2.2. The increased potential for spills is also discussed in section B.4.2.2

Ballast Water

Ballast water discharged from LNGCs while at the marine berth would consist of open-ocean water collected during ballast water exchange performed during transoceanic shipping (see section B.4.4.2). The route travelled by LNGCs arriving at the Project and the location of the open-ocean source of ballast water would vary depending on each carrier’s itinerary prior to reaching the LNG terminal. The average mean salinity of Corpus Christi Bay is about 29 parts per thousand, but can range from 26 to 42 parts per thousand depending on water depth and location, with the highest salinities occurring to the south of the bay near the Gulf of Mexico (COE, 2003a; Cuddy, 2015). Open ocean seawater typically averages about 35 parts per thousand (Science Daily, 2018). Discharge of ballast water may result in a temporary increase in water salinity within the marine berth; however, the discharged water would quickly disperse and return to ambient levels.

Ballast water is not anticipated to significantly impact water temperature or pH in the marine berth. As ballast water is stored in the LNGC hull below the water line, ballast water temperatures would be similar to ambient water temperatures. The pH of ballast water would reflect the open-ocean conditions at the source of the last ballast water exchange prior to arriving at the LNG terminal. The average pH of the oceans near the surface, within the range where ballast water would be taken in by LNGCs, is about 8.1 (Sciencing.com, 2018). The average pH in Corpus Christi Bay was similarly measured at 8.1, and hence, no impacts on pH are anticipated as a result of ballast water discharge (Cuddy, 2015).

Cooling Water

LNGCs would re-circulate water for engine cooling while at the LNG terminal berth, requiring water for cooling of the main engine/condenser and diesel generators. Cooling water discharge would be expected to have no effect on the salinity or pH of the water since it would be withdrawn and discharged from the same sources in the berth. Cooling water return temperatures can vary widely depending on the type of LNGC and mode of operation. Cooling water discharged at the Project berth while in port-mode could range from between 2.7 degrees F and 7.2 degrees F (Caterpillar, 2007; 2011; 2012). Due to the relatively small temperature differences and the relatively small volume of discharge compared to the total water within Corpus Christi Bay, any discharged cooling water that is warmer than the ambient water would diminish shortly after discharge. Therefore, impacts on water quality as a result of cooling water intake and discharge would be intermittent and minor.

Conclusion

Construction and operation of the Stage 3 LNG Facilities would temporarily decrease water quality within the vicinity of the site as a result of stormwater runoff and discharge of hydrostatic test water. Through implementation of BMPs, the SPCC Plan, and our Procedures, potential impacts resulting from stormwater runoff or the discharge of hydrostatic test water would be adequately minimized or avoided, and not significant. In addition, impacts on water quality resulting from ballast and cooling water discharge would be temporary and minor, only affecting a relatively small area in the vicinity of the marine berth. Additional potential impacts from ballast and cooling water discharges are included in section B.4.2.2.

3.2.2 Stage 3 Pipeline

The proposed Stage 3 Pipeline begins within the North Corpus Christi Bay watershed (HUC 12110201), and ends in the Aransas watershed (HUC 12100407). Eight surface waterbodies would be crossed by the Stage 3 Pipeline. None of these waterbodies are listed in the TCEQ Draft 303(d) Water Quality Inventory (TCEQ, 2016), and officially designated uses have not been assigned. No waterbody segments that would be crossed by the Stage 3 Pipeline are included on the list of impaired waterbodies under Section 303(d) of the CWA. There are no potable water intakes within 3 miles downstream of any waterbody crossing (TCEQ, 2018) and no source water protection areas would be crossed by the Stage 3 Pipeline (Miller, 2015). Table B.3.2-2 summarizes information regarding the waterbodies which would be crossed by the Stage 3 Pipeline. None of the contractor yards associated with the Stage 3 Pipeline would impact waterbodies. However, two dry stormwater conveyance ditches are present adjacent to the Gregory Contractor Yard. These ditches would be crossed via existing access roads with culverts. In addition, CCPL would utilize orange safety fencing near these ditches to ensure that construction equipment does not interfere with the conveyance of water during storm events. Cheniere stated that erosion control devices such as silt fence would also be utilized as needed to prevent sediment from entering the ditches.

Table B.3.2-2

Waterbodies Crossed by the Stage 3 Pipeline

Waterbody	Milepost	Stream Type [a]	Crossing Width (ft) [b]	Stream Designation [c]	State Water Quality Classification	Fishery Type	Crossing Method [d]
La Quinta Ditch	0.1	I	40	Intermediate	Unclassified	Warmwater	HDD
Drainage Ditch	0.7	C	45	Intermediate	Unclassified	Warmwater	HDD
Drainage Ditch	1.9	I	20	Intermediate	Unclassified	Warmwater	Open cut
Drainage Ditch	4.3	I	15	Intermediate	Unclassified	Warmwater	Open cut
Drainage Ditch	12.0	I	15	Intermediate	Unclassified	Warmwater	Open cut
Oliver Creek	16.2	P	40	Intermediate	Unclassified	Warmwater	HDD
Chiltipin Creek	17.4	P	70	Intermediate	Unclassified	Warmwater	HDD
Drainage Ditch	18.0	I	4	Minor	Unclassified	Warmwater	Open cut

[a] P = Perennial, I = Intermittent, C = Canal

[b] Crossing width is from water's edge to water's edge per our Procedures, as measured either during waterbody survey or civil survey.

[c] Stream designations includes minor, intermediate, and major. Minor waterbodies are less than or equal to 10 feet wide at the water's edge at the time of crossing; intermediate waterbodies are greater than 10 feet wide but less than or equal to 100 feet wide at the water's edge at the time of crossing; and major waterbodies are greater than 100 feet wide at the water's edge at the time of crossing.

[d] HDD = horizontal directional drill

The Stage 3 Pipeline would use the HDD method to cross one intermittent and two perennial waterbodies, as well as one canal. The open cut method would be used to cross the remaining waterbodies, most of which are typically dry. Crossing waterbodies via HDD would significantly reduce potential impacts on waterbodies as the pipe would be installed underneath the stream bed.

Use of the HDD method could result in an inadvertent release of drilling mud into waterbodies. Drilling mud primarily consists of water and bentonite clay. CCPL would utilize approximately 1 million gallons of water sourced from municipal suppliers for the drilling mud sourced from local municipalities and/or water districts, the exact source would be confirmed before construction. CCPL would utilize MaxGel (or equivalent viscosifier) as a drilling mud additive for the Stage 3 Pipeline HDDs. MaxGel is nonhazardous and primarily comprised of bentonite along with silica and gypsum. CCPL has not identified any other drilling mud additives. If other additives are necessary, only pre-approved, non-toxic, non-petroleum-based products would be used. If an inadvertent return of drilling mud were to occur, it could temporarily impact water quality. However, CCPL would implement measures, as identified in its *Horizontal Directional Drill Procedures and Inadvertent Return Plan,* to minimize this impact, including monitoring of mud volumes and maintenance of instrumentation to accurately locate the pilot hole alignment and depth. CCPL stated that a final *Horizontal Directional Drill Procedures and Inadvertent Return Plan* would be provided prior to construction that would incorporate the FERC's Draft *Guidance for Horizontal Directional Drill Monitoring, Inadvertent Return Response, and Contingency Plans* (2018).

In addition, Cheniere has committed to reporting incidents involving drilling mud circulation loss and inadvertent returns to the ground surface in biweekly or monthly status reports. HDD mud disposal would also only occur within approved Project workspaces, with landowner consent according to the Plan and/or at a licensed disposal facility. CCPL's environmental inspector would work closely with the HDD operation to ensure that HDD mud is free of contaminants prior to disposition. Testing of drilling mud and unanticipated discoveries of contamination in drilling mud are further discussed in section B.3.1.2. In the event that an HDD cannot be completed at the proposed location, an alternate crossing methodology and/or location would be analyzed. CCPL would take into account geotechnical conditions, topography, the condition of the riparian area, water quality, and potential threatened and endangered species when selecting an alternative HDD location. CCPL would obtain approvals from all applicable regulatory agencies and would submit the proposed alternative HDD location(s) to FERC for review and approval.

Potential impacts on water quality resulting from the open-cut waterbody crossing method may include: temporary disturbance of riparian vegetation, which may lead to erosion-related impacts; inadvertent discharge of spoil material into the waterbody; and release of hydrocarbons into the waterbody via an unanticipated release from construction equipment. CCPL would minimize the above potential impact via implementation of our Procedures and the Project-specific SPCC Plan. These measures include, but are not limited to, conducting all open-cut installations within 24 to 48 hours, limited use of equipment operating within the waterbody, and refueling equipment greater than 100 feet from waterbodies. Furthermore, impacts on the water quality of crossed waterbodies as a result of increased turbidity or sedimentation during Pipeline construction and operation would be short-term and minor because in stream construction activities would occur within 48 hours.

Prior to being placed into service, the Stage 3 Pipeline would be hydrostatically tested to ensure structural integrity. Up to 11 million gallons of water may be required for hydrostatic testing of the Stage 3 Pipeline. It is anticipated that CCPL would obtain test water from the San Patricio Municipal Water District. Test water would be discharged at a controlled rate into La Quinta Ditch located near the south end of the Stage 3 Pipeline. CCPL would use appropriate energy dissipation and erosion control measures discussed in section B.3.2.1. Hydrostatic testing of the Stage 3 Pipeline may be conducted on an incremental basis, with test water contained in certain pipeline segments before being sent to other segments for testing. Biocides would be utilized for corrosion prevention in cases where water is held within the pipeline for longer than 30 days. The use of biocides would be incorporated into the relevant permitting processes for discharge of hydrostatic test water.

Waterbodies crossed by the Pipeline via the open cut method would experience short-term decreases in water quality resulting from increased turbidity, sedimentation, and overall stream bed and bank disturbance. However, we have determined that implementation of Cheniere's SPCC Plan as well as use of the measures outlined in our Procedures would adequately minimize impacts on surface water resources.

3.3 Wetlands

Wetlands are areas that are inundated or saturated for a sufficient duration or frequency to provide hydrologic and soil conditions conducive to a specialized assemblage of plant species. Wetlands provide valuable natural services, including flood control, water filtration, wildlife habitat, and outdoor recreational opportunities.

After reviewing FWS National Wetlands Inventory (NWI) maps, Cheniere conducted field surveys using methods set forth within the 1987 COE Wetland Delineation Manual and the Regional Supplement (November 2010) to locate and delineate wetlands within the Project areas. These wetlands were described using the Cowardin classification system (Cowardin et al., 1979).

3.3.1 Stage 3 LNG Facilities

The Stage 3 LNG Facilities would be located almost entirely within DMPA 2, which is authorized for dredged material placement as part of the construction of the Liquefaction Project. DMPA 2 is mapped as a lake, based on NWI data, reflecting that the site consists of former bauxite residue beds (FWS, 2015).

A small area to the southwest of DMPA 2 and two small areas to the east are mapped as freshwater ponds. A drainage feature outside of the site, adjacent to the east edge of the site, is mapped as freshwater emergent wetland.

A wetland delineation was completed for the Stage 3 LNG Facilities site in August 2015 and submitted to the COE for approval in November 2015. The COE issued a determination in June 2016 and concluded that all aquatic features within the site are non-jurisdictional. No impacts on COE-jurisdictional wetlands would occur within the Stage 3 LNG Facilities construction and permanent impact areas. Wetlands determined not to be under the jurisdiction of the COE are presented in table B.3.3-1. These wetlands primarily consist of isolated depressions formed as a result of placement of dredge material in DMPA 2 or through stormwater conveyances.

Table B.3.3-1

COE Non-jurisdictional Wetlands Impacted by the Stage 3 LNG Facilities

Wetland ID	Description	Temporary Impact (acres)	Permanent Impact (acres)
1E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	2.33	0.00
4E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	5.35	0.00
5E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.29	0.00
6E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.29	0.00
8E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.32	0.00
9E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.32	0.00
11E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.33	0.00
13E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.01	0.00
14E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.01	0.00
15E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	2.22	0.00
18E	Isolated wetland in water-filled depression created in dry land incidental to construction activities.	0.59	0.00
1W	Stormwater control feature excavated from uplands.	0.00	1.54
2W	Stormwater control feature excavated from uplands.	0.00	4.54
4W	Stormwater control feature excavated from uplands.	0.00	9.32

Cheniere would avoid potential impacts to areas off-site through implementation of our Procedures, the Project specific SWPPP and SPCC Plan during construction and restoration, ensuring that all disturbance is contained within the approved site and no sedimentation or other impacts would occur to areas off the Stage 3 LNG Facilities site. No marine facilities would be constructed and no waterway modification would be required for the Stage 3 Project; therefore, no dredge or fill would be required.

3.3.2 Stage 3 Pipeline

A wetland delineation was completed for the Stage 3 Pipeline with a report submitted to the COE in November 2015. Cheniere requested a pre-jurisdictional determination, which assumes that all wetlands and waterbodies crossed by the Project are COE-jurisdictional "waters of the U.S." for the purposes of permitting under Section 404 of the CWA. The Stage 3 Pipeline impacts on "waters of the U.S." qualify for coverage under the COE Nationwide Permit 12 for Utility Lines. As the Stage 3 Pipeline impacts would not exceed thresholds outlined in the 2017 Nationwide Permit General Conditions or the 2017 Nationwide Permit Regional Conditions for Texas, the Stage 3 Pipeline would be automatically authorized under Nationwide Permit 12 and would not require the COE to issue a Project-specific permit under Section 404 of the CWA. Wetlands crossed by the Stage 3 Pipeline are listed in table B.3.3-2.

Table B.3.3-2

Wetlands Crossed by the Stage 3 Pipeline

Alignment Sheet ID [a]	Cowardin Classification [b]	Milepost	Centerline Crossing Length (feet)	Crossing Method	Impact Type	Impact Acreage
Wetland 1-4	PEM	0.7	10	HDD	N/A	0.00
Wetland 18.5-3	PEM	18.5	N/A	Workspace Only	Temporary	0.04

[a] The feature marked as Wetland 1-3 on Alignment Sheet 1[9] is not a jurisdictional wetland but a stormwater drainage feature.

[b] PEM = palustrine emergent

Two wetlands would be crossed by the Stage 3 Pipeline. One of the wetlands would be crossed via HDD, and no impacts are anticipated. In the case of an inadvertent return of drilling mud, CCPL would implement measures as identified in its *Horizontal Directional Drill Procedures and Inadvertent Return Plan* to minimize potential impacts to the wetland (section B.3.2.2).

The other wetland, a PEM wetland located at MP 18.5 (Wetland 18.5-3), would be impacted by construction of the Stage 3 Pipeline, but would not be directly crossed by the Stage 3 Pipeline (i.e., no trenching in the wetland would occur). CCPL would minimize impacts on this wetland by adhering to the measures outlined in the FERC Procedures, including topsoil segregation (if wetland is not saturated at the time of construction) and restoration of pre-construction contours to allow for natural revegetation from the existing seed bank, as well as storage of hazardous materials, parking vehicles overnight, and refueling greater than 100 feet from the wetland. Following construction, the PEM wetland would remain in an herbaceous state with CCPL maintaining the permanent right-of-way in accordance with the FERC Procedures, and therefore, no permanent impacts on this wetland would occur as a result of the Project.

Based on the delineation results, CCPL's plan to HDD under a wetland, and the implementation of our procedures at the other wetland crossing, we determine that construction and operation of the Stage 3 Pipeline would not have significant impacts on wetlands.

[9] The Stage 3 Pipeline alignment sheets are available on the FERC eLibrary at https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp under accession number 20181130-5214.

4.0 VEGETATION, WILDLIFE, AND THREATENED AND ENDANGERED SPECIES

4.1 Vegetation

4.1.1 Stage 3 LNG Facilities

The proposed Stage 3 LNG Facilities site lies within the southeastern portion of the Gulf Prairies and Marshes region (Gould, 1975). This region can be subdivided into two vegetation units: (1) the gulf marshes covering approximately 500,000 acres, and (2) the gulf prairies or grasslands covering nearly 9 million acres (Hatch et al., 1990). The low gulf marshes comprise a narrow strip of land adjacent to the coast that is commonly covered with saline water and ranges in elevation from sea level to just a few feet above sea level. The gulf prairies extend 30 to 80 miles inland of the gulf marshes and have a nearly flat topography ranging from sea level to 250 feet above sea level (Hatch et al., 1990). The gulf prairies are used for crops, livestock grazing, wildlife production, and increasingly for urban and industrial centers. Approximately one-third of the area is cultivated. The following habitat/community types are present within the proposed Stage 3 LNG Facilities site:

- Inland Prairies and grassland - highly disturbed, containing a mosaic of coastal grass/forb species and scrub/shrub species including: Bermuda grass (*Cynodon dactylon*), Camphor daisy (*Machaeranthera phyllocephala*), sea ox-eye (*Borrichia frutescens*), coastal dropseed (*Sporobolus virginicus*), sea oats (*Uniola paniculata*), mesquite (*Prosopis juliflora*), saltcedar (*Tamarix ramosissima*), sugarberry (*Celtis laevigata*), Carolina holly (*Ilex ambigua*), Georgia holly (*Ilex longipes*), and various palm trees.
- Bare Ground and Seasonally Flooded - bauxite disposal area and areas created by excavations by other industrial users prior to acquisition. No consistent cover of vegetative species.
- Agricultural Fields - west of bare ground and seasonally flooded areas, containing the typically grown crops of cotton, sorghum, soybeans, and corn.

Table B.4.1-1 lists the acreage of each habitat/community types affected by construction and operation by Stage 3 LNG Facilities construction and operation. CCL Stage III would implement our Plan and Procedures along with any Project-specific recommendations and requirements associated with their permits during construction, restoration, and operation of the Stage 3 LNG Facilities (which includes measures for post-construction maintenance and monitoring). New permanent impacts associated with the Stage 3 LNG Facilities would occur on mostly bare ground, minimizing the impact that operation would have on vegetated areas. The permanent impact areas for the Stage 3 LNG Facilities would be maintained and stabilized using a variety of cover types including limestone road base, crushed concrete, asphalt, and rock/gravel.

Table B.4.1-1
Habitat/Vegetation Type Affected by the Stage 3 LNG Facilities

Habitat Type	Area Affected (acres)					
	Construction [a]			Operation		
	Overlap with Approved Liquefaction Project [b]	New Disturbance	Total Disturbance	Overlap with Approved Liquefaction Project [a]	New Disturbance	Total Disturbance
Inland Prairies and Grasslands	53.0	0.0	53.0	53.0	0.0	53.0

Table B.4.1-1
Habitat/Vegetation Type Affected by the Stage 3 LNG Facilities

Habitat Type	Area Affected (acres)					
	Construction [a]			Operation		
	Overlap with Approved Liquefaction Project [b]	New Disturbance	Total Disturbance	Overlap with Approved Liquefaction Project [a]	New Disturbance	Total Disturbance
Bare Ground / Seasonally Flooded Areas	1,208.5	12.9	1,221.4	866.5	12.9	879.4
Total	**1,261.5**	**12.9**	**1,274.4**	**919.5**	**12.9**	**932.4**

[a] Total construction impacts include both temporary and permanent work areas.
[b] Indicates the acreage of overlap with the previously authorized Liquefaction Project area.

Based on the disturbed nature of the Stage 3 LNG Facilities site, the amounts and types of vegetation impacted, and CCL Stage III's proposed impact minimization and mitigation measures, we have determined that constructing and operating the Stage 3 LNG Facilities would not significantly impact vegetation.

4.1.2 Stage 3 Pipeline

The Stage 3 Pipeline would lie within the Gulf Prairies and Marshes vegetation region, which is described in section B.4.1.1. The following habitat/community types are present along the proposed Stage 3 Pipeline route:

- Bare Ground - consisting of industrial land including roadways covered in gravel or pavement, and contain little or no vegetative coverage
- Agricultural Land - primary crops include cotton, sorghum, soybeans, and corn
- Open Land - includes inland prairies and grasslands described in section B.4.1.1 as well as other natural habitat types, such as rangeland. Additional species seen, not mentioned in section B.4.1.1, include western ragweed (*Ambrosia psilostachya*), common sunflower (*Helianthus annus*), Indian blanket-flower (*Gaillardia grandiflora*), prickly pear (*Opuntia sp*.), scarlet sage (*Salvia coccinca*), silver-leaf night-shade (*Solanum elegnifolium*), King Ranch bluestem (*Bothriochloa ischaemum*), Texas windmillgrass (*Chloris texensis*), Johnson grass (*Sorghum halepense*), buffelgrass (*Pennisetum ciliare*), huisache (*Acacia smallii*), retama (*Parkinsonia aculeata*), bluewood condalia (*Condalia hookeri*), honey mesquite (*Prosopis glandulosa*), and live oak (*Quercus virginiana*) (Gould, 1975; Hatch et al., 1990)
- Wetlands - palustrine emergent (PEM) with species including bulltongue (*Sagittaria lancifolia*), alligator weed (*Alternanthera philoxeroides*), spikerush (*Eleocharis* sp.), coontail (*Ceratophyllum demersum*), white water-lily (*Nymphaea odorata*), horned bladderwort (*Utricularia cornuta*), spiderlily (*Hymenocallis* sp.), maidencane (*Panicum hemitomom*), pondweed (*Potamogeton* sp.), soft rush (*Juncus effusus*), seashore paspalum (*Paspalum vaginatum*), southern naiad (*Najas guadalupensis*), Walteri millet (*Echinochloa walteri*), saltgrass (*Distichlis spicata*), water hyssop (*Bacopa* sp.), rattle bush (*Sesbania* sp.), smartweed (*Polygonum* sp.), saltmeadow cordgrass (*Spartina patens*), flatsedge (*Cyperus* sp.), three-square bulrush (*Scirpus pungens*), and delta duck-potato (*Sagittaria platyphylla*) (Correll and Johnson, 1970)

Table B.4.1-2 lists the habitats that would be affected by the Stage 3 Pipeline Facilities. In open lands, a permanent easement would be maintained in an herbaceous state, which would not result in conversion of habitat. Agricultural and bare ground would only be affected during construction, as agricultural crops would be grown within the permanent right-of-way during operation. Impacts to wetlands are discussed in section B.3.3.2. CCPL would minimize long-term impacts to vegetation/habitats where possible through the restoration of pre-construction vegetation in temporarily affected areas.

As the Project would cross through mostly open low-lying vegetation types, large mature trees are not expected to occur within the construction work space for the Project. If present, clearing of mature trees (i.e., trees with a diameter at breast height in excess of 12 inches) would be avoided in temporary workspaces to the extent possible; however, all trees would be removed from within the permanent right-of-way.

There are two HDDs in which Cheniere proposes to utilize up to a 100-foot-wide workspace corridor consisting of an existing permanent easement between HDD entry and exit locations, including between milepost 0.0 to 0.8 (HDD-4) and milepost 1.2 to 1.6 (HDD-1). While Cheniere has stated that these areas are part of their existing permanent easement, we requested that the workspace be depicted on their alignment sheets and HDD plan and profile drawings. Updated alignment sheets and plan and profile drawings[10] still do not identify this workspace. In response to our environmental information requests, Cheniere stated that the workspace proposed for use between milepost 0.0 and 0.8 includes a laydown area that is currently being utilized for the Liquefaction Project and is proposed to continue to be utilized during construction of the Stage 3 Project. As such, no clearing or grading would be conducted within this area, as it is already in industrial use. While the area between milepost 1.2 and 1.6 for the HDD of U.S. Highway 181 has been partially disturbed for industrial use, there are some vegetated areas that Cheniere proposes to clear between the HDD entry and exit locations. Cheniere stated that this area was necessary for ingress and egress to the HDD location. We disagree. Based on aerial imagery and the proposed workspace outside of the HDD entry and exit locations at MP 1.2 and 1.6, sufficient workspace is available for accessing the HDD entry and exit locations. Therefore, **we recommend:**

- **<u>Prior to construction of the Stage 3 Pipeline</u>, CCPL should file with the Secretary, for review and written approval by the Director of OEP, revised alignment sheets and HDD plan and profile drawings that:**
  - **a) removes all workspace, except the minimum amount necessary to place guide wires, between the HDD entry and exit locations at milepost 1.2 and 1.6; and**
  - **b) depicts all workspace necessary for placement and operation of equipment around each HDD entry and exit location, including that proposed to be located within an existing permanent easement.**

Fragmentation of habitats (i.e., the breaking up of contiguous areas of vegetation into smaller patches that become progressively smaller and isolated over time) can occur as a result of linear developments. Because pipeline rights-of-way are revegetated with herbaceous cover and allowed to revegetate with low scrub vegetation, habitat fragmentation by a pipeline right-of-way is primarily a concern only in mature forested habitats. The Stage 3 Pipeline would not cross mature forest habitat and, is not expected to result in significant habitat fragmentation.

[10] The Stage 3 Pipeline alignment sheets and HDD plan and profile drawings are available on the FERC eLibrary website at https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp under accession number 20181130-5214.

CCPL would implement measures from our Plan and Procedures during construction, restoration, and operation of the Stage 3 Pipeline including reseeding, revegetation, and post-construction maintenance and monitoring. Use of these measures would minimize short- and long-term impacts on vegetation within areas disturbed during construction and within the permanent operational right-of-way.

Table B.4.1-2

Habitat/Vegetation Type Affected by Construction and Operation of the Stage 3 Pipeline and Associated Facilities

Habitat Type	Area Affected (acres)					
	Construction [a]			Operation [b]		
	Overlap with Corpus Christi Pipeline [c]	New Disturbance	Total Disturbance	Overlap with Corpus Christi Pipeline [c]	New Disturbance	Total Disturbance
Agricultural Land	173.0	102.3	275.3	51.4	52.2	103.6
Open Land	87.8	22.1	109.9	41.2	12.7	53.9
Bare Ground (i.e., Industrial Land and maintained open land not in industrial use)	89.7	9.3	99.0	6.5	7.0	13.5
Wetland/Open Water	<0.1	<0.1	<0.1	0.0	0.0	0.0
Total	**350.5**	**133.7**	**484.2**	**99.1**	**71.9**	**171.1**

[a] Includes 120-foot-wide construction right-of-way, which includes temporary workspace and permanent operational right-of-way. Also includes additional temporary workspace, Sinton Compressor Station expansion, access roads, and contractor and pipe yards.
[b] Includes permanent operational right-of-way and aboveground facilities.
[c] Indicates the acreage of overlap with the 48-inch-diameter Corpus Christi Pipeline.
[d] Totals may not equal the sum of the addends due to rounding.

Revegetation would be considered successful if the right-of-way surface condition is similar to adjacent undisturbed land, and vegetation has been properly restored. NRCS has provided CCPL recommendations for appropriate seed mixes that would be used during restoration. CCPL would create appropriate mixes based on soil types and landowner input within the affected areas. CCPL would seed affected areas with mixtures shown in table B.4.1-3 following completion of right-of-way to quickly restore vegetation cover in non-agricultural areas.

Table B.4.1-3

Seed Mixtures for the Stage 3 Pipeline

Temporary Seed Mixture	Application Rate (pounds per acre)
Oats – *Avena sativa*	64
Hairy vetch – *Vicia villosa* Roth	16
Foxtail millet – *Setaria italica*	25
Rye - *Secale cereale*	25
Permanent Seed Mixture	**Application Rate (pounds per acre)**
Slender grama - *Dilley germplam*	8
Texas grama - *Atascosa germplasm*	10
Big sacaton - *Falfurrias germplasm*	1
Green sprangletop – *Leptochola dubia*	1.7
shortspike windmill grass - *Welder germplasm*	0.5
Prostrate bundleflower - *Balli germplasm*	5
awnless bushsunflower - *Venado germplasm*	2.6
Orange zexmenia - *Goliad germplasm*	6
Carrizo Blend Little bluestem - *Schizachyrium scoparium* (Michx.) Nash var. *scoparium*	5
Pink Pappusgrass - *Maverick germplasm*	3
False Rhodesgrass - *Kinney germplasm*	1
Multifflower false rhodesgrass - *Hidalgo germplasm*	1
Canada wildrye - *Lavaca germplasm*	10
Hall's panicum - *Oso germplasm*	1
'Eldorado' Engelmann's daisy - *Engelmannia peristenia*	15

Pollinator species, including various birds, bats, bees, butterflies, moths, wasps, flies, and beetles carry pollen from one plant to another as they collect nectar. This process, known as pollination, is important in facilitating plant reproduction, including 75 percent of the most common human food crops. Pollinator populations appear to be declining, with a total of 30 native pollinators species (bees, butterflies, and moths) designated by TPWD as Species of Greatest Conservation Need in Texas. TPWD has developed the *Texas Monarch and Native Pollinator Conservation Plan* (2016a) to conserve habitat, educate the public and continue research and monitoring of native pollinator populations.

In addition, the June 20, 2014 Presidential Memorandum, *Creating a Federal Strategy to Promote the Health of Honey Bees and Other Pollinators*, states that "given the breadth, severity, and persistence of pollinator losses, it is critical to expand Federal efforts and take new steps to reverse pollinator losses and help restore populations to healthy levels." In response to the Presidential Memorandum, the federal

Pollinator Health Task Force published a *National Strategy to Promote the Health of Honey Bees and Other Pollinators* in May 2015. This strategy outlines a process to increase and improve pollinator habitat.

In a letter dated July 9, 2015, TPWD requested that Cheniere reseed disturbed areas with species suitable for pollinator species. Similarly, the FWS also recommended planting for pollinators and consulting with the Texas Plant Materials Center on October 30, 2015. None of the species listed in table B.4.1-3 are included on the TPWD *Management Recommendations for Native Insect Pollinators in Texas* (2016b). In addition, Cheniere has not provided documentation of consultation with the South Texas Plant Materials Center. Therefore, **we recommend that:**

- **Prior to construction of the Stage 3 Pipeline, CCPL should consult with the TPWD and the South Texas Plant Materials Center regarding the suitability of the proposed seed mix for support of pollinator species, and file with the Secretary documentation of its consultations and a final proposed seed mix, for review and written approval by the Director of OEP.**

Based on the amounts and types of vegetation impacted along the pipeline route, the temporary nature of the impacts, and Cheniere's impact minimization measures, we have determined that constructing and operating the Pipeline would not significantly affect vegetation.

4.2 Wildlife

4.2.1 Terrestrial Resources

Stage 3 LNG Facilities

The Stage 3 LNG Facilities site lies within the Tamaulipan Biotic Province, which supports a diverse fauna composed of a mixture of species common in neighboring biotic provinces, including neotropical species from the south, grassland species from the north and northwest, Austroriparian species from the northeast, and some Chihuahuan species from the west and southwest (Blair, 1950). At least 19 species of lizards and 36 species of snakes occur in the Tamaulipan Biotic Province (Blair, 1950) and could potentially occur at the Stage 3 LNG Facilities site. Amphibian species that could occur within the site include Blanchard's cricket frog (*Acnis creptians blanchardi*), Texas toad (*Bufo speciosus*), Great Plains narrowmouth toad (*Gastnophryne olivacea*), and bullfrog (*Rana catesbiana*). Terrestrial reptiles that could occur within the site include the western glass lizard (*Ophisaurus attenuatus attenuatus*), six-lined racerunner (*Cnemidophorus sexlineatus soxlineatus*), keeled earless lizard (*Holbnookiapropinqua propinqua*), Texas spotted whiptail (*Cnemidophonus gulanis*), western coachwhip (*Masticophis flagellum tesaceus*), ground snake (*Sonora semiannulata*), and western diamondback rattlesnake (*Crotalus atrox*). Bird species of the Tamaulipan Biotic Province associated with terrestrial habitats similar to those that occur within the Stage 3 LNG Facilities site include many species of raptors and songbirds (Blair, 1950). At least 61 mammalian species occur or have occurred within recent times in the Tamaulipan Biotic Province (Blair, 1950). Mammals that could occur at the Stage 3 LNG Facilities site include the black-tailed jackrabbit (*Lepus californicus*), feral hogs (*Sus scrofa*), Gulf Coast kangaroo rat (*Dipodomys compactus*), rice rat (*Oryzomys palustris*), fulvous harvest mouse (*Reithrodontomys fulvescens*), raccoon (*Procyon lotor*), striped skunk (*Mephitis mephitis*), and coyote (*Canis latrans*).

Most of the areas that would be disturbed by construction and operation of the Stage 3 LNG Facilities have been previously disturbed (by past industrial activities and/or the Liquefaction Project), with most of the permanent impacts occurring on bare ground. These areas currently serve as poor quality habitat for wildlife. Therefore, construction and operation of the Stage 3 LNG Facilities would have an insignificant impact on wildlife resources through the permanent loss or conversion of currently disturbed/low-quality habitats. Other impacts (e.g., incidental take of wildlife) are expected to be minimal due to the current disturbed nature of the site. For opportunistic species that thrive in disturbed habitats, the areas nearby and/or adjacent to the site provide similar and ample habitats, and wildlife that may be displaced temporarily during or permanently after construction of the Stage 3 LNG Facilities would likely move to these habitats.

To minimize impacts on wildlife, Cheniere selected a highly disturbed site for the Stage 3 LNG Facilities. Cheniere would also implement our Plan and Procedures to avoid or minimize off-site impacts. Additionally, Cheniere would implement recommendations received from TPWD on July 9, 2015 to avoid or reduce impacts on species and habitat of potential concern such as: adhering to the state-listed species avoidance and relocation recommendations detailed in section B.4.4.2; construction contractor education regarding reptile susceptibility to construction impacts during the spring; and establishment and enforcement of speed limits within the construction areas for safety and environmental protection purposes.

Based on the disturbed nature of the Stage 3 LNG Facilities site as well as the characteristics of the wildlife known to occur or potentially occur in the Project area, and CCL Stage III’s implementation of its mitigation measures, we have determined that construction and operation of the Stage 3 LNG Facilities would not significantly impact terrestrial wildlife.

Stage 3 Pipeline

As stated in section B.4.1.2, the Stage 3 Pipeline would cross a variety of vegetation types:

- Bare ground – as this habitat does not support much vegetation, most wildlife would be expected to use or traverse these areas only on occasion;
- Agricultural land – provides food and cover for species such as the northern mockingbird (*Mimus polyglottos),* mourning dove (*Zanaida macrounra*), hispid cotton rat (*Sigmodon hispidus*), and the Great Plains rat snake (*Elaphe guttata emoryi*);
- Open land – supports many species including western glass lizard (*Ophisaurus attenuatus attenuatus*), western coachwhip (*Masticophis flagellum tesaceus*), black-tailed jackrabbit (*Lepus califonicus*), and coyote (*Canis latrans*); and
- Wetlands – PEM wetlands support species including Woodhouse’s toad (*Bufo woodhousii*), diamondback water snake (*Neroida rhombifer*), American widgeon (*Anas americana*), and swamp rabbit (*Sylvilagus aquaticus*).

Impacts on wildlife from construction of the Stage 3 Pipeline Facilities would include displacement, stress, and direct mortality of some less mobile species. These impacts are expected to be short-term and minimal as most of the construction activities for the Stage 3 Pipeline Facilities would occur in previously disturbed agricultural areas. A total of 484.2 acres would be impacted for construction of the Stage 3 Pipeline Facilities, and of that, 171.1 acres would be retained for permanent operation. Areas adjacent to the pipeline would provide similar and ample habitats for wildlife displaced temporarily during construction and permanently after construction. Temporary work areas would be allowed to revegetate, restoring the pre-construction structure and function of affected habitat types. Open habitat with shrub and tree species within the operational right-of-way, would be permanently kept in an herbaceous state, resulting in permanent impacts.

To minimize impacts on wildlife, CCPL would co-locate 99 percent of the Stage 3 Pipeline with the Corpus Christi Pipeline. CCPL would implement our Plan and Procedures to avoid or minimize off-site impacts. CCPL would also implement TPWD recommendations presented in section B.4.1.1, as well as the following TPWD recommendations: use HDD methods to cross Oliver Creek and Chiltipin Creek to avoid direct impact on these waterbodies and their associated riparian areas and inspect trenches left open overnight the following day prior to the commencement of work. If any state-listed species are trapped in the trenches, personnel with proper TPWD authorization would remove the animal. Further, CCPL has committed to use of exclusion fencing in areas occupied by livestock and escape ramps where deemed appropriate. TPWD has stated in a letter dated September 24, 2018 that these measures are acceptable.

Based on the types of available habitat within the Project area and with the implementation of the described mitigation measures, we have determined that construction and operation of the Stage 3 Pipeline would not significantly impact terrestrial wildlife.

4.2.2 Fisheries Resources

Stage 3 LNG Facilities

No direct impacts would occur to fisheries resources during construction and operation of the Stage 3 LNG Facilities. The National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS) stated on May 28, 2015 that the Stage 3 Project would have no effect on Essential Fish Habitat (EFH). Common fish found in the Project area include pinfish (*Lagodon rhomboides*), spot (*Leiostomus xanthurus*), striped anchovy (*Anchoa hepsetus*), and spotted seatrout (*Cynoscion nebulosus*). Hydrostatic test water, spills, and increased ship traffic during operation of the Project could indirectly impact fisheries resources as further discussed below.

Hydrostatic Test Water

As discussed in section B.3.2.1, a biocide consisting of sodium hypochlorite (bleach) would be utilized during hydrostatic testing of the LNG storage tanks. Sodium hypochlorite is toxic to freshwater fish and invertebrates; however, when it is exposed to sunlight and organic matter, it breaks down into non-toxic compounds (EPA, 1991; GreenFacts, 2017). In sea water, chlorine levels decline rapidly, but hypobromite (which is toxic to aquatic organisms) is formed (EPA, 1991). To minimize potential impacts on aquatic resources as a result of discharge of hydrostatic test water treated with sodium hypochlorite, CCL Stage III would permit the discharge of hydrostatic test water through the National Pollutant Discharge Elimination System permit process. This process is cited by the EPA as the primary method to ensure that discharge of sodium hypochlorite would not pose significant adverse effects (EPA, 1991). Therefore, we conclude that impacts on fisheries and other aquatic resources resulting from construction of the Stage 3 Facilities would not be significant.

Spills

During construction and operation, hazardous materials resulting from spills or leaks entering the La Quinta Channel could have adverse impacts on aquatic resources. The impacts would be caused by either the physical nature of the material (e.g., physical contamination and smothering) or by its chemical components (e.g., toxic effects and bioaccumulation). These impacts would depend on the depth and volume of the spill, as well as the properties of the material spilled. To prevent spills and leaks, CCL Stage III would implement the SPCC Plan during construction and operation, which outlines potential sources of releases at the site, measures to prevent a release, and initial responses in the event of a spill. Increased vessel traffic during construction and operation of the Project would also result in an increased potential for spills of hazardous materials. However, all ships are required to maintain a Shipboard Oil Pollution Emergency Plan to minimize impacts on aquatic resources. Given the impact minimization and mitigation measures described above, we conclude that the probability of a spill of hazardous materials is small and any resulting impacts on aquatic resources would be temporary and not significant.

Ballast Water

LNGCs arriving at the Project could include the largest presently existing (Q-Max class) LNGCs with capacities of approximately 267,000 cubic meters and with the capacity to discharge approximately 9 to 30 million gallons of ballast water at a rate up to 1.7 million gallons per hour.

Ballast discharge could impact water quality, fish, and other aquatic organisms. The general characteristics of the discharged ballast water would be very similar to that of the water pumped aboard each LNGC during the mandatory ballast water exchange operation. The location, weather, and existing tidal/current conditions where this ballast water exchange would take place would determine the unique characteristics of the ballast seawater aboard each LNGC upon its arrival at the marine berth. Discharge of ballast water could result in temporary and localized changes in salinity and temperature which could have minor impacts on aquatic species in the vicinity. Ballast discharge could also result in the introduction of nonindigenous aquatic species which could also impact fish and other aquatic organisms.

The Coast Guard's ballast water management regulations (33 CFR 151.2025 and 46 CFR 162) established a standard for the allowable concentration of living organisms in ships' ballast water discharged into waters of the U.S. The Coast Guard also established engineering requirements and an approval process for ballast water treatment systems installed on ships. All ships calling on U.S. ports must either carry out open sea exchange of ballast water or ballast water treatment, in addition to fouling and sediment management and document these activities in the ship's log book. In 2017, the International Convention for the Control and Management of Ships' Ballast Water and Sediments developed measures that must be implemented to minimize the potential for introduction of non-native species through ballast water. These measures have since been adopted by the International Maritime Organization (IMO) and are required to be implemented in all ships engaged in international trade. While the open sea exchange of ballast water has been used in the past and reduces the potential for non-native species introductions, on-board ballast water treatment systems are more effective at removing potential non-native species from ballast water. There are two different standards that ships must meet. All new ships must meet the "D-2" performance standard, which establishes the maximum number of viable organisms allowed to be discharged in ballast water. Conformity with the D-2 standard requires ships to utilize on-board ballast water treatment systems. Existing ships that do not currently have on-board ballast water treatment systems must continue to, at a minimum, conduct open sea exchanges of ballast water ("D-1" standard). Eventually, all ships will be required to conform with the D-2 standard. The timetable for conformity with the D-2 standard for existing ships is based on the date of the ship's International Oil Pollution Prevention Certificate renewal survey, which occurs every five years (International Maritime Organization, 2017). Therefore, most ships calling on the Project, estimated to begin in 2023 at the earliest, would be expected to have conformed to D-2 standards.

Cheniere would have no authority over the operations of LNGCs visiting the Project. However, to minimize and avoid potential impacts on marine species that could result from ballast water discharges, Cheniere would request that visiting vessels provide documentation to demonstrate their compliance with ballast water regulations and BMPs.

Cooling Water

While at the berth, LNGC engines would only run generators as a power source, which do not require the same magnitude of power that must be generated for underway propulsion purposes. Therefore, significantly less cooling water is required during this type of operation than while the LNGC is underway.

While at the marine berth ship cooling water would be withdrawn and discharged below the water line on the sides of the ship through screened water ports, also known as "sea chests." Water intakes could result in the impingement and entrainment of fish as well as ichthyoplankton (fish eggs and larvae). These actions could impact the rates of stress, injury and/or mortality experienced by fish. Screens on the sea chests would minimize these impacts and reduce rates of water withdrawal and discharge.

Cooling water use by LNGCs would vary depending on vessel type and size. Based on other FERC-evaluated LNG projects, rate of cooling water use by LNGCs could range from about 1,250 to 9,800 m^3/hour (330,000 to 2,600,000 gallons/hour; see the Jordan Cove Environmental Impact Statement (EIS) [FERC, 2009; FERC, 2015] as well as the Broadwater EIS [FERC, 2008]). Loading time when cooling pumps would be in operation at the marine berth based on other LNG projects would likely range from about 18 to 30 hours. Based on the range of these values, cooling water use and resulting discharge to the bay could range from 5.9 million to 52 million gallons during each vessel loading trip. The main water discharge from the LNGCs while at dock would be heated condenser cooling water. Based upon similar LNGCs in operation, the change in water temperature is anticipated to range from 2.7 degrees F to 7.2 degrees F (see section B.3.2.1). These elevated levels may be harmful to marine organisms that are located directly within the heated water discharge plume. However, considering the large volume of the adjacent bay water, water temperatures would rapidly dilute and equilibrate with adjacent water, and this impact would be temporary, occurring only during the estimated 18 to 30 hours required to load an LNGC. Additionally, most mobile organisms that could experience an elevated temperature could actively avoid or move out of the limited zone. As a result, we conclude that there would be no substantial effects on marine organisms from elevated temperatures resulting from the discharge of cooling water from LNGCs while at the marine berth for the Project.

Stage 3 Pipeline

The Stage 3 Pipeline would cross eight waterbodies. No fisheries of special concern, state or federally listed threatened and endangered species, or fish of significant commercial and recreational value have been identified as potentially occurring in waterbodies that would be crossed by the Stage 3 Pipeline. Common fish found in Project area waters include, inland silverside (*Menidia beryllina*), western mosquitofish (*Gambusia affinis*), bluegill (*Lepomis macrochirus*), and red shiner (*Cyprinella lutrensis*) (Fishes of Texas, 2018). Construction of the Stage 3 Pipeline would result in the temporary loss of aquatic habitat, disturb the stream bed, and increase turbidity and sedimentation. The loss of habitat and localized changes to water quality could increase the amount of stress, injury and mortality experienced by fish in waterbodies crossed by the Stage 3 Pipeline. CCPL would avoid and/or minimize clearing of vegetation along creeks and manmade drainages to the extent practical during construction.

CCPL would cross the two largest waterbodies, Oliver Creek and Chiltipin Creek, as well as two smaller waterbodies by HDD and would use measures and BMPs contained in our Plan and Procedures, as well as the *Horizontal Directional Drill Procedures and Inadvertent Return Plan*, to avoid and minimize impact on waterbodies and aquatic resources.

As discussed in section B.3.2.2, HDD drilling mud consists primarily of water mixed with bentonite. Bentonite by itself is essentially non-toxic; however, bentonite can act like a fine particulate sediment in water, which could affect aquatic resources in the area around an inadvertent return. CCPL would utilize MaxGel (or equivalent viscosifier), which is nonhazardous and primarily comprised of silica and gypsum. Silica and gypsum are only known to be hazardous to animals if inhaled when airborne. Because the MaxGel would be mixed with water, no direct impacts on wildlife or aquatic resources from the MaxGel are anticipated in the event of an inadvertent return. If an inadvertent return of drilling mud occurs in a wetland or waterbody, most aquatic organisms would be able to avoid or move away from the affected area. However, drilling mud from an inadvertent return that accumulates on the waterbody bottom could cover benthic organisms and estuarine food sources (resulting in mortality or a reduction in local food availability).

CCPL would minimize the potential for an inadvertent return of drilling mud by implementing measures outlined in section B.1.2.2, such as monitoring of drilling mud returns and downhole pressures. Further, CCPL would comply with the measures outlined in its *Horizontal Directional Drill Procedures and Inadvertent Return Plan* to address potential impacts resulting from a release of drilling mud during an HDD crossing, as discussed in section B.3.3.2.

Based on the characteristics of the fisheries contained within the eight waterbodies that would be crossed, CCPL's use of HDDs to cross Oliver and Chiltipin creeks, and its implementation of impact minimization measures as described in our Procedures, we have determined that constructing and operating the Pipeline facilities would not significantly impact fisheries.

4.2.3 Marine Mammals

The Stage 3 Project would include an anticipated increase in the maximum marine vessel traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year. A number of marine mammals are commonly observed in the Gulf of Mexico. Some species have a great affinity to coastal, inshore waters, while others are more commonly observed offshore in deeper, pelagic waters. Many species are also commonly observed in shipping channels in Texas and Louisiana; the most common and prolific being the bottlenose dolphin. The *Marine Mammal Protection Act* of 1972 serves to protect all marine mammals, both in coastal waters and on the high seas. Twenty-nine species of marine mammals have been observed in the Gulf of Mexico, five of which are also listed as threatened or endangered by the FWS and NMFS (table B.4.2-1).

Table B.4.2-1

Marine Mammals that Have Been Observed in the Gulf of Mexico

Common Name	Scientific Name
North Atlantic Right Whale [a]	*Eubalaena glacialis*
Humpback Whale (Mexico Distinct Population Segment) [b]	*Megapetra novaeangliae*
Fin Whale [a]	*Balaenoptera physalus*
Sei Whale [a]	*Balaenoptera borealis*
Minke Whale	*Balaenoptera acutorostrata*
Blue Whale [a]	*Balaenoptera musculus*
Sperm Whale [a]	*Physeter macrocephalus*
Dwarf Sperm Whale	*Kogia simus*
Pygmy Sperm Whale	*Kogia breviceps*
Killer Whale [b]	*Orcinus orca*
Pygmy Killer Whale	*Feresa attenuate*
Goose-Beaked Whale	*Ziphius cavirostris*
Gervais' Beaked Whale	*Mesoplodon europaeus*
Blainville's Beaked Whale	*Mesoplodon densirostris*
Sowerby's Beaked Whale	*Mesoplodon bidens*
Bryde's Whale [a]	*Balaenoptera edeni*
Short-finned Pilot Whale	*Globicephala macrorhynchus*
False Killer Whale [b]	*Pseudorca crassidens*
Melon-headed Whale	*Peponocephala electra*

Table B.4.2-1 Marine Mammals that Have Been Observed in the Gulf of Mexico	
Common Name	**Scientific Name**
Atlantic Spotted Dolphin	*Stenella frontalis*
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*
West Indian Manatee	*Trichechus manatus*

[a] Indicates species under the jurisdiction of NMFS (2017).

[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.

Potential Impacts and Mitigation

Increased marine traffic could potentially affect marine mammals through vessel strikes and spills of hazardous materials, as well as impacts related to vessel usage of ballast and cooling water. Impacts resulting from spills of hazardous materials and ballast and cooling water exchanges would be similar to that discussed in section B.4.2.2 for fisheries resources.

Vessel Strikes

Vessel traffic can result in strikes with marine species, which can cause mortality or injury events, increased stress levels, or avoidance of the area by marine species. Due to their preference for offshore waters and their relative rarity in Texas waters, the occurrence of federally listed whales 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 highly mobile wildlife. To minimize potential vessel strikes, Cheniere 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 and Reporting for Mariners* (2008). LNGC operators trading at terminals in North America are also familiar with the now long-existing measures identified by NMFS.

Cheniere would also implement additional measures designed to avoid or minimize vessel strikes of the West Indian manatee in nearshore waters within Corpus Christi Bay. Training would be provided to all personnel involved in marine operations associated with the Stage 3 LNG Facilities about ways to avoid potential impacts on the West Indian manatee. This training would include: 1) information advising that manatees may be found in the La Quinta Ship Channel; 2) materials, such as a poster, to assist in identifying the species; 3) instructions not to feed or water the animal; and 4) directions to call the Corpus Christi Ecological Services Field Office of the FWS in the event that a manatee is sighted in or near the Project area.

Due to the minor increase in LNGC traffic and implementation of vessel strike avoidance measures and reporting requirements we conclude impacts to marine mammals or sea turtles would not be significant.

4.3 Migratory Birds

Migratory birds follow broad routes called flyways between breeding grounds in the north and wintering grounds in the tropical regions of Mexico, Central and South America, and the Caribbean for the non-breeding season. Some species migrate from breeding areas in the north to the Gulf Coast for the non-breeding season. South Texas and the Gulf of Mexico are part of the Central Flyway, an important pathway for migratory birds, with many coastal and marine species using the coastlines of Louisiana and Texas during migration (FWS, 2018b; Central Flyway Council, 2018). The vegetation communities within the Project area provide potential habitat for a wide variety of migratory bird species including songbirds, waterbirds, and raptors. Migratory birds are federally protected under the MBTA. The MBTA (16 USC 703-711) as amended, implements protections for many native migratory game and non-game birds, with exceptions for the control of species that cause damage to agricultural or other interests. The MBTA prohibits the take of any migratory bird or their parts, nest, and eggs, where "take" means to "pursue, hunt, shoot, wound, kill, trap, capture, or collect." In addition to the MBTA, the BGEPA provides additional protection to bald and golden eagles. Non-breeding or wintering bald eagles could occur in the Project area because it provides suitable foraging habitat with abundant food sources of fish and waterfowl.

Executive Order 13186 requires all federal agencies undertaking activities that may negatively affect migratory birds to take a prescribed set of actions to further implement the MBTA, and directs federal agencies to develop a memorandum of understanding (MOU) with the FWS that promotes the conservation of migratory birds. FERC entered into a MOU with the FWS in March 2011. The focus of the MOU is on avoiding or minimizing adverse impacts on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the two agencies.

Though all migratory birds are afforded protection under the MBTA, both Executive Order 13186 and the MOU require that Birds of Conservation Concern (BCC) and federally listed species be given priority when considering effects on migratory birds. BCCs are a subset of MBTA-protected species identified by FWS as those in the greatest need of additional conservation action to avoid future listing under the ESA. Priority landbirds are species noted by the Partners in Flight cooperative effort as species of "continental concern." Partners in Flight was formed in 1990, as a cooperative effort between federal, state, local agencies, conservation groups, industry, and academic institutions. In 2016, they released a revision of their Landbird Conservation Plan, which details species of "continental concern", which would be listed as Priority landbirds (Rosenberg et al. 2016). Executive Order 13186 states that emphasis should be placed on species of concern, priority habitats, key risk factors, and that particular focus should be given to addressing population-level impacts. BCCs and Priority landbirds potentially occurring in the Project sites are outlined in table B.4.3-1.

Table B.4.3-1

Priority Landbird Species Potentially Occurring in San Patricio County

Common Name	Scientific Name	Potential to Occur
Audubon's Shearwater	*Puffinus lherminieri*	Non-breeding
Band-rumped Storm-Petrel	*Oceanodroma castro*	Non-breeding
American Bittern	*Botaurus lentiginosus*	Breeding
Least Bittern	*Ixobrychus exilis*	Breeding
Reddish Egret	*Egretta rufescens*	Breeding
Swallow-tailed Kite	*Elanoides forficatus*	Breeding

Table B.4.3-1

Priority Landbird Species Potentially Occurring in San Patricio County

Common Name	Scientific Name	Potential to Occur
Bald Eagle	*Haliaeetus leucocephalus*	Breeding
White-tailed Hawk	*Geranoaetus albicaudatus*	Breeding
Peregrine Falcon	*Falco peregrinus*	Non-breeding
Yellow Rail	*Coturnicops noveboracensis*	Non-breeding
Black Rail	*Laterallus jamaicensis*	Breeding
Snowy Plover	*Charadrius nivosus*	Breeding
Wilson's Plover	*Charadrius wilsonia*	Breeding
Mountain Plover	*Charadrius montanus*	Non-breeding
American Oystercatcher	*Haematopus palliatus*	Breeding
Solitary Sandpiper	*Tringa solitaria*	Non-breeding
Lesser Yellowlegs	*Tringa flavipes*	Non-breeding
Upland Sandpiper	*Bartramia longicauda*	Non-breeding
Whimbrel	*Numenius phaeopus*	Non-breeding
Long-billed Curlew	*Numenius americanus*	Breeding
Hudsonian Godwit	*Limosa haemastica*	Non-breeding
Marbled Godwit	*Limosa fedoa*	Non-breeding
Red Knot	*Calidris canutus*	Non-breeding
Buff-breasted Sandpiper	*Calidris subruficollis*	Non-breeding
Short-billed Dowitcher	*Limnodromus griseus*	Non-breeding
Gull-billed Tern	*Gelochelidon nilotica*	Breeding
Least Tern	*Sternula antillarum*	Breeding
Sandwich Tern	*Thalasseus sandvicensis*	Breeding
Black Skimmer	*Rynchops niger*	Breeding
Short-eared Owl	*Asio flammeus*	Non-breeding
Loggerhead Shrike	*Lanius ludovicianus*	Breeding
Sedge Wren	*Cistothorus platensis*	Non-breeding
Sprague's Pipit	*Anthus spragueii*	Non-breeding
Prothonotary Warbler	*Protonotaria citrea*	Breeding
Swainson's Warbler	*Limnothlypis swainsonii*	Breeding
Botteri's Sparrow	*Peucaea botterii*	Breeding
Grasshopper Sparrow	*Ammodramus savannarum*	Breeding
Henslow's Sparrow	*Centronyx henslowii*	Non-breeding
Le Conte's Sparrow	*Ammospiza leconteii*	Non-breeding
Nelson's Sharp-tailed Sparrow	*Ammospiza caudacuta*	Non-breeding
Seaside Sparrow	*Ammospiza maritima*	Breeding
Painted Bunting	*Passerina ciris*	Breeding
Dickcissel	*Spiza americana*	Breeding
Source: FWS 2008; Rosenberg et al. 2016		

The Project would be located in the Gulf Coastal Prairie Bird Conservation Region (BCR) 37. This is one of eight regions designated in Texas as part of the North America Bird Conservation Initiative in order to provide a framework that would facilitate coordinated conservation and evaluations of major bird initiatives. Overall, this BCR features one of the greatest concentrations of colonial waterbirds in the world, with breeding reddish egret, roseate spoonbill, brown pelican, and large numbers of herons, egrets, ibis, terns, and skimmers (FWS, 2000). This BCR also provides critical in-transit habitat for migrating shorebirds, including Whimbrel and Hudsonian Godwit, and for most of the neotropical migrant forest birds of eastern North America (using both the Central and the Mississippi Flyways).

A bird colony is a group of birds nesting together at the same place and the same time. Several species in the Project region are considered colonial birds, including the state threatened reddish egret (*Egretta rufescens*); however, there is no suitable nesting habitat within the Project area for colonial nesting birds. In addition, Cheniere would conduct all clearing activities outside of the nesting season.

Cheniere is committed to employing BMPs to avoid impacting migratory birds during construction and operation. These practices could include the following: 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 compound, and marking guy wires (if utilized) with visual markers/bird diverters. These measures would reduce the likelihood of avian collisions with structures as well as the likelihood of disturbing individuals found in adjacent habitats, which includes minimizing impacts to ground nesting birds. Based on these measures, we conclude the Project would have no significant impact on migratory bird populations. Additionally, Cheniere would implement recommendations received from TPWD on July 9, 2015 to avoid or reduce impacts on migratory birds such as adhering to state-listed species avoidance and relocation requirements and construction contractor education regarding potential for encountering wintering and/or nesting migratory birds.

4.3.1 Stage 3 LNG Facilities

Disturbance from construction of the Stage 3 LNG Facilities could result in some migratory birds avoiding construction areas. Impacts on migratory birds from construction and operation of the Stage 3 LNG Facilities are expected to be minimal because the site is highly industrialized, although the existing DMPA may provide some marginal habitat. The high amount of activity on the properties surrounding the site would likely limit the extent of migratory bird use of these marginal habitats, and avian species would be more likely to use other less disturbed habitats in the general area. The new LNG storage tank and other structures at the site would be easily visible to avian species and it is likely that avian species would avoid the tank and structures while in flight; however, some limited avian impacts during flight could occur with the LNG storage tank and flares (which could result in individual avian mortalities). Flaring from the elevated flares would be minimized to the extent practical, and flaring would be conducted as needed to ensure the safe operation of the Stage 3 LNG Facilities. Cheniere would implement measures to avoid or minimize the risk of avian collisions with project structures, as well as minimize the potential impacts associated with loss of marginal habitats.

To further reduce impacts, Cheniere proposes to clear woody vegetation outside of the peak bird nesting season between March 1 and August 31. If vegetation clearing must occur during the nesting season, Cheniere would survey areas to be cleared for active nests, and if found, would avoid clearing within the TPWD recommended buffer of 150-feet until the young have fledged or the nest is abandoned.

4.3.2 Stage 3 Pipeline

The primary impact on migratory birds from the Stage 3 Pipeline would be from construction activities, primarily right-of-way clearing. Impacts would be the greatest if right-of-way clearing occurred during the breeding season. However, because most habitats that would be crossed by the Stage 3 Pipeline are active agricultural lands, these impacts are expected to be minor. If adult birds must move from the right-of-way to avoid temporary construction, this impact would be of limited duration and would not result in substantial or long-term impacts on migratory birds. The linear nature of the Stage 3 Pipeline and the use of previously and continually disturbed areas would minimize impacts on migratory bird species. This would not constitute a population-level impact given the stability of local populations and the abundance of available habitat outside of the Stage 3 Pipeline right-of-way.

Due to the relatively short duration of construction activities, the current use of the area, and implementation of the BMPs described above to reduce impacts on migratory birds, impacts on migratory birds from construction and operation of the Project would not be significant.

As discussed above for the Stage 3 LNG Facilities, as a measure to further protect any migratory birds that may be found along the Stage 3 Pipeline route, CCPL would avoid clearing woody vegetation during the peak nesting period between March 1 and August 31 of any year. If vegetation clearing must be conducted during this time, CCPL would survey for migratory bird nests no more than three weeks prior to commencing work. If an active migratory bird nest is found, CCPL would consult with the FWS to identify the most appropriate measures to be taken to avoid or minimize impacts on migratory birds.

4.4 Special Status, Threatened, and Endangered Species

Federal agencies are required under Section 7 of the ESA, as amended, to ensure that any actions authorized, funded, or carried out by the agency would not jeopardize the continued existence of a federally listed endangered or threatened species, or result in the destruction or adverse modification of the designated critical habitat of a federally listed species.

As the lead federal agency authorizing the Project, FERC is required to consult with FWS and/or NMFS, to determine whether federally listed threatened or endangered species or designated critical habitat are found in the vicinity of the Project, and to evaluate the proposed action's potential effects on those species or critical habitats. The project sponsor is designated as FERC's non-federal representative for purposes of initial coordination and informal consultation with the FWS and NMFS. In compliance with ESA, Cheniere has been assisting the FERC in meeting its Section 7 obligations by conducting informal consultations with the FWS and NMFS about species under their jurisdictions that would be potentially affected by the Project. In addition, Cheniere also consulted with the TPWD. TPWD, under TAC Title 31, Part 2, Chapter 68, lists species threatened with statewide extinction, and Chapter 65 prohibits take of a state listed fish or wildlife species. A summary of consultations with TPWD are provided in section B.4.4.2.

4.4.1 Federally Listed Species

Fourteen species are federally listed as threatened or endangered in San Patricio County, including four marine mammals, two mammals, four birds, and five turtles (table B.4.4-1). In addition, two species, the black rail and Gulf of Mexico Bryde's whale, are proposed for listing as threatened and endangered, respectively, and one species, the golden orb mussel, is a candidate species for listing. Suitable habitat was identified in the Project area for all but three of these species, the Gulf Coast jaguarundi, ocelot and eastern black rail; therefore, the Project would have *no effect* on these species. The proposed Project is *not likely to adversely affect* the remaining species through the implementation of minimization and avoidance measures proposed by Cheniere.

Cheniere would utilize EIs during all phases of construction. The EIs would be trained to identify threatened or endangered (T&E) species. In addition, all construction staff would receive general environmental training that would include awareness of the potential for T&E species thought to occur in the area. If any T&E species are observed in the immediate Project area during active construction, the EIs, along with the Cheniere environmental leads, would determine if there is a need for any special avoidance or minimization measures. The EIs also have stop work authority in the instance of T&E occurrence.

Table B.4.4-1

Federally Listed Species within San Patricio County, Texas

Species	Status	Preferred Habitat	Effect Determination	Justification
West Indian Manatee (*Trichechus manatus*)	Threatened	Warm, shallow coastal waters, estuaries, bays, rivers, and lakes.	May affect, not likely to adversely affect	Suitable Habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Fin Whale (*Balaenoptera physalus*)	Endangered	Deep waters of the continental shelf	May affect, not likely to adversely affect	Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.
Sei Whale (*Balaenoptera borealis*)	Endangered	Deep waters of the continental shelf.	May affect, not likely to adversely affect	Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.
Sperm Whale (*Physeter macrocephalus*)	Endangered	Deep waters of the continental shelf.	May affect, not likely to adversely affect	Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.
Gulf of Mexico Bryde's Whale (*Balaenoptera edeni*)	Proposed Endangered	Deep waters of the continental shelf.	May affect, not likely to adversely affect	Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.
Gulf Coast Jaguarundi (*Herpailurus (=Felis) yagouaroundi cacomitli*)	Endangered	Dense, thorny brushlands, chaparral.	No effect	Surveys of the Project area found semi-suitable habitat, however San Patricio county is out of the species current known range. The species is believed to be extirpated from San Patricio County.
Ocelot (*Leopardus (=Felis) paradalis*)	Endangered	Large acreages of dense, thorny brush, mesquite-oak and oak forests and partially cleared land with high canopy cover.	No effect	Surveys of the Project area found semi- suitable habitat, however the habitat is small and isolated. The ocelot is not known to inhabit this part of San Patricio county.
Piping Plover (Charadrius melodus)	Threatened	Beaches, mudflats, and sandflats.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Rufa Red Knot (Calidris canutus rufa)	Threatened	Shoreline habitat.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.

Table B.4.4-1

Federally Listed Species within San Patricio County, Texas

Species	**Status**	**Preferred Habitat**	**Effect Determination**	**Justification**
Whooping Crane (*Grus americana*)	Endangered	Brackish marshes, bays, and flats in winter.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Eastern Black Rail (*Laterallus jamaicensis jamaicensis*)	Proposed Threatened	Saltgrass marsh.	No effect	Suitable habitat is not present within the Project area.
Green Sea Turtle (*Chelonia mydas*) North Atlantic DPS	Threatened	Gulf and bay systems, shallow water seagrass beds, jetties, and open water.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Hawksbill Sea Turtle (*Eretmochelys imbricata*)	Endangered	Gulf and bay systems, warm, shallow waters, especially in rocky marine environments, jetties and coral reefs.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Kemp's Ridley Sea Turtle (*Lepidochelys kempii*)	Endangered	Gulf and bay systems.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Leatherback Sea Turtle (*Dermochelys coriacea*)	Endangered	Gulf and bay systems.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Loggerhead Sea Turtle (*Caretta caretta*)	Threatened	Gulf and bay systems.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.
Golden Orb (*Quadrula aurea*)	Candidate	Flowing waters in moderately sized rivers in substrates of firm mud, sand, and gravel.	May affect, not likely to adversely affect	Suitable habitat is present within the Project area. Effects are expected to be discountable or insignificant.

Marine Mammals

Potential impacts on marine mammals as a result of the Stage 3 Project would result from the increase in LNGC vessel traffic (by up to 100 round trip LNGC transits per year over the 300 roundtrip transits authorized for the Liquefaction Project) which could potentially affect listed species through vessel strikes, as well as impacts related to vessel's usage of ballast and cooling water. As discussed in section B.4.2.3, measures would be taken to minimize the risk of vessel strikes with marine mammals, as well as measures to minimize the effects of ballast and cooling water on marine life. As a result, the Project may affect, but is not likely to adversely affect federally listed marine mammals. Below is a summary of the marine mammals that could be impacted by the Project.

West Indian Manatee

The West Indian manatee is federally listed as threatened and state-listed as endangered. Manatees are found in rivers, estuaries, and coastal areas of the tropical and subtropical New World from the southeastern United States coast along Central America and the West Indies to the northern coastline of South America. They occur mainly in larger rivers and brackish water bays. They are extremely rare in Texas and have been sighted in Corpus Christi Bay, Laguna Madre, Cow Bayou, near Sabine Lake, Copano Bay, Bolivar Peninsula, and the mouth of the Rio Grande (Texas Tech University, 1997). Hunting of manatees was first responsible for the decline of their populations but manatees now face danger from collisions with power boats, entrapment in floodgates, navigation locks, fishing nets, and water pipes. Loss of warm water habitat along with ingestion of marine debris is also a threat to the continued survival of the West Indian Manatee. While manatees have been observed in the Project vicinity, sightings are very rare and typically involve only a single animal that vacates the region relatively quickly. Cheniere would implement the measures recommended by the FWS described in section B.4.2.3. As a result, the Project may affect, but is not likely to adversely affect this species.

Sperm Whale

The sperm whale is a toothed whale that inhabits the deeper waters of the world's oceans throughout the year, where they feed primarily on squid and other deep sea creatures. Migrations are not as distinct as other species and are thought to primarily follow food resources (NMFS, 2010a). Sperm whales are present in the northern Gulf of Mexico in all seasons, but are more common during the summer months (NMFS, 2014). The sperm whale is the only federally listed whale that is known to commonly occur in the Gulf of Mexico (NMFS, 2012) and the only whale with a measurable injury rate due to vessel strikes in the Gulf of Mexico (NMFS, 2018). As discussed in section B.4.2.3, vessel strikes would be minimized by the LNGCs implementing measures outlined in the NMFS *Vessel Strike Avoidance Measures and Reporting for Mariners* (2008). In addition, LNGCs would be required to maintain a Shipboard Oil Pollution Emergency Plan to minimize impacts on aquatic resources from spills. Therefore, we have determined that the Project may affect, but is not likely to adversely affect sperm whales.

Baleen Whales

Baleen whales, including the fin whale, sei whale, and the Gulf of Mexico Bryde's whale that was recently proposed for listing, are listed by NMFS as occurring within the southeast region. These whales are not commonly found in the Gulf of Mexico, but could occur within the area during migrations or other movements (NMFS, 2012). Feeding is not expected in or around the Gulf of Mexico as these species usually feed on zooplankton and small fish aggregations during summer months in the northern Atlantic Ocean (NMFS, 1998, 2010b, 2011). Calving and breeding grounds have not been identified for these species in the Gulf of Mexico. Impacts on federally listed baleen whales would be minimized through the implementation of measures similar to those discussed above for the sperm whale. Therefore, we have determined that the Project may affect, but is not likely to adversely affect federally listed baleen whales.

Birds

Potential impacts on birds as a result of the Stage 3 Project and associated measures to minimize impacts are discussed in section B.4.3, including clearing outside of the primary nesting season of March 1 to August 31. Below is a summary of the listed bird species that could be impacted by the Project.

Piping Plover

The piping plover is listed as threatened by both the FWS and the TPWD. Shorebird hunting during the early 1900s caused the first known major decline of piping plovers (Bent, 1929). Since then, loss or modification of habitat resulting from commercial, residential, and recreational developments, dune stabilization, damming and channelization of rivers (eliminating sandbars, encroachment of vegetation, and altering water flows), and wetland drainage have further contributed to the decline of the species. Additional threats include human disturbances through recreational use of habitat, and predation of eggs by feral pets. Piping plovers typically inhabit shorelines of oceans, rivers, and inland lakes. Nest sites include sandy beaches, especially where scattered tufts of grass are present; sandbars; causeways; bare areas on dredge-created and natural alluvial islands in rivers; gravel pits along rivers; silty flats and salt-encrusted bare areas of sand, gravel, or pebbly mud on interior alkali lakes and ponds. On the wintering grounds, these birds use beaches, mudflats, sandflats, dunes, and off-shore spoil islands.

The piping plover begins arriving at its post-breeding and wintering grounds in Texas in mid to late July. Haig and Oring (1985) found that early in the post-breeding season, piping plovers frequented beaches, but later tended to inhabit ephemeral sand flats along the backside of barrier islands. Observations of wintering piping plovers in Alabama did not indicate a seasonal preference between habitats, although wintering plovers spent more than 85 percent of their time on sand flats or mud flats each month (Johnson and Baldassarre, 1988). Along the Texas coast, a correlation appears to exist between tidal height and habitat selection, with piping plovers actively feeding on tidal flats during periods of low tides, and on the Gulf beaches during high tides (Eubanks, 1991; Zonick, et al., 1998; Drake et al., 2000).

A designated Critical Habitat unit is located along Highway 181 southwest of Portland, TX, less than 5 miles from the Project workspace; however, construction and operation actions would not disturb piping plovers using this unit. The piping plover habitat on the Project location is relatively small when compared to the abundance of habitat in the immediate vicinity. Construction activities therefore may result in piping plovers seeking refuge in nearby area habitats. We determine that the Project may affect, but is not likely to adversely affect the piping plover.

