Final Environmental Impact Statement

Corpus Christi LNG Project

Corpus Christi Liquefaction, LLC	Docket No. CP12-507-000
Cheniere Corpus Christi Pipeline, L.P.	Docket No. CP12-508-000
	DOE Docket No. FE 12-97-LNG
	FERC/EIS-0252F

Federal Energy Regulatory Commission

Office of Energy Projects
Washington, DC 20426

Cooperating Agencies:
U.S. Army Corps of Engineers
U.S. Coast Guard
U.S. Department of Transportation
U.S. Environmental Protection Agency
U.S. Department of Energy

October 2014

Docket Nos.
CP12-507-000
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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas 2
Corpus Christi Liquefaction, LLC and
Cheniere Corpus Christi Pipeline, LP
Docket Nos. CP12-507-000
CP12-508-000

TO THE PARTY ADDRESSED

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared a final environmental impact statement (EIS) for the Corpus Christi LNG Project (Project), proposed by Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP (collectively Cheniere) in the above-referenced dockets. Cheniere requests authorization to construct and operate the facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export liquefied natural gas (LNG) elsewhere. The Project liquefaction facilities would enable Cheniere to export LNG equivalent to approximately 2.1 billion standard cubic feet (Bscf) per day of natural gas, and the vaporization facilities would enable Cheniere to sendout approximately 400 million standard cubic feet (MMscf) per day of natural gas into its proposed pipeline system.

The final EIS 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 proposed Project, with the mitigation measures recommended in the EIS, would ensure that impacts in the Project area would be avoided or minimized and would not be significant. Construction and operation of the Project would result in mostly temporary and short-term environmental impacts; however, some long-term and permanent environmental impacts would occur.

The U.S. Army Corps of Engineers (COE), U.S. Coast Guard, U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), and U.S. Department of Transportation (DOT) participated as cooperating agencies in the preparation of the EIS. 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 U.S. Coast Guard, EPA, and DOT cooperated in the preparation of this EIS because of their special expertise with respect to resources potentially affected by the proposal. Although the cooperating agencies provide input to the conclusions and recommendations presented in the final EIS, the agencies will present their own conclusions and recommendations in their respective Records of Decision or determinations for the Project.

The final EIS addresses the potential environmental effects of the construction and operation of the following Project facilities:

- liquefaction facilities, including three liquefaction trains each capable of liquefying approximately 700 MMscf per day of natural gas;
- vaporization facilities, including two trains of ambient air vaporizers and send out pumps each capable of vaporizing sufficient LNG volume for each to send out approximately 200 MMscf per day of natural gas;
- LNG storage facilities, including three LNG storage tanks each capable of storing LNG equivalent to approximately 3.4 Bscf of natural gas;
- marine terminal with two LNG carrier berths;
- 23 miles of 48-inch-diameter pipeline;
- one 41,000 horsepower compressor station and one 12,260 horsepower compressor station; and
- ancillary facilities.

The FERC staff mailed copies of the final EIS 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; newspapers and libraries in the Project area; and parties to this proceeding. Everyone on our environmental mailing list will receive a CD version of the final EIS. In addition, the final EIS is available for public viewing on the FERC's website (www.ferc.gov) using the eLibrary link. A limited number of copies are available for distribution and public inspection at:

Federal Energy Regulatory Commission
Public Reference Room
888 First Street NE, Room 2A
Washington, DC 20426
(202) 502-8371

Questions?

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. Click on the eLibrary link, click on “General Search,” and enter the docket number excluding the last three digits in the Docket Number field (i.e., CP12-507 and CP12-508). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnline Support@ferc.gov or toll free at (866) 208-3676; for TTY, contact (202) 502-8659. 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 that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to http://www.ferc.gov/docs-filing/esubscription.asp.

CORPUS CHRISTI LNG PROJECT

DRAFT ENVIRONMENTAL IMPACT STATEMENT

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TECHNICAL ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
µPa	micropascal
$\mu g/Sm^3$	microgram per standard cubic meter
% vol	percent by volume
AAV	ambient air vaporizer
ACHP	Advisory Council on Historic Preservation
AEP	American Electric Power, Inc.
AEGL	Acute Exposure Guideline Level
AMSL	above mean sea level
APE	area of potential effect
API	American Petroleum Institute
AQCR	Air Quality Control Region
ARMP	Aquatic Resources Mitigation Plan
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ATWS	additional temporary workspace
BA	biological assessment
BACT	Best Available Control Technology
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BIA	Bureau of Indian Affairs
BLEVE	boiling-liquid-expanding-vapor explosion
BMP	best management practice
BOG	boil-off gas
BTEX	benzene, toluene, ethylbenzene, and xylene
BTU/ft^2-hr	British thermal units per square foot per hour
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CAMx	Comprehensive Air Quality Model with Extensions
Cameron LNG	Cameron LNG, LLC
CCMSA	Corpus Christi Metropolitan Statistical Area
CCS	carbon capture and storage

CE FLNG	CE FLNG, LLC
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CH_4	methane
Cheniere	Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P.
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
Coast Guard	U.S. Coast Guard
Commission	Federal Energy Regulatory Commission
COE	U.S. Army Corps of Engineers
COTP	Captain of the Port
Crosstex	Crosstex Corpus Christi Natural Gas Transmission
CWA	Clean Water Act
CZMA	Coastal Zone Management Act of 1972
CZMP	Coastal Zone Management Program
dB	decibel
dBA	A-weighted decibel
DCS	Distributed Control System
DMPA	dredge material placement area
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
DRI	direct iron reduced
DRS	Dispute Resolution Service
E1AB	estuarine submerged aquatic bed
E2EM	estuarine intertidal emergent
E2SS	estuarine intertidal scrub/shrub
E2US	estuarine unconsolidated shore
EEZ	Exclusive Economic Zone
EFH	essential fish habitat
EI	Environmental Inspector

EIS	Environmental Impact Statement
ELS	Excelerate Liquefaction Solutions, LLC
EOS	Eos LNG, LLC
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ERDC	Engineering Research and Development Center
ERL	Effects Range Low
ERP	Emergency Response Plan
ERPG	Emergency Response Planning Guideline
ESA	Endangered Species Act of 1973
ESD	Emergency Shutdown
FAA	Federal Aviation Administration
FDCP	Fugitive Dust Control Plan
FE	Fossil Energy
FEED	Front End Engineering Design
FEMA	Federal Emergency Management Administration
FERC	Federal Energy Regulatory Commission
FHR	Flint Hills Resources Corpus Christi, LLC
FIP	Federal Implementation Plan
FLEX	Freeport LNG Expansion, LP and FLNG Liquefaction, LLC
FLNG	floating liquefied natural gas
FLSO	Floating Liquefaction Storage Offloading
FR	Federal Register
Freeport LNG	Freeport LNG Development, LP
ft^3	cubic feet
FWS	U.S. Fish and Wildlife Service
g	gravity
Gasfin	Gasfin Development USA, LLC
GCRA	Global Change Research Act of 1990
GHG	greenhouse gas
GIWW	Gulf Intracoastal Waterway
Golden Pass	Golden Pass Products, LLC
gpm	gallons per minute

Gulf LNG	Gulf LNG Energy, LLC
Gulf Coast LNG	Gulf Coast LNG Export, LLC
Gulf South	Gulf South Pipeline Company, L.P.
GWP	Global warming potential
H_2S	hydrogen sulfide
HAP	hazardous air pollutants
HAZOP	hazard and operability review
HB	House Bill
HCA	high consequence areas
HDD	horizontal directional drill
hp	horsepower
HRC	Heavies Removal Column
IEA	International Energy Agency
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
ISA	International Society for Automation
ISD	Independent School District
kPa	Kilopascal
kW/m^2	kilowatt per square meter
lb/hr	pound per hour
lb/MWh	pounds per megawatt-hour
lb/y	pounds per year
L_d	day-time sound level
L_{dn}	day-night average sound level
L_{eq}	equivalent sound level
LFL	lower flammable limit
LNG	liquefied natural gas
LOR	Letter of Recommendation
LPG	liquid petroleum gas
M&R	meter and regulator
m^3	cubic meters
MACT	Maximum Achievable Control Technology
MAOP	maximum allowable operating pressure

mcy	million cubic yards
Memorandum	Memorandum of Understanding on Natural Gas Transportation Facilities
mg/L	milligrams per liter
MLV	mainline valves
MMBtu	million British thermal units
MMscf	million standard cubic feet
MP	milepost
MRR	Mandatory Greenhouse Gas Reporting Rule
MSA	Magnuson-Stevens Fishery Conservation and Management Act of 1976
mtpa	million tons per annum
mtpy	million tons per year
MTSA	Maritime Transportation Security Act of 2002
MW	megawatt
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAISA	National Aquatic Invasive Species Act of 2003
NANPCA	Nonindigenous Aquatic Nuisance Prevention and Control Act of 1990
NAVD 88	North American Vertical Datum of 1988
NEPA	National Environmental Policy Act of 1969
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFIA	National Flood Insurance Act of 1968
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NGL	natural gas liquids
NGPL	Natural Gas Pipeline Company, LLC
NGVD29	National Geodetic Vertical Datum of 1929
NHPA	National Historic Preservation Act of 1966
nm	nautical mile
NMFS	National Oceanic and Atmospheric Administration National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NOAA Fisheries	National Oceanic and Atmospheric Administration National Marine Fisheries Service Office of Sustainable Fisheries

NOI	Notice of Intent
NOx	Nitrogen oxides
NO_2	Nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resource Conservation Service
NRHP	National Register of Historic Places
NSA	noise sensitive areas
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	Ozone
OEP	Office of Energy Projects
Offshore Wind	Offshore Wind Power Systems of Texas, LLC
OSBL	outside battery limit
OSHA	Occupational Safety and Health Administration
OxyChem	Occidental Chemical Corporation
P&IDs	Piping and Instrument Diagrams
PCL	protective concentration level
PEM	palustrine emergent
PFD	process flow diagram
PHMSA	Pipeline and Hazardous Materials Safety Administration
Pipeline	new bi-directional natural gas pipeline
Plan	Upland Erosion Control, Revegetation, and Maintenance Plan
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
POCCA	Port of Corpus Christi Authority
ppb	part per billion
ppm	part per million
ppm-v	parts per million by volume
Procedure	Wetland and Waterbody Construction and Mitigation Procedures
Project	Corpus Christi LNG Project

PSD	prevention of significant deterioration
psf	pounds per square foot
psi	pounds per square inch
psig	pounds per square inch gauge
PSM	Process Safety Management of Highly Hazardous Chemicals, Explosives and Blasting Agents
PTE	potential to emit
RACT	Reasonably Available Control Technology
RHA	Rivers and Harbors Act
Royal	Royal Production Company
RRC	Railroad Commission of Texas
RPT	rapid phase transition
RSZ	reduced speed zone
RV	recreational vehicle
Sabine Pass LNG	Sabine Pass LNG, LP
SAV	Submerged Aquatic Vegetation
SEP	surface emissive power
SH	State Highway
SHPO	Texas State Historic Preservation Office
SILs	Significant impact levels
SIP	State Implementation Plan
SIS	Safety Implemented System
SO_2	sulfur dioxide
SPCC	Spill Prevention, Control, and Countermeasure
SWPPP	Stormwater Pollution Prevention Plan
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
Tejas	Kinder Morgan Tejas Pipeline LLC
Tennessee Gas	Tennessee Gas Pipeline Company, LLC
Terminal	LNG export and import facility
Texas Eastern	Texas Eastern Transmission, LP
TGLO	Texas General Land Office
THC	Texas Historical Commission

TPCO	Tianjin Pipe Corporation
TPWD	Texas Parks and Wildlife Department
tpy	tons per year
Transco	Transcontinental Gas Pipe Line Company, LLC
Trunkline LNG	Trunkline LNG Company, LLC
TxDOT	Texas Department of Transportation
UFL	upper flammable limit
US	United States Highway
USC	United States Code
USDA	U.S. Department of Agriculture
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
VOC	volatile organic compounds
Waller	Waller Point LNG
WSA	Waterway Suitability Assessment

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The staff of the Federal Energy Regulatory Commission (FERC or Commission) prepared this Environmental Impact Statement (EIS) to assess the environmental issues associated with the construction of facilities proposed by Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP, which are collectively referred to as Cheniere. The EIS was prepared in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA) and its implementing regulations under Title 18 of the Code of Federal Regulations, Part 380 (18 CFR 380). On August 31, 2012, Cheniere filed an application with the FERC in Docket Numbers CP12-507-000 and CP12-508-000 pursuant to Section 3(a) and Section 7 of the Natural Gas Act (NGA) and Parts 153, 157, and 284 of the Commission's regulations. This project is referred to as the Corpus Christi LNG Project (Project) and consists of both a liquefied natural gas (LNG) terminal and natural gas pipeline facilities.

The purpose of this EIS is to inform the FERC decision-makers, the public, and the permitting agencies about the potential adverse and beneficial environmental impacts of the proposed Project and its alternatives, and recommend mitigation measures that would reduce adverse impacts to the extent practicable. We[1] prepared our analysis based on information provided by Cheniere and further developed from data requests, field investigations, scoping, literature research, and contacts with or comments from federal, state, and local agencies, Native American tribes, and individual members of the public.

The FERC is the federal agency responsible for authorizing interstate natural gas transmission facilities under the NGA, and is the lead federal agency for the preparation of this EIS in compliance with the requirements of NEPA. The U.S. Army Corps of Engineers (COE), U.S. Coast Guard (Coast Guard), U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), and U.S. Department of Transportation (DOT) are cooperating agencies for the development of this EIS consistent with 40 CFR 1501.6(b). A cooperating agency has jurisdiction by law or has special expertise with respect to environmental resource issues associated with the Project.

PROPOSED ACTION

According to Cheniere, the Project would provide facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export LNG elsewhere.

Terminal

Cheniere would construct the LNG import and export terminal (Terminal) on a 991-acre site located along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio and Nueces Counties, Texas. The Terminal would include the following key facilities:

- liquefaction facilities, including three liquefaction trains, each capable of liquefying approximately 700 million standard cubic feet (MMscf) per day of natural gas;

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

- vaporization facilities, including two trains of ambient air vaporizers (AAV) and send out pumps, each capable of vaporizing sufficient LNG volume to send out approximately 200 MMscf per day of natural gas;
- LNG storage facilities, including three LNG storage tanks each capable of storing 160,000 cubic meters of LNG equivalent to approximately 3.4 billion standard cubic feet (Bscf) of natural gas; and
- marine terminal facilities with two LNG carrier berths.

Pipeline

Cheniere proposes to construct and operate about 23 miles of 48-inch-diameter natural gas pipeline (Pipeline) and two compressor stations, the Taft Compressor Station (12,260 horsepower) and the Sinton Compressor Station (41,000 horsepower). Additional ancillary facilities include six meter and regulator stations installed at the Terminal as well as interconnects with Texas Eastern Transmission, L.P.; Kinder Morgan Tejas Pipeline, LLC; Natural Gas Pipeline Company, LLC; Transcontinental Gas Pipe Line Company, LLC; and Tennessee Gas Pipeline Company, LLC. Cheniere would install five mainline valves along the pipeline route, including a pig[2] launcher and receiver at the beginning and end of the pipeline, respectively.

PUBLIC INVOLVEMENT

On December 22, 2011, the FERC began its pre-filing review of Cheniere's Project and established the pre-filing Docket Number PF12-3-000 to place information related to the Project into the public record. As part of the pre-filing process, Cheniere sponsored a public open house in Portland, Texas on February 28, 2012. The purpose of the open house was to provide affected landowners, government and agency officials, and the general public with information about the Project and to give them an opportunity to ask questions and express their concerns. We participated in the open house and provided information regarding the Commission's environmental review process to interested stakeholders.

On June 1, 2012, the FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Corpus Christi LNG Terminal and Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meeting*. This notice was sent to about 500 interested parties including federal, state, and local officials; agency representatives; conservation organizations; Native American tribes; local libraries and newspapers in the Project area; and property owners in the vicinity of the proposed Project facilities. On June 26, 2012, we conducted a site visit and held a public scoping meeting in Portland, Texas to provide an opportunity for the public to learn more about the Project and to provide oral comments on environmental issues to be addressed in the EIS.

Additionally, we initiated consultations with federal and state agencies to identify issues that should be addressed in the EIS. We conducted an interagency meeting for the Project on June 27, 2012 in Corpus Christi, Texas.

Through the scoping and agency comment process, we received comments on a variety of environmental issues. We continued to receive and consider public comments during the entire

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[2] A pipeline "pig" is an internal device to clean or inspect the pipeline. A pig launcher/receiver is an aboveground facility where pigs are inserted into or retrieved from the pipeline.

pre-filing period and throughout development of this EIS. Substantive environmental issues identified through this public review process are addressed in this EIS. The transcripts of the public scoping meeting and all written comments are part of the FERC's public record for the Project and are available for viewing under the Project docket numbers. [3,4]

In addition, we held a public comment meeting in Portland, Texas on July 15, 2014 to provide an opportunity for stakeholders to comment on the draft EIS issued on June 13, 2014. A transcript of the meeting, comments received during the meeting, and all the comments received on the draft EIS are included in appendix I of the EIS.

PROJECT IMPACTS

We evaluated the potential impacts of construction and operation of the Project on geology; soils; water use and quality; wetlands; vegetation; wildlife, aquatic resources, and essential fish habitat (EFH); threatened, endangered, and special status species; land use, recreation, and visual resources; socioeconomics; cultural resources; air quality and noise; reliability and safety; and cumulative impacts. Where necessary, we are recommending additional mitigation to minimize or avoid these impacts. Section 5.3 of the EIS contains a compilation of our recommendations.

Overall, construction of the Project facilities would temporarily disturb approximately 1,412 acres for construction, including extra temporary workspaces, contractor yards, access roads, and aboveground facilities. About 647 acres would be retained as permanent easements for operation of the facilities. Cheniere would allow the remaining 765 acres to return to preconstruction uses.

Construction of the Terminal would result in permanent impacts on about 469 acres of open land and open water. All affected land areas would be permanently converted to industrial land. The 23-mile pipeline right-of-way would be collocated with existing right-of-way corridors to the extent practicable (about 86 percent of the total length). Construction of the pipeline would impact about 421 acres of agricultural, open, and industrial land, but we have determined that impacts would not be significant as the majority of the area disturbed by the pipeline is within agricultural areas and would return to preconstruction conditions soon after construction is complete.

Regarding federally listed threatened and endangered species, on October 29, 2012, the National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS) notified Cheniere that initiation of Section 7 consultation under the Endangered Species Act would not be required; and in letters dated August 8, 2013 and November 5, 2013, the U.S. Fish and Wildlife Service (FWS) concurred with determinations that the Project is not likely to adversely affect species under its jurisdiction.

We have completed the process of compliance with the National Historic Preservation Act (NHPA), as well. We consulted with Indian tribes that may have an interest in the Project area, and with the Texas State Historic Preservation Office (SHPO), and found that no traditional

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[3] Transcript of the public scoping meeting for the Project (Docket No. PF12-3-000, Accession No. 20120626-4008) is available on the FERC website at http://ferc.gov/docs-filing/elibrary.asp.

[4] Comments submitted after the Project application was filed with the FERC are part of the public record for the Project (Docket No. CP12-507-000 and CP12-508-000) and are available on the FERC website at http://ferc.gov/docs-filing/elibrary.asp.

cultural properties or sites of religious significance to Indian tribes were identified in the area of potential effect (APE), and no historic properties would be affected by the Project.

Based on our analysis, public scoping, and agency consultations, the major issues associated with the Project are impacts on aquatic resources, including EFH and wetlands; air quality and noise; safety and reliability; and cumulative impacts.

Wetlands and Aquatic Resources

Based on consultations with NMFS, and COE we determined that the proposed Terminal would impact EFH and wetlands. Although construction of the marine berths at the Terminal would result in the loss and permanent conversion of estuarine submerged aquatic seagrass beds, cordgrass salt marsh, emergent marsh, vegetated sand flats, unvegetated sand flats, and unvegetated shallow water EFH, the deep water habitat would recolonize with soft-bottom benthic organisms after completion of dredging and would continue to provide a prey base for EFH species. To minimize impacts on wetlands, EFH, and EFH species, Cheniere has reduced its work space requirements and would use a hydraulic cutterhead dredge that would reduce sedimentation and turbidity. Cheniere would further mitigate impacts on EFH and 25.7 acres of impacted wetlands by implementing its Aquatic Resources Mitigation Plan.

Air Quality and Noise

Most Project-related air emissions would be produced by operation of the Terminal and the Sinton and Taft Compressor Stations. Cheniere would comply with all applicable air permit requirements for those facilities. Multiple air dispersion modeling analyses, which included LNG carriers and other nearby emission sources, demonstrated that operation of these facilities would not result in an exceedance of the National Ambient Air Quality Standards at any location, with the exception of nitrogen dioxide for the Terminal. An expanded analysis determined that operation of the Terminal would not contribute significantly to exceedances of the 1-hour nitrogen dioxide National Ambient Air Quality Standard. As a result, we conclude that the Project would not result in a significant adverse impact on either the regional or local air quality.

Cheniere performed detailed noise assessments for each of the proposed horizontal directional drilling locations. To mitigate significant noise impacts at several noise sensitive areas, Cheniere has committed to performing all horizontal directional drilling activities, except the pipe pullback, during daylight hours. During operation of the Project, potential noise impacts would be limited to the vicinity of the Terminal and Sinton and Taft Compressor Stations. These facilities would include design measures to minimize sound generation. The proposed facilities with noise mitigation measures implemented are projected to comply with the FERC day-night sound level criterion of 55 decibels on the A-weighted scale at the nearest noise sensitive areas. We are also recommending that Cheniere conduct noise surveys during operation of each facility to ensure that noise levels meet our criterion.