Red Knot

The red knot is listed as threatened by the FWS. Because this species depends on suitable habitat, food, and weather conditions at far-flung sites across the Western Hemisphere (i.e., from Tierra del Fuego in Argentina to the central Canadian Arctic), it can be sensitive to changes in habitat, food availability, and weather conditions within narrow seasonal windows as this bird migrates between wintering and breeding areas. Red knots may also be sensitive to alterations related to climate change, which can affect the arctic tundra ecosystem where the knots breed; coastal habitats (due to rising sea levels) where the knots stop-over during migration; food resources throughout the species range; and storm and weather patterns and severity levels. The red knot habitat on the Project location consists of a small beach area adjacent to the marine berth and is relatively small when compared to the abundance of preferable habitat in the immediate vicinity. As this Project would impact areas adjacent to the shoreline (about 1.5 miles away) but not directly within shoreline habitats or in areas that would be considered suitable habitat for this species, this project may affect, but is not likely to adversely affect this species.

Whooping Crane

The whooping crane is listed as endangered by both the FWS and the TPWD. The main threat to whooping cranes in the wild is the potential of a hurricane or contaminant spill destroying their wintering habitat on the Texas coast. Collisions with power lines and fences are known hazards to wild whooping cranes. The whooping crane has been recorded in San Patricio County, and may potentially access waters on the bay side and interior of Mustang and Padre Islands, which is located outside the Project area.

While the whooping crane has been recently sighted in San Patricio County, such occurrences are rare. Given its rarity and suitable habitat only in waters on the leeward side of nearby barrier islands (located outside of the Project area), this project may affect, but is not likely to adversely affect this species.

Eastern Black Rail

The eastern black rail (*Laterallus jamaicensis jamaicensis*) is one of four subspecies within the Americas. It is partially migratory, with the northern most portion of the population migrating to the southern breeding grounds for the winter (FWS, 2018a). The eastern black rail inhabits marshes that can range in salinity from salt to fresh, and be tidally or non-tidally influenced. Along the migratory routes, the rail can be found in wet sedge meadows and shallow wetlands dominated by cattails (FWS, 2018b). A year-round resident of the Texas coast, the eastern black rail utilizes saltgrass marshes for breeding, feeding, and sheltering. Historically found along the Atlantic Coast, only Texas and Florida remain as population strongholds, with recent surveys indicating a population of around 1,300 individuals along the upper Texas Coast (FWS, 2018a).

In October 2018, the FWS proposed the eastern black rail for listing as threatened under the ESA, with no critical habitat. Threats to the species include invasive species, fire suppression, sea-level rise, and human modification of habitat (FWS, 2018b). No suitable habitat is present within the Project area. Given its rarity and lack of habitat within the Project area, the Project would have no effect on this species.

Marine Reptiles

Green Sea Turtle

The North Atlantic distinct population segment (DPS) of the green sea turtle is listed as threatened by the federal and state government. Green sea turtles inhabit shallow waters with an abundance of marine algae and seagrasses. They prefer lagoons, bays, inlets, shoals, and estuaries. They use coral reefs and rocky outcrops near feeding areas to rest, and they feed on marine plants, mollusks, sponges, crustaceans, and jellyfish. They tend to nest on their natal beach (NMFS, 2004; COE, 2003b). Commercial harvest of eggs as food, collection of body parts to be used for leather and jewelry, and stuffing of whole small turtles are threats to this species. Population recovery is hindered further by the incidental take of green sea turtles during shrimp harvests, and outbreaks of epidemic tumor infections have introduced a severe threat to the population.

Green sea turtles are a circumtropical species occurring both in tropical and subtropical waters. In the western Atlantic, they range from Massachusetts to the Virgin Islands and Puerto Rico. Known nesting sites for the green sea turtle in the continental U.S. include North Carolina, South Carolina, Georgia, Florida, and Texas. In Texas, green sea turtles can be found in Matagorda Bay, Aransas Bay, and the lower Laguna Madre. Preferred nesting and foraging areas for this species are not found near the Project site.

Atlantic Hawksbill Sea Turtle

The Atlantic hawksbill sea turtle (a federal and state-listed endangered species) inhabits coastal reefs, bays, rocky areas, estuaries, and lagoons at depths up to 70 feet. Hatchlings may be found in the open sea floating on masses of marine plants, while juveniles, subadults, and adults may be found near coral reefs (i.e., their primary foraging area). They prefer to feed on invertebrates such as sponges, mollusks, and sea urchins, although they are omnivorous. Atlantic hawksbills come ashore to nest and prefer undisturbed, deep sand beaches. Preferred beaches may range from high-energy to small pocket beaches bounded by crevices of cliff walls with woody vegetation near the waterline (NMFS, 2004; COE, 2003b). The greatest threat to this population has been the harvest of turtles to supply the tortoise shell market and stuffed turtle curios. It is also used to manufacture leather, oil, perfume, and cosmetics.

Atlantic hawksbill sea turtles are circumtropical and occur in the tropical and subtropical areas of the Atlantic, Pacific, and Indian Oceans. Nesting sites are known along the Yucatan Peninsula of Mexico, the U.S. Virgin Islands, Puerto Rico, and the Florida Keys. Post-hatchlings and juveniles are seen with some regularity in Texas and Florida, in areas primarily associated with stone jetties (NMFS, 2004). As such, Atlantic hawksbill sea turtles within the Project region, would primarily be located around the stone jetties associated with Aransas Pass, approximately 10 miles east of the Project site and along the LNGC route.

Kemp's Ridley Sea Turtle

Kemp's ridley sea turtles (a federal and state-listed endangered species) inhabit shallow coastal and estuarine waters over sand or mud bottoms. Juveniles feed on sargassum while adults are largely shallow water benthic feeders. Food items include shrimp, snails, bivalves, jellyfish, and marine plants (NMFS, 2004; COE, 2003b). Collection of eggs, capture for meat and other products, direct take for indigenous use, ingestion of man-made materials, collision with boats, and disturbance or destruction of nesting areas are all factors that have contributed to the decline of this species. Despite these factors, the population appears to be in the early stages of recovery.

Kemp's ridley sea turtles inhabit primarily coastal waters in the northwestern Atlantic and the Gulf. The majority of this species nests at beaches near Rancho Nuevo, Tamanlipas, Mexico, about 315 miles south of the Project area, with a secondary nesting area at Tuxpan, Vera Cruz. The Kemp's ridley is the most documented sea turtle nesting on Texas beaches. This species could be a transient to the Project area between crustacean-rich feeding areas in the northern Gulf and breeding grounds in Texas and Mexico (NMFS, 2004; COE, 2003).

Leatherback Sea Turtle

Leatherback sea turtles (a federal and state-listed endangered species) spend most of their time in the open ocean and come to land only to nest. They may be found in coastal waters when nesting or following jellyfish concentrations. They feed mainly on jellyfish and sea squirts as well as sea urchins, crustaceans, fish, and floating seaweed. They prefer sandy beaches with a deepwater approach for nesting (NMFS, 2004; COE, 2003b). Overexploitation by humans and incidental mortality due to shrimping and fishing activities have contributed to a decline in the population, as has degradation and disruption of nesting habitat and egg collection.

Leatherbacks are one of the widest-ranging sea turtles and are found in both the Pacific and Atlantic oceans. To optimize foraging and nesting opportunities, they migrate between boreal, temperate, and tropical waters. In the western Atlantic, their range extends from Nova Scotia to South America, and into the Gulf. While important nesting sites in the western Atlantic include French Guiana and Columbia, they are also known to nest along the U.S. Virgin Islands, Puerto Rico, and Florida. Although leatherback sea turtle sightings have been recorded in Corpus Christi Bay, this species is rare along the Texas coast and no nest sites have been recorded in over 60 years (NMFS, 2004; COE, 2003b).

Loggerhead Sea Turtle

In the Atlantic, the loggerhead's range extends from Newfoundland to as far south as Argentina. The Northwest Atlantic DPS (which could be found within the project area) is listed as threatened by FWS and TPWD. The primary Atlantic nesting sites are along the east coast of Florida but additional sites occur in Georgia, the Carolinas, and along the Gulf Coast of Florida. A handful of nests are documented each year in Texas. In the eastern Pacific, loggerheads are reported from Alaska to Chile (NMFS, 2004; COE, 2003b). The greatest threats to this sea turtle species are coastal development, commercial fisheries, and pollution. Loggerhead sea turtles inhabit continental shelves, bays, estuaries, and lagoons in temperate, subtropical, and tropical waters.

Mating takes place from late March to early June, and eggs are laid throughout the summer. After hatching, loggerhead hatchlings move to the sea and often float on sargassum masses for three to five years. Subadults occupy near-shore and estuarine habitats, whereas adults occupy a variety of habitats that range from turbid bays to clear water. The young feed on prey such as gastropods, crustacean fragments, and sargassum, while adults mainly forage on the bottom, though they may also feed on jellyfish from the surface. Loggerhead sea turtles nest on open, sandy beaches above the high tide mark and seaward of well-developed dunes. They prefer steeply sloped beaches with gradually sloped offshore approaches (NMFS, 2004; COE, 2003b).

In Texas, loggerheads favor shallow, inner continental shelf waters and have been recorded in Corpus Christi Bay. They may be present in Texas marine waters year-round; however, they are most noticeable during the spring when Portuguese-Man-of-War are abundant (COE, 2003b). Most loggerhead sightings have been in the northern Gulf of Mexico near jettied passes and in open water.

Sea Turtle Conclusion

Potential impacts to sea turtles as a result of the Stage 3 Project would result from the increase in LNGC vessel traffic (by up to 100 round trip LNGC transits per year over the 300 roundtrip transits authorized for the Liquefaction Project) which could potentially affect sea turtles through vessel strikes, as well as impacts related to vessel's use of ballast and cooling water. The measures identified in section B.4.2.3 to minimize the risk of vessel strikes on marine mammals, would similarly minimize risk of vessel strikes on sea turtles. As a result, the Project may affect, but is not likely to adversely affect sea turtles, in the marine environment, and would have no effect on nesting sea turtles.

Mussels

The golden orb is a candidate species under the ESA (i.e., a species that the FWS has determined may warrant future protection under the ESA), and is listed as threatened by the TPWD. It is a freshwater mussel that can be found in shallow waters in medium to large rivers. This species appears to be restricted to flowing waters with sand, gravel, and cobble bottoms at depths from a few centimeters to over three meters and is intolerant of scouring floods producing excess silt and mud deposition. The golden orb is also intolerant of impoundment in most instances (NatureServe, 2012). The remaining known populations in Texas are centralized around the Corpus Christi area, with one of the nine known populations occurring in Lake Corpus Christi. The nine known populations appear to be restricted to four rivers in Texas. It appears that the golden orb has been extirpated from the Aransas River Basin, of which Chiltipin Creek is located. The remaining drainages crossed by the Project are prone to drying up in drought times and do not support a long-term population of mussels. Therefore, the Project may affect, but is not likely to adversely affect this species.

Conclusion

A variety of measures have been proposed by Cheniere that would minimize impacts on federally listed species, including but not limited to, preconstruction surveys, environmental training programs, and implementation to NMFS-issued guidance that outlines collision avoidance measures to be implemented in order to minimize impacts on marine mammals and sea turtles. However, because consultations with the FWS and NMFS are ongoing, **we recommend that:**

- **Cheniere should not begin construction activities until:**
  a. **the FERC staff receives comments from the FWS and the NMFS regarding the proposed action;**
  b. **the FERC staff completes formal ESA consultation with the FWS and NMFS, if required; and**
  c. **Cheniere has received written notification from the Director of OEP that construction or use of mitigation may begin.**

4.4.2 State-listed Species

There are 21 state-listed threatened or endangered species identified by the TPWD as potentially occurring in San Patricio County, as summarized in table B.4.4-2. Table B.4-4.2 excludes the species that are also federally listed which are discussed in section B.4.4.1.

Avoidance and minimization measures discussed in previous sections B.4.2, B.4.3, and B.4.4.1 would also minimize and/or avoid impacts on state-listed species. No additional measures outside of those previously discussed would be implemented to protect state-listed species. In a letter dated September 24, 2018, TPWD stated its acceptance of these measures as adequate for protection of resources under TPWD purview.

Table B.4.4-2

State-Listed Species within the Project County

Species	Status	Habitat Assessment	Effect Determination
Fish			
Opossum pipefish (*Microphis brachyurus*)	Threatened	Anadromous and breeds in freshwater. Spends majority of its time in open ocean.	Suitable habitat present.
Smalltooth sawfish (*Pristis pectinata*)[a]	Endangered	Sheltered bays, shallow banks, and in estuaries or river mouths for young and mangrove, reef, seagrass, and coral for adults.	Suitable habitat present, but likely extirpated in Texas.
Amphibians			
Sheep frog (*Hypopachus variolosus*)	Threatened	Tropical humid forests.	No suitable habitat present.
Black-spotted newt (*Notophthalmus meridionalis*)	Threatened	Freshwater ponds, canals, and ditches.	No suitable habitat present.
South Texas siren (*Siren* sp.)	Threatened	Freshwater ponds, ditches, and swamps.	No suitable habitat present.
Reptiles			
Texas tortoise (*Gopherus berlandieri*)	Endangered	Cactus rich areas of south Texas.	Suitable habitat present.
Timber/canebrake rattlesnake (*Crotalus horridus*)	Threatened	Hilly woodlands and thickets near freshwater.	No suitable habitat present.
Texas horned lizard (*Phrynosoma cornutum*)	Threatened	Loose sand and loamy soils throughout Texas.	Suitable habitat present.
Texas scarlet snake (*Cemophora coccinea lineri*)	Threatened	Sandy thickets of the Texas Coastal Bend.	No suitable habitat present.
Texas indigo snake (*Drymarchon melanurus erebennus*)	Threatened	Sparsely vegetated areas of south Texas.	Suitable habitat present.
Birds			
Reddish egret (*Egretta rufescens*)	Threatened	Coastal marshes, shell beaches, sandflats, and mudflats.	Suitable habitat present.
White-faced ibis (*Plegadis chihi*)	Threatened	Freshwater marshes, swamps, and ponds.	No suitable habitat present.

Table B.4.4-2 **State-Listed Species within the Project County**			
Species	**Status**	**Habitat Assessment**	**Effect Determination**
White-tailed hawk (*Buteo albicaudatus*)	Threatened	Coastal grasslands.	Suitable habitat present.
Peregrine falcon (*Falco peregrinus*)	Threatened	Urban, concentrations along coast and barrier islands	Suitable habitat present.
Northern aplomado falcon (*Falco femoralis septentrionalis*)	Endangered	Savanna, open woodland, grass plains, plowed fields, coastal prairies, and marshes.	Suitable habitat present.
Eskimo curlew (*Numenius borealis*) [a]	Endangered	Grasslands, pastures, plowed fields, marshes, and mudflats.	No suitable habitat present.
Sooty tern (*Sterna fuscata*)	Threatened	Islands and coastal beaches.	Suitable habitat present.
Wood stork (*Mycteria Americana*)	Threatened	Prairie ponds, flooded pastures, and fields, ditches and other shallow standing water including salt-water.	Suitable habitat present.
Mammals			
Southern yellow bat (*Lasiurus ega*)	Threatened	Roosts in palm trees of far south Texas.	No suitable habitat present.
White-nosed coati (*Nausa narica*)	Threatened	Woodlands, riparian corridors, and canyons.	No suitable habitat present.
Red Wolf (*Canis rufus*)	Endangered	Brushy or forested areas and coastal prairies.	Suitable habitat present, but likely extirpated in Texas.

As presented in table B.4.4-2 above, suitable habitat is present in the Project area for several state-listed threatened and endangered species. Cheniere consulted with TPWD regarding potential impacts on state-listed threatened and endangered species. In a letter dated July 9, 2015, TPWD provided recommendations to minimize impacts on state-listed species potentially occurring in the Project area. In an email dated September 20, 2018, Cheniere responded to TPWD recommendations. On September 24, 2018, TPWD issued a letter stating that Cheniere's responses to the TPWD recommendation are acceptable. Measures that Cheniere would implement, based on TPWD recommendation, are summarized below.

Fish

Potentially suitable habitat for the opossum pipefish occurs within perennial freshwater streams crossed by the pipeline, but this species primarily occurs within the open ocean and would be very rare within the Project area. No suitable habitat for the opossum pipefish is located within the Stage 3 LNG Facilities site. All perennial stream crossings for the Stage 3 Pipeline would be conducted via HDD, thereby minimizing direct impacts on the waterbodies. Additional information regarding HDD crossings of waterbodies is provided in section B.3.3.2. Through implementation of these measures, we have determined that impacts on the opossum pipefish would not be significant.

Reptiles

Suitable habitat is present for three state-listed reptiles, Texas horned lizard, Texas tortoise, and Texas indigo snake. To minimize impacts on all three of these species, as well as other wildlife in the Project area, Cheniere would monitor any excavations (e.g., trenches) left open overnight each morning prior to resuming work. If state-listed species are observed within excavations, they would be removed by individuals that are authorized by TPWD to handle state-listed species. Escape ramps would also be constructed within the trenches, as appropriate. Cheniere also stated that it would ensure that all contractors and Project personnel would be made aware that all reptiles, including state-listed species, become more active in the spring. Cheniere would also enforce speed limits within the Project area for safety, which would minimize the potential for vehicle strikes on wildlife, including state-listed species. In addition to the measures outlined above, Cheniere would further minimize impacts on Texas tortoises by allowing individuals in the Project area to leave on its own or have the tortoise relocated as far as necessary from the Project activities to protect it from being negatively impacted, but within a 5 to 10-acre area, which is the typical home range of the Texas tortoise.

While Cheniere would implement measures to minimize impacts on state-listed reptiles, there is still potential for individuals to be adversely impacted by construction of the Project. However, these impacts would be short-term and localized and are not anticipated to be significant.

Birds

Potentially suitable habitat is present within the Project area for five state-listed birds including reddish egret, white-tailed hawk, peregrine falcon, northern aplomado falcon, and sooty tern. Impacts on these species as a result of the Project would be similar to those discussed in section B.4.3 for migratory birds and section B.4.4.1 for federally listed species. Impacts on these species would primarily be minimized by restricting clearing activities to outside of the primary nesting season of March 1 to August 31. If vegetation clearing must occur during the nesting season, Cheniere would survey areas to be cleared for active nests, and if found, would avoid clearing within the TPWD recommended buffer of 150 feet until the young have fledged or the nest is abandoned. Through implementation of these measures, we have determined that impacts on state-listed birds would not be significant.

5.0 CULTURAL RESOURCES

Section 106 of the National Historic Preservation Act, as amended, requires FERC to consider the effect of its undertakings on properties listed, or eligible for listing, on the National Register of Historic Places (NRHP), and to afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. Cheniere, as a non-federal party, is assisting us in meeting our obligations under Section 106 of National Historic Preservation Act and implementing regulations at 36 CFR 800.

5.1 Survey Results and Consultations

We sent copies of our NOI for the Project to a wide range of stakeholders, including the ACHP, Texas Historical Commission, and federally recognized Indian tribes (tribes) that may have an interest in the Project area. The NOI stated that we use the NOI to initiate consultations with State Historic Preservation Officers (SHPO)[11] and to solicit their views and those of other government agencies, interested tribes, and the public on the Projects' potential effects on historic properties.

[11] In Texas, the SHPO is part of the Texas Historical Commission.

In addition to the NOI, on May 5, 2016, FERC staff sent letters inviting consultation to 11 federally recognized Native American tribes including, the Apache Tribe of Oklahoma, Comanche Nation of Oklahoma, Jicarilla Apache Nation of New Mexico, Kickapoo Tribe of Oklahoma, Kickapoo Traditional Tribe of Texas, Kiowa Indian Tribe of Oklahoma, Mescalero Apache Tribe of New Mexico, Ysleta Del Sur Pueblo, Kickapoo Tribe of Kansas, Tonkawa Tribe of Oklahoma, and Wichita and Affiliated Tribes. On May 26, 2016, the Tonkawa Tribe of Oklahoma filed a letter stating that they had no comments on the Project. To date, no other tribes have responded to our request for comment.

In addition, Cheniere sent Project information to the three tribes (Caddo Nation, Tonkawa Tribe of Oklahoma, and Wichita and Affiliated Tribes) in letters dated September 15, 2015 and October 17, 2017. To date, none of the tribes have responded to Cheniere.

Cheniere submitted multiple Project notification letters to the Texas SHPO providing Project information, as well as multiple requests for concurrence of no further work for Project components previously surveyed for cultural resources on behalf of the Liquefaction Project. In addition, Cheniere performed cultural resource surveys of areas not previously surveyed along the Stage 3 Pipeline and requested concurrence that no surveys are necessary within additional areas associated with the Stage 3 LNG Facilities. However, there are some areas along the Stage 3 Pipeline where surveys and/or consultation with the Texas SHPO have not occurred, as identified in table B.5.1-1. All surveys conducted to date were either negative for cultural resources or had resources (five isolated finds) that were determined to be ineligible for listing in the National Register of Historic Places. The Texas SHPO concurred with all of Cheniere's findings that the Project would have no effect and/or have no adverse effect on cultural resources. Details regarding all correspondence between Cheniere and the Texas SHPO is provided in appendix A.

Table B.5.1-1

Stage 3 Pipeline Facilities Not Surveyed for Cultural Resources

Facility	Approximate Milepost	Acreage
ATWS for ditch crossing	0.8	0.24
ATWS for HDD	1.6	0.21
ATWS for road crossing (both sides of crossing) and multiple existing pipelines	5.7	0.14
		0.19
ATWS for multiple private road and existing pipeline crossings	6.2	0.09
Access Road TAR 8.7	8.7	0.38
Access Road TAR 12.1	12.1	0.89
Access Road TAR 14.1	14.1	0.39
ATWS	16.1	0.02
Access Road TAR 16.1	16.1	0.09
ATWS for HDD	17.3	0.23

CCPL committed to completing surveys of the areas presented in table B.5.1-1 prior to construction and to provide the results of these surveys in their Implementation Plan. Cheniere also stated that access roads TAR 8.7, TAR 14.1, and PAR 18.4 are existing roads that would be used for the Project in the same manner as their current use and that SHPO consultation is not required. We disagree. As consultations with SHPO are not complete for all Project workspaces and Cheniere has not committed to consulting with SHPO for areas presented in table B.5.1-1, **we recommend that:**

- **Cheniere should <u>not begin construction</u> of the Project <u>until</u>:**

a. **CCPL files with the Secretary supplemental cultural resource survey reports for the Stage 3 Pipeline workspaces where surveys have not been completed, along with the Texas SHPO's comments on the reports;**

b. **ACHP is afforded an opportunity to comment if historic properties would be adversely affected; and**

c. **FERC staff reviews and the Director of the OEP approves all reports and plans and notifies Cheniere in writing that construction may proceed.**

All materials filed with the Commission containing <u>location, character, and ownership information</u> about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "<u>CUI//PRIV - DO NOT RELEASE</u>."

5.2 Unanticipated Discovery Plan

In the event that unanticipated finds are uncovered during Project construction, Cheniere would implement the procedures outlined its *Unanticipated Discovery Plan*. Cheniere committed to provide its *Unanticipated Discovery Plan* prior to construction in its Implementation Plan for our review and approval.

5.3 Conclusion

No traditional cultural properties or properties of religious or cultural importance to Tribes have been identified by Cheniere, the Texas SHPO, or Tribes contacted by the FERC staff. Cheniere consulted with the Texas SHPO regarding the potential effects to cultural resources, but surveys and consultations with the Texas SHPO have not been completed for the Project.

6.0 LAND USE, RECREATION, AND VISUAL RESOURCES

6.1 Land Use

Land use in the Project area consists of the following:

- agricultural – includes active or rotated cropland;
- industrial – includes impervious surfaces such as roads and industrial facilities as well as bare ground areas and gravel roadways;
- open land – includes grasslands and shrub scrub vegetation with few mature trees; and
- wetlands – includes PEM wetlands and stormwater conveyances. PEM wetlands are dominated by vascular emergent plants and are not tidally influenced.

6.1.1 Stage 3 LNG Facilities

Construction of Stage 3 LNG Facilities would affect a total of 1,274.4 acres of land, of which 932.4 acres would be maintained for operation. Table B.6.1-1 summarizes the acreage of land uses that would be affected by the construction and operation of the Stage 3 LNG Facilities. Approximately 1,261.5 acres (99 percent) of the total 1,274.4 acres, is being impacted by the currently-under construction Liquefaction Project.

Table B.6.1-1 Land Use Affected by the Stage 3 LNG Facilities						
Land Use	**Area Affected (acres)**					
	Construction [a]			**Operation**		
	Overlap with Approved Liquefaction Project [b]	**New Disturbance**	**Total Disturbance**	**Overlap with Approved Liquefaction Project** [b]	**New Disturbance**	**Total Disturbance**
Open Land	53.0	0.0	53.0	53.0	0.0	53.0
Industrial	1,181.04	12.9	1,193.94	851.1	12.9	864.0
Wetlands	27.46	0.0	27.46	15.4	0.0	15.4
Total	**1,261.5**	**12.9**	**1,274.4**	**919.5**	**12.9**	**932.4**

a Total construction impacts include both temporary and permanent work areas.
b Indicates the acreage of overlap with the previously approved Liquefaction Project area.

The 1,261.5 acres of construction workspace associated with the Stage 3 LNG Facilities would be used for construction, parking, and laydown. Though the area is categorized as industrial and open land, the entire workspace is currently under industrial land use associated with the Liquefaction Project, and was used for industrial purposes by previous land owners.

Operation of the Stage 3 LNG Facilities would require approximately 932.4 acres of land, of which 919.5 acres were previously approved for operation of the Liquefaction Project. Due to the industrial use of adjacent land and the previously disturbed nature of the area, impacts on land use from the Stage 3 LNG Facilities would be minor.

The access road on the east side of the Stage 3 LNG Facilities and the La Quinta Road are private roads and are well-established and utilized by numerous entities, some of which are unrelated to the Stage 3 Project. Impacts associated with the roads necessary to access the Stage 3 LNG Facilities would total 18.5 acres.

6.1.2 Stage 3 Pipeline

A total of 484.2 acres of land would be affected during construction of the Stage 3 Pipeline and associated aboveground facilities. About 171.1 acres would be maintained as permanent right-of-way or facilities for operation of the pipeline. The permanent right-of-way would generally be maintained in herbaceous cover or allowed to return to previous uses in accordance with easement agreements. Land use affected by the Stage 3 Pipeline would consist of agricultural, industrial, and open land. Tables B.6.1-2 and B.6.1-3 summarizes the acreage of land uses affected by the construction and operation, respectively, of the pipeline and aboveground facilities.

Table B.6.1-2

Land Use Affected by Construction of the Stage 3 Pipeline and Associated Facilities

Facility	Construction (acres)								Construction Total (acres)		
	Agricultural		Open		Industrial		Wetland				
	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Total
Pipeline [a]	164.7	102.3	50.3	7.8	16.7	9.0	0.0	<0.1	**231.4**	**119.4**	**350.8**
M&R Stations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
Pig Launcher and Receiver [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
MLVs [c]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
Sinton Compressor Station Expansion	0.0	0.0	0.0	14.0	28.6	0.0	0.0	0.0	**28.6**	**14.0**	**42.6**
Access Roads	8.3	0.0	9.2	0.0	1.3	0.3	0.0	0.0	**18.8**	**0.3**	**19.1**
Contractor and Pipe Yards	0.0	0.0	18.2	0.0	53.5	0.0	0.0	0.0	**71.7**	**0.0**	**71.7**
Project Total	**173.0**	**102.3**	**77.7**	**21.8**	**100.1**	**9.3**	**0.0**	**<0.1**	**350.5**	**133.7**	**484.2**
Project Total (combined)	**275.3**		**99.5**		**109.4**		**<0.1**				

Source: U.S. Department of Agriculture – Farm Service Agency: National Agriculture Imagery Program, 2016

[a] Construction impacts include construction right-of-way and additional temporary workspace, including the existing Tejas Interconnect and Work Area.

[b] Located entirely within area reported for the Sinton Compressor Station expansion and the Stage 3 LNG Facilities M&R Station.

[c] Acreages for MLVs located at MPs 0.0 and 21.0 are included within acreages of other aboveground facilities, and acreages for MLVs at MPs 7.3 and 12.8 are included within acreages of the pipeline.

Table B.6.1-3

Land Use Affected by Operation of the Stage 3 Pipeline and Associated Facilities

Facility	Operation (acres)								Operation Total (acres)		
	Agricultural		Open		Industrial		Wetland				
	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Overlapping 48" Corpus Christi Pipeline	New Stage 3 Pipeline Impacts	Total
Pipeline [a]	45.0	52.0	8.8	12.8	5.8	7.0	0.0	0.0	**59.6**	**71.8**	**131.4**
M&R Stations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
Pig Launcher and Receiver [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
MLVs [c]	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	**0.2**	**0.2**	**0.4**
Sinton Compressor Station Expansion	0.0	0.0	0.0	0.0	26.6	0.0	0.0	0.0	**26.6**	**0.0**	**26.6**
Access Roads	6.2	0.0	5.8	0.0	0.7	0.0	0.0	0.0	**12.7**	**0.0**	**12.7**
Contractor and Pipe Yards	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	**0.0**	**0.0**
Project Total	**51.4**	**52.2**	**14.6**	**12.8**	**33.1**	**7.0**	**0.0**	**0.0**	**99.1**	**72.0**	**171.1**
Project Total (combined)	**103.6**		**27.4**		**40.1**		**0.0**				

Source: U.S. Department of Agriculture – Farm Service Agency: National Agriculture Imagery Program, 2016

[a] Operational Impacts include 50-foot-wide permanent right-of-way.

[b] Located entirely within area reported for the Sinton Compressor Station Expansion and the Stage 3 LNG Facilities M&R Station.

[c] Acreages for MLVs located at MPs 0.0 and 21.0 are included within acreages of other aboveground facilities. The MLVs at MPs 7.3 and 12.8 would each require approximately 0.5 acre during operation, of which approximately 0.3 acre would be located within the Stage 3 Pipeline permanent right-of-way, 0.1 acre would be within the existing Corpus Christi Pipeline permanent right-of-way, and 0.1 acre would result in new permanent impacts outside of the permanent pipeline rights-of-way.

The Stage 3 Pipeline would originate at the Stage 3 LNG Facilities and terminate at the Sinton Compressor Station, north of the City of Sinton, Texas. The Stage 3 Pipeline would cross through a portion of a wind energy facility, the Papalote Creek Wind Farm between approximate MP 7.0 and MP 10.0. There would be no impacts to the wind farm as a result of the construction and operation of the Stage 3 Pipeline. Table B.6.1-4 summarizes the land uses crossed by the proposed Stage 3 Pipeline by milepost. The new pipeline route would parallel the Corpus Christi Pipeline for the majority of its length.

Table B.6.1-4
Land Use Crossed by the Stage 3 Pipeline by Milepost

Milepost	Segment Length (miles)	Land Use
0.0-0.7	0.7	Industrial
0.7-0.7	<0.1	Wetland
0.7-1.45	0.75	Industrial
1.45-17.45	16.0	Agricultural
17.45-20.9	3.45	Open
20.9-21.0	0.1	Industrial
Total	**21.0**	--

Agricultural lands would be the primary land affected by the construction and operation of the Stage 3 Pipeline Facilities. Typical crops grown along the route include cotton, sorghum, corn, and soybeans. No specialty crops or orchards were identified along the route that would require special construction or restoration measures. CCPL would restore all agricultural land affected by the Stage 3 Pipeline to its original use, including the permanent pipeline right-of-way. Prior to construction, CCPL would work with the affected landowners to identify any drain tiles within the construction workspace. Any drain tiles damaged during construction would be repaired to landowner specification or to pre-construction conditions. Open land crossed by the Stage 3 Pipeline includes rangeland, bare land, or other sparsely vegetated areas.

All areas within the Stage 3 LNG Facilities, including the southern-most end of the Stage 3 Pipeline, have been surveyed. Design of the pipeline has resulted in the shifting of several workspaces and access roads outside of the previously surveyed areas. However, the shifts are minor and the environmental data from the previous surveys were utilized in the shifts. CCPL stated that it would survey all areas in the final design that are outside the original survey corridor and would provide this data in its construction Implementation Plan.

Construction of the additional facilities at the Sinton Compressor Station would require a total of 42.6 acres of land characterized as industrial (28.6 acres) and open land (14.0 acres). Following the completion of construction, no new permanent impacts would occur as a result of operation of the Sinton Compressor Station.

M&R Stations would be required to source the natural gas to the Stage 3 LNG Facilities. Pig launcher/receiver facilities would be constructed at each end of the Stage 3 Pipeline. M&R stations and pig launcher/receiver facilities would be constructed entirely within the Stage 3 LNG Facilities and Sinton Compressor Station boundaries and accounted for in these locations; therefore, separate affected areas are not provided.

A total of four MLVs would be installed along the Stage 3 Pipeline, including one in the Stage 3 LNG Facilities M&R Station (MP 0.0), one at MP 7.3, one at MP 12.8, and one at the Sinton Compressor Station (MP 21.0). Each MLV would be within a 100-foot by 200-foot graveled and fenced area. The land use impacts for the MLVs within the Stage 3 LNG Facilities M&R Station and the Sinton Compressor Station are included in the impacts for those aboveground facilities in which the MLVs are located. The MLVs at MPs 7.3 and 12.8 would each require approximately 0.5 acre during operation, of which approximately 0.3 acre would be located within the Stage 3 Pipeline permanent right-of-way, 0.1 acre would be within the existing Corpus Christi Pipeline permanent right-of-way, and 0.1 acre would result in new permanent impacts outside of the permanent pipeline rights-of-way. Land use impacts for the portions of these MLVs that are located within the Stage 3 Pipeline permanent right-of-way are included in the construction and operation impacts for the pipeline in table B.6.1-2. Construction and operation of the MLVs at MPs 7.3 and 12.8 would result in the permanent conversion of approximately 1.0 acre of agricultural land to industrial land.

Where the Stage 3 Pipeline would cross active agricultural fields, the pipeline would be buried to a minimum depth of 4 feet to accommodate deep tilling. Elsewhere, the pipeline would be buried a minimum of 3 feet deep. Additional depth of cover would be provided where requested by landowners during right-of-way negotiations, or at road crossings where required by road permits. Final designed burial depth would be determined during the detailed design phase based on land use anticipated at the time of construction.

Access roads would require 6.4 acres of temporary impacts on agricultural, industrial, and open land. An additional 12.7 acres would be maintained as permanent roads; however, these areas were previously used for construction of the Corpus Christi Pipeline. No new permanent roads are proposed in the Stage 3 Project that were not included for construction or operation of the Corpus Christi Pipeline, including from the timeframe of the original application submittal through approval of the final construction variance. The only new road is a temporary access road.

Four construction staging and pipe storage yards, totaling 71.7 acres, would be required for construction of the Stage 3 Pipeline Facilities. The existing land uses at the yards are industrial and open land. All land use impacts associated with these yards would be temporary.

6.2 Existing Residences and Planned Developments

The Stage 3 LNG Facilities would be located in an industrial area, and would be surrounded by industrial development. There are no existing residential developments within 0.25 mile of the Stage 3 LNG Facilities. The nearest residential areas to the Stage 3 LNG Facilities site are in Gregory (approximately 0.7 mile northwest), Portland (approximately 1.0 mile west), and Ingleside (2.9 miles east). The land surrounding the Stage 3 LNG Facilities has been used for disposal of aluminum ore and related waste products for over 50 years. The area to the south is the site of the Liquefaction Project, which is currently under construction. Voestalpine has constructed and is currently operating a direct reduction iron plant to the southwest of the proposed Stage 3 LNG Facilities. In addition, Tianjin Pipe Corporation America is operating a steel pipe manufacturing facility immediately north of the proposed Stage 3 LNG Facilities across Highway 361.

The nearest residence to temporary construction activities that would occur in association with the Stage 3 LNG Facilities is located approximately 0.1 mile northwest of the junction of La Quinta Road and SH 35, on the opposite side of the highway from the Project. The proposed temporary work area is currently being utilized in association with construction of the Liquefaction Project.

There are no existing residences or buildings within 50 feet of the Stage 3 Pipeline construction work area. Further, there are no planned residential areas within 0.25 mile of either the proposed Stage 3 LNG Facilities site or the proposed Stage 3 Pipeline (San Patricio County Economic Development Corporation, 2016). The Port of Corpus Christi Authority cancelled construction of the La Quinta Trade

Gateway Terminal on the adjacent 1,100-acre property to the west and southwest of the Stage 3 LNG Facilities in April 2017.

6.3 Recreation and Special Interest Areas

There are no public or conservation lands within or within 0.25 mile of the proposed Stage 3 LNG Facilities site, or crossed by or within 0.25 mile of the proposed Stage 3 Pipeline. There are no special land uses within 0.25 mile of the proposed Stage 3 LNG Facilities site, or crossed by or within 0.25 mile of proposed Stage 3 Pipeline (TPWD, 2016c; San Patricio County, 2013; San Patricio County Economic Development Corporation, 2016).

There are no natural, recreational or scenic areas or registered natural landmarks on or within 0.25 mile of the proposed Stage 3 LNG Facilities site, nor crossed by or within 0.25 mile of the proposed Stage 3 Pipeline. There are no designated or proposed National or State Wild and Scenic Rivers within 0.25 mile of the proposed Stage 3 LNG Facilities site, and none are crossed by or within 0.25 mile of the proposed Stage 3 Pipeline (U.S. Department of the Interior, 2015).

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, 2016).

During operation of the Stage 3 Project there would be an anticipated increase in the maximum marine vessel traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year. CCL Stage III contacted the Coast Guard and submitted a Waterway Suitability Assessment to seek a LOR confirming that the increase of 100 LNGCs per year would not materially impact the waterway. LNGCs would be restricted to the existing deep draft navigation channels (Corpus Christi Ship Channel and La Quinta Ship Channel). Potential conflicts with recreational boating traffic would be unlikely, as recreational boaters do not depend exclusively on the deep draft waterways and typically spend the majority of their time in less industrialized areas.

No sources of contamination are located within 0.25 mile of the proposed Stage 3 LNG Facilities; however, there is one potential source of contamination within 0.25 mile of the Stage 3 Pipeline (EDR, 2016). The Taft Dump is located about 0.25 mile from MP 8.1 and has been closed for approximately 40 years. In addition, a relatively small area of hydrocarbon-impacted soils was identified within approximately 200 feet of the Stage 3 Pipeline at approximate MP 0.3. This contamination is thought to be a relic of a historic crude oil pipeline release. In the event of an unanticipated discovery of contamination, Cheniere would implement the following:

- The individual who makes the discovery would stop work, if necessary, and notify the Cheniere EI.
- If work was not initially stopped, the EI would stop work, if necessary.
- Applicable agency notification would be made, if necessary.
- The EI and applicable contractors (response team), in consultation with a Project safety representative, would assess whether it is safe to respond to the discovery.

- If safe to respond, the response team would work to the extent practical to prevent spreading of contamination. This may be accomplished via limitation of future excavation, construction of temporary containment berms, covering of contaminated soils with visqueen plastic, etc.
- The response team would characterize and dispose of encountered waste, if required by applicable law and/or landowner agreements.

A detailed procedure for responding to unanticipated discoveries of contamination would be developed by Cheniere prior to commencement of construction, and filed with the Secretary for our review and approval.

6.4 Coastal Zone Management

Section 307(c)(3) of the *Coastal Zone Management Act* (CZMA) requires that all federally licensed and permitted activated be consistent with approved state CZMA Programs. The Texas Land Commissioner administers the state's Coastal Management Plan, and is the lead state agency that performs federal consistency reviews. The Stage 3 LNG Facilities and the majority of the Stage 3 Pipeline (between MP 0.0 and approximate MP 19.4), would be within the Texas Coastal Zone. The Texas General Land Office issued a letter on January 23, 2019, concluding that the Stage 3 LNG Facilities would likely not have adverse impacts on coastal natural resource areas in the coastal zone. The CZMA consistency determination for the Stage 3 Pipeline is automatic with use of Nationwide Permit 12 for impacts on waters of the U.S., as discussed in section B.3.3.

6.5 Visual Resources

The degree of visual impact that may result from a Project is typically determined by considering the general character of the existing landscape and the visually prominent features of the proposed facilities. The Stage 3 LNG Facilities would be located in an existing industrial setting north of the Liquefaction Project, northeast of Voestalpine's direct reduction iron plant, south of the TPCO America steel pipe facility, and northwest of the existing, but not operating Sherwin Alumina plant. The visual impacts of the Stage 3 LNG Facilities would be similar to the surrounding industrial complexes. The Stage 3 LNG Facilities would include an LNG storage tank, similar to the tanks that are to be constructed as part of the Liquefaction Project. The LNG storage tank would be approximately 215 feet high from the foundation base to the top of the jib crane, and approximately 258 feet in diameter. The height of the LNG storage tank would be significantly lower than the tallest structure (tower) on the adjacent Voestalpine site, which is at a height of 450 feet above grade.

The Stage 3 LNG Facilities would also include wet and dry flares that would be approximately 197 feet above grade. The flare stacks would be visible when in use in both day and night conditions. Flaring would rarely occur, so the flares would be similar in appearance to a large cell tower for a majority of the time. The flares would be installed to accommodate emergency reliefs, facilitate maintenance purging, and start-up flaring only and would not be used during routine operation.

The Stage 3 LNG Facilities would use the minimum lighting necessary to allow personnel to safely work and inspect the equipment. There would be lighting along the perimeter fence as required by security regulations. The lighting at the Stage 3 LNG Facilities would be consistent with lighting at the approved Liquefaction Project and impacts to the environment are expected to be minimal.

Impacts on visual resources resulting from the storage tanks and flare stacks would be moderate and permanent, but due to the proximity of the Stage 3 LNG Facilities to other industrial structures, the storage tanks and flare stack would be consistent with the surrounding land use.

The majority of the Stage 3 Pipeline would be constructed within agricultural land and/or adjacent to existing rights-of-way, which would not alter the landscape of the region. The underground facilities associated with the Stage 3 Pipeline would not result in significant changes to the existing viewshed, although the rights-of-way would be cleared of woody cover during project construction and operation. The additional facilities at the Sinton Compressor Station would be located within the existing Sinton Compressor Station and would not be visible from residences or publicly-accessible locations; therefore, no visual impacts are anticipated. Other aboveground facilities associated with the Stage 3 Pipeline, such as valves, would be relatively small and are not expected to have visual impacts.

7.0 SOCIOECONOMICS

Socioeconomics is an evaluation of the basic conditions (attributes and resources) associated with the human environment, particularly the population and economic activity within a region. Economic activity generally encompasses regional employment, personal income, and revenues and expenditures. Impacts on the fundamental socioeconomic components can influence other issues such as regional housing availability and provision of community services. All data presented in this section represents the most current data available at the writing of this EA.

This section addresses several different factors that could affect the quality of life and economy in the area surrounding the Project area where employees might live, shop, and use public resources. These factors include public services such as fire, police, and medical facilities; educational facilities; and environmental justice.

The socioeconomic analysis for the proposed Project examines data from San Patricio and Nueces counties, where the majority of the Project workforce is anticipated to reside during construction and operation.

7.1 Population, Economy, and Employment

Table B.7.1-1 provides a summary of current and projected populations of the potentially affected counties in the Project vicinity.

Table B.7.1-1

Population by County and State

Geographic Area	2017 Population	2017 Population Density (persons/ square mile)	Population Change (Percent)		Projected Population Change (Percent)	
			2000 to 2010	2010 to 2017	2010 to 2020	2020 to 2030
Nueces County	362,204	522.3	8.5%	6.5%	6.5%	5.1%
San Patricio County	66,236	79.0	-3.5%	2.2%	9.8%	9.1%
State of Texas	28,059,337	107.4	20.6%	11.6%	8.3%	6.4%

Sources: Texas Demographic Center, 2018; Texas State Data Center, 2015; U.S. Census Bureau, 2015

While populations rose in Nueces and San Patricio counties, the increases between 2010 and 2017 were at slower rates than the State of Texas as a whole. Population is expected to continue to increase statewide and in both Nueces and San Patricio counties over the next two decades. Projected population increases in San Patricio County are larger than statewide projections, while lower than statewide increases are projected for Nueces County. Nueces County is almost five times as densely populated than the state as a whole, while San Patricio County is less densely populated. This primarily reflects the presence of

Corpus Christi, the eighth largest city in Texas, with a total estimated population of 325,080 in 2016 (Texas State Data Center, 2016). Corpus Christi is mainly located in Nueces County but also extends into San Patricio, Aransas, and Kleberg counties.

The cities of Gregory and Portland are the closest municipalities to the Stage 3 LNG Facilities site, with estimated 2016 populations of 1,971 and 15,660, respectively (Texas State Data Center, 2016). The Stage 3 Pipeline begins at the Stage 3 LNG Facilities site and traverses near the cities of Sinton and Taft, which had respective estimated populations of 5,729 and 3,088 in 2016 (Texas State Data Center, 2016).

Table B.7.1-2 presents the 2016 employment, by economic sector, for Nueces and San Patricio counties and the State of Texas. The construction industry was the largest economic sector in San Patricio County, followed by consumer services and state and local government. In Nueces County, the consumer services industry was the largest economic sector, followed by social services and producer services. Producer services, consumer services, and social services were the largest industries in the State of Texas, as presented in table B.7.1-2.

Table B.7.1-2

Employment by Sector by County and State, 2016

Economic Sector	Nueces County	San Patricio County	State of Texas
Total Employment [a]	218,301	30,349	16,644,179
PERCENT OF TOTAL			
Farming	0.4	2.9	1.6
Forestry, fishing, related activities	0.2	1.3	0.4
Mining	3.2	4.1	2.9
Utilities	0.4	0.6	0.3
Construction	10.1	16.6	6.5
Manufacturing	3.8	4.3	5.5
Wholesale trade	3.1	1.4	4.1
Retail trade	9.9	10.8	9.9
Transportation and warehousing	2.8	2.6	4.1
Finance and insurance	4.1	3.2	5.7
Real estate	3.8	3.1	4.3
Services (Consumer) [b]	17.1	15.0	15.1
Services (Producer) [b]	11.4	9.3	15.8
Services (Social) [b]	15.3	6.0	11.4
Federal government	4.1	5.6	2.2
State and local government	10.2	13.2	10.1

Table B.7.1-2
Employment by Sector by County and State, 2016
Source: U.S. Bureau of Economic Analysis, 2017 [a] Total employment includes 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 a person holds counted at full weight. [b] Nine 2-digit North American Industry Classification System service categories are combined here into these three divisions for ease of presentation. ▪ Consumer services consists of: other services; arts, entertainment, and recreation; and accommodation and food services. ▪ Producer services consists of: information; professional and technical services; management of companies and enterprises; and administrative and waste services. ▪ Social services consist of: educational services and health care and social assistance.

Travel and tourism also contribute to the local Corpus Christi economy. Corpus Christi is the sixth most visited metropolitan area in Texas, with leisure-based visitors accounting for an estimated 81 percent of total visitor days and tourism-related industries supporting more than 5 percent of the area's value added economic activity and 8 percent of total employment in the Corpus Christi Metropolitan Statistical Area (Lee, 2014). An estimated 47 percent of visitor trips to the Corpus Christi area were related to nature and wildlife, particularly beach strolling, bird watching, and hunting and fishing (Lee, 2014). A separate study estimated that the travel industry accounted for 6.8 percent of total employment in Nueces County in 2016 and 4.3 percent in San Patricio County (Dean Runyan Associates, 2017).

In 2017, Texas had a lower unemployment rate (4.3 percent) than the national average of 4.4 percent (U.S. Bureau of Labor Statistics, 2018a). However, the unemployment rate in Nueces County (5.4 percent) and San Patricio County (7.6 percent) was higher than both the state and national averages in 2017 (table B.7.1-3). The percentage of the population below the poverty level in Nueces County (15.1 percent) was lower than the state average (15.6 percent) in 2016, while San Patricio County had a higher percentage below the poverty line (15.8 percent). The 2017 median household income for Nueces County ($53,562) and San Patricio County ($51,667) were slightly lower than the State of Texas ($56,583), as presented in table B.7.1-3.

Table B.7.1-3

Employment, Poverty, and Income by County and State

Indicator	Nueces County	San Patricio County	State of Texas
Unemployment Rate (2017) (%)	5.4	7.6	4.3
Unemployment Rate (2016) (%)	5.7	7.6	4.6
Population below the Poverty Level (2016) (%)	15.1	15.8	15.6
Median Household Income (2016) ($)	53,562	51,667	56,583
Median Household Income (% of State Median)	94.7	91.3	100.0
Sources: U.S. Census Bureau, 2018a; U.S. Bureau of Labor Statistics, 2017, 2018a, 2018b			

Projected employment during construction and operation of the Stage 3 Project is summarized in table B.7.1-4. The Stage 3 Project would have an estimated total construction payroll of $1.2 billion to $1.3 billion over the 48-month construction period. Total material purchases are expected to be approximately $1.0 billion, of which approximately $360 million to $480 million (36 percent to 48 percent) would be made locally (within San Patricio and Nueces counties). These expenditures, along with spending on equipment and services in the region, would generate economic activity and support employment and income elsewhere in the economy through the multiplier effect. The multiplier effect occurs as initial changes in demand affect the local economy and generate indirect and induced impacts.

Local workers (currently residing within a 50-mile commuting distance of the work site) are expected to account for the majority of the construction workforce for the duration of the Project. The remaining construction workforce would consist of non-local workers. Non-local workers would temporarily relocate to the Project vicinity for the duration of their employment. Some workers would possibly commute home on weekends, depending on the location of their primary residence. Very few, if any, of the non-local workers employed during the construction phase would be expected to permanently relocate to the Project area.

CCL Stage III would employ approximately 240 full-time operational staff at the Stage 3 LNG Facilities, divided into multiple daily shifts. An estimated staff of six would be employed to operate the Stage 3 Pipeline. The majority of these positions are expected to be hired locally, with a limited number of workers expected to permanently relocate to the Project area. Limited relocation for operational staff positions are expected, because a large, skilled workforce exists in the region, primarily due to the existing presence of the local refining and petrochemical sectors as well as training programs at local colleges. Employment numbers for the Project are summarized in table B.7.1-4.

Table B.7.1-4

Number of Workers Required for the Stage 3 Project

Facility	Number of Workers During Construction	Number of Workers at Peak Construction	Total Duration (months)	Number of Permanent Workers During Operation
Stage 3 LNG Facilities	1,056 [a]	2,400 [a]	48	240
Stage 3 Pipeline	250	400	12	6
Total	1,306	2,800	48	246

[a] Numbers are based on concurrent construction of all seven liquefaction trains.

7.2 Housing

The majority of the construction workforce would be hired and/or contracted locally, and would likely commute to and from their homes to work each day. The remaining construction workforce is assumed to permanently reside further than commuting distance from the Project sites and would be expected to temporarily relocate to the Project vicinity for the duration of their employment; possibly commuting home on weekends, depending on the location of their primary residence.

Housing resources are summarized by county and nearby community in table B.7.2-1 and are based on U.S. Census Bureau estimates for 2012 to 2016 (2018b, 2018c). These estimates suggest that rental housing is available in San Patricio and Nueces counties, with a substantial number of units available for rent in Corpus Christi. All of which are located within commuting distance of the proposed Project. Additional units classified for seasonal, recreational, or occasional use may also be available (table B.7.2-1).

Table B.7.2-1

Temporary Housing Units Available in the Stage 3 Project Area

County/City	Housing Units [a]				Number of Hotel/ Motel Rooms 2016 [c]	Number of Camp-grounds/ RV Parks [d]
	Total Housing Units	Rental Vacancy Rate (Percent)	Units Available for Rent	For Seasonal, Recreational, or Occasional Use [b]		
Nueces County	145,791	6.0	3,553	4,969	9,796	24
Corpus Christi	27,131	5.9	3,284	2,604	7,893	11
San Patricio County	129,357	6.0	468	827	1,091	17
Gregory	720	0.0	0	0	NA	0
Ingleside	3,648	7.1	74	0	196	0
Portland	6,202	11.1	262	77	446	1
Sinton	2,118	4.2	23	56	78	1
Taft	1,180	3.2	13	0	NA	0

NA = not available

[a] Data on housing units are from the American Community Survey 5-year estimates for 2012-2016 (U.S. Census Bureau, 2018b; 2018c).
[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.
[c] Number of hotel and motel rooms are for 2016 from the Texas Hotel Report (Source Strategies, Inc., 2016).
[d] Number of campgrounds and recreation vehicle (RV) parks as advertised in www.yellowbook.com. Actual numbers may vary (YellowBook, 2015).

The vacant rental housing, motels/hotels, and RV parks in the Project vicinity are sufficient to accommodate the estimated peak non-local workforce. Since many workers are expected to room with each other to lower costs, and peak construction months would be limited, the available housing is expected to be considerably more than needed.

Due to the relatively small non-local workforce and the availability of temporary housing within commuting distance of the Project area, we conclude that construction of the Project would have a minor, temporary impact on housing in the affected area. Operation of the Project would result in a limited number of non-local workers permanently relocating to the affected area. However, even if all 246 operation personnel (240 associated with the Stage 3 LNG Facilities and 6 associated with the Stage 3 Pipeline) are non-local, an adequate number of housing units are available. Therefore, we conclude that operation of the Project would have a negligible but permanent impact on the local housing market.

7.2.1 Displacement of Residences and Businesses

The Stage 3 LNG Facilities would be largely located on reclaimed industrial property owned by an affiliate of CCL Stage III, and there are no existing or planned residential developments within 0.25 mile of the Stage 3 LNG Facilities site. The Stage 3 Pipeline would run parallel to the Corpus Christi Pipeline and primarily across agricultural lands. No residences or buildings are located within 50 feet of the Stage 3 Pipeline construction work areas. If construction requires the removal of private property features such as gates or fences, the landowner or tenant would be notified beforehand. Following completion of construction, the property would be restored in accordance with any agreements between

CCPL and the landowner. Therefore, we conclude that construction and operation of the Project would not displace residences or businesses.

7.3 Public Services

This section describes the community and public services available within the affected area, including schools, emergency response protocols and medical facilities, and fire and police protection. Construction of the Stage 3 LNG Facilities and the Stage 3 Pipeline could result in increased demand for emergency services. Cheniere would work directly with local law enforcement, fire departments, and emergency medical services to coordinate for effective emergency response. Table B.7.3-1 provides the total number of the public facilities with the Project vicinity.

Table B.7.3-1

Public Service Data for the Stage 3 Project Area

County / Municipality	Number of Police Departments	Number of Fire Departments (by type)	Number of Hospitals [a]	Number of Hospital Beds
COUNTIES				
San Patricio	8	1 (Career) / 7 (Volunteer)	1	75
Nueces	7	7 (Career) / 2 (Volunteer)	6	1,906
MUNICIPALITIES				
Corpus Christi	1	3 (City Career, Refinery Terminal, Naval Air Station)	6	1,906
Portland	1	1 (Professional plus Volunteer)	0	0
Gregory	1	1 (Volunteer)	0	0
Sinton	1	1 (Volunteer)	0	0
Taft	1	1 (Volunteer)	0	0
Ingleside	1	1 (Volunteer)	0	0

Source: Cheniere, 2012
[a] Hospitals do not include rehabilitation, long-term, and psychiatric hospitals.

Public health infrastructure in San Patricio County includes one community hospital, five health centers, and ten private clinics. The nearest hospital, Care Regional Medical Center in Aransas Pass is located approximately 9 miles from the Stage 3 LNG Facilities site and is equipped with a trauma center. Additional hospitals with trauma centers are located nearby in Corpus Christi. Nueces County has six hospitals, including Christus Spohn Hospital, Corpus Christi Medical Center, Driscoll Children's Hospital, Kindred Hospital, Northwest Regional Hospital, and Doctors Regional Medical Center, and all of which are located in Corpus Christi, about 9 miles southwest of the Stage 3 LNG Facilities.

Health care demands during the Project construction phase are expected to include emergency medical services to treat injuries resulting from construction accidents such as slips, trips, and falls. Medical facilities within the Project vicinity are sufficient to absorb any increase in demand by the temporary construction workforce, with minimal cost to the local governments. Ultimately, we conclude that the impacts on the local hospitals are expected to be negligible. The addition of about 240 full-time workers for operation of the Stage 3 LNG Facilities and 6 full-time workers for operation of the Stage 3 Pipeline would have a negligible effect on hospitals since these workers would mostly be hired from the local/regional labor pool.

As shown in table B.7.3-1, the cities of Portland, Gregory, Corpus Christi, Taft, Ingleside, and Sinton each have police and fire departments. The Gregory Police Department is the closest police department to the Stage 3 LNG Facilities site. Law enforcement and emergency services are also provided by the San Patricio County Sheriff's Office in Sinton, Texas. The Portland City Fire Department is the nearest professional fire service to the Stage 3 LNG Facilities site. Emergency services, including medical, fire, and law enforcement, are available through the "911" service and can address large scale emergency responses, as needed.

Construction-related demands on local agencies could include increased enforcement activities associated with issuing permits for vehicle load and width limits, local police assistance during construction at road crossings to facilitate traffic flow, and emergency medical services to treat injuries resulting from construction accidents.

The Stage 3 LNG Facilities site would be located in an unincorporated area that is not served on a regular basis by a municipal fire department. However, CCL Stage III is coordinating with the Portland and Gregory fire departments to discuss response to firefighting needs during construction of the Stage 3 LNG Facilities. We conclude that construction of the Project would have only minor and temporary negative impacts on the local police and fire services. During operation, CCL Stage III would contract with the Refinery Terminal Fire Company to provide firefighting and emergency services to the Stage 3 LNG Facilities with personnel and equipment permanently stationed onsite; therefore, we conclude that operation of the Stage III Project would have a negligible effect on local police and fire services.

The Stage 3 LNG Facilities site is located within the Gregory-Portland Independent School District (ISD), and the Stage 3 Pipeline traverses Gregory-Portland ISD, Taft ISD, and Sinton ISD. Table B.7.3-2 lists the number of public schools within each school district in San Patricio and Nueces counties. In the 2015-2016 school year, there were about 76,022 students enrolled in the 141 schools in these two counties (The Texas Tribune, 2017; Texas Education Agency, 2012; 2017).

Table B.7.3-2

School Districts and School Enrollment in the Stage 3 Project Area Counties, 2015-2016

School District	Number of Schools					Enrollment
	Total	Elementary	Middle/ Jr. High	High School	Other	
SAN PATRICIO COUNTY						
Aransas Pass ISD	5	3	1	1	0	1,806
Gregory-Portland ISD	7	4	2	1	0	4,587
Ingleside ISD	5	3	1	1	0	2,274
Mathis ISD	4	1	2	1	0	1,684
Odem-Edroy ISD	3	1	1	1	0	1,014
Sinton ISD	5	2	1	2	1	2,164
Taft ISD	3	1	1	1	0	1,119
NUECES COUNTY						
Agua Dulce ISD	2	1	0	1	0	380
Banquete ISD	3	1	1	1	0	939
Bishop Cons. ISD	5	3	1	1	0	1,375
Calallen ISD	6	3	1	2	0	4,030
Corpus Christi ISD	61	37	12	11	1	38,521
Driscoll ISD	1	0	1	0	0	282

Table B.7.3-2

School Districts and School Enrollment in the Stage 3 Project Area Counties, 2015-2016

School District	Number of Schools					Enrollment
	Total	Elementary	Middle/ Jr. High	High School	Other	
Flour Bluff ISD	7	3	3	1	0	5,755
London ISD	2	1	0	0	1	827
Port Aransas ISD	3	1	1	1	0	544
Robstown ISD	8	5	1	2	0	2,836
Tuloso-Midway ISD	6	2	1	3	1	3,841
West OSO ISD	5	2	1	2	0	2,008
Source: The Texas Tribune, 2017; Texas Education Agency, 2012; 2017						

A small portion of non-local workers temporarily relocating to the Project area could be accompanied by their families. The potential addition of a limited number of students in the Project vicinity would not be expected to affect existing average student/teacher ratios in any one location. The addition of about 240 full-time workers at the Stage 3 LNG Facilities and 6 full-time workers along the Stage 3 Pipeline would have a negligible effect on the local school system because these workers would be mostly hired from the local/regional labor pool.

7.4 Transportation and Traffic

7.4.1 Land Transportation and Traffic

__Stage 3 LNG Facilities__

The Stage 3 LNG Facilities site would be located on La Quinta Road, which intersects SH 35 and SH 361 in Gregory. From Gregory, US 181 provides access to Portland, Corpus Christi, and Interstate 37 (I-37) to the south, and Sinton and US 77 to the north. The City of San Antonio is located approximately 150 miles northwest of Gregory via I-37, and Houston is approximately 210 miles northeast via US 77/59.

Construction traffic would access the Stage 3 LNG Facilities site primarily via SH 361. Once at the site, most construction traffic would utilize La Quinta Road, which parallels the western boundary of the permanent site, while some would use a permanent access road authorized as part of the Liquefaction Project. Some construction traffic would access the temporary construction work areas on the west side via La Quinta Road. Material deliveries to the site would be via truck using the same access point as construction traffic. Heavy material delivery would occur via barge to the construction dock authorized for the Liquefaction Project.

There would be an increase in heavy truck traffic and workforce traffic to the Stage 3 LNG Facilities site during construction. CCL Stage III estimates an average of 20 to 30 deliveries via truck per day during construction, with an estimated peak of 44 to 55 trips per day. Total estimated daily construction traffic at peak construction would be approximately 800 roundtrips per day, including worker vehicles. Based on available traffic count data, construction of the Stage 3 LNG Facilities is not expected to significantly impact traffic flow on SH 35, as the estimated peak volume represents a daily increase in traffic of about 2 percent. This is based on the existing annual average traffic of 47,120 vehicles per day traveling the stretch of SH 35 near La Quinta Road (Texas Department of Transportation [TXDOT], 2017).

Vehicles traveling to the site could have an impact on traffic at the intersection of SH 35 and Broadway (in Portland) and in Gregory. A southbound SH 35 frontage road to northbound SH 35 frontage road U- turn exists at Broadway, which should minimize the traffic impact at this intersection. Vehicles exiting the site may have an impact on traffic at the intersection of SH 35 at State Loop 202. However, a U-turn lane that connects the northbound SH 35 frontage road to the southbound SH 35 southbound main lanes is located just west of State Loop 202. This connector would provide vehicles leaving the site an additional route, which would minimize impacts at the intersection.

CCL Stage III anticipates approximately three ethylene deliveries and one propane delivery for startup and up to 16 annual ethylene deliveries and approximately four annual propane deliveries for operation of the facilities. Both ethylene and propane deliveries are expected to be made via 2,000-gallon capacity (approximate) highway transport trucks.

CCL Stage III consulted with the TXDOT to determine the need for a Project-specific Traffic Management Plan on October 5, 2018. During this consultation, CCL Stage III committed to remain engaged with TXDOT and other members of the industry on local/regional transportation issues. Based on this commitment, along with CCL Stage III's past record of coordination with TXDOT, TXDOT determined that a Project-specific Traffic Management Plan is not needed.

Operation of the Stage 3 LNG Facilities would require an estimated 240 employees, divided between three daily shifts. Assuming these workers would each commute to work in their own vehicles, the addition of these vehicle trips would be equivalent to about 0.5 percent of existing traffic volumes as measured at SH 35 near the exit for La Quinta Road, and would not be expected to affect existing traffic flow patterns.

Overall, potential impacts on land transportation from the Stage 3 LNG Facilities site would primarily occur during the construction phase of the Project. This increase in traffic would be temporary and represent a relatively small increase in existing traffic volumes on surrounding roadways. Increases in traffic volume during operation of the Stage 3 LNG Facilities are expected to be relatively small and not result in a noticeable overall increase in area traffic.

Stage 3 Pipeline

Temporary impacts on the transportation network during construction of the Stage 3 Pipeline would result from construction across roads and from the movement of construction personnel, equipment, and materials to the pipeline right-of-way. The Stage 3 Pipeline would cross 18 roadways, including SH 35, US 181, SH 188, and US 77, as well as a number of local roadways. Roads crossed by the Stage 3 Pipeline and the proposed crossing method for each road are listed in table B.7.4-1.

Table B.7.4-1

Roadways Crossed by the Stage 3 Pipeline

Roadway Name	Milepost	Roadway Type	Jurisdiction	Construction Crossing Method
La Quinta Road	0.1	Paved	County	Bore
US 181 / SH 35	1.4	Paved	Federal / State	HDD
County Road (CR) 2986	2.4	Paved	County	Bore
CR 3667	4.5	Unpaved	County	Open Cut
CR 3567	5.7	Paved	County	Bore
CR 1612	6.9	Paved	County	Bore

Table B.7.4-1

Roadways Crossed by the Stage 3 Pipeline

Roadway Name	Milepost	Roadway Type	Jurisdiction	Construction Crossing Method
CR 78	7.5	Paved	County	Bore
CR 75	8.0	Unpaved	County	Open Cut
SH 893	9.1	Paved	State	Bore
SH 631	9.5	Paved	State	Bore
CR 1944	9.9	Paved	County	Bore
CR 2965	12.7	Unpaved	County	Open Cut
US 181	14.6	Paved	Federal	Bore
CR 1210	15.6	Unpaved	County	Open Cut
CR 63	16.3	Paved	County	Bore
SH 188	16.5	Paved	State	HDD
US 77	19.6	Paved	Federal	HDD

Construction of the Stage 3 Pipeline would result in some minor, short-term impacts on area roadways along the 21-mile route. Short-term impacts on traffic flow could occur where the pipeline would be installed beneath roadways due to safety precautions for workers crossing and working in the vicinity of the road crossings. However, most of these crossings would be constructed by bore and would have minimal impacts on traffic patterns and would not be expected to result in road closures.

Other roads would be crossed using the open-cut method, which would temporarily disrupt road traffic. During the open-cut method of roadway crossing, at least one lane of traffic would typically be kept open when constructing on or across residential streets. During the brief period when a road is completely cut, steel plates would be available on-site to cover the trench to permit travel by emergency vehicles. Traffic lanes and home access would be maintained except for the temporary periods essential for installing the Stage 3 Pipeline. If the landowner's primary access to their residence is impeded, alternative access would be provided via temporary driveway or temporary drive-over.

Construction of the Stage 3 Pipeline would require approximately 250 workers. Construction traffic using ware yards would result in localized increases in traffic, but existing traffic in the area is generally limited, and the increased traffic from construction is expected to be minor. If needed, traffic control personnel would be utilized to manage traffic in areas of active construction, but this would typically only be required for times when large trucks are entering or exiting the pipeline workspaces and associated traffic impacts would be of short duration. CCPL would repair any direct damage to local public roadways caused by construction equipment.

Based on the limited workforce required, operation of the Stage 3 Pipeline would not be expected to affect transportation or traffic in the vicinity of the Project.

7.4.2 Marine Transportation

The Port of Corpus Christi is the fourth largest port in the United States in total tonnage. The primary deep draft navigation channel serving the Port of Corpus Christi is the Corpus Christi Ship Channel, which extends from the Gulf of Mexico (via the Aransas Pass at Port Aransas) to the Port of Corpus Christi Inner Harbor. The La Quinta Ship Channel is an arterial deep draft navigation channel to the Corpus Christi

Ship channel. Traffic consists of offshore drilling rigs and platforms, tank ships and barges carrying chemicals and products to and from the chemical plants, and bulk cargo carriers loaded with alumina and ores.

Shallow-draft commercial vessel traffic (less than 18-foot draft) transits the ship channel between Harbor Island and the Gulf of Mexico. On average, this traffic volume is less than six vessels per day. Several fishing boats and other small craft also dock at Harbor Island and use either the Corpus Christi Ship Channel or Aransas Channel, and the Aransas Pass Jetty and Outer Bar Channels to access the Gulf of Mexico.

The marine terminal facilities required for mooring and loading LNGCs for the Stage 3 Project would be the same facilities utilized by the Liquefaction Project. No new marine facilities would be required for the Stage 3 Project. Some large materials required for construction of the Stage 3 LNG Facilities would be delivered via barge utilizing the construction dock constructed for the Liquefaction Project. Deliveries from the waterside would help reduce potential land transportation-related impacts during peak construction. The number of deliveries that would occur via barge is not expected to affect existing marine transportation patterns.

The Stage 3 Project would result in an anticipated increase in the maximum marine vessel traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year. The same tugs used for the Liquefaction Project would be available to facilitate maneuvering of LNGCs associated with the Stage 3 Project. Each LNGC visiting the Stage 3 LNG Facilities would be under the guidance of a licensed member of the Aransas-Corpus Christi Pilots who would be aboard the vessel for the entire transit between the sea buoy and the Liquefaction Project marine facilities. LNGCs would move at speeds determined to be safe to maintain proper maneuverability by the vessel's master and pilot. Piloted channel transit times in each direction for an LNGC are presently estimated to be three to four hours, including docking and undocking operations, between the sea buoy off Aransas Pass and the Liquefaction Project marine facilities. Actual underway time would be approximately 1.25 hours in the Corpus Christi Ship Channel and approximately 45 minutes to 1 hour in the La Quinta Ship Channel. It is anticipated that a moving safety and security zone would be established that would essentially limit deep draft traffic to a one-way pattern when LNGCs are in the channel. However, that restriction is not expected to have adverse impacts on overall marine traffic patterns.

The majority of vessel traffic that enters Corpus Christi Bay, via either the Corpus Christi Ship Channel or the Gulf Intracoastal Waterway (GIWW), is bound for the Port of Corpus Christi Inner Harbor. With a portion of the Corpus Christi Ship Channel and the GIWW both located seaward of the La Quinta Channel, transiting LNGCs could have a transient effect on vessel traffic flow in the Corpus Christi Ship Channel and GIWW. The majority 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 a relatively short distance as the tug and barge tow route and the LNGC route would overlap for only about 1.5 nautical miles between the GIWW's intersection with the Corpus Christi Ship Channel and the branch to the La Quinta Channel. Although subject to the restrictions of the moving safety and security zone around the transiting LNGC, ship traffic would generally share the Corpus Christi Ship Channel between the Aransas Pass Sea Buoy and the entrance of the La Quinta Channel; a distance of approximately 15 nautical miles.

The Port Aransas Ferry system crosses the Corpus Christi Ship Channel within approximately 0.6 nautical miles of the Aransas Pass Jetty Channel. Typically, four to six ferryboats operate during daylight hours, when LNGCs would be transiting. The estimated increase in the maximum marine vessel traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year that would occur as a result of the Stage 3 Project would result in LNGCs entering and leaving the Corpus Christi Ship Channel at an average rate of slightly more than two vessels per day. It is estimated that at most, two ferry trips may be potentially delayed up to a maximum of 20 minutes due to the passage of an LNGC. According to TXDOT, as documented in the Waterway Suitability Assessment for the Liquefaction Project, ferry operators in the area are accustomed to navigating around large vessels with safety zones and do not anticipate significant impacts on ferry operations from LNGCs under normal conditions (Gillespie, 2011).