Safety and Reliability

We evaluated the safety of the proposed Terminal facility, the related LNG carrier transit, and the bi-directional pipeline. As part of our evaluation of the Terminal, we performed a technical review of the preliminary engineering design to ensure sufficient layers of protection would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the public. The DOT reviewed the initial data and methodology Cheniere used to determine the design spills from various leakage sources, including piping, containers, and equipment containing hazardous liquids, and stated it had no objection to Cheniere's methodology for determining the candidate design spills used to establish the required siting for its proposed Terminal. The Coast Guard reviewed the suitability of the Corpus Christi Ship Channel from the entrance approach at Port Aransas to the La Quinta Junction and the entire length of La Quinta Channel, and issued a letter of recommendation (LOR) indicating the waterway would be suitable for the type and frequency of the marine traffic associated with the proposed Project. In addition, Cheniere would be required to comply with all regulations in 49 CFR 192 for its pipeline and 33 CFR 105, 33 CFR 127, and 49 CFR 193 for its Terminal facilities. Based on our engineering design analysis and our recommendations presented in section 4.12 of the EIS for the Terminal, we conclude that the Project would not result in significant increased public safety risks.

Cumulative Impacts

We also conclude that the potential impact of the Project, when combined with the impacts from the other projects considered, would not result in a significant impact on resources within the cumulative impact areas. Although we recognize concurrent construction of the proposed Project and other projects in the vicinity of the Terminal site would result in increased workers in the area, periods of increased traffic, and impacts on public services, we are not recommending additional mitigation at this time. Therefore, we have determined that with the implementation of Cheniere's mitigation measures, the impacts of the Project when added with other projects' impacts would not result in significant cumulative impacts.

More detailed discussions of impacts on all resources affected by the Project, Cheniere's proposed mitigation, and our recommendations to avoid or further reduce impacts, are presented in sections 4.0 and 5.0 of this EIS.

ALTERNATIVES CONSIDERED

We assessed alternatives that could achieve the Project objectives. The range of alternatives analyzed included the No-Action Alternative, system alternatives, alternative Terminal sites, alternative Pipeline routes, and alternative compressor station sites. Alternatives were evaluated and compared to the Project to determine if these alternatives were environmentally preferable to the proposed Project.

While the No-Action Alternative would avoid the environmental impacts identified in this EIS, adoption of this alternative would also preclude meeting the Project objectives. If the Project is not approved and built, the need could potentially be met by other LNG export and import projects developed elsewhere in the Gulf Coast region or in other areas of the U.S. Implementation of other LNG export/import projects would likely result in impacts similar to or greater than those of the proposed Project.

We evaluated 12 system alternatives for the Terminal, including 6 operating LNG import terminals in the Gulf of Mexico area, and 6 proposed or planned export projects along the Gulf Coast. All of the systems were eliminated from further consideration for reasons that include the need for substantial construction beyond that currently proposed, production volume limitations, in-service dates scheduled significantly beyond Cheniere's schedule, and environmental impacts that were considered comparable to or greater than those of the proposed Project.

We also evaluated three alternative Terminal sites, two in proximity to the proposed site and one near Brownsville, Texas. Construction of the Terminal at each of the alternative sites would have comparable or greater impacts when compared to the proposed Terminal site; therefore, none of the three sites evaluated were determined to be environmentally preferable.

Approximately 86 percent of the pipeline would be collocated, overlap, or parallel existing rights-of-way. As a result, many types of environmental impacts have been lessened. Two route alternatives were evaluated; however, we did not identify any site-specific environmental concerns along the proposed route that would drive the need to recommend the alternative pipeline routes.

We evaluated a total of five alternative sites for the proposed compressor stations, but determined that none of these sites were environmentally preferable to the proposed sites.

CONCLUSIONS

We conclude that if the Project is constructed and operated in accordance with applicable laws and regulations, Cheniere's proposed mitigation, and our recommendations presented in section 5.3 of this EIS, it would result in some adverse environmental impacts; however, those impacts would not be significant. The principal reasons for our decision include:

- the Terminal facilities are sited in an existing industrialized area;
- dredge material would be disposed of beneficially to cap bauxite disposal beds;
- impacts on wetlands and aquatic habitat, including EFH, would be mitigated per Cheniere's Aquatic Resources Mitigation Plan;
- adequate safety features would be incorporated into the design and operation of the Terminal facilities;
- the proposed pipeline route would be collocated, overlap, or parallel existing rights-of-way;
- Cheniere would implement the FERC *Upland Erosion Control, Revegetation, and Maintenance Plan* and *Wetland and Waterbody Construction and Mitigation Procedures* to minimize construction impacts on soils, wetlands, and waterbodies;
- the use of the horizontal directional drilling method for crossing waterbodies would avoid disturbances to the beds and banks of these waterbodies;
- the Project would have no effect or would be not likely to adversely affect any federal or state listed threatened or endangered species;
- the Project would have no effect on cultural resources;
- all appropriate consultations with the U.S. Fish and Wildlife Service, Texas Department of Wildlife and Fisheries, and NMFS would be completed before construction is allowed to start; and
- the FERC's environmental and engineering inspection and mitigation monitoring program for this Project would ensure compliance with all mitigation measures and conditions of any FERC Authorization.

In addition, we developed site-specific mitigation measures that Cheniere should implement to further reduce the environmental impacts that would otherwise result from construction of the Project. We are recommending these mitigation measures, presented in section 5.3 of this EIS, be attached as conditions to any authorization issued by the Commission for this Project.

INTRODUCTION

SECTION 1

1.0 INTRODUCTION

The staff of the Federal Energy Regulatory Commission (FERC or Commission) prepared this Environmental Impact Statement (EIS) to describe our assessment of the potential environmental impacts that may occur from constructing and operating the Corpus Christi Liquefaction, LLC's and Cheniere Corpus Christi Pipeline, L.P.'s liquefied natural gas (LNG) import and export terminal and associated natural gas pipeline in Nueces and San Patricio Counties, Texas (collectively referred to as the Corpus Christi LNG Project or Project).

On August 31, 2012, Corpus Christi Liquefaction, LLC filed an application with the FERC, in Docket No. CP12-507-000, under Section 3(a) of the Natural Gas Act (NGA) and under Title 18 of the Code of Federal Regulations (CFR), Parts 153 and 380 of the Commission's regulations to construct and operate LNG import and export facilities. On the same day, Cheniere Corpus Christi Pipeline, L.P. also filed an application with the FERC in Docket No. CP12-508-000, under Section 7(c) of the NGA and 18 CFR Parts 157, 284, and 380 of the Commission's regulations. These applications were noticed in the *Federal Register* (FR) on September 14, 2012.

Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P. are both subsidiaries of Cheniere Energy Inc. (hereafter collectively referred to as Cheniere). As part of the Commission's consideration of these applications, we[5] prepared this EIS to assess the potential environmental impacts resulting from construction and operation of the proposed Project in accordance with the National Environmental Policy Act of 1969 (NEPA).

1.1 REGULATORY BACKGROUND

Cheniere initially filed an application with the FERC in Docket Nos. CP04-37-000, CP04-44-000, CP04-45-000, and CP04-46-000 on December 22, 2003, seeking Commission approvals under Sections 3 and 7 of the NGA to construct and operate a LNG import terminal and associated natural gas pipeline at the Project site. The Commission issued a final EIS on March 3, 2005. Cheniere received an authorization under Docket No. CP04-37-000 on April 18, 2005. On June 8, 2012, the Commission issued an Order vacating the authorization to construct the facilities since Cheniere did not construct the facilities in its authorized timeframe.

In this revised proposed Project, Docket Nos. CP12-507-000 and CP12-508-000, Cheniere seeks authorization to construct and operate an LNG export and import facility (Terminal) at the site of the previously authorized Corpus Christi import terminal. In addition, Cheniere seeks authority for: a Certificate of Public Convenience and Necessity (Certificate), to authorize the construction and operation of a new bi-directional natural gas pipeline (Pipeline), to be located along the same route as was previously authorized; a blanket certificate authorizing Cheniere to engage in certain self-implementing routine activities under 18 CFR Part 157, Subpart F, of the Commission's regulations; and a blanket certificate authorizing Cheniere to transport natural gas, on an open access and self-implementing basis, under 18 CFR Part 284, Subpart G of the Commission's regulations. The new Pipeline would extend from the Terminal to north of Sinton, Texas, and be capable of transporting up to a maximum of 2.25 billion cubic feet per day (Bcf/d) of natural gas to markets throughout the United States or to the Terminal, via interconnections with a number of existing interstate and intrastate pipeline systems.

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[5] "We", "us", and "our" refer to the environmental staff of the FERC's Office of Energy Projects.

Figure 1.1-1 shows the general location of the proposed facilities, figure 1.1-2 shows an artist’s rendering of the proposed Terminal facilities, and the Terminal boundary is shown in figure 1.1-3. Pipeline alignment sheets for the Project are provided in appendix A.