In lieu of a Project-specific transportation plan for marine traffic, CCL Stage III has developed a Waterway Suitability Assessment, which addresses overall traffic patterns, waterway conditions, and safety and security matters for the proposed LNGC traffic in conjunction with other existing and potential future marine traffic. CCL Stage III submitted the Waterway Suitability Assessment to the Coast Guard in February 2016 with a request for a LOR confirming that the increase of 100 LNGCs per year would not significantly impact the waterway. The Coast Guard issued the LOR for the Project on August 15, 2018, and we have determined that Project impacts on ship traffic would not be significant.

7.5 Property Values

Currently available information does not support any firm conclusion with respect to the effects of natural gas or LNG facilities on property values. No significant impacts on property values are anticipated from construction and operation of the Stage 3 Project. The Stage 3 LNG Faculties would be located in an industrial area surrounded by industrial and commercial development, with no existing or planned residential development within 0.25 mile. The Stage 3 Pipeline would be located primarily in agricultural areas and parallel to the existing Corpus Christi Pipeline.

The impact a pipeline may have on the value of a tract of land depends on many factors including size, the value of adjacent properties, presence of other pipelines, the current value of the land, and the extent of development and other aspects of current land use. As part of the easement acquisition process, CCPL would compensate landowners as appropriate for unrestored construction damage to their property, including damage to crops and pasture. In the event that a landowner observes damage after restoration is complete, CCPL has stated that it would work with the landowner to correct the deficiency. Thus, we conclude that the Stage 3 Project is unlikely to incrementally add to any potential effects associated with the Corpus Christi Pipeline.

7.6 Tax Revenues

Available budget information shows revenues (and expenditures) for Fiscal Year 2018 in Nueces and San Patricio counties to be $182.6 ($209.2) million and $34.8 ($37.9) million, respectively (Nueces County, 2016; San Patricio County, 2017). CCL Stage III estimates that the Project would bring an influx of jobs and tax money to the area. According to a Perryman Group report (2018) prepared on behalf of CCL Stage III, *The Anticipated Impact of the Stage 3 Project of Cheniere's Corpus Christi Liquefaction Facilities on Business Activity in Corpus Christi, Texas, and the US,*[12] estimated tax revenues associated with the construction of the Project are approximately: $220 million for local taxing entities; $168 million for the state of Texas; and $737 million for the federal government. Estimated tax revenues associated with the operation of the Project, over a 25-year period, are approximately: $21 million for local taxing entities; $23 million for the state of Texas; and $85 million for the federal government.

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12 *The Anticipated Impact of the Stage 3 Project of Cheniere's Corpus Christi Liquefaction Facilities on Business Activities in Corpus Christi, Texas, and the US* is available on the FERC's eLibrary at www.ferc.gov under accession no. 20181001-5294.

7.7 Environmental Justice

For projects with major aboveground facilities, FERC regulations (18 CFR 380.12(g)(1)) direct us to consider the impacts on human health or the environment of the local populations, including impacts that would be disproportionately high and adverse for minority and low-income populations.

The EPA's Environmental Justice Policies (which are directed, in part, by Executive Order 12898: *Federal Action to Address Environmental Justice in Minority Populations and Low-Income Populations*) focus on enhancing opportunities for residents to participate in decision making. The EPA (2011) states that Environmental Justice involves meaningful involvement so that: "(1) potentially affected community residents have an appropriate opportunity to participate in decisions about a proposed activity that would affect their environment and/or health; (2) the public's contributions can influence the regulatory agency's decision; (3) the concerns of all participants involved would be considered in the decision-making process; and (4) the decision-makers seek out and facilitate the involvement of those potentially affected."

In accordance with the Executive Order 12898, all public documents and notices for the Project were made readily available to the public during our review of the Project. Cheniere notified the various landowners and stakeholders located in the vicinity of the Project and held an open house on July 1, 2017 to provide information to interested parties. As discussed in section A.5.0, FERC staff also conducted outreach efforts such as mailing the NOI to about 530 parties notifying them of the Project.

The Council on Environmental Quality (CEQ) also has called on federal agencies to actively scrutinize a number of important issues with respect to environmental justice (CEQ, 1997). As part of our NEPA review, we have evaluated potential environmental justice impacts related to the Project taking into account the following:

- the racial and economic composition of affected communities;
- health-related issues that may amplify project effects on minority or low-income individuals; and
- public participation strategies, including community or tribal participation in the NEPA process (CEQ, 1997).

The EPA provides guidance on determining whether there is a minority or low-income community to be addressed in a NEPA analysis. According to this guidance, minority population issues must be addressed when they comprise over 50 percent of an affected area or when the minority population percentage of the affected area is substantially greater than the minority percentage in the larger area of the general population. According to USC 689(3), low-income populations are defined as a geographic area represented by a census tract or equivalent county division where the poverty rate is 20 percent or greater. Therefore, low-income populations for this analysis were determined to be those with 20 percent or greater of the population living below the poverty threshold or when the percent of the population in the affected area living below the poverty threshold is substantially greater than the percent of the population living below the poverty threshold in the larger area of the general population (e.g., county).

In accordance with these guidelines, we prepared an environmental justice analysis for the Project utilizing a three-step approach to conduct our review. These steps are:

1. determine the existence of minority and low-income populations;
2. determine if resource impacts are high and adverse; and
3. determine if the impacts fall disproportionately on environmental justice populations.

To develop a more accurate understanding of the racial and ethnic characteristics of the communities in the immediate vicinity of the Project facilities, data were used from census block groups, as opposed to the larger geographic areas included in census tract and county level data. The EPA's Environmental Justice Screening and Mapping Tool was utilized, in part, to confirm the presence of census block groups that contain minority and low-income populations (EPA, 2017b). In this analysis, the minority and low-income population percentages in the State of Texas and the Project-area counties were compared to the respective percentages within the census block groups intersected by a 3.0-mile radius around the Stage 3 LNG Facilities and a 0.5-mile radius around the Stage 3 Pipeline and associated facilities. These census block groups comprised the affected community based on the potential environmental impact.

7.7.1 Stage 3 LNG Facilities

Table B.7.7-1 and figure B.7.7-1 provide an overview of the racial composition and economic characteristics of the population in the block groups within a 3-mile radius of the Stage 3 LNG Facilities.

Table B.7.7-1

Racial, Ethnic, and Poverty Statistics for Census Block Groups within 3.0-Mile Radius of the Stage 3 LNG Facilities

State / County / Tract / Block Group	Total Population	White (%)	Hispanic or Latino origin (of any race) (%)	African American (%)	Asian (%)	Some Other Race (%) [a]	Total Minority Population (%)	Percent Below Poverty Level (%)
Texas	26,956,435	43.4	38.6	11.6	2.0	2.0	**54.2**	15.1
Nueces County [b]	355,667	30.8	62.6	3.6	1.8	1.2	**69.2**	16.2
San Patricio County	66,706	40.1	56.1	1.6	1.0	1.2	**59.9**	14.1
Tract 105, Block Group 1 [c]	959	11.3	86.4	0.2	1.3	0.8	**88.7**	**29.5**
Tract 107, Block Group 1 [c]	847	41.7	57.9	0.5	0.0	0.0	**58.4**	0.0
Tract 107, Block Group 2 [d]	2,672	69.1	25.2	3.9	0.4	1.3	30.8	8.1
Tract 62, Block Group 1 [c]	876	87.6	6.5	5.9	0.0	0.0	12.4	0.0
Tract 103.01, Block Group 3 [c]	1,759	32.9	58.6	1.0	3.2	4.3	**79.5**	**20.1**
Tract 103.02, Block Group 3 [c]	445	45.8	52.4	0.0	0.0	1.8	**54.2**	**27.4**
Tract 105, Block Group 2 [c]	1,110	2.2	94.2	0.0	3.6	0.0	**97.8**	12.1
Tract 106.01, Block Group 3 [c]	894	32.3	65.2	1.0	0.0	1.5	**67.7**	9.2
Tract 106.01, Block Group 4 [c]	1,184	46.2	53.7	0.1	0.0	0.0	**53.8**	0.0
Tract 106.02, Block Group 1 [c]	2,033	50.7	46.0	2.5	0.2	0.6	49.3	3.6
Tract 106.02, Block Group 2 [c]	1,934	49.5	47.9	1.8	0.4	0.5	**50.6**	5.0
Tract 106.03, Block Group 1 [c]	2,597	82.1	15.0	0.4	1.0	1.6	18.0	3.0
Tract 106.04, Block Group 1 [c]	1,180	72.5	25.4	0.0	2.1	0.0	27.5	2.5

Table B.7.7-1

Racial, Ethnic, and Poverty Statistics for Census Block Groups within 3.0-Mile Radius of the Stage 3 LNG Facilities

State / County / Tract / Block Group	Total Population	White (%)	Hispanic or Latino origin (of any race) (%)	African American (%)	Asian (%)	Some Other Race (%) [a]	Total Minority Population (%)	Percent Below Poverty Level (%)
Tract 106.04, Block Group 2 [c]	1,987	66.6	31.3	0.0	1.5	0.7	33.5	3.2

Sources: U.S. Census Bureau, 2016

[a] The Other Race category is inclusive of census respondents identifying as American Indian and Alaska Native; Native Hawaiian and Other Pacific Island; and/or Some Other Race.
[b] Nueces County is located within 3.0 miles of the Stage 3 LNG Facilities, but would not be directly impacted by the Project.
[c] The block group is located within 3.0 miles of the Stage 3 LNG Facilities, but would not be directly impacted by the Project.
[d] The block group would be impacted by the Stage 3 LNG Facilities.

Bold values indicate a percentage that exceeds thresholds defined in text, and is an environmental justice population.

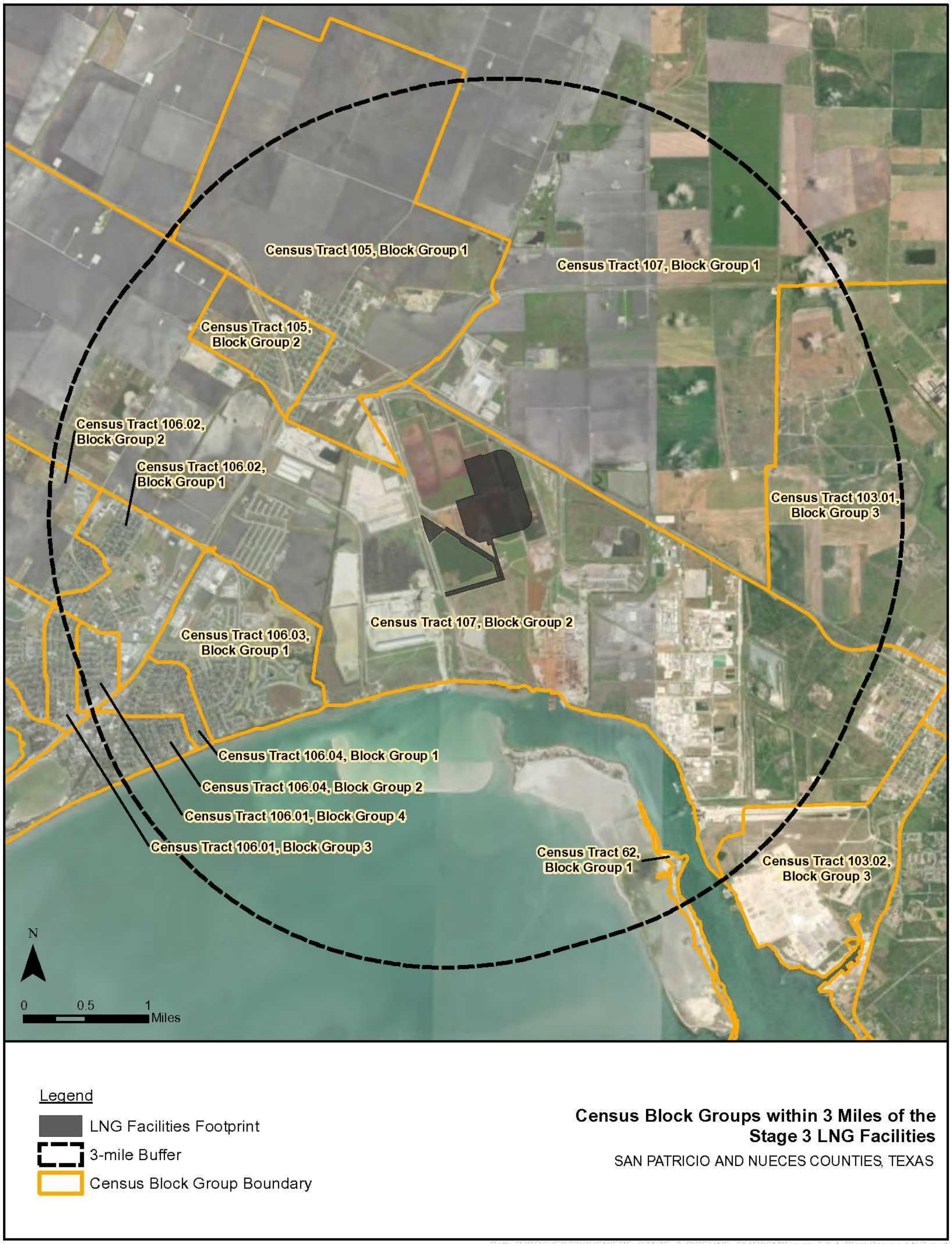

Figure B.7.7-1 Census Block Groups within 3.0-Mile Radius of the Stage 3 LNG Facilities

Eight of the 14 block groups located within 3.0 miles of the Stage 3 LNG Facilities have minority populations greater than the general EPA guidance of 50 percent. However, only three of these eight block groups have minority populations that are significantly greater than the minority populations of the reference communities (i.e., the counties in which they are located). Additionally, three of the 14 block groups have poverty rates that exceed 20 percent, indicating that these are low-income communities. According to the EPA guidelines, these are environmental justice populations located within the vicinity of the Stage 3 LNG Facilities.

Although the demographics indicate that potential environmental justice communities are present within the block groups near the Stage 3 LNG Facilities, there is no evidence that these communities would be disproportionately affected by the Project or that these communities would appreciably exceed impacts on the general population. As stated previously, the counties in which the communities are located (i.e., Nueces and San Patricio counties) contain minority populations that are greater than 50 percent. Additionally, the census block group in which the Stage 3 LNG Facilities would be located (i.e., Tract 107, Block Group 2) has minority populations and low-income populations that are less than 50 percent and 20 percent thresholds, respectively. The closest residential community that contains an environmental justice population is approximately 0.7 mile northwest of the proposed Stage 3 LNG Facilities in Gregory, Texas. However, as discussed in sections B.3.0 and B.8.1, construction and operation of the Stage 3 LNG Facilities would not significantly affect water quality or air quality. Construction of the Stage 3 LNG Facilities would result in an increase in traffic and noise in the environmental justice communities; however, as noted in sections B.7.4.1 and B.8.2.2, these impacts would be temporary and minor. Therefore, it is not anticipated that the Project would cause significant adverse health or environmental harm to any community with a disproportionate number of minority or low-income populations. Further, CCL Stage III has sited the Stage 3 LNG Facilities based on the proximity to the existing LNG facilities rather than land value or avoiding impacts on a particular community. The Stage 3 LNG Facilities are expected to generate economic benefits for local residences by stimulating economic growth and employment and by increasing the local tax base (see sections B.7.1 and B.7.6). Therefore, we have determined that construction and operation of the Stage 3 LNG Facilities would not have a disproportionate adverse impact on minority and low-income residents in the area.

7.7.2 Stage 3 Pipeline

Table B.7.7-2 and figure B.7.7-2 provide an overview of the racial composition and economic characteristics of the population in the block groups within a 0.5-mile radius of the Stage 3 Pipeline.

Table B.7.7-2

Racial, Ethnic, and Poverty Statistics for Census Block Groups within 0.5-Mile Radius of the Stage 3 Pipeline

State / County / Tract / Block Group	Total Population	White (%)	Hispanic or Latino origin (of any race) (%)	African American (%)	Asian (%)	Some Other Race (%) [a]	Total Minority Population (%)	Percent Below Poverty Level (%)
Texas	26,956,435	43.4	38.6	11.6	2.0	2.0	**54.2**	15.1
San Patricio County	66,706	40.1	56.1	1.6	1.0	1.2	**59.9**	14.1
Tract 105, Block Group 1 [b]	959	11.3	86.4	0.2	1.3	0.8	**88.7**	**29.5**
Tract 107, Block Group 1 [c]	847	41.7	57.9	0.5	0.0	0.0	**58.4**	0.0

Table B.7.7-2

Racial, Ethnic, and Poverty Statistics for Census Block Groups within 0.5-Mile Radius of the Stage 3 Pipeline

State / County / Tract / Block Group	Total Population	White (%)	Hispanic or Latino origin (of any race) (%)	African American (%)	Asian (%)	Some Other Race (%) [a]	Total Minority Population (%)	Percent Below Poverty Level (%)
Tract 107, Block Group 2 [c]	2,672	69.1	25.2	3.9	0.4	1.3	30.8	8.1
Tract 109, Block Group 1 [c]	1,521	48.9	51.1	0.0	0.0	0.0	**51.1**	18.5
Tract 110, Block Group 2 [c]	866	23.0	77.0	0.0	0.0	0.0	**77.0**	**39.8**
Tract 105, Block Group 2 [b]	1,110	2.2	94.2	0.0	3.6	0.0	**97.8**	12.1
Tract 108, Block Group 3 [b]	913	0.0	97.5	0.0	0.0	2.5	**100.0**	**26.9**
Tract 108, Block Group 4 [b]	836	10.0	88.9	1.1	0.0	0.0	**90.0**	**21.4**

Sources: U.S. Census Bureau, 2016

[a] The Other Race category is inclusive of Census respondents identifying as American Indian and Alaska Native; Native Hawaiian and Other Pacific Island; and/or Some Other Race.

[b] The block group is located within 0.5 mile of the Stage 3 Pipeline, but is not directly impacted by the Project.

[c] The block group is impacted by the Stage 3 Pipeline.

Bold values indicate a percentage that exceeds thresholds defined in text, and is an environmental justice population.

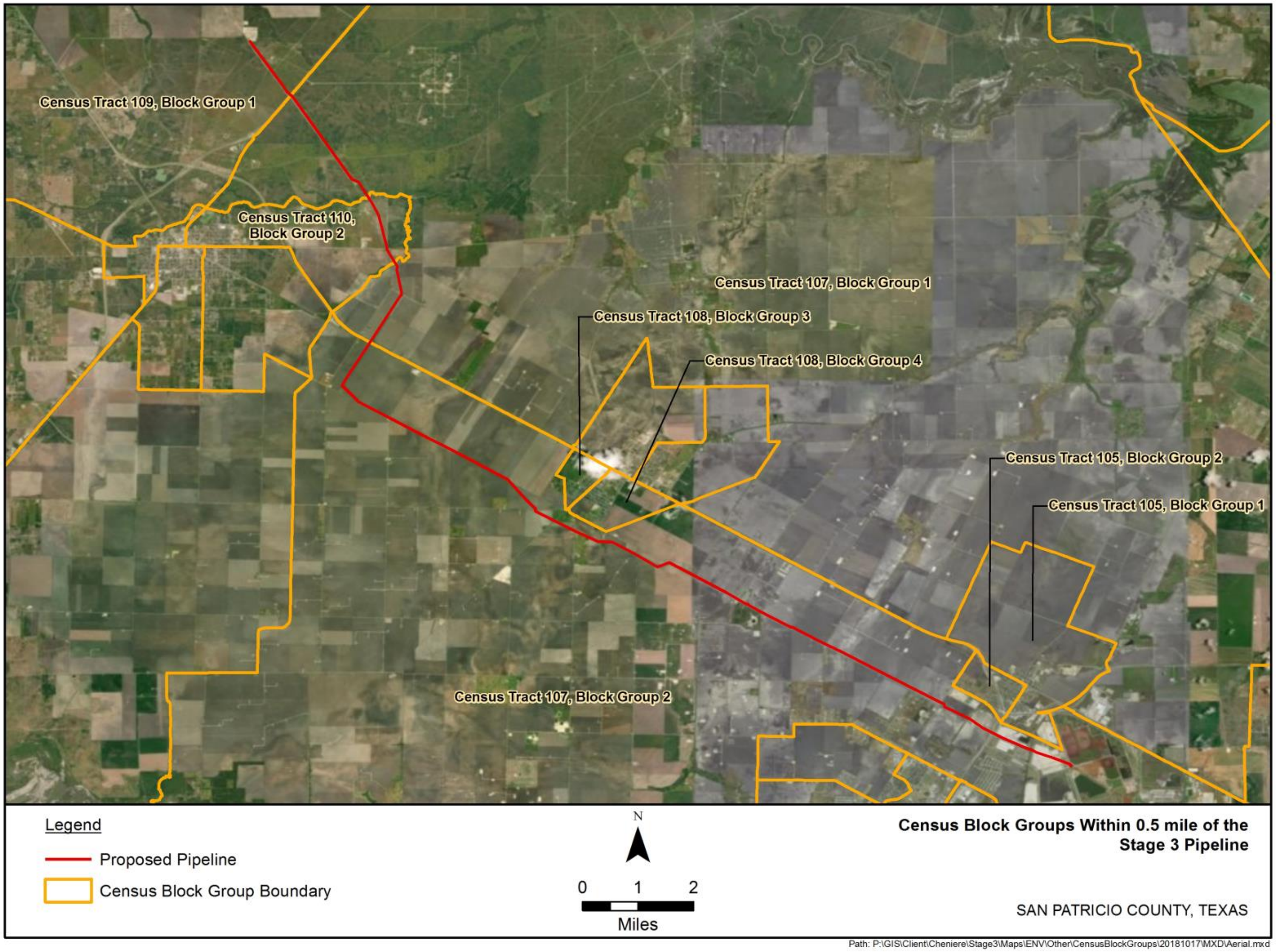

Figure B.7.7-2 Census Block Groups within 0.5-Mile Radius of the Stage 3 Pipeline

Seven of the eight block groups located within 0.5 mile of the Stage 3 Pipeline have minority populations that exceed 50 percent. However, only four of these block groups have minority populations that are significantly greater than the minority populations present within the reference community. Four of the eight block groups also have poverty rates that exceed 20 percent. According to the EPA guidelines, these are environmental justice populations located within the vicinity of the Stage 3 Pipeline.

Similar to the Stage 3 LNG Facilities, there is no evidence that the environmental justice populations located within 0.5 mile of the Stage 3 Pipeline would be disproportionately affected by the Project or that impacts on these communities would appreciably exceed impacts on the general population. The county in which the communities are located (i.e., San Patricio County) contain minority populations that are greater than 50 percent. Further, the Stage 3 Pipeline and associated facilities were sited in areas characterized as agricultural, industrial, or open land with few residences, and there are no existing residences located within 50 feet of the pipeline right-of-way. Although the Project could result in temporary, minor traffic delays during peak construction times, the Stage 3 Pipeline is not expected to have disproportionate, adverse impacts on minority and low-income residents in the area. Additionally, it is not anticipated that the Project would cause significant adverse health or environmental harm to any community with a disproportionate number of minority or low-income populations. Construction and operation of the Stage 3 Pipeline and associated facilities are expected to generate economic benefits for the affected communities through an increase in employment opportunities and tax revenues (see section B.7.6). Therefore, we have determined that construction and operation of the Stage 3 Pipeline would not have a disproportionate, adverse impact on the environmental justice communities located within 0.5 mile of the Stage 3 Pipeline.

8.0 AIR QUALITY AND NOISE

8.1 Air Quality

Air quality would be affected by construction and operation of the Project. Although air emissions would be generated by operation of equipment during construction of the Project facilities, most air emissions associated with the Project would result from the long-term operation of the Project facilities. This section addresses the construction- and operation-based emissions from the Project as well as applicable regulatory requirements and projected impacts on air quality. The term *air quality* refers to the relative concentrations of pollutants in the ambient air. The subsections below describe well-established air quality concepts that are applied to characterize air quality and to determine the significance of increases in air pollution. This includes metrics for specific air pollutants known as criteria pollutants, in terms of ambient air quality standards (AAQS), regional designations to manage air quality known as Air Quality Control Regions (AQCR), and the ongoing monitoring of ambient air pollutant concentrations under state and federal programs.

Combustion of fossil fuels, such as natural gas, produces criteria air pollutants, such as nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), and inhalable particulate matter ($PM_{2.5}$ and PM_{10}). $PM_{2.5}$ includes particles with an aerodynamic diameter less than or equal to 2.5 micrometers, and PM_{10} includes particles with an aerodynamic diameter less than or equal to 10 micrometers. Combustion of fossil fuels also produces volatile organic compounds (VOCs), a large group of organic chemicals that have a high vapor pressure at room temperature; and oxides of nitrogen (NO_x). VOCs react with nitrogen oxides, typically on warm summer days, to form ozone, which is another criteria air pollutant. Other byproducts of combustion are greenhouse gases (GHGs) and hazardous air pollutants (HAPs). HAPs are chemicals known to cause cancer and other serious health impacts.

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 thrown up in to the atmosphere by moving vehicles, construction equipment, earth movement, and/or wind erosion. Fugitive emissions, in the context of this EA, would be fugitive emissions of methane and/or VOCs from operational pipelines and aboveground facilities.

8.1.1 Regional Climate

The Project area climate can be characterized as humid subtropical and is significantly influenced by its location in the Texas Coastal Zone (i.e., proximity to the Gulf of Mexico). In general, Corpus Christi has very short mild winters and long hot summers, although the sea breeze can help moderate peak temperatures. Climate data obtained from NOAA for the period of 1981 to 2010[13] show that daily average high temperatures range from 67 degrees F during January to 94 degrees F during August. Daily average low temperatures range from 47 degrees F during January to 75 degrees F during August. The record minimum and maximum temperatures are 11 degrees F and 109 degrees F, respectively. The climatological annual average precipitation amounts to approximately 32 inches, with a monthly maximum of 5 inches in September and a monthly minimum of 1.5 inches in January (NOAA, 2013). Two principal wind patterns dominate the Texas Coastal Zone: frequent, strong southeasterly winds (essentially at any time of the year, but most pronounced in the spring through mid-summer) and north-northeasterly winds associated with cold fronts from October through March. The prevailing wind for the region is from the southeast and has an annual average velocity of 12 miles per hour (mph) (NOAA, 2018).

Two principal wind patterns dominate the Texas Coastal Zone – frequent, strong southeasterly winds (essentially at any time of the year, but most pronounced in the spring through mid-summer) and north-northeasterly winds associated with cold fronts from October through March. The prevailing wind for the region is from the southeast and has an annual average velocity of 12 mph (NOAA, 2018). The prevailing southeast wind is further strengthened by the thermal winds which develop when the air over the heated land in west Texas is warmer than the air over the relatively cooler waters of the Gulf of Mexico. This effect is most pronounced in the spring and summer.

Existing Air Quality

The EPA has established National Ambient Air Quality Standards (NAAQS) for six criteria pollutants: SO_2, CO, ozone (O_3), NO_2, particulate matter (PM_{10} and $PM_{2.5}$), and lead. There are two classifications of NAAQS, primary and secondary standards. Primary standards set limits the EPA believes are necessary 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 federal NAAQS for criteria pollutants are the same as the state standards established by the TCEQ in accordance with Section 30 of the TAC §101.21. The TCEQ has also established 30-minute average property line standards for SO_2 and H_2S in 30 TAC §112. The federal NAAQS and Texas-specific standards (referenced as net ground-level concentrations) are summarized in table B.8.1-1.

13 Climate data is presented by NOAA as a rolling 30-year average on the decade (e.g., 1981 to 2010, 1971 to 2000, etc.). Therefore, the 1981 to 2010 period is the most recent such climatic average dataset available.

Table B.8.1-1

Ambient Air Quality Standards

Pollutant	Averaging Period	Primary NAAQS (µg/m³)	Secondary NAAQS (µg/m³)	Texas NGLC
PM_{10}	24-hr [a]	150	150	-
$PM_{2.5}$	Annual [b]	12	15	-
	24-hr [c]	35	35	-
NO_2	Annual [d]	100	100	-
	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 [j]	Rolling 3-month average [d]	0.15	0.15	-
SO_2 [k]	3-hr [f]	N/A	1,300 (0.5 ppm)	
	1-hr [l]	196 (75 ppb)	N/A	
	30-min	-	-	1,021 [m]
H_2S	30-min	-	-	108/162 [n]

µg/m³ = 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 µg/m³ or 0.12 ppm) in 2005 for all areas, some areas (excluding the Project area) have continuing obligations to adhere to the standard.
[h] Final rule for the current 8-hr ozone standard became effective December 28, 2015. Revocation of the previous (2008) ozone standards and transitioning to the current (2015) standards would be addressed in the implementation rule for the current standards.
[i] Annual 4th-highest daily maximum 8-hr concentration, averaged over three years.
[j] In areas designated nonattainment for the Pb standards prior to promulgation of the current (2008) standards, and for which implmentation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standard (1.5 µg/m³ as a calendar quarter average) also remains in effect.
[k] The revoked 24-hr and annual average SO_2 standards (365 µg/m³ and 80 µg/m³, respectively) remain in effect in any area: 1) where it is not yet one year since the effective date of designation under the current (2010) standards; and 2) for which an implementation plan providing for attainment of the current (2010) standards has not been submitted and approved and which is designated nonattainment under the previous SO_2 standards or is not meeting the requirements of a SIP call under the previous SO_2 standards (40 CFR §50.4(3)).
[l] 99th percentile of the 1-hr daily maximum concentrations, averaged over three years.
[m] Net ground-level concentration not to be exceeded at the property boundary (30 TAC §112.3).
[n] Net ground-level concentration of 108 µg/m³ not to be exceeded on property normally occupied by people (30 TAC §112.31) and net ground-level concentration of 162 µg/m³ not to be exceeded on property not normally occupied by people (30 TAC §112.32).

Air Quality Control Regions and Attainment Status

AQCRs are areas established for air quality planning purposes in which state implementation plans (SIPs) 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 CAA and its amendments, as a means to implement the CAA and comply with the NAAQS through SIPs. 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 emission reductions throughout the AQCR. The entire Project area (including the Stage 3 LNG Facilities and Stage 3 Pipeline) is located 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. 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 (HGB) area, which is a "marginal" nonattainment area for the 2015 8-hour ozone standard. Additionally, the HGB 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. As discussed in the General Conformity section below, construction material transport emissions for the Project occurring within the HGB area would be below the applicable general conformity thresholds.

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 Cheniere to characterize ambient air quality for regulated criteria pollutants in the vicinity of the Project. The assessment included the following pollutants: O_3, CO, NO_2, $PM_{2.5}$, PM_{10}, SO_2, and lead. Concentration data from representative monitors for the 2015 through 2017 period are summarized in table 8.1.1-2. The concentrations shown in this table are maximum or near maximum values (as defined by EPA – see table 8.1.1-2 footnotes) 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. For each pollutant, table B.8.1-2 lists the available measured concentrations in terms of annual mean concentration values for each year and/or maximum short-term concentrations. As shown in the table, each of the measured pollutant concentrations is below the associated NAAQS for each applicable averaging period, thus indicating continued, ongoing attainment of the standards.

Table B.8.1-2

Ambient Air Quality Concentrations in the Vicinity of the Stage 3 Project

Pollutant	Averaging Period	Concentration (µg/m^3) by Year			Monitor Information	
		2015	2016	2017	Location	ID No.
CO	8-hour [a]	1,265	1,035	1,150	Cameron County	480610006
	1-hour [a]	2,185	1,380	2,530	Cameron County	480610006
NO_2	Annual [b]	4	3	4	Brazoria County	480391016
	1-hour [c]	38	36	36	Brazoria County	480391016
O_3	8-hour [d]	127	122	118	Nueces County	483550025
$PM_{2.5}$	Annual [b]	910	9	9	Nueces County	483550032
	24-hour [c]	30	27	22	Nueces County	483550032
PM_{10}	24-hour [a]	53	45	43	Nueces County	483550034

Table B.8.1-2 Ambient Air Quality Concentrations in the Vicinity of the Stage 3 Project						
Pollutant	**Averaging Period**	**Concentration (μg/m³) by Year**			**Monitor Information**	
		2015	**2016**	**2017**	**Location**	**ID No.**
SO_2	3-hour [a]	3	7	4	Nueces County	483550032
	1-hour [e]	10	20	21	Nueces County	483550032
Lead	3-month [f]	0.007	0.008	0.005	Cameron County	480610006

μg/m³ = micrograms per cubic meter
Except for lead, concentration values have been rounded to the nearest whole μg/m³
[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.

Greenhouse Gases

The EPA has defined air pollution to include the mix of six long-lived and directly emitted GHGs (CO_2, CH_4, N_2O, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride). The EPA found that the current and projected concentrations of these six GHGs in the atmosphere threaten the public health and welfare of current and future generations through climate change.

GHG, including CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, and perfluorocarbons, are naturally occurring pollutants in the atmosphere and products of human activities, including burning fossil fuels. These gases are the integral components of the atmosphere's greenhouse effect that warms the earth's surface and moderate day/night temperature variation. In general, the most abundant GHGs are water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and O_3. GHG produced by fossil-fuel combustion are CO_2, CH_4, and N_2O. GHGs are non-toxic and non-hazardous at normal ambient concentrations. GHGs emissions due to human activity are the primary cause of increased levels of all GHG since the industrial age.

As with any fossil fuel-fired project or activity, the project would contribute to GHG emissions. The principle GHGs that would be produced by the project are CO_2, CH_4, and N_2O. Emissions of GHGs are quantified and regulated in units of carbon dioxide equivalents (CO_2e). The CO_2e unit of measure takes into account the global warming potential (GWP) of each GHG over a specified timeframe. The GWP is a ratio relative to CO_2 that is based on the particular GHG's ability to absorb solar radiation as well its residence time within the atmosphere. Thus, 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 (EPA, 2017c). To obtain the CO_2e quantity, the mass of the particular compound is multiplied by the corresponding GWP and the product 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.

The EPA has expanded its regulations to include the emission of GHGs from major stationary sources under the Prevention of Significant Deterioration (PSD) program. The EPA's current rules require that a stationary source that is major for a non-GHG-regulated New Source Review (NSR) pollutant must also evaluate GHG emissions prior to beginning construction of a new or modified major source with mass-based GHG emissions equal to or greater than 100,000 tons per year (tpy) and significant net emission increases in units of CO_2e equal to or greater than 75,000 tpy. There are no NAAQS or other significant impact thresholds for GHGs.

8.1.2 Regulatory Requirements for Air Quality

The Project would be potentially subject to a variety of federal and state regulations pertaining to the construction and operation of air emission sources. The CAA, 42 USC 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 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 facilities are required to obtain an air quality permit before initiating construction.

The following sections summarize the applicability of various federal and state regulations.

New Source Review/Prevention of Significant Deterioration

Separate pre-construction review procedures for major new sources of air pollution (and major modifications of major sources) have been established for projects that are proposed to be built in attainment areas versus nonattainment areas. The pre-construction permit program for new or modified major sources located 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. Construction of major new stationary sources in nonattainment areas must be reviewed in accordance with the nonattainment NSR regulations, which contain stricter thresholds and requirements. Because all of the stationary emission sources at the Project facilities are located within an attainment area for all criteria pollutants, nonattainment NSR does not apply. Rather, each facility must be reviewed to determine applicability with the PSD program.

The PSD rule defines a major stationary source as any source with a potential to emit (PTE) 100 tpy or more of any criteria pollutant for source categories listed in 40 CFR §52.21(b)(1)(i) or 250 tpy or more of any criteria pollutant for source categories that are not listed. In addition, with respect to GHG, the major source threshold for CO_2e is 100,000 tpy. The Liquefaction Project is an existing major stationary source of NSR-regulated air pollutants.

Any change to a major stationary source that qualifies as a major modification under PSD rules (40 CFR §52.21 and 30 TAC §116.60 – §116.63) is subject to PSD permitting. A major modification is defined as any physical change or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant, and a significant net emissions increase of that pollutant from the major stationary source. Emission increases are compared against significant emission increase thresholds (100 tpy for CO; 40 tpy for NO_x, VOC, and SO_2 each; 15 tpy for PM_{10}, and 10 tpy for directly-emitted $PM_{2.5}$; 75,000 tpy for CO_2e) to assess PSD applicability; increases less than the thresholds do not trigger PSD review. CCL Stage III, as a modification to the currently permitted Liquefaction Project facilities, must be evaluated to determine if this modification qualifies as "major," requiring PSD review.

CCL Stage III originally was authorized, in February 2017, to construct and operate the Stage 3 facilities per TCEQ NSR Permit No. 139479, PSD Permit No. PSD-TX-1496, and GHG Permit No. PSD-TX-157. The original design, which included the construction of two large-scale liquefaction trains and the ancillary equipment to support these trains, triggered PSD review for multiple pollutants. In June 2018, CCL Stage III filed an application to amend the issued TCEQ NSR, PSD, and GHG permits to address revised designs for the Project. Most notably, the combustion turbines are not part of the revised Project design. CCL Stage III filed the FERC application for the Project concurrent with submitting the TCEQ NSR/PSD/GHG permit amendment application to the TCEQ.

Table B.8.1-3 shows the currently-authorized annual emission rate for each PSD-regulated pollutant for the Stage 3 Project LNG Facilities, as well as the proposed emission rates for the revised Project design currently under review. The change in emissions results in a net decrease in emission rates for all PSD-regulated pollutants; therefore, PSD review would not be triggered by the design revision. The TCEQ NSR/PSD/GHG air permit amendment application submitted to the TCEQ in June 2018 detailed the Project design revision and the resulting emission changes. A revised permit application air quality analysis addressing the revised emissions was submitted to the TCEQ in December 2018.

Table B.8.1-3

Major Stationary Source/Prevention of Significant Deterioration (PSD) Applicability Analysis - Stage 3 LNG Facilities

Pollutant [a]	Current Authorized Emission Rates for the Stage 3 Project [b] (tpy)	Stage 3 Project current project Emissions (tpy)	Emission Rate Change (tpy)	Major Stationary Source Threshold Level (tpy)	PSD Review Triggered?
PM_{10}	40.6	19.8	-20.8	15	No
$PM_{2.5}$	40.6	19.8	-20.8	10	No
NO_x	1,730.2	238.2	-1,492.0	40	No
SO_2	24.0	7.4	-16.6	40	No
CO	1,645.9	1,006.1	-639.8	100	No
VOC	108.3	108.2	-0.1	40	No
CO_2e	2,372,879	900,845	-1,472,034	75,000	No [c]

[a] Projected emissions of other NSR/PSD-regulated pollutants are small to negligible.

[b] Authorized under TCEQ Permit No. 139479, issued to CCL for the Stage 3 Project on February 14, 2017.

[c] CO_2e threshold is only applicable if the major source threshold for another criteria pollutant is exceeded.

Table B.8.1-4 shows the estimated annual emission rates for each PSD-regulated pollutant for the Project's Sinton Compressor Station. The station is not an existing major source under the PSD permitting program, because the potential emissions of all PSD-regulated pollutants are less than the major source threshold (250 tpy). A modification to an existing non-major (or minor) source does not trigger PSD review unless the modification itself has emissions greater than the major source threshold. The emission increases associated with the expansion of the Sinton Compressor Station are less than 250 tpy for all PSD-regulated pollutants; therefore, it is not subject to PSD review.

Table B.8.1-4

Major Stationary Source/Prevention of Significant Deterioration (PSD) Applicability Analysis - Sinton Compressor Station

Pollutant [a]	Major Source Threshold (tpy)	Existing Station Emissions (tpy)	Existing Major Source? (Yes/No)	New Emissions from the Modifications (tpy)	New Emissions Alone Major? (Yes/No)
PM_{10}	250	9.6	No	11.5	No
$PM_{2.5}$	250	9.6	No	11.5	No
NO_x	250	80.2	No	95.9	No
SO_2	250	19.8	No	23.9	No
CO	250	91.0	No	94.6	No
VOC	250	36.0	No	11.4	No
CO_2e	75,000	NA	No [b]	187,305 [c]	No [b]

Table B.8.1-4

Major Stationary Source/Prevention of Significant Deterioration (PSD) Applicability Analysis - Sinton Compressor Station

Pollutant [a]	Major Source Threshold (tpy)	Existing Station Emissions (tpy)	Existing Major Source? (Yes/No)	New Emissions from the Modifications (tpy)	New Emissions Alone Major? (Yes/No)

[a] Projected emissions of other NSR/PSD-regulated pollutants are small to negligible.
[b] CO_2e threshold is only applicable if the major source threshold for another criteria pollutant is exceeded.
[c] Does not include the emissions from increased operation of the existing (Stage 1 and 2) turbines under the Project.
NA = not available

Title V 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 Part 70 and in 30 TAC §122. The operating permits required by these regulations are often referred to as Title V or Part 70 operating permits.

Major sources (i.e., sources with a PTE greater than a major source threshold level) are required to obtain a Title V operating permit. Title V major source threshold levels are 100 tpy for any regulated air pollutant (excluding any air pollutant regulated solely under Section 112 – for HAPs – of the CAA); 10 tpy for an individual HAP; or 25 tpy for any combination of HAPs. Additionally, facilities that have the potential to emit GHGs at a threshold level of 100,000 tpy CO_2e are also subject to Title V permitting requirements.

The Liquefaction Project is an existing major source subject to the Title V permitting program, operating under federal permit no. O3580. Therefore, CCL Stage III would need to apply to the TCEQ for a new or revised Title V operating permit for the Project changes before beginning Project operation per 30 TAC §122.130. After consideration of the Title V program and emissions increases associated with the Sinton Compressor Station under the Project, the station still is not a major source of air emissions, and a Title V operating permit is not required for it.

New Source Performance Standards

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. Note that electric motors would be used to drive the compressors associated with the Project. Therefore, NSPS regulations for controlling emissions from combustion turbines do not apply.

Subpart A of 40 CFR Part 60, *General Provisions*, includes broader definitions of applicability and various methods for maintaining compliance with requirements listed in subsequent subparts of 40 CFR Part 60. This subpart also specifies the state agencies to which the EPA has delegated authority to implement and enforce standards of performance. The TCEQ has been delegated authority for all 40 CFR Part 60 standards promulgated by the EPA. Equipment at the Project facilities that is subject to any of the NSPS subparts listed below would be subject to Subpart A.

Subpart Dc of 40 CFR Part 60, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, applies to the seven hot oil furnaces for the Project, each of which has an average heat input rating of 50 million British thermal units per hour (MMBtu/hr). NSPS Subpart

Dc applies to each steam generating unit that commences construction after June 9, 1989, that has a maximum heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The seven hot oil furnaces would be subject to the notification and recordkeeping requirements of NSPS Subpart Dc as defined in §60.48c(a) and §60.48c(g)(1)-(3) and (i).

Subpart Kb of 40 CFR Part 60, *Standards of Performance for Volatile Organic Liquid Storage Vessels,* applies to storage vessels containing volatile organic liquids. Regulatory applicability is dependent on the construction date, size, vapor pressure, and contents of the storage vessel. Subpart Kb applies to new tanks, unless otherwise exempted, 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 (kPa). 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 kPa. Pressure tanks are exempt from the requirements of Subpart Kb.

The new LNG storage tank would have a capacity of 160,000 m^3, which would meet the volume criteria for Subpart Kb applicability. LNG is considered a volatile organic liquid, because a small portion of the LNG would consist of VOCs. The LNG storage tank would operate at approximately -260 degrees F, and the true vapor pressure of the VOC (assumed to be propane) at this temperature is 0.0007 kPa. This would be well below the applicability threshold of 3.5 kPa; therefore, Subpart Kb would not apply to the LNG storage tank.

The Project would rely on existing storage tanks (i.e., permitted under the Liquefaction Project) when processing condensate at both the Stage 3 LNG Facilities and Sinton Compressor Station. Specifically, there is one existing condensate storage tank at the Liquefaction Project that would be used by the Project. This tank has a capacity greater than 75 m^3 and stores VOCs with a maximum true vapor pressure of approximately 15 kPa. This 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. There are two existing condensate storage tanks at the Sinton Compressor Station that would be used for the Project. Subpart Kb would not apply to these tanks, because each has a capacity less than 75 m^3.

The Project would include the addition of seven storage tanks for amine at the Stage 3 LNG Facilities. These tanks would have a storage capacity greater than 75 m^3, but amine has a vapor pressure much less than 15 kPa (and 3.5 kPa as well); therefore, Subpart Kb would not apply to these tanks.

Project design also includes 10 fixed-roof diesel storage tanks. Diesel has a vapor pressure less than 3.5 kPa. Subpart Kb would not apply to these tanks because each would have capacity less than 75 m^3.

Subpart KKKK of 40 CFR Part 60, *Standards of Performance for Stationary Combustion Turbines*, applies to a combustion turbine with a heat input rate at peak load equal to or greater than 10 MMBtu/hr. The two combustion turbines proposed for the Sinton Compressor Station, each with a maximum heat input rate of 216 MMBtu/hr, are subject to this regulation, and must comply with the NO_x and SO_2 emission limits stipulated therein.

Subpart OOOOa of 40 CFR Part 60, *Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015*, applies to emissions of GHG (methane) and VOC from affected facilities listed in §60.5365a(a) through (j). Examples of rule-identified facilities typically associated with natural gas facilities (including LNG storage/export operations) include centrifugal and reciprocating compressors, pneumatic controllers and pumps, storage vessels, and compressor station fugitive emission components. Storage vessels (specific to the existing (Liquefaction Project) condensate storage tanks that would be used by the Project) are projected to have VOC emissions less than the Subpart OOOOa applicability threshold of 6 tpy, and these vessels are not subject to the Subpart OOOOa requirements. The Sinton Compressor Station would have fugitive GHG and VOC emissions components, which is an affected facility under the rule. Therefore, CCL Stage III would be required to develop and implement a fugitive emissions monitoring plan. Initial and subsequent quarterly monitoring for, and if necessary, repair of equipment leaks would be required.

Subpart IIII of 40 CFR Part 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. The rule also requires owners and operators to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer. These requirements of Subpart IIII would apply to the nine diesel-fired standby emergency generators (eight at the Stage 3 LNG Facilities and one at the Sinton Compressor Station) and two fire water pump engines (both at the Stage 3 LNG Facilities) proposed for the Project. The recordkeeping and reporting requirements would also apply.

National Emission Standards for Hazardous Air Pollutants

The National Emission Standards for Hazardous Air Pollutants (NESHAP) codified in 40 CFR Parts 61 and 63 regulate HAP emissions. Part 61 was promulgated prior to the 1990 Clean Air Act Amendments (CAAA) and regulates specific HAPs, such as asbestos, benzene, beryllium, inorganic arsenic, mercury, radionuclides, and vinyl chloride.

The 1990 CAAA 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 CAAA. These standards, also known as the Maximum Achievable Control Technology (MACT) standards, were promulgated under Part 63. The 1990 CAAA defines a major source of HAPs as any source that has a PTE 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 are incorporated by reference in 30 TAC §113.55 and §113.00.

The Liquefaction Project is a major source of HAPs. The NESHAP regulations described in the following paragraphs have been identified as being potentially applicable to Project-specific emission units. Note that electric motors would be used to drive the compressors associated with the Project. Therefore, NESHAP regulations for controlling emissions from combustion turbines do not apply.

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 Part 63. This subpart also specifies the state agencies to which the EPA has delegated authority to implement and enforce NESHAP. Although not all NESHAPs have been delegated to the State of Texas, the specific NESHAPs that are applicable to the Project equipment have been delegated to the TCEQ.

Subpart Y of 40 CFR Part 63, *National Emission Standards for Marine Tank Vessel Loading Operations*, applies to marine vessel loading operations at facilities that are considered major sources of HAPs. Because the marine vessel tank loading operations would occur at loading berths that only transfer liquids containing organic HAPs as impurities, as the term is defined in 40 CFR §63.561, the existing Liquefaction Project is exempt from Subpart Y [40 CFR §63.560(d)(5)].

Subpart EEEE of 40 CFR Part 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 condensate for the Project would occur at existing facilities for the Liquefaction Project, which is subject to the requirements of this rule.

Subpart ZZZZ of 40 CFR Part 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. Seven of the eight standby diesel generators proposed for the Stage 3 LNG Facilities have a rating of 1,000 brake-horsepower (bhp); therefore, these generators are subject to Subpart ZZZZ. According to 40 CFR §63.6590(b)(1), as emergency reciprocating internal combustion engines, these seven generators would be subject to only the initial notification requirement of 40 CFR §63.6645(f). One of the eight standby diesel generators and the two fire water pump diesel engines proposed for the Stage 3 LNG Facilities have a rating of less than 500 bhp, and these units would have to meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII, per 40 CFR §63.6590(c)(2).

Subpart DDDDD of 40 CFR Part 63, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to boilers and process heaters located at a major source of HAPs. The seven hot oil furnaces proposed for the Project meet the definition of a process heater, and Subpart DDDDD requirements apply. The natural gas-fired furnaces would not be subject to emission limits under the rule, but would be subject to work practice standards and an annual tune-up.

The Sinton Compressor Station is classified as an area source of HAPs. The two standby diesel generators proposed for the Sinton Compressor Station expansion are considered a new emergency reciprocating internal combustion engine at an area source and would have to meet with the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII, per 40 CFR §63.6590(c)(1). No other NESHAP regulations apply to the Sinton Compressor Station expansion.

Greenhouse Gas Reporting Rule

Subpart W under 40 CFR Part 98, the Mandatory Greenhouse Gas Reporting Rule, requires petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2e per year to report annual emissions of GHG to the EPA. “LNG storage” and “LNG import and export equipment” are industry segments specially included in the source category definition of petroleum and natural gas systems. Equipment subject to reporting includes storage of LNG, liquefaction of natural gas, and regasification of LNG.

Emissions of GHGs associated with the construction and operation of the Project were calculated. In addition, GHG emissions were converted to total CO_2e emissions based on the GWP of each pollutant. Although the reporting rule does not apply to construction emissions, construction emissions have been included for accounting and disclosure purposes. GHG emissions from operation of the Project would be included as part of the GHG reporting for the Liquefaction Project facilities.

Chemical Accident Prevention Provisions

The chemical accident prevention provisions, codified in 40 CFR Part 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 specified in the regulation, the facility must prepare and submit a risk management plan (RMP). An RMP is not required to be submitted to the EPA until the chemicals are stored onsite at the facility.

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 an RMP. 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 CAAA.

Stationary sources are defined in 40 CFR Part 68 as any buildings, structures, equipment, installations, or substance-emitting stationary activities which belong to the same industrial group, that are located 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. 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 193 and would not be required to prepare an RMP.

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 in section B.8.1.1 of this EA, the Project facilities are located in an area currently designated by EPA as in attainment of all NAAQS or unclassifiable for all criteria pollutants. Operating emissions for these facilities would be located entirely within designated unclassifiable/attainment areas for all criteria air pollutants and would be subject to evaluation under the NSR permitting program, and 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 Liquefaction Project construction dock via the GIWW. The Port of Houston is located in the HGB "marginal" ozone nonattainment area (2015 8-hour NAAQS), and 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 barge/tug emissions located in that nonattainment area (which is still classified as "severe" for the 1997 8-hour ozone standard).

CCL Stage III 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 areas based on the emissions generated during the time spent traveling through each of these areas.

CCL Stage III estimated that the total potential direct and indirect emissions of NO_x and VOC from the Project construction-related activity (i.e., construction barge/tug travel in HGB ozone nonattainment area) for each year in the 2020 through 2024 period would be 3.83 tpy and 0.14 tpy, respectively, as presented in resented in resource report 9. Because these emissions would be less than 25 tpy for each year, a General Conformity Determination is not required for the Project.

State Air Quality Requirements

In addition to the federal regulations identified above, the TCEQ has its own air quality regulations, codified in 30 TAC. The state requirements potentially applicable to the Project are discussed below:

- 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 114 – *Control of Air Pollution from Motor Vehicles*. This chapter addresses inspection requirements and maintenance and operation of air pollution control systems/devices for motor vehicles owned and/or operated at the Project facilities. This chapter applies to use of construction- and operations-related vehicles.
- 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. CCL Stage III is currently authorized by the TCEQ under Permit Nos. 139479/PSD-TX-1496/GHG PSD-TX-157 to construct the Project. CCL Stage III has applied to the TCEQ to amend those permits to update the project design. Those design changes result in a decrease in all TCEQ-authorized emission rates at the Stage 3 LNG Facilities; as a result, the Project would not trigger PSD review. With regard to the Sinton Compressor Station, because the potential emissions for the proposed changes to the station are below major source thresholds, CCPL has applied to the TCEQ to revise the existing Standard Permit (No. 136544) for the station.
- 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.

8.1.3 Construction Emissions Impacts and Mitigation

<u>Construction Emissions and Impacts</u>

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. More specifically, the construction activities that would generate air emissions include:

- site preparation (vegetation clearing, trenching, land contouring, foundation preparation, etc.);
- construction/installation of Project facilities;
- operation of off-road construction equipment and trucks during construction;
- operation of marine vessels (e.g., equipment barges/tugs) during construction; and
- workers' vehicles used for commuting to and from the construction site and delivery trucks (i.e., on-road vehicles).

The total period of construction for the Project facilities is estimated by Cheniere to be about 48 months. Note that the in-service date of at least one of the seven liquefaction trains would occur about 36 months after the start of Project construction.

Emission increases associated with the Project construction activities would have short-term, localized impacts on air quality. These emissions are not subject to the air quality permitting requirements that apply to emissions from operation of stationary sources associated with the Project. It should be noted that there are no residential or sensitive populations within 1.5 miles of the Stage 3 LNG Facilities. Nevertheless, the construction-related emission rates are discussed in this section as a means of identifying potential air quality concerns associated with the construction phase of the Project and to assist in developing mitigation.

The amount of fugitive dust generated in an area under construction would depend on numerous factors including:

- nature and intensity of the construction activity;
- speed, weight, and volume of vehicular traffic;
- size of area disturbed;
- amount of exposed soil and soil properties (silt and moisture content); and
- wind speed.

Fugitive dust would be produced primarily during site preparation activities, when the Project area would be cleared of debris, leveled, and graded. Site preparation activities for the Project would include land clearing, grading, filling, and placement of aggregate materials (e.g., for laydown areas and access roads). Site preparation activities would generate fugitive dust from earthmoving and movement of construction equipment over unpaved surfaces and tailpipe emissions from construction equipment and vehicle engines. Site preparation equipment would include bulldozers, compactors, graders, dump trucks, and other mobile construction equipment. On-road truck traffic (e.g., supply trucks) and worker commuter vehicles at the Project sites also would generate fugitive dust from travel on paved and unpaved surfaces. Cheniere intends to conduct periodic watering of unpaved roads to reduce the generation of fugitive dust.

The construction equipment and trucks/vehicles would be powered by internal combustion engines that would generate PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC, and CO emissions. These emissions would be generated by a variety of diesel-fueled (primarily) equipment, including off-road sources (e.g., bulldozers, cranes), on-road sources (e.g., construction worker vehicles, miscellaneous trucks), and marine vessels (e.g., barges/tugs). Most of the on-road vehicles would likely burn gasoline, although supply trucks and some worker pickup trucks would burn ultra-low-sulfur diesel fuel.

Construction of the Stage 3 LNG Facilities would include seven liquefaction trains, one 160,000-m^3 LNG storage tank, major mechanical equipment, pipeline interconnects, and piping and instrumentation, as well as construction of foundations, miscellaneous storage tanks, flares, and buildings. The Project construction equipment would include cranes, forklifts, manlifts, cement pump trucks, air compressors, welders, generators (for various duties, such as pumping, lighting, etc.), and miscellaneous trucks, which would result in fuel combustion emissions and fugitive dust emissions.

Project construction materials would be delivered primarily by barge to the Liquefaction Project construction dock. Cheniere estimates that a total of approximately 104 marine deliveries over the construction period would be needed for construction materials being shipped from the ports of Houston and Corpus Christi. Barge/tug operations would result in fuel combustion emissions from diesel-fired engines.

The construction of the Stage 3 Pipeline would include trenching, pipe-laying, and backfilling (in addition to the previously-described site preparation activities). The internal combustion engines powering most of the Pipeline construction equipment and vehicles would burn ultra-low-sulfur diesel fuel, and the remaining vehicles would burn gasoline. Equipment that would be used for the Stage 3 Pipeline construction activities would include various earthmoving equipment, cranes forklifts, compressors, pumps, trenchers, welders, borers, generators, and miscellaneous trucks.

The construction of the expansion at the Sinton Compressor Station would include two compressor units (two Titan 130E turbines), major mechanical equipment, pipeline interconnects, piping and instrumentation, and two M&R stations, as well as construction of foundations and buildings. The construction equipment would include cranes, forklifts, welders, pumps, generators, and miscellaneous trucks, which would result in fuel combustion and fugitive dust emissions.

Cheniere developed an inventory of off-road equipment and vehicles, on-road vehicles, and expected activity levels (either hours of operation or miles travelled) based on the expected duration of Project construction for the purposes of calculating emissions. The level of activity for each piece of construction equipment was combined with the relevant EPA emission factors (e.g., MOVES2014) to quantify annual emission estimates. Vehicle emissions would be minimized through compliance with 30 TAC Chapter 114 – Control of Air Pollution from Motor Vehicles and the use of ultra-low-sulfur diesel. Fuel combustion emissions from barges/tugs were calculated using engine sizes, activity levels, and emission factors based on EPA-sponsored marine vessel emissions estimation guidance. Fugitive dust emission estimates associated with land clearing activities for the Project were based on an estimate of total disturbed acreage and the use of emission factors based on Western Governors' Association-sponsored guidance, including an emission reduction or control factor of 50 percent for application of a dust suppressant (e.g., water).

The total criteria air pollutant and GHG (as CO_2e) emissions associated with construction-related activities for the Stage 3 LNG Facilities are summarized in table B.8.1-5. The total criteria air pollutant and GHG (as CO_2e) emissions associated with construction-related activities for the Stage 3 Pipeline and Sinton Compressor Station are summarized in table B.8.1-6. These totals include fuel combustion emissions as well as fugitive dust (i.e., particulate) emissions. The total PM_{10} and $PM_{2.5}$ emissions shown table B.8.1-5 are mainly the result of fugitive dust-generating activities, with most of the fugitive dust emissions associated with land disturbance activities. Note that the estimated annual construction emissions are based on the latest available information on Project schedule; and the timing and magnitude of annual emissions could vary based on when construction activities actually occur, which is dependent on business-related and other (e.g., regulatory) factors.

Table B.8.1-5

Annual Project Construction Emissions (tpy) - Stage 3 LNG Facilities

Year	**Pollutant**							
	PM_{10}	**$PM_{2.5}$**	**NO_x**	**CO**	**SO_2**	**VOC**	**HAPs**	**CO_2e [a]**
2019	263.2	32.0	78.0	46.1	0.4	5.6	1.6	17,003
2020	271.6	40.0	217.5	123.9	0.6	15.1	4.3	44,142
2021	280.7	49.0	380.2	239.8	0.8	27.4	7.8	79,022
2022	271.1	39.7	168.0	151.5	0.5	14.0	4.2	39,134
2023	260.1	29.0	29.8	30.3	0.3	2.3	0.8	7,400
Total Emissions (tons per construction duration)	**1,346.8**	**189.7**	**873.4**	**591.6**	**2.6**	**64.2**	**18.6**	**186,700**

[a] Metric tons

Table B.8.1-6

Annual Project Construction Emissions (tpy) - Stage 3 Pipeline and Sinton Compressor Station

Year	**Pollutant**							
	PM_{10}	**$PM_{2.5}$**	**NO_x**	**CO**	**SO_2**	**VOC**	**HAPs**	**CO_2e [a]**
2020	374.3	42.2	27.8	35.0	0.02	3.0	0.8	7,099

[a] Metric tons

Emissions over the construction period would increase pollutant concentrations in the vicinity of the Project. However, the effect on ambient air quality would vary with time due to the intensity of activities during the construction period, the mobility of the sources, and the variety of emission sources. There may be localized minor to moderate elevated levels of fugitive dust and tailpipe emissions in the vicinity of construction areas during periods of peak construction activity. In addition, there would be overlap of emissions from liquefaction train commissioning and operation and construction activities for the remaining trains. The potential impact of the overlap of emissions from construction, commissioning, and/or operations are discussed in the Operations Impacts Assessment section.

Construction Emissions Mitigation Measures

As discussed previously, fugitive dust accounts for significant PM emissions during the construction period for the Project. Therefore, fugitive dust controls would play an important role in reducing potential effects on air quality in the Project area. Project construction activities would be subject to 30 TAC §111.145, which requires the use of water or suitable oil or chemical for control of dust during construction activities or land-clearing operations.

In addition to the regulation-based precautions, Cheniere developed a *Fugitive Dust Control Plan* (FDCP), committing to additional measures to reduce fugitive dust emissions. FERC staff reviewed the FDCP and finds it acceptable. Measures outlined in the FDCP, include the following:

- use of a dedicated water truck to apply water to heavily used unpaved areas;
- ensure that dump trucks and other open-bodied trucks hauling soil or other dusty materials to or from the Project site are covered;
- use of signage to direct construction vehicle traffic to designated roads;
- enforcement of a 15-mph speed limit on unsurfaced roads;
- use of gravel or larger rock at construction entrance and exit locations; and
- measures to clean paved roads upon mud or dirt track-out.

Cheniere would minimize vehicular exhaust and crankcase emissions from gasoline- and diesel-fired engines by complying with applicable EPA mobile source emission performance standards and by using equipment manufactured to meet these standards. Additionally, Cheniere would be expected to implement the following work practices:

- Maintain construction equipment in accordance with manufacturers' recommendations. Maintenance and tuning of all construction-related equipment would be conducted in accordance with the original equipment manufacturers' recommendations; and
- Minimize engine idling to the extent practicable. Cheniere would instruct Project construction personnel to minimize the idle time of equipment to 5 minutes or less when not in active use. Cheniere'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.

Based on the projected level of construction activity, there may be localized minor to moderate elevated levels of fugitive dust and tailpipe emissions near construction areas during the 48-month construction period associated with the Project.

The construction emissions' impact on ambient air quality would vary with time due to the construction schedule, the mobility of the sources, and the variety of emission sources. Fugitive dust and other emissions due to construction activities generally do not pose a significant increase in regional pollutant levels, but local pollutant levels would increase at times during the construction period. Considering these factors, we determine that construction of the Project would not have a long-term, permanent effect on air quality in the area.

8.1.4 Operation Emissions and Impacts and Mitigation

Operating Air Emissions

Operation of the Stage 3 LNG Facilities would result in air emissions from stationary equipment (e.g., furnaces, flares, oxidizers, and emergency generators) and mobile sources (e.g., LNGCs and tugs). Also, operation of the Sinton Compressor Station would result in air emissions from stationary equipment (e.g., gas compressor turbines and emergency generators). Operational-phase emissions from a variety of sources/equipment would be permanent. These various sources and associated criteria pollutant, GHG, and HAP emission rates are discussed in detail in the following sections.

Stage 3 LNG Facilities

The Stage 3 LNG Facilities would operate seven natural gas liquefaction trains. Stationary and mobile sources of air emissions associated with operation of the Stage 3 LNG Facilities include:

- 10 diesel-fired engines for emergency use (eight standby emergency generators and two fire water pumps);
- seven hot oil furnaces;
- nine flares (three wet gas flares, three dry gas flares, and three multi-point ground flares for control of vented organic compound emissions);
- seven thermal oxidizers (for control of acid gas emissions);
- additional condensate processing through existing tank storage and truck loading;
- miscellaneous storage tanks (e.g., amine, diesel fuel);
- fugitive VOC and GHG emissions sources (e.g., loading operations, leaks from equipment such as valves, flanges, and connectors);
- equipment maintenance, start-up, and shutdown (MSS) activities;
- maneuvering and hoteling LNGCs; and
- truck traffic.

Emissions of NO_x, CO, PM_{10}, $PM_{2.5}$, SO, GHG, and HAP would be generated primarily by the fuel combustion sources. VOC emissions would be primarily generated by process fugitive sources. The flares are used only for start-up, shutdown, routine maintenance, and non-routine venting of emissions due to excess pressure. CCL Stage III plans to continuously operate the Stage 3 LNG Facilities, thus limiting start-up/shutdown events to those associated with periodic routine maintenance or the need to shut down due to equipment malfunction.

Once constructed, the Stage 3 LNG Facilities would undergo a pre-commissioning and commissioning process before they could be fully operational. This initial start-up process, which would occur over a multi-month period, would result in air emissions. Table B.8.1-7 summarizes the estimated criteria pollutants, GHGs, and HAPs emissions for the initial start-up activities.

Table B.8.1-7

Annual Emissions (tpy) Associated with Initial Start-Up of the Stage 3 LNG Facilities

Emission Source	Pollutant							
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2e	Total HAPs
Flares - initial commissioning [a]	21.7	17.5	169.9	0.02	--	--	40,017	0.1

[a] Because initial commissioning is a one-time activity that occurs before the plant is fully operational, emissions associated with this temporary activity are exempted from the PSD analysis (per 40 CFR § 52.21(i)(3)(ii)).

After completing the pre-commissioning and commissioning process, the Stage 3 LNG Facilities would start commercial operations. Table B.8.1-8 provides a summary of the estimated annual criteria air pollutant, GHG (as CO_{2e}), and HAP emission rates for sources, including marine vessels, associated with routine operation of the Stage 3 LNG Facilities. The annual emissions are based on continuous operation of the liquefaction trains (8,760 hours per year or 24 hours/day), except for standby generators and fire water pumps, which are based on a maximum annual operation of 100 hours.

Table B.8.1-8

Annual Emissions (tpy) for Operation of the Stage 3 LNG Facilities

Emission Source	Pollutant							
	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	HAPs	CO_2e [a]
Thermal oxidizers (7)	8	8	64.4	90.2	5.6	2	0.79	501,452
Hot oil furnaces (7)	11.4	11.4	46.9	126.3	5.7	8.3	2.83	191,735
Flares - wet gas (3), dry gas (3): normal operations	--	--	7.1	28.1	0.00002	0.9	0.01	2,138
Flares - Multi-point ground (3): normal operations	--	--	42.3	168.6	0.002	28.4	1.77	12,944
Flares - planned MSS	--	--	22.8	187.6	0.01	9.8	0.05	85,913
Marine flare [b]	--	--	46.7	400.3	--	3.4	--	99,953
Condensate storage/loading [b]	0.2	0.2	3.4	1.9	0.01	0.2	0.04	3,289
Standby generator diesel engines (8)	0.2	0.2	4.5	2.9	0.006	0.6	0.01	608
Firewater pump engines (2)	0.01	0.01	0.1	0.1	0.0004	0.02	0.0003	28
Diesel storage tanks (10)	--	--	--	--	--	0.0004	--	0
Amine storage tanks (7)	--	--	--	--	--	2E-06	--	0
Fugitive emissions	--	--	--	--	--	54.6	0.5	2,778
Miscellaneous MSS [c]	--	--	--	--	--	1E-06	--	7
Total Emissions	**11.8**	**11.8**	**174**	**916**	**5.7**	**106**	**5.2**	**399,393**

a Metric tons per year
b The marine flare, condensate storage tank, and loading operations would be shared with the Liquefaction Project. The emission rates shown are the increases for the Stage 3 Project.
c Includes MSS emissions not sent to the flare, such as that from the vacuum truck (condensate handling)

The main power load for operation of the Project liquefaction trains would be the electric motor drivers coupled to refrigeration compressors, with the electric power being provided via the local electric transmission grid.

The Texas *Clean Air Act* and TCEQ rules (30 TAC §116.111) stipulate that all construction permit applicants must evaluate (and apply) best available control technology (BACT) for the air emission sources. The TCEQ reviewed and approved CCL Stage III's BACT analysis for the Stage 3 LNG Facilities sources, including the hot oil furnaces, internal combustion engines (standby generators and fire water pumps), process fugitives, flares, and thermal oxidizers. Methods for reducing criteria pollutant emissions for each of these sources were evaluated based on technical feasibility. CCL Stage III would reduce emissions of NO_x from the hot oil furnaces through use of ultra-low NO_x burners, and CO and VOC emissions would be controlled through the use of good combustion practices. The limited-use emergency generators/engines would utilize good combustion practices and ultra-low sulfur diesel fuel to reduce emissions; especially for

PM and SO_2 emissions. CCL Stage III would use the TCEQ 28VHP Leak Detection and Repair (LDAR) Program for process fugitives from equipment in VOC service to control VOC emissions. Emissions from the flares would be reduced through good combustion practices and process design that minimizes the amount of routine and MSS flaring needed. Emissions from the oxidizers would be reduced through the use of low-NO_x burners and good combustion practices. The resulting BACT-based emission rates are consistent with NSPS, NESHAP, and/or TCEQ-published BACT emission standards applicable to the Project emission sources.

Flaring emissions would occur during the regularly scheduled maintenance event on an LNG train and for the "gassing up" process for inserted LNGCs and the "cooling down" process for warm LNGCs. Shutdown and start-up of the LNG train for maintenance is assumed by CCL Stage III to occur once per year for each train. Approximately 10 LNGCs per year for the Project would call on the port with their tanks filled with inert gas (mixture of mainly nitrogen and CO_2). Prior to the gassing up process, the tanks would be blown out directly to the marine flare. Additionally, approximately 83 LNGCs per year for the Project would require cooling down before LNG loading. CCL Stage III accounted for these additional flare emissions in their analysis.

During operation of the Stage 3 LNG Facilities, LNGCs and supporting marine vessels would routinely generate air emissions. The calculation assumptions/methodologies and emission factors used by CCL Stage III to develop emission rates for the marine vessels are consistent with those used for the Liquefaction Project.

Marine vessel emissions are quantified for operation in transit within state territorial waters, for maneuvering to the pier, and for hoteling at the pier. LNGC transiting would occur over an 8-hour time period for each ship call (four hours arriving and four hours departing), with each LNGC accompanied by two tug boats. LNGC maneuvering would occur over a 2-hour time period for each ship call (1 hour arriving and 1 hour departing) with the assistance of four tugboats for part of that hour and the accompaniment of one security vessel. While the LNGC is docked at the pier, emissions would be generated by carrier hoteling (i.e., standby and cargo loading operations on the carrier) for an approximate representative time period of 20 hours. One of the four tugboats would operate in idle/standby mode during this time. CCL Stage III analyzed emissions from the hoteling and maneuvering (including thruster) operations for the LNGCs assuming that the power requirements would be met through use of either a steam turbine, slow speed diesel (SSD) engine, or dual fuel diesel-electric engine. This analysis assumes primarily natural gas as fuel, although use of marine gas oil (MGO) for maneuvering operations with a SSD engine was also considered. CCL Stage III estimated LNGC maneuvering emissions assuming a representative main engine size rating of 30,000 kilowatts (kW).

CCL Stage III's emission calculations for marine vessels are based on a representative set of emission factors for each criteria air pollutant and each applicable phase of vessel operation (i.e., transiting, maneuvering, hoteling, idling/standby). The sources of emission factors are: 1) EPA emissions estimation guidance documents[14]; 2) engine manufacturer/vendor data; 3) EPA Tier 4 exhaust standards for marine compression-ignition engines; and 4) International Convention for the Prevention of Pollution from Ships (or MARPOL) Annex VI standards. Per EPA guidance, low load adjustment factors are applied to the emission factors for operation of the LNGC SSD engine. For marine vessel operation on diesel or MGO fuel, CCL Stage III's SO_2 emission calculations are based on emission factors assuming use of fuel oil with

[14] EPA's *AP-42 – Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* and *Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories (Final Report), April 2009*.

a sulfur content of 0.1 percent, which is consistent with the requirements of the MARPOL Annex VI standards for the North America Emission Control Area.

Table B.8.1-9 presents a summary of the estimated annual criteria air pollutant and GHG (as CO_2e) emissions associated with 1) LNGCs, tugboats (four for each ship call), and security vessels (one for each ship call) maneuvering to the pier; and 2) LNGCs hoteling at the pier with one tugboat idling nearby. Table B.8.1-10 presents a summary of the estimated annual criteria air pollutant and GHG (as CO_2e) emissions for LNGCs transiting in state waters with the accompaniment of two tug boats. The emissions described in this paragraph, which are not subject to review under the NSR/PSD program, are based on 100 carrier calls per year for the Project.

Table B.8.1-9
Annual Emissions (tpy) Associated with Maneuvering and Hoteling Operations for the LNGCs and Supporting Marine Vessels

Emission Source	Pollutant						
	NO_x	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_2e
LNGCs	6.7	9.4	2.7	1.2	0.06	0.06	1,495
Security Vessel	1.0	2.8	0.1	0.02	0.02	0.02	396
Tugs	1.3	3.7	0.1	0.03	0.03	0.03	527
Total Emissions	**9.0**	**15.8**	**2.9**	**1.2**	**0.1**	**0.1**	**2,418**

Table B.8.1-10
Annual Emissions (tpy) Associated with Operation of Marine Vessels in Transit in State Waters

Emission Source	Pollutant						
	NO_x	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_2e
LNGCs	28.2	4.3	2.4	23.3	3.6	3.3	1,385
Tugs	5.1	14.1	0.5	0.1	0.1	0.1	2,014
Total Emissions	**33.3**	**18.4**	**3.0**	**23.4**	**3.7**	**3.4**	**3,399**

Stage 3 Pipeline and Sinton Compressor Station

Sources of air emissions associated with the changes to the existing Sinton Compressor Station and along the new Stage 3 Pipeline would include:

- two new gas-fired Solar Titan 130e-22402S turbine/compressor units (23,436 hp each);
- two new standby diesel generators for emergency power;
- increased emissions from the existing two gas-fired turbine/compressor units (to account for potential operation during extreme weather conditions);
- additional condensate processing through existing tank storage and truck loading;
- new fugitive VOC and GHG emission sources (e.g., valves, flanges, connectors); and
- two new M&R stations (for pipeline interconnects).

Emissions of NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, GHG, and HAP would be generated primarily by the fuel combustion sources. The main combustion sources at the station are the natural gas-fired turbines. VOC emissions would be generated primarily by equipment MSS activities. In addition to emissions from the two new turbines, the Project would result in increased emissions from the two existing turbines at the Sinton Compressor Station due to increased firing rates (to account for operation during extreme weather conditions). The Project would also result in additional VOC emissions being generated by the additional condensate stored and loaded to trucks.

Table B.8.1-11 provides a summary of the estimated annual criteria air pollutant, GHG (as CO_2e), and HAP emissions for the additional sources proposed for installation at the Sinton Compressor Station and M&R stations. For the new combustion turbines, the annual emissions are based on continuous operation (i.e., 8,760 hours per year). For the standby diesel generators, annual emissions are based on operation of 100 hours per year. As previously discussed, the Sinton Compressor Station is not a major source under the PSD program and is not a major source of HAP emissions. Note that minimal fugitive emissions (0.001 tpy of VOC, <0.001 tpy of HAP, and 2.3 tpy of CO_2e) would be generated by the Stage 3 Pipeline during normal operation.

Table B.8.1-11

Annual Emissions (tpy) for Operation of the Sinton Compressor Station and M&R Stations

Emission Source	**Pollutant**						
	NO_x	**CO**	**VOC**	**PM_{10} / $PM_{2.5}$**	**SO_2**	**Total HAP**	**CO_2e**
Gas Turbines (2) [a]	87.6	91.8	10.3	10.6	21.8	4.9	187,205
Standby Generators (2)	0.5	1	0.2	0.02	0.02	0.05	101
Fugitive Emissions [a]	-	-	8.2	-	-	0.05	27,219
Tank Emissions	-	-	1.3	-	-	0.06	-
Total Emissions	**88.1**	**92.8**	**20.0**	**10.6**	**21.8**	**5.1**	**214,525**

[a] Includes MSS (startup and shutdown) emissions and M&R stations.

Rare situations (e.g., pipeline maintenance/inspections) may require "blowing down" a segment of the pipeline. The air pollutant emissions of concern for such limited events at the station are included in the fugitive emissions category in table B.8.1-11. CCL Stage III would minimize these emissions by reducing operating pressures to the maximum extent practicable for the maintenance event.

Operational emissions from the Sinton Compressor Station would be mitigated by compliance with TCEQ Standard Permit requirements and applicable federal NSPS and NESHAP. Emissions from the new natural gas-fired turbines at the station would be required to comply with 40 CFR Part 60, Subpart KKKK. The new standby generators would be subject to 40 CFR Part 60, Subpart JJJJ (and 40 CFR Part 63, Subpart ZZZZ for area sources). CCL Stage III would minimize fugitive emissions by conducting leak surveys and taking corrective action in accordance with 40 CFR Part 60, Subpart OOOOa and 40 CFR Part 98, Subpart W.

Operations Impacts Assessment

To provide a more thorough evaluation of the potential impacts on air quality in the vicinity of the Project, Cheniere conducted a quantitative assessment of air emissions, including marine vessel emissions, associated with operation of the Stage 3 Project and the Liquefaction Project. This assessment used EPA-and TCEQ recommended pollutant dispersion modeling methods to predict off-site (i.e., ambient) concentrations in the vicinity of the Project for comparison against applicable federal and state ambient air quality standards.

Although the Project is not subject to review under the PSD permitting program based on the amended potential emissions, the TCEQ required a revised air quality impact analysis for the updated Project design to satisfy NSR permitting requirements. Cheniere conducted an air quality impacts analysis in accordance with TCEQ modeling guidelines and the air quality modeling protocol previously reviewed by TCEQ. This analysis, which Cheniere submitted to TCEQ in December 2018, included on-shore Project emission sources and off-site emission sources to satisfy TCEQ impact assessment requirements. In conducting the air quality impact analysis to address FERC requirements, CCL Stage III built upon the analysis conducted to satisfy TCEQ modeling requirements, addressing emissions from on-shore stationary sources (including the Liquefaction Project emission sources) as well as LNGCs maneuvering to and hoteling at the pier and supporting marine vessel (e.g., tugboats) activities. The focus of the impact analysis was assessing compliance with the NAAQS and PSD Increments. The results of this analysis, shown in table B.8.1-12, indicate that emissions associated with the Project LNG Facilities, including stationary and marine sources would be below the NAAQS. A full impact analysis also was required to demonstrate compliance with the 24-hr $PM_{2.5}$ PSD Increment (9 µg/m^3). The total $PM_{2.5}$ impact from off-site PSD increment-consuming emission sources and the Project emission sources, including the estimated secondary $PM_{2.5}$ formation contribution, was 7.6 µg/m^3; therefore, emissions associated with the Project LNG Facilities would neither cause nor contribute to an exceedance of the 24-hr $PM_{2.5}$

Table B.8.1-12

Summary of Air Quality Impact Analysis Results

Pollutant	Averaging Period	Model-Predicted Concentration (µg/m^3)	Background Concentration (µg/m^3) [a]	Total Concentration (µg/m^3)	NAAQS (µg/m^3)
NO_2	1-hour	130.4 [c]	36.0	166.4	188
	Annual	6.9 [c]	11.2	18.1	100
$PM_{2.5}$	24-hour	2.4 [c]	25.8	30.9 [b]	35
	Annual	0.1 [d]	N/A	N/A	12
PM_{10}	24-hour	1.7 [d]	N/A	N/A	35
SO_2	1-hour	1.8 [d]	N/A	N/A	196
	3-hour	1.4 [d]	N/A	N/A	1,300
	24-hour	1.0 [d]	N/A	N/A	365
	Annual	0.07 [d]	N/A	N/A	80
CO	1-hour	782.6 [d]	N/A	N/A	40,000
	8-hour	237.9 [d]	N/A	N/A	10,000

N/A = Not applicable

a Background concentrations are based on available representative monitoring data for the 2015-2017 period.

b Includes estimated secondary $PM_{2.5}$ formation concentration of 2.7 µg/m^3.

c Model-predicted concentration includes emissions from operation of both the Stage 3 LNG Facilities, the Liquefaction Project, and off-site sources.

d Maximum model-predicted concentration is below the Significant Impact Level (SIL) for this pollutant and averaging period; therefore, a full impact analysis is not required.

The impact on atmospheric ozone, another criteria air pollutant, were assessed by CCL Stage III using EPA and TCEQ guidance. This assessment, accounting for the combined impacts from ozone precursors (NO_x and VOC), showed that the 8-hour daily maximum impact from the Project would be below the SIL for ozone; therefore, a cumulative impact analysis would not be required.

With regard to State/TCEQ standards, CCL Stage III conducted a State property line analysis for SO_2 and H_2S emissions and a health effects analysis for toxic air pollutant emissions. SO_2 and H_2S impacts were predicted, through a dispersion modeling analysis, to be less than 2 percent of the 30 TAC Chapter 112 standards; therefore, the concentrations are considered insignificant. The results of the health effects analysis triggered a sitewide modeling analysis for methyldiethanolamine (aMDEA) solvent emissions only. The results of that analysis showed that the maximum impact of aMDEA would be less than the 1-hour Effects Screening Level for that substance.

As noted previously, there would be an overlap of construction, commissioning, and operational emissions in certain years as construction of liquefaction trains are completed and begin commercial operation, while other trains are still under construction. Table B.8.1-13 shows the Project's year-by-year total annual emissions for construction, commissioning, and operational activities. Emissions associated with commissioning and operational activities would overlap with those from construction activities during the last two years of construction (2022 and 2023). The operational emissions for those years were estimated by adjusting the total maximum emission rates by the representative equivalent number of liquefaction trains expected to be in operation during the particular year. The representative equivalent number of trains expected to be in operation during 2022 and 2023 is 1.83 and 5, respectively.

Table B.8.1-13

LNG Facility Combined Construction, Commissioning, and Operation Emissions (tpy)

Year	Pollutant							
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	Total HAPs	CO_2e [a]
2019 [b]	106	9	81	0.4	638	74	2	24,102
2020 [b]	217	15	124	0.6	272	40	4	44,141
2021 [b]	380	27	240	0.8	281	49	8	79,024
2022 [c]	280	310	351	14	277	44	9	318,077
2023 [c]	298	779	281	34	278	41	9	698,967

a Metric tons
b Construction activity
c Construction, commissioning, and operation activities

The combination of construction, commissioning, and operational short-term emissions would, at times, be in excess of the modeled operational emissions alone in 2022 and 2023. During the concurrent construction, commissioning, and operational activities, the higher levels of emissions could result in air quality impacts greater than those summarized in table B.8.1-13. These higher concentrations would not be persistent at any one time during these years due to the dynamic and fluctuating nature of construction activities within a day, week, or month.

A separate air quality impact analysis was conducted by CCL Stage III, per TCEQ modeling guidelines, for the Sinton Compressor Station. The emissions for all stationary sources at the station under the Project were accounted for in the analysis, which generally followed applicable EPA- and/or TCEQ-recommended procedures. AERMOD was the dispersion model used to estimate ground-level concentrations, based on meteorological data for the 2011-2015 period for Corpus Christi International Airport. The results of this analysis are summarized in table B.8.1-14.

Table B.8.1-14

Summary of Air Quality Impact Analysis Results for the Sinton Compressor Station

Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Background Concentration (µg/m³) [a]	Total Concentration (µg/m³)	Ambient Air Quality Standard (µg/m³) [b]
NO_2	1-hour	75.2	36.0	111.2	188
	Annual	5.9	4.2	10.1	100
$PM_{2.5}$	24-hour	4.6	26.3 [c]	30.9	35
	Annual	0.52	9.3 [c]	9.8	12
PM_{10}	24-hour	6	53.0 [c]	59.0	35
SO_2	30-minute	23.7	NA	NA	1,021
	1-hour	18.9	17.1	36.0	196
	3-hour	22.2 [d]	--	--	1,300
	24-hour	13.1	1.4	14.5	365
	Annual	1.4	1.4	2.8	80
CO	1-hour	1,930 [e]	--	--	40,000
	8-hour	1,464	1,222	2,686	10,000

NA = Not applicable
[a] Background concentrations are based on available representative monitoring data for the 2015-2017 period.
[b] All standards are NAAQS, except for 30-minute average SO_2, which is a Texas property line standard.
[c] PM background concentrations are from the Dona Park Monitor (EPA No. 48-355-0034), which is located in Corpus Christi, adjacent to Up River Road and a large sparsely vegetated lot.
[d] Maximum model-predicted concentration is below the 3-hour SO_2 Significant Impact Level of 25 µg/m³.
[e] Maximum model-predicted concentration is below the 1-hour CO Significant Impact Level of 2,000 µg/m³.

The results of the air quality impact analysis for the Sinton Compressor Station showed that potential ground-level concentrations would be below Federal and State air quality standards. Therefore, operation of the station emission sources under the Project would not cause or contribute to an exceedance of those standards.

During the approximately 48-month construction period, residents in the vicinity of the Project may experience local, temporary impacts on air quality. These impacts would be reduced through the implementation of the measures outlined in the FDCP and other construction work practices designed to minimize construction-generated air pollutant emissions. During operation of the completed Project, we have determined that associated air emissions would have minor impacts on the local air quality and would not result in significant impacts on regional air quality. However, during times prior to Project completion, when commissioning and/or operational activities are occurring concurrent with construction activities, impacts could be greater. Due to the temporary nature of construction activities, implementation of the FDCP, and since the emissions associated with the operation of the Project would be below the NAAQ, we conclude that construction and operation of the Project would not have a significant impact on air quality.

8.2 Noise

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

Two measurements used by some federal agencies to relate the time-varying quality of environmental noise to its known effects on people are the equivalent sound level (L_{eq}) and the day-night equivalent sound level (L_{dn}). The L_{eq} is a sound level containing the same sound energy as the instantaneous sound levels measured over a specific time period. Noise levels are perceived differently, depending on length of exposure and time of day. The L_{dn} takes into account the duration and time the noise is encountered. Specifically, in the calculation of the L_{dn}, late night to early morning (10:00 p.m. to 7:00 a.m.) noise exposures are penalized by 10 A-weighted decibels (dBA), to account for people's greater sensitivity to sound during the nighttime hours. The A-weighted scale is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies. For an essentially steady sound source that operates continuously over a 24-hour period, the L_{dn} is 6.4 dBA above the measured L_{eq}.

In 1974, the EPA published its *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*. This document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has indicated that an L_{dn} of 55 dBA protects the public from indoor and outdoor activity interference. CCL has adopted this criterion to evaluate the potential noise impacts from the Project at noise-sensitive areas (NSAs) such as residences, schools, or hospitals. Because of the 10 dBA nighttime penalty added when calculating the L_{dn}, for a facility to meet the L_{dn} 55 dBA limit, it must be designed such that average noise levels on a 24-hour basis do not exceed 48.6 dBA L_{eq} at any NSA. In general, a person's threshold of perception for a change in loudness is about 3 dBA, whereas a 5 dBA change is clearly noticeable, and a 10 dBA change is perceived as either twice or half as loud.

There are no noise regulations or ordinances at the state or county level applicable to the Project. At the local level, ordinances were identified for the City of Corpus Christi and the City of Portland. However, due to the separation distance of the Project from the nearest point in the City of Corpus Christi, those ordinance requirements are not applicable to the Project. The City of Gregory and the City of Sinton had no noise regulations. The City of Portland ordinances related to noise are addressed in Section 11-182 "Noise nuisance enumeration" of the Code of Ordinances, which provides the following noise limits based on land use zoning:

The following defined acts shall be prima facie evidence of unreasonable conduct:

- The making of noise which exceeds sixty-three (63) decibels in any residentially zoned area (as defined by the city zoning ordinance) when measured from property under separate ownership.
- The making of noise which exceeds seventy (70) decibels in any commercially zoned area as defined by the city zoning ordinance, when measured from property under separate ownership.
- The making of noise which exceeds seventy-two (72) decibels in any industrially zoned area as defined by the city zoning ordinance, when measured from property under separate ownership.

- The making of noise which exceeds eighty-five (85) decibels using the L_{eq} method of noise measure for noise emanating from entertainment zoned property as defined by the city zoning ordinance, when measured from property under separate ownership.

These limits are less stringent than the FERC criterion and would not be exceeded in this project.

8.2.1 Existing Noise Conditions

Stage 3 LNG Facilities

The proposed Project site is located north of Corpus Christi Bay and south of Highway 361. No NSAs have been identified within a 1-mile radius of the Project. For the purpose of studying noise impacts, the nine nearest NSAs were identified, and are approximately 1.7 to 3.3-miles from the noise-producing equipment at the LNG Project site. Sound level measurements were performed at nine locations close to the NSAs. The measurement locations are designated LNG-1 through LNG-9, while the corresponding NSAs are numbered NSA 1 through NSA 9. The figures that show NSA measurement locations are located in appendix B of the EA.

- The measurement locations are LNG-1: a residential neighborhood located about 2 miles southwest of the Project area;
- LNG-2: the Northshore Country Club in Portland located about 2.3 miles southwest of the Project area;
- LNG-3: the recently developed Santa Catalina section of a residential subdivision located about 2-miles west of the Project area;
- LNG-4: the northern portion of a residential neighborhood located about 1.7 miles west of the Project area;
- LNG-5: the residential neighborhood on the southwest side of the Town of Gregory located about 1.8 miles northwest of the Project area;
- LNG-6: the closest residential neighborhood to the northwest of the Project area, located about 1.7 miles northwest of the Project area;
- LNG-7: an isolated single family residential structure located about 2 miles north of the Project area;
- LNG-8: an isolated single family residential structure located about 2.5 miles northeast of the Project area; and
- LNG-9: Ingleside High School located about 3.3 miles southeast of the Project area.

Existing ambient sound levels were measured at these nine locations. Nighttime insect noise was identified at LNG-1 and LNG-8 and was filtered from the measured sound levels to provide a more conservative characterization of the existing acoustic environment. Property access was not granted for LNG-7 (Cheniere did not provide reasoning in the application) so baseline sound measurements were collected at publicly accessible land near SH 35. Interference from roadway noise could have affected both daytime and nighttime measurements at LNG-7; therefore, the baseline sound levels measured at LNG-7 were adjusted using sound attenuation calculations to estimate the corresponding sound level at the setback distance of the residential structure.

Daytime sound levels were measured:

- July 27, 2017 at LNG-1, LNG-2, LNG-7, LNG-8, and LNG-9;

- July 28, 2017 at LNG-3;
- April 3, 2018 at LNG-4 and LNG-5; and
- July 28, 2017 at LNG-3 and LNG-6.

Nighttime sound levels were measured on:

- July 27, 2017 at LNG-1, LNG-2, and LNG-3;
- April 5, 2018 at LNG-4; on April 3, 2018 at LNG-5;
- July 26, 2017 at LNG-6; and
- July 28, 2018 at LNG-7, LNG-8, and LNG-9.

Measured ambient sound levels ranged from 47 to 62 dBA L_{dn}. Daytime sound levels were greater than nighttime sound levels at all NSA measurement locations.

Sinton Compressor Station

Baseline sound measurements were conducted in the vicinity of the Sinton Compressor Station expansion, located near milepost 21 (MP 21) of the Stage 3 Pipeline, northwest of US Highway 77 in a sparsely populated area. The City of Sinton is approximately 3 miles south of the compressor station. One NSA was identified within a 1-mile radius of the Project: a single-family residential structure on Carson Road in Sinton (S-1), located approximately 0.6 mile southeast of the Sinton Compressor Station. Sound levels were measured at the NSA on April 4, 2018. The measured ambient sound level was 50 dBA L_{dn}. Daytime levels were louder than nighttime levels due to traffic and train-related noise being mostly limited to daytime hours.

Horizontal Directional Drilling Sites

Baseline sound measurements were conducted near four sites where HDD is proposed:

- La Quinta Road (HDD-1) crossing has an approximately length of 3,880-feet and is located between MPs 0.0 and 0.8,
- U.S. Highway 181/SH 35 (HDD-2) crossing has an approximate length of 2,200-feet and is located between MPs 1.2 and 1.6;
- Oliver Creek (HDD-3) crossing has an approximate length of 2,800-feet and is located between MPs 16.0 and 16.6; and
- Chiltipin Creek (HDD-4) crossing has an approximate length of 2,400-feet and is located between MPs 17.3 and 17.8.

The NSAs for the HDD site baseline sound surveys were selected with respect to their distances to the entry and exit locations of the HDD sites. Seven sound level measurement locations were used to characterize the environment around the closest NSAs to the four HDD sites:

- HN-2: two residences west of the Project,
- HN-5: several residences along County Road 2921,
- HN-6: the NSA located closest to HDD-3 entry and exit sites,

- HS-1: two rural residences along County Road 1612,
- HS-2: a residence at the west of the intersection of Cupertino Street and Bay Breeze Drive,
- HS-3: a residential neighborhood in the northeast part of Portland, Texas, and
- HS-7: residences located northwest of HDD-2 entry site.

NSAs selected for the Stage 3 LNG Facilities Project were also applicable to many of the HDD site baseline sound surveys.

Ambient sound level measurements were conducted over the 4-day period from April 2 to 5, 2018. Measured ambient sound levels ranged from 44 to 61 dBA L_{dn}. Daytime sound levels were greater than nighttime sound levels at all NSA measurement locations.

8.2.2 Construction Noise Impacts and Mitigation

Noise emissions would be variable during the construction period and would occasionally exceed the existing ambient sound levels in the area; however, due to the temporary nature of construction noise, no long-term effects are anticipated.

Noise levels from facility construction were evaluated by CCL Stage III using a screening-level analysis approach that follows guidelines provided by the Federal Highway Administration (FHWA). The calculation methodology used the quantity and type of construction equipment by phase as well as typical noise source levels associated with that equipment to determine the composite sound levels for a standard distance of 50 feet. Variations in power and usage impose additional complexity in characterizing construction noise levels. The analysis conservatively assumes all construction equipment in a given construction phase would operate simultaneously at their typical load usage rating. Attenuation factors such as ground effects and terrain shielding were ignored.

Stage 3 LNG Facilities

Construction activities at the Stage 3 LNG Facilities would generate temporary increases in sound levels over an approximately 1-year period. Cheniere stated that only standard construction equipment would be used, and most construction would take place during normal working hours of 7:00 a.m. until 7:00 p.m. Emergencies, extreme weather events, or other unusual circumstances may necessitate nighttime work. Construction noise emissions are variable, as the types of equipment in use at a construction site change with the construction phase and the type of activities. The first phase of Stage 3 LNG Facilities construction consists of site preparation and earth work (e.g., excavation, filling and grading using heavy earth-moving equipment). The second phase is foundation preparation and concrete pouring. The third phase would generate the highest sound levels and would consist of erection of LNG tanks and installation of refrigeration equipment and piping. The fourth phase is installation of mechanical and electrical equipment.

The construction equipment would differ during each phase of construction, but in general, heavy equipment (e.g., bulldozers, loaders, dump trucks) would be used during the excavation phase of the Project construction. Noise is generated during construction primarily from diesel engines that power the equipment. Exhaust noise is usually the predominant source of diesel engine noise.

CCL Stage III developed a construction noise evaluation for the Stage 3 LNG Facilities. The equipment shown in table B.8.2-1 was included in the analysis for each construction phase at the facilities.

Table B.8.2-1

Stage 3 LNG Facilities Representative Maximum Noise Levels by Construction Phase at the Closest NSA (1.7 miles)

Construction Phase	Construction Equipment	Daytime Count at Peak	Nighttime Count at Peak	Reference Noise Level at 50 ft (15 m)	Usage Factor (%) [a]	Daytime Composite Noise Level, dBA L_{eq}	Nighttime Composite Noise Level, dBA L_{eq}	24-hour Composite Noise Level, dBA L_{dn}
Site Preparation	Dump Trucks	2	1	84	40	43	41	48
	Cat 325 B Track Hoe	1	1	80	40			
	Cat 938G Front End Loader	3	1	80	40			
	Straight Mast Forklift	1	0	85	20			
	Rough Terrain Forklift Telescoping Boom 5 ton	1	1	85	20			
	Fuel Service Truck	1	1	84	40			
	40 Passenger Bus	3	2	74	40			
Excavation	Cat D3 Dozer	1	0	85	40	42	37	45
	Case 580 Extend Boom Rubber Tire Hoe	1	1	80	40			
	Cat 228 Skid Steer Loader	1	0	80	40			
	60” Smooth Drum Roller	1	0	85	20			
	80-89” Compactor	1	0	80	20			
	Sled Compactor	2	1	85	20			
	Roller Compactor	2	1	85	20			
Foundation Placement	Stakebed Truck 1 Ton Tommy Lift	2	1	84	40	41	40	47
	Pump	5	5	77	50			
	Water Dust Control Truck-1500 gal	1	1	84	40			

Table B.8.2-1

Stage 3 LNG Facilities Representative Maximum Noise Levels by Construction Phase at the Closest NSA (1.7 miles)

Construction Phase	Construction Equipment	Daytime Count at Peak	Nighttime Count at Peak	Reference Noise Level at 50 ft (15 m)	Usage Factor (%) [a]	Daytime Composite Noise Level, dBA L_{eq}	Nighttime Composite Noise Level, dBA L_{eq}	24-hour Composite Noise Level, dBA L_{dn}
Installation of Mechanical Equipment	Air Compressor	6	2	80	40	41	37	44
	Welding Machine	18	8	73	40			
	Portable Light Plant	2	8	64	50			
	SUV-Staff	1	1	65	40			
Building Construction	Liebherr 200 Ton Crawler	1	0	83	16	49	46	53
	Liebherr 160 Ton Crawler	1	1	83	16			
	Grove 90 Ton	1	1	83	43			
	Grove 60 Ton	2	1	83	43			
	Cherry Pickers	2	1	85	40			
	48’ Step Deck Trailer	4	2	84	40			
	Pickup-Staff	15	5	55	40			
	ATV/Gator	8	4	85	40			
	Various Lefits (24, 40, 60, and 80 foot)	6	3	85	20			
	Various Generators (15, 150 kW)	10	4	70	50			
Finishing and Site Cleanup	Cat D3 Dozer	1	0	85	40	37	39	31
	Cat 325 B Track Hoe	2		80	40			
	SUV-Staff	2		65	40			

The sound levels for each phase of construction were predicted for the nine NSAs associated with the Stage 3 LNG Facilities. The results of the noise analysis are shown in Table B.8.2-2 for the two closest NSAs (LNG-4 and LNG-6) at 1.7 miles from the facility.

Table B.8.2-2

Summary of Stage 3 LNG Facilities Construction Acoustic Analysis Results

Construction Phase	NSA Location			Existing Ambient Sound level, L_{dn} (dBA)	Construction Noise Contribution, L_{dn} (dBA)	Cumulative Sound Level (Ambient + Construction), L_{dn} (dBA)	Net Increase (dBA)
	NSA	Distance from site to NSA (miles)	Direction from site to NSA				
Site Preparation	4	1.7	W	53	48	54	1
	6	1.7	NW	58	48	58	<1
Excavation	4	1.7	W	53	45	54	1
	6	1.7	NW	58	45	58	<1
Foundation Placement	4	1.7	W	53	47	54	1
	6	1.7	NW	58	47	58	<1
Installation of Mechanical Equipment	4	1.7	W	53	44	54	1
	6	1.7	NW	58	44	58	<1
Building Construction	4	1.7	W	53	53	56	3
	6	1.7	NW	58	53	59	1
Finishing and Site Cleanup	4	1.7	W	53	39	53	<1
	6	1.7	NW	58	39	58	<1

CCL Stage III expects that there may be some nighttime construction work at the Project site, with a smaller quantity of equipment in operation during nighttime hours than during daytime hours. CCL Stage III's construction sound level predictions for both day and night construction activities indicate that the overall construction sound levels would be lower than 55 dBA L_{dn} at all NSAs for all construction phases.

Stage 3 Pipeline Facilities / Sinton Compressor Station

Construction of the Stage 3 Pipeline would also result in short-term noise impacts, primarily due to the heavy equipment used in clearing and grading, pipe trenching, pipe welding, trench backfill, and right-of-way restoration activities. These activities would be temporary and of short duration at any given point along the linear pipeline route. No heavy construction activities are expected during nighttime hours at the Sinton CS. Nighttime work may be necessary for hydrotesting or commissioning of the station. Hydrotesting does not produce significant noise and commissioning should be a short-term activity.

Construction at the Sinton Compressor Station can be divided into six phases that feature different types of construction equipment. The six phases are: site preparation, excavation, foundation placement, installation of gas handling equipment and piping, building construction, and finishing and site cleanup. The sound levels resulting from construction activities vary significantly depending on such factors as the type and age of equipment, the specific equipment manufacturer and model, the activities being completed, and the overall condition of the equipment and exhaust system mufflers. CCPL has predicted sound levels of 55 dBA L_{dn} or lower for all construction phases at the Sinton Compressor Station NSA.

Pile driving and/or dynamic compaction activity is not expected as part of Project construction at either the Stage 3 LNG Facilities or the Sinton Compressor Station. At the Stage 3 LNG Facilities, the LNG storage tank would be supported by a base slab at grade. In addition, the ground improvement method proposed for the LNG trains and/or other support facilities would be to install grout columns with a load transfer pad throughout.

CCPL developed a construction noise analysis for the construction activities at the Sinton Compressor Station. The expected construction equipment was separated by construction activity phase, with the overall sound level for each phase calculated for the closest NSA to the Sinton Compressor Station site. The results of the analysis are presented in Table B.8.2-3.

Table B.8.2-3

Summary of Sinton Compressor Station Expansion Construction Acoustic Analysis Results

NSA Location			Existing Ambient L_{dn} (dBA)	Construction Noise Contribution, L_{dn} (dBA)	Cumulative Sound Level (Ambient + Construction), L_{dn} (dBA)	Net Increase (dBA)
NSA	Distance from site to NSA (miles)	Direction from site to NSA				
1	0.6	SE	52	55	57	5

Construction Noise Mitigation

Results of the construction acoustic analysis showed that noise produced by construction activities would contribute 55 dBA L_{dn} or less at nearby NSAs. In order to minimize potential noise impacts at nearby NSAs, CCL Stage III has committed to implement the following noise mitigation measures during construction activities to the extent practicable:

- Equipment and trucks used for Project construction would use the best available noise control techniques (e.g., improved mufflers, equipment redesign, use of intake silencers, ducts, engine enclosures and acoustically-attenuating shields or shrouds);
- Stationary noise sources would be located as far from adjacent NSAs as possible and would be muffled and enclosed within temporary sheds, incorporate insulation barriers or other measures to the extent feasible;
- Construction site and access road speed limits would be established and enforced during the construction period;
- Electrically-powered equipment would be used instead of pneumatic or internal combustion powered equipment, where feasible;
- Material stockpiles and mobile equipment staging, parking, and maintenance areas would be located as far as practicable from NSAs;
- The use of noise-producing signals, including horns, whistles, alarms, and bells, would be for safety warning purposes only; and
- No Project-related public address or music system would be audible at any adjacent NSA.

Horizontal Directional Drilling

There are four sites on the Stage 3 Pipeline where HDD work is proposed. Drilling at each of the proposed HDD locations would take place for four to six weeks. All activities, with the potential exception of the pipe pullback, would be performed during daytime hours. The drilling contractor would consider several factors to determine if pipe pullback would be required on a 24-hour basis, including soil conditions, equipment and personnel schedule, landowner requests, and permit approvals. The equipment would consist of an HDD rig and auxiliary support equipment including electric mud pumps, portable generators, a crane, mud mixing and cleaning equipment, forklifts, loaders, trucks, and portable light sets. Of these, the HDD rig is expected to be the dominant sound source.

CCPL developed a noise analysis for each HDD entry and exit work area. The results of the analysis are shown in Table B.8.2-5. This analysis shows that the sound level contributions from the HDD equipment would range from 29 to 51 dBA L_{eq} at nearby NSAs.

To be conservative, CCPL assumed that nighttime HDD operations would occur for the entire nighttime period.

Table B.8.2-4

Summary of HDD Acoustic Modeling Results Incorporating the Nighttime HDD Activities

HDD Site	NSA Location			Existing L_{dn} (dBA)	HDD Contribution (L_{dn} dBA) for Entry and Exit Equipment	Existing plus HDD Contribution (L_{dn} dBA)	Net Increase (dBA)
	NSA	Distance from NSA to Entry/Exit Site (miles)	Direction from Entry site to NSA				
HDD-1 La Quinta Road	2	0.6/1.3	SW	55	39	55	<1
	4	0.4/1.2	SW	53	45	54	1
	5	0.6/1.4	NE	61	43	61	<1
	6	0.81.3	N	58	39	58	<1
HDD-2 US Highway 181/ SH 35	1	0.9/1.2	NW	60	35	60	<1
	2	0.6/0.5	S	55	47	56	1
	3	1.1/1.2	SW	59	34	59	<1
	4	0.8/0.5	SE	53	44	54	<1
	5	0.5/0.6	NE	61	45	61	<1
	6	0.8/0.7	NE	58	40	58	<1
	7	0.9/1.3	NW	52	39	52	<1
HDD-3 Oliver Creek	1	0.2/0.3	N	53	56	58	5
	2	0.8/0.3	SE	44	37	44	1
	3	0.8/1.2	SW	44	40	45	2
HDD-4	1	0.5/0.2	SW	58	54	60	1

The noise analysis table above incorporates the nighttime pipe pullback activity at HDD locations using the CadnaA acoustic modeling program. The modeling assumed simultaneous operation of pipe pullback equipment at both HDD entry and exit points at a given crossing.

CCPL provided an HDD noise analysis that included nighttime drilling activities. The analysis determined that if nighttime drilling activities are required, the predicted sound levels due to HDD activities for the NSAs associated the La Quinta Road, US Hwy 181/SH 35, and Chiltipin Creek HDDs are expected to be negligible, with HDD contributions of less than 55 dBA L_{dn} and predicted increases in the ambient sound levels of 1 decibel or less.

At the Oliver Creek HDD-3 site, modeling predicted that the HDD contribution would be 56 dBA L_{dn} at NSA 1, which is located approximately 0.2 mile from the HDD entry and 0.3 mile from the HDD exit. This would result in an overall noise level (existing plus nighttime HDD contribution) of 58 dBA L_{dn} and result in an increase of 5 dBA in the ambient sound levels.

If nighttime HDD work is required at HDD-3, CCPL would implement mitigation measures, such as the construction of a sound wall with a length of at least 25 feet on the north side of the HDD operations at the entry side of the HDD prior to the start of nighttime HDD work. With the incorporation of a sound wall or comparable mitigation measure, the HDD contribution is estimated to be reduced to 51 dBA L_{dn}, which would result in an overall noise level (existing plus nighttime HDD contribution) of 55 dBA L_{dn} and an increase of 2 dB in the ambient sound levels.[15]

In addition to the sound wall, CCPL would implement the following additional noise mitigation measures:

- Limit truck traffic during overnight periods.
- Minimize noise from the use of backup alarms, using alternative measures that meet Occupational Safety and Health Administration regulations. This may include use of self-adjusting ambient-sensitive backup alarms, manually adjustable alarms on low setting, use of observers, and/or scheduling of activities so that alarm noise is minimized during nighttime periods;
- Fit all engines associated with nighttime HDD activities with critical-grade exhaust mufflers;
- Install acoustically rated enclosures on power generators located within the immediate HDD operational work areas; and
- Establish a public outreach program to notify residences within 1,000 feet of pending nighttime construction activities.

Site-specific plans that show HDD site detail such as equipment location and the location of noise walls have not been prepared at this time but would be prepared by the HDD contractor(s) prior to the start of construction. As noted earlier, if nighttime HDD work is required at the Oliver Creek HDD, CCPL would commit to installing appropriate mitigation on both the entry and exit side of HDD-3 prior to the start of nighttime HDD work. Proposed noise mitigation would be included on any site-specific plans prepared for the Oliver Creek HDD, and provided to FERC in a construction implementation plan, for our review and approval. With the incorporation of mitigation, the HDD contribution is estimated to be reduced to 51 dBA L_{dn}, which would result in an overall noise level of 55 dBA L_{dn} and an increase of 2 dB. These levels would comply with FERC criteria and are expected to be negligible.

Construction Summary

With the implementation of the mitigation measures outlined above, construction of the Project facilities would not have significant impacts on the acoustical environment at the nearby NSAs.

[15] As identified by Cheniere in their *Noise Analysis and Mitigation Plan for 24-Hour HDD Operations*, which is available on the FERC eLibrary website at https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp under accession number 20181221-5034.

8.2.3 Operational Noise Impacts and Mitigation

Stage 3 LNG Facilities

Operations of the Stage 3 LNG Facilities have the potential to result in noise impacts at nearby NSAs. Equipment planned for the Stage 3 LNG Facilities includes pumps, compressors, air coolers, ground flares, fired heaters, and their associated piping and equipment.

CCL Stage III developed a detailed noise model of the facility using SoundPLAN version 7.4. The results of the analysis are shown in Table B.8.2-6 for standard Project operations.

The M&R Stations would be constructed entirely with the Sinton Compressor Station and Stage 3 LNG Facilities boundaries and any incremental sound level contribution from the M&R equipment would be expected to be insignificant. In addition, the nearest NSA to the M&R station would be 0.63 mile, which is greater than 0.50 mile. Therefore, a noise assessment from the M&R would not be warranted.

Table B.8.2-5

Noise Impact Summary for the Stage 3 LNG Facilities

NSA	Existing Ambient L_{dn} (dBA)	Contribution from Previously Authorized Equipment Only, L_{dn} (dBA)	Predicted Noise Contribution from Stage 3 LNG Facilities Only, L_{dn} (dBA)	Predicted Cumulative Noise Contribution, L_{dn} (dBA) [a]	Existing Ambient and Predicted Cumulative Noise L_{dn} (dBA)	Expected Increase (dBA)
LNG-1	47	51	48	**53**	54	7
LNG-2	54	51	46	**52**	56	2
LNG-3	51	52	49	**54**	56	5
LNG-4	53	50	52	**54**	57	4
LNG-5	61	52	52	**55**	62	1
LNG-6	58	50	52	**54**	60	2
LNG-7	62	49	49	**52**	62	<1
LNG-8	49	49	46	**51**	53	4
LNG-9	50	48	42	**49**	52	2

[a] These values are the combined operations of the previously authorized Liquefaction Project equipment and the Stage 3 LNG Facilities.

The results of the acoustical analysis for the entire LNG terminal (Stage 3 LNG Facilities and previously authorized Liquefaction Project facilities) indicate that sound level contribution at the nearest NSAs from the combined Project equipment and previously authorized equipment would be below 55 dBA L_{dn}. Also, the increase in noise levels at the NSAs would just reach the threshold of a perceptible change. Although noise impacts from operation of the Project are not projected to be significant, to confirm the acoustical analysis is consistent with the actual operational noise levels, **we recommend that:**

- **CCL Stage III should file a full power load noise survey with the Secretary <u>no later than 60 days</u> after each liquefaction train is placed into service. If the noise attributable to operation of the equipment at the LNG terminal exceeds an L_{dn} of 55 dBA at the nearest NSA, <u>within 60 days</u> CCL Stage III should modify operation of the Stage 3 LNG Facilities**

or install additional noise controls until a noise level below an L_{dn} of 55 dBA at the NSA is achieved. CCL Stage III should confirm compliance with the above requirement by filing a second noise survey with the Secretary <u>no later than 60 days</u> after it installs the additional noise controls.

In addition, **we recommend that:**

- **CCL Stage III should file a noise survey with the Secretary <u>no later than 60 days</u> after placing the entire Stage 3 LNG Facilities into service. If a full-load noise survey is not possible, CCL Stage III should provide an interim survey at the maximum possible horsepower load <u>within 60 days</u> of placing the Stage 3 LNG Facilities into service and provide the full-load noise survey <u>within 6 months</u>. If the noise attributable to operation of the equipment at the LNG terminal exceeds an L_{dn} of 55 dBA at the nearest NSA under interim or full horsepower load conditions, CCL Stage III should file a report on what changes are needed and should install the additional noise controls to meet the level <u>within 1 year</u> of the in-service date. CCL Stage III should confirm compliance with the above requirement by filing an additional full-load noise survey with the Secretary <u>no later than 60 days</u> after it installs the additional noise controls.**

Flaring

CCL Stage III anticipates that both planned and unplanned flaring would occur at the Stage 3 LNG Facilities; however, emergency flaring is not assessed for compliance since such activities would be infrequent and short-term in duration. During startup and commissioning, the ground flares may operate 24-hours per day for approximately 30 days at a rate of 150,000 lb/hr and an additional 20 days at a rate of 75,000 lb/hr. During commissioning, the highest noise levels would occur if six trains are in operation and the seventh train is starting up with ground flaring at the 150,000 lb/hr rate. This operating condition would be expected to occur for approximately 30 days during commissioning.

CCL Stage III provided the predicted sound level contribution of the Stage 3 LNG Facilities equipment with and without the ground flare in operation. The CCL Stage III predicted sound level contributions of the Stage 3 LNG Facilities with the ground flare in operation are shown in table B.8.2-7. The table also shows the contribution of the Stage 3 LNG Facilities without the ground flare in operation and the calculated ground flare contribution.

The noise originating from a ground flare would be a function of the design and materials of construction of the barrier wall that surrounds the ground flare as well as the flare load itself. The height and the details of the baffles provided for ventilation and air flow to the burners are key factors in determining the overall transmission loss of the barrier.

In the event that further mitigation of the noise was to be required (due to higher than predicted sound levels), potential options to be considered would include raising the height of the barrier wall, modifying the ventilation/air flow baffles, and/or modifying the materials of construction and shape of the barrier along with, if necessary, to provide additional absorbent material on the burner facing surfaces. The table below shows the estimated noise from ground flaring based on a flaring rate of 150,000 lb/hr.

During ground flaring, CCL Stage III predicts that the combined sound levels due to the Project and the previously authorized CCL Stage III equipment would exceed 55 dBA L_{dn} at NSAs 4, 5, and 6, with predicted levels of up to 56 to 57 dBA L_{dn} during ground flare operation. These levels are predicted to cause temporary increases in the sound levels at these three NSAs of 5, 1, and 2 dBA L_{dn}, respectively. It is likely that ground flaring would be clearly audible at the NSAs during commissioning. Since the closest NSAs to flaring activities are 1.7 – 3.3 miles away, and based on the noise analysis above and considering that the noise from ground flaring would be considered temporary, we anticipate that noise from ground flaring would not have a significant impact on the environment.

Table B.8.2-6

Noise Impact Summary for Stage 3 LNG Facilities with Ground Flaring

NSA	Existing Ambient, L_{dn} (dBA)	Predicted Noise Contribution from Stage 3 LNG Facilities Only, with Ground Flare, L_{dn} (dBA) [b]	Predicted Cumulative Noise Contribution with Ground Flare, L_{dn} (dBA) [a]	Future Operational (Ambient + Cumulative) L_{dn} (dBA)	Expected Increase (dBA)
LNG-1	47	50	54	55	8
LNG-2	54	49	53	57	3
LNG-3	51	51	53	55	4
LNG-4	53	53	57	58	5
LNG-5	61	54	56	62	1
LNG-6	58	54	56	60	2
LNG-7	62	53	54	63	1
LNG-8	49	49	52	54	5
LNG-9	50	44	49	53	3

[a] These values are the combined operations of the previously authorized equipment, the Stage 3 LNG Facilities, and the ground flare.
[b] The Stage 3 LNG Facilities cannot operate without ground flaring.

Sinton Compressor Station

CCPL anticipates that the operation of the Sinton Compressor Station has the potential to result in noise impacts at the nearby NSA. CCPL developed a computer noise model of the Sinton Compressor Station using Cadna/A version 2018MR1. The acoustic model incorporated the previously authorized equipment at the Sinton Compressor Station as well as the proposed Project equipment.

CCPL incorporated extensive noise mitigation in the Sinton Compressor Station design. The principal noise mitigation measures were as follows:

- Acoustically Insulated Compressor Station Buildings - the building housing the turbine packages would be acoustically insulated. In addition, all doors, windows, and vent louvers would be acoustically treated;
- Air Inlet- the Solar Titan 130 turbine air inlets would be fitted with properly sized combustion air inlet silencers. If possible, the inlet silencer would be located inside of the compressor building. If the inlet silencer is not located inside the compressor building, then the inlet ductwork between the between the silencer and the building wall may need to be acoustically lagged;
- Exhaust Silencer- combustion turbines would be equipped with exhaust silencers. If located outside, the breach stack and muffler may be covered and/or lagged to achieve adequate transmission, if determined to be required during final design; and
- Lagging- if required, aboveground piping outside the compressor station building may be covered with acoustic pipe insulation or equal noise abatement techniques.

Table B.8.2-7

Noise Impact Summary for the Sinton Compressor Station

NSA	Distance from Station (miles)	Direction from site to NSA	Existing Ambient L_{dn} (dBA)	Predicted Noise Contribution from Stage 3 Equipment Only, L_{dn} [a] (dBA)	Predicted Cumulative Noise Contribution, Ldn (dBA) b	Future Operational (Ambient + Cumulative) Ldn (dBA)	Predicted Increase Above Existing Ldn (dBA)
1	0.6	SE	52	40	54	55	<6

[a] This is the sound level contribution from the two proposed units at the Sinton Compressor Station.
[b] Includes the sound level contribution from the combined operations of all previously authorized equipment along with the two proposed units.

The modeling results provided by CCPL indicate that the Sinton Compressor Station, with the noise mitigations implemented by CCPL, would contribute less than 55 dBA L_{dn} at the closest NSA, see table B.8.2-8. To ensure that the actual noise levels resulting from operation of the Sinton Compressor Station are not significant, **we recommend that:**

- **CCPL should file noise surveys with the Secretary <u>no later than 60 days</u> after placing the modified Sinton Compressor Station in service. If a full load condition noise survey is not possible, CCPL should provide an interim survey at the maximum possible horsepower load and provide the full load survey <u>within 6 months</u>. If the noise attributable to the operation of all of the equipment at the compressor station, under interim or full horsepower load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, CCPL should file a report on what changes are needed and should install the additional noise controls to meet the level <u>within 1 year</u> of the in-service date. CCPL should confirm compliance with the above requirement by filing a second noise survey with the Secretary <u>no later than 60 days</u> after it installs the additional noise controls.**

<u>Meter and Regulator Stations</u>

CCPL proposes to install two M&R stations within the Sinton Compressor Station and one M&R station collocated with the Stage 3 LNG Facilities. All three proposed M&R facilities are greater than 0.5 miles from the closest NSAs so no detailed noise assessment was performed. Sound generated by M&R stations is related to operation of the meter run, control valve, and associated piping and is also somewhat dependent on the flowrate conditions downstream and upstream of the station. Considering that both M&R stations would be collocated with other larger Project components, CCPL does not anticipate that sound produced by the M&R stations would result in any appreciable incremental increase in received sound levels at nearby NSAs.

<u>Venting at the Sinton Compressor Station</u>

CCPL stated that the sound levels associated with high pressure gas venting are a function of initial pressure, the diameter and type of vent valve, and the diameter and arrangement of the downstream vent piping. Venting sound levels are loudest at the beginning of the venting event and they decrease as the system pressure decreases. There are typically two types of gas venting events at compressor stations: routine unit venting that occurs when a compressor is stopped and gas between the suction/discharge vales and compressor is vented to atmosphere through a silencer; and full station venting that occurs when all of the station piping is depressurized and gas is vented via a silencer.

Due to the short duration and infrequent timing of station venting, CCPL expects the events would have minimal influence on the 24-hour L_{dn} values projected for these facilities. The vent silencers at the station have been designed to produce no more than 60 dBA at 300 feet during standard venting events.

Vibration

Operation of the equipment for the Stage 3 LNG Facilities and the Sinton Compressor Station would not generate vibration, but construction of the facilities and site grading would require the use of equipment that could generate vibration. Possible sources of vibration may include bulldozers, dump trucks, backhoes, rollers, and other construction equipment that produces vibration. As stated in sections A.8.0 and B.1.2.2, no blasting would be required for construction.

Construction activities from the Stage 3 LNG Facilities would occur within approximately 1.7 miles from the nearest NSA, and construction from the Sinton Compressor Station would occur within approximately 0.46 miles from the nearest NSA. According to the Federal Transit Administration guidelines, a vibration level of 65 VdB is the threshold of perceptibility for humans. For a significant impact to occur, vibration levels must exceed 80 VdB during infrequent events (Federal Transit Administration, 2006). Based on the levels published by the Federal Transit Administration (2006) and the type of equipment proposed for use at the Project, coupled with the distance to the nearest NSA, Cheniere predicted that the maximum vibration levels would range from 11 VdB to 27 VdB at the nearest NSAs, which is well below the level of human perception. This vibration level is considered acceptable for impacts to residential homes and is considered to be a less than significant impact.

CCL Stage III's analysis of low-frequency sound levels from the Stage 3 LNG Facility indicates that the predicted low-frequency sound levels are lower than the American National Standards Institute thresholds for noise induced vibration for both standard operation and ground flare operations. This indicates that annoyance from low frequency noise from the flare and normal facility operations is not expected.

Operation Summary

With the implementation of the mitigation measures presented above, and compliance with our recommendations, we conclude that operational noise from the Project would not have a significant impact on the acoustical environment at the nearby NSAs.

9.0 RELIABILITY AND SAFETY

9.1 LNG Safety

9.1.1 LNG Facility Reliability, Safety, and Security Regulatory Oversight

LNG facilities handle flammable and sometimes toxic materials that can pose a risk to the public if not properly managed. These risks are managed by the companies owning the facilities, through selecting the site location and plant layout as well as through suitable design, engineering, construction, and operation of the LNG facilities. Multiple federal agencies share regulatory authority over the LNG facilities and the operator's approach to risk management. The safety, security, and reliability of the Stage 3 LNG Facilities would be regulated by the USDOT, the Coast Guard, and the FERC.

In February 2004, the USDOT, 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 LNGC operations, and maximizing the exchange of information related to the safety and security aspects of the 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. The USDOT 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.

The USDOT establishes and has the authority to enforce the federal safety standards for the location, design, installation, construction, inspection, testing, operation, and maintenance of onshore LNG facilities under the *Natural Gas Pipeline Safety Act* (49 USC 1671 *et seq.*). The USDOT's LNG safety regulations are codified in 49 CFR 193, which prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that are subject to federal pipeline safety laws (49 USC 60101 *et seq.*) and 49 CFR 192. On August 31, 2018, the USDOT and the FERC signed a memorandum of understanding (MOU) regarding methods to improve coordination throughout the LNG permit application process for FERC jurisdictional LNG facilities. In the MOU, the USDOT PHMSA agreed to issue a LOD stating whether a proposed LNG facility would be capable of complying with location criteria and wind force design standards contained in Subpart B of Part 193. The Commission committed to rely upon the USDOT PHMSA determination in conducting its review of whether the facilities would be consistent with the public interest. The issuance of the LOD does not abrogate the USDOT PHMSA's continuing authority and responsibility over a proposed project's compliance with Part 193 during construction and future operation of the facility. The USDOT PHMSA's conclusion on the siting and hazard analysis required by Part 193 would be based on preliminary design information which may be revised as the engineering design progresses to final design. The USDOT 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 by 49 CFR 193, which would be completed during later stages of the Project. If the Project is authorized, constructed, and operated, the Stage 3 LNG Facilities, as defined in 49 CFR 193, would be subject to the USDOT's inspection and enforcement programs to ensure compliance with the requirements of 49 CFR 193.

The Coast Guard has authority over the safety of an LNG terminal's marine transfer area and LNGC traffic, as well as over security plans for the waterfront facilities handling LNG terminal and LNGC traffic. The Coast Guard regulations for waterfront facilities handling LNG are codified in 33 CFR 105 and 33 CFR 127. As a cooperating agency, the Coast Guard assists FERC staff in evaluating whether an applicant's proposed waterway would be suitable for LNGC traffic and whether the waterfront facilities handling LNG would be operated in accordance with 33 CFR 105 and 33 CFR 127. If the Stage 3 LNG Facilities are constructed and become operational, the Stage 3 LNG Facilities would be subject to the Coast Guard inspection program to ensure compliance with the requirements of 33 CFR 105 and 33 CFR 127.

FERC authorizes the siting and construction of LNG terminals under the NGA and delegated authority from the DOE. The FERC requires standard information to be submitted to perform safety and reliability engineering reviews. FERC's filing regulations are codified in 18 CFR 380.12 (m) and (o), and requires each applicant to identify how its proposed design would comply with the USDOT's siting requirements of 49 CFR 193, Subpart B. The level of detail necessary for this submittal requires the applicant to perform substantial front-end engineering of the complete project. The design information is required to be site-specific and developed to the extent that further detailed design would not result in significant changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs. As part of the review required for a FERC Order, we use this information from the applicant to assess whether the proposed facilities would have a public safety impact and to recommend additional mitigation measures to the Commission for incorporation as conditions in the Order. If the Stage 3 LNG Facilities are approved, FERC staff would review material filed to satisfy the conditions of the Order and conduct periodic inspections throughout construction and operation.

In addition, the *Energy Policy Act* of 2005 requires the FERC to coordinate and consult with the U.S. Department of Defense (DOD) on the siting, construction, expansion, and operation of LNG terminals that would affect the military. On November 21, 2007, FERC and the DOD (http://www.ferc.gov/legal/mou/mou-dod.pdf) entered into a MOU formalizing this process. In accordance with MOU, FERC sent a letter to the DOD on November 10, 2015 requesting their comments on whether the planned Project could potentially have an impact on the test, training, or operational activities of any active military installation. On October 9, 2018, the FERC received a response letter from the DOD Siting Clearinghouse stating that the Project would have a minimal impact on military training and operations conducted in San Patricio County, Texas.

9.1.2 USDOT Siting Requirements and 49 CFR 193, Subpart B Determination

Siting LNG facilities, as defined by 49 CFR 193, with regard to ensuring that the proposed site selection and location would not pose an unacceptable level or risk to public safety is required by the USDOT's regulations in 49 CFR 193, Subpart B. The Commission's regulations under 18 CFR 380.12 (o) (14) require CCL Stage III to identify how the proposed design complies with the siting requirements of 49 CFR 193, Subpart B. The scope of the USDOT's siting authority under 49 CFR 193 applies to LNG facilities used in the transportation of gas by pipeline subject to the federal pipeline safety laws and 49 CFR 192.[16]

The regulations in 49 CFR 193, Subpart B require the establishment of an exclusion zone surrounding an LNG facility in which an operator or government agency must exercise legal control over the activities where specified levels of thermal radiation and flammable vapors may occur in the event of a release for as long as the facility is in operation at. 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 into 49 CFR 193, Subpart B by reference, with regulatory preemption in the event of conflict. The following sections of 49 CFR 193, Subpart B specifically address siting requirements:

- Section 193.2051, Scope, states that each LNG facility designed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001), which is incorporated by reference in 49 CFR 193.2013, under Subpart A. In the event of a conflict with NFPA 59A (2001), the regulatory requirements in 49 CFR 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

[16] 49 CFR 193.2001 (b) (3), Scope of part, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the LNGC and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

the applicable wind load data in American Society of Civil Engineers (ASCE) 7 (2005). All other LNG facilities must be designed for a sustained wind velocity of not less than 150 mph unless the USDOT Administrator finds a lower wind speed is justified or the most critical combination of wind velocity and duration for 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, and include but may not be 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) 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 the USDOT.
- 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.[17]

Taken together, 49 CFR 193, Subpart B and NFPA 59A (2001) require that flammable LNG vapors from design spills do not extend beyond areas in which the operator or a government agency legally controls all activities. Furthermore, consideration of other hazards which may affect the public or plant personnel must be evaluated as prescribed in NFPA 59A (2001) section 2.1.1 (d).

Title 49 CFR 193, Subpart B and NFPA 59A (2001) also specify three radiant heat flux levels which must be considered for LNG storage tank spills 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;[18]
- 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;[19] and

[17] The USDOT has approved two additional models for the determination of vapor dispersion exclusion zones in accordance with 49 CFR 193.2059, under Subpart B: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Versions 6.6 and 6.7 (Oct. 7, 2011).

[18] 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 30-40 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.

[19] 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 10-15 seconds, 1 percent mortality in approximately 50 seconds, and 100 percent mortality in

- 10,000 Btu/ft^2-hr - This level cannot extend beyond the plant property line that can be built upon.[20]

The requirements for design spills from process or transfer areas are more stringent. For LNG spills, the 1,600 Btu/ft^2-hr flux level cannot extend beyond the plant property line onto a property that can be built upon. In addition, section 2.1.1 of NFPA 59A (2001) requires that factors applicable to the specific site with a bearing on the safety of plant personnel and the surrounding public must be considered, including an evaluation of potential incidents and safety measures incorporated into the design or operation of the facility. The USDOT PHMSA has indicated that potential incidents, such as vapor cloud explosions and toxic releases, should be considered to comply with Part 193, Subpart B.[21]

In accordance with the August 31, 2018 MOU, the USDOT PHMSA will issue a LOD to the Commission after the USDOT PHMSA completes its analysis of whether the proposed Stage 3 LNG Facilities would meet the USDOT siting standards. The LOD will evaluate the hazard modeling results and endpoints used to establish exclusion zones, as well as CCL Stage III's evaluation on other hazards specific to the site that have a bearing on the safety of plant personnel and surrounding public. The LOD will also evaluate whether soil and general investigations of the site have been made in accordance with NFPA 59A (2001) section 2.1.4 and the degree to which the facilities can withstand natural hazards in accordance with NFPA 59A (2001) section 2.1.1(c), including compliance with wind force design requirements in 49 CFR 193.2067, under Subpart B. The LOD will serve as one of the considerations for the Commission to deliberate in its decision to authorize or deny an application. In a letter to the Commission dated March 22, 2019, the USDOT stated that the LOD for the Project would be issued no later than May 17, 2019.

9.1.3 Coast Guard Safety Regulatory Requirements and Letter of Recommendation

LNGC Historical Record

Since 1959, LNGCs have transported LNG without a major release of cargo or a major accident involving an LNGC. There are more than 370 LNGCs in operation routinely transporting LNG between more than 100 import/export terminals currently in operation worldwide. Since U.S. LNG terminals first began operating under FERC jurisdiction in the 1970s, there have been thousands of individual LNGC 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 LNGCs, including minor collisions with other 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

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.

[20] The 10,000 Btu/ft^2-hr flux level is associated with producing pain in less than 1 seconds, first degree burns in 1 second, 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.

[21] The USDOT 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 August 2018.

occurrences, representing the range of incidents experienced by the worldwide LNGC 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 U.S. 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 LNGC 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 LNGC 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 LNGC crew extinguished the fire and the LNGC crew completed unloading.
- **Khannur** had a cargo tank overfill into the LNGC'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 LNGC 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 LNGC, 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 LNGC 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 LNGC 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 carrier 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 LNGC 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.
- **Aseem** collided with a very large crude carrier (VLCC) Shinyo Ocean off the Port of Fujairah on March 26, 2019. The VLCC suffered severe portside hull height breach and Aseem 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.

LNGC Safety Regulatory Oversight

The Coast Guard exercises regulatory authority over LNGCs under 46 CFR 154, which contains the U.S. safety standards for self-propelled LNGCs transporting bulk liquefied gases. The LNGCs visiting the Stage 3 LNG Facilities would also be constructed and operated in accordance with the IMO *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk* and the *International Convention for the Safety of Life at Sea*. All LNGCs entering U.S. waters are required to possess 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 LNGC is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNGCs under 46 CFR 154.

The LNGCs that would deliver or receive LNG to or from the Stage 3 LNG Facilities 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 marine vessels and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against marine vessels; improve security aboard marine vessels and ashore; and reduce the risk to passengers, crew, and port personnel on board marine vessels and in port areas. All LNGCs, as well as other cargo marine 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 marine vessels are as follows:

- marine vessels must develop security plans and have a Vessel Security Officer;
- marine vessels must have a security alert system to transmit ship-to-shore security alerts identifying the marine vessel, its location, and an indication of whether the security of the marine vessel 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 marine vessels; and
- marine vessels must have equipment onboard to help maintain or enhance the physical security of the marine vessel.

In 2002, the MTSA was enacted by the U.S. Congress and aligned domestic regulations with the maritime security standards of the *International Ship and Port Facility Security Code* and the *Code for the*

Construction and Equipment of Ships Carrying Liquefied Gases in Bulk and the *International Convention for the Safety of Life at Sea*. The Coast Guard's regulations in 33 CFR 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 LNGCs servicing the Stage 3 LNG Facilities 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 USC 191); the *Ports and Waterways Safety Act* of 1972, as amended (33 USC 1221, *et seq.*); and the MTSA of 2002 (46 USC 701). The Coast Guard is responsible for matters related to navigation safety, LNGC 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 105.

Both the Coast Guard regulations under 33 CFR 127 and FERC regulations under 18 CFR 157.21 require an applicant who intends to build an LNG terminal facility to submit a Letter of Intent 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 Letter of Intent.

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 LNGC 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 the 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 LNGC 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 LNGC 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 (LNG) Marine Traffic* (NVIC 01-11).

NVIC 01-11 directs the use of the three concentric Zones of Concern, based on LNGCs 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) (12,000 Btu/ft^2-hr) from a pool fire.
- 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 kW/m^2 (1,600 Btu/ft^2-hr) from a pool fire.
- Zone 3 – impacts on people and property from a pool fire or an un-ignited 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 worst case un-ignited release. Impacts to people and property could be significant if the vapor cloud reaches an ignition source and burns back to the source.

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 LNGC'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 LNGCs 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 LNGCs from the channel and the width of the channel.

The Coast Guard may also prepare a 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.

CCL Stage III's Waterway Suitability Assessment

On May 27, 2015, CCL Stage III submitted a Letter of Intent to the COTP, Sector Corpus Christi to notify the Coast Guard that it proposed to construct LNG export facilities. On May 28, 2015, CCL Stage III received approval to use the WSA from the previously authorized the Liquefaction Project facilities (CP12-507-000) as the preliminary WSA for CCL Stage III Project. CCL Stage III submitted the Follow-on WSA to the Coast Guard on February 29, 2016.

LNGC Routes and Hazard Analysis

CCL Stage III proposes no changes to the marine facilities previously authorized under the Liquefaction Project. However, the proposed Project would increase the maximum LNGC traffic from the currently-authorized 300 LNGCs up to 400 LNGCs per year. The LNGC route and the associated hazards would remain largely unchanged and are described below.

A LNGC's transit to and from the LNG terminal would enter/exit at Port Aransas and pass by Harbor Island and Pelican Island, before turning at Ingleside at the Bay near Cooks Island. The LNGC would head north by Quinta Island before reaching its final destination at the LNG terminal. 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. A LNGC 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.

NVIC 01-11 references the Zones of Concern for assisting in a risk assessment of the waterway. As LNGCs proceed along the intended track line, Hazard Zone 1 would encompass coastal areas along Port Aransas, including University of Texas Marine Science Institute, Coast Guard Port Aransas Station, and Roberts Point Park. Hazard Zone 1 would also encircle coastal areas along Ingleside consisting primarily of industrial facilities. Portions of Pelican Island, Cooks Island, and La Quinta Island would also be within Zone 1. Commercial vessels and recreational and fishing vessels may also fall within Zone 1, depending on their course and whether a safety and security zone is established that would preclude them from being within Zone 1, as recommended in the Coast Guard's LOR Analysis. Transit of such vessels through a Zone 1 area of concern can also be avoided by timing and course changes, if conditions permit. Zone 2 would cover a wider swath of coastal areas along Port Aransas and Ingleside, including Port Aransas Fire Department and Police Department, and multiple residential, commercial, industrial, and institutional (e.g., church, school, etc.) buildings. Pelican Island, Cooks Island, and La Quinta Island would also be entirely within Zone 2. Zone 3 would span Port Aransas in almost its entirety and larger portions of Ingleside, including multiple residential, commercial, industrial, and institutional (e.g., church, school, etc.) buildings. The areas impacted by the three different hazard zones are illustrated for both accidental and intentional events in figures B.9.1-1 and B.9.1-2, respectively.

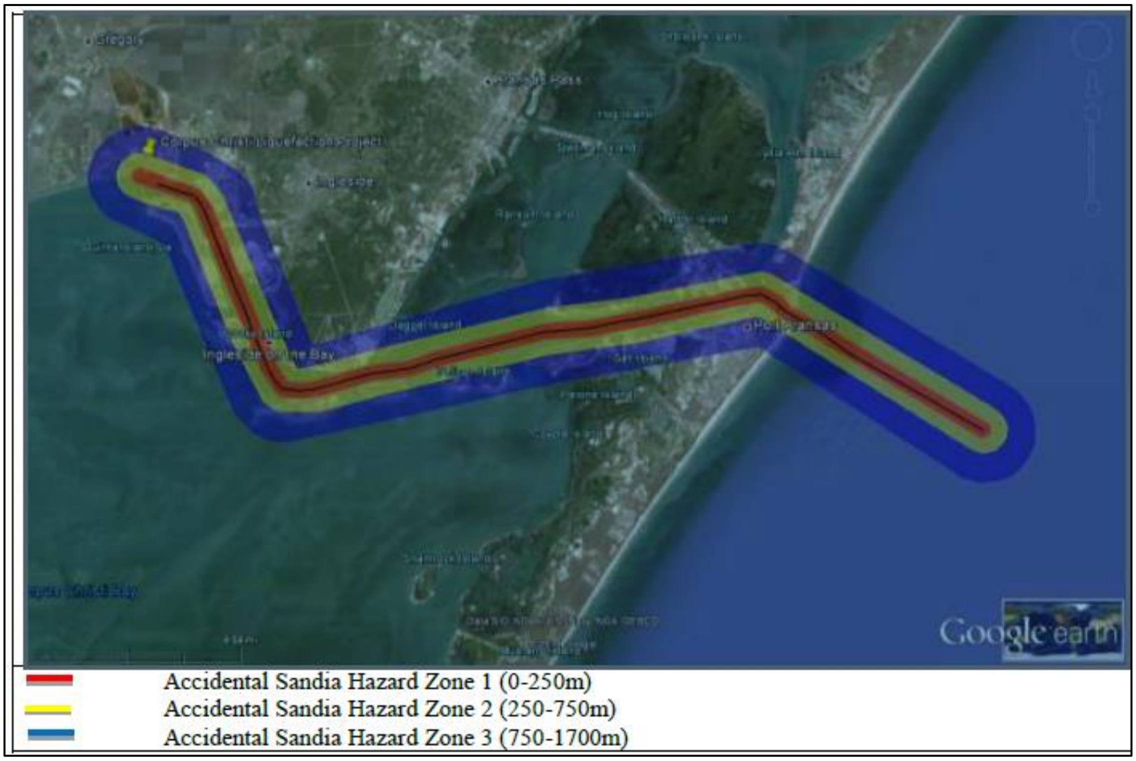

Figure B.9.1-1 Accidental Hazard Zones along LNGC Route

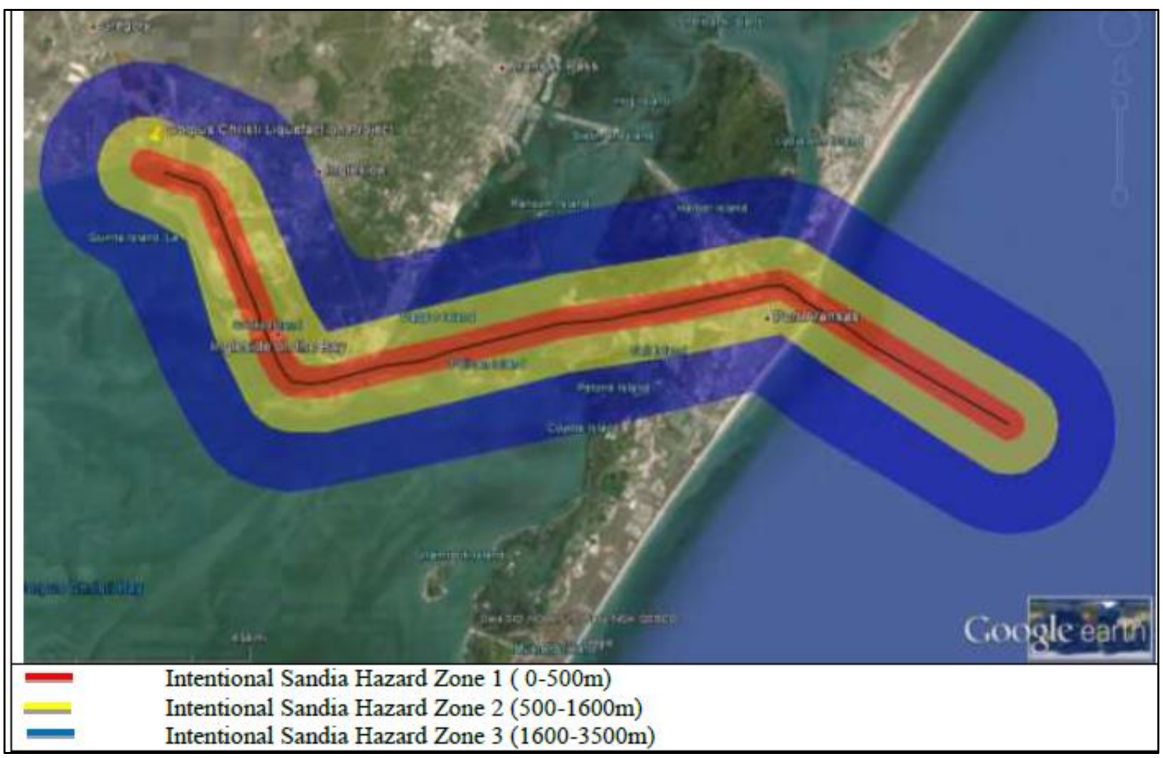

Figure B.9.1-2 Intentional Hazard Zones along LNGC Route

<u>**Coast Guard Letter of Recommendation and Analysis**</u>

In a letter dated August 15, 2018, the Coast Guard issued a LOR and LOR Analysis to the FERC stating that the Corpus Christi Ship Channel would be considered suitable for accommodating the type and frequency of LNGCs 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 Port of Corpus Christi, local facility security representatives, the Aransas-Corpus Christi Pilots Association, and maritime stakeholders. The LOR was based on full implementation of the strategies and risk management measures identified by the Coast Guard to CCL Stage III in its WSA.