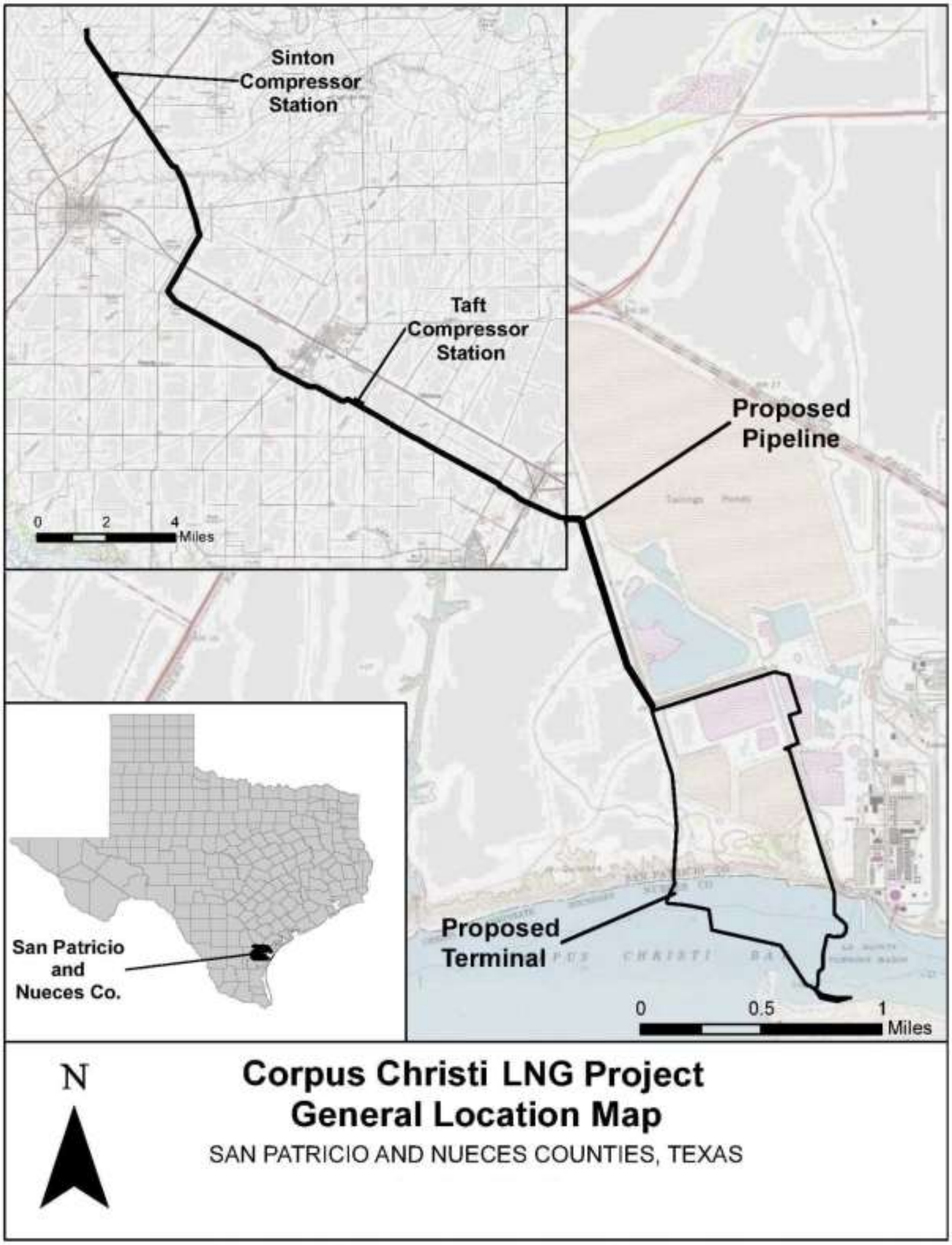

Figure 1.1-1 Corpus Christi LNG Project General Location

Figure 1.1-2 Artist Impression of Proposed Terminal Facilities

Figure 1.1-3 **Terminal Facilities Boundary**

1.2 PROJECT PURPOSE AND NEED

Cheniere states that the purpose of the Project is to provide facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export LNG elsewhere. Depending on market dynamics, the Project would enable LNG to be imported, vaporized, and sent out for delivery to U.S. consumers, or the liquefaction facilities would allow the export of natural gas as LNG to other countries for consumption. The Project liquefaction facilities would enable Cheniere to export LNG equivalent to approximately 2.1 billion standard cubic feet (Bscf) per day of natural gas, and the vaporization facilities would enable Cheniere to sendout approximately 400 million standard cubic feet (MMscf) per day of natural gas into its proposed pipeline system.

Under Section 3 of the NGA, the FERC considers, as part of its decision to authorize natural gas facilities, all factors bearing on the public interest. Specifically, regarding whether to authorize natural gas facilities for importation or exportation, the FERC shall authorize the proposal unless it finds that the proposed facilities would 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 necessity, and if so, grants a Certificate to construct and operate them. The Commission bases its decisions on technical competence, financing, rates, market demand, gas supply, environmental impact, long-term feasibility, and other issues concerning the proposed Project.

The Project has a water-dependency purpose as it relates to import, or the liquefaction and subsequent exportation of domestic natural gas. LNG vessels would be utilized to transport LNG to and from worldwide markets. The Project requires marine berths for loading and unloading of LNG vessels for waterborne transport of LNG.

1.3 PURPOSE AND SCOPE OF THE EIS

The EIS describes the affected environment as it currently exists, the environmental consequences of the Project, and compares the Project's potential impact with various alternatives. The EIS also presents our conclusions and recommended mitigation measures. The FERC would use the EIS as an element in its review of Cheniere's applications to determine whether to authorize the Project.

Our principal purposes in preparing this EIS are to:

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

Topics addressed in this EIS include alternatives; geology; soils and sediments; water resources; wetlands; vegetation; wildlife and aquatic resources; threatened, endangered, and other special status species; land use, recreation, and visual resources; socioeconomics; transportation and traffic; cultural resources; air quality and noise; reliability and safety; and cumulative impacts. Our analysis in this EIS focuses on facilities that are under the Commission's jurisdiction (i.e., the proposed Terminal and Pipeline). Minor non-jurisdictional facilities would also be constructed and abandoned in association with the Project (see section 1.5).

When considering the environmental consequences of constructing and operating the Project, the duration and significance of any potential impacts are described according to the following four levels:

- ***Temporary*** impacts generally occur during construction, with the resources returning to preconstruction conditions almost immediately after construction;
- ***Short-term*** impacts could continue for approximately 3 years following construction;
- ***Long-term*** impacts would require more than 3 years to recover, but eventually would recover to preconstruction conditions; and
- ***Permanent*** impacts could occur as a result of activities that modify resources to the extent that they may not return to preconstruction conditions during the life of the Project such as with the construction of an aboveground facility.

1.3.1 Federal Energy Regulatory Commission Purpose and Role

The FERC is the federal agency responsible for authorizing onshore LNG facilities. As such, the FERC is the lead federal agency for the preparation of this EIS in compliance with the requirements of the NEPA, the Council on Environmental Quality (CEQ) regulations for implementing the NEPA (40 CFR 1500-1508), and the FERC regulations for implementing the NEPA (18 CFR 380).

Several agencies are cooperating agencies for the development of this EIS. A cooperating federal agency has jurisdiction by law or special expertise with respect to environmental impacts associated with the proposal, and is involved in the NEPA analysis. Cooperating agencies for the Project include: the U.S. Army Corps of Engineers (COE), U.S. Coast Guard (Coast Guard), U.S. Department of Transportation (DOT), U.S. Environmental Protection Agency (EPA), and DOE.

FERC consulted with the cooperating agencies throughout the pre-filing and the application phases of the Project. The cooperating agencies provided input on the Project during several conference calls and an interagency scoping meeting held on June 27, 2012 in order to solicit comments and concerns regarding the Project. Agency representatives also participated in the public scoping meeting held on June 26, 2012. The cooperating agencies had the opportunity to comment on the preliminary draft EIS. FERC consulted with those agencies about their comments and incorporated them into this EIS.

1.3.2 U.S. Army Corps of Engineers Purpose and Role

The COE has jurisdictional authority pursuant to Section 404 of the Clean Water Act (CWA) (Title 33 of the United States Code [USC], Section 1344 [33 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. The COE must comply with the requirements of the NEPA before issuing permits under these statutes. In addition, when a Section 404 discharge is proposed and a standard permit is required, the COE must consider whether the proposed Section 404 discharge represents the least environmentally damaging, practicable alternative pursuant to the CWA Section 404(b)(1) guidelines. The COE must also carry out its public interest review process before a standard permit can be issued. Although this final EIS addresses environmental impacts associated with the Project as they relate to the COE's jurisdictional permitting authority, it does not serve as a public notice for any COE permits or take the place of the COE's permit review process.

The COE elected to participate as a cooperating agency in the preparation of this EIS. However, though the COE provided content in regards to its jurisdictional authority for preparation of this EIS, it determined that an evaluation of its regulatory statutes under NEPA was conducted in the form of an Environmental Assessment finalized on July 23, 2014.

1.3.3 U.S. Coast Guard Purpose and Role

The Coast Guard is the federal agency responsible for determining the suitability of waterways 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 of 2002 (MTSA) (46 USC 701). The Coast Guard is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment 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 reviews, approval and compliance verification as provided in 33 CFR 105, and siting as it pertains to the management of vessel traffic in and around LNG facilities to a point 12 nautical miles (nm) seaward from the coastline (to the territorial seas).

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). In a letter dated March 21, 2013, the Coast Guard issued a LOR for the Project. In the LOR the Coast Guard stated that after reviewing the WSA, they recommend 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 LNG marine traffic.

1.3.4 U.S. Department of Transportation Purpose and Role

The DOT has prescribed the minimum federal safety standards for LNG facilities in compliance with 49 USC 60101. Those standards are codified in 49 CFR Part 193 and apply to the siting, design, construction, operation, maintenance, and security of LNG facilities. The National Fire Protection Association (NFPA) Standard 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*, is incorporated into these requirements by reference, with regulatory preemption in the event of conflict. In accordance with the 1985 Memorandum of Understanding on LNG facilities and the 2004 Interagency Agreement on the safety and security review of waterfront import/export LNG facilities, the DOT participates as a cooperating agency and assists in assessing any mitigation measures that may become conditions of approval for any project. DOT staff is reviewing our analysis and would provide comments on our conclusions regarding compliance with Part 193 regulations.

1.3.5 U.S. Environmental Protection Agency Purpose and Role

The EPA has delegated water quality certification, under Section 401 of the CWA, to the jurisdiction of individual state agencies. The EPA may assume Section 401 authority if no state program exists, if the state program is not functioning adequately, or at the request of the state. 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 of used water into waterbodies. In addition to its authority under the CWA, the EPA also 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 are allowed to develop and implement their own regulations for non-major sources of air pollutants.

In addition to its permitting responsibilities, the EPA is required under Section 309 of the CAA to review and publicly comment on the environmental impacts of major federal actions including actions that are the subject of draft and final EISs, and responsible for implementing certain procedural provisions of NEPA (e.g., publishing Notices of Availability of the draft and final EISs) to establish statutory timeframes for the environmental review process.

1.3.6 U.S. Department of Energy Purpose and Role

The DOE must meet its obligation under Section 3 of the NGA to authorize the import and export of natural gas, including LNG, unless it finds that the 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 that require national treatment for trade in natural gas are deemed to be consistent with the public interest (FTA countries) and the Secretary of Energy must grant authorization without modification or delay. On October 16, 2012, in FE Docket No. 12-99-LNG, DOE issued DOE/FE Order No. 3164 granting Cheniere authorization to export LNG by vessel from the Terminal to FTA countries.

In the case of LNG export applications to non-FTA countries, section 3(a) of the NGA requires DOE to conduct a public interest review and to grant the applications unless DOE finds that the proposed exports would not be consistent with the public interest. Additionally, NEPA requires DOE to consider the environmental impacts of its decisions on non-FTA export applications. In this regard, DOE acts as a cooperating agency with the FERC as the lead agency in the EIS pursuant to the requirements of NEPA.

The purpose and need for DOE action for the current proposal is to respond to the August 31, 2012 application for authority to export LNG from the Project to non-FTA countries filed by Cheniere with the DOE Office of Fossil Energy (FE Docket No. 12-97-LNG). The DOE is conducting its review under Section 3(a) of the NGA to evaluate the Cheniere application for long-term, multi-contract authorization to export up to 767 billion cubic feet per year of domestic natural gas as LNG for a 25-year period, commencing the earlier of either the date of first export or 10 years from the date of issuance of the requested authorization. Cheniere seeks to export LNG from the Terminal to any non-FTA country that has, or in the future develops, the capacity to import LNG, and with which trade is not prohibited by U.S. law or policy.

The DOE will not make a decision on applications to export LNG to non-FTA countries until DOE has met all of its statutory responsibilities. In accordance with 40 CFR 1506.3, after an independent review of this EIS, the DOE may adopt it prior to issuing a Record of Decision on Cheniere's application for authority to export LNG.

1.4 PUBLIC REVIEW AND COMMENT

1.4.1 Pre-filing and Public Scoping

Cheniere initiated the FERC pre-filing process for the Project on December 13, 2011. On December 22, 2011, the Commission staff granted Cheniere's request to utilize the pre-filing process and assigned Docket No. PF11-3-000 to staff activities involved with the Project. The pre-filing process ended on August 31, 2012 when Cheniere submitted its applications to the FERC. The pre-filing process allows the FERC staff to become involved with scoping of environmental issues before the applicant files its application, thus overlapping the applicant's planning process with the FERC process.

During the pre-filing process, we conducted biweekly conference calls with Cheniere to discuss Project progress and identify and address issues and concerns that had been raised. Interested agencies were invited to participate on these calls. Summaries of biweekly conference calls and written scoping comments are part of the public record for the Project and are available for viewing on the FERC website (http://www.ferc.gov).