Although CCL Stage III has suggested mitigation measures for responsibly managing the maritime safety and security risks associated with LNGC traffic, the necessary vessel traffic and/or facility control measures may change depending on changes in conditions along the waterway. The Coast Guard regulations in 33 CFR 127 require that applicants annually review WSAs until a facility begins operation. The annual review and report to the Coast Guard would identify any changes in conditions, such as changes to the port environment, the LNG facility, or the LNGC route, that would affect the suitability of the waterway.

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 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 infrastructure and key resources, the port, the marine environment, and the LNGC.

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 LNGC 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 LNGC 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.

9.1.4 LNG Facility Security Regulatory Requirements

The security requirements for the Stage 3 LNG Project Facilities are governed by 33 CFR 105, 33 CFR 127, and 49 CFR 193, Subpart J. Title 33 CFR 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 proposed project facilities. CCL Stage III would also be required to control and restrict access, patrol and monitor the plant, detect unauthorized access, and respond to security threats or breaches under 33 CFR 105. Some of the responsibilities of the applicant include, but are not limited to:

- designating a Facility Security Officer with a general knowledge of current security threats and patterns, security assessment methodology, vessel and facility operations, conditions, security measures, emergency preparedness, response, and contingency plans, who would be responsible for implementing the FSA and FSP and performing an annual audit for the life of the Project;

- conducting a FSA to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures; developing a FSP based on the FSA, with procedures for: responding to transportation security incidents; notification and coordination with federal, state, and local authorities; prevention of unauthorized access; measures to prevent or deter entrance with dangerous substances or devices; training; and evacuation;
- defining the security organizational structure with facility personnel with knowledge or training in current security threats and patterns; recognition and detection of dangerous substances and devices; recognition of characteristics and behavioral patterns of persons who are likely to threaten security; techniques to circumvent security measures; emergency procedures and contingency plans; operation, testing, calibration, and maintenance of security equipment; and inspection, control, monitoring, and screening techniques;
- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, LNGC stores and bunkers, and monitoring; ensuring that the Transportation Worker Identification Credential (TWIC) program is properly implemented;
- ensuring coordination of shore leave for LNGC personnel or crew change out as well as access through the facility for visitors to the LNGC;
- conducting drills and exercises to test the proficiency of security and facility personnel on a quarterly and annual basis; and
- reporting all breaches of security and transportation security incidents to the National Response Center.

Title 33 CFR 127 has requirements for access controls, lighting, security systems, security personnel, protective enclosures, communications, and emergency power. In addition, an LNG facility regulated under 33 CFR 105 and 33 CFR 127 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 implementation of the rule was first proposed to be in effect August 23, 2018. In a subsequent notice issued on June 22, 2018, the Coast Guard indicated delaying the effective date for certain facilities by 3 years, until August 23, 2021. On August 2, 2018, the President of the U.S. signed into law the *Transportation Worker Identification Credential Accountability Act* of 2018 (H.R. 5729). This law prohibits the Coast Guard from implementing the rule requiring electronic inspections of TWICs until after the U.S. Department of Homeland Security (DHS) has submitted a report to the Congress. Although the implementation of this rule has been postponed for certain facilities, the company may need to consider the rule when developing access control and security plan provisions for the facility.

Title 49 CFR 193, Subpart J also specifies security requirements for the onshore components of LNG terminals, including requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources, and warning signs. If the Project is authorized, constructed, and operated, compliance with the security requirements of 33 CFR 105, 33 CFR 127, and 49 CFR 193, Subpart J would be subject to the respective Coast Guard and the USDOT inspection and enforcement programs.

CCL Stage III provided preliminary information on these security features and indicated additional details would be completed in the final design. A data request requesting additional details was also issued. We recommend in section B.9.1.6 that CCL Stage III file final design details on these security features, for review and approval, that demonstrate lighting coverage adequately cover the perimeter of the site and interior of the LNG terminal in accordance with CCL Stage III's specification to meet API 540 and federal regulations, including in liquefaction areas, storage tank pump platform area, truck transfer areas, interior and exterior of buildings, and along paths/roads of access and egress; demonstrate camera coverage adequately cover interior of plant, including a camera be provided at the top of each LNG storage tank, and coverage within pretreatment areas, within liquefaction areas, within truck transfer areas, and buildings; demonstrate fencing set back from exterior structures and vegetation and from interior hazardous piping and equipment by at least 10 feet; and provide vehicle barriers and design details at controlled access points. Furthermore, in accordance with the February 2004 Interagency Agreement among the FERC, the USDOT, and the Coast Guard, FERC staff would collaborate with the Coast Guard and the USDOT on the Project's security features.

9.1.5 FERC Engineering and Technical Review of the Preliminary Engineering Designs

LNG Facility Historical Record

The operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment with the exception of the October 20, 1944 failure at an LNG plant in Cleveland, Ohio. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people.[22] 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 the proposed Stage 3 LNG Facilities, we evaluate the preliminary and final specifications for suitable materials of construction and for the design of spill containment systems that would properly contain a spill at the site.

Another operational accident occurred in 1979 at the Cove Point LNG plant in Lusby, Maryland. A pump electrical seal located on a submerged electrical motor LNG pump leaked causing flammable gas vapors to enter an electrical conduit and settle in a confined space. When a worker switched off a circuit breaker, the flammable gas ignited, causing severe damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident led to changes in the national fire codes to better ensure that the situation would not occur again. To ensure that this potential hazard would be addressed for proposed facilities that have electrical seal interfaces, we evaluated the preliminary design and recommend in section B.9.1.6 that CCL Stage III file, for review and approval, the final design details of the electrical seal design at the interface between flammable fluids and the electrical conduit or wiring system, details of the electrical seal leak detection system, and the details of a downstream physical break (i.e., air gap) in the electrical conduit to prevent the migration of flammable vapors.

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

[22] 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.

1981. To ensure that this potential hazard would be addressed for the proposed Stage 3 LNG Facilities, we evaluate the preliminary design for mitigation of flammable vapor dispersion and ignition in buildings and combustion equipment to ensure they would be adequately covered by hazard detection equipment that could isolate and deactivate any combustion equipment whose continued operation could add to or sustain an emergency. We also recommend in section B.9.1.6 that CCL Stage III file, for review and approval, the final design details of hazard detection equipment, including the location and elevation of all detection equipment, instrument tag numbers, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.

On March 31, 2014, a detonation occurred within a gas heater at Northwest Pipeline Corporation's LNG peak-shaving plant in Plymouth, Washington[23]. 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 the 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 the proposed Stage 3 LNG Facilities, we recommend in section B.9.1.6 that CCL Stage III file a plan for purging, for review and approval, which addresses the requirements of the American Gas Association *Purging Principles and Practice* and provide justification if not using an inert or non-flammable gas for purging. In evaluating such plans, we would assess whether the purging could be done safely based on review of other plans and lessons learned from this and other past incidents. If a plan proposes the use of flammable mediums for cleaning, dry-out, or other activities, we would evaluate the plans against other recommended and generally accepted good engineering practices, such as NFPA 56, *Standard for Fire and Explosion Prevention during Cleaning and Purging of Flammable Gas Piping Systems*.

We also recommend in section B.9.1.6 that CCL Stage III provide, for review and approval, operating and maintenance plans, including safety procedures, prior to commissioning. In evaluating such plans, we would assess whether the plans cover all standard operations, including purging activities associated with startup and shutdown. Also, in order to prevent other sources of projectiles from affecting occupied buildings and storage tanks, we recommend in section B.9.1.6 that CCL Stage III incorporate mitigation into their final design with supportive information, for review and approval, that demonstrates it would mitigate the risk of a pressure vessel burst or boiling liquid expanding vapor explosion (BLEVE) from occurring.

FERC Preliminary Engineering Review

The FERC requires an applicant to provide safety, reliability, and engineering design information as part of its application, including hazard identification studies and front-end-engineering-design (FEED) information, for its proposed project. FERC staff evaluates this 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.

[23] 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.

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

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

We believe 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 designs for these layers of protection is 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.

Process Design

In order to liquefy natural gas, most liquefaction technologies require that the feed gas stream to 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, including mercury, H_2S, CO_2, water, and heavy hydrocarbons. For example, mercury is typically limited to limit concentrations to less than 0.01 micrograms per normal cubic meter because it can induce embrittlement and corrosion, resulting in a catastrophic failure of equipment.

The inlet gas would be heated and pressure regulated prior to entering feed gas pretreatment processes. Once the inlet gas is conditioned, the H_2S and mercury would be removed from the feed gas by contacting non-regenerative Mercury/H_2S removal beds. Spent absorbent material within the Mercury/H_2S removal beds would be periodically returned to the supplier or a licensed third-party contractor for metals removal and recovery. However, the application did not provide a means to monitor mercury breakthrough downstream of the Mercury/H_2S beds to ensure that the mercury removal beds are operating as designed. We recommend in section B.9.1.6 that CCL Stage III provide a means to monitor for mercury breakthrough by means of an analyzer, sample connection, or preventive maintenance inspections of the heat exchangers.

The feed gas is then routed to the AGRU where CO_2 as well as trace amounts of sulfur compounds (e.g., H_2S, carbonyl sulfide, and mercaptans) from the feed gas stream would be removed by contact with an amine-based solvent in an absorber column. Once the acid gas accumulates in the amine solution, an amine regenerator column would release the acid gas from the amine solution. The regenerated amine solution would be recycled back to the absorber column, and the acid gas would be routed to the thermal oxidizer where CO_2 and trace amounts of hydrocarbon would be incinerated.

The feed gas exiting the amine absorber column then enters a knock out drum where bulk water would be recovered and recycled back to the AGRU. Any remaining water in the feed gas would be removed using regenerative molecular sieve beds. Water collected during the molecular sieve regeneration process would be routed back to the AGRU. The treated dry gas would then flow to the heavy hydrocarbon removal unit to extract the heavy hydrocarbons. The extracted heavy hydrocarbons would be stabilized and would be sent to the condensate storage facilities authorized in the Liquefaction Project under FERC docket number CP12-507-000. Stored condensate would be removed from the site by pipeline and, if needed, could be removed by truck.

After removal of the heavy hydrocarbons and the other components from the natural gas feed stream, CCL Stage III would liquefy the natural gas. In this process, the treated gas would be routed to the liquefaction cold box and would be cooled by a thermal exchange process driven by a closed loop refrigeration system using a single mixed refrigerant. The mixed refrigerant would be comprised of nitrogen, methane, ethylene, propane, n-butane, and iso-pentane. There would be no on-site refrigerant storage tanks. Make-up methane would be provided from the treated gas stream entering the liquefaction cold box and the other refrigerants would be trucked to the facility as needed.

As part of our engineering review, we evaluated the process flow diagrams (PFDs) and heat and material balances (HMBs) to determine the liquefaction capacities relative to the requested capacity in the application. While the application indicates a nameplate capacity equating to 9.53 MTPA and maximum liquefaction rate of up to 11.45 MTPA, the PFDs and HMBs do not cover the maximum liquefaction rate and suggest a maximum liquefaction rate of 9.93 MTPA. This is in part because CCL Stage III only provided process simulations for average ambient conditions with some variation in feed gas composition as opposed to the recommended variation in both ambient conditions and feed gas conditions. This is important, as the PFDs and HMBs provide the flow rates, pressures, and temperatures that form the basis of design for other engineering documents, including piping and instrumentation diagrams (P&IDs), piping specifications, hazard analyses, and other pertinent engineering information. As a result, CCL Stage III indicated, in a response to our January 3, 2019 data request, that CCL Stage III will be conducting additional process simulations in detailed design for low and high ambient conditions. We recommend in section B.9.1.6 that CCL Stage III provide updated PFDs and HMBs that demonstrate the peak liquefaction rate is achievable. We also recommend that modifications to other engineering information be requested prior to the implementation of the modification and that a change log be provided explaining the rationale for those changes. This would capture any other changes to other engineering information as a result of the process simulations.

After cooling the natural gas into its liquid form, the LNG would be routed to and stored in a new full containment LNG storage tank or in the three full containment LNG storage tanks that were authorized in the Liquefaction Project under FERC docket number CP12-507-000. During export operations, LNG stored in the new LNG storage tank would be transferred through in-tank pumps to the LNG storage tanks that were authorized in the Liquefaction Project under FERC docket number CP12-507-000 and would not be capable of sending LNG directly to the marine facilities. The pump discharge piping would penetrate through the roof of the LNG storage tank and is an inherently safer design when compared to penetrating the side of an LNG storage tank. Once LNG is transferred to the previously authorized Liquefaction Project LNG storage tanks, the in-tank pumps in those LNG storage tanks would send out LNG through the previously authorized marine transfer line and marine transfer arms connected to LNGCs. The LNG transferred to the LNGCs would displace vapors from the LNGCs, which would be sent back to the LNG storage containers. Once loaded, the LNGC would be disconnected and leave for export.

Low pressure boil-off gas (BOG) generated from the proposed LNG storage tank (LNG is continuously boiling) and other proposed piping and equipment, such as the LNG rundown line, would be compressed and routed to the BOG system previously authorized in the Liquefaction Project under FERC docket number CP12-507-000. If the Liquefaction Project BOG system cannot accept BOG, the BOG would be routed to a pipeline compressor and the Stage III Pipeline. This closed BOG system would prevent the release of BOG to the atmosphere and would be in accordance with NFPA 59A. This would be an inherently safer design when compared to allowing the BOG to vent to the atmosphere.

In addition, the Stage 3 LNG Facilities would consist of many utilities and associated auxiliary equipment. The major auxiliary systems required for the operation of the Project include BOG, fuel gas, hot oil, flares, instrument and utility air, potable and utility water, demineralized water, nitrogen, and diesel. Hot oil would provide heat to the amine regenerator reboiler, the feed gas heater, the condensate stabilizer reboiler, and the regeneration gas heater. Three wet flare stacks, three cold flare stacks, and three multi-point ground flares would be designed to handle and control the vent gases from the process areas. Utility nitrogen would be supplied via an existing nitrogen pipeline from Air Liquide. Refrigerant quality nitrogen would be supplied by nitrogen trucks. Electric power would be generated off-site. Diesel would be stored in dedicated day tanks for each essential diesel generator and diesel firewater pump.

The failure of process equipment could pose potential harm if not properly safeguarded through the use of appropriate controls and operation. CCL Stage III would install process control valves and instrumentation to safely operate and monitor the facilities. Alarms would have visual and audible notification in the control room to warn operators that process conditions may be approaching design limits. CCL Stage III would design their control systems and human machine interfaces to match the control center at the previously authorized Liquefaction Project which meets the International Society for Automation (ISA) Standards 5.3 and 5.5, and 60.1, 60.3, 60.4, and 60.6, and other standards and recommended practices. FERC staff recommends that CCL Stage III provide final specifications for these systems. We would verify these include specifications for human machine interface and other provisions to reduce the likelihood of human error that are similar to those in the ISA standards. We also recommend in section B.9.1.6 that CCL Stage III develop and implement an alarm management program, for review and approval to ensure the effectiveness of the alarms. FERC staff would evaluate the alarm management program against recommended and generally accepted good engineering practices, such as ISA Standard 18.2.

Operators would have the capability to take action from the control room to mitigate an upset. CCL Stage III would develop facility operation procedures after completion of the final design; this timing is fully consistent with accepted industry practice. We recommend in section B.9.1.6 that CCL Stage III file more information, for review and approval, on the operating and maintenance procedures prior to commissioning, including safety procedures, hot work procedures and permits, abnormal operating conditions procedures, and personnel training prior to commissioning. We would evaluate these procedures 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 American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS), *Guidelines for Writing Effective Operating and Maintenance Procedures*; AIChE CCPS, *Guidelines for Management of Change for Process Safety*; AIChE CCPS, *Guidelines for Effective Pre-Startup Safety Reviews*; AGA, *Purging Practices and Principles*; and NFPA Standard 51B, *Standard for Fire Prevention During Welding, Cutting, and Other Hot Work*. In addition, we recommend in section B.9.1.6 that CCL Stage III tag and label instrumentation and valves, piping, and equipment and provide car-seals/locks to address human factor considerations and improve facility safety and prevent incidents.

In the event of a process deviation, emergency shutdown valves and instrumentation would be installed to monitor, alarm, shut down, and isolate equipment and piping during process upsets or emergency conditions. Each LNG train would have emergency shutdown capability and individual process units would have shutdown capabilities. However, CCL Stage III would not install a site-wide or project-wide ESD button. Alternatively, CCL Stage III would shut each unit down sequentially depending on the incident impacts. We recommend in section B.9.1.6 that CCL Stage III 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 Stage III Project. Safety-instrumented systems would comply with ISA Standard 84.00.01 and other recommended and generally accepted good engineering practices. We recommend in section B.9.1.6 that CCL Stage III file information, for review and approval, on the final design, installation, and commissioning of instrumentation and emergency shutdown equipment to ensure appropriate cause-and-effect alarm or shutdown logic and enhanced representation of the emergency shutdown system in the plant control room and throughout the plant.

In developing the FEED, CCL Stage III conducted a process hazard analysis using the "What If" methodology based on the Project's plot plans, general arrangement drawings, and elevation drawings. The process hazard analysis examined the response of a process system to equipment failures, operator errors, and off-normal process conditions and developed recommendations to address actionable risks.

A more detailed hazard and operability review (HAZOP) analysis would be performed by CCL Stage III during the final design to identify the major process hazards that may occur during the operation of the Stage 3 LNG 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. We recommend in section B.9.1.6 that CCL Stage III file the HAZOP study on the completed final design for review and approval. We would evaluate the HAZOP 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*. We also recommend in section B.9.1.6 that CCL Stage III file the resolutions of the recommendations generated by the HAZOP review be provided for review and approval by FERC staff. Once the design has been subjected to a HAZOP review, the design development team would track, manage, and keep records of changes in the facility design, construction, operations, documentation, and personnel. CCL Stage III would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled based on its management of change procedures. If our recommendations are adopted into the Order, resolutions of the recommendations generated by the HAZOP review would be monitored by FERC staff. We also recommend in section B.9.1.6 that CCL Stage III file all changes to their FEED for review and approval by FERC staff. However, major modifications could require an amendment or new proceeding.

If the Project is authorized, constructed, and operated, CCL Stage III would install equipment in accordance with its design. We recommend in section B.9.1.6 that Project facilities be subject to construction inspections and that CCL Stage III provide, for review and approval, commissioning plans, procedures, and commissioning demonstration tests that would verify the performance of equipment. In addition, we recommend in section B.9.1.6 that CCL Stage III provide semi-annual reports that include abnormal operating conditions and planned facility modifications. Furthermore, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment is being properly maintained and to verify basis of design conditions, such as feed gas and sendout conditions, do not exceed the original basis of design.

Mechanical Design

CCL Stage III provided codes and standards for the design, fabrication, construction, and installation of piping and equipment and specifications for the facility. The design specifies materials of construction and ratings suitable for the pressure and temperature conditions of the process design. Piping would be designed, fabricated, assembled, erected, inspected, examined, and tested in accordance with the ASME Standards B31.3, B36.10, and B36.19. Valves and fittings would be designed to standards and recommended practices such as API Standards 594, 598, 600, 602, 603, 607, 608, and 609; ASME Standards B16.5, B16.10, B16.20, B16.25, and B16.34; and ISA Standards 75.01.01, 75.08.01, 75.08.02, 75.08.05, 75.08.06, and 75.19.01.

Pressure vessels would be designed, fabricated, inspected, examined, and tested in accordance with ASME Boiler and Pressure Vessel Code (BPVC) Section VIII per 49 CFR 193, Subparts C, D, and E, and by incorporation NFPA 59A (2001 edition). Heat exchangers would be designed to ASME BPVC Section VIII standards; API Standards 660, 661, and 662; and the Tubular Exchanger Manufacturers Association standards. Fired heaters would be specified and designed to standards and recommended practices, such as API Standards 556 and 560 and NFPA 85. Rotating equipment would be designed to standards and recommended practices, such as API Standards 610, 613, 614, 617, 670, 671, 675, 676, and 682 and ASME Standards B73.1 and B73.2.

The LNG storage tank must be design, fabricated, tested, and inspected in accordance with 49 CFR 193, Subpart D, NFPA 59A (2001 and 2006), and API Standard 620. In addition, CCL Stage III would design, fabricate, test, and inspect the full containment LNG storage tank in accordance with API Standard 625 and American Concrete Institute Standard 376. Other low-pressure storage tanks such as the amine and condensate storage tanks, would be designed, inspected, and maintained in accordance with the API Standards 650 and 653.

Pressure and vacuum safety relief valves and flares would be installed to protect the storage containers, pressure vessels, process equipment, and piping from an unexpected or uncontrolled pressure excursion. The safety relief valves would be designed to handle process upsets and thermal expansion, per NFPA 59A (2001), ASME Standard B31.3, and ASME BPVC Section VIII; and would be designed in accordance with API Standards 520, 521, 526, 527, 537, 2000, and other recommended and generally accepted good engineering practices. However, the multipoint ground flare would be designed to a wind speed that is less than 183 mph 3-second gust and has a single fuel source. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide quantitative analysis which evaluates the reliability of the multi point ground flare pilots, including the potential common cause failures of the pilots being designed to less than 183 mph 3-second gust and having a single fuel source. The analysis should demonstrate that the fences enclosing the ground flare would reduce the wind velocity to 125 mph or less and multiple sources of fuel gas exist. Otherwise, CCL Stage II should provide a dispersion analysis of an unlit flare scenario and indicate what safeguards would be in place of preventing offsite impacts from that scenario. In addition, flare load calculations provided in the within the application appear to use flare emissivity factors which are less conservative than are typically seen and which erroneously assigned a higher molecular to the dry flare and a lower molecular weight to the wet flare when performing their calculations. Therefore, we recommend in section B.9.1.6 CCL Stage III provide final design information on pressure and vacuum relief devices, for review and approval, to ensure that the final sizing, design, and installation of these components are adequate and in accordance with the standards referenced and other recommended and generally accepted good engineering practices.

Although many of the codes and standards were described or listed as ones the Project would meet, CCL Stage III did not make reference to all codes and standards required by regulations or that are recommended and generally accepted good engineering practices. In addition, there were inconsistencies among the codes and standards provided in the list, specifications, and data sheets. CCL Stage III stated in their December 8, 2018 filing that the codes and standards listed Resource Report 13, Appendix D.1 are considered to be the most significant and applicable to the Project. However, it is unclear if CCL Stage III would adhere to all codes and standards required by regulations and are recommended and generally accepted good engineering practices. In addition, a review of some of the preliminary specifications resulted in data requests. CCL Stage III responded to those data requests and plans on making changes in final design to resolve them. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide, for review and approval, a summarized list of all referenced codes and standards and the final specifications for all equipment.

If the Project is authorized, constructed, and operated, CCL Stage III would install equipment in accordance with its design and FERC staff would verify equipment nameplates to ensure equipment is being installed based on approved design. In addition, FERC staff would conduct construction inspections including reviewing quality assurance and quality control plans to ensure construction work is being performed according to proposed Project specifications, procedures, codes, and standards. We recommend in section B.9.1.6 CCL Stage III provide semi-annual reports that include equipment malfunctions and abnormal maintenance activities. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to inspections to verify that the equipment is being properly maintained during the life of the facility.

Hazard Mitigation Design

If operational control of the facilities were lost and operational controls and emergency shutdown systems failed to maintain the Project within the design limits of the piping, containers, and safety relief valves, a release could potentially occur. FERC regulations under 18 CFR 380.12 (o) (1) through (4) require applicants to provide information on spill containment, spacing and plant layout, hazard detection, hazard control, and firewater systems. In addition, 18 CFR 380.12 (o) (7) requires applicants to provide engineering studies on the design approach and 18 CFR 380.12 (o) (14) requires applicants to demonstrate how they comply with 49 CFR 193 and NFPA 59A. As required by 49 CFR 193, Subpart I and by incorporation section 9.1.2 of NFPA 59A (2001), fire protection must be provided for all of the USDOT PHMSA regulated LNG plant facilities based on an evaluation of sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. NFPA 59A (2001) also requires the evaluation to determine the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, and emergency response equipment, training, and qualifications. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193, Subpart I and would be subject to USDOT's inspection and enforcement programs. However, NFPA 59A (2001) also 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 and includes subjective performance-based language on where emergency shutdown systems and hazard control are required and does not provide any additional guidance on placement or selection of hazard detection equipment and provides minimal requirements on firewater. Therefore, FERC staff evaluated the proposed spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response to ensure they would provide adequate protection of the Stage 3 LNG Facilities, as described more fully below.

CCL Stage III performed a preliminary fire protection evaluation to ensure that adequate mitigation would be in place, including spill containment and spacing, hazard detection, emergency shutdown and depressurization systems, hazard control, firewater coverage, structural protection, and onsite and offsite emergency response. We recommend in section B.9.1.6 that CCL Stage III provide a final fire protection evaluation for review and approval, and to provide more information on the final design, installation, and commissioning of spill containment, hazard detection, hazard control, firewater systems, structural fire protection, and onsite and offsite emergency response procedures.

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 49 CFR 193.2181, under Subpart C specifies that each impounding system serving an LNG storage tank must have a minimum volumetric liquid capacity of 110 percent of the LNG tank's maximum design liquid capacity for an impoundment serving a single tank, unless surge is accounted for in the impoundment design. If authorized, constructed, and operated, LNG facilities as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193, Subpart C and would be subject to USDOT's inspection and enforcement programs. For full-containment LNG tanks, we also consider it prudent to provide a barrier to prevent liquid from flowing to an unintended area (i.e., outside the plant property). The purpose of the barrier is to prevent liquid from flowing off the plant property and does not define containment or an impounding area for thermal radiation or flammable vapor exclusion zone calculations or other code requirements already met by sumps and impoundments throughout the site.

CCL Stage III proposes one full-containment LNG storage tank for which the outer tank wall would serve as the impoundment system. FERC staff calculations show that CCL Stage III provided volumes for the capacities to demonstrate the outer tank would exceed 110 percent. In addition, CCL Stage III indicates that the tertiary containment system would be primarily defined by the roads that encircle the seven LNG trains and the LNG storage tank and would prevent LNG from flowing off plant property in the event that outer tank impoundment failed.

CCL Stage III 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 Stage III proposes to install curbing, paving, and trenches to direct potential LNG, mixed refrigerant, or condensate liquid releases in each liquefaction area to either the ISBL Impoundment. LNG releases from the rundown header, on top of each LNG storage tank, or during transfer operations to the previously authorized Liquefaction Project LNG storage tanks would be collected in a trench system and would be routed to the OSBL Impoundment Basin. Releases in the refrigerant delivery trucks would be collected in curbed areas and directed to the ISBL Impoundment Basin. Local bunds would be provided to contain liquid releases from the amine storage tank. In addition, local curbing would be provided around pretreatment equipment and selectively throughout the Project. However, it is unclear if local bunds would be appropriately sized. We recommend in section B.9.1.6 that CCL Stage III provide additional information on the final design of the impoundment systems for review and approval.

Under NFPA 59A (2001) section 2.2.2.2, the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the USDOT PHMSA. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193, Subpart C and would be subject to USDOT's inspection and enforcement programs. However, we evaluate whether all hazardous liquids are provided with spill containment based on the largest flow capacity from a single pipe for 10 minutes accounting for de-inventory or the liquid capacity of the largest vessel served, whichever is greater. In addition, we recommend in section B.9.1.6 that CCL Stage III provide additional information on the final design of the impoundment systems for review and approval.

FERC staff also evaluated the means to remove water from impounding areas to ensure impoundment volumes would not be reduced through accumulations of rainwater or snow. In addition, FERC staff evaluated whether there are provisions to ensure that hazardous fluids are not accidentally discharged through the systems intended to remove rainwater. In addition, if authorized, constructed, and operated, all LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to USDOT's inspection and enforcement programs. CCL Stage III indicates that the stormwater pumps would be automatically operated by staggered level control and interlocked using low temperature and flammable gas detectors to automatically shutoff or prevent startup of the pumps when exposed to LNG, refrigerant or condensate. While stormwater removal pumps would be proposed for the large impoundment basins and bunded areas described above, CCL Stage III also proposes to install normally-closed valves on local bunds and curbed areas. CCL Stage III is consulting with the USDOT PHMSA on the use of normally-closed valves instead of stormwater removal pumps required in 49 CFR 193.2173, under Subpart C. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide the USDOT PHMSA correspondence accepting the use of normally closed valves to remove stormwater from curbed areas. If authorized, constructed, and operated, final compliance with the requirements of 49 CFR 193, Subpart C would be subject to the USDOT's inspection and enforcement programs.

If the Project is authorized, constructed, and operated, CCL Stage III would install spill impoundments in accordance with its design and FERC staff would verify during construction inspections that the spill containment system including dimensions, slopes of curbing and trenches, and volumetric capacity matches final design information. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to verify that impoundments are being properly maintained.

Spacing and Plant Layout

The spacing of vessels and equipment between each other, from ignition sources, and to the property line must meet the requirements of 49 CFR 193, Subparts C, D, and E, which incorporate NFPA 59A (2001). NFPA 59A (2001) includes spacing and plant layout requirements and further references NFPA 30, NFPA 58, and NFPA 59 for additional spacing and plant layout requirements. If the LNG facilities, as defined in 49 CFR 193, are authorized, constructed, and operated, CCL Stage III must comply with the requirements of 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs.

In addition, FERC staff evaluated the spacing to determine if there could be cascading damage and to inform what fire protection measures may be necessary to reduce the risk of cascading damage. If it was not practical for spacing to mitigate the potential for cascading damage, FERC staff evaluated whether other mitigation measures were in place and evaluated those systems in further detail, as discussed in subsequent sections. FERC staff evaluated hazards associated with releases and whether any damage would result in cascading damage.

To minimize the risk of cryogenic spills causing structural supports and equipment from cooling below their minimum design metal temperature, CCL Stage III would have spill containment systems surrounding cryogenic equipment and would generally locate cryogenic equipment away from process areas that do not handle cryogenic materials. In addition, FERC staff recommends CCL Stage III file drawings and specifications for structural passive protection systems to protect equipment and supports that could be exposed to cryogenic releases.

To minimize risk for flammable or toxic vapor ingress into buildings and flammable vapors reaching areas that could result in cascading damage from explosions, CCL Stage III would generally locate buildings away from process areas and would locate fired equipment and ignition sources away from process areas and generally propose to arrange their process facilities to be relatively unconfined and uncongested. The LNG tank is also generally located away from process equipment and would sit on the ground such that there would not be a confined area underneath it. CCL Stage III also committed to providing hazard detection devices at the air intakes of buildings that would isolate or shut down any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. However, CCL Stage III did not yet include these hazard detectors on its drawings. Therefore, we recommend in section B.9.1.6 that CCL Stage III conduct a technical review of facility, for review and approval, identifying all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release and demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. We also recommend in section B.9.1.6 that Project facilities be subject to periodic inspections during construction to verify flammable/toxic gas detection equipment is installed in heating, ventilation, and air condition intakes of buildings at appropriate locations. In addition, we recommend in section B.9.1.6 that Project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that flammable/toxic gas detection equipment installed in building air intakes function as designed and are being maintained and calibrated.

To minimize the risk of pool and jet fires from causing cascading damage that could exacerbate the initial hazard, CCL Stage III would generally locate flammable and combustible containing piping and equipment away from process areas that do not handle flammable and combustible materials. In addition, CCL Stage III located their impoundments such that the radiant heats would have a minimal impact on most areas of the plant. A fire from the LNG storage tank outer containment walls would have less than 10,000 Btu/ft^2-hr at the adjacent process area, but would have 4,000 Btu/ft^2-hr extend over process areas. Jet fires may also extend over portions of the plant. To mitigate impoundment and jet fires within the plant, CCL Stage III indicates that measures would be in place to prevent cascading events, including fire-safe emergency shutdown valves with fire resistant instrument and power cabling, depressurization systems, fire and gas detectors, fire proofing of structural steel columns supporting critical equipment, deluge systems, water curtains, and fire monitors and hydrants. However, details of these systems would be developed in final design. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide the final design of these mitigation measures, for review and approval, to demonstrate cascading events would be mitigated. In addition, we recommend in section B.9.1.6 that CCL Stage III provide an analysis, for review and approval, demonstrating the LNG storage tank can withstand the cryogenic temperatures and radiant heat from which it would be exposed from a tank roof spill and fire.

If the Project is authorized, CCL Stage III would finalize the plot plan, and we recommend in section B.9.1.6 that CCL Stage III provide any changes for review and approval to ensure capacities and setbacks are maintained. If the Project facilities are constructed, CCL Stage III would install equipment in accordance with the spacing indicated on the plot plans. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction to verify equipment is installed in appropriate locations and the spacing is met in the field. We also recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment setbacks from other equipment and ignition sources are being maintained during operations.

Ignition Controls

CCL Stage III's plant areas would be designated with an appropriate hazardous electrical classification and process seals commensurate with the risk of the hazardous fluids being handled in accordance with NFPA 59A, 70, and 497 and API RP 500. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to USDOT's inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001) and NFPA 70 (1999). Depending on the risk level, these areas would either be unclassified or classified as Class 1 Division 1, or Class 1 Division 2. Electrical equipment located in these classified 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. We evaluated CCL Stage III's electrical area classification drawings to determine whether CCL Stage III would meet these electrical area classification requirements and good engineering practices in NFPA 59A, 70, 497, and API RP 500. We also raised inconsistencies in data requests regarding electrical area classification codes and standards and electrical area classification nomenclature on data sheets. CCL Stage III indicated they would make changes to the data sheets to resolve those issues.

If the Project is authorized, CCL Stage III would finalize the electrical area classification drawings and would describe changes made from the FEED design. We recommend in section B.9.1.6 that CCL Stage III file the final design of the electrical area classification drawings for review and approval. If the Project facilities are constructed, CCL Stage III would install appropriately classed electrical equipment, and we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction for FERC staff to spot check electrical equipment and verify equipment is installed per classification and are properly bonded or grounded in accordance with NFPA 70. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to ensure electrical equipment is maintained (e.g., bolts on explosion proof equipment properly installed and maintained, panels provided with purge, etc.), and electrical equipment are appropriately de-energized and locked out and tagged out when being serviced.

In addition, submerged pumps and instrumentation would be equipped with electrical process seals, and instrumentation in accordance with NFPA 59A (2001) and NFPA 70. We recommend in section B.9.1.6 that CCL Stage III provide, for review and approval, final design drawings showing process seals 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. In addition, we recommend in section B.9.1.6 that CCL Stage III file, for review and approval, details of an air gap or vent 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. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to ensure electrical process seals for submerged pumps continue to conform to NFPA 59A and NFPA 70 and that air gaps are being properly maintained.

Hazard Detection, Emergency Shutdown, and Depressurization Systems

CCL Stage III would also install hazard detection systems to detect cryogenic spills, flammable and toxic vapors, and fires. The hazard detection systems would alarm and notify personnel in the area and control room to initiate an emergency shutdown, depressurization, or initiate appropriate procedures, and would meet NFPA 72, ISA Standard 12.13.01, and other recommended and generally accepted good engineering practices. In addition, we recommend in section B.9.1.6 that CCL Stage III file specifications, for review and approval, of the final design of fire safety specifications, including hazard detection, hazard control, and firewater systems.

FERC staff also evaluated the adequacy of the general hazard detection type, location, and layout to ensure adequate 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). However, we noted a number of areas that did not seem to have adequate coverage, including sparse distribution of flame detectors and lack of hydrogen detectors in areas of battery storage and lack of H_2S toxic gas detectors and flammable gas detectors near the thermal oxidizer or hot oil furnace. Therefore, we recommend in section B.9.1.6 that CCL Stage III file a hazard detection study to evaluate the effectiveness of their flammable and combustible gas detection and flame and heat detection systems in accordance with ISA 84.00.07 or equivalent methodologies that would demonstrate 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact that could extend off site 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, and different wind speeds and directions. Given the propensity of hydrogen to ignite and generate damaging overpressures, FERC staff recommend in section B.9.1.6 that CCL Stage III file an analysis of the off gassing of hydrogen in battery storage areas and demonstrate ventilation calculations limit concentrations below the lower flammability limits (e.g., 25 percent LFL) and that hydrogen detectors be installed that alarm (e.g., 20 to 25 percent LFL) and initiate mitigative actions (e.g., 40 to 50 percent LFL). We also recommend that CCL Stage III install toxic and flammable gas detection in the vicinity of the hot oil furnace and thermal oxidizer, at the LNG storage tank, and at the HVAC intake of the firewater pump building. Several other issues were raised in data requests. CCL indicated they would make changes to resolve those issues or that we would follow up as part of our normal course of review of the final design.

Furthermore, we recommend in section B.9.1.6 that CCL Stage III provide additional information, for review and approval, on the final design of all hazard detection systems (e.g., manufacturer and model, elevations, etc.) and hazard detection layout drawings. In addition, FERC staff recommend in section B.9.1.6 that CCL Stage III file the final design of the cause and effect matrices.

If the Project is authorized and constructed, CCL Stage III would install hazard detectors according to its final specifications and drawings, and we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction to verify hazard detectors and emergency shutdown pushbuttons are appropriately installed per approved design and functional based on cause and effect matrixes prior to introduction of hazardous fluids. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to verify hazard detector coverage and functionality is being 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, and would meet NFPA 59A (2001), 10, 12, 17, and 2001; API 2218 and 2510A; and other recommended and generally accepted good engineering practices. We evaluated the adequacy of the number and availability of handheld, wheeled, and fixed fire extinguishing devices throughout the site based on the FEED. FERC staff also generally evaluated whether the spacing of the fire extinguishers meet NFPA 10 and agent type and capacities meet NFPA 59A (2009 and later editions). The hazard control plans do not appear to meet NFPA 10 travel distances to most components containing flammable or combustible fluids (Class B) with 20 pounds (lb) hand-held fire extinguishers (30-50 feet) and 300-lb wheeled extinguishers (100 feet). However, CCL Stage III indicated that final layouts would be developed to meet the spacing requirements in NFPA 10. Therefore, we recommend in section B.9.1.6 that CCL Stage III file facility plan drawings that demonstrate extinguishers meet the minimum travel distances required by NFPA 10. The agent storage capacities of 20 lb for hand-held (minimum 20 lb) and 300 lb wheeled (minimum 125 lb) also appear to meet NFPA 59A requirements. However, CCL Stage III was inconsistent on the agent types that would be used (e.g., potassium bicarbonate, sodium bicarbonate, etc.) for the 20 lb hand-held fire extinguishers but indicated that the 300 lb wheeled fire extinguishers would be Purple K (potassium bicarbonate). CCL Stage III also indicated hazard control would be provided in electrical and instrumentation building with automated clean agent systems installed in non-occupied buildings containing critical electrical equipment and CO_2 extinguishers, but did not provide capacities for the CO_2 extinguishers. In addition, installation heights, visibility, flow rate capacities, and other requirements should be confirmed in final design and in the field where design details, such as manufacturer, obstructions, and elevations, would be better known. FERC staff recommend in section B.9.1.6 that CCL Stage III file additional information, for review and approval, on the final design of these systems (e.g., manufacturer and model, elevations, flowrate, type, capacities, etc.) demonstrating they would meet NFPA 10 and where the final design could change as a result of these details or other changes in the final design of the Project.

In addition, FERC staff evaluated whether fire protection systems would be installed in gas turbine enclosures. It is unclear what protection would be installed in gas turbine enclosures and if the fire suppression system may be carbon dioxide in accordance with NFPA 12, water mist in accordance with NFPA 750, or clean agent in accordance with NFPA 2001. Therefore, we recommend in section B.9.1.6 that CCL Stage III file additional information on the final design of these systems, for review and approval, where details are yet to be determined (e.g., manufacturer and model, elevations, flowrate, capacities, etc.) and where the final design could change as a result of these details or other changes in the final design of the Project.

If the Project is authorized and constructed, CCL Stage III would install hazard control equipment, and we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction to verify hazard control equipment is installed in the field and functional prior to introduction of hazardous fluids. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to verify in the field that hazard control coverage and is being properly maintained and inspected.

Passive Cryogenic and Fire Protection

If cryogenic releases or fires could not be mitigated from impacting facility components to insignificant levels, passive protection (e.g., fireproofing structural steel, cryogenic protection, etc.) should be provided to prevent failure of structural supports of equipment and pipe racks. DOT PHMSA 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) 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. In addition, NFPA 59A (2001) does not address passive cryogenic 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. Therefore, FERC staff evaluated whether passive cryogenic and fire protection would be applied to pressure vessels and structural supports to facilities that could be exposed to cryogenic liquids or to radiant heats of 4,000 Btu/ft^2-hr or greater from fires with durations that could result in failures[24] and that they are specified in accordance with recommended and generally accepted good engineering practices, such as ISO 20088, API 2001, API 2010A, API 2218, ASCE/SFPE 29, ASTM E 84, ASTME E 2226, IEEE 1202, ISO 22899, NACE 0198, NFPA 58, NFPA 255, NFPA 290, OTI 95 634, UL 1709, and/or UL 2080, with a cryogenic temperature and duration or fire protection rating of a commensurate to the exposure.

To minimize the risk of cryogenic spills causing structural supports and equipment from cooling below their minimum design metal temperature to a point of failure, CCL Stage III would specify materials of construction that would not fail when exposed to a cryogenic release or would coat or shield structural supports and equipment with materials that would be cryogenic resistant. In addition, CCL Stage III would generally locate cryogenic equipment away from non-cryogenic process areas and would direct cryogenic releases to remote impoundment basins. However, the cryogenic passive protection drawings did not indicate on the method or exact locations that would and would not be protected from cryogenic releases or the performance characteristics of the passive cryogenic protection. Therefore, we recommend in section B.9.1.6 that CCL Stage III file drawings and specifications for the cryogenic structural protection and calculations or test results (e.g., ISO 20088) that demonstrate the effectiveness of the cryogenic structural protection.

To minimize the risk of pool and jet fires causing structural supports and equipment from heating above their maximum design metal temperatures to a point of failure, CCL Stage III would specify materials of construction that would not fail when exposed to a fire or would install structural fire protection. CCL Stage III indicated the structural fire protection would meet API 2218, UL 1709, and other recommended and generally accepted good engineering practices. API 2218 requires structural fire protection in certain areas and also recommends fire envelopes be defined based on potential fire scenarios for defining where passive fire protection is needed. API 2218 also recommends the use of UL 1709 for performance requirements of passive fire protection in areas that are determined to be subjected to pool fires and provides more limited guidance on defining what jet fire scenarios to consider or the performance requirements of passive fire protection. However, API 2218 does not define the pool fire or jet fire scenarios or the radiant heats to be used to determine the extent of passive fire protection. In addition, CCL Stage III indicated that a fire scenario envelope is defined as 30 feet above grade and from the edge of equipment. However, CCL Stage III did not provide a basis for these values and they would seem to not provide adequate protection. In addition, when inconsistencies between drawings and data sheets were pointed out, CCL Stage III indicated that fireproofing would be determined in final design. Therefore, we recommend in section B.9.1.6 that CCL Stage III file final drawings and specifications for the passive fire protection and calculations or test results (e.g., ISO 22899, NFPA 290, OTI 95 634, etc.) that demonstrate the effectiveness of the passive fire protection. We also recommend that passive protection be defined based on scenarios that could lead to offsite impacts or cascading damage and that structural supports may fail as low as

[24] 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.

4,900 Btu/ft^2-hr[25] and pressurized equipment may fail as low as 4,000 Btu/ft^2-hr[26], and recognize pool fire tests under UL 1709 are for 65,000 Btu/ft^2-hr (2,000°F) in 5 minutes and a 1 hour duration, which would provide thicker passive protection than may be necessary to prevent failure in some areas and thinner passive protection than may be necessary to prevent failure in other areas. We also note the application of fireproofing is sometimes prescribed in API 2218 to be 20 to 40 feet high, which may be less than or more than a pool fire height or jet fire flame length. Therefore, we also recommend in section B.9.1.6 that CCL Stage III file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each significant component within the 4,000 Btu/ft^2-hr zone from pool or jet fires that could cause failure of the component. Trucks at the truck loading/unloading areas should be included in the analysis. 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 for the thickness limiting temperature rise and active mitigation should be justified with calculations demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the vessel. In addition, we recommend in section B.9.1.6 that CCL Stage III file the final design of these mitigation measures, for review and approval, to demonstrate cascading events would be mitigated.

CCL Stage III also indicated that electrical, instrument, and control systems used to activate emergency systems would be designed to withstand a 20-minute fire exposure equivalent to UL 1709. In addition, CCL Stage III indicated electrical transformers would utilize less flammable insulating fluid and therefore would not have fire rated barriers to prevent cascading damage. In addition, the plot plans did not indicate there was sufficient spacing to prevent cascading damage. Recommended and generally accepted good engineering practices, such as NFPA 850, require transformers that use less flammable insulating fluids to still have firewalls or separation distances to prevent cascading failures. Therefore, we recommend in section B.9.1.6 that CCL Stage III either separate or provide fire walls for electrical transformers in accordance with NFPA 850 or equivalent that would prevent cascading damage.

If the Project is authorized and constructed, CCL Stage III would install structural cryogenic and fire protection according to its design, and we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction to verify structural cryogenic and fire protection is properly installed in the field as designed prior to introduction of hazardous fluids. In addition, we

[25] FERC staff's heat impact preliminary analyses indicate most carbon structural steels (e.g., ASTM A36), will begin to have a noticeable loss of strength at 570°F (300°C), lose approximately 1/3 of strength at 840°F (450°C), and lose approximately 1/2 of strength at 1,000°F (540°C). These temperatures would correspond to black body radiant heats of approximately 2,000 Btu/ft^2-hr (6.1 kW/m^2), 4,900 Btu/ft^2-hr (15.5 kW/m^2), and 7,750 Btu/ft^2-hr (24.5 kW/m^2), respectively, and the latter radiant heats may correspond to when structural steel begins to exceed yield strengths and suffer possible structural damage based on allowable stress/strength designs in structural and mechanical design codes (e.g., ASCE 7, AISC 360, ASME B31.3, ASME BPVC, etc.), which most commonly limit stresses to 1/2 to 2/3 of yield strength. In addition, these values are in line with NFPA 59A (2016 edition and 2019 editions) that recommend similar temperature and corresponding radiant heats for steel, ABS Consulting, *Consequence Assessment Methods for Incidents Involving Release from Liquefied Natural Gas Carriers*, 2004 that reports long term exposures at approximately 8,000 Btu/ft^2-hr (25 kW/m^2) steel surfaces experience serious dislocation as well as paint peeling, and structural elements undergo substantial deformation according to damage resulting from thermal radiation for various materials, and Sandia National Laboratories, *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*, 2004, that reports durations of more than 10 minutes at approximately 12,000 Btu/ft^2-hr causes temperatures to rise to 980°F (530°C) and result in 25 to 40 percent loss in steel strength and damages structures.

[26] FERC staff recognize that pressurized equipment in accordance with ASME BPVC allows for pressure relief valves to pressures to rise to 1.2 times the design pressure, which would lower the pressure in the vessel to less than the bursting pressure of typically 3 to 4 times the design pressure but adds stress to the equipment above normal design conditions, and causes a reduction in temperature and subsequent reduction in radiant heat from 4,900 Btu/ft2-hr to 4,000 Btu/ft2-hr for when pressurized equipment may fail. We also recognize that 4,000 Btu/ft2-hr is a commonly used endpoint in fire analyses.

recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to continue to verify that passive protection is being properly maintained.

Firewater Systems

CCL Stage III would also provide firewater systems, including remotely operated firewater monitors, sprinkler systems, fixed water spray systems, 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. These firewater systems would be designed, tested, and maintained to meet NFPA 59A (2001), 13, 14, 15, 20, 22, 24, 25, and 750 requirements.

FERC staff evaluated the adequacy of the general firewater system coverage and verified the appropriateness of the associated firewater demands of those systems and worst-case fire scenarios to size the firewater pumps. Based on that review, we noted a lack of firewater coverage in various areas. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide firewater coverage by two or more hydrants or monitors (or deluge systems) based on radiant heat exposure and corresponding design densities and areas to be cooled by firewater for all areas that contain flammable or combustible fluids, including the LNG storage tank, refrigerant compressor skid, heavy hydrocarbon removal unit, and liquefaction cold box. We also recommend in section B.9.1.6 that CCL Stage III provide final firewater capacities for the monitors and hydrants in order to verify the appropriateness of the associated firewater demands of those systems and worst-case fire scenarios to size the firewater pumps, including whether firewater demand needs to consider demand for two or more adjacent fire zones if they could result in cascading damage. In addition, where coverage circles intersect pipe racks, large vessels or process equipment, the firewater coverage could be blocked, and the coverage circles should be modified to account for obstructions during the final design. In addition, where areas may be inaccessible or difficult to access in the event of an emergency, we recommend in section B.9.1.6 that CCL Stage III install deluge systems or remotely operable or automatic monitors. We recommend in section B.9.1.6 that CCL Stage III complete and document the firewater monitor and hydrant coverage test to verify that actual coverage area from each monitor and hydrant as shown on facility plot plan(s).

FERC staff also assessed whether the reliability of the firewater pumps and firewater source are appropriate. CCL Stage III proposes to install two 480,000-gallon firewater tanks. Each tank has sufficient capacity to supply firewater for a 2-hour rated demand case of 4,000 gallons per minute. However, CCL Stage III has not demonstrated that the demand case provided is sufficient to adequately service the facility. Therefore, we recommend in section B.9.1.6 that CCL Stage III demonstrate the firewater demand is based upon the cooling exposure needs for pool and jet fires, including potential for radiant heats to affect adjacent areas. In addition, CCL Stage III indicated that the Firewater Tank is being built in accordance with API 650 instead of AWWA D-100. NFPA 59A (1994 and thereafter) indicates fire protection water systems must be designed in accordance with NFPA 22, which incorporates AWWA D-100. CCL Stage III concedes that API 650 would provide a thinner tank shell than AWWA D100 if following the basic rules of AWWA D-100, but contends that API 650 provides an equivalent level of safety as AWWA D-100 and that they would follow other applicable NFPA 22 requirements for the firewater tank, such as anti-vortex plate and inlet connections. However, CCL Stage III did not provide anything that demonstrates the relative difference in tank shell thickness, stress levels, or other quantitative comparison to better support equivalency of API 650 to AWWA D-100 and they did not address other design aspects questioned nor define what they view as applicable in NFPA 22. Therefore, we recommend in section B.9.1.6 that CCL Stage III demonstrate that API 650 provides equivalent or greater protection than NFPA 22 and AWWA D-100 in regards to the design of the firewater storage tanks, including requirements for inflow piping refilling the tank within 8 hours, higher wall thicknesses, venting, manholes, anti-vortex plates, and other pertinent differences.

In addition, we recommend in section B.9.1.6 that CCL Stage III file additional information on the final design of all the firewater systems, for review and approval, where details are yet to be determined (e.g., manufacturer and model, nozzle types, etc.) and where the final design could change as a result of these details or other changes in the final design of the Project.

If the Project is authorized and constructed, CCL Stage III would install the firewater system based on the final specifications and drawings, and we recommend in section B.9.1.6 that the Project facilities be subject to periodic inspections during construction and that companies provide results of commissioning tests to verify the firewater systems are installed and functional as designed prior to introduction of hazardous fluids. FERC staff also recommend in section B.9.1.6 that CCL Stage III should specify that the firewater flow test meter is equipped with a transmitter and that a pressure transmitter is installed upstream of the flow transmitter, which should both be connected to the DCS and recorded to keep a history of flow test data. FERC staff also recommend in section B.9.1.6 that the largest firewater pump or component be able to be removed for maintenance from the firewater pump building. In addition, we recommend in section B.9.1.6 that the Project facilities be subject to regular inspections throughout the life of the facility to ensure firewater system is being properly maintained and tested.

Geotechnical and Structural Design

CCL Stage III 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, seiche, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, sea level rise, landslides, wildfires, volcanic activity, and geomagnetism.

Geotechnical Evaluation

FERC regulations under 18 CFR 380.12 (h) (3) require geotechnical investigations to be provided. In addition, FERC regulations under 18 CFR 380.12 (o) (14) require an applicant demonstrate compliance with regulations under 49 CFR 193 and NFPA 59A. All LNG facilities, as defined in 49 CFR 193, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs. The USDOT 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 out in 49 CFR 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 Stage 3 LNG Facilities, as described below.

The Stage 3 LNG Facilities are located just north of the existing Liquefaction Project along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio County, Texas. The Stage 3 LNG Facilities are located within the Coastal Prairie region of the Gulf Coastal Plain physiographic province of Texas (Bureau of Economic Geology, 1996). Holocene-aged deposits are characteristic of this region and primarily consist of alluvial, deltaic, beach, bay-estuary, and marsh deposits. These deposits are underlain by deep Pleistocene-aged deltaic and alluvial deposits interlayered with clays and sands. The Coastal Plain lies along the Atlantic seaboard and Gulf Coast of the U.S., stretching 100 to 200 miles inland and 100 to 200 miles offshore, to the edge of the continental shelf. This belt of Late Cretaceous to Holocene sedimentary rocks comprises an elevated sea bottom with low topographic relief dipping seaward. In Texas, the Coastal Plain includes a system of alternating synclines (troughs) and anticlines (peaks) oriented perpendicular to the coastline (Hosman, 1996). The surficial geology underlying the region is composed of Quaternary Holocene and Pleistocene-aged sediments made of alluvium of the Rio Grande and coastal deposits of dune, estuary, lagoon, deltaic, tidal-flat, beach, and barrier island environments (Page et al., 2005).

The site would be cleared, grubbed, and prepared using standard earthmoving and compaction equipment. The existing ground surface elevation within DMPA 2 varies from El. +54 to +60 feet as a result of dredged hydraulic fill placement. The existing grade is low in the flare area, and the elevation would be raised by fill material. The flare site is occupied with recently deposited silty-clay sediments, it is relatively flat, and the ground surface varied from El. +38 ft to +41.5 feet in January 2017. The existing ground surface elevation at the laydown areas varies from El. +22 to +24 feet.

CCL Stage III contracted TWEI to conduct geotechnical investigations and report to evaluate existing soil site conditions and proposed foundation design for the Project. TWEI reviewed previous geotechnical investigations that were performed to evaluate the bauxite residue and underlying natural soils. Those previous studies were conducted before placement of dredged hydraulic fill from the ongoing construction of previously authorized Liquefaction Project. TWEI performed additional soil borings, test pits, and conducted laboratory tests to evaluate: recently placed dredged hydraulic fill; subsurface conditions at the flare area; subsurface conditions at the laydown yards; and subsurface conditions along the access roads between the plant area and laydown yard. The initial geotechnical investigation included conducting: 18 test boring ranging in depth from 36 to 267 feet; 10 cone penetration tests with pore pressure measurements (PCPT) ranging in depths from 39 to 41 feet; 8 monitoring wells to depths ranging from 36 to 44 feet; and 2 P&S suspension logging tests to measure shear and compression waves. A second geotechnical investigation included: 88 test borings ranging in depth from 14 to 300 feet; 33 PCPT ranging in depth of 33 to 135 feet; 6 downhole seismocone penetration tests (SCPT) to depths of 75 to 115 feet depth; 5 shallow test pits (TP) to 5 feet depth; and 3 pressure meter tests (PMT) to 154 feet depth. A third geotechnical investigation included the following: 31 boings ranging in depth from 15 to 140 feet; and 3 test pits ranging in depths from 14 to 23 feet. From the three geotechnical investigations, more than 10 laboratory tests on over 140 recovered soil samples were conducted, including classification tests (water content, Atterberg liquid and plastic limits, sieve tests), compression tests, consolidation tests, shear tests, and corrosion potential tests (pH, sulfate, chloride, electrical resistivity) in general accordance with pertinent ASTM standards. FERC staff evaluated the geotechnical investigation to ensure the adequacy in the number, coverage, and types of the geotechnical borings, CPTs, SCPTs, and other tests. FERC staff issued data requests on the lack of coverage for certain portions of the LNG terminal, including the Train 4 area, LNG tank area, flare area, and complete lack of coverage of Trains 5 through 7. CCL Stage III confirmed that additional geotechnical explorations are being planned for the remaining portions of the Train 4 area, LNG tank area, and flare area, and the final results would be filed for FERC staff review. CCL Stage III also indicated that geotechnical exploration for Trains 5 through 7 has not been performed to date because the area is currently being used as decant ponds for fines and water runoff associated with Liquefaction Project dredging activities. CCL Stage III proposes as part of earthwork operations for Trains 1 through 4 and associated flare areas, dredge spoils from above approximately El. 48 ft in roadway areas and El. 43 ft in foundation areas of Trains 1 through 4 and associated flare areas would be transported and placed in the area of Trains 5 through 7 and associated flare areas. Following these activities, geotechnical exploration consisting of sample borings, cone penetration tests, and seismic cone penetration tests would be conducted together with laboratory testing of recovered samples to assess the characteristics of the dredge spoil and underlying bauxite residue and natural soils. Upon a data request, CCL Stage III has indicated that the LNG tank area, and Trains 4 through 7 and associate flare area geotechnical investigation and results are expected to show similar soil characteristics with the Trains 1 through 4 and associated flare areas and existing data for LNG tank area. Therefore, CCL Stage III is expecting to use similar soil modification and foundation designs for Trains 1 through 7 and associated flare areas. However, given the proposed construction schedule and current lack of geotechnical investigation on portions of the facility to support the soil conditions, soil modification, or foundation designs would be similar to the LNG tank area, Trains 1 through 4 and associated flare area, which are all critical to the safe design of the facilities, we recommend in section B.9.1.6 that prior to initial site preparation, CCL Stage III file supplemental geotechnical investigations for the remaining portions of Train 4, the LNG tank area, and associated flare area and entire Trains 5 through 7 and associated flare area, including geotechnical investigation location plan with spacing of no more than 300 feet and field sampling methods and laboratory tests that are at least as comprehensive as the existing geotechnical investigations. We also recommend that geotechnical test borings be performed to a minimum depth of 100 feet, or until refusal. In addition, the geotechnical investigations and report must demonstrate soil modifications and foundation designs would be similar to Trains 1 through 3 and portions of the LNG tank and flare areas already investigated. If the geotechnical investigations are not as comprehensive or indicate soil modifications and foundation designs different from the existing geotechnical investigation results then a variance or amendment to the Project must be filed for review and approval depending on the degree and number of differences. FERC staff would continue its review of the results of the geotechnical investigation to ensure foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

Based on the test borings conducted thus far, the subsurface profile of Trains 1 through 3 flare area indicates near surface dredged silty-clay sediments and underlying bauxite residue to El. +24 to +21 feet are very soft and highly compressibility; medium dense to sands between El. +15 to +2 feet, including very dense sands; and very stiff to hard clays between El. +2 to -44 feet, including layers to medium dense to dense sands. For the laydown yard area, the soil stratigraphy is stiff sandy lean and fat clay between +23 to +15 feet; and loose to medium dense clayey and silty sands between +15 to +6 feet. The subsurface profile of tank area indicates clay and sands to very soft bauxite residue between +58 to +23 feet; stiff lean clay to medium dense to very dense silty sands between +23 to +5 feet; very stiff to hard fat clays to dense clayey sand between +5 to -28 feet; hard lean clay to very dense silty sands between -28 to -50 feet; hard lean and fat clay to very dense silty sands between -60 to -85 feet; hard fat clay to very dense silty sands between -85 to -130 feet; and hard fat clay to very dense silty sands to hard fat clay between -130 to -380 feet. The subsurface profile for Train 1 area and adjacent laydown area indicates soft clay to loose sand between +58 to +34 feet; very soft bauxite residue to stiff lean and fat clay between +34 to +15 feet; medium dense to dense silty sands to very stiff fat clays between +15 to -16 feet; hard lean clay with sand layers to very dense silty sands with clay layers between -16 to -65 feet; and hard lean and fat clay to very dense silty sands to hard fat clay between -65 to -120 feet. The Trains 2 through 4 area indicate clay and sands to very soft bauxite residue between +58 to +24 feet; stiff lean clay to medium dense to dense silty sands between +24 to +6 feet; very stiff fat clays to dense silty sands and clayey sands between +6 to -28 feet; very stiff lean and fat clay with sand layers to very dense silty sands with clay layers between -28 to -84 feet; and very stiff fat clay to very dense silty sands between -84 ft to -130 feet. Overall, the thickness of the bauxite material at the Project site is from 11 feet to 15 feet and located between Elevations +21 and +37 feet, and it is currently covered by the recently deposited dredged hydraulic fill soils. The bauxite materials are generally very soft and highly compressible. Much of the available data leads to a conclusion that the bauxite residue could be classified as cohesive lean clays, or loose semi-cohesive silts and loose clayey sands.

TWEI indicated that the groundwater level was observed at a depth ranging between El. +10 feet to El. +15 feet, as a result of 25-foot thick hydraulic fill deposits within the DMPA 2 area, the water bearing sands could be artesian pressures. The accurate measurement of water level within the sand aquifer could be measured with the installation of standpipe piezometers during site re-grading activity.

Corrosion potential tests for pH, chloride, and sulfate ion concentrations were performed on selected soil samples and bauxite residue. Electrical resistivity tests were performed within dredged clay soils. Based on the results of the laboratory testing, the dredged soils and underlying bauxite residue have high to very high potential to corrode unprotected steel. Based on the sulfate ion concentration data, the dredged soils and bauxite residue have mild to moderate potential for corroding concrete. CCL Stage III indicates the corrosion potential would be considered in the design.

Considering the subsurface conditions for the Stage 3 LNG Facilities, CCL Stage III is proposing to support the permanent structures on mat foundations or shallow spread footings placed on improved subgrade. Prior to subgrade improvement, dredged soil would be excavated to El. +42 to +43 ft. Side slopes of the approximately 13-foot deep excavation would be 1V:4H. Site preparation would include cut and fill activities. Finished grade elevation at the LNG processing Train/Tank area and Flare area would be +48 feet and +47 feet, respectively. The dredged material would be placed in the areas of Trains 5 through 7 to a rough grade of about El. 48 feet. TWEI provided recommendations for several soil improvement options including Controlled Modulus Columns (CMCs) and load transfer platforms. CCL Stage III has indicated that CMCs and load transfer platforms have been selected as their base case and would be installed in all areas that would support shallow foundations and mats, as well as the LNG storage tank foundation. Shallow soil mixing techniques would be used to stabilize a minimum of 5 feet of dredged spill at roadway locations. When work progresses to Trains 5 through 7, further excavation to El. 43 feet or 2 feet would precede CMC and load transfer pad installation. Shallow soil mixing techniques would again be used to stabilize a minimum of 5 feet of dredged spoil at roadway locations. Detailed drawings for site preparation and CMC design would be developed and submitted to the FERC for review during final design phase. The CMC stabilization approach would allow for flexibility in the design as the percentage of additives mixed with the bauxite residue could be modified dependent on structural loads. This stabilization approach could also facilitate steep excavation for installation of underground utilities and sumps. CMC columns can be load tested after installation. In addition to greatly improving bearing capacity and greatly reduce the compressibility of the soft subgrade layers, the CMS approach would greatly increase the average shear velocity of soil profile. The displacement of soils laterally during grouted columns installation would eliminate disposal of Bauxite residue offsite. CCL Stage III committed to implementing soil improvement verification requirements for all seven trains, and that the shear modulus would be equal to or greater than those presented in the geotechnical report. As previously discussed, we recommend in section B.9.1.6 that prior to initial site preparation CCL Stage III file a supplemental geotechnical investigation for the Trains 5 through 7, and remaining portions of Train 4, the LNG tank area, and flare areas, including geotechnical investigation location plan with spacing of no more than 300 feet and field sampling methods and laboratory tests that are at least as comprehensive as the existing geotechnical investigations that confirm soil modifications and foundation designs would be similar to Trains 1 through 3 and portions of the LNG tank and flare areas already investigated. FERC staff will continue its review of the results of the geotechnical investigation to ensure foundation designs are appropriate prior to construction of final design and throughout the life of the facilities.

CCL Stage III also engaged KBR to perform settlement analysis for the Project site. An upper bound settlement analysis was performed neglecting the preloading effects as a result of dredged fill placement to El. +58 feet. The preloading of the DMPA 2 area with dredged material would result in reduced settlement after construction. Increasing the grade elevation from El. +35 to El. +48 feet, would result in additional overburden pressure applied to the natural clays and sands. TWEI suggested installation of settlement monitoring plate to monitor the rate soil deformation during soil improvement and subsequent construction phase. As a result of elevating the entire Project site from El. +37 feet to El. +48 feet, generally uniform settlement is anticipated with the foot print of the spread footings and mat foundations. CCL Stage III has stated that they intend to implement a settlement monitoring system to measure uniform and differential settlement and to record inner and outer tank movements during construction and hydrostatic testing would be provided that would be compliant with API 620, API 625, API 653, and ACI 376. During hydrostatic testing and emptying of the tank, settlements, rotations and base slab tilting would be monitored. During construction, settlements of the base slab and inner tank would be monitored on a weekly basis. Additionally, CCL Stage III indicated that the target for upper limit of the LNG tank foundation settlement is be +/- 6 inches, and the LNG tank contractor will be given this target for their analysis and design; there are no other large flexible tanks in the scope of this Project. In order to address the potential impact, we recommend in section B.9.1.6 that CCL Stage III file the information of the upper limit for total settlement for large flexible foundations and the maximum total edge settlement at the proposed Project area, which is consistent with standard practice for LNG facilities constructed in the U.S. for the LNG tanks that the CMCs would be designed to satisfy.

The results of CCL Stage III's geotechnical investigation at the Project site indicate that subsurface conditions are suitable for Trains 1 through 3 and some of the flare areas, if proposed site preparation, foundation design, and construction methods are implemented in addition to the satisfaction of proposed recommendations. Additional geotechnical investigation is needed to confirm that the subsurface conditions are suitable for the soil modification and foundation designs for Trains 4 through 7, the LNG tank area, and remaining flare areas, and whether similar site preparation, foundation design, and construction methods should be implemented in addition to the satisfaction of proposed recommendations.

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) requires an applicant to demonstrate how they would comply with 49 CFR 193 and NFPA 59A. The USDOT regulations under 49 CFR 193 have some specific requirements on designs to withstand certain loads from natural hazards and also incorporates by reference NFPA 59A (2001 and 2006) and ASCE 7-05 and ASCE 7-93 via NFPA 59A (2001). NFPA 59A (2001) section 2.1.1. (c) also requires that CCL Stage III 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. This would be covered in the USDOT PHMSA's LOD on 49 CFR 193, Subpart B. However, the LOD would not cover whether the facility is designed appropriately against these hazards, which would be part of 49 CFR 193, Subpart C. Unlike other natural hazards, wind loads are covered in 49 CFR 193, Subpart B and would be covered in the LOD. If authorized, constructed, and operated, all LNG facilities, as defined by 49 CFR 193 must comply with the requirements of 49 CFR 193 and would be subject to USDOT's inspection and enforcement programs.

In addition, the facilities would be designed and constructed to the requirements in the 2006 International Building Code (IBC) and ASCE 7-05 for seismic design. These 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 potential engineering design to withstand impacts from natural hazards, such as earthquakes, tsunamis, seiche, hurricanes, tornadoes, floods, rain, ice, snow, regional subsidence, sea level rise, landslides, wildfires, volcanic activity, and geomagnetism. In addition, we recommend in section B.9.1.6 that CCL Stage III file final design information (e.g., structural drawings, specifications, and calculations) and associated quality assurance and control procedures with the documents stamped and sealed by the professional engineer of record. If the Project is authorized and constructed, CCL Stage III would install equipment in accordance with its final design. In addition, we recommend in section B.9.1.6 that CCL Stage III file, for review and approval, settlement results during hydrostatic tests of the LNG storage containers and periodically thereafter to verify settlement is as expected and does not exceed the applicable criteria in API 620, API 625, API 653, and ACI 376.

Earthquakes, Tsunamis, and Seiche

FERC regulations under 18 CFR 380.12 (h) (5) require evaluation of earthquake hazards based on whether there is potential seismicity, surface faulting, or liquefaction. 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). To assess the potential impact from earthquakes and tsunamis, CCL Stage III evaluated historic earthquakes along fault locations and their resultant ground motions.

The USGS maintains a database containing information on surface and subsurface faults and folds in the U.S. that are believed to be sources of earthquakes of greater than 6.0 magnitude occurring during the past 1.6 million years (Quaternary Period).[27] CCL Stage III would not be near such faults, which are primarily on the West Coast. However, in the Gulf Coastal Plains, there are several hundred growth faults that are known or suspected to be active. Most of these growth faults are located within the Houston-Galveston (Texas) area subsidence bowl, but many others are known to exist from Brownsville, Texas to east of New Orleans, Louisiana. Evidence of modern activity of these growth faults includes changes in elevation that can lead to damage to pavement, buildings, and other structures. Subsidence has also been recorded occurring naturally through fault movements and compaction/consolidation of Holocene deposits.