On February 28, 2012, the FERC staff participated in a visit to the proposed facility site. Cheniere hosted an open house information session for landowners, agencies, and other interested stakeholders on February 28, 2012 in Portland, Texas, which FERC staff also participated in. The open house provided stakeholders the opportunity to learn about the Project and ask questions in an informal setting. Notification of the open house was mailed to stakeholders and published in local newspapers. Approximately 120 interested parties attended the open house. On June 1, 2012, the FERC issued a *Notice of Intent to Prepare an Environmental Assessment for the Planned Corpus Christi LNG Terminal and Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping Meeting* (NOI)[6]. The NOI was sent to over 500 interested parties including federal, state, and local officials; agency representatives; conservation organizations; local libraries and newspapers; property owners along the proposed pipeline route, and interveners in the proceeding. There was a 30-day comment period on the NOI which ended on July 2, 2012. We received 25 comments in response to the NOI.

Of the 25 comments filed during the public scoping period, four were from state or federal agencies, one was from a non-profit environmental group, and the remaining 20 were from adjacent landowners or individuals. The majority of comments indicated concerns regarding water contamination, air quality, safety, outdoor recreation, fish and wildlife, visual resources, and noise and light pollution. Commenters also expressed a preference that the FERC

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[6] Based on comments during scoping and Project impacts, we determined that an EIS would be more appropriate.

prepare an EIS in lieu of an Environmental Assessment. Cheniere addressed all comments filed during the public scoping period on July 16, 2012.

On June 26, 2012, the FERC conducted another site visit of the Terminal site and the Pipeline route. That same day, the FERC conducted a public scoping meeting in Portland, Texas to provide an opportunity for the public to learn more about the Project and provide comments on environmental issues addressed in the EIS. Nine people provided verbal comments at the scoping meeting and three individuals submitted written comments. A transcript of the scoping meeting and all written comments provided at the meeting has been entered into the public record for the Project, under Docket No. PF11-3-000.

On June 27, 2012, the FERC held an interagency scoping meeting to solicit comments and concerns regarding the Project from other jurisdictional agencies. Representatives from eight state and federal agencies were present including the COE, DOT, Coast Guard, U.S. Fish and Wildlife Service (FWS), National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS), Railroad Commission of Texas (RRC), Texas General Land Office (TGLO), and Texas Parks and Wildlife Department (TPWD).

On April 26, 2012, FERC staff issued a letter to the U.S. Department of Defense requesting comments on whether the Project could potentially have an impact on the test, training, or operational activities of any active military installation. To date, no military installations have been identified as being potentially impacted.

Table 1.5-1 lists the environmental issues that were identified during the scoping process described above, as well as comments received in response to our Notice of Application issued September 14, 2012. Table 1.5-1 also indicates the section of this EIS in which each issue is addressed. Additional issues that we independently identified are also addressed.

Table 1.4-1
Issues Identified and Comments Received During the Scoping Process for the Corpus Christi LNG Project

Issue/Specific Comment	EIS Section Addressing Comment
General	
Right of eminent domain	2.4.3
Spill contingency plan	2.4
Hurricane response plan	4.1.1.5
LNG capacity of ships	2.1.4.1
Alternatives	
Alternative flare locations	3.1.5.1
Alternative facility locations	3.1.4
Renewable energy alternatives	3.1.2
Alternatives in production volumes/capacity	3.1.3.2
Water Resources	
Water use during construction and operation, including source and discharges	4.3.1.2
Surface water and groundwater contamination	4.3
Waterbody crossings	4.3.2.2
Stormwater pollution	4.3.1.2 & 4.3.2.2
Hydrostatic testing	4.3.1.2 & 4.3.2.2
Turbidity and resuspension of bottom sediments	4.3.1.2
Ballast water	4.6.2.1
Wildlife and Aquatic Resources	
Impacts of water discharges on aquatic species	4.6.2
Underwater noise/vibrations	4.6.2.1
Impacts from ship traffic on aquatic resources	4.6.2.1
Invasive species	4.6.2
Migratory birds	4.6.3
Habitat loss	4.6
Impacts of storage tanks on birds	4.6.3.1
Threatened and Endangered Species	
Measures to avoid/minimize impacts on sensitive species	4.7.3
Land Use, Recreation, and Aesthetics	
Light pollution	4.8.1.6
Impacts of storage tanks on visual resources	4.8.1.5
Impacts on outdoor recreation opportunities	4.8.1.3 & 4.8.2.3
Recreational fishing and boating	4.8.1.3 & 4.8.2.3
Changes in land use	4.8.1.6 & 4.8.2.6
Socioeconomics	
Available workforce	4.9.2
Economic impacts of LNG exports	3.1.2
Economic impacts of domestic use of LNG	3.1.2
Property values	4.9.3

Table 1.4-1
Issues Identified and Comments Received During the Scoping Process for the Corpus Christi LNG Project

Issue/Specific Comment	EIS Section Addressing Comment
Insurance rates	4.9
Job growth	4.9.2
Natural gas prices	3.1.2
Transportation and Traffic	
Safe navigation of ship channel	4.9.10.1
Impacts of increased ship traffic	4.9.10.1
Cultural Resources	
Proximity to the Taft House and Native American historical site	4.10.2 & 4.10.4
Air Quality	
Greenhouse gas emissions and mitigation	4.11.1.4
Attainment status	4.11.1.2
Dust mitigation	4.11.1.4
Impacts of emissions on human health	4.11.1.3
Increased coal production/use	3.1.2
Global oil and coal use	3.1.2
Noise	
Impacts from noise during construction	4.11.2
Impacts from noise during operations	4.11.2
Reliability and Safety	
Safety of flares	4.12.1
Emergency notification systems	4.12.1
Catastrophic system failures	4.12.1
Potential for terminal to be a terrorist target	4.12.1
Proximity to a densely populated area	4.12.1
Cumulative Impacts	
Induced production	4.13.1
Impacts of increased natural gas production	4.13.1
Hydraulic fracturing	4.13.1

On October 16, 2012, April 30, 2013, and October 30, 2013, the FERC issued a Project update to inform the public and agencies of the status of the FERC review process. This document, as well as all documents and comments submitted as a part of the Project pre-filing and application processes, are publically available online at www.ferc.gov/docs-filing/elibrary.asp.

1.4.2 Public Review of the Draft EIS

The draft EIS for the proposed Project was issued for public review on June 13, 2014, and the notice of availability (NOA) for the draft EIS was published in the Federal Register on June 20, 2014 (Volume 79, Number 119, Document No. 2014-14375, pages 35344 to 35345). The NOA included notice of a public comment meeting on July 15, 2014 in Portland, Texas. The NOA also provided summary information regarding the draft EIS and requested submission of all comments by August 4, 2014. Copies of the draft EIS were also sent to agencies, elected officials, media organizations, Native American Tribes, private landowners, and other interested parties. An electronic version of the draft EIS is available for download on the FERC website under Docket Nos. CP12-507-000 and CP 12-508-000. The distribution list for the draft EIS is presented in Appendix F.

The public comment meeting was held in Portland, Texas on July 15, 2014 to solicit both verbal and written comments on the draft EIS. The meeting was held in the vicinity of the proposed Project, at the same location as the scoping meeting held on June 27, 2012. At the comment meeting, the FERC received written comments from five individuals and verbal comments from 32 people. The verbal comments were recorded and transcribed by a court reporter. The transcripts of the public comment meetings and all written comments on the draft EIS are part of the public record for the Project.

In addition to receiving written and verbal comments at the draft EIS comment meeting, the FERC received nine written comments from federal, state, and local agencies; interested parties; and Cheniere. All written comments directly pertaining to the draft EIS, the transcripts of verbal comments presented at the draft EIS comment meeting, and responses to comments are presented in appendix I.

1.4.3 Final EIS

In accordance with CEQ regulations implementing NEPA, no agency decision on the proposed action may be made until 30 days after the EPA publishes a NOA of the final EIS in the Federal Register. However, CEQ regulations provide an exception to this rule when an agency decision is subject to a formal internal appeal process that allows other agencies or the public to make their views known. This is the case at the FEC, where any Commission decision on the proposed action would be subject to a 30-day rehearing period. Therefore, the FERC decision may be made and recorded concurrently with the publication of the final EIS.

1.5 NON-JURISDICTIONAL FACILITIES

Under Section 7 of the NGA, the FERC is required to consider, as part of a decision to authorize jurisdictional facilities, all facilities that are directly related to a proposed project where there is sufficient federal control and responsibility to warrant environmental analysis as part of the NEPA environmental review for the proposed project. Some proposed projects have associated facilities that do not come under the jurisdiction of the Commission. These “non-jurisdictional” facilities may be integral to the need for the proposed facilities, or they may be merely associated as minor components of jurisdictional facilities that would be constructed and operated as a result of authorization of the proposed facilities.

The jurisdictional facilities for the Project include the Terminal and the Pipeline and are discussed extensively throughout this EIS. Two non-jurisdictional facilities were identified in association with the proposed Project: an electrical powerline and substations and a potable waterline. These facilities are addressed below and are also addressed in our cumulative impacts analysis in section 4.13 of this EIS. Figure 1.6-1 shows the locations of the non-jurisdictional facilities to be constructed concurrent with the Terminal facilities. Both the electrical powerline and the potable waterline would be constructed within the Utility/Access Easement. These non-jurisdictional facilities would be constructed in compliance with all applicable federal and state regulations.

Figure 1.5-1 **Locations of Non-Jurisdictional Facilities**

1.5.1 Electrical Power Lines and Substations

An electrical power line extension and a substation would be required for construction and operation power supply. An overhead power line would be extended from the junction of State Highway (SH) 35 and SH 361 to a new facilities substation located on approximately 11.6 acres of previously disturbed industrial, road, and utility corridor. The electrical substation would be placed on a 4.8-acre parcel owned by Cheniere at the south end of the power line easement. The overhead power line and electrical substation would be designed, built, owned, and operated by American Electric Power, Inc. (AEP), the local power transmission provider.

Cheniere would also design, build, own, and operate a power line that would extend from the AEP substation to the facilities substation at the Terminal. The underground power would be constructed within previously disturbed areas adjacent to La Quinta Road and/or within the Terminal property. Environmental impacts associated with the installation of the power lines and substations would be confined to existing, previously disturbed industrial areas and would be negligible.

1.5.2 Waterline

The Project would require a pipeline connection to the San Patricio Municipal Water District potable water system at the north end of La Quinta Road for site personnel and the supply by pipeline of raw or semi-processed water to be used for Terminal operations. Examples of use include: use as a feed source to the demineralized water system for injection into the gas turbines for nitrogen dioxide control and for make-up of the amine unit; for humidification equipment at the inlet to the gas turbine drivers; and potable water for the additional operation and maintenance activities. Water use associated with the Project is further discussed in section 4.3 of this EIS. The waterline would be constructed within the same corridor as the power lines discussed above and would be located entirely within previously disturbed areas, resulting in negligible environmental impacts.