Growth faults have been mapped extensively in the subsurface of the Texas coastal region, and specifically beneath the Corpus Christi area in the vicinity of the Project site. From oldest to youngest, onshore Texas growth fault zones are known as the Wilcox zone (Paleocene – Eocene), Yegua zone (middle to late Eocene), Vicksburg zone (Oligocene) and Frio zone (late Oligocene). Miocene and younger zones are developed offshore (Ewing, 1986). Growth faults in south Texas have been investigated as potential sources of permanent ground deformation for new nuclear power plants proposed by South Texas Power (2006) in Bay City, and by Exelon in Victoria County (2008), the latter site which is located about 96 kilometers north of Corpus Christi. These studies have documented that the surface expression of movement on onshore growth faults at depth is broad monoclonal warping with relief of a few feet expressed over horizontal distances of a few hundreds of feet in Quaternary Beaumont Formation (350,000 to 100,000 years in age: see South Texas Power (2006) and Exelon (2008) and references therein). Associated average movement rates across the faults typically are on the order of 10^{-4} to 10^{-5} inches per year. The South Texas and Exelon studies indicate that surface deformation associated with these faults produces very subtle topographic features that require high resolution techniques to resolve, and may be below the detection limit of typical boring techniques in the near subsurface. The site and surrounding areas are underlain by the middle to late Quaternary Beaumont Formation. Growth faults are mapped in the subsurface both to the west and east of the site location. AECOM interpreted that the topographic lineament is a warp or monocline related to movement of one of the subsurface growth faults mapped in the vicinity of the site by Ewing (1986). In the case of the Project site, 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 faults 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 predicted tilting during the lifetime of the facility would not produce detectable changes in the ground surface elevation. It is possible that movement on the fault is episodic rather than continuous; in this case, a discrete slip event at depth of 2 feet or less may produce measurable tilting at the surface. That distribution of such slip as tilting over a horizontal distance of approximately 800 feet would increase the eastward slope of the land surface by less than a degree. AECOM concluded that the facility does not need to incorporate the surface deformation due to growth faulting in the design of the facilities. However,

[27] USGS, Earthquake Hazards Program, Quaternary Fault and Fold Database of the United States, https://earthquake.usgs.gov/hazards/qfaults/, accessed August 2018.

while this tilt may be less than global tilt criteria in API 625 (<5in*D/H), it may cause tilting in excess of criteria in ACI 376 for uniform planar tilting (maximum of 1/500) and could impact other criteria, such as criteria in API 653 for out-of-plane settlement. Therefore, we recommend in section B.9.1.6 that CCL Stage III file final design information to confirm that CCL Stage III would implement settlement monitoring system to measure uniform and differential settlement, and they shall be monitored at permanently installed benchmark points periodically during the life of the facility, including during construction, during hydrotesting, during commissioning, and at least annually during operation that would be compliant with but not limited to API 620, API 625, API 653, and ACI 376.

CCL Stage III engaged AECOM to perform a site-specific fault and seismic analysis for the Project, involving field investigations and subsequent data evaluation. A total of 6 faults and 13 seismic source zones that represent earthquakes associated with buried or generally unknown faults (background) were considered. The site is located within the Gulf Highly Extended Crust seismotectonic zone. There are no active faults in the site region. However, because of the large magnitudes of past events (1811-1812) and relatively high rate of activity, four faults in the New Madrid seismic zone and the Meers fault in Oklahoma were included into the probabilistic seismic hazard analysis. CCL Stage III also engaged Lettis Consultants International, Inc. to produce a supplemental seismic, tsunami, and geologic hazards report for the Project. This supplemental report follows up on the draft report "Seismic and Tsunami Hazard Evaluations for CCL Stage III" produced by AECOM (Wong et al., 2015). CCL Stage III engaged Lettis Consultants International, Inc. to address subsidence. 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 soil, natural gas, or groundwater, or in places where fluid is expelled from underlying sediments. Subsidence in the Gulf Coast region primarily results from groundwater extraction, oil and gas extraction, and slumping along growth faults. Various degrees of subsidence have been documented along the Texas coast, with the greatest incidences occurring in the Houston-Galveston area. Groundwater extraction in San Patricio County is primarily for irrigation, and the amount pumped varies by season and year. There are no water wells in the vicinity of the Project site, and while there are several oil and gas fields in San Patricio County, there is no significant petroleum extraction near the proposed Project site. Currently, no significant land subsidence has been documented adjacent to the Project site. However, at locations to the northeast of the Project site, such as Galveston, Texas and the Mississippi delta in Louisiana, the land surface is actively subsiding at rates up to 25 millimeters per year. Additionally, previous studies (Ratzlaff, 1980) indicate that for most of the Corpus Christi area land subsidence is generally less than 0.5 feet. The maximum periods of record are 1918 to 1951 in Refugio and San Patricio Counties and 1942 to 1975 in Nueces County. The Project site is located on late Pleistocene Beaumont Formation. Several studies (Kulp, 2000; Tornqvist et al., 2008; Yuill, 2009; Meckel et al., 2006) have shown that most sediment compaction comes from Holocene-aged sediments and that the compaction process is complete for older deposits. CCL Stage III indicated the significant subsidence from sediment compaction is not anticipated at the Project site.

While the presence of major tectonic faults and growth faults can require special consideration, the presence or lack of major tectonic faults identified near the site does not define whether earthquake ground motions can impact the site, because ground motions can be felt large distances away from an earthquake hypocenter depending on a number of factors.

To address the potential ground motions at the site, the USDOT regulations in 49 CFR 193.2101, under Subpart C require that field-fabricated LNG tanks must comply with NFPA 59A (2006), Section 7.2.2 and be designed to continue safely operating with earthquake ground motions at the ground surface at the site that have a 10 percent probability of being exceeded in 50 years (475 year mean return interval), termed the operating basis earthquake (OBE). In addition, the USDOT regulations in 49 CFR 193.2101, under Subpart C require that LNG tanks be designed to have the ability to safely shutdown when subjected to earthquake ground motions which have a 2 percent probability of being exceeded in 50 years (2,475 year mean return interval) at the ground surface at the site (termed the safe shutdown earthquake [SSE]). The USDOT regulations in 49 CFR 193.2101, under Subpart C also incorporate by reference NFPA 59A (2001) Chapter 6, which require piping systems conveying flammable liquids and flammable gases with service temperatures below -20 degrees Fahrenheit, be designed as required for seismic ground motions. If authorized, constructed, and operated, the LNG facilities, as defined by 49 CFR 193, would be subject to the USDOT's inspection and enforcement programs.

In addition, FERC staff recognizes CCL Stage III would also need to address hazardous fluid piping with service temperatures at -20 degrees Fahrenheit and higher, and equipment other than piping, and LNG storage (shop built and field fabricated) containers. We also recognize the current FERC regulations under 18 CFR 380.12(h) (5) continue to incorporate National Bureau of Standards Information Report 84-2833. National Bureau of Standards Information Report 84-2833 provides guidance on classifying stationary storage containers and related safety equipment as Category I and classifying the remainder of the LNG project structures, systems, and components as either Category II or Category III, but does not provide specific guidance for the seismic design requirements for them. Absent any other regulatory requirements, this guidance recommends that other LNG project structures classified as Seismic Category II or Category III be seismically designed to satisfy the Design Earthquake and seismic requirements of the ASCE 7-05 in order to demonstrate there is not a significant impact on the safety of the public. ASCE 7-05 is recommended as it is a complete American National Standards Institute consensus design standard, its seismic requirements are based directly on the National Earthquake Hazards Reduction Program Recommended Provisions, and it is referenced directly by the IBC. Having a link directly to the IBC and ASCE 7 is important to accommodate seals by the engineer of record because the IBC is directly linked to state professional licensing laws while the National Earthquake Hazards Reduction Program Recommended Provisions are not.

The geotechnical investigations of the existing site performed by TWEI indicate the improved site is classified as Site Class D[28] based on a site average shear wave velocity (Vs) and the time-averaged shear-wave velocity in the top 30 m (V_S30) for the site is 849 feet per second determined with ASCE 7-05 and IBC (2006). This is in accordance with ASCE 7-05, which is incorporated directly into 49 CFR 193 for shop fabricated containers less than 70,000 gallons and via NFPA 59A (2006) for field fabricated containers. This is also in accordance with IBC (2006). Sites with soil conditions of this type would experience significant amplifications of surface earthquake ground motions. However, due to the absence of a major fault in proximity to the site and lower ground motions, the seismic risk to the site is considered low.

AECOM performed a site-specific seismic hazard analysis for the site. The analysis concluded that the site would have a horizontal OBE PGA of 0.027 g at 0.2 s-period and a horizontal SSE PGA of 0.109 g at 0.2 s-period. The OBE has a 10 percent probability of being exceed in 50 years (475 year mean return interval) while the SSE has a 2 percent chance of being exceeded in 50 years (2,475 year mean return interval). The AECOM report also provided site-specific vertical OBE and SSE ground motion response spectra for site, and indicated the vertical design acceleration response spectra OBE and SSE shall be equal to two-thirds of the respective horizontal OBE and SSE response spectra as per NFPA 59A. In addition, the AECOM report provided site-specific values of S_{DS} and S_{D1} (0.073 g and 0.051 g, respectively) that are used for the design of Seismic Category II and III structures systems and components in accordance with ASCE 7-05. These ground motions are very low compared to other locations in the U.S. Based on the

[28] There are six different site classes in ASCE 7-05, 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).

design ground motions for the site and the importance of the facilities, the facility seismic design is assigned Seismic Design Category A in accordance with ASCE 7-05. Based on the ATC[29] and USGS[30] tools, FERC staff found the OBE and SSE peak spectral accelerations at 0.2 s-period for the site based on Site Class D to equal 0.028 g and 0.118 g, respectively, which are similar to the CCL Stage III site-specific values. FERC staff agrees the SSE PGA, OBE PGA, and 5 percent damped spectral design accelerations used by CCL Stage III are acceptable.

ASCE 7-05 also requires determination of the Seismic Design Category based on the Occupancy Category (or Risk Category in ASCE 7-10 and 7-16) and severity of the earthquake design motion. The Occupancy Category (or Risk Category) is based on the importance of the facility and the risk it poses to the public.[31] FERC staff has identified the Project as a Seismic Design Category A based on the ground motions for the site and an Occupancy Category (or Risk Category) of III or IV, this seismic design categorization would appear to be consistent with the IBC (2006) and ASCE 7-05 (and ASCE 7-10).

Seismic events can also result in soil liquefaction in which saturated, non-cohesive soils temporarily lose their strength/cohesion and liquefy (i.e., behave like viscous liquid) as a result of increased pore pressure and reduced effective stress when subjected to dynamic forces such as intense and prolonged ground shaking. Areas susceptible to liquefaction may include saturated soils that are generally sandy or silty. Typically, these soils are located along rivers, streams, lakes, and shorelines or in areas with shallow groundwater. The Project site would have underlying water-saturated sediments and could be susceptible to liquefaction under sufficiently strong ground motion. The site-specific seismic study indicates sandy layers between -16 to -50 feet below grade at the Train 1 area and sandy layers between -28 to -50 feet below grade at the Trains 2 through 4 area; however, the potential for a large enough seismic event near enough to cause soil liquefaction in the Project area is very low. CCL Stage III indicated that they would file Trains 5 through 7 site detail information with FERC staff for final review after soil investigation have been performed. Also, the LNG facilities at the site would be constructed on a site improved with either soil stabilization or CMCs with load transfer platforms, which would mitigate any potential impacts of soil liquefaction in areas where they are used. We recommend these geotechnical investigations be filed to confirm that the subsurface conditions are suitable for the soil modification and foundation designs. If the geotechnical investigations are not as comprehensive or indicate soil modifications and foundation designs differentiate from the existing geotechnical investigation results, then a variance or amendment to the Project must be filed for review and approval depending on the degree and number of differences.

Seismic events in waterbodies can also cause tsunamis or seiche by sudden displacement of the sea floors in the ocean or standing water. Tsunamis and seiche may also be generated from volcanic eruptions or landslides. Tsunami wave action can cause extensive damage to coastal regions and facilities. There is little evidence to suggest that the Gulf of Mexico is prone to tsunami events, but the occurrence of a tsunami

[29] Applied Technology Council, https://hazards.atcouncil.org, December 2018.

[30] U.S. Geological Survey, https://earthquake.usgs.gov/earthquakes, December 2018.

[31] ASCE 7-05 defines Occupancy Categories I, II, III, and IV. Occupancy Category I represents facilities with a low hazard to human life in even of failure, such as agricultural facilities; Occupancy Category III represents facilities with a substantial hazard to human life in the event of failure or with a substantial economic impact or disruption of day to day civilian life in the event of failure, such as buildings where more than 300 people aggregate, daycare facilities with facilities greater than 150, schools with capacities greater than 250 for elementary and secondary and greater than 500 for colleges, health care facilities with 50 or more patients, jails and detention facilities, power generating stations, water treatment facilities, telecommunication centers, hazardous facilities that could impact public; Occupancy Category IV represents essential facilities, such as hospitals, fire, rescue, and police stations, emergency shelters, power generating stations and utilities needed in an emergency, aviation control towers, water storage and pump structures for fire suppression, national defense facilities, and hazardous facilities that could substantially impact public; and Occupancy Category II represents all other facilities. ASCE 7-10 changed the term to Risk Categories I, II, III, and IV with some modification.

is possible. Two did occur in the Gulf of Mexico in the early 20th century and had wave heights of 3 feet or less (USGS, 2014c), which is not significantly higher than the average breaking wave height of 1.5 feet (Owen, 2008). Hydrodynamic modeling conducted off the coast of south Texas in 2004 indicated that the maximum tsunami run-up could be as high as 12 feet above mean sea level. No earthquake-generating faults have been identified that are likely to produce tsunamis, despite recorded seismic activity in the area. The Project area is located on the north side of Corpus Christi Bay, which is protected by Mustang and San Jose Islands. Based on the results of the ten Brink et al. (2009) study, the probability of a landslide-generated tsunami affecting the Project area is considered extremely low. With no observable tsunami of any consequence observed in historical times and the low occurrence rate of landslides in the Gulf of Mexico that are sufficiently large to generate a tsunami, the run-up for return period of 100 or 500 years is probably on the order of centimeters. There are no significant seismic sources of tsunamis in the Gulf of Mexico, and distant seismic sources outside the Gulf may produce tsunamis but with run-ups of less than 1 meter along the Gulf coastline. In addition, CCL Stage III has stated that critical equipment foundations would be elevated high enough (greater than El +45 feet) to withstand a Category 5 hurricane storm surge.

The potential for tsunamis associated with submarine landslides is more likely a source in the Gulf of Mexico and remains a focus of government research (USGS, 2009). CCL Stage III's *Nature Hazards Design Investigation and Forces* report included a Tsunami Hazard Assessment for the Project area. There are four main submarine landslide hazard zones in the Gulf of Mexico, including the Northwest Gulf of Mexico, Mississippi Canyon and Fan, the Florida Escarpment, and the Campeche Escarpment (ten Brink el al., 2009). Based on modeling and limited historical data, it is estimated that tsunamis generated from landslides would be significantly less than the hurricane design storm surge elevations discussed below, so any tsunami hazard has been considered in design.

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 Stage III 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 Stage III stated that the load combinations specified in Chapter 2 of ASCE 7-05 shall be used in this Project design. CCL Stage III indicates the sustained wind speed of 150 mph shall be used for the design of all LNG facilities. The 150-mph sustained wind speed is equivalent to a 183 mph 3-second gust at 33 feet above ground per exposure C category (conversion made by Durst Wind Curve per ASCE 7-05) and is approximately equivalent to a 14,000 year mean return interval or has a 0.36 percent probability of exceedance in a 50-year period for the site. The 183 mph 3-second gust equates to a strong Category 4 hurricane using the Saffir Simpson scale (130-156 mph sustained winds, 166-195 mph 3-second gusts). CCL Stage III also indicates the design wind speed for other non-LNG structures, which would be 130 mph 3-second gust per ASCE 7-05 Figure 6-1A. The importance factor, I, shall be 1.15 in accordance with ASCE 7-05 for non-LNG facilities. The definition of non-LNG facilities seems to potentially include piping and equipment containing hazardous fluids. However, a table included in the application seems to indicate certain piping and equipment containing hazardous fluids other than LNG would be designed to 183 mph 3-second gust. Therefore, it is unclear as to whether some of these non-LNG buildings and structures would qualify as LNG facilities under the USDOT PHMSA regulations, and, if so, whether anything less than 150 mph sustained (183 mph 3-second gust) or a 10,000-year return period (170 to 180 mph 3-second gust) would meet the USDOT PHMSA requirements. CCL Stage III must meet 49 CFR 193.2067, under Subpart B for wind load requirements. In accordance with the MOU, the USDOT PHMSA will evaluate in its LOD whether an applicant's proposed project meets the USDOT requirements under Subpart B. As a result, we would work with the USDOT PHMSA staff when we review structural calculations, and we recommend in section B.9.1.6 that CCL Stage III file its design wind speed criteria for all structures not covered by the LOD to be designed to withstand winds commensurate with the risk and reliability associated with the facilities in accordance with ASCE 7-16 or equivalent. If the Project is constructed and becomes operational, the facilities would be subject to the USDOT's inspection and enforcement programs. Final determination of whether the facilities are in compliance with the requirements of 49 CFR 193, Subpart B would be made by the USDOT PHMSA staff.

In addition, as noted in the limitation of ASCE 7-05, tornadoes were not considered in developing basic wind speed distributions. This leaves a potential gap in potential impacts from tornadoes. Therefore, FERC staff evaluated the potential for tornadoes. Appendix C of ASCE 7-05 makes reference to American Nuclear Society 2.3 (1983 edition), *Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites*. This document has since been revised in 2011 and reaffirmed in 2016 and is consistent with NUREG/CR-4461, *Tornado Climatology of the Contiguous U.S.*, Rev. 2 (NUREG, 2007). These documents provide maps of a 100,000 mean year return period for tornadoes using 2-degree latitude and longitude boxes in the region to estimate a tornado striking within 4,000 feet of an area. Figures 5-8 and 8-1 from NUREG/CR-4461 indicate a 100,000-year maximum tornado wind speeds would be approximately 118 mph 3-second gusts for the Project site location. Later editions of ASCE 7 (ASCE 7--10 and ASCE 7-16) make reference to International Code Council 500, *Standard for Design and Construction of Storm Shelters*, for 10,000-year tornadoes. However, the International Code Council 500 maps were conservatively developed based on tornadoes striking regions and indicate a 200 mph 3-second gust for a 10,000-year event, which is higher than the 118 mph 3-second gust in American Nuclear Society 2.3 and NUREG/CR-4461.

In addition, FERC staff 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.[32,33] Since 1900, there have been 32 tropical storms or hurricanes that have made landfall within 65 nautical miles of the Project site. The most recent major hurricane was Harvey in 2017, which peaked as a Category 4 hurricane. Hurricane Harvey's center made landfall on the northern end of San Jose Island about 21 nautical miles east of the proposed Project site as a Category 4 hurricane with 133 mph sustained winds. Corpus Christi was spared the worst of the Hurricane Harvey's effects, which were widespread but mostly minor damage was reported. There were several hurricanes that were considered major (i.e., Category 3 or higher): Hurricane Bret in 1999 (Category 4 at peak with 144 mph sustained winds, but Category 3 with 115 mph sustained winds at landfall); Hurricane Celia in 1970 (Category 3 at peak with 127 mph sustained winds, and Category 3 with 120 mph sustained winds at landfall); Hurricane Beulah in 1967 (Category 5 at peak with 161 mph sustained winds, but Category 4 with 136 mph sustained winds at landfall); two unnamed hurricanes in 1945 (Category 3 at peak with 115 mph sustained winds, but Category 2 with 101 mph sustained winds at landfall) and 1942 (Category 3 at peak with 115 mph sustained winds, but Category 2 with 110 mph sustained winds at landfall); and two other unnamed hurricanes in 1919 (Category 4 at peak with 150 mph sustained winds, but Category 2 with 110 mph sustained winds at landfall) and 1916 (Category 4 at peak with 132 mph sustained winds, but Category 1 with 90 mph sustained winds at landfall). Since 1950, there were around 52 historical tornado events that had been recorded found in or near within 10 nautical miles of the Project site. Those were 30 tornados rated category EF-0 (65-85 mph 3-second gust winds); 15 tornados rated category EF-1

[32] DHS, Homeland Infrastructure Foundation-Level Data, https://hifld-geoplatform.opendata.arcgis.com/, August 2018.

[33] NOAA, Historical Hurricane Tracker, https://coast.noaa.gov/hurricanes/, August 2018.

(86--110 mph 3-second gust winds); 5 tornados rated EF-2 (111-135 mph 3-second gust winds) and 2 tornados rated EF-3 (136-165 mph 3-second gust winds). As a result, we believe the use of an equivalent 183 mph 3-second gust equates to a strong Category 4 hurricane using the Saffir Simpson scale (131--155 mph sustained winds, 166--195 mph 3-second gusts), is adequate for the LNG storage tanks and conservative from a risk standpoint for the other LNG and hazardous facilities. The USDOT PHMSA will provide a LOD on the Project's compliance with 49 CFR 193, Subpart B with regard to wind speed. This determination will be provided to the Commission as further consideration to the Commission on its decision to authorize or deny the Project.

The USDOT regulations in 49 CFR 193.2067, under Subpart B would require the impounding system for the LNG storage tanks to withstand impact forces from wind borne missiles. ASCE 7 also recognizes the facility would be in a windborne debris region. Windborne debris has the potential to perforate equipment and the LNG storage tanks if not properly designed to withstand such impacts. The potential impact is dependent on the equivalent projectile wind speed, characteristics of projectile, and methodology or model used to determine whether penetration or perforation would occur. However, no criteria are provided in 49 CFR 193 or ASCE 7 for these specific parameters. NFPA 59A (2016) recommends CEB 187 be used to determine projectile perforation depths. In order to address the potential impact, CCL Stage III confirmed that the outer tank shell and roof of the LNG storage tank would be designed to resist the potential impact from a wind-borne missile or the impact from explosion of a 200 pounds rigid body traveling at a velocity of 150 mph. This is equivalent to a 6-inch gate valve traveling at hurricane wind velocity. CCL Stage III indicated the impact loading would meet or exceed the USDOT, DOE, NRC, and ACI 376 requirements. Also, the Tank Data Sheet would be updated to incorporate the basis for the impact loading and filed for review. We recognize wind borne debris should represent items readily available at or in proximity to the site that may not be secured to withstand such wind. In order to address the potential impact, we recommend in section B.9.1.6 that CCL Stage III provide a projectile analysis for review and approval to demonstrate that the outer concrete impoundment wall of the full containment LNG tank could withstand wind borne projectiles prior to construction of final design. FERC staff would compare the analysis and specified projectiles and speeds using established methods, such as CEB 187, DOE, and NRC guidance.

CCL Stage III engaged AECOM to estimate the future elevations of sea level at the Project site for the key 'benchmark' years of 2050, 2080, and 2100. These calculations were based on the projections of linear relationships derived from linear regressions of Global and Gulf of Mexico satellite and Global and local tidal gauge data from Rockport, Texas and Bob Hall Pier, Corpus Christi, Texas. The range of projected SLR for the Project site calculated from analyses predicts a SLR range of 0.62 to 1.25 feet by 2050, 0.98 to 2.1 feet by 2080, and 1.2 to 2.7 feet by 2100. These results are consistent and within the range of predicted SLR from the IPCC AR5 (2012) and NOAA (2012).

FERC staff evaluated the design against a 500-year still water elevation (SWEL) with a 500-year wave crest and sea level rise and subsidence. Using maximum envelope of water (MEOW) storm surge inundation maps generated from the Sea, Lake, and Overland Surge from Hurricanes (SLOSH) model developed by NOAA National Hurricane Center, a 500-year event would equate to a Category 2 hurricane and from 6 feet to over 8 feet MEOW with most areas between 6-7 feet. This is predominantly lower than indicated in the 500-year FEMA maps. In addition, while NOAA seems to provide higher resolution of topographic features, it limits its SLOSH maps to storm surge levels at high tide above 9 feet. As a result, FERC staff evaluated the storm surge against other sources using SLOSH maps that indicate a similar upper range of 6-7 feet MEOW for Category 2 hurricanes, and also indicated 10-12 feet MEOW for Category 3 hurricanes, 14-17 feet MEOW for Category 4 hurricanes, and 17-21 feet MEOW for Category 5 hurricanes. This data suggests that CCL Stage III's design may withstand Category 5 hurricane storm surge SWEL equivalent to approximately a 1,000 to 10,000-year mean return intervals. Also, we would expect an intermediate projected sea level rise and subsidence of 1.11 feet between 2020 and 2050, as provided by

NOAA (2017). The proposed Project area is located just north of the existing Liquefaction Project, and it is approximately 6,000 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. Adding the 500-year storm surge, sea level rise and subsidence results in a total elevation of 23 feet. FERC staff also evaluated CCL Stage III's proposed 500-year flood against the 2016 FEMA Flood Insurance Study for San Patricio County, Texas (FEMA, 2016), which provides various transection lines and associated 10-, 50-, 100-, and 500-year SWELs, 500-year wave envelopes, and 500-year wave effects along the length of the transection lines. We believe the use of intermediate values from NOAA for sea level rise and subsidence is more appropriate for design, and higher projections are more appropriate for planning envelope. Also, the Project area is outside of the VE (velocity wave) zone that corresponds to the 100-year (1 percent annual chance) coastal floodplains that have additional hazards associated with storm waves. The Project area is also outside the 500-year (0.2 percent annual chance) flood area. Furthermore, CCL Stage III has committed that elevations of the Stage 3 LNG Facilities would be greater than 45 feet above mean sea level, which makes them inherently protected against a Category 5 hurricane storm surge. As a result, we believe the facility would be able to withstand storm surge without damage during a 500-year storm event.

The Texas and Louisiana Gulf Coast area is experiencing the highest rates of coastal erosion and wetland loss in the U.S. (Ruple, 1993). The average coastal erosion rate is -1.2 meters per year between 2000 and 2012 along the Texas coastal shoreline, with South Padre Island experiencing a shoreline loss rate of -1.6 meters per year between 2000 and 2012 (McKenna, 2014). The Project area is located just north of the existing Liquefaction Project and is approximately 6,000 feet from the shoreline in the south; therefore, the shoreline erosion would unlikely occur at the Project site during the Project life cycle.

Landslides and Other Natural Hazards

Due to the low relief across the Project site, there is little likelihood that landslides or slope movement at the site would be a realistic hazard. Landslides involve the downslope movement of earth materials under force of gravity due to natural or human causes. The Project area has low relief which reduces the possibility of landslides.

Volcanic activity is primarily a concern along plate boundaries on the West Coast and Alaska and also Hawaii. Based on FERC staff review of maps from USGS[34] and DHS[35] of the nearly 1,500 volcanoes with eruptions since the Holocene period (in the past 10,000 years), there is no known active or historic volcanic activity within proximity of the site, with the closest being over 565 miles away across the Gulf of Mexico in Los Atlixcos, Mexico.

Geomagnetic disturbances (GMDs) 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[20] provides a map of GMD intensities with an estimated 100-year mean return interval.[36] The map indicates the Project site could experience GMD intensities of 250-400 nano-Tesla with a 100 year mean return interval. However, the Stage 3 LNG Facilities would be designed such that if a loss of power were to occur the valves would move into a fail-safe position. In addition, the LNG terminal is an export facility that does not serve any U.S. customers.

[34] USGS, *U.S. Volcanoes and Current Activity Alerts*, https://volcanoes.usgs.gov/index.html, accessed August 2018.

[35] DHS, *Homeland Infrastructure Foundation-Level Data (HIFLD)*, Natural Hazards, hifld-geoplatform.opendata.arcgis.com, accessed August 2018.

[36] USGS, *Magnetic Anomaly Maps and Data for North America*, https://mrdata.usgs.gov/magnetic/map-us.html#home, accessed August 2018.

External Impacts

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 Project 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 along external roads and rail, impacts from aircraft operations to and from nearby airports and heliports, impacts from pipeline failures from nearby pipelines, and impacts to and from adjacent facilities that handle hazardous materials under EPA's RMP regulations and power plants, including nuclear facilities under Nuclear Regulatory Commission 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 Project 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 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 193, must comply with the requirements of 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs. The USDOT regulations in 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 truck that could reasonably be expected to cause the most severe loading if the liquefaction 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 USDOT 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 USDOT's FHWA[37], National Highway Traffic Safety Administration (NHTSA)[38],

[37] U.S. DOT FHWA, Office of Highway Policy Information, *Highway Statistics 2016*, https://www.fhwa.dot.gov/policyinformation/statistics/2016/, accessed March 2019.
[38] U.S. DOT NHTSA, *Traffic Safety Facts Annual Report Tables*, https://cdan.nhtsa.gov/tsftables/tsfar.htm, accessed March 2019.

PHMSA[39], EPA and NOAA[40], and other reports[41,42,43], frequency of trucks, and proposed mitigation to prevent or reduce the impacts of a vehicular incident.

Incident data from USDOT FHWA, NHTSA, and PHMSA, indicates hazardous material incidents are very infrequent (4e-3 incidents per lane mile per year) and nearly 75 to 80 percent of hazardous material vehicular incidents occur during unloading and loading operations, while the other 20 to 25 percent occur while in transit or in transit storage. In addition, approximately 99 percent of 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 with spillage result in injuries, and less than 0.1 percent of all reportable hazardous material incidents with spillage result in fatalities.

The EPA and NOAA report that 80 percent of fires that lead to container ruptures results in projectiles, and that 80 percent of projectiles from liquefied petroleum gas (LPG) incidents, which constitute the largest product involved in BLEVEs, travel less than 660 feet. The EPA also reports that there are on average 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 490-820 feet and within 6.25 times the estimated or observed fireball radius. The data also showed projectiles have traveled up to 3,900 feet for large LPG vessels and 1,200 feet for LPG rail cars. In all the documented cases, the projectiles traveled less than 15 times the fireball diameter, but one of the reports indicated up to 30 times the fireball diameter is possible albeit very rare.

Unmitigated consequences under average ambient conditions from releases of 1,000 gallons through a 1-inch hole would result in distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to 175 feet for jet fires. Unmitigated consequences under worst case weather conditions from catastrophic failures of trucks 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 5-15 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. Based on distribution function of the projectile distances, FERC staff estimate approximately 90 percent of all projectiles for a 10,000-gallon tanker truck would be within 0.5 mile and there is approximately a 1 percent probability they would extend beyond 1 mile and less than 0.1 percent probability they would extend 30 times the fireball diameter. These values are also close to the distances provided by the DOT FHWA[44] for designating hazardous material trucking routes (0.5 mile for flammable gases for potential impact distance) and DOT PHMSA[45] for emergency response (0.5 to 1 mile for initial evacuation and 1 mile for potential BLEVEs for flammable gases).

During startup and operation of the Project, approximately 10 trucks or tanker trucks per train would transport commodities (e.g., refrigerants, diesel, hot oil, liquid nitrogen, condensate product, etc.) to

[39] U.S. DOT PHMSA, Office of Hazardous Material Safety, *Incdent Reports Database Search*, https://hazmatonline.phmsa.dot.gov/IncidentReportsSearch/Welcome.aspx, accessed March 2019.
[40] EPA, NOAA, ALOHA®, User's Manual, The CAMEO® Software System, February 2007.
[41] Birk, A.M., BLEVE Response and Prevention Technical Documentation, 1995.
[42] AIChE, CCPS, Guidelines for Vapor Cloud Explosion, Pressure Vessel Burst, BLEVE, and Flash Fire Hazards, Second Edition, 2010.
[43] Lees, F.P, Lees Loss Prevention in the Process Industries, Hazard Identification, Assessment, and Control, Volume 2, Second Edition, 1996.
[44] USDOT, FHWA, Office of Highway Safety, Guidelines for Applying Criteria to Designate Routes for Transporting Hazardous Materials, September 1994.
[45] USDOT, PHMSA, Emergency Response Guidebook, 2016.

or from the facility. Approximately 40 trucks a year would be required for make-up losses when all 7 trains. We recommend in section B.9.1.6 that CCL Stage III file specifications and drawings of vehicle barriers at the access points, for review and approval, to further mitigate accidental and intentional vehicle impacts. In addition, FERC staff could not locate information in the application indicating that CCL Stage III would install guard rails, bollards, stop signs, speed limits, etc. that would be located internal to the liquefaction facility to protect equipment containing hazardous fluids and safety related equipment. Therefore, we recommend in section B.9.1.6 that CCL Stage III provide final design information, for review and approval, on internal road and vehicle protections, such as guard rails, barriers, and bollards to protect transfer piping, pumps, and compressors, etc. to ensure that they are located away from roadway or protected from damage by vehicle movements.

The closest road to the Project site would be the four lane Highway 361 to the northern side of the proposed site. The closest CCL Stage III LNG facilities would be the ground flare approximately 800 feet from the road. The closest liquefaction train (Train 7) would be approximately 1,300 feet from the road (and farthest Train 1 approximately 3,300 feet from road), and the tank would be approximately 3,800 feet from the road. These distances are farther than the hazard distances from the smaller 1,000-gallon or less releases constituting approximately 99 percent of all hazardous material incidents and farther than the worst-case jet fires from the 10,000-gallon or more releases constituting 1 percent of the hazardous material incidents described above. However, at least some of the facilities would be within range of the potential worst case unmitigated flammable vapor dispersion, fireball, and BLEVE impacts from the 10,000-gallon or more releases constituting 1 percent of the hazardous material incidents.

In total, there is approximately 2.46 miles of road within 1 mile of the Project's 3,346,000 ft^2 footprint with approximately 3,100,000 ft^2 constituting the liquefaction and process areas, approximately 161,000 ft^2 of flare related equipment and approximately 66,000 ft^2 of the LNG storage tank. 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 be any cascading failures that would impact the public. Projectiles from BLEVEs do have the potential to cause cascading damage that would impact the public if it were to reach the LNG storage tank. However, the LNG storage tank is approximately 3,800 feet away and less than 5 percent of projectiles would be able to extend far enough to reach the tank, and the tank would constitute less than 1 percent of the potential impact area of the projectiles that could reach that far. The tank would also be designed to withstand certain projectiles that would further protect it from cascading effects. In addition, CCL Stage III has committed to include coordination with local emergency responders with regard to potential rail incidents.

Due to the low risk of a vehicular incident occurring that could directly impact the site, the low risk of hazardous material truck incidents, the low risk of a hazardous material truck incidents impacting the site that would cause cascading damage that could impact the public, and the proposed and recommended mitigation, we conclude the Project would not pose a significant risk or a significant increase in risk to the public from external impacts occurring on the road.

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 Project site and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs. The USDOT regulations in 49 CFR 193.2155 (a) (5) (ii), under Subpart C state 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 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 USDOT 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. There would be no rail transportation associated with the Project.

FERC staff evaluated the risk of the rail operations based on the consequences from a release, incident data from the Federal Rail Administration and PHMSA, and frequency of rail operations near the Project area. Incident data from the Federal Rail Administration and PHMSA indicates hazardous material incidents are very infrequent (6e-3 incidents per rail mile per year). In addition, approximately 95 percent of releases are 1,000 gallons or less, and catastrophic events that would spill 30,000 gallons or more make up less than 1 percent of releases. In addition, less than 1 percent of hazardous material incidents result in injuries, and less than 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 much more modest distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to175 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, 1,225-1,500 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 7-20 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. These values are also close to the distances provided by USDOT PHMSA for emergency response (0.5 to 1 mile for initial evacuation and 1 mile for potential BLEVEs for flammable gases). 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 the 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 property boundary, with the closest Stage 3 LNG Facilities (ground flare) being approximately 800 feet from the rail line and the closest liquefaction train (Train 7) being approximately 1,300 feet from the rail line (and farthest Train 1 approximately 3,300 feet from rail line), and the tank being within approximately 3,800 feet of 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. However, at least some of the facilities would be within range of the potential worst case unmitigated flammable vapor dispersion, fireball, and BLEVE impacts from the 30,000-gallon or more releases constituting 1 percent of the hazardous material incidents.

In total, there is approximately 13,000 feet (2.46 miles) of rail within 1 mile of the Project's 3,346,000 ft^2 footprint with approximately 3,100,000 ft^2 constituting the liquefaction and process areas, approximately 161,000 ft^2 of flare related equipment and approximately 66,000 ft^2 of the LNG storage tank. 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 be any cascading failures that would impact the public. Projectiles from BLEVEs do have the potential to cause cascading damage that would impact the public if it were to reach the LNG storage tank. However, the LNG storage tank is approximately 3,800 feet away and less than 10 percent of projectiles would be able to extend far enough to reach the tank, and the tank would constitute less than 1 percent of the potential impact area of the projectiles that could reach that far. The tank would also be designed to withstand certain projectiles that would further protect it from cascading effects. In addition, CCL Stage III has 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, and the proposed and recommended mitigation, we conclude the Project would not pose a significant risk or a significant increase in risk to the public from external impacts occurring on the rail line.

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 193, must comply with the requirements of 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs. The USDOT regulations in 49 CFR 193.2155 (b), under Subpart C require an LNG storage tank must not be located within a horizontal distance of 1 mile from the ends, or 0.25 mile from the nearest point of a runway, whichever is longer and that the height of LNG structures in the vicinity of an airport must comply with FAA requirements. In addition, FERC staff evaluated the risk of an aircraft impact from nearby airports.

There is one on-site heliport situated 1.20 miles south of the proposed Project location and nine airports located within 22 miles of the proposed Project site as follows:

- Three general aviation airports are Hunt Airport located 4.78 miles southwest, Mustang Beach Airport located 12.5 miles south-southeast, and San Patricio County Airport located 18.9 miles north-northwest of the proposed Project site.
- Two general and military aviation airports with helicopter operations are McCampbell Airport located 3.51 miles northeast and Aransas County Airport located 18.4 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 16.4 miles south-southwest of the proposed Project site.
- Two Navy airfields and one naval air station are Cabaniss Field Navy Landing Airfield located 17.0 miles south-southwest, Waldron Field Navy Landing Airfield located 18.2 miles south-southwest and Naval Air Station Corpus Christi located 14.0 miles south-southwest of the proposed Project site, respectively.

All airports are farther than the 0.25-mile distance referenced in the USDOT PHMSA regulations. The USDOT FAA regulations in 14 CFR 77 require CCL Stage III to provide a notice to the FAA of its proposed construction. This notification should identify all equipment that are more than 200 feet above ground level or lesser heights if the facilities are within 20,000 feet of an airport (at 100:1 ratio or 50:1 ratio depending on length of runway) or within 5,000 feet of a heliport (at 100:1 ratio). The closest airport to the proposed Project site is the McCampbell Airport at a distance of 3.51 miles or 18,533 feet and its only runway is 4,975 feet. Since its runway is more than 3,200 feet, the notification should identify all equipment that are more than 185 feet above ground level (based on the 100:1 ratio stipulation). CCL Stage III submitted a request for aeronautical studies for its flare stacks, LNG storage tank, and construction cranes. The USDOT FAA, has provided a determination of no hazard for each one.

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. Because CCL Stage III does not anticipate utilizing the on-site heliport for construction or normal operations and would only be made available to necessitate emergency medical evacuations, 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 USDOT regulations under 49 CFR 192 and are discussed in section B.4.9.2. If authorized, constructed, and operated, LNG facilities as defined in 49 CFR 193, must comply with the requirements of 49 CFR 192 and 49 CFR 193 and would be subject to the USDOT's inspection and enforcement programs. 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 PHMSA, and proposed mitigation to prevent or reduce the impacts of a pipeline incident from the Project.

For existing pipelines, FERC staff identified a number of 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 Stage 3 LNG Facilities are situated on top of the buried pipelines. Preliminary information was provided for each pipeline and we recommend in section B.9.1.6 that CCL Stage III provide a live load analysis in coordination with local pipeline operators.

In addition, FERC staff determined that elevated LNG rundown lines located on a trestle and a heavy haul road would briefly overpass several buried pipelines to connect the Stage III Facilities with the existing Liquefaction Project LNG Storage Tanks. Therefore, we recommend in section B.9.1.6 that CCL Stage III perform an analysis to determine that activities on the heavy haul road would never exceed the maximum load capability of the buried pipelines.

Based on recommendations of FERC staff, the potential likelihood of pipeline incidents and potential consequences from a pipeline incident, FERC staff concludes the proposed 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 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.

Given the distances and locations of the facilities relative to the populated areas of the Portland and Corpus Christi communities, 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 pose a significant risk to the Project and subsequently to the public.

Onsite and Offsite Emergency Response Plans

As part of its application, CCL Stage III indicated that the Project would expand the current CCL ERP to include the CCL Stage III facilities. The emergency procedures would 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. The facility would also provide appropriate personnel protective equipment to enable operations personnel and first responder access to the area.

In addition, we recommend in section B.9.1.6 that CCL Stage III provide, for review and approval, an updated ERP prior to construction of final design. We also recommend in section B.9.1.6 that CCL Stage III file three dimensional drawings, prior to construction of final design, for review and approval, that demonstrate there is a sufficient number of access and egress locations. In addition, we recommend in section B.9.1.6 that Project facilities be subject to regular inspections throughout the life of the facility and would continue to require companies to file updates to the ERP.

9.1.6 Recommendations from FERC Preliminary Engineering and Technical Review

Based on FERC staff's preliminary engineering and technical review of the reliability and safety of the CCL Stage III Project, we recommend the following mitigation measures 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 facilities to enhance the reliability and safety of the facilities and to mitigate the risk of impact on the public.

- **Prior to initial site preparation, CCL Stage III should file with the Secretary documentation of consultation with the USDOT PHMSA on whether using normally-closed valves as a stormwater removal device on curbed areas would meet the requirements of 49 CFR 193.**
- **Prior to initial site preparation, CCL Stage III should file with the Secretary supplemental geotechnical investigations for Trains 5 through 7, and remaining portions of Train 4, the LNG tank area, and flare areas. The geotechnical reports should be stamped and sealed by the professional engineer-of-record registered in Texas, and should include a geotechnical investigation location plan with spacing of no more than 300 ft and field sampling methods and laboratory tests that are at least as comprehensive as the existing geotechnical investigations. Geotechnical test boring should be performed to a minimum depth of 100 feet below grade, or until refusal. In addition, the geotechnical investigations and reports must demonstrate soil modifications and foundation designs would be similar to Trains 1-3 and portions of the LNG tank and flare areas already investigated.**
- **Prior to construction of final design, CCL Stage III should file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Texas:**

  a. site preparation drawings and specifications;

  b. LNG storage tank and foundation design drawings and calculations;

  c. LNG terminal structures and foundation design drawings and calculations (including prefabricated and field constructed structures as well as demonstrating the cold box would take all wind loads and that no wind loads would be transmitted from the cold box to the Heavies Removal Scrub Column/Reflux Drum, 01-C-1511/01-V-1511);

  d. seismic specifications for procured equipment prior to issuing requests for quotations; and

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

  In addition, CCL Stage III should file, in its Implementation Plan, the schedule for producing this information.
- **Prior to initial site preparation, CCL Stage III should file with the Secretary the upper limit for total settlement for large flexible foundations and the maximum total edge settlement at the proposed Project area for the LNG tanks that the CMCs would be designed to satisfy.**
- **Prior to initial site preparation, CCL Stage III should file with the Secretary a detailed analysis that demonstrates external loads exerted by vehicular traffic and construction equipment would not exceed the maximum live load capability of buried pipelines at or adjacent to the Project. The analysis should be stamped and sealed by the professional engineer-of-record, registered in Texas and should include the depth of existing buried pipelines and evidence that the maximum load should be higher than plant construction and operation activities require. In addition, provide construction and operations procedures to demonstrate that the maximum allowable weight would never be exceeded.**

Information pertaining to these specific recommendations should 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 recommendation. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000),

including security information, should 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 should be subject to public disclosure. All information should be filed <u>a minimum of 30 days</u> before approval to proceed is requested.

- **<u>Prior to initial site preparation</u>, CCL Stage III should file an overall Project schedule, which includes the proposed stages of the commissioning plan.**

- **<u>Prior to initial site preparation</u>, CCL Stage III should file procedures for controlling access during construction.**

- **<u>Prior to initial site preparation</u>, CCL Stage III should file quality assurance and quality control procedures for construction activities.**

- **<u>Prior to initial site preparation</u>, CCL Stage III should file its design wind speed criteria for all other facilities not covered by USDOT PHMSA's LOD to be designed to withstand wind speeds commensurate with the risk and reliability associated with the facilities in accordance with ASCE 7-16 or equivalent.**

- **<u>Prior to initial site preparation</u>, CCL Stage III should develop an Emergency Response Plan (including evacuation) which integrates the CCL Stage III Facilities into the existing plan for the Liquefaction Project and coordinate procedures with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan should include at a minimum:**

  a. designated contacts with state and local emergency response agencies;

  b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

  c. procedures for notifying residents and recreational users within areas of potential hazard;

  d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

  e. locations of permanent sirens and other warning devices; and

  f. an "emergency coordinator" on each LNGC to activate sirens and other warning devices.

  CCL Stage III should notify the FERC staff of all planning meetings in advance and should report progress on the development of its Emergency Response Plan <u>at 3-month intervals</u>.

- **<u>Prior to initial site preparation</u>, CCL Stage III should file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that should 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. CCL Stage III should notify FERC staff of all planning meetings in advance and should report progress on the development of its Cost Sharing Plan <u>at 3-month intervals</u>.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file change logs that list and explain any changes made from the front end engineering design provided in CCL Stage III's application and filings. A list of all changes with an explanation for the design alteration should be provided and all changes should be clearly indicated on all diagrams and drawings.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file information/revisions pertaining to its response to numbers 4, 13, 39, 44, 45, 46, 52, and 58 of the December 19, 2018 data request and to its response to numbers 3, 8, 9, 20, 21, 22, 23, 24, 27, 31, 34, 38, 39, 41, 47, and 64 of the January 3, 2019 data request, which indicated features to be included or considered in the final design.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file lighting drawings. The lighting drawings should show the location, elevation, type of light fixture, and lux levels of the lighting system and should be in accordance with the proposed specification to meet API 540 and provide illumination along the perimeter of the facility and along paths/roads of access and egress to facilitate security monitoring and emergency response operations.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file security camera and intrusion detection drawings. The security camera drawings should show the location, areas covered, and features of the camera (fixed, tilt/pan/zoom, motion detection alerts, low light, mounting height, etc.) to verify camera coverage of the entire perimeter with redundancies, and cameras interior to the terminal that would enable rapid monitoring of the LNG terminal including a camera be provided at the top of the LNG storage tank, and coverage within pretreatment areas, within liquefaction areas, within truck transfer areas, and buildings. The drawings should show or note the location of the intrusion detection to verify it covers the entire perimeter of the LNG plant.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file fencing drawings. The fencing drawings should provide details of fencing that demonstrates it would restrict and deter access around the entire facility and has a setback from exterior features (e.g., power lines, trees, etc.) and from interior features (e.g., piping, equipment, buildings, etc.) that does not allow for the fence to be overcome.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings and specifications for crash rated vehicle barriers at each facility entrance for access control.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file up-to-date PFDs and P&IDs. The PFDs should include HMBs at low, design, and high ambient temperatures and demonstrate the peak liquefaction rate of 11.45 MTPA is achievable. The P&IDs should include vendor P&IDs and 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.

- **Prior to construction of final design, CCL Stage III should 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.**
- **Prior to construction of final design, CCL Stage III should file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs.**
- **Prior to construction of final design, CCL Stage III should file a HAZOP prior to issuing the P&IDs for construction. A copy of the review, a list of the recommendations, and actions taken on the recommendations should be filed.**
- **Prior to construction of final design, CCL Stage III should file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions).**
- **Prior to construction of final design, CCL Stage should provide a means to monitor for mercury breakthrough by means of an analyzer, sample connection downstream of the mercury removal package, or preventative maintenance inspections of the heat exchangers.**
- **Prior to construction of final design, CCL Stage III should provide a dynamic simulation that shows that upon plant shutdown, the loop seal provided upstream of the AGRU would be sufficient to prevent backflow or provide a check valve.**
- **Prior to construction of final design, CCL Stage III should provide in the design of the AGRU connections to and space for a temporary or permanent amine reclamation module.**
- **Prior to construction of final design, CCL Stage III should include LNG storage tank fill flow measurement with high flow alarm.**
- **Prior to construction of final design, CCL Stage III should include BOG flow measurement from each LNG storage tank.**
- **Prior to construction of final design, CCL Stage III should provide process data sheets that specify the start-up, operating, and shutdown conditions for the BOG Compressors.**
- **Prior to construction of final design, the design of HV-71031 should be provided with administrative controls to prevent it from isolating the discretionary vent.**
- **Prior to construction of final design, CCL Stage III should design the hot oil return system and drum to equal pressures or provide dynamic simulation results of a catastrophic tube rupture in the hot oil system that demonstrates the hot oil return system and drum are properly protected and would not fail in the event of a tube rupture in the system.**
- **Prior to construction of final design, CCL Stage III should file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system**

for review and approval. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

- **<u>Prior to construction of final design</u>, CCL Stage III should 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 Stage III Project.**
- **<u>Prior to construction of final design</u>, CCL Stage III should specify that all emergency shutdown valves would be equipped with open and closed position switches connected to the Distributed Control System/Safety Instrumented System.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file an evaluation of emergency shutdown valve closure times. The evaluation should account for the time to detect an upset or hazardous condition, notify plant personnel, and close the emergency shutdown valve.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump startup and shutdown operations.**
- **<u>Prior to construction of final design</u>, CCL Stage III should provide extruded fins for MR Interstage Condensers 01-EA-1611, 01-EA-1612, and 01-EA-1611or demonstrate the fin type would be suitable for the temperature range per API 662 and the crevice of the fin would not result in potential corrosion of the carbon steel tube where corrosion allowances on the tubes are not recommended per API 662.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file 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, safety instrument system [SIS], cable, other electrical and instrumentation); and**

  d. **security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, firewater).**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a list of all codes and standards and the final specification document number where they are referenced.**
- **<u>Prior to construction of final design</u>, CCL Stage III should include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file complete specifications and drawings of the proposed LNG tank design and installation.**
- **<u>Prior to construction of final design</u>, CCL Stage III should demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.**

- **<u>Prior to construction of final design</u>, CCL Stage III should provide a stress analysis that demonstrates that piping and adjacent equipment would not be overstressed if travel pins are removed with the pipe empty or flooded with LNG.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. The flare load calculations should justify the lower emissivity factors and molecular weights used for the dry and wet flares.**
- **<u>Prior to construction of final design</u>, CCL Stage III should demonstrate the flare has been sized for LNG production rates during plant cooldown when the liquefaction exchanger is operating at the rundown rate provided in Process Basis of Design, Document No. G720-15-EM-GEN-G10-0002.**
- **<u>Prior to construction of final design</u>, CCL Stage III should confirm that all overprotection devices downstream of a control valve with a bypass valve arrangement would be sized based on the full flow of a wide open control valve or bypass valve.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file an evaluation of all bypass lines which includes a spec break to ensure the line downstream of the break would not be overpressurized or relocate the spec break to the downstream header.**
- **<u>Prior to construction of final design,</u> CCL Stage III should provide quantitative analysis which evaluates the reliability of the multi point ground flare pilots, including the potential common cause failures of the pilots being designed to less than 183 mph 3-second gust and having a single fuel source. The analysis should demonstrate that the fences enclosing the ground flare would reduce the wind velocity to 125 mph or less and multiple sources of fuel gas exist. Otherwise, CCL Stage III should provide a dispersion analysis of an unlit flare scenario and indicate what safeguards would be in place for preventing offsite impacts from that scenario.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations should be filed. The evaluation should justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). The justification for the flammable and combustible gas detection and flame and heat detection should be in accordance with ISA 84.00.07 or equivalent methodologies that would demonstrate 90% or more of releases (unignited and ignited) that could result in an off-site or cascading impact that could extend off site 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, and different wind speeds and directions. The evaluation should demonstrate jet fires from the pipeline compressor and feed gas tie in would be mitigated (e.g., firewall, water curtain, etc.) such that it does not impede evacuation. The justification for firewater should provide calculations for all firewater demands (including firewater coverage on the LNG storage tank, refrigerant compressor skid, heavy hydrocarbon removal unit, liquefaction cold box, and adjacent fire zones if they could result in cascading damage) based on design densities, surface area, and throw distance and specifications for the corresponding hydrant and monitors needed to reach and cool equipment.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comer that would transfer spills from the tank top to the ground-level impoundment system. The spill containment drawings should show containment for all hazardous fluids, including all liquids handled above their flash point, from the largest flow from a single line for 10 minutes, including de-inventory, or the maximum liquid from the largest vessel (or total of impounded vessels) or otherwise demonstrate that providing spill containment would not significantly reduce the flammable vapor dispersion or radiant heat consequences of a spill.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file detailed calculations to confirm that the final fire water volumes would be accounted for when evaluating the capacity of the impoundment system during a spill and fire scenario.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a critical equipment and building siting assessment to ensure plant buildings that are occupied or critical to the safety of the LNG plant are adequately protected from potential hazards involving fires and vapor cloud explosions. The evaluation should evaluate the potential relocation of the firewater pumps and tank and buildings and their protection from flammable vapors, explosions, and fires from hazardous fluid containing equipment or provide analyses demonstrating they would be adequately protected from such events.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file electrical area classification drawings.**
- **<u>Prior to construction of final design</u>, CCL Stage III should provide documentation demonstrating adequate ventilation, detection, and electrical area classification based on the final selection of the batteries, and associated hydrogen off-gassing rates.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001).**
- **<u>Prior to construction of final design</u>, CCL Stage III should 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 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.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file complete drawings and a list of the hazard detection equipment. The drawings should clearly show the location and elevation of all detection equipment. The list should include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a technical review of facility design that:**

  a. identifies all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release; and

  b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion or heating

ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency.

- **<u>Prior to construction of final design</u>, CCL Stage III should include in its design toxic gas detection near the Mercury/H2S Absorber and flammable gas detection at each hot oil furnace, thermal oxidizer, and LNG Storage Tank.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings of the hazard detection in buildings, including hazard detection in the firewater pump building.**
- **<u>Prior to construction of final design</u>, CCL Stage III should 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, propane, ethane/ethylene, pentane, and condensate.**
- **<u>Prior to construction of final design</u>, CCL Stage III should 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 natural gas liquids and hydrogen sulfide.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file an evaluation of the voting logic and voting degradation for hazard detectors.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a design that includes hazard detection suitable to detect high temperatures and smoldering combustion products in electrical buildings and control room buildings.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a drawing showing the location of the emergency shutdown buttons. Emergency shutdown buttons should be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.**
- **<u>Prior to construction of final design</u>, CCL Stage III should 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 should clearly show the location and elevation by tag number of all fixed dry chemical systems in accordance with NFPA 17, and wheeled and hand-held extinguishers location travel distances are along normal paths of access and egress and in compliance with NFPA 10. The list should include the equipment tag number, manufacturer and model, elevations, agent type, agent capacity, discharge rate, automatic and manual remote signals initiating discharge of the units, and equipment covered.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a design that includes clean agent systems in the instrumentation buildings.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings and specifications for the structural passive protection systems to protect equipment and supports from cryogenic releases.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file calculations or test results for the structural passive protection systems to protect equipment and supports from cryogenic releases.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings and specifications for the structural passive protection systems to protect equipment and supports from pool and jet fires.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each significant component within the 4,000 Btu/ft^2-hr zone from pool or jet fires that could cause failure of the component. Trucks at the truck transfer station should be included in the analysis. A combination of passive and active protection should be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation should be supported by calculations for the thickness limiting temperature rise and effectiveness of active mitigation should be justified with calculations demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the vessel.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file an evaluation and associated specifications and drawings of how they would prevent cascading damage of transformers (e.g., fire walls or spacing) in accordance with NFPA 850 or equivalent.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file facility plan drawings showing the proposed location of the firewater. Plan drawings should clearly show the location of firewater piping, post indicator 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 (e.g., NFPA 24 indicates max of six) can be isolated with post indicator valves. The drawings should also provide coverage in all areas that contain flammable or combustible fluids, including the LNG storage tank, refrigerant compressor skid, heavy hydrocarbon removal unit, and liquefaction cold box, by two or more hydrants or monitors and automatic or remotely operated monitors or fixed systems in areas inaccessible or difficult to access in the event of an emergency. The coverage circles should take into account obstructions to the firewater coverage and should reflect the number of firewater needed to reach and cool exposed surfaces in potentially subjected to damaging radiant heats from a fire. Drawings should also include piping and instrumentation diagrams of the firewater systems.**

- **<u>Prior to construction of final design</u>, CCL Stage III should demonstrate that API 650 provides equivalent or greater protections than NFPA 22 and AWWA D-100 in regards to the design of the firewater storage tanks. The equivalency should address NFPA 22 and AWWA D-100 requirements for inflow piping refilling the tank within 8 hours, higher wall thicknesses, venting, manholes, anti-vortex plates, and other pertinent differences.**

- **<u>Prior to construction of final design</u>, CCL Stage III should specify that the firewater flow test meter is equipped with a transmitter and that a pressure transmitter is installed upstream of the flow transmitter. The flow transmitter and pressure transmitter should be connected to the DCS and recorded to maintain a historical record of pump performance tests.**

- **<u>Prior to construction of final design</u>, CCL Stage III should specify that fire house and shelter are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file drawings of the storage tank, piping support structure, and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file the structural analysis of the LNG storage tank and outer containment demonstrating they are designed to withstand all loads and combinations.**

- **<u>Prior to construction of final design</u>, CCL Stage III should file an analysis of the structural integrity of the outer containment of the full containment LNG storage tanks when exposed to a roof tank top fire.**
- **<u>Prior to construction of final design</u>, CCL Stage III should file a projectile analysis to demonstrate that the outer concrete impoundment wall of a full-containment LNG storage tank could withstand projectiles from explosions and high winds. The analysis should detail the projectile speeds and characteristics and method used to determine penetration or perforation depths.**
- **<u>Prior to construction of final design,</u> CCL Stage III should file drawings and documentation showing the location of all internal road vehicle protections, such as guard rails, barriers, and bollards to protect transfer piping, pumps, and compressors, etc. to ensure that they are located away from roadway or protected from inadvertent damage from vehicles.**
- **<u>Prior to commissioning</u>, CCL Stage III should file a detailed schedule for commissioning through equipment startup. The schedule should include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. CCL Stage III should file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup would be issued.**
- **<u>Prior to commissioning</u>, CCL Stage III should 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.**
- **<u>Prior to commissioning</u>, CCL Stage III should file 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.**
- **<u>Prior to commissioning</u>, CCL Stage III should tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**
- **<u>Prior to commissioning</u>, CCL Stage III should file a plan to maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff has completed the required training.**
- **<u>Prior to commissioning</u>, CCL Stage III should file a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Principles and Practice, and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing.**
- **<u>Prior to commissioning</u>, CCL Stage III should file the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3. In addition, CCL Stage III should file a line list with pneumatic and hydrostatic test pressures.**
- **<u>Prior to commissioning</u>, CCL Stage III should file the settlement results from hydrostatic testing of the LNG storage containers as well as a routine monitoring program to ensure settlements are as expected and do not exceed applicable criteria in API 620, API 625, API 653, and ACI 376. The program should specify what actions would be taken after seismic events.**
- **<u>Prior to commissioning</u>, CCL Stage III should equip the LNG storage tank and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and**

record the relative settlement between the LNG storage tank and adjacent piping. The settlement record should be reported in the semi-annual operational reports.

- **Prior to introduction of hazardous fluids, CCL Stage III 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.**
- **Prior to introduction of hazardous fluids, CCL Stage III should develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms.**
- **Prior to introduction of hazardous fluids, CCL Stage III should complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review should 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, should be filed.**
- **Prior to introduction of hazardous fluids, CCL Stage III should complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s).**
- **CCL Stage III should file a request for written authorization from the Director of OEP prior to unloading or loading the first LNG commissioning cargo. After production of first LNG, CCL Stage III 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.**
- **Prior to commencement of service, CCL Stage III should 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 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 Stage III or other appropriate parties.**
- **Prior to commencement of service, CCL Stage III should notify the FERC staff of any proposed revisions to the security plan and physical security of the plant.**
- **Prior to commencement of service, CCL Stage III should label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001).**
- **Prior to commencement of service, CCL Stage III should file plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring.**

- **Prior to commencement of service, CCL Stage III should develop procedures for handling offsite contractors including responsibilities, restrictions, and limitations and for supervision of these contractors by CCL Stage III staff.**

In addition, we recommend that the following measures should apply throughout the life of the Stage 3 LNG Facilities.

- **The facility should 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 Stage III 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 described below, including facility events that have taken place since the previously submitted semi-annual report, should be submitted.**

- **Semi-annual operational reports should be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., LNGC 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 should include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also should be reported. Reports should 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.**

- **In the event the temperature of any region of the LNG storage container becomes less than the minimum specified operating temperature for the material, the Commission should be notified within 24 hours and procedures for corrective action should be specified.**

- **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) should 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 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 LNG 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 should include investigation results and recommendations to minimize a reoccurrence of the incident.

9.1.7 Conclusions on LNG Facility and LNGC Reliability and Safety

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

As a cooperating agency, the USDOT assists the FERC by determining whether CCL Stage III's proposed design would meet the USDOT's 49 CFR 193, Subpart B siting requirements. The USDOT will provide a LOD on the Project's compliance with 49 CFR 193, Subpart B. This determination will be provided to the Commission as further consideration to the Commission on its decision to authorize or deny the Project. If the Project is authorized, constructed, and operated, the facility would be subject to the USDOT's inspection and enforcement program; final determination of whether a facility is in compliance with the requirements of 49 CFR 193 would be made by the USDOT staff.

As a cooperating agency, the Coast Guard also assisted the FERC staff by reviewing the proposed LNG terminal and the associated LNGC traffic. The Coast Guard reviewed a WSA submitted by CCL Stage III that focused on the navigation safety and maritime security aspects of LNGC transits along the affected waterway. On September 11, 2015, the Coast Guard issued a LOR to FERC staff indicating the Corpus Christi Ship Channel from the entrance approach at Port Aransas to the La Quinta Junction, and the entire length of the La Quinta Channel would be considered suitable for accommodating the type and frequency of LNG marine traffic associated with this Project, based on the WSA and in accordance with the guidance in the Coast Guard's NVIC 01-11. If the Project is authorized and constructed, the facilities would be subject to the Coast Guard's inspection and enforcement program to ensure compliance with the requirements of 33 CFR 105 and 33 CFR 127.

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

9.2 Pipeline Safety

The transportation of natural gas by pipeline involves some incremental risk to the public due to the potential for accidental release of natural gas. The greatest hazard is a fire or explosion following a major pipeline rupture.

Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death.

Methane has an auto-ignition temperature of 1,000 degrees F and is flammable at concentrations between 5.0 percent and 15.0 percent in air. An unconfined mixture of methane and air is not explosive; however, it may ignite and burn if there is an ignition source. A flammable concentration within an enclosed space in the presence of an ignition source can explode. It is buoyant at atmospheric temperatures and disperses rapidly in air.

9.2.1 Pipeline Safety Standards

The USDOT is mandated to prescribe minimum safety standards to protect against risks posed by pipeline facilities under Title 49, USC Chapter 601. The USDOT's PHMSA administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards which set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety. PHMSA's safety mission is to ensure that people and the environment are protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level.

Title 49, USC Chapter 601 provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards. A state may also act as USDOT's agent to inspect interstate facilities within its boundaries; however, the USDOT is responsible for enforcement actions.

The USDOT pipeline standards are published in Parts 190-199 of Title 49 of the CFR. Part 192 specifically addresses natural gas pipeline safety issues.

Under a MOU on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993, between the USDOT and the FERC, the USDOT has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it will design, install, inspect, test, construct, operate, replace, and maintain the facility for which a Certificate is requested in accordance with federal safety standards and plans for maintenance and inspection. Alternatively, an applicant must certify that it has been granted a waiver of the requirements of the safety standards by the USDOT in accordance with section 3(e) of the *Natural Gas Pipeline Safety Act*. The FERC accepts this certification and does not impose additional safety standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Memorandum to promptly alert USDOT. The Memorandum also provides for referring complaints and inquiries made by state and local governments and the general public involving safety matters related to pipelines under the Commission's jurisdiction.

The FERC also participates as a member of the USDOT's Technical Pipeline Safety Standards Committee which determines if proposed safety regulations are reasonable, feasible, and practicable.

The pipeline and aboveground facilities associated with the Project must be designed, constructed, operated, and maintained in accordance with the USDOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. The USDOT specifies material selection and qualification; minimum design requirements; and protection from internal, external, and atmospheric corrosion.

The USDOT also defines area classifications, based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined below:

Class 1 Location with 10 or fewer buildings intended for human occupancy;

Class 2 Location with more than 10 but less than 46 buildings intended for human occupancy;

Class 3 Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month period; and

Class 4 Location where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. For instance, pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (*e.g.,* 10.0 miles in Class 1, 7.5 miles in Class 2, 4.0 miles in Class 3, and 2.5 miles in Class 4). Pipe wall thickness and pipeline design pressures; hydrostatic test pressures; maximum allowable operating pressure (MAOP); inspection and testing of welds; and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas.

The entirety of the Stage 3 Pipeline is located in areas designed as Class 1. If a subsequent increase in population density adjacent to the right-of-way results in a change in class location for the pipeline and to comply with the USDOT requirements for the new class location, CCPL would reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness.

The USDOT Pipeline Safety Regulations require operators to develop and follow a written integrity management program that contain all the elements described in 49 CFR 192.911 and address the risks on each transmission pipeline segment. The rule establishes an integrity management program which applies to all high consequence areas (HCA). The USDOT has published rules that define HCAs where a gas pipeline accident could do considerable harm to people and their property and requires an integrity management program to minimize the potential for an accident. This definition satisfies, in part, the Congressional mandate for USDOT to prescribe standards that establish criteria for identifying each gas pipeline facility in a high-density- population area.

The HCAs may be defined in one of two ways. In the first method an HCA includes:

- current class 3 and 4 locations;
- any area in Class 1 or 2 where the potential impact radius[46] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle;[47] or
- any area in Class 1 or 2 where the potential impact circle includes an identified site.

An identified site is an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period; a building that is occupied by 20 or more persons on at least 5 days a week for any 10 weeks in any 12-month period; or a facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

In the second method, an HCA includes any area within a potential impact circle which contains 20 or more buildings intended for human occupancy or an identified site.

Once a pipeline operator has determined the HCAs along its pipeline, it must apply the elements of its integrity management program to those segments of the pipeline within HCAs. The USDOT regulations

46 The potential impact radius is calculated as the product of 0.69 and the square root of the MAOP of the pipeline in psig multiplied by the square of the pipeline diameter in inches.

47 The potential impact circle is a circle of radius equal to the potential impact radius.

specify the requirements for the integrity management plan at section 192.911. The Stage 3 Pipeline does not cross any areas identified as an HCA.

The USDOT prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Each pipeline operator is required to establish an emergency plan that includes procedures to minimize the hazards of a natural gas pipeline emergency. Key elements of the plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- emergency system shutdown and safe restoration of service;
- making personnel, equipment, tools, and materials available at the scene of an emergency; and
- protecting people first and then property, and making them safe from actual or potential hazards.

The USDOT requires that each operator establish and maintain liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. The operator must also establish a continuing education program to enable customers, the public, government officials, and those engaged in excavation activities to recognize a gas pipeline emergency and report it to appropriate public officials. CCPL would develop a written Public Awareness Plan that conforms to the requirements of 49 CFR 192.616. This written plan would be designed to educate the landowners, public, government officials, emergency responders, and person engaged in excavation activities in the area of the Stage 3 Pipeline. This plan would include: efforts to educate the above-named parties on the characteristics of natural gas, an explanation of the One-Call process and how it should be utilized by those planning excavation activities in the vicinity of the Stage 3 Pipeline, possible hazards associated with the unintended release of gas, steps that should be taken immediately for individual safety concerns, and procedures for reporting these incidents to CCPL.

Pipeline Accident Data

The USDOT requires all operators of natural gas transmission pipelines to notify the USDOT of any significant incident and to submit a report within 20 days. Significant incidents are defined as any leaks that caused a death or personal injury requiring hospitalization or involve property damage of more than $50,000 (1984 dollars).[48] During the 20-year period from 1998 through 2017, a total of 1,365 significant incidents were reported on the more than 300,000 total miles of natural gas transmission pipelines nationwide (USDOT, 2018a; 2018b).

Additional insight into the nature of service incidents may be found by examining the primary factors that caused the failures. Table B.9.2-3 provides a distribution of the causal factors as well as the number of each incident by cause. The dominant causes of pipeline incidents are corrosion and pipeline material, weld or equipment failure collectively constituting 53.2 percent of all significant incidents. The pipelines included in the data set in table B.9.2-3 vary widely in terms of age, diameter, and level of corrosion control. Each variable influences the incident frequency that may be expected for a specific segment of pipeline. The frequency of significant incidents is strongly dependent on pipeline age. Older

[48] $50,000 in 1984 dollars is approximately $123,510 as of January 2019 (Bureau of Labor Statistics, 2019).

pipelines have a higher frequency of corrosion incidents and material failure, because corrosion and pipeline stress/strain are a time-dependent process.

Table B.9.2-1

Natural Gas Transmission Pipeline Significant Incidents by Cause (1998-2017)

Cause	Number of Incidents	Percentage
Corrosion	324	23.7
Excavation [a]	198	14.5
Pipeline material, weld, or equipment failure	403	29.5
Natural forces [b]	148	10.8
Outside force [c]	90	6.6
Incorrect operation	54	4.0
All other causes [d]	148	10.8
Total	**1,365**	**-**

Source: USDOT, 2018c.

[a] Includes third-party damage.

[b] Natural force damage includes earth movement, heavy rain, floods, landslides, mudslides, lightning, temperature, high winds, and other natural force damage.

[c] Outside force damage includes previous mechanical damage, electrical arcing, static electricity, fire/explosion, fishing/maritime activity, intentional damage, and vehicle damage (not associated with excavation).

[d] All other causes include miscellaneous, unspecified, or unknown causes.

The use of both an external protective coating and a cathodic protection system,[49] required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe.

Outside forces, including excavations and natural events, are the cause in 31.9 percent of significant pipeline incidents nationwide from 1998 and 2017. Table B.9.2-2 provides a breakdown of outside force incidents by cause. These mostly result from the encroachment of mechanical equipment such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geologic hazards; weather effects such as winds, storms, and thermal strains; and willful damage.

Older pipelines have a higher frequency of outside forces incidents partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller-diameter pipelines; which have a greater rate of outside forces incidents. Small diameter pipelines are more easily crushed or broken by mechanical equipment or earth movement.

Since 1982, operators have been required to participate in “One-Call” public utility systems in populated areas to minimize unauthorized excavation activities near pipelines. The “One-Call” system is a service used by public utilities and some private sector companies (e.g., oil pipelines, cable television) to provide preconstruction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts.

[49] Cathodic protection is a technique to reduce corrosion (rust) of the natural gas pipeline through the use of an induced current or a sacrificial anode (like zinc) that corrodes at faster rate to reduce corrosion.