1.6 PERMITS, APPROVALS, AND REGULATORY REVIEWS

As the lead federal agency for the Project, the FERC is required to comply with various federal environmental laws and regulations, including but not limited to, the Endangered Species Act of 1973 (ESA), the Magnuson-Stevens Fishery Conservation and Management Act of 1976 (MSA), the RHA, the CWA, the CAA, the Federal Aviation Act of 1958, the NGA, the MTSA, the National Historic Preservation Act of 1966 (NHPA), the Coastal Zone Management Act of 1972 (CZMA), and the National Flood Insurance Act of 1968 (NFIA). Each of these statutes has been taken into account in the preparation of this document.

Major permits, approvals, and consultations for the Project are identified in table 1.6-1 and discussed below. The FERC encourages cooperation between applicants and state and local authorities, but this does not mean that state and local agencies, through applications of state and local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by the FERC. Any state or local permits issued with respect to jurisdictional facilities must be consistent with the conditions of any authorization issued by the FERC.

1.6.1 Endangered Species Act

Section 7 of the ESA, as amended, states that any project authorized, funded, or conducted by any federal agency (e.g., FERC) 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 Section 1536(a)(2)(1988)). The FERC, or Cheniere as a non-federal party, is required to consult with the FWS and NMFS to determine whether any federally listed or proposed endangered or threatened species or their designated critical habitat occur in the vicinity of the Project. If the FERC determines that these species or habitats may be impacted by the Project, the FERC is required to prepare a biological assessment (BA) to identify the nature and extent of adverse impact, and to recommend measures to avoid or reduce potential impacts on habitat and/or species. If, however, the FERC determines that no federally listed or proposed endangered or threatened species or their designated critical habitat would be impacted by the Project, no further action is necessary under the ESA (see section 4.7 of this EIS for the status of our compliance with Section 7 of the ESA).

1.6.2 Magnuson-Stevens Fishery Conservation Management Act

The MSA, as amended by the Sustainable Fisheries Act of 1996 (Public Law 104-267), established procedures designed to identify, conserve, and enhance essential fish habitat (EFH) for those species regulated under a federal fisheries management plan. The MSA requires federal agencies to consult with the National Oceanic and Atmospheric Administration National Marine Fisheries Service Office of Sustainable Fisheries (NOAA Fisheries) on all actions or proposed actions authorized, funded, or undertaken by the agency that may adversely impact EFH (MSA Section 305(b)(2)). Although absolute criteria have not been established for conducting EFH consultations, NOAA Fisheries recommends consolidating EFH consultations with interagency coordination procedures required by other statutes such as NEPA, the Fish and Wildlife Coordination Act, or the ESA (50 CFR 600.920(e)) in order to reduce duplication and improve efficiency. As part of the consultation process, the FERC has prepared an EFH Assessment included in appendix B of this EIS.

1.6.3 Rivers and Harbors Act

The RHA pertains to activities in navigable waters as well as harbor and river improvements. Section 10 of the RHA prohibits the unauthorized obstruction or alteration of any navigable water of the U.S. Construction of any structure or the accomplishment of any other work affecting course, location, condition, or physical capacity of waters of the U.S. must be authorized by the COE (see section 4.3 for the status of our compliance with the RHA).

1.6.4 Clean Water Act

The CWA, as amended, regulates the discharges of pollutants into waters of the U.S. and regulates quality standards for surface waters. To enact this goal both the EPA and the COE have regulatory authority under the CWA. The EPA has implemented pollution control programs including setting wastewater standards for industry and creating water quality standards for all contaminants in surface waters. Under the CWA, it is unlawful to discharge any pollutant from a point source into waters of the U.S. without a permit. The EPA operates the NPDES permit program which regulates discharges by industrial, municipal, and other facilities, that directly enter surface waters. Section 404 of the CWA regulates the discharge of dredged or fill material into waters of the U.S. and is under jurisdiction of the COE. The status of NPDES and Section 404 permitting requirements are further addressed in section 4.3 of this EIS.

Section 401 of the CWA requires that an applicant for a federal permit to conduct any activity that may result in a discharge to waters of the U.S. must provide the federal regulatory agency with a Section 401 certification. Section 401 certifications are made by the state in which the discharge originates and declares that the discharge would comply with applicable provisions of the act, including the state water quality standards. The RRC is the regulatory authority delegated with Section 401 certification for the state of Texas for oil and gas operations. The RRC also permits nonpoint discharges associated with oil and gas activities from stormwater to waters of the U.S. under the Texas Administrative Code (TAC) Title 16 Part 1 Chapter 3.

1.6.5 Clean Air Act

The CAA, as amended, defines the EPA's responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. Under the CAA, the EPA sets limits on certain air pollutants and limits emissions of air pollutants coming from sources such as industrial facilities. The EPA has delegated the authority to implement these regulations to state and local agencies. In Texas, the Texas Commission on Environmental Quality (TCEQ) is responsible for enforcement of air quality standards at a state level as well as implementation of federal air programs, with the exception of issuing permits for greenhouse gas (GHG) emissions, which is handled under a Federal Implementation Plan (FIP). However, on February 18, 2014, EPA issued a proposed rulemaking approving Texas' GHG permitting program. In anticipation of a final rulemaking, EPA offered applicants who are currently in the permitting process with EPA the choice of continuing the permitting process with EPA, or moving their applications to the TCEQ. On June 14, 2014, House Bill (HB) 788 authorizing the TCEQ permitting of GHG emissions became law in Texas. However, in order to implement HB 788, further rule changes in the TAC will need to be made and adopted, which must then be approved by EPA as part of revisions to the State Implementation Plan (SIP). Once EPA approves the SIP revisions and withdraws the FIP, the TCEQ will become the permitting authority for GHG emissions. If a final rulemaking fails to occur, applicants who chose to move their applications to the TCEQ would have the opportunity to return back to EPA for federal permitting at the point in the application process where EPA left off. The EPA also issued a rule in 2010 finalizing GHG reporting requirements for the petroleum and natural gas industry (40 CFR Part 98).

The June 23, 2014 U.S. Supreme Court decision addressing the application of stationary source permitting requirements to GHG (*Utility Air Regulatory Group v. Environmental Protection Agency, No. 12-1146*) fundamentally changed GHG permitting requirements, regardless of whether permits are issued by EPA or the states. In summary, 1) where new sources emit GHG as the only pollutant with the potential to be emitted above the major source threshold, and 2) where existing major source modifications emit GHG as the only pollutant for which there is a significant emissions increase (and a significant net emissions increase) projects no longer require Prevention of Significant Deterioration (PSD) or Title V permits.

1.6.6 Federal Aviation Act

The Federal Aviation Act of 1958 (as amended) created the Federal Aviation Administration (FAA) and delegates their authority "to provide for the regulation and promotion of civil aviation in such manner as to best foster its development and safety, and to provide for the safe and efficient use of the airspace by both civil and military aircraft, and for other purposes." Title 14 of the USC, Section 44718, *Structures Interfering with Air Commerce*, outlines the regulations associated with "the construction, alteration, establishment, or expansion, or the proposed construction, alteration, establishment, or expansion of a structure or sanitary landfill when notice would promote safety in air commerce and the efficient use and preservation of the navigable airspace and of airport traffic capacity at public-use airports."

Any construction or alteration of structures meeting the requirements outlined in 49 CFR 77, *Safe, Efficient Use, and Preservation of the Navigable Airspace*, requires that adequate notice is provided to the FAA of that construction or alteration. Subsequent to the receipt of that notice the FAA would issue a public notice of their intent to perform an aeronautical study of the obstruction to air navigational facilities and would determine the effect the obstruction would have on the safe and efficient use of navigable airspace. Following the completion of the study, the FAA would issue a determination stating whether the proposed construction or alteration would be a hazard to air navigation. The FAA issued a public notice in regards to the proposed flare stacks associated with the Terminal on September 14, 2012. Additional information regarding safety associated with the flare stacks is provided in section 4.12 of this EIS.

1.6.7 Maritime Transportation Security Act

The MTSA is designed to protect the nation's ports and waterways from a terrorist attack. It requires vessels and port facilities to conduct vulnerability assessments and develop security plans. The MTSA also requires the establishment of Area Maritime Security Committees at all of the nation's ports. These committees are tasked with coordinating activities of all port stakeholders including the Maritime Industry, the boating public, and other federal, state, and local agencies. As a cooperating agency with the FERC, the Coast Guard prepared a LOR to analyze the potential navigation safety and maritime security risks associated with the Project. The Coast Guard also has responsibilities relating to LNG waterfront facilities at 33 CFR 127.

1.6.8 National Historic Preservation Act

Section 106 of the NHPA, as amended, requires the FERC to take into account the impacts of its undertakings on historic properties, and afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. Historic properties include prehistoric or historic sites, districts, buildings, structures, objects, or properties of traditional religious or cultural importance listed in or eligible for listing in the National Register of Historic Places (NRHP). In accordance with the ACHP's regulations for implementing Section 106, at 36 CFR 800.2(a)(3), the FERC staff is using the services of the applicant and its consultants to prepare information, analyses, and recommendations. However, we remain responsible for all findings and determinations. We will follow the process of complying with Section 106 outlined in Part 800 by consulting with the Texas State Historic Preservation Office (SHPO), identifying historic properties in the area of potential effect (APE), and assessing potential project effects. In Texas, the Texas Historical Commission (THC) houses the SHPO. Section 4.10 of this EIS summarizes the status of our compliance with the NHPA.

1.6.9 Coastal Zone Management Act

The CZMA calls for the "effective management, beneficial use, protection, and development" of the nation's coastal zone and promotes active state involvement in achieving those goals. As a means to reach those goals, the CZMA requires participating states to develop management programs that demonstrate how these states would meet their obligations and responsibilities in managing their coastal areas. In the state of Texas, the TGLO is the agency responsible for administering its Coastal Zone Management Program (CZMP). Because Section 307 of the CZMA requires federal agency activities to be consistent to the maximum extent practicable with the enforceable policies of a management program, the FERC has requested that Cheniere seek a determination of consistency with Texas's CZMP. Sections 4.8.1.5 and 4.8.2.5 of this EIS summarize our compliance with the CZMA.

1.6.10 National Flood Insurance Act

The NFIA created the National Flood Insurance Program and delegated the authority to manage the program to the Federal Emergency Management Administration (FEMA). The purpose of the NFIA was to make flood insurance available, improve floodplain management, and develop maps of flood hazard zones. State and local governments must implement floodplain management regulations consistent with the federal criteria outlined in 44 CFR 60, *Criteria for Land Management and Use*. Participating local governments in flood-prone areas, as designated by FEMA, agree to adopt and enforce ordinances that meet or exceed FEMA requirements to reduce the risk of flooding. Additional information regarding flood risks and our compliance with the NFIA is provided in section 4.1.1.5 of this EIS.

Table 1.6-1
Environmental Permits and Agency Reviews for the Corpus Christi LNG Project

Agency	Regulation/Permit/Approval	Agency Actions	Submission Date/Status
Federal			
COE	Section 404 of the CWA; Section 10 of the Rivers and Harbors Act	Section 404/10 Individual Permit - Request to amend Permit No. SWG-2007-01637	Permit issued July 23, 2014; request to amend permit submitted on September 9, 2014
Coast Guard	33 CFR 105; 33 CFR 127 ; Notice to mariners; Maritime Transportation Security Act	Letter of Recommendation	Received March 21, 2013
EPA	Section 402 of the CWA; 44 CFR 9; CAA	GHG PSD Permit/Sinton CS	Draft issued February 6, 2014
		NPDES Stormwater Construction Permit	Notification prior to construction
FWS	Section 7 of the ESA	Threatened and endangered species consultation	Concurrence received August 8, 2013 and November 5, 2013
NOAA Fisheries/NMFS	Section 7 of the ESA; Section 305 of the MSA; Marine Mammal Protection Act; Fish and Wildlife Coordination Act	Marine threatened and endangered species consultation; EFH consultation	Issued response October 29, 2012 stating that reinitiating consultations is not required and the “may affect, but not likely to adversely affect” determination from the 2005 consultation remains valid. Issued comments to the COE in response to the public notice on June 28, 2013 regarding recommendations for Essential Fish Habitat impacts.
Federal Aviation Administration	Section 1101 of the Federal Aviation Act	Notice of proposed construction of a structure (flare stacks) exceeding airspace obstruction standards	FAA issued a response that the structure would have no substantial adverse effect on the safe and efficient utilization of the navigable airspace by aircraft or on the operation of air navigation on January 29, 2013
DOE	Section 3 of the NGA; 15 USC Section 717b	Application for authorization to export LNG to non-Free Trade Agreement countries	Application submitted August 31, 2012
		Application for long-term authorization to export LNG to Free Trade Agreement countries	Authorization granted October 16, 2012
State			
RRC	Section 401 of the CWA;	Water Quality Certification	Permit issued July 23, 2014
	Coastal Zone Management Act	Coastal Zone Consistency Determination	Consistency determination issued November 14, 2013
	TAC Title 16 Part 1 Chapter 3	Stormwater Discharge Permit	Notification prior to construction
TCEQ	Texas Clean Air Act; CAA; 40 CFR 50-99	GHG PSD permit/Terminal	Submitted April 14, 2014
		PSD Air Permit Terminal PSD Air permit Sinton CS	Draft issued July 8, 2013 Final issued December 20, 2013
		Title V Air Permit/Terminal Title V Air Permit/Sinton CS	Submitted November 7, 2012 Submitted November 7, 2012

Table 1.6-1
Environmental Permits and Agency Reviews for the Corpus Christi LNG Project

Agency	Regulation/Permit/Approval	Agency Actions	Submission Date/Status
THC	Section 106 of the NHPA	Request for concurrence with determination that previously submitted reports and determinations remain valid.	SHPO concurrence dated May 25, 2012 and July 3, 2012.
		Request for concurrence with determination that no additional archaeological investigations would be necessary at the laydown area, parking area, borrow pit, and compressor station.	SHPO concurrence dated August 15, 2012.
		Request for concurrence with determination that the additional ancillary work areas (Tool and Lunch Area, Temporary Laydown Area North, Temporary Laydown Access, Temporary Parking Area, and La Quinta Road Utility Corridor) will not affect any historic properties.	SHPO concurrence dated April 22, 2013.
Local			
San Patricio County Emergency Management	44 CFR 60	County Floodplain Permit	Submitted prior to construction

PROPOSED ACTION

SECTION 2

2.0 DESCRIPTION OF PROPOSED ACTION

The Project consists of a new natural gas liquefaction and export plant, as well as LNG import facilities with regasification capabilities (Terminal) all located along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio and Nueces Counties, Texas. The Terminal includes two marine berths each containing a maneuvering area as well as a protected marine berth area capable of accommodating two LNG carriers at a time for import/export; however, the total loading or unloading rate would not exceed 12,000 cubic meters (m^3) per hour.

Additionally, the Project involves the construction and operation of a new 48-inch-diameter, 23-mile, bi-directional natural gas pipeline (Pipeline) extending from the proposed Terminal to north of Sinton in San Patricio County. The new Pipeline would transfer the imported natural gas to markets throughout Texas and the U.S. via interconnections with a number of existing intrastate and interstate pipeline systems, and to transfer natural gas to the Terminal for liquefaction and export.

A general map of the Terminal facilities is provided as figure 1.1-1 and the proposed site boundary is provided as figure 1.1-3. The following sections describe the proposed facilities associated with the Project, construction procedures and schedule, environmental compliance and inspection monitoring, operation and maintenance procedures, safety controls, and land requirements.

2.1 TERMINAL (IMPORT AND EXPORT) FACILITIES

The Terminal would include liquefaction facilities, marine terminal and LNG transfer lines, LNG storage facilities, LNG vaporization facilities, flare facilities, and other infrastructure.

2.1.1 Liquefaction Facilities – Export

The Terminal would include three LNG liquefaction trains, necessary to liquefy natural gas, each capable of liquefying approximately 700 MMscf per day of natural gas. Each liquefaction train consists of multiple facilities which include:

- facilities which remove carbon dioxide (CO_2), hydrogen sulfide (H_2S), and sulfur compounds from feed gas;
- facilities to remove water and mercury from the feed gas;
- facilities to remove heavy hydrocarbons (such as benzene, toluene, ethylbenzene, and xylene [BTEX]) from the feed gas to avoid freezing in the liquefaction unit;
- standard annular combustor aero-derivative LM2500 G4+ gas turbine-driven refrigerant compressors – each gas turbine would have water injection for emissions control, and Inlet Air Humidification Systems to be operated when the ambient temperature is at or above 60 degrees Fahrenheit (°F);
- waste heat recovery systems for regenerating the gas driers and amine system;
- induced draft air coolers;
- associated control systems and electrical infrastructure;

- utility connections and distribution systems; and
- piping, piperacks, foundations, and structures within the LNG train battery limits.

BTEX and acid gas impurities removed from the natural gas stream prior to liquefaction would be disposed of by passing through a triazine scavenger bed which absorbs any H_2S. The remaining waste gas contains CO_2 and would be mixed with a small amount of fuel gas and sent to a thermal oxidizer. Cheniere would then send the spent solvent to a licensed disposal facility. While the feed gas contains no mercury, as a precaution, Cheniere would provide mercury removal beds and any mercury collected would be sent to a licensed disposal facility.

2.1.2 LNG Vaporization Facilities – Import

Cheniere would install two trains of ambient air vaporizers (AAVs) and send out pumps each capable of vaporizing sufficient LNG volume to send out approximately 200 MMscf per day of natural gas. Each AAV train would be comprised of approximately 18 to 20 AAV cells and associated piping, valves, and one high-pressure LNG send-out pump. Each AAV train would cycle the AAV cells between operation and defrost, with some cells vaporizing and some cells in defrost mode at any one time, depending on ambient conditions. Cheniere selected the AAV vaporization system because they provide the most fuel efficient method for regasifying LNG. The AAVs do not require combustion to regasify as opposed to traditional Submerged Combustion Vaporizers.

2.1.3 LNG Storage Facilities

The LNG would be stored in three, full containment storage tanks. The tanks would be oriented in a straight line, separated by 50 meters. Each tank would be 194 feet above grade and 258.5 feet in diameter. The tanks would be designed to store a nominal volume of 160,000 m^3 (1,006,400 barrels) of LNG at a temperature of -270°F and a maximum internal pressure of 3.5 pounds per square inch gauge (psig) (though the normal operating conditions would be -260°F and 1.5 psig). The tank system would meet the requirements of the NFPA 59A, 49 CFR Part 193, and American Petroleum Institute (API) Standard 620 Appendix Q.

There would be several major components to the LNG storage tanks:

- A 9 percent nickel steel open top 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 space between the inner container and the outer container would be insulated with expanded perlite to maintain the outer container at near ambient temperature. The insulation beneath the inner container would be cellular glass load-bearing insulation that would support the weight of the inner container and the LNG.
- An outer tank comprised of reinforced concrete with a domed concrete roof. The outer tank would be designed for the specified internal pressure of 3.5 psig, and a sustained wind speed of 150 miles per hour (mph). In addition, the tank would be designed for seismic loads in accordance with NFPA 59A and the site specific seismic reports, internal pressure imposed by insulation loads, and roof and platform dead loads.
- An insulated aluminum deck over the inner container, suspended from the roof. The aluminum support deck would be insulated with fiberglass blankets so that the outer tank

roof and vapor space above the suspended deck would 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 tanks would be supported on a reinforced concrete mat with electric base heating to prevent frost heave. Each tank would also have five in-tank pump well columns, four of which would be fully installed with foot valve, electrical components, structural supports, instrumentation, piping, etc. The fifth pump well column would be equipped with a foot valve only for use as a future spare pump. All LNG piping would enter the tank through the concrete tank roof. All piping systems would be in accordance with American Society of Mechanical Engineers (ASME) B31.3 and NFPA 59A Chapter 6. Each LNG tank would also be equipped with a cool down temperature detection system to monitor the inner tank bottom plate and inner tank shell continuously during cool-down procedures; foundation temperature sensors located at strategic locations under the tank; instrumentation to monitor the quality and level of LNG in the tank and to monitor tank contents for stratification; a safety-rated control system to monitor the LNG level and control the fill line shutoff valves; pressure and vacuum relief systems; platforms, elevators, and stairways with intermediate landings attached to the outer tank; spill protection of the tank roof over the edge of the roof dome; lighting and aircraft warning lights; electrical grounding system; electrical base heating; a settlement monitoring system to measure and record inner and outer container movements during construction, hydrostatic testing, and operation; and seismic monitors.

2.1.4 Marine Terminal and LNG Transfer Lines

Access to the proposed marine terminal associated with the Terminal facilities from the Gulf of Mexico would be through a series of channels. The navigation channels that would be used to reach the marine terminal include the Aransas Pass Safety Fairway, Aransas Pass Outer Bar Channel, Jetty Channel, Corpus Christi Ship Channel (including the Inner Basins at Harbor Island and the junction with the La Quinta Channel), and the La Quinta Channel. The marine terminal would be located on the north end of the La Quinta Channel. Land-based facilities associated with the Terminal would be located in San Patricio County, while marine facilities would be in Nueces County.

2.1.4.1 LNG Carriers and Marine Berths

The proposed marine terminal would include two LNG carrier berths. Both berths would consist of a maneuvering area and a protected marine berth area. Cheniere estimates that approximately 200 to 300 LNG carrier round-trip transits through the Corpus Christi Bay would occur annually. To facilitate maneuvering of the LNG carriers, Cheniere would keep tug boats available. When not in use, the tug boats would be docked at the marine facilities.

Each marine berth would consist of at least four breasting dolphins, consisting of reinforced concrete structures on piles. The dolphins would be equipped with fenders suitable to safely berth and moor the full-size range of ships anticipated at the Terminal. The breasting dolphins would also be equipped with quick-release mooring hooks for spring lines to provide the necessary mooring lines arrangement flexibility for various sizes of vessels. In addition to the breasting dolphins, six mooring dolphins would be provided, each consisting of reinforced concrete structures on piles and equipped with quick release mooring hooks.

The LNG cargo transfer docks would be single-level concrete structures supported on piles. Each dock would consist of a reinforced concrete beam and slab structure, approximately 90 feet wide by approximately 116 feet long. The piles to support the dock and dolphins would be driven during daylight hours only and operations would observe the procedures necessary to minimize impacts on aquatic life and marine mammals (see sections 4.6 and 4.7). The procedures would include exclusion zones, sound attenuation, soft start procedures, visual monitoring, and shutdown and delay procedures. Each dock would be curbed to confine potential LNG spillage and its surface would be sloped to a collection point. Drainage from the collection point would be via the LNG spill collecting trough to a spill impoundment basin.