Table B.9.2-2 Outside Forces Incidents by Cause (1998-2017) [a]		
Cause	**Number of Excavation, Natural Forces, and Outside Force Incidents**	**Percentage of Outside Force Incidents**
Third party excavation damage	160	36.7
Operator/contractor excavation damage	26	6.0
Unspecified excavation damage/previous damage	12	2.8
Heavy rain, floods, mudslides, landslides	78	17.9
Earth movement, earthquakes, subsidence	29	6.7
Lightning, temperature, high winds	30	6.9
Other or unspecified natural forces	11	2.5
Vehicle (not engaged with excavation)	52	11.9
Fire/explosion	10	2.3
Previous mechanical damage	6	1.4
Fishing or maritime activity	9	2.1
Intentional damage	1	0.2
Electrical arcing from other equipment/facility	1	0.2
Other outside force	11	2.5
Total	**436**	**-**

Source: USDOT, 2018d
[a] Excavation, outside force, and natural force from table B.9.2-1.

9.2.2 Impact on Public Safety

The service incident data summarized in table B.9.2-5 include natural gas transmission system failures of all magnitudes with widely varying consequences. Table B.9.2-5presents the annual injuries and fatalities that occurred on natural gas transmission lines from incidents for the 5-year period between 2013 and 2017. The data has been separated into employees and nonemployees to better identify a fatality rate experienced by the general public.

The majority of fatalities from pipelines are due to local distribution pipelines (not included in table B.9.2-5). These are natural gas pipelines that are not regulated by FERC and that distribute natural gas to homes and businesses after transportation through interstate natural gas transmission pipelines. In general, these distribution lines are smaller diameter pipes and/or plastic pipes, often made of plastic or cast iron rather than welded steel, and tend to be older pipelines which are more susceptible to damage. In addition, distribution systems do not have large rights-of-way and pipeline markers common to the FERC regulated natural gas transmission pipelines.

Table B.9.2-3 Injuries and Fatalities – Natural Gas Transmission Pipelines		
Year	**Injuries**	**Fatalities**
2013	2	0
2014	1	1
2015	16	6
2016	3	3
2017	3	3

Source: USDOT, 2018a.

The nationwide totals of accidental fatalities from various manmade and natural hazards are listed in table B.9.2-6 in order to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. Direct comparisons between accident categories should be made cautiously because individual exposures to hazards are not uniform among all categories.

The available data shows that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 1998 to 2017, there were an average of 68 significant incidents, 9 injuries and 3 fatalities per year (USDOT, 2018c). The number of significant incidents over the more than 300,000 miles of natural gas transmission lines indicates the risk is low for an incident at any given location. The operation of the Pipeline Facilities of the Stage 3 Project would represent a slight increase in risk to the nearby public. We conclude that, with the implementation of the standard safety design criteria, the Stage 3 Pipeline would be constructed and operated safely.

Table B.9.2-4

Nationwide Accidental Fatalities by Cause

Type of Accident	Annual Number of Deaths
Motor vehicle [a]	35,369
Poisoning [a]	38,851
Falls [a]	30,208
Drowning [a]	3,391
Fire, smoke inhalation, burns [a]	2,760
Floods [b]	81
Tornado [b]	72
Lightning [b]	49
Hurricane [b]	47
Natural gas distribution lines [c]	13
Natural gas transmission pipelines [c]	2

[a] All data, unless otherwise noted, reflects 2007 statistics from U.S. Census Bureau, Statistical Abstract of the United States: 2010b (129th Edition) Washington, DC, 2009; http://www.census.gov/statab.

[b] NOAA National Weather Service, Office of Climate, Water and Weather Services, 30-year average (1988-2017) http://www.weather.gov/om/hazstats.shtml. [c] Bureau of Labor Statistics, 2016 Census of Occupational Injuries.

[c] Accident data presented for natural gas distribution lines and transmission pipelines represent the 20-year average between 1998 and 2017 (USDOT, 2018a).

10.0 CUMULATIVE IMPACTS

NEPA requires the lead federal agency to consider the potential cumulative impacts of proposals under its review. Cumulative impacts may result when the environmental effects associated with the Project are superimposed on or added to impacts associated with past, present, and reasonably foreseeable future actions. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over a period of time.

The Project-specific impacts are discussed in detail in other sections of this EA. The purpose of this section is to identify and describe cumulative impacts that would potentially result from implementation of the Project along with other projects that could affect the same resources in the same approximate timeframe. To ensure that this analysis focuses on relevant projects and potentially significant impacts, the actions included in the cumulative impact analysis include projects that:

- impact a resource potentially affected by the Project;

- impact that resource within all or part of the timespan encompassed by the proposed or reasonably expected construction and operation schedule of the Project; and
- impact that resource within all or part of the same geographic area affected by the Project. The geographic area considered varies depending on the resource being discussed, which is the general area (geographic scope) in which the Project could contribute to cumulative impacts on that particular resource.

The resources that would be affected as a result of the Project include soils; groundwater; surface water; wetlands; vegetation; wildlife and aquatic resources; threatened, endangered, and other special status species; land use; socioeconomics; air quality; and noise.

The Project would be an expansion of the Liquefaction Project currently under construction. The Liquefaction Project impact analysis and associated cumulative effects were analyzed in the 2014 EIS.[50] The majority of the area used for construction of the Stage 3 LNG Facilities (99 percent) would be within the areas disturbed during construction of the Liquefaction Project. Similarly, the Stage 3 Pipeline would be collocated for 99 percent of the route with the recently completed Corpus Christi Pipeline.

The regional landscape in the Project area has been radically altered by human occupation over the last 150 years, first by agriculture, and later by the development of extensive industrial and port facilities. As a result, the region includes a substantial amount of commercial developments, residential areas, and public infrastructure (e.g., schools, hospitals, roads).

10.1 Temporal and Geographic Distribution (Geographic Scope)

For the purpose of this analysis, the temporal extent of other projects would start in the recent past and extend out for the expected duration of the impacts caused by the Project. Some Project impacts from construction could occur as soon as site preparation begins and occur over about 48 months, while operational impacts are assumed to exist throughout the life of the facility. Cheniere proposes to begin operations in 2023 and the facilities would be designed and capable of operating for an indefinite period of time with proper maintenance.

The geographic distribution of the area considered in the cumulative effects analysis varies by project and by resource. The cumulative impact analysis area, or geographic scope, for a resource may be substantially greater than the corresponding project-specific area of impact in order to consider an area large enough to encompass likely effects from other projects on the same resource. The CEQ (1997) recommends setting the geographic scope based on the natural boundaries of the resource affected, rather than jurisdictional boundaries. Resource-specific geographic scopes are provided in table B.10.1-1 and used to assess cumulative impacts for each resource.

Based on our analysis in the previous sections, we conclude that the Project has little or no impacts on the following resources: geology, recreation, and cultural resources. Because the Project does not contribute to impacts on these resources, we do not consider them further in this analysis.

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[50] The EIS for the Corpus Christi Liquefaction Project is available on the FERC eLibrary website at https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp under accession number 20141008-4001.

Table B.10.1-1 Resource-specific Geographic Scopes	
Environmental Resource	**Geographic Scope**
Soils	Within or adjacent to the construction workspace/right-of-way
Water Resources	HUC 12 Watershed
Vegetation	HUC 12 Watershed
Wildlife and Aquatic Resources	HUC 12 Watershed
Threatened, Endangered, and other Special Status Species	HUC 12 Watershed
Land Use and Visual Resources	Right-of-way and a 0.5-mile radius around the Project facilities
Socioeconomics	San Patricio and Nueces Counties
Air Quality[51]	Construction: right-of-way and 0.25-mile radius around Project facilities Operation: right-of-way and 50-km radius around Project facilities
Noise	Construction: NSAs within 0.25 mile of the pipeline or aboveground facilities, and within 0.5 mile of HDD or direct pipe installation. Operation: Any facility that could have an impact on an NSA within 1-mile of a Project stationary facility.

10.2 Projects and Activities Considered

With respect to past actions, CEQ guidance (2005) allows agencies to adopt a broad, aggregated approach without "delving into the historical details of individual past actions." Past projects that are no longer contributing to changes in the environment are included as part of the environmental baseline. Past, present, and reasonably foreseeable projects within the geographic scope for the Project, that might cause cumulative impacts when considered with the Project, are discussed in this section. FERC-regulated projects are those for which the proponent has submitted a formal application to the FERC, and planned projects are projects that are either in pre-filing or have been announced. Planned projects also include projects not under the FERC's jurisdiction that have been identified through publicly available information such as press releases, internet searches, and the applicant's communications with local agencies. As discussed in section A.7.0, there are non-jurisdictional facilities associated with the Project (two powerlines and an electrical substation). Cheniere has stated that all of these facilities would be within the Project area, and impacts associated with these non-jurisdictional facilities have been assessed throughout this EA and are not discussed separately for cumulative impacts.

Other projects considered for cumulative impacts are defined within 40 CFR 1508.7 as, "those projects within the geographic scope and timeframe of the Project that are not considered speculative." Projects are not considered speculative if there are existing proposals, a commitment of resources or funding, or those for which the permitting process has commenced. Present effects of past actions with the potential to cumulatively interact with the Project were considered for the cumulative analysis.

The majority of impacts from the Project would be contained within or adjacent to the boundaries of the Project construction right-of-way, ATWS, and site boundaries. For example, the use of the FERC Plan and Procedures, as well as Cheniere's Project-specific plans such as its Erosion and Sediment Control Plan, would help ensure that ground disturbance and site-stabilization activities would remain within work

[51] We note that GHGs do not have a localized geographic scope. GHG emissions from the Project would combine with projects world-wide to increase CO_2, methane, and other GHG concentrations in the atmosphere.

areas. The implementation of these plans would also limit the cumulative impacts on other resources by restoring vegetation communities once construction is complete. As described in the impact analysis in section B, the impacts for the Project are generally localized, within previously disturbed areas, and not significant. As the impacts of the Project would be localized, they would not be expected to contribute significantly to the cumulative impact in the region. As a result, we have related the scope of our analysis to the magnitude of the aforementioned environmental impacts described in the impact analysis.

Projects within the geographic scope of analysis are shown on figure B.10.2-1 and listed in table B.10.2-1, and include the following: FERC-jurisdictional projects, other industrial facilities, federal and state agency projects, non-FERC-jurisdictional pipelines, road projects, commercial developments, and residential developments. These projects were identified through an independent review of publicly available information, aerial and satellite imagery, consultations with federal agencies, and information provided by Cheniere.

Table B.10.2-1 lists the other projects considered in the cumulative impacts analysis for land-disturbing and other nearby impacts that could contribute to cumulative impacts on the following resources: groundwater, surface water, wetlands, vegetation, wildlife (aquatic and terrestrial), land use, visual resources, air quality, and noise. This table identifies the type of project, the distance from the Stage 3 Project, a short description, the construction and operation timeline, the number of workers required, and the approximate size of the action. Finally, the table identifies the relevant geographic scope for the resources listed above potentially affected by each project.

Table B.10.2-1

Other Projects Potentially Contributing to Cumulative Impacts

Project Name	Project Description	Distance of the project from the proposed Project (miles)	Estimated Land Area	Estimated Construction Date	Estimates of construction workforce	Estimates of operation workforce	Resources Assessed for Cumulative Impacts
Corpus Christi LNG Project	LNG liquefaction and export terminal	Immediately south	1,500 acres	2015 - 2019	3,300	256	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise
Cheniere Corpus Christi Pipeline LP	A 23-mile long, 48-inch diameter pipeline that is included in the Corpus Christi LNG Project	Immediately adjacent to the proposed Project's 21-mile pipeline	1,500 acres	2015 - 2018	Unknown	Unknown	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise
OxyChem Markham Ethylene Pipeline	Ethylene sendout pipeline	1.4 miles southeast	114.5-mile-long 100-foot-wide right-of-way	Dec. 2014 - Jan. 2018	Unknown	Unknown	Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Socioeconomics; Air Quality [a]
OxyChem San Patricio Pipeline	Ethane pipeline to supply ethylene plant	1.4 miles southeast	18.5-mile-long pipeline, 50-foot-wide permanent right-of-way	Dec. 2014 - Jan. 2019	Unknown	Unknown	Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Socioeconomics; Air Quality [a]

Table B.10.2-1

Other Projects Potentially Contributing to Cumulative Impacts

Project Name	Project Description	Distance of the project from the proposed Project (miles)	Estimated Land Area	Estimated Construction Date	Estimates of construction workforce	Estimates of operation workforce	Resources Assessed for Cumulative Impacts
Flint Hills Resources Corpus Christi LLC, Ingleside Marine Terminal Expansion	Special warehousing and storage of crude oil, addition of four new crude oil storage tanks, new pumps, and piping	6.4 miles southeast	Approximately 110 acres	2018 - 2019	Unknown	Unknown	Socioeconomics; Air Quality
South Texas Gateway Operating, LLC, Crude Marine Terminal	3.4 million barrels of crude oil storage capacity, two deep-water vessel docks capable of berthing Very Large Crude Carriers, and crude oil export from the planned Gray Oak pipeline from the Permian Basin	6.54 miles southeast	212 acres	2019 - 2020	Unknown	20	Socioeconomics; Air Quality [a]
ExxonMobil/SABIC Plastics Manufacturing Facility - Gulf Coast Growth Ventures Project	Construction of a 1.8-million-ton ethane steam cracker.	Adjacent to the Project pipeline	1,300 acres	2019	6,000	600	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise
Midway Farms Wind Project	Wind energy generation project	1.79 miles north	16,000 acres	2018 - 2019	Unknown	Unknown	Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Socioeconomics; Air Quality [a]
Karankawa Wind Farm	Wind energy generation project	29 miles, northwest	23,743 acres	2018	Unknown	Unknown	Socioeconomics

Table B.10.2-1

Other Projects Potentially Contributing to Cumulative Impacts

Project Name	Project Description	Distance of the project from the proposed Project (miles)	Estimated Land Area	Estimated Construction Date	Estimates of construction workforce	Estimates of operation workforce	Resources Assessed for Cumulative Impacts
Corpus Christi Ship Channel Improvement Project	Various improvements to the POCCA waterway system	Approx. 6 miles south	Unknown	2017 - 2020	Unknown	Unknown	Socioeconomics
Tennessee Gas Lone Star Project	Construction of a new bi-directional enclosed compressor station	5 miles west	72.2 acres	2018 - 2019	300	6	Socioeconomics; Air Quality
Williams Gulf Connector Expansion Project	Additional compression and other improvements to the Transco system between Louisiana and south Texas. Includes construction of a new compressor station (Station 17) in San Patricio County.	1.3 miles northwest	55.2 acres	2018 - 2019	Unknown	Unknown	Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Socioeconomics; Air Quality
TXDOT: Rehab Roadway and Widen FM 1945 (ID: 120802011)	Rehab Roadway and Widen	4 miles west	4.2 miles of roadway	2022	Unknown	Unknown	Socioeconomics
TXDOT: Construct Oak Lane Interchange SH 35 (ID:018006067)	Construct Oak Lane Interchange	6.13 miles east	0.8 miles of roadway	Unknown	Unknown	Unknown	Socioeconomics
TXDOT: Construct Auxiliary Lanes and Ramp Reversal to Exist 4-Ln Freeway (ID: 010104097)	Construct Auxiliary Lanes and Ramp Reversal to Exist 4-Ln Freeway	Crosses Project pipeline	1.7 miles of roadway	Unknown	Unknown	Unknown	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise

Table B.10.2-1

Other Projects Potentially Contributing to Cumulative Impacts

Project Name	Project Description	Distance of the project from the proposed Project (miles)	Estimated Land Area	Estimated Construction Date	Estimates of construction workforce	Estimates of operation workforce	Resources Assessed for Cumulative Impacts
TXDOT: Rehabilitate Roadway and Widen of FM 2725 (ID: 275601011)	Rehabilitate Roadway and Widen	5.87 miles east	3.5 miles of roadway	2022	Unknown	Unknown	Socioeconomics
TXDOT: New Location Roadway SH 200 (ID:354001001)	New Location Roadway SH 200	2.89 miles east	4.8 miles of roadway	Unknown	Unknown	Unknown	Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Socioeconomics
TXDOT: Construct Additional Travel Lanes on IH 37 (ID: 007405099)	Construct Additional Travel Lanes	12.25 miles southwest	13.8 miles of roadway	2024	Unknown	Unknown	Socioeconomics
TXDOT: Upgrade To 5-Lane Urban Roadway by Constructing additional 2 Lanes on FM 2986 (ID: 302601026)	Upgrade To 5-Lane Urban Roadway by Constructing additional 2 Lanes	Crosses Project pipeline	2.2 miles	Unknown	Unknown	Unknown	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise
TXDOT: Constr. Grade Separation Over Sunset Rd By Building 4-Ln Divided Main Lanes at Existing at Grade Inters at US 181 (ID:010104112)	Constr. Grade Separation Over Sunset Rd By Building 4-Ln Divided Main Lanes at Existing at Grade Inters	Crosses Project pipeline	1.8 miles	Unknown	Unknown	Unknown	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise

Table B.10.2-1

Other Projects Potentially Contributing to Cumulative Impacts

Project Name	Project Description	Distance of the project from the proposed Project (miles)	Estimated Land Area	Estimated Construction Date	Estimates of construction workforce	Estimates of operation workforce	Resources Assessed for Cumulative Impacts
TXDOT: Upgrade To 5-Lane Urban Roadway by Constructing Additional 2 Lanes on FM 893 (ID:120901030)	Upgrade To 5-Lane Urban Roadway by Constructing Additional 2 Lanes	2.47 miles southwest	1.4 miles of roadway	Unknown	Unknown	Unknown	Socioeconomics
TXDOT: Upgrade/add Direct Connectors on SH 361 (ID:018010082)	Upgrade/add Direct Connectors	Adjacent to the Stage 3 Facilities	0.6 miles of roadway	Unknown	Unknown	Unknown	Soils; Water Resources; Vegetation, Wildlife and Aquatic Resources, TES; Land Use; Visual Resources; Socioeconomics; Air Quality; Noise

TES = Threatened and Endangered Species

[a] The Project is located within the geographic scope for air quality operation impacts. However, the project would not result in operation emissions; therefore, the project would not contribute to cumulative impacts on air quality.

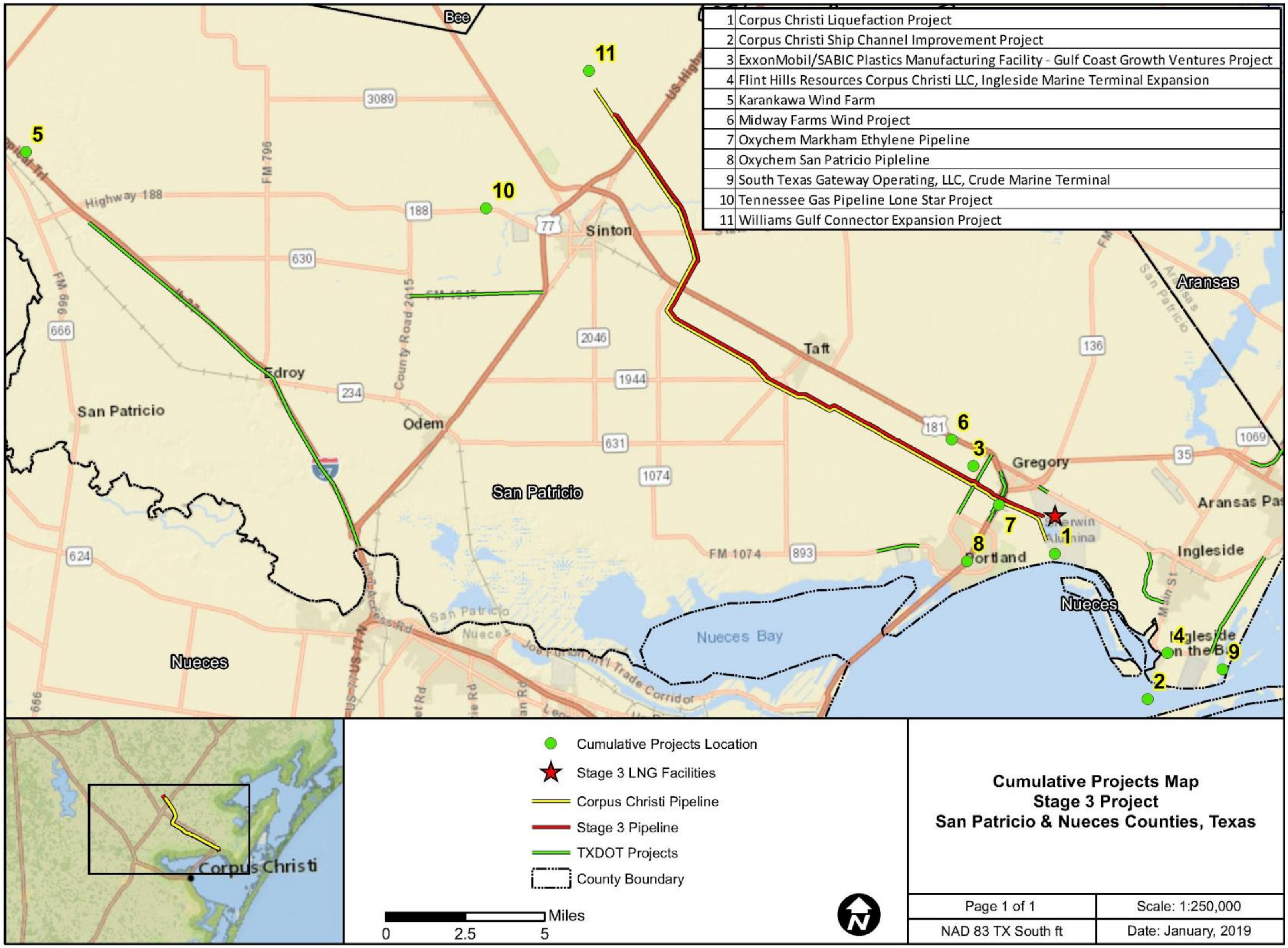

Figure B.10.2-1 Projects Considered for Cumulative Impacts Analysis

10.3 Analysis of Cumulative Impacts

10.3.1 Soils

The geographic scope for cumulative impacts on soils was considered to be the area that would be affected by and adjacent to the Stage 3 Project workspaces. Other projects within the geographic scope for soils that are included in the cumulative impacts analysis are identified in table B.10.2-1 and include the currently under construction Liquefaction Project, recently completed Corpus Christi Pipeline, one industrial facility, and four road projects.

Construction activities including clearing, grading, excavation, backfilling, and movement of construction equipment may affect soils within the Stage 3 Project area. Clearing of vegetation exposes and loosens soils making it more susceptible to wind and water erosion and establishment of invasive plant species. Movement of heavy construction equipment, grading, and spoil storage can result in compaction of soils, which can reduce porosity, increase runoff, and inhibit revegetation. Excavation and movement of soils, as well as import of soils for fill, can result in changes to the physical properties of soils and mix topsoil and subsoil, which can also inhibit revegetation. Soil impacts would typically be greatest in areas where new aboveground facilities are placed, such as the new liquefaction trains and the storage tank, and areas that would be permanently paved or graveled. Other areas temporarily used during construction may have permanent impacts on soils due to excavation. Areas temporarily impacted by construction would be restored to preconstruction conditions, as discussed in section 2.0.

Through implementation of BMPs outlined in the FERC Plan and Procedures, including topsoil segregation, reseeding, and use of erosion control devices, Cheniere would minimize the potential for soil impacts to extend beyond the Stage 3 Project area. Cumulative impacts on soils may occur when adjacent projects increase the area of soil disturbance resulting in greater potential for the adverse impacts identified above, or when projects disturb the same area in succession. In the latter circumstance, soil disturbance may be prolonged and revegetation delayed, so that soils are not sufficiently stabilized resulting in increased potential for runoff and erosion. In addition, the prolonged exposure of soils can provide additional opportunity for the establishment of invasive plant species.

The Stage 3 Pipeline would cross several of the road projects and would be constructed adjacent to the Gulf Coast Growth Ventures Project, which if constructed at the same time as the Stage 3 Pipeline, could result in cumulative impacts on soils. The Stage 3 Pipeline would also be collocated with the recently completed Corpus Christi Pipeline, and it is anticipated that restoration and stabilization of soils would be completed prior to construction of the Stage 3 Pipeline; therefore, cumulative impacts resulting from the Corpus Christi Pipeline are not anticipated. Construction of the Stage 3 LNG Facilities would be concurrent with the Corpus Christi Liquefaction Project. As the majority of the Stage 3 LNG Facilities are sited on areas currently being used for construction of the Liquefaction Project, cumulative impacts on soils would occur as the result of the continued use of these areas during the placement of permanent structures.

It is anticipated that the other projects considered for cumulative impacts on soils would implement erosion controls similar to those that would be used by Cheniere. Through the implementation of Cheniere's proposed mitigation measures, impacts on soils from the Stage 3 Pipeline would be short term, contributing to minor cumulative impacts. The Stage 3 LNG Facilities would contribute to permanent cumulative impacts on soils. However, the soils primarily consist of previously disturbed soils from decades of industrial use (bauxite storage); therefore, cumulative impacts on soils as a result of the Stage 3 LNG Facilities would be minor.

10.3.2 Water resources

Groundwater Resources

The geographic scope for cumulative impacts on groundwater resources was considered to be the HUC 12 watershed affected by the Stage 3 Project. Other projects located within the geographic scope for groundwater resources that are included in the cumulative impacts analysis are identified in table B.10.2-1.

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, the majority of potential impacts on groundwater resources associated with the Project would be short-term and localized, primarily associated with clearing, grading, excavating, filling, and placement of ground improvement columns and foundations, 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.

There is one area of contaminated groundwater that is present within the Stage 3 LNG Facilities site (see section B.3.1.1). Construction of the Project and other projects occurring within the area including the Liquefaction Project, could contribute to the further spread of groundwater contamination. However, through the implementation of our recommendation (see section B.3.1.1) impacts on groundwater resulting from the further spread of contamination would be minimized.

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 Stage 3 Project and other projects within HUC 12 watershed. However, Cheniere would implement its Plan and Procedures, as well as its SPCC Plan to minimize the risk of spills and mitigate potential impacts. Therefore, the potential impacts on groundwater as a result of contamination, if any, are anticipated to be temporary, localized, and minor. Other projects considered are anticipated to implement similar measures to prevent spills of hazardous materials from contaminating groundwater; therefore, we have determined that cumulative impacts on groundwater quality would be minor. Furthermore, the Stage 3 Project would not contribute to cumulative impacts on groundwater use because Cheniere does not propose to withdraw groundwater for the Project.

Surface Water Resources

The geographic scope for surface water resources was considered to be the HUC 12 watershed. Several of the projects listed in table B.10.2-1 could be under construction at the same time as the Stage 3 Project; therefore, there is potential for cumulative impacts on water quality within the HUC 12 watershed.

Construction of the Project would impact surface water resources as a result of stormwater runoff, hydrostatic testing water withdrawal and discharge, open-cut pipeline installation techniques, inadvertent returns of drilling mud, and increased potential for fuel spills. Other projects considered for cumulative impacts would have similar impacts on surface waterbodies if constructed concurrent with the Project. The concurrent construction of other projects involving clearing, grading, or other earthwork may also increase the potential for cumulative impacts on water quality from increased stormwater runoff. All project proponents would be required to adhere to state and federal regulations regarding hydrostatic, construction, and industrial stormwater and wastewater discharges. By Cheniere and other project proponents enforcing compliance with these regulations, and with the implementation of BMPs, including the *Project Erosion and Sedimentation Control Plan* 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 implement 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 Stage 3 Project and other Projects in the HUC 12 watershed are anticipated to be short-term and minor.

No impacts on surface water resources are anticipated as a result of operation of the Stage 3 Pipeline. However, CCL Stage III's proposed increase of 100 LNGCs annually, would result in impacts on surface water quality within the La Quinta Channel from ballast water discharge, cooling water discharge, and increased potential for fuel spills. With the exception of the Liquefaction Project, none of the other projects considered for cumulative impacts on surface water quality (see table B.10.2-1) are anticipated to result in increased vessel traffic or direct impacts on the La Quinta Channel. In addition, the Stage 3 LNG Facilities would impact surface water resources through the discharge of industrial wastewater and stormwater. As discussed above, Cheniere and other project proponents requiring the discharge of stormwater and wastewater 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 Stage 3 LNG Facilities are anticipated to be negligible.

Wetlands

The geographic scope for cumulative impacts on wetlands was determined to be the HUC 12 watershed. Wetlands provide important ecosystem functions due to their ability to retain water, minimizing flooding and improving water quality by filtering contaminants before reaching surface waterbodies. Therefore, conversion of wetlands to uplands or developed land can affect water quality, as well as flooding, within a watershed. Wetlands also provide valuable wildlife habitat.

The COE issues permits under Section 404 of the CWA for construction in jurisdictional Waters of the U.S., including wetlands, and requires mitigation or compensation to ensure there is no net loss of wetlands or wetland functions. Wetlands present within the Stage 3 LNG Facilities site are isolated and were likely formed as a result of the placement of dredge material during construction of the Liquefaction Project. As such, the COE determined that these wetlands are not considered Waters of the U.S. and are not subject to Section 404 of the CWA. Nevertheless, the majority of wetland impacts within the Stage 3 LNG Facilities would be temporary. Construction of the Stage 3 Pipeline would temporarily impact less than 0.1 acre of PEM wetlands. All projects and activities listed in table B.10.2-1 that would impact jurisdictional wetlands would be required to comply with the CWA by avoiding, minimizing, or mitigating wetland impacts. Due to the isolated and primarily temporary nature of wetland impacts associated with the Project, and the requirement of other projects considered for cumulative impacts to mitigate for wetland loss, we conclude that cumulative impacts on wetlands would be negligible.

10.3.3 Vegetation, Wildlife, and Threatened and Endangered Species

The geographic scope for cumulative impacts on vegetation, wildlife, and threatened and endangered species was considered to be the HUC 12 watershed. Other projects located within the geographic scope for vegetation that are included in the cumulative impacts analysis are identified in table B.10.2-1.

Vegetation

Vegetation plays an important role in an ecosystem, providing wildlife habitat, stabilizing soils, assisting in drainage, and providing filtration of stormwater within the watershed. Removal of vegetation can lead to loss or degradation of wildlife habitat, increased stormwater runoff, decreased water quality, increased erosion, and increased flooding. The Stage 3 LNG Facilities would result in the temporary and permanent conversion of vegetated areas to unvegetated industrial land. Impacts on vegetation as a result of the Stage 3 Pipeline would primarily be temporary with permanent impacts consisting of the conversion of some scrub shrub habitats to herbaceous habitats as a result of routine maintenance of the permanent easement. In addition, construction of two MLVs along the Stage 3 Pipeline would result in the permanent conversion of vegetated areas to industrial land. Following the completion of construction, temporary workspaces associated with the Stage 3 LNG Facilities and all workspaces associated with the Stage 3 Pipeline (with the exception of two MLVs) would be revegetated in accordance with the FERC Plan.

Similar to the Stage 3 Project, other pipeline projects considered for cumulative impacts on vegetation would result in temporary impacts on vegetation during construction and could result in the conversion of shrublands to herbaceous vegetation; however, permanent conversion of vegetation to developed land associated with these types of projects is typically limited to associated aboveground facilities. Other industrial projects, wind projects, and road expansion projects considered in table B.10.2-1 would result in the permanent conversion of vegetated areas to industrial or developed land. These projects, if constructed in the same general location and timeframe, could have a cumulative impact on local vegetation communities but would not have a significant impact on regional vegetation.

These effects would be greatest during any overlap in the construction timing of these projects. Based on a desktop review, many of the projects considered are located within developed or previously disturbed areas and appear to require minimal vegetation clearing. Vegetation near the proposed Project has been affected by ongoing industrial development and construction and maintenance of existing roads, railroads, natural gas and oil pipelines, utility lines, and electrical transmission line rights-of-way. As cumulative impacts on regional vegetation would not be significant and vegetation impacts from construction and operation of the Stage 3 Project are anticipated to be insignificant, we conclude that the Project when considered with the impacts of the other projects would not contribute to significant cumulative impacts on vegetation.

Wildlife and Aquatic Resources

Increased development and loss of habitat within the geographic scope would cause wildlife to either adapt to new conditions (in the case of generalist species) or relocate to undisturbed suitable habitat. Displacement of wildlife could result in additional stress and increased competition in available habitats. In addition, direct mortality of less mobile species may occur as a result of development activities. Concurrent construction and operation of the Project with other projects included in table B.10.2-1, would result in temporary and permanent disturbance of habitat, increased noise and lighting, and increased traffic that could disturb wildlife in the area.

Impacts on wildlife as a result of the Stage 3 Pipeline and other pipeline projects in the area are anticipated to be temporary, with wildlife returning to the area following the completion of construction. Operation of the Stage 3 LNG Facilities and other industrial facilities would result in permanent impacts on wildlife from habitat loss, increased potential for bird strikes from elevated structures such as storage tanks, flares, and wind turbines, and increased noise and lighting. The Stage 3 LNG Facilities would be constructed in an industrial area that likely provides poor quality habitat for wildlife. In addition, the overall acreage of affected habitat of projects considered for cumulative impacts on wildlife (see table B.10.2-1) is relatively small compared to the total available habitat in the geographic scope. Therefore, we conclude that cumulative impacts on wildlife are not significant and that the Project when considered with the other projects in the HUC 12 watershed would not contribute to significant cumulative impacts on wildlife resources.

Impacts on aquatic resources as a result of the Project would primarily be limited to waterbodies crossed by the Stage 3 Pipeline and the increase of 100 LNGCs calling on the LNG terminal annually. Cumulative impacts on aquatic resources as a result of the Stage 3 Pipeline would only occur if other projects considered in table B.10.2-1 would impact the waterbodies crossed by the Stage 3 Pipeline at the same time as the Stage 3 Pipeline. As the majority of waterbodies that would be crossed by the open cut method for the Stage 3 Pipeline are intermittent drainages, aquatic resources, such as fish, are likely not present. Further, these crossings would be conducted within 24 to 48 hours in accordance with the FERC Procedures, thus limiting the potential for other projects considered to overlap with the Stage 3 Pipeline. Larger, perennial waterbodies, such as Chiltipin Creek and Oliver Creek would be crossed via the HDD method. Therefore, impacts on these waterbodies would be limited to an inadvertent return and would be avoided or minimized through the implementation of measures outlined in CCPL's *Horizontal Directional Drill Procedures and Inadvertent Return Plan*. Due to the limited potential for the Stage 3 Pipeline to impact aquatic resources, potential cumulative impacts would be temporary and not significant.

The increase of 100 LNGCs annually associated with operation of the Stage 3 LNG Facilities would impact aquatic resources by increasing the potential for vessel strikes by transiting LNGCs in the Gulf of Mexico and the La Quinta Channel, impingement and entrainment of aquatic resources during cooling water intake, and alteration of water quality during ballast water and cooling water discharges. With the exception of the Liquefaction Project, none of the other projects considered for cumulative impacts are known to result in increases in vessel traffic. All LNGCs calling on the Liquefaction Terminal as a result of the Stage 3 Project and the Liquefaction Project would transit existing vessel transit routes and would implement the NMFS *Vessel Strike Avoidance Measures and Reporting for Mariners* (2008) to minimize the potential for vessel strikes. The operation of an additional 100 LNGCs within the existing marine berth at the LNG terminal would result in more frequent ballast water and cooling water discharges, and cooling water intakes. These impacts are anticipated to be limited to the marine berth (see section B.4.2.2); therefore, cumulative impacts on aquatic resources as a result of the Stage 3 LNG Facilities are anticipated to be minor.

<u>Threatened and Endangered Species</u>

The Stage 3 Project, and all projects listed in table B.10.2-1 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, the FWS and NMFS would review each project's potential impacts on federally listed species. Because the Stage 3 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 watershed, would not contribute to significant cumulative impacts on threatened, endangered, and other special status species.

10.3.4 Land Use and Visual Resources

The geographic scope for land use and visual resources includes the Project right-of-way, as well as a 0.5-mile-radius around the Project facilities.

Land Use

Projects with permanent aboveground components (e.g., buildings), wind energy projects, and roads would generally have the greatest impacts on land use. Operational impacts of a pipeline typically have less impacts on land use because the pipeline would be buried and allow for most uses of the land to resume following construction. Therefore, with the exception of aboveground facilities and the permanent right-of-way, pipeline projects typically only have temporary impacts on land use. The only new aboveground facilities associated with the Stage 3 Pipeline that would result in conversion of land use are two MLVs. Land use along the Stage 3 Pipeline primarily consists of open land and agricultural land. Following completion of construction, operation of the Stage 3 Pipeline would not result in the conversion of these land uses. Several of the projects listed in table B.10.2-1 would cross or be located adjacent to the Stage 3 Pipeline, including several road projects, a large industrial facility (Gulf Coast Growth Ventures Project) and the Corpus Christi Pipeline. Impacts on land use associated with the Corpus Christi Pipeline would be similar to those discussed for the Stage 3 Pipeline. The majority of the road projects presented in table B.10.2-1 are modifications to existing roads and would similarly not result in changes to the existing land use. Construction of the Stage 3 LNG Facilities would primarily be located on land previously disturbed for the Liquefaction Project adjacent to other industrial facilities. While the construction of other large industrial facilities, such as the Gulf Coast Growth Ventures Project would result in the conversion of open land to industrial land, this impact is minor compared to the open land available in the Project area. Therefore, we conclude that cumulative impacts on land use would be minor.

Visual Resources

Cumulative impacts on visual resources would be greatest near aboveground facilities. Clearing of tall vegetation such as trees can also result in impacts on visual resources. Because the Stage 3 Pipeline is primarily located within agricultural and open land, impacts on visual resources as a result of vegetation clearing are not anticipated. Concurrent construction of the Stage 3 Pipeline and other projects included in table B.10.2-1 would result in short-term cumulative impacts as a result of increased construction equipment; however, these impacts would be localized and minor. Permanent impacts on visual resources as a result of the Stage 3 Pipeline are not anticipated as the modifications at the Sinton Compressor Station would be located within the existing station and would not be visible from residences or publicly-accessible locations. The Stage 3 LNG Facilities and the Liquefaction Project would contribute to cumulative impacts on visual resources as a result of the LNG storage tanks and elevated flares, but these facilities are or would be located within an industrial area and are consistent with the surrounding viewshed. Therefore, we conclude that cumulative impacts on visual resources would be negligible.

10.3.5 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. While many of the projects listed in table B.10.2-1 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, such as the Gulf Coast Growth Ventures Project. For the purposes of this analysis, the review of cumulative impacts focused on projects that are anticipated to be constructed concurrently with the Stage 3 Project, when socioeconomic cumulative impacts would be greatest.

Cheniere anticipates that the Project workforce would primarily consist of local individuals. However, the concurrent construction of other large industrial projects, such as the Gulf Coast Growth Ventures Project, could limit the availability of local workers. In addition, 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. Based on the number of available rental units and motels/hotels in Project area, it is anticipated that there would be sufficient housing available, even if additional non-local workers were needed. 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. Cheniere and other large industrial projects would work directly with local law enforcement, fire departments, and emergency medical services to coordinate for effective emergency response. For the reasons listed, we conclude that cumulative impacts on public services and housing 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

The Stage 3 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 Stage 3 Project as well as the other projects, the overall cumulative impact on taxes and revenue during construction and operation of the Project is anticipated to be generally positive.

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. The Stage 3 Pipeline would have limited impacts on traffic due to the linear and transitory nature of construction activities. Construction of the Stage 3 LNG Facilities would have the greatest impact on traffic, especially during peak construction. Due to staggered project schedules and the distance of the various projects listed in table B.10.2-1 from the Stage 3 LNG Facilities, cumulative impacts on traffic are anticipated to be localized and minor.

The Project and the Liquefaction Project would contribute to cumulative impacts on marine traffic. However, as both projects have received a LOR from the Coast Guard concluding that the La Quinta Channel is suitable for the anticipated increase in vessel traffic, cumulative impacts on marine traffic would not be significant.

10.3.6 Air and Noise Quality

Air

Emissions of criteria air pollutants and HAPs (i.e., non-GHG pollutants) from sources in the vicinity of the Project would be additive. The cumulative impact area for air quality during the construction and operation phases of the Project is the area adjacent to and near the boundary of the Project site. More specifically, the geographic scope for construction air emissions was the right-of-way and a 0.25-mile radius around Project facilities for construction and a 50-kilometer radius around Project facilities for operations. All projects listed in table B.10.2-1 are considered in the cumulative impact analysis for air quality.

Although FERC considers a geographic scope for cumulative impacts assessment of criteria pollutants and HAPs of 50 kilometers around the Project site, FERC does not use such a geographic scope to evaluate GHG emissions. GHGs were identified by the EPA as pollutants in the context of climate change. GHG emissions do not directly cause local ambient air quality impacts. GHG emissions result in fundamentally global impacts that feedback to localized climate change impacts. Thus, the geographic scope for cumulative analysis of GHG emissions is global rather than local or regional. For example, a project 1 mile away emitting 1 ton of GHGs would contribute to climate change in a similar manner as a project 2,000 miles distant also emitting 1 ton of GHGs.

Construction of the Project and many of the past, present, or future projects listed in table B.10.2-1 would involve the use of construction equipment that generates air pollution; including fugitive dust. Temporary cumulative impacts on local air quality from non-GHG pollutants would result from overlapping construction schedules and geographies of other projects combined with the proposed Project, including any ongoing construction for the Liquefaction Project (scheduled for completion in 2019). Also, construction schedules for the Project pipeline and the adjacent Gulf Coast Growth Ventures Project (scheduled for completion in 2020) could overlap, resulting in temporary cumulative impacts on local air quality from non-GHG pollutants. In general, the emissions from construction activities for the Project and other projects in the region would result in short-term cumulative emissions that would be substantially localized to each project area. Operation of construction equipment for the Project would be primarily restricted to daylight hours and would be minimized through typical controls and practices, some of which are required under TCEQ rules; therefore, construction emissions are not expected to have a significant cumulative impact on local or regional air quality.

Operation of the Project, including LNG carriers and associated support vessels in the vicinity of the marine berth, would contribute cumulatively to non-GHG air pollutant levels in combination with some of the other projects identified as part of the cumulative impacts analysis. As discussed in section B.8.1, detailed air quality impact analyses were conducted by CCL Stage III to quantitatively evaluate the combined impacts from operation of the Project and other emission sources in the region (including the Liquefaction Project emission sources), plus representative pollutant background concentrations. Those combined impacts were compared against the NAAQS, which are designed to be protective of human health and welfare, including the environment. The results of the air quality impact analyses demonstrated that the Project emissions would not cause or contribute to an exceedance of the NAAQS.

Newly proposed (future) projects in the area would contribute cumulatively to air quality impacts from non-GHG pollutants through construction and operation activities. Each of these projects would need to comply with federal, state, and local air quality regulations, which may require controls to limit the emissions of certain criteria pollutants or HAPs. Although outside the scope of our analysis, it is anticipated that these project activities would result in increased permanent emissions of criteria pollutants, HAPs, and GHGs within the region. The Project's associated operating emissions would be mitigated by compliance with conditions in federal and state permits and approvals. Thus, Project operations are not anticipated to contribute to the cumulative impact of non-GHG air pollutants on local or regional air quality.

Climate Change

Climate change is the variation in climate (including temperature, precipitation, humidity, wind, and other meteorological variables) over time, whether due to natural variability, human activities, or a combination of both, and cannot be characterized by an individual event or anomalous weather pattern. For example, a severe drought or abnormally hot summer in a particular region is not a certain indication of climate change. However, a series of severe droughts or hot summers that statistically alter the trend in average precipitation or temperature over decades may indicate climate change. Recent research has begun to attribute certain extreme weather events to climate change (U.S. scientific body on climate change is the U.S. Global Change Research Program [USGCRP], 2018).

The leading U.S. scientific body on climate change is the USGCRP, composed of representatives from thirteen federal departments and agencies.[52] The Global Change Research Act of 1990 requires the USGCRP to submit a report to the President and Congress no less than every four years that "1) integrates, evaluates, and interprets the findings of the Program; 2) analyzes the effects of global change on the natural environment, agriculture, energy production and use, land and water resources, transportation, human health and welfare, human social systems, and biological diversity; and 3) analyzes current trends in global change, both human-induced and natural, and projects major trends for the subsequent 25 to 100 years." These reports describe the state of the science relating to climate change and the effects of climate change on different regions of the U.S. and on various societal and environmental sectors, such as water resources, agriculture, energy use, and human health.

In 2017 and 2018, the USGCRP issued its *Climate Science Special Report: Fourth National Climate Assessment*, Volumes I and II (Fourth Assessment Report) (USGCRP, 2017; and USGCRP, 2018, respectively). The Fourth Assessment Report states that climate change has resulted in a wide range of impacts across every region of the country. Those impacts extend beyond atmospheric climate change alone and include changes to water resources, transportation, agriculture, ecosystems, and human health. The U.S. and the world are warming; global sea level is rising and acidifying; and certain weather events are becoming more frequent and more severe. These changes are driven by accumulation of GHG in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources. These impacts have accelerated throughout the end 20th and into the 21st century (USGCRP 2018).

Climate change is a global phenomenon; however, for this analysis, we will focus on the existing and potential cumulative climate change impacts in the Project area. The USGCRP's Fourth Assessment Report notes the following observations of environmental impacts are attributed to climate change in the Southern Great Plains and South Texas regions (USGCRP, 2017; USGCRP, 2018):

- The region has experienced an increase in annual average temperature of 1°-2°F since the early 20th century, with the greatest warming during the winter months;
- 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 has increased since the early 1980s; and
- Global sea level rise over the past century averaged approximately eight inches; along the Texas coastline, 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 Project region with a high or very high level of confidence[53] (USGCRP, 2018):

[52] The USGCRP member agencies are: Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Department of Health and Human Services, Department of the Interior, Department of State, Department of Transportation, Environmental Protection Agency, National Aeronautics and Space Administration, National Science Foundation, Smithsonian Institution, and U.S. Agency for International Development.

[53] The report authors assessed current scientific understanding of climate change based on available scientific literature. Each "Key Finding" listed in the report is accompanied by a confidence statement indicating the

- Annual average temperatures in the Southern Great Plains are projected to increase by 3.6°–5.1°F by the mid-21st century and by 4.4°-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 water availability; and
- Sea level rise along the western Gulf of Mexico during the remainder of the 21st century is likely to be greater than the projected global average of 1-4 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 and operation of the Project are described in section B.8.1. Construction and operation of the Project would increase the atmospheric concentration of GHGs in combination with past and future emissions from all other sources and contribute incrementally to future climate change impacts.

Currently, there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to a project's incremental contribution to GHGs. We have looked at atmospheric modeling used by the EPA, National Aeronautics and Space Administration, the Intergovernmental Panel on Climate Change, and others and we found that these models are not reasonable for project-level analysis for a number of reasons. For example, these global models are not suited to determine the incremental impact of individual projects, due to both scale and overwhelming complexity. We also reviewed simpler models and mathematical techniques to determine global physical effects caused by GHG emissions, such as increases in global atmospheric CO_2 concentrations, atmospheric forcing, or ocean CO_2 absorption. We could not identify a reliable, less complex model for this task and we are not aware of a tool to meaningfully attribute specific increases in global CO_2 concentrations, heat forcing, or similar global impacts to project-specific GHG emissions. Similarly, it is not currently possible to determine localized or regional impacts from GHG emissions from the Project.

Absent such a method for relating GHG emissions to specific resource impacts, we are not able to assess potential GHG-related impacts attributable to this project. Additionally, we have not been able to

consistency of evidence or the consistency of model projections. A high level of confidence results from "moderate evidence (several sources, some consistency, methods vary and/or documentation limited, etc.), medium consensus." A *very* high level of confidence results from "strong evidence (established theory, multiple sources, consistent results, well documented and accepted methods, etc.), high consensus." https://science2017.globalchange.gov/chapter/front-matter-guide/

find any GHG emission reduction goals established either at the federal level[54] or by the State of Texas. Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, we are unable to determine the significance of the Project's contribution to climate change.

Noise

The geographic scope for noise was conservatively estimated to be the area within a 1-mile radius around aboveground facilities for operation. For construction, the geographic scope includes 0.25 mile from the pipeline and aboveground facilities and 0.50 mile from HDDs. The other projects encompassed by this geographic scope are presented in table B.10.2-1.

Cumulative noise impacts on residences and other NSAs are related to the distance from the disparate noise sources as well as the timing of each noise source. For instance, construction activities would not have any cumulative noise impact unless they are taking place simultaneously. There is the potential for operations noise from nearby projects to contribute to cumulative sound level impacts at NSAs, depending on the distance and direction of the projects to each other and the NSAs.

Construction

There could be cumulative construction noise impacts if construction schedules for the various projects overlap. However, due to the linear nature of roadway and pipeline construction and the typically staggered schedule, it is unlikely that construction noise impacts from the TXDOT and pipeline projects would overlap.

Construction is scheduled to be complete for the Liquefaction Project in 2019. Construction of this projects could be complete before the Project construction begins, so cumulative impacts from construction are unlikely. The construction schedule for the Gulf Coast Growth Ventures Project shows that construction of that project is likely to overlap with Project construction. Cumulative noise impacts may occur due to the combined construction activities at the Gulf Coast Growth Ventures Project site and the Stage 3 Pipeline. However, pipeline construction activities, with the exception of HDD work, are typically short-term at any given location so any cumulative construction noise impacts would be temporary.

We conclude that the construction noise impact of the projects is largely not additive with other ongoing construction and would only create a minor cumulative noise impact on the larger region.

Operations

The Liquefaction Project sound levels have been included in the noise assessment, so those cumulative impacts have been addressed in the analysis in section B.8.2 of this EA. The Stage 3 Pipeline would not have significant operational sound level impacts, except for the Sinton Compressor Station, which is located approximately 19 miles from the Stage 3 LNG Facilities equipment, and which would not have any cumulative impacts for noise due to the distance from the other projects considered in this cumulative impacts analysis.

The only project with the potential to have a cumulative operational noise impact is the Gulf Coast Growth Ventures Project. The Gulf Coast Growth Ventures Project is located adjacent to the Stage 3 Pipeline. The Gulf Coast Growth Ventures Project is currently under development, but the most recently

54 The national emissions reduction targets expressed in the EPA's Clean Power Plan and the Paris climate accord are pending repeal and withdrawal, respectively.

published rendering indicates that the Gulf Coast Growth Ventures Project area would be located about 4 miles from the Stage 3 LNG Facilities center. The closest NSAs to the Gulf Coast Growth Ventures Project are about 2.8 miles from the Stage 3 LNG Facilities center. At this distance, it is likely the Gulf Coast Growth Ventures Project and other environmental noise sources would dominate. While there would be cumulative noise impacts, especially at NSAs located directly between the Gulf Coast Growth Ventures Project and the Stage 3 LNG Facilities due to the combined effects of operational noise from both facilities, these are expected to be minor. However, without a detailed noise analysis and prediction for the Gulf Coast Growth Ventures Project, it is not possible to quantify these impacts.

The Stage 3 Pipeline would not have any noise impacts during operations of the pipeline, so while the pipeline is adjacent to the Gulf Coast Growth Ventures Project facility, it would not have any long-term noise impact on the NSAs close to the Gulf Coast Growth Ventures Project.

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. However, without a detailed noise analysis for the Gulf Coast Growth Ventures Project, it is not possible to fully quantify the potential cumulative operational noise impacts from the Gulf Coast Growth Ventures Project and the Stage 3 LNG Facilities.

SECTION C – ALTERNATIVES

In accordance with NEPA and FERC policy and EPA recommendations, we evaluated a range of alternatives to determine whether an alternative would be preferable to the proposed action. The range of alternatives evaluated include the No-Action Alternative, system alternatives, site alternatives, and route alternatives. Our criteria for determining if an alternative is "preferable" are discussed in the following section.

1.0 EVALUATION PROCESS

The purpose of this evaluation is to determine whether an alternative would be preferable to 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:

- the alternative meets the stated purpose of the project;
- is technically and economically feasible and practical; and
- offers a significant environmental advantage over a proposed action.

The alternatives were reviewed against the evaluation criteria in the sequence presented above. The first consideration for including an alternative in our analysis is whether or not it could satisfy the stated purpose of the project. An alternative that cannot achieve the purpose for the project cannot be considered as an acceptable replacement for the project.

For further consideration, an alternative has to be technically and economically feasible. Technically practical alternatives, with exceptions, would generally require the use of common construction methods. An alternative that would require the use of a new, unique, or experimental construction method may not be technically practical because the required technology is not available or is unproven. Economically practical alternatives would result in an action that generally maintains the price competitive nature of the proposed action. Generally, we do not consider the cost of an alternative as a critical factor unless the added cost to design, permit, and construct the alternative would render the project economically impractical.

Determining if an alternative provides a significant environmental advantage requires a comparison of the impacts on each resource as well as an analysis of impacts on resources that are not common to the alternatives being considered. The determination must then balance the overall impacts and all other relevant considerations. In comparing the impact between resources (factors), we also considered the degree of impact anticipated on each resource. Ultimately, an alternative that results in equal or minor advantages in terms of environmental impact would not compel us to shift the impacts from the current set of landowners to a new set of landowners.

We considered a range of alternatives in light of the Project's objectives, feasibility, and environmental consequences. Through environmental comparison and application of our professional judgment, each alternative is considered to a point where it becomes clear whether the alternative could or could not meet the three evaluation criteria. To ensure a consistent environmental comparison and to normalize the comparison factors, we generally used desktop sources of information (e.g., publicly available data, aerial imagery) and assumed the same right-of-way widths and general workspace requirements. We evaluated data collected in the field if surveys were completed for both the proposed site or route and its corresponding alternative site or route. Where appropriate, we also used site-specific information (e.g., detailed designs). Our environmental analysis and this evaluation consider quantitative data (e.g., counts, acreage, or mileage) and uses common comparative factors such as total length, amount of collocation, and land requirements.

Our evaluation also considers impacts on both the natural and human environments. The natural environment includes water resources and wetlands, vegetation, wildlife and fisheries habitat, farmland soils, and geology. The human environment includes nearby landowners, residences, land uses and recreation, utilities, and industrial and commercial development near construction workspaces. In recognition of the competing interests and the different nature of impacts resulting from an alternative that sometimes exists (i.e., impacts on the natural environment versus impacts on the human environment), we also consider other factors that are relevant to a particular alternative or discount or eliminate factors that are not relevant or may have less weight or significance. In our analysis of alternatives, we often have to weigh impacts on one kind of resource (i.e., habitat for a species) against another resource (i.e., residential construction).

It is intended that each of the cooperating agencies, as discussed in section A.4.0, will review this alternatives analysis for consistency with their own administrative procedures, and those agencies with NEPA obligations may choose to adopt this analysis as part of their decision-making process.

1.1 No-Action Alternative

Under the no-action alternative Cheniere would not construct the Project. If the Project is not constructed, then neither the adverse environmental nor beneficial potential economic impacts described in this EA would occur. Implementing the no-action alternative would not allow Cheniere to meet the purpose and need as described in section A.2.0.

It is reasonable to expect that if the Project is not constructed (the no-action alternative), export of LNG from one or more new or expanded LNG export facilities located near a natural gas production and distribution hub could eventually be constructed in response to the established demand. Thus, although the environmental impacts associated with constructing and operating the Project would not occur under the no-action alternative, equal or greater impacts could occur at other location(s) in the region as a result of another LNG export project seeking to meet the demand identified by Cheniere.

We conclude that the no-action alternative does not meet the Project objective and an alternative project to meet the market demand would likely not provide a significant environmental advantage over the proposed action. Therefore, we do not consider it further.

1.2 System Alternatives

System alternatives are alternatives to the proposed action that would make use of other existing, modified, or proposed facilities that would meet the stated purpose of the proposed actions. A system alternative would make it unnecessary to construct part or all of the proposed facilities, though additions or modifications to existing facilities may result in environmental impacts that are less than, equal to, or greater than the environmental impacts of the proposed facility.

1.2.1 Stage 3 LNG Facilities

On the Gulf Coast, there is currently one operating LNG export terminal (Sabine Pass LNG in Cameron Parish, Louisiana) and seven approved LNG export terminals (Corpus Christi LNG in San Patricio County, Texas; Freeport LNG in Brazoria County, Texas; Cameron LNG in Cameron Parish, Louisiana; Lake Charles LNG in Calcasieu Parish, Louisiana; Magnolia LNG in Calcasieu Parish, Louisiana; Golden Pass LNG in Sabine Pass, Texas, and Calcasieu Pass LNG in Cameron Parish, Louisiana). Additional LNG export terminals are at various stages of regulatory review. Each of these existing, approved, or proposed projects would need to add facilities similar to those proposed for the Stage 3 LNG Facilities. New LNG terminals or expansion of existing LNG terminals would either have similar environmental impacts (if expansion were possible within previously disturbed areas) or significantly larger impacts (if a greenfield site was required). Additional air emissions would occur regardless of which project the facilities were expanded. Because the Stage 3 Project does not have significant environmental impacts, none of these system alternatives could offer a significant environmental advantage over the proposed action. Therefore, we do not find any of the system alternatives to be preferable to the proposed action.

1.2.2 Stage 3 Pipeline

There are no existing pipelines with adequate capacity that could connect the Stage 3 Project to existing natural gas supplies in the region. The existing Corpus Christi Pipeline does not have adequate capacity to provide feed gas to both the Liquefaction Project and the Stage 3 Project. As a result, one or more pipeline companies would have to build pipelines to the Stage 3 LNG Facilities, which would result in similar or greater environmental impacts than the proposed Stage 3 Pipeline. The current proposed route would provide a single artery to connect the other pipelines in the region to the Stage 3 LNG Facilities which would minimize environmental impacts. Therefore, we do not find any pipeline system alternatives to be preferable to the proposed action.

1.3 Site Alternatives

Site Alternatives include different locations for the Stage 3 LNG Facilities that could reduce environmental impacts and still allow the Project to meet its objectives. Development of a new site would require construction of new berths and marine facilities and the associated marine impacts and additional environmental impacts on natural resources. For these reasons, we did not evaluate site alternatives further.

1.3.1 Pipeline Corridor

We evaluated route alternatives as compared to CCPL's filed proposed route to determine whether their implementation would be preferable to the proposed corresponding action. The siting of the proposed Stage 3 Pipeline was primarily influenced by the location of the proposed Stage 3 LNG Facilities, the existing Corpus Christi Pipeline, and the number of existing high-pressure natural gas pipeline systems in the South Texas region to provide available gas for the Project. The route is 99 percent collocated with the existing 48-inch-diameter natural gas pipeline corridor. The two route alternatives evaluated are depicted in figure C.1.3-1 and discussed below.

Route Alternative 1

Route Alternative 1 would begin at MP 0.0 of the proposed Stage 3 Pipeline and turn east and then north through areas within the Stage 3 LNG Facilities site that would not be permanently used for other Project components, before leaving the Stage 3 LNG Facilities site. It would then continue north, crossing SH 361 and SH 35. Once across SH 35 the alternative would turn west and northwest, and generally crossing agricultural fields along field and property lines, skirting to the north of Gregory and Taft, until joining the proposed Stage 3 Pipeline route near MP 16.0.

Alternative 1 would be about 2.4 miles longer and impact about 35 more acres than the proposed Stage 3 Pipeline route. The alternative would also create new right-of-way, whereas 99 percent of the corresponding section of the Stage 3 Pipeline would be adjacent to existing pipeline right-of-way.

Route Alternative 2

Route Alternative 2 would follow the same route as Route Alternative 1 for about 3.5 miles until crossing of SH 35. At this point Alternative 2 would continue north, and then northwest, generally crossing agricultural fields for about 10 miles until crossing SH 188. After crossing SH 188, the alternative would traverse to the west, crossing Chiltipin Creek about 4 miles northeast of the proposed crossing location, and then continuing west and north, partially along existing gathering pipeline rights-of-way, before reaching the end of the proposed Stage 3 Pipeline at the Sinton Compressor Station.

Alternative 2 would be about 3.9 miles longer and impact about 57 more acres than the proposed Stage 3 Pipeline route. The alternative would also create new right-of-way for much of its length with only about 3.7 miles (15 percent) following existing right-of-way, compared to 99 percent of the corresponding section of the proposed Stage 3 Pipeline following existing pipeline right-of-way.

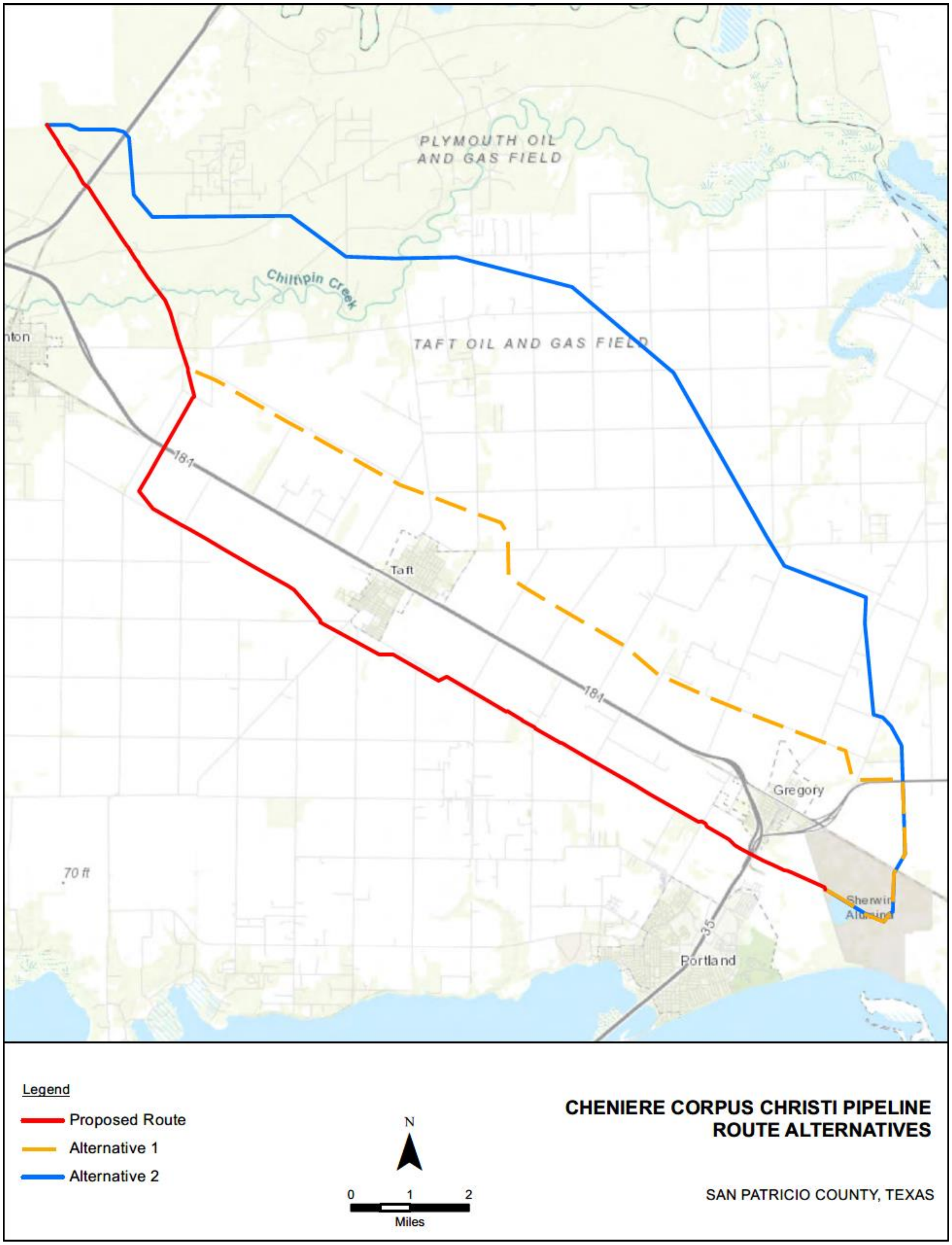

Figure C.1.3-1 Stage 3 Pipeline Route Alternatives

Our review of these routes finds that the differences in impacts between the alternatives is minor, as summarized in table C.1.3-1. However, the proposed route is the shortest of the three route options, has the smallest footprint for both construction and operation, and is collocated 99 percent of the route with the existing Corpus Christi Pipeline. Therefore, none of the alternative routes offered a significant environmental advantage, and thus are not recommended.

Table C.1.3-1

Route Alternative Comparisons

Feature	Route Alternative 1	Stage 3 Pipeline (MPs 0-16.0)	Route Alternative 2	Stage 3 Pipeline (MPs 0-20.9)
Pipeline Length (miles)	18.4	16.0	24.8	20.9
Construction impact (acres) [a]	267.6	232.7	360.7	304.0
Wetland Impacts [b]				
PEM (acres)	0	0.03	0.7	0.03
PSS (acres)	0	0	0	0.2
Waterbodies crossed [c]				
Perennial (number)	0	0	1	1
Intermittent (number)	0	0	3	2
Canal/ditch (number)	12	4	13	4
State and federal lands crossed (acres)	0	0	0	0
Cultural resource sites crossed (number) [d]	0	0	0	0
Sensitive environmental areas crossed (No)	0	0	0	0

[a] Assuming 120-foot-wide construction right-of-way.
[b] Based on NWI data.
[c] Based on National Hydrographic Dataset (NHD) data.
[d] Based on Texas Historical Commission public datasets.

1.4 Alternatives Considered

Based on the results of the alternatives analysis discussed in the preceding sections, we find that the Stage 3 Project, as currently proposed and modified by our recommended mitigation measures, is the preferred alternative that can meet the Project's objectives.

SECTION D – CONCLUSIONS AND RECOMMENDATIONS

Based on the analysis contained in this EA, we have determined that if Cheniere constructs and operates the proposed facilities in accordance with its application and supplements and our recommended mitigation measures, approval of this proposal would not constitute a major federal action significantly affecting the quality of the human environment. We recommend that the Order contain a finding of no significant impact and include the following mitigation measures listed below as conditions to any authorization the Commission may issue.

1. Cheniere shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA, unless modified by the Order. Cheniere 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 before using that modification.
2. **For the Stage 3 LNG Facilities**, 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 the Project construction and operation.
3. **For the Stage 3 Pipeline**, 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 environmental resources during construction and operation of the Project. This authority shall allow:
    a. the modification of conditions of the Order;
    b. stop-work authority; 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.
4. **Prior to any construction**, Cheniere shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, EIs, and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

5. 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**, Cheniere shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

   For the pipeline, CCPL's exercise of eminent domain authority granted under NGA section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. CCPL's right of eminent domain granted under NGA section 7(h) does not authorize it to increase the size of its natural gas pipeline to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

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

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

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

   a. implementation of cultural resources mitigation measures;

   b. implementation of endangered, threatened, or special concern species mitigation measures;

   c. recommendations by state regulatory authorities; and

   d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **Within 60 days of the acceptance of the authorization and before construction begins**, Cheniere shall file an Implementation Plan with the Secretary for review and written approval by the Director of OEP. Cheniere must file revisions to the plan as schedules change. The plan shall identify:

   a. how Cheniere 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 Cheniere 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 Cheniere will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel change), with the opportunity for OEP staff to participate in the training session(s);

f. the company personnel (if known) and specific portion of Cheniere's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) Cheniere will follow if non-compliance 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.

8. Cheniere shall employ a team of EIs, including at least one EI for the Stage 3 LNG Facilities, and at least one EI per construction spread for the Stage 3 Pipeline Facilities. The EI(s) 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 7 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.

9. Beginning with the filing of its Implementation Plan, Cheniere shall file updated status reports with the Secretary on a **biweekly** basis for the Stage 3 Pipeline Facilities and a **monthly** basis for the Stage 3 LNG Facilities 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 Cheniere's efforts to obtain the necessary federal authorizations;

b. Project schedule, including current 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 Cheniere from other federal, state, or local permitting agencies concerning instances of noncompliance, and Cheniere's response.

10. Cheniere must receive written authorization from the Director of OEP **before commencing construction of any Project facilities**. To obtain such authorization, Cheniere must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

11. CCL Stage III must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the Stage 3 LNG 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.

12. CCPL must receive written authorization from the Director of OEP **before placing the Stage 3 Pipeline Facilities into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the Stage 3 Pipeline Facilities are proceeding satisfactorily.

13. CCL Stage III must receive written authorization from the Director of OEP **before placing the Stage 3 LNG Facilities into service**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval, can be expected to operate safely as designed, and the rehabilitation and restoration of the areas affected by the Stage 3 LNG Facilities are proceeding satisfactorily.

14. **Within 30 days of placing the authorized facilities in service**, Cheniere 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 Cheniere 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.

15. **Prior to construction of the Stage 3 LNG Facilities**, CCL Stage III shall file with the Secretary, for review and written approval by the Director of the OEP, groundwater containment and disposal guidelines and practices that will be implemented during construction in areas of known groundwater contamination. CCL Stage III shall develop the groundwater containment and disposal guidelines and practices in consultation with the TCEQ, and its filing shall include documentation of its consultation with TCEQ. *(section B.3.1.1)*

16. **Prior to construction of the Stage 3 Pipeline**, CCPL shall file with the Secretary, for review and written approval by the Director of the OEP, an updated *Horizontal Directional Drill Procedures and Inadvertent Return Plan* that includes procedures for environmental testing of drilling mud prior to any placement in upland areas or other beneficial reuse, including a list of testing parameters. *(section B.3.1.2)*

17. **Prior to construction of the Stage 3 Pipeline**, CCPL shall file with the Secretary, for review and written approval by the Director of OEP, revised alignment sheets and HDD plan and profile drawings that:

    a. removes all workspace, except the minimum amount necessary to place guide wires, between the HDD entry and exit locations at milepost 1.2 and 1.6; and

    b. depicts all workspace necessary for placement and operation of equipment around each HDD entry and exit location, including that proposed to be located within an existing permanent easement. *(section B.4.1.2)*

18. **Prior to construction of the Stage 3 Pipeline,** CCPL shall consult with the TPWD and the South Texas Plant Materials Center regarding the suitability of the proposed seed mix for support of pollinator species, and file with the Secretary documentation of its consultations and a final proposed seed mix, for review and written approval by the Director of OEP. *(section B.4.1.2)*

19. Cheniere shall **not begin** construction activities **until**:

    a. the FERC staff receives comments from the FWS and the NMFS regarding the proposed action;

    b. the FERC staff completes formal ESA consultation with the FWS and NMFS, if required; and

    c. Cheniere has received written notification from the Director of OEP that construction or use of mitigation may begin. *(section B.4.4.1)*

20. Cheniere shall **not begin construction** of the Project **until**:

    a. CCPL files with the Secretary supplemental cultural resource survey reports for the Stage 3 Pipeline workspaces where surveys have not been completed, along with the Texas SHPO's comments on the reports;

    b. ACHP is afforded an opportunity to comment if historic properties would be adversely affected; and

    c. FERC staff reviews and the Director of the OEP approves all reports and plans and notifies Cheniere in writing that construction may proceed.

    All materials filed with the Commission containing **location, character, and ownership information** about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "**CUI//PRIV - DO NOT RELEASE**." *(section B.5.1)*

21. CCL Stage III shall file a full power load noise survey with the Secretary **no later than 60 days** after each liquefaction train is placed into service. If the noise attributable to operation of the equipment at the LNG terminal exceeds an L_{dn} of 55 dBA at the nearest NSA, **within 60 days** CCL Stage III shall modify operation of the Stage 3 LNG Facilities or install additional noise controls until a noise level below an L_{dn} of 55 dBA at the NSA is achieved. CCL Stage III shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section B.8.2.3)*

22. CCL Stage III shall file a noise survey with the Secretary **no later than 60 days** after placing the entire Stage 3 LNG Facilities into service. If a full-load noise survey is not possible, CCL Stage III shall provide an interim survey at the maximum possible horsepower load **within 60 days** of placing the Stage 3 LNG Facilities into service and provide the full-load noise survey **within 6 months**. If the noise attributable to operation of the equipment at the LNG terminal exceeds an L_{dn} of 55 dBA at the nearest NSA under interim or full horsepower load conditions, CCL Stage III 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 Stage III shall confirm compliance with the above requirement by filing an additional full-load noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section B.8.2.3)*

23. CCPL shall file noise surveys with the Secretary **no later than 60 days** after placing the modified Sinton Compressor Station in service. If a full load condition noise survey is not possible, CCPL shall provide an interim survey at the maximum possible horsepower load and provide the full load survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the compressor station, under interim or full horsepower load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, CCPL 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. CCPL shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section B.8.2.3)*

24. **Prior to initial site preparation,** CCL Stage III shall file with the Secretary documentation of consultation with the USDOT PHMSA on whether using normally-closed valves as a stormwater removal device on curbed areas will meet the requirements of 49 CFR 193. *(section B.9.1.6)*

25. **Prior to initial site preparation,** CCL Stage III shall file with the Secretary supplemental geotechnical investigations for Trains 5 through 7, and remaining portions of Train 4, the LNG tank area, and flare areas. The geotechnical reports shall be stamped and sealed by the professional engineer-of-record registered in Texas, and shall include a geotechnical investigation location plan with spacing of no more than 300 ft and field sampling methods and laboratory tests that are at least as comprehensive as the existing geotechnical investigations. Geotechnical test boring shall be performed to a minimum depth of 100 feet below grade, or until refusal. In addition, the geotechnical investigations and reports must demonstrate soil modifications and foundation designs will be similar to Trains 1-3 and portions of the LNG tank and flare areas already investigated. *(section B.9.1.6)*

26. **Prior to construction of final design,** CCL Stage III shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Texas:

    a. site preparation drawings and specifications;

    b. LNG storage tank and foundation design drawings and calculations;

    c. LNG terminal structures and foundation design drawings and calculations (including prefabricated and field constructed structures as well as demonstrating the cold box will take all wind loads and that no wind loads will be transmitted from the cold box to the Heavies Removal Scrub Column/Reflux Drum, 01-C-1511/01-V-1511);

    d. seismic specifications for procured equipment prior to issuing requests for quotations; and

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

    In addition, CCL Stage III shall file, in its Implementation Plan, the schedule for producing this information. *(section B.9.1.6)*

27. **Prior to initial site preparation,** CCL Stage III shall file with the Secretary the upper limit for total settlement for large flexible foundations and the maximum total edge settlement at the proposed Project area for the LNG tanks that the CMCs will be designed to satisfy. *(section B.9.1.6)*

28. **Prior to initial site preparation,** CCL Stage III shall file with the Secretary a detailed analysis that demonstrates external loads exerted by vehicular traffic and construction equipment will not exceed the maximum live load capability of buried pipelines at or adjacent to the Project. The

analysis shall be stamped and sealed by the professional engineer-of-record, registered in Texas and shall include the depth of existing buried pipelines and evidence that the maximum load shall be higher than plant construction and operation activities require. In addition, provide construction and operations procedures to demonstrate that the maximum allowable weight will never be exceeded.

Information pertaining to recommendations 29 through 124 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 recommendation. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, shall be submitted as critical energy infrastructure information pursuant to 18 CFR 388.113. See Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016). Information pertaining to items such as offsite emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements shall be subject to public disclosure. All information shall be filed a **minimum of 30 days** before approval to proceed is requested. *(section B.9.1.6)*

29. **Prior to initial site preparation,** CCL Stage III shall file an overall Project schedule, which includes the proposed stages of the commissioning plan. *(section B.9.1.6)*

30. **Prior to initial site preparation,** CCL Stage III shall file procedures for controlling access during construction. *(section B.9.1.6)*

31. **Prior to initial site preparation,** CCL Stage III shall file quality assurance and quality control procedures for construction activities. *(section B.9.1.6)*

32. **Prior to initial site preparation,** CCL Stage III shall file its design wind speed criteria for all other facilities not covered by USDOT PHMSA's LOD to be designed to withstand wind speeds commensurate with the risk and reliability associated with the facilities in accordance with ASCE 7-16 or equivalent. *(section B.9.1.6)*

33. **Prior to initial site preparation,** CCL Stage III shall develop an Emergency Response Plan (including evacuation) which integrates the CCL Stage III Facilities into the existing plan for the Liquefaction Project and coordinate procedures with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan shall include at a minimum:

    a. designated contacts with state and local emergency response agencies;
    b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;
    c. procedures for notifying residents and recreational users within areas of potential hazard;
    d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;
    e. locations of permanent sirens and other warning devices; and
    f. an "emergency coordinator" on each LNGC to activate sirens and other warning devices.

    CCL Stage III shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its Emergency Response Plan **at 3-month intervals**. *(section B.9.1.6)*

34. **Prior to initial site preparation,** CCL Stage III shall file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that shall 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. CCL Stage III 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**. *(section B.9.1.6)*

35. **Prior to construction of final design,** CCL Stage III shall file change logs that list and explain any changes made from the front end engineering design provided in CCL Stage III's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings. *(section B.9.1.6)*

36. **Prior to construction of final design,** CCL Stage III shall file information/revisions pertaining to its response to numbers 4, 13, 39, 44, 45, 46, 52, and 58 of the December 19, 2018 data request and to its response to numbers 3, 8, 9, 20, 21, 22, 23, 24, 27, 31, 34, 38, 39, 41, 47, and 64 of the January 3, 2019 data request, which indicated features to be included or considered in the final design. *(section B.9.1.6)*

37. **Prior to construction of final design,** CCL Stage III shall file lighting drawings. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall be in accordance with the proposed specification to meet API 540 and provide illumination along the perimeter of the facility and along paths/roads of access and egress to facilitate security monitoring and emergency response operations. *(section B.9.1.6)*

38. **Prior to construction of final design,** CCL Stage III shall file security camera and intrusion detection drawings. The security camera drawings shall show the location, areas covered, and features of the camera (fixed, tilt/pan/zoom, motion detection alerts, low light, mounting height, etc.) to verify camera coverage of the entire perimeter with redundancies, and cameras interior to the terminal that will enable rapid monitoring of the LNG terminal including a camera be provided at the top of the LNG storage tank, and coverage within pretreatment areas, within liquefaction areas, within truck transfer areas, and buildings. The drawings shall show or note the location of the intrusion detection to verify it covers the entire perimeter of the LNG plant. *(section B.9.1.6)*

39. **Prior to construction of final design,** CCL Stage III shall file fencing drawings. The fencing drawings shall provide details of fencing that demonstrates it will restrict and deter access around the entire facility and has a setback from exterior features (e.g., power lines, trees, etc.) and from interior features (e.g., piping, equipment, buildings, etc.) that does not allow for the fence to be overcome. *(section B.9.1.6)*

40. **Prior to construction of final design,** CCL Stage III shall file drawings and specifications for crash rated vehicle barriers at each facility entrance for access control. *(section B.9.1.6)*

41. **Prior to construction of final design,** CCL Stage III shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. *(section B.9.1.6)*

42. **Prior to construction of final design,** CCL Stage III shall file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion. *(section B.9.1.6)*

43. **Prior to construction of final design,** CCL Stage III shall file up-to-date PFDs and P&IDs. The PFDs shall include HMBs at low, design, and high ambient temperatures and demonstrate the peak liquefaction rate of 11.45 MTPA is achievable. The P&IDs shall include vendor P&IDs and 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. *(section B.9.1.6)*

44. **Prior to construction of final design,** CCL Stage III 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. *(section B.9.1.6)*

45. **Prior to construction of final design,** CCL Stage III shall file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs. *(section B.9.1.6)*

46. **Prior to construction of final design,** CCL Stage III shall file a HAZOP prior to issuing the P&IDs for construction. A copy of the review, a list of the recommendations, and actions taken on the recommendations shall be filed. *(section B.9.1.6)*

47. **Prior to construction of final design,** CCL Stage III shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions). *(section B.9.1.6)*

48. **Prior to construction of final design,** CCL Stage shall provide a means to monitor for mercury breakthrough by means of an analyzer, sample connection downstream of the mercury removal package, or preventative maintenance inspections of the heat exchangers. *(section B.9.1.6)*

49. **Prior to construction of final design,** CCL Stage III shall provide a dynamic simulation that shows that upon plant shutdown, the loop seal provided upstream of the AGRU will be sufficient to prevent backflow or provide a check valve. *(section B.9.1.6)*

50. **Prior to construction of final design,** CCL Stage III shall provide in the design of the AGRU connections to and space for a temporary or permanent amine reclamation module. *(section B.9.1.6)*

51. **Prior to construction of final design,** CCL Stage III shall include LNG storage tank fill flow measurement with high flow alarm. *(section B.9.1.6)*

52. **Prior to construction of final design,** CCL Stage III shall include BOG flow measurement from each LNG storage tank. *(section B.9.1.6)*

53. **Prior to construction of final design,** CCL Stage III shall provide process data sheets that specify the start-up, operating, and shutdown conditions for the BOG Compressors. *(section B.9.1.6)*

54. **Prior to construction of final design,** the design of HV-71031 shall be provided with administrative controls to prevent it from isolating the discretionary vent. *(section B.9.1.6)*

55. **Prior to construction of final design,** CCL Stage III shall design the hot oil return system and drum to equal pressures or provide dynamic simulation results of a catastrophic tube rupture in the hot oil system that demonstrates the hot oil return system and drum are properly protected and would not fail in the event of a tube rupture in the system. *(section B.9.1.6)*

56. **Prior to construction of final design,** CCL Stage III shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system for review and approval. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points. *(section B.9.1.6)*

57. **Prior to construction of final design,** CCL Stage III 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 Stage III Project. *(section B.9.1.6)*

58. **Prior to construction of final design,** CCL Stage III shall specify that all emergency shutdown valves will be equipped with open and closed position switches connected to the Distributed Control System/Safety Instrumented System. *(section B.9.1.6)*

59. **Prior to construction of final design,** CCL Stage III 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. *(section B.9.1.6)*

60. **Prior to construction of final design,** CCL Stage III shall file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump startup and shutdown operations. *(section B.9.1.6)*

61. **Prior to construction of final design,** CCL Stage III shall provide extruded fins for MR Interstage Condensers 01-EA-1611, 01-EA-1612, and 01-EA-1611or demonstrate the fin type will be suitable for the temperature range per API 662 and the crevice of the fin will not result in potential corrosion of the carbon steel tube where corrosion allowances on the tubes are not recommended per API 662. *(section B.9.1.6)*

62. **Prior to construction of final design,** CCL Stage III shall file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications shall include:

    a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, blast resistant buildings);

    b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, other specialized equipment);

    c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable, other electrical and instrumentation); and

    d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, firewater). *(section B.9.1.6)*

63. **Prior to construction of final design,** CCL Stage III shall file a list of all codes and standards and the final specification document number where they are referenced. *(section B.9.1.6)*

64. **Prior to construction of final design,** CCL Stage III shall include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control. *(section B.9.1.6)*

65. **Prior to construction of final design,** CCL Stage III shall file complete specifications and drawings of the proposed LNG tank design and installation. *(section B.9.1.6)*

66. **Prior to construction of final design,** CCL Stage III shall demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. *(section B.9.1.6)*

67. **Prior to construction of final design,** CCL Stage III shall provide a stress analysis that demonstrates that piping and adjacent equipment will not be overstressed if travel pins are removed with the pipe empty or flooded with LNG. *(section B.9.1.6)*

68. **Prior to construction of final design,** CCL Stage III 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. The flare load calculations shall justify the lower emissivity factors and molecular weights used for the dry and wet flares. *(section B.9.1.6)*

69. **Prior to construction of final design,** CCL Stage III shall demonstrate the flare has been sized for LNG production rates during plant cooldown when the liquefaction exchanger is operating at the rundown rate provided in Process Basis of Design, Document No. G720-15- EM-GEN-G10-0002. *(section B.9.1.6)*

70. **Prior to construction of final design,** CCL Stage III shall confirm that all overprotection devices downstream of a control valve with a bypass valve arrangement will be sized based on the full flow of a wide open control valve or bypass valve. *(section B.9.1.6)*

71. **Prior to construction of final design,** CCL Stage III shall file an evaluation of all bypass lines which includes a spec break to ensure the line downstream of the break will not be overpressurized or relocate the spec break to the downstream header. *(section B.9.1.6)*

72. **Prior to construction of final design,** CCL Stage III shall provide quantitative analysis which evaluates the reliability of the multi point ground flare pilots, including the potential common cause failures of the pilots being designed to less than 183 mph 3-second gust and having a single fuel source. The analysis shall demonstrate that the fences enclosing the ground flare will reduce the wind velocity to 125 mph or less and multiple sources of fuel gas exist. Otherwise, CCL Stage III shall provide a dispersion analysis of an unlit flare scenario and indicate what safeguards will be in place for preventing offsite impacts from that scenario. *(section B.9.1.6)*

73. **Prior to construction of final design,** CCL Stage III shall file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). The justification for the flammable and combustible gas detection and flame and heat detection shall be in accordance with ISA 84.00.07 or equivalent methodologies that will demonstrate 90% or more of releases (unignited and ignited) that could result in an off-site or cascading impact that could extend off site will 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, and different wind speeds and directions. The evaluation shall demonstrate jet fires from the pipeline compressor and feed gas tie in will be mitigated (e.g., firewall, water curtain, etc.) such that it does not impede evacuation. The justification for firewater shall provide calculations for all firewater demands (including firewater coverage on the LNG storage tank, refrigerant compressor skid, heavy hydrocarbon removal unit, liquefaction cold box, and adjacent fire zones if they could result in cascading damage) based on design densities, surface area, and throw distance and specifications for the corresponding hydrant and monitors needed to reach and cool equipment. *(section B.9.1.6)*

74. **Prior to construction of final design,** CCL Stage III shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comer that will transfer spills from the tank top to the ground-level impoundment system. The spill containment drawings shall show containment for all hazardous fluids, including all liquids handled above their flash point, from the largest flow from a single line for 10 minutes, including de-inventory, or the maximum liquid from the largest vessel (or total of impounded vessels) or otherwise demonstrate that providing spill containment will not significantly reduce the flammable vapor dispersion or radiant heat consequences of a spill. *(section B.9.1.6)*

75. **Prior to construction of final design,** CCL Stage III shall file detailed calculations to confirm that the final fire water volumes will be accounted for when evaluating the capacity of the impoundment system during a spill and fire scenario. *(section B.9.1.6)*

76. **Prior to construction of final design,** CCL Stage III shall file a critical equipment and building siting assessment to ensure plant buildings that are occupied or critical to the safety of the LNG plant are adequately protected from potential hazards involving fires and vapor cloud explosions. The evaluation shall evaluate the potential relocation of the firewater pumps and tank and buildings and their protection from flammable vapors, explosions, and fires from hazardous fluid containing equipment or provide analyses demonstrating they will be adequately protected from such events. *(section B.9.1.6)*

77. **Prior to construction of final design,** CCL Stage III shall file electrical area classification drawings. *(section B.9.1.6)*

78. **Prior to construction of final design,** CCL Stage III shall provide documentation demonstrating adequate ventilation, detection, and electrical area classification based on the final selection of the batteries, and associated hydrogen off-gassing rates. *(section B.9.1.6)*

79. **Prior to construction of final design,** CCL Stage III shall file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001). *(section B.9.1.6)*

80. **Prior to construction of final design,** CCL Stage III 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. *(section B.9.1.6)*

81. **Prior to construction of final design,** CCL Stage III 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. The list shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment. *(section B.9.1.6)*

82. **Prior to construction of final design,** CCL Stage III shall file a technical review of facility design that:

    a. identifies all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release; and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices will isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. *(section B.9.1.6)*

83. **Prior to construction of final design,** CCL Stage III shall include in its design toxic gas detection near the Mercury/H2S Absorber and flammable gas detection at each hot oil furnace, thermal oxidizer, and LNG Storage Tank. *(section B.9.1.6)*

84. **Prior to construction of final design,** CCL Stage III shall file drawings of the hazard detection in buildings, including hazard detection in the firewater pump building. *(section B.9.1.6)*

85. **Prior to construction of final design,** CCL Stage III 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, propane, ethane/ethylene, pentane, and condensate. *(section B.9.1.6)*

86. **Prior to construction of final design,** CCL Stage III 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 natural gas liquids and hydrogen sulfide. *(section B.9.1.6)*

87. **Prior to construction of final design,** CCL Stage III shall file an evaluation of the voting logic and voting degradation for hazard detectors. *(section B.9.1.6)*

88. **Prior to construction of final design,** CCL Stage III shall file a design that includes hazard detection suitable to detect high temperatures and smoldering combustion products in electrical buildings and control room buildings. *(section B.9.1.6)*

89. **Prior to construction of final design,** CCL Stage III shall file a drawing showing the location of the emergency shutdown buttons. Emergency shutdown buttons shall be easily accessible, conspicuously labeled, and located in an area which will be accessible during an emergency. *(section B.9.1.6)*

90. **Prior to construction of final design,** CCL Stage III 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 dry chemical systems in accordance with NFPA 17, and wheeled and hand-held extinguishers location travel distances are along normal paths of access and egress and in compliance with NFPA 10. The list shall include the equipment tag number, manufacturer and model, elevations, agent type, agent capacity, discharge rate, automatic and manual remote signals initiating discharge of the units, and equipment covered. *(section B.9.1.6)*

91. **Prior to construction of final design,** CCL Stage III shall file a design that includes clean agent systems in the instrumentation buildings. *(section B.9.1.6)*

92. **Prior to construction of final design,** CCL Stage III shall file drawings and specifications for the structural passive protection systems to protect equipment and supports from cryogenic releases. *(section B.9.1.6)*

93. **Prior to construction of final design,** CCL Stage III shall file calculations or test results for the structural passive protection systems to protect equipment and supports from cryogenic releases. *(section B.9.1.6)*

94. **Prior to construction of final design,** CCL Stage III shall file drawings and specifications for the structural passive protection systems to protect equipment and supports from pool and jet fires. *(section B.9.1.6)*

95. **Prior to construction of final design,** CCL Stage III shall file a detailed quantitative analysis to demonstrate that adequate mitigation will be provided for each significant component within the 4,000 Btu/ft^2-hr zone from pool or jet fires that could cause failure of the component. Trucks at the truck transfer station shall be included in the analysis. A combination of passive and active

protection shall be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation shall be supported by calculations for the thickness limiting temperature rise and effectiveness of active mitigation shall be justified with calculations demonstrating flow rates and durations of any cooling water will mitigate the heat absorbed by the vessel. *(section B.9.1.6)*

96. **Prior to construction of final design,** CCL Stage III shall file an evaluation and associated specifications and drawings of how they will prevent cascading damage of transformers (e.g., fire walls or spacing) in accordance with NFPA 850 or equivalent. *(section B.9.1.6)*

97. **Prior to construction of final design,** CCL Stage III shall file facility plan drawings showing the proposed location of the firewater. Plan drawings shall clearly show the location of firewater piping, post indicator 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 (e.g., NFPA 24 indicates max of six) can be isolated with post indicator valves. The drawings shall also provide coverage in all areas that contain flammable or combustible fluids, including the LNG storage tank, refrigerant compressor skid, heavy hydrocarbon removal unit, and liquefaction cold box, by two or more hydrants or monitors and automatic or remotely operated monitors or fixed systems in areas inaccessible or difficult to access in the event of an emergency. The coverage circles shall take into account obstructions to the firewater coverage and shall reflect the number of firewater needed to reach and cool exposed surfaces in potentially subjected to damaging radiant heats from a fire. Drawings shall also include piping and instrumentation diagrams of the firewater systems. *(section B.9.1.6)*

98. **Prior to construction of final design,** CCL Stage III shall demonstrate that API 650 provides equivalent or greater protections than NFPA 22 and AWWA D-100 in regards to the design of the firewater storage tanks. The equivalency shall address NFPA 22 and AWWA D-100 requirements for inflow piping refilling the tank within 8 hours, higher wall thicknesses, venting, manholes, anti-vortex plates, and other pertinent differences. *(section B.9.1.6)*

99. **Prior to construction of final design,** CCL Stage III shall specify that the firewater flow test meter is equipped with a transmitter and that a pressure transmitter is installed upstream of the flow transmitter. The flow transmitter and pressure transmitter shall be connected to the DCS and recorded to maintain a historical record of pump performance tests. *(section B.9.1.6)*

100. **Prior to construction of final design,** CCL Stage III shall specify that fire house and shelter are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane. *(section B.9.1.6)*

101. **Prior to construction of final design,** CCL Stage III shall file drawings of the storage tank, piping support structure, and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances. *(section B.9.1.6)*

102. **Prior to construction of final design,** CCL Stage III shall file the structural analysis of the LNG storage tank and outer containment demonstrating they are designed to withstand all loads and combinations. *(section B.9.1.6)*

103. **Prior to construction of final design,** CCL Stage III shall file an analysis of the structural integrity of the outer containment of the full containment LNG storage tanks when exposed to a roof tank top fire. *(section B.9.1.6)*

104. **Prior to construction of final design,** CCL Stage III shall file a projectile analysis to demonstrate that the outer concrete impoundment wall of a full-containment LNG storage tank could withstand projectiles from explosions and high winds. The analysis shall detail the projectile speeds and characteristics and method used to determine penetration or perforation depths. *(section B.9.1.6)*

105. **Prior to construction of final design,** CCL Stage III shall file drawings and documentation showing the location of all internal road vehicle protections, such as guard rails, barriers, and bollards to protect transfer piping, pumps, and compressors, etc. to ensure that they are located away from roadway or protected from inadvertent damage from vehicles. *(section B.9.1.6)*

106. **Prior to commissioning,** CCL Stage III 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 Stage III 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. *(section B.9.1.6)*

107. **Prior to commissioning,** CCL Stage III 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. *(section B.9.1.6)*

108. **Prior to commissioning,** CCL Stage III shall file 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. *(section B.9.1.6)*

109. **Prior to commissioning,** CCL Stage III shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. *(section B.9.1.6)*

110. **Prior to commissioning,** CCL Stage III shall file a plan to maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff has completed the required training. *(section B.9.1.6)*

111. **Prior to commissioning,** CCL Stage III 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. *(section B.9.1.6)*

112. **Prior to commissioning,** CCL Stage III shall file the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3. In addition, CCL Stage III shall file a line list with pneumatic and hydrostatic test pressures. *(section B.9.1.6)*

113. **Prior to commissioning,** CCL Stage III shall file the settlement results from hydrostatic testing of the LNG storage containers as well as a routine monitoring program to ensure settlements are as expected and do not exceed applicable criteria in API 620, API 625, API 653, and ACI 376. The program shall specify what actions will be taken after seismic events. *(section B.9.1.6)*

114. **Prior to commissioning,** CCL Stage III shall equip the LNG storage tank and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and record the relative settlement between the LNG storage tank and adjacent piping. The settlement record shall be reported in the semi-annual operational reports. *(section B.9.1.6)*

115. **Prior to introduction of hazardous fluids,** CCL Stage III 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. *(section B.9.1.6)*

116. **Prior to introduction of hazardous fluids,** CCL Stage III shall develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms. *(section B.9.1.6)*

117. **Prior to introduction of hazardous fluids,** CCL Stage III shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed. *(section B.9.1.6)*

118. **Prior to introduction of hazardous fluids,** CCL Stage III shall complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s). *(section B.9.1.6)*

119. CCL Stage III shall file a request for written authorization from the Director of OEP **prior to unloading or loading the first LNG commissioning cargo.** After production of first LNG, CCL Stage III 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**. *(section B.9.1.6)*

120. **Prior to commencement of service,** CCL Stage III shall file a request for written authorization from the Director of OEP. Such authorization will only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the 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 Stage III or other appropriate parties. *(section B.9.1.6)*

121. **Prior to commencement of service,** CCL Stage III shall notify the FERC staff of any proposed revisions to the security plan and physical security of the plant. *(section B.9.1.6)*

122. **Prior to commencement of service,** CCL Stage III shall label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001). *(section B.9.1.6)*

123. **Prior to commencement of service,** CCL Stage III shall file plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring. *(section B.9.1.6)*

124. **Prior to commencement of service,** CCL Stage III shall develop procedures for handling offsite contractors including responsibilities, restrictions, and limitations and for supervision of these contractors by CCL Stage III staff. *(section B.9.1.6)*

In addition, conditions 125 through 128 shall apply **throughout the life of the Stage 3 LNG Facilities**.

125. 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 Stage III 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. *(section B.9.1.6)*

126. **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., LNGC arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall be included in the semi-annual operational reports. Such information will provide the FERC staff with early notice of anticipated future construction/maintenance at the LNG facilities. *(section B.9.1.6)*

127. In the event the temperature of any region of the LNG storage container becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified. *(section B.9.1.6)*

128. 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 LNG 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 will 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. *(section B.9.1.6)*

SECTION E – REFERENCES

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APPENDIX A

SUMMARY OF CORRESPONDENCE BETWEEN CHENIERE AND THE TEXAS SHPO

APPENDIX A

Stage 3 Project SHPO/THC Review of Project Components

SHPO/THC Reviewer	Description of Correspondence Review, and/or Determination	Correspondence Date	Stage 3 Project Component
Mr. David Camarena, THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within areas of two temporary construction access roads for LNG Terminal.	May 21, 2015	Access roads for Stage 3 LNG Facilities
Mr. David Camarena, THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within areas of two temporary construction access roads for LNG Terminal.	May 29, 2015	Access roads for Stage 3 LNG Facilities
Mr. David Camarena, THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within new temporary access road for LNG terminal	July 29, 2015	Access road for Stage 3 LNG Facilities
Mr. David Camarena, THC Project Reviewer	Letter from THC indicating concurrence that no additional archaeological survey would be required within new temporary access road for LNG terminal	August 6, 2015	Access road for Stage 3 LNG Facilities
Mr. David Camarena, THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within the areas of seven additional work areas and a utility corridor for LNG terminal site	September 18, 2015	Portions of Stage 3 LNG Facilities work area
Mr. David Camarena, THC Project Reviewer	Letter from THC indicating concurrence that no additional archaeological survey would be required within the areas of seven additional work areas and a utility corridor for LNG terminal site	September 24, 2015	Portions of Stage 3 LNG Facilities work area
Mr. David Camarena, THC Project Reviewer	Letter to THC describing Stage 3 Pipeline and its relationship to the previously reviewed and authorized Corpus Christi Liquefaction Project pipeline.	September 18, 2015	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO
Mark Wolfe THC SHPO	Letter from THC recommending an intensive pedestrian survey of the expanded Stage 3 Pipeline area not previously surveyed.	October 19, 2015	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO
Mr. Casey Hanson THC Project Reviewer	Letter to THC to request review of report entitled Corpus Christi Liquefaction Project and Stage 3 Project Phase I Archaeological Survey pursuant to Section 106 of the NHPA	February 12, 2016	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO
Mr. Mark Wolfe THC SHPO	Letter from THC stating that review of Corpus Christi Liquefaction Project and Stage 3 Project Phase I Archaeological Survey resulted in concurrence with conclusions of no effect to historic properties by construction and operation of the project. Requested that final report address some editorial comments.	February 18, 2016	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO
Mr. Casey Hanson THC Project Reviewer	Letter to THC transmitting the revised Phase I report entitled Corpus Christi Liquefaction Project and Stage 3 Project Phase I Archaeological Survey (Revision 1). Report was revised to reflect editorial comments received from THC on February 18, 2016.	February 22, 2016	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO
Mark Wolfe THC SHPO	Letter from THC to Tetra Tech acknowledging receipt of final revised Phase I report providing project review under Section 106 of NHPA.	February 29, 2016	Stage 3 Pipeline areas not previously surveyed or reviewed by SHPO

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Stage 3 Project SHPO/THC Review of Project Components

SHPO/THC Reviewer	Description of Correspondence Review, and/or Determination	Correspondence Date	Stage 3 Project Component
Mr. David Camarena THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within one additional work area for LNG terminal.	February 3, 2016	Stage 3 LNG Facilities
Mr. David Camarena THC Project Reviewer	Letter from THC indicating concurrence that no additional archaeological survey would be required within one additional work area for LNG terminal.	February 9, 2016	Stage 3 LNG Facilities
Mr. Casey Hanson THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within one additional work area for LNG terminal (Solis property).	April 1, 2016	Stage 3 LNG Facilities work space
Mr. Mark Wolfe THC SHPO	Letter from THC indicating concurrence that no additional archaeological survey would be required within one additional work area for LNG terminal (Solis property).	April 5, 2016	Stage 3 LNG Facilities work space
Mr. Casey Hanson THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within one additional work area within LNG terminal site.	July 1, 2016	Stage 3 LNG Facilities work space
Mr. Mark Wolfe THC SHPO	Letter from THC indicating concurrence that no additional archaeological survey would be required within one additional work area within LNG terminal site.	July 6, 2016	Stage 3 LNG Facilities work space
Mr. Casey Hanson THC Project Reviewer	Letter to THC to requesting archaeological survey space and access concurrence that no additional is required within additional construction work road spur locations along Corpus Christi pipeline.	October 19, 2016	Stage 3 Pipeline
Mr. Mark Wolfe THC SHPO	THC concurred that no additional survey was required within areas of additional construction work space and access road spur locations along Corpus Christi pipeline.	October 21, 2016	Stage 3 Pipeline
Mr. Casey Hanson THC Project Reviewer	Letter report on archaeological investigation of two temporary construction yards (Gregory Yards 1 and 3) where no NRHP-eligible cultural resources were identified.	November 21, 2016	Stage 3 Pipeline, Gregory Yards 1 and 3
Mr. Mark Wolfe THC SHPO	Letter report of November 21, 2016 deemed acceptable. No additional investigation requested.	December 7, 2016	Stage 3 Pipeline, Gregory Yards 1 and 3
Mr. Casey Hanson THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within two additional work areas within the LNG terminal site.	April 7, 2017	Additional work area within Stage 3 LNG Facilities site
Mr. Mark Wolfe THC SHPO	THC concurred that no additional survey was required for two additional work areas within the LNG terminal site.	April 17, 2017	Additional work area within Stage 3 LNG facilities site
Mr. Casey Hanson THC Project Reviewer	Letter report on archaeological investigation of a temporary construction yard for LNG terminal where no NRHP-eligible cultural resources were identified.	August 18, 2017	Additional work area for Stage 3 LNG Facilities (Gillespie Yard)

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Stage 3 Project SHPO/THC Review of Project Components

SHPO/THC Reviewer	Description of Correspondence Review, and/or Determination	Correspondence Date	Stage 3 Project Component
Mr. Mark Wolfe THC SHPO	THC requested an eligibility recommendation for site 41SP196, a previously identified possible archaeological site located within the temporary construction yard described in the August 18, 2017 letter to Mr. Hanson.	September 20, 2017	Additional work area for Stage 3 LNG Facilities (Gillespie Yard)
Mr. Casey Hanson THC Project Reviewer	Revised letter report on archaeological investigation of a temporary construction yard for LNG terminal where no NRHP-eligible cultural resources were identified.	October 26, 2017	Additional work area for Stage 3 LNG Facilities (Gillespie Yard)
Mr. Mark Wolfe THC SHPO	THC concurred that no NRHP-eligible cultural resources would be affected by the Project in the area of a temporary construction yard (discussed August 18, 2017, September 20, 2017, and October 26, 2017).	November 14, 2017	Additional work area for Stage 3 LNG Facilities (Gillespie Yard)
Mr. Casey Hanson THC Project Reviewer	Letter to THC requesting concurrence that no additional archaeological survey would be required within expanded ATWS at Sinton Compressor Station.	May 29, 2018	New ATWS at Sinton Compressor Station
Mr. Mark Wolfe THC SHPO	Letter from THC indicating concurrence that no archaeological survey would be required and no historic properties affected.	June 20, 2018	New ATWS at Sinton Compressor Station

APPENDIX B

LOCATION OF NSAs FOR HDDs

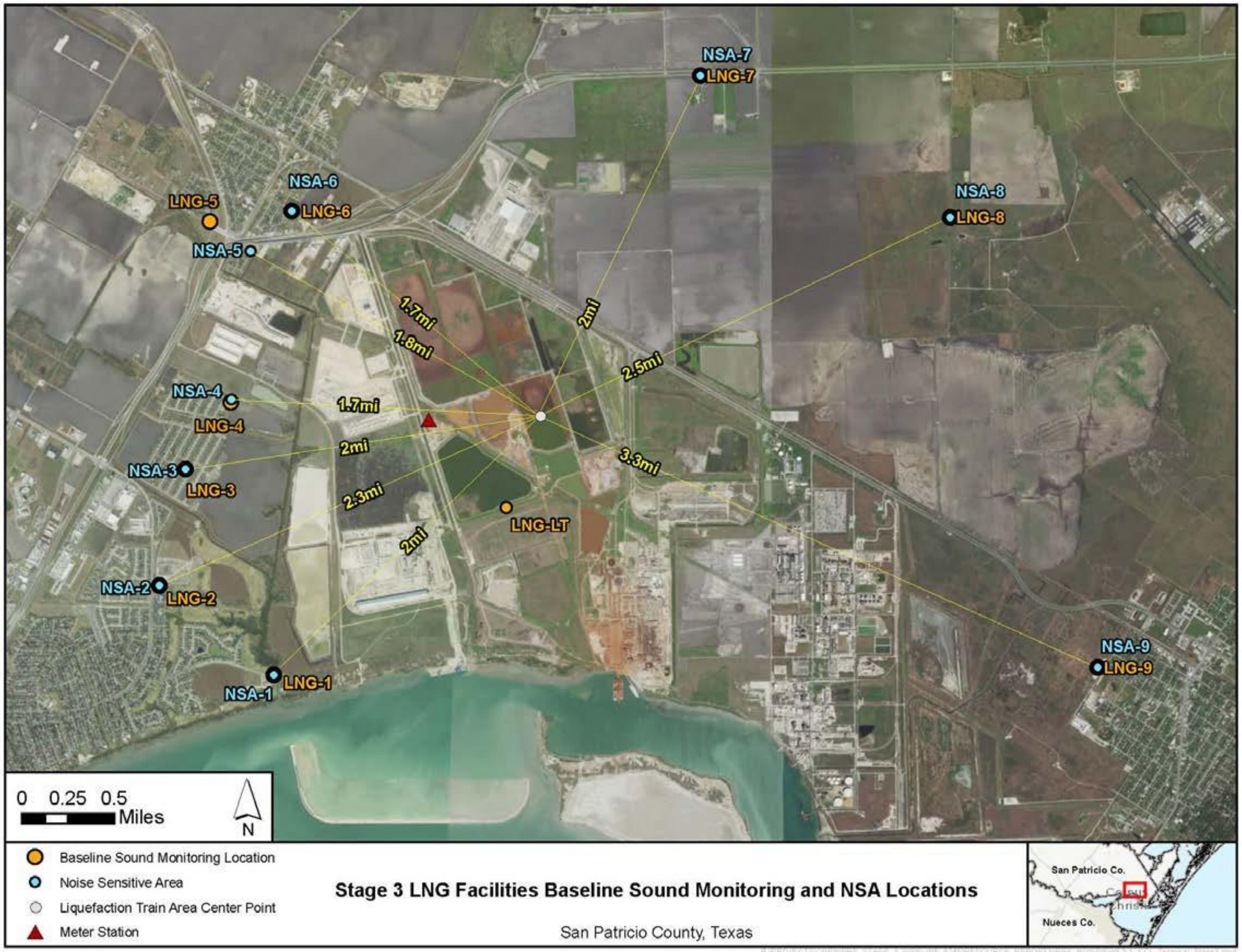

Figure 1 Stage 3 LNG Facilities Baseline Sound Monitoring and NSA Locations

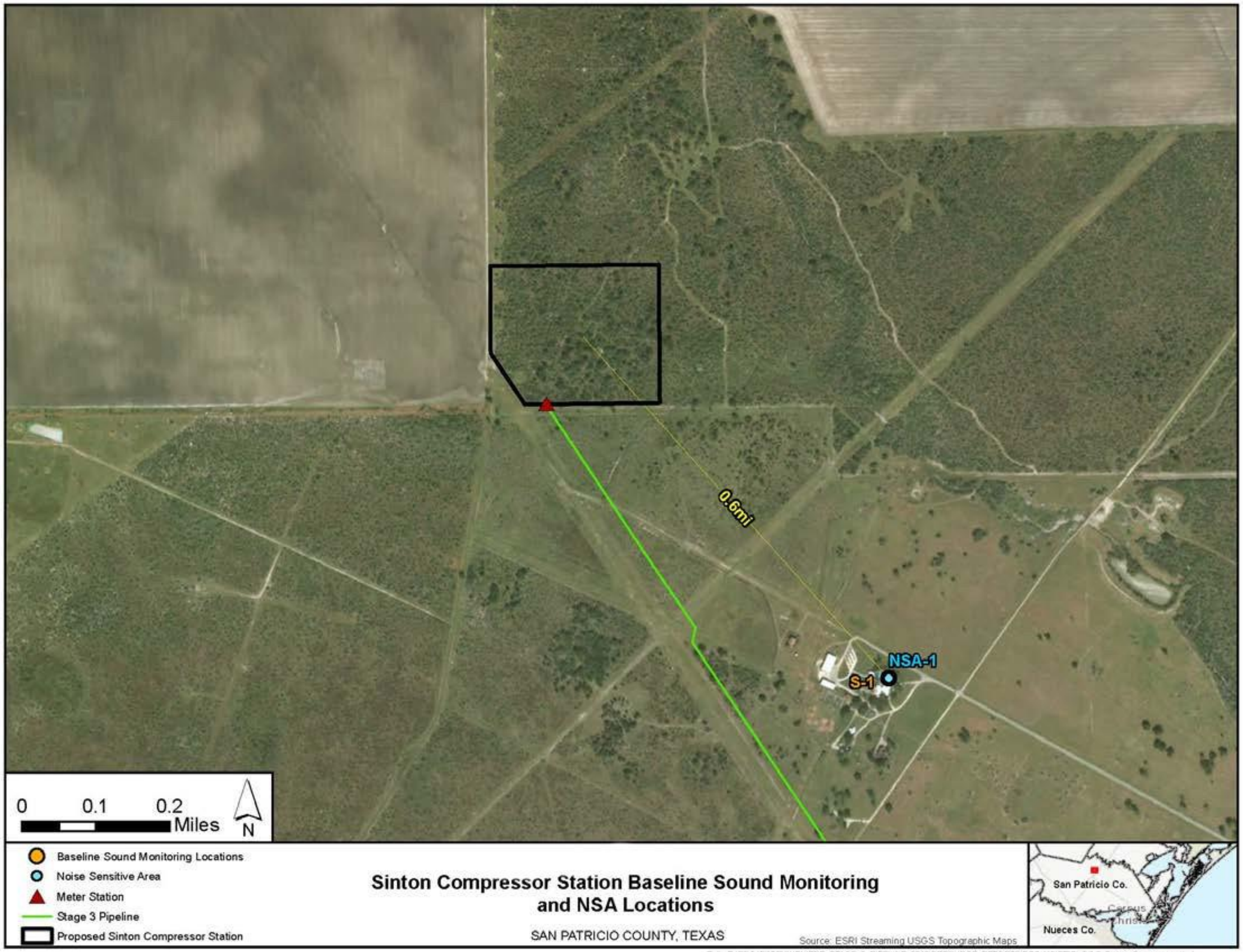

Figure 2 Sinton Compressor Station Baseline Sound Monitoring and NSA Locations

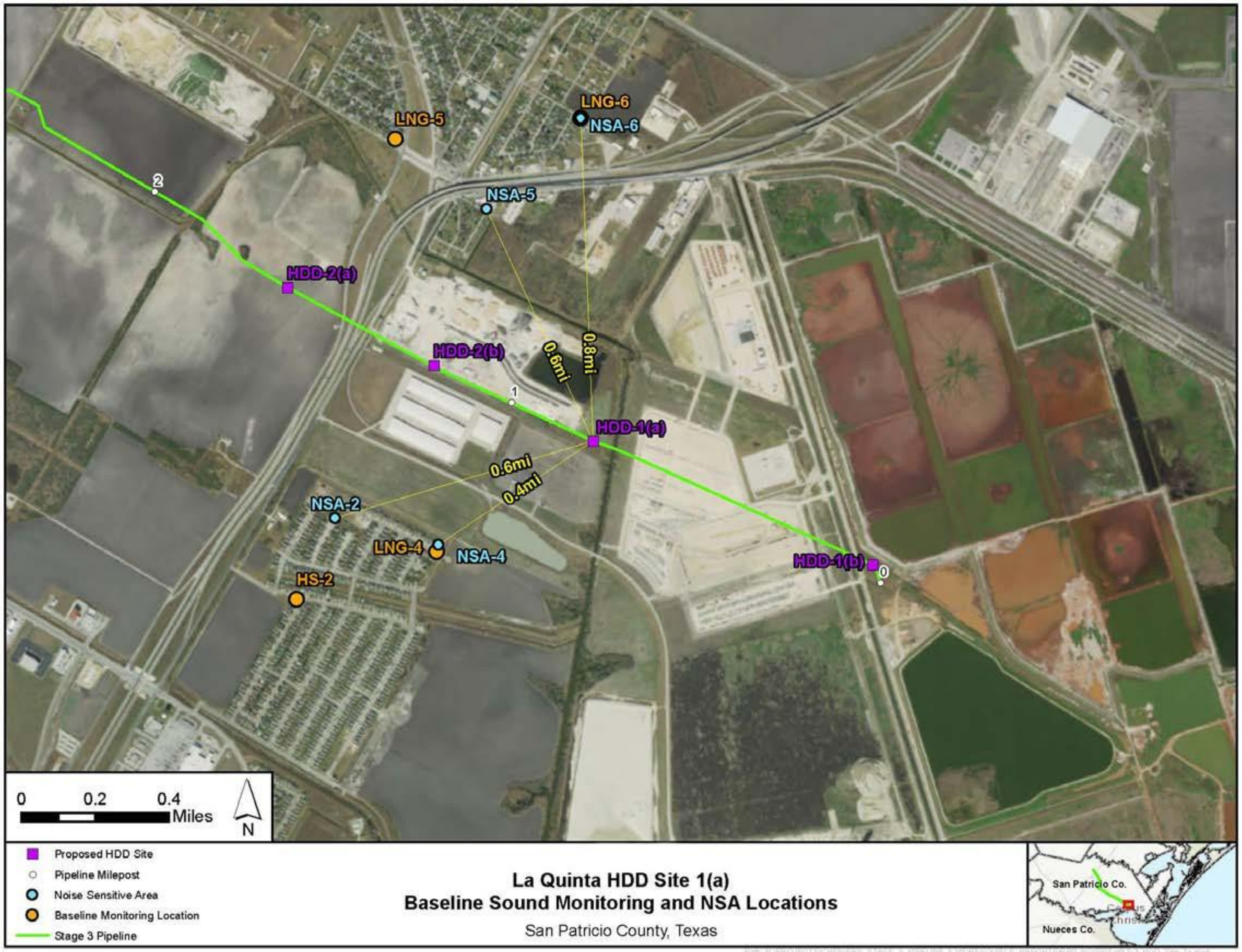

Figure 3 La Quinta HDD Site 1(a) Baseline Sound Monitoring and NSA Locations

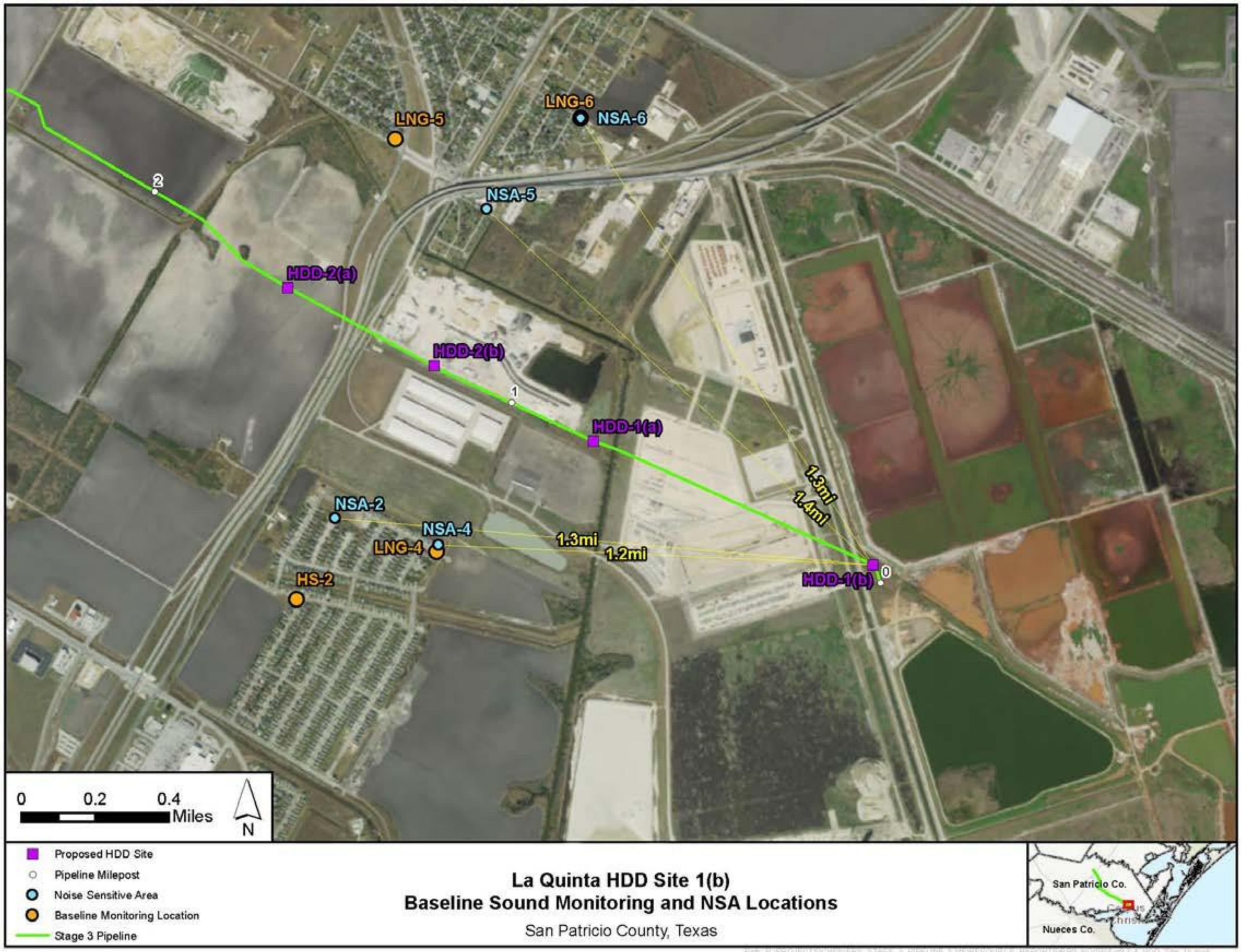

Figure 4 La Quinta HDD Site 1(b) Baseline Sound Monitoring and NSA Locations

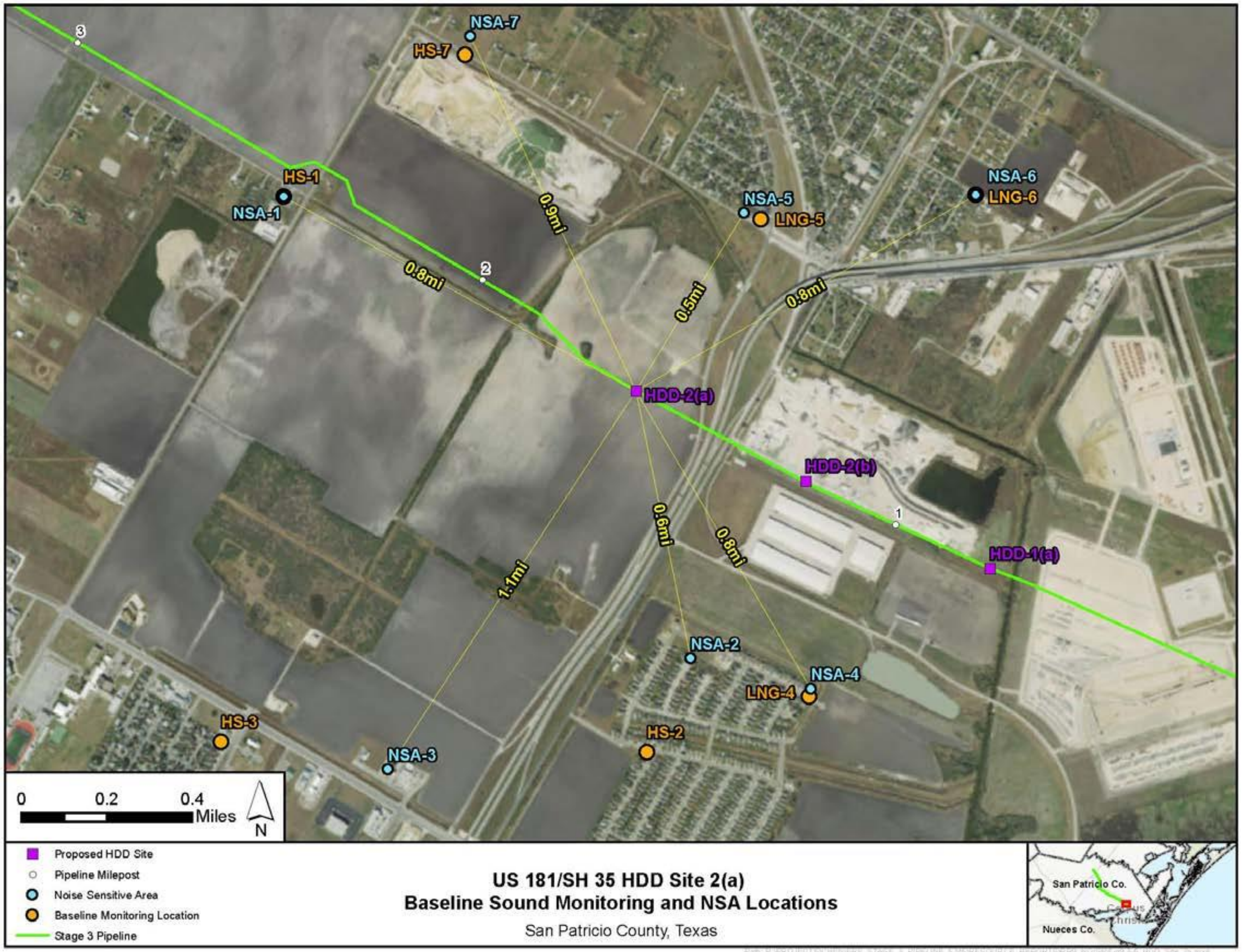

Figure 5 US 181/SH 35 HDD Site 2(a) Baseline Sound Monitoring and NSA Locations

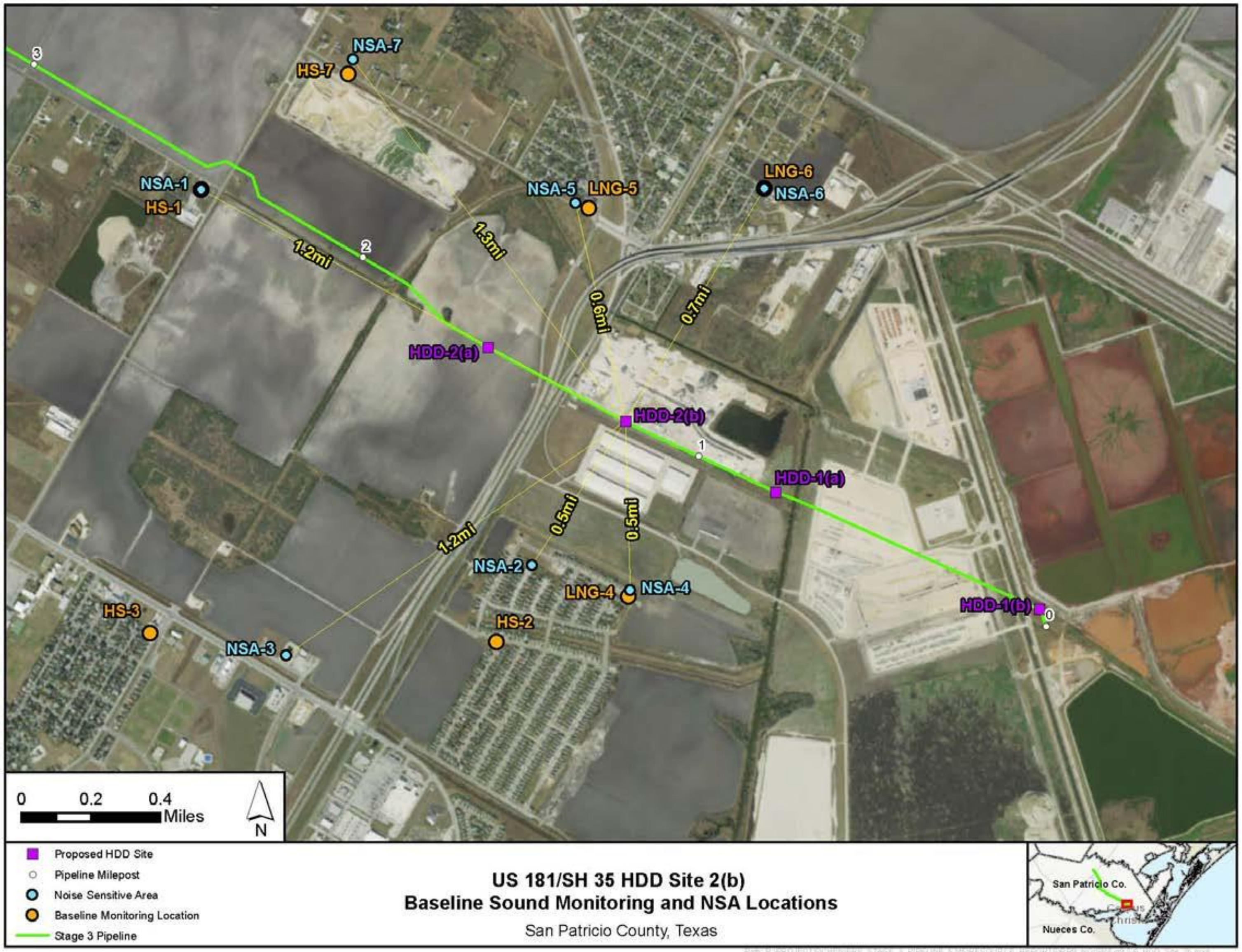

Figure 6 US 181/SH 35 HDD Site 2(b) Baseline Sound Monitoring and NSA Locations

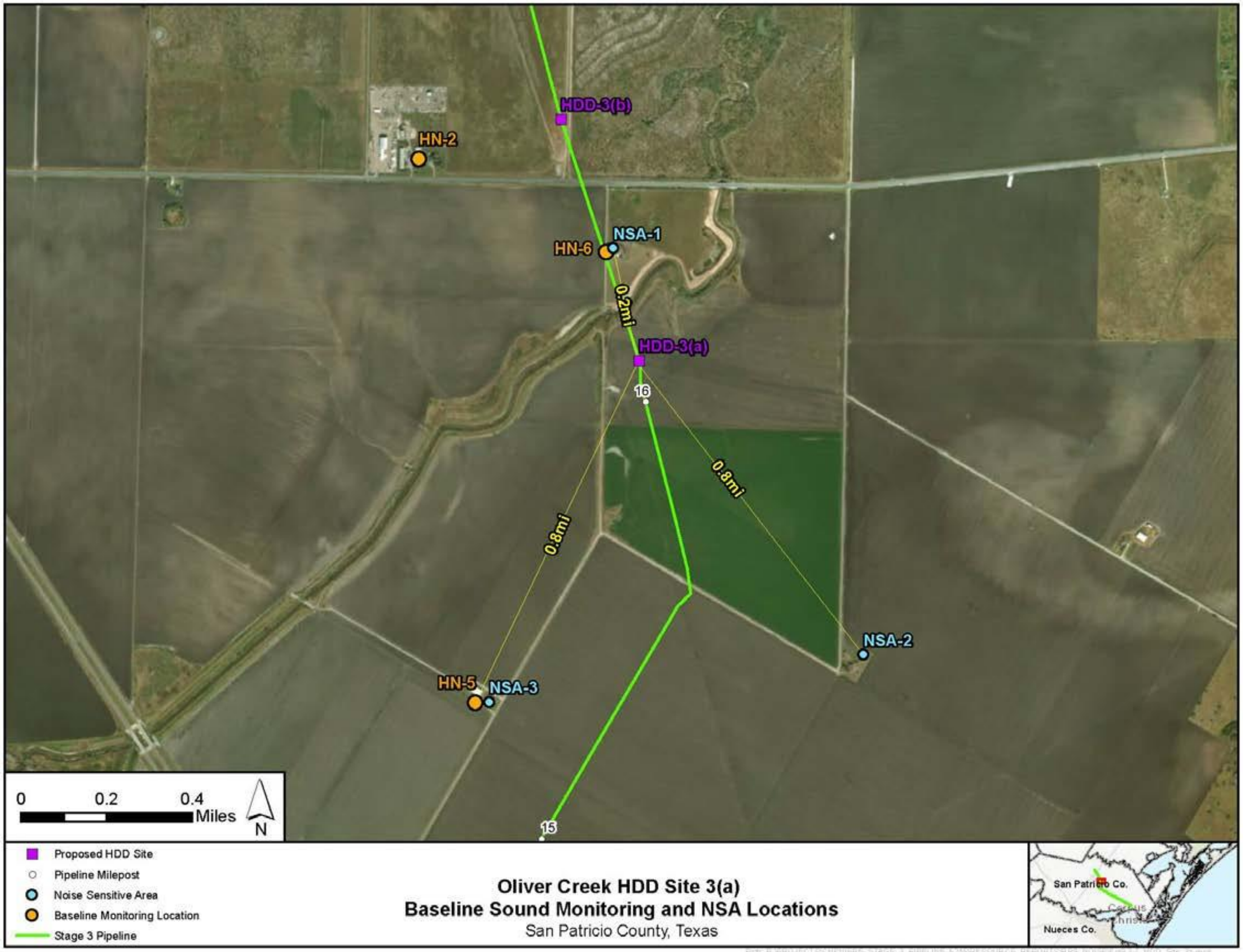

Figure 7 Oliver Creek HDD Site 3(a) Baseline Sound Monitoring and NSA Locations

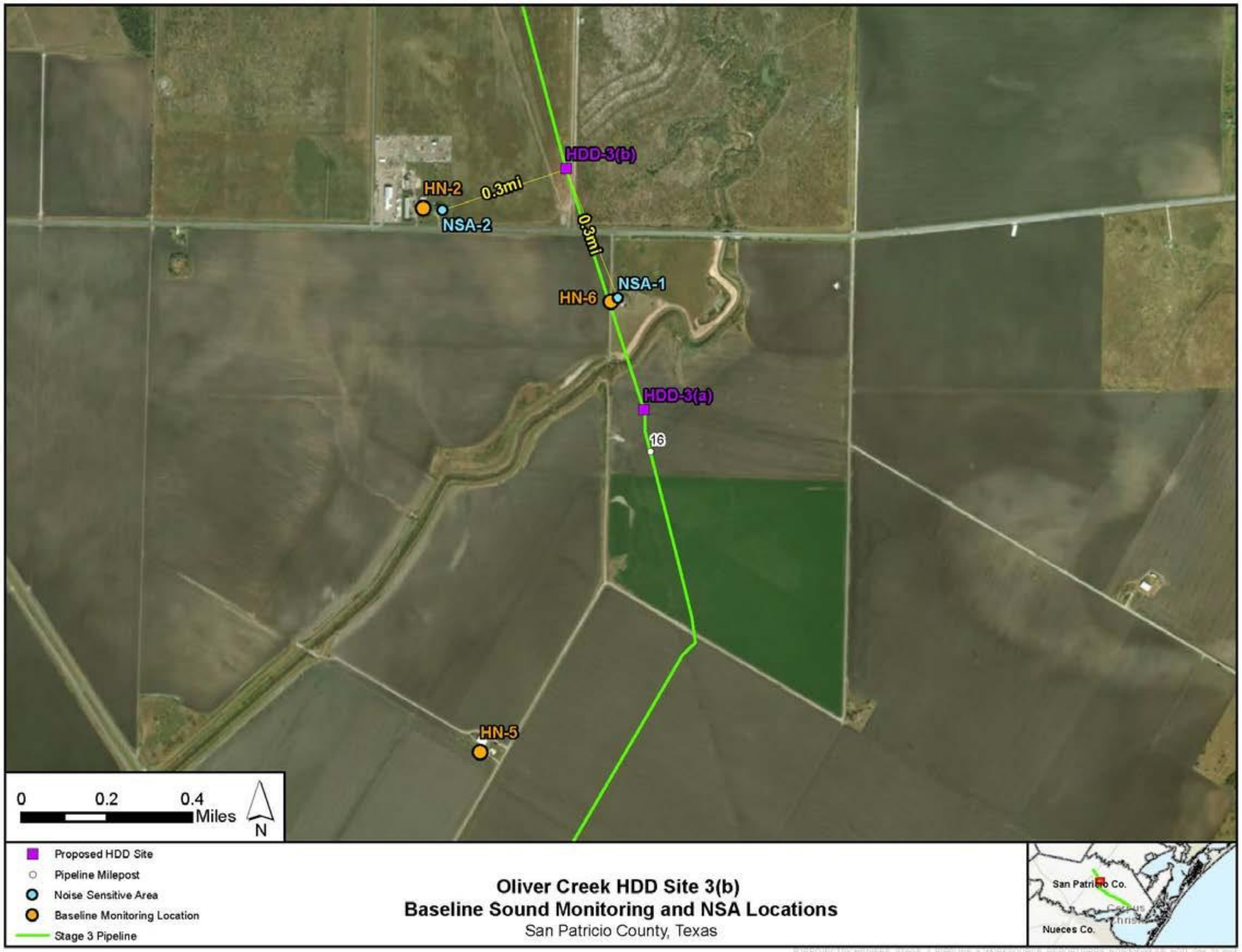

Figure 8 Oliver Creek HDD Site 3(b) Baseline Sound Monitoring and NSA Locations

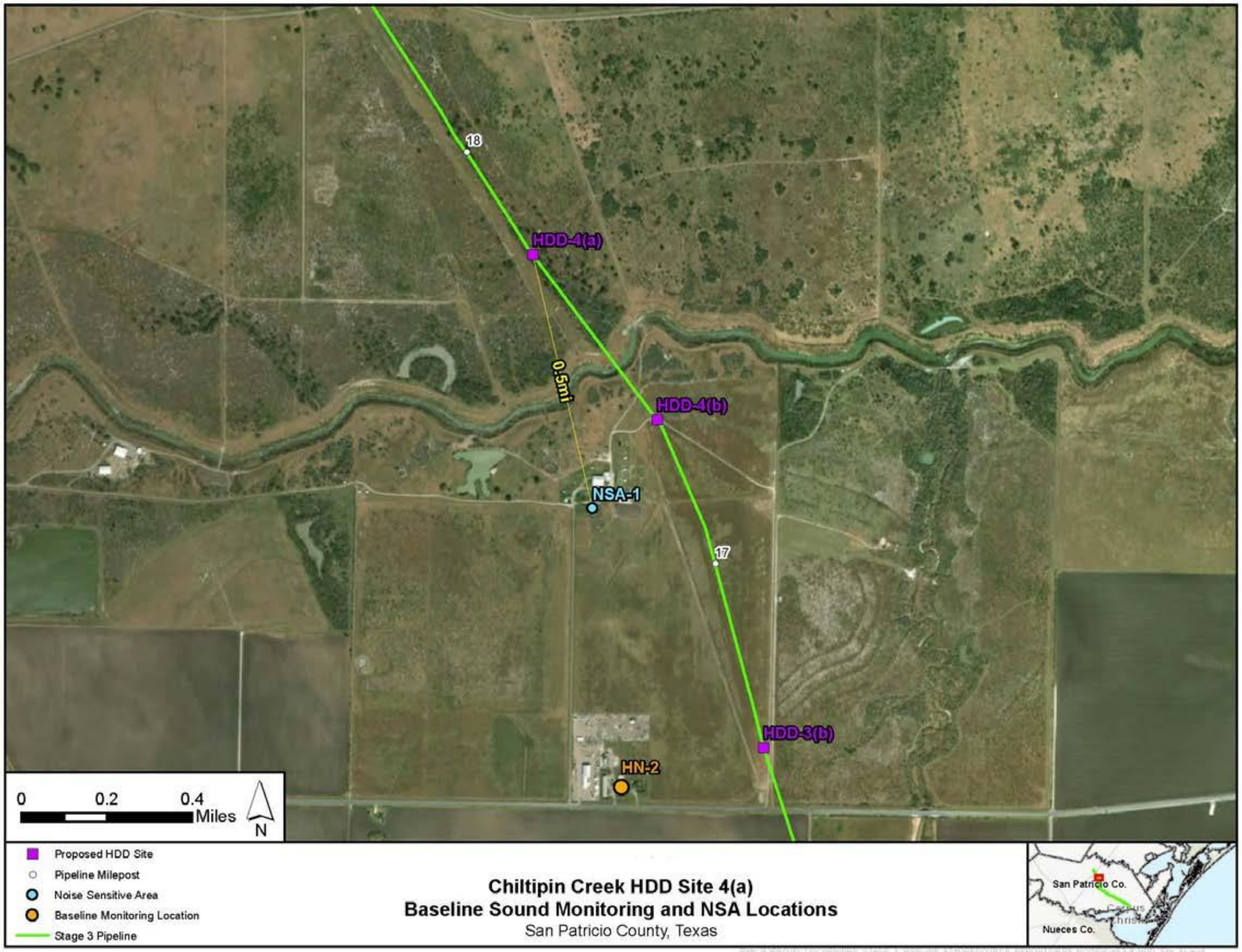

Figure 9 Chiltipin Creek HDD Site 4(a) Baseline Sound Monitoring and NSA Locations

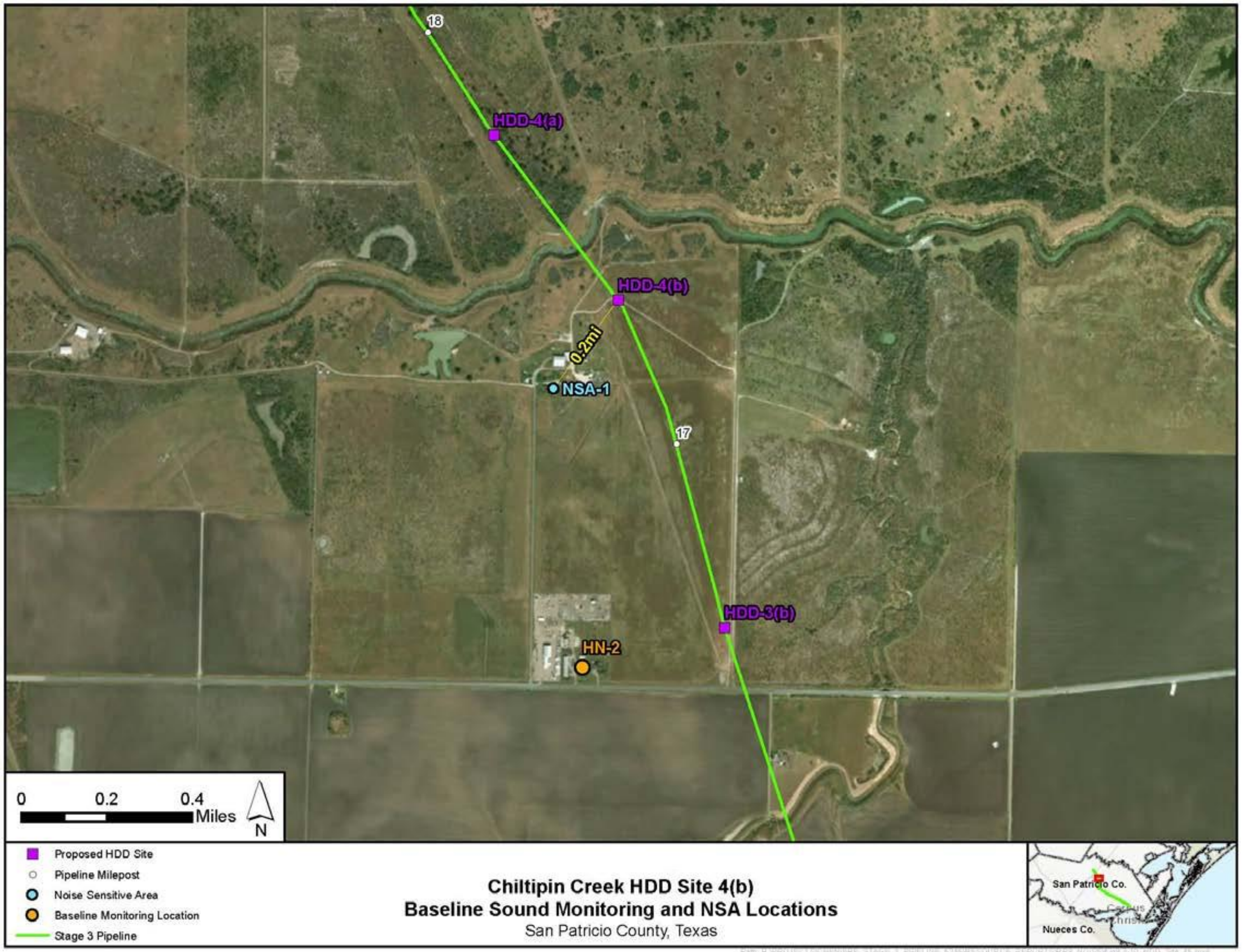

Figure 10 Chiltipin Creek HDD Site 4(b) Baseline Sound Monitoring and NSA Locations