Shipboard LNG cargo pumps would deliver the LNG from each marine berth to the LNG storage tanks at a design rate no more than 12,000 m^3 per hour via two parallel LNG transfer lines for the unloading/vaporizing (import) mode. During the liquefaction (export) mode, in-tank pumps would deliver LNG to ships from the storage tanks at a design rate no more than 12,000 m^3 per hour. Three 20-inch-diameter marine cryogenic cargo transfer arms would be installed for liquid delivery to/from the storage tanks, and one 20-inch-diameter arm would provide vapor return flow between the ship and the Terminal. The cargo transfer arms would be designed with swivel joints and equipped with sensors to provide the required range of movement between the ship and the shore connections. Each arm would be fitted with a powered emergency release coupling and associated valves to protect the arm and ship's manifold while also avoid spillage of its liquid contents in the case of unusual movement of the ship continuing beyond the normal operating envelope. Each arm would be operated by a hydraulic system with a counterbalance weight to reduce the weight of the arm bearing on the shipside connection and to reduce the power required to maneuver the arm into position.

The LNG cargo transfer docks would also allow access for a mobile crane that Cheniere anticipates would be required to facilitate maintenance service on the cargo transfer arms. The facilities would be designed to provide safe berthing for receipt and mooring of LNG carriers and to ensure the safe transfer of LNG cargoes between the ships and the onshore storage facilities. Design of the marine facilities would be in accordance with applicable codes and standards, including but not limited to, Oil Companies International Marine Forum, Society of International Gas Tanker and Terminal Operators, API, and American Society of Civil Engineers (ASCE).

Cheniere indicated that they confirmed its proposed facility design with simulations which demonstrated maneuvering and docking of all modeled LNG carriers would be accomplished with no more than three Z-drive tractor tugs (each having approximately 70 metric tons shallow water bollard pull capability) under most anticipated environmental conditions of weather, current, tide, etc. However, Cheniere plans to have four tugs boats in reserve at the Terminal site to assist in LNG carrier maneuvering. Cheniere also had the berth layout reviewed by experienced pilots, and changes were made based on their recommendations. Computer simulations of the maneuvering and berthing evolutions were then conducted at the COE Engineering Research and Development Center's (ERDC) Ship and Tow Simulator located in Vicksburg, Mississippi. Additional computer simulations were conducted using updated LNG carrier computer models on a Transas full-mission bridge simulator at the Maritime Institute of Training and Graduate Studies located in Linthicum, Maryland.

The LNG carrier berths would be protected as much as practicable from other ship traffic, particularly in the unlikely case of a ship becoming disabled while passing the Terminal. The location and configuration of the berths would be such that the LNG carrier berths would be recessed and at enough of an angle to avoid this, while maintaining sufficient maneuvering area in case a docked LNG carrier needs to make an emergency departure. Cheniere's final berth layout was confirmed to meet these criteria at the ERDC as well as the Maritime Institute of Training and Graduate Studies.

LNG carriers would load/discharge LNG cargoes at the berths via the bidirectional cargo transfer arms. LNG would flow via the stainless steel insulated LNG transfer lines for delivery to the LNG storage tanks or to the LNG carrier. During berth idle periods when no cargo transfer operations are being conducted, the contents of the LNG transfer lines would be recirculated from one LNG storage tank to the jetty and back to another LNG tank to keep the LNG lines cold.

Ballast is a necessary safety feature of commercial shipping that provides control of longitudinal trim and transverse stability during voyages and while in port. Controlling ballast weight and placement also ensures adequate submergence of the propeller, reduces stresses on the ship's hull, and controls both the longitudinal and vertical locations of the center of gravity as required for safe navigation and operation of ships. Impacts resulting from ballast water are discussed in sections 4.3 and 4.6.

2.1.4.2 Barges

Barges would be necessary for transportation of equipment to the Terminal site during construction. A roll-on/roll-off area would be sited to the west of the LNG carrier berths for unloading equipment from barges. The primary materials that would be used in construction of the marine berth include steel-pipe pilings, concrete, and reinforcing steel for the concrete. Cheniere anticipates that the reinforcing steel would be fabricated off site and trucked to the Terminal site or delivered by barge to the construction dock. The concrete would be produced in a batch located at the main Project site or purchased from a local supplier, depending on local availability at the time of construction.

2.1.4.3 Dredge Disposal

To accommodate the deepest draft LNG carriers, Cheniere would dredge the berth areas to a minimum depth of -46 feet North American Vertical Datum of 1988 (NAVD88), plus 2 feet paid allowed overdredge to ensure the minimum depth is met, and 2 feet advanced maintenance dredge. Cheniere anticipates that 2 feet of maintenance dredging would be required approximately every three years to ensure minimum depth is maintained. A 3:1 side slope would form the sides of the slip, portions of which would be protected using articulated block mats or other suitable means of stabilization, where required. Cheniere would also expand the existing maneuvering area to the same parameters described for the berths.

Initial dredging of the berths would result in the dredging of approximately 4.4 million cubic yards (mcy) of material, while maintenance dredging is anticipated to occur every three years and produce approximately 200,000 cubic yards of material. Dredge materials would be disposed of in two ways. Some of the dredged material would be used to fill a portion of a former 90-acre clay borrow pit northeast of the Project site. The remainder of the dredged material would be used to cap old bauxite disposal beds located in a 385-acre area immediately north of the Project site. This area is known as dredge material placement area (DMPA) 2. The dredge material would be transferred to DMPA 2 via an approximately 11,000-foot-long, 30-

inch-diameter slurry pipe. The dredge material would be evenly distributed across the bauxite beds and the water would be decanted and monitored as it leaves the DMPA to permitted outfalls. The resulting soil would be a cap over the old bauxite beds which would allow revegetation to occur, reducing the red dust in the area. Figure 2.1-1 shows the location of the 90-acre clay pit disposal area as well as DMPA 2, in relation to the Terminal site.

A portion of the marine terminal's berth approach area was recently dredged by the COE as part of an extension of the La Quinta Channel. The two marine berths associated with Terminal would be designed to accommodate a broad range of present and future LNG carrier size and type classes, including the largest presently existing (Q-max class) LNG carriers with cargo capacities of up to approximately 267,000 m^3.

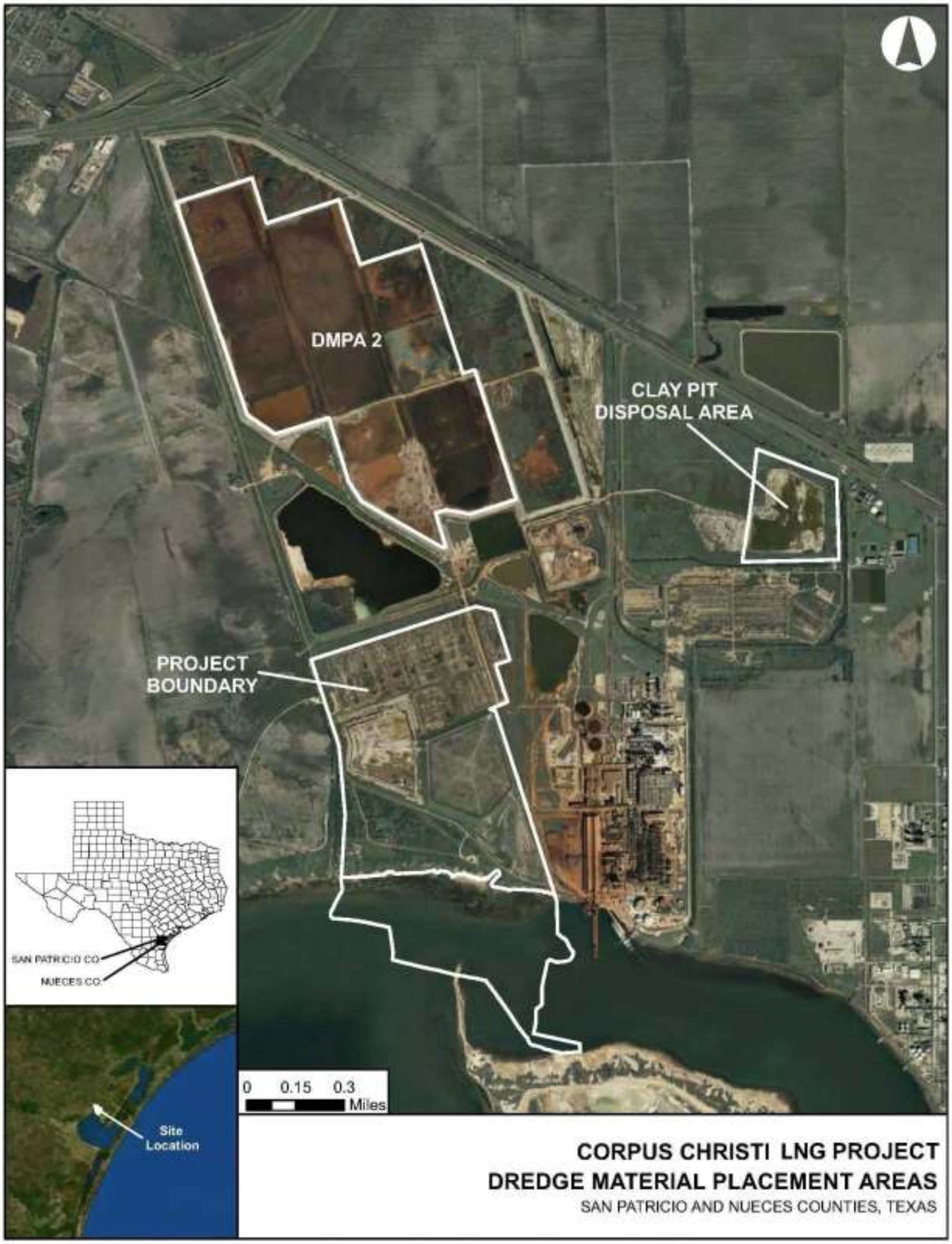

Figure 2.1-1 **Proposed Dredge Material Placement Areas**

2.1.5 Flare Facilities

All liquefaction plant hydrocarbon emergency relief loads would go to a closed flare system. The flares are the control technology for volatile organic compounds (VOCs) and organic hazardous air pollutants (HAPs), and achieve 98 percent combustion efficiency over all conditions including plant start-up, shut-down, continuous operation and emergency flaring at all rates.

The Project would include flares to protect the process and the LNG loading and unloading system during upset or emergency cases. Five flares consisting of three types would be installed for the Project, including two wet gas flares, two dry gas flares, and one marine flare.

Two identical wet/dry flare systems would be provided, with each system sized for loads from two LNG trains. The first wet/dry system would be exclusively for Train 1 with the second for Train 3. Relief from Train 2 would be routed to either of the two flare systems, allowing both systems to provide relief for two trains. The marine flare would be utilized for purging inert gases from some ships and as pressure control for the emergency venting of the three LNG storage tanks. The wet and dry flares would be located on the common derrick structure approximately 500 feet tall. This arrangement would incorporate demountable flares to facilitate ease of flare tip maintenance. Critical Project structures and equipment, including ships at the marine berths would be outside the high heat flux zones.

Each flare would be ignited by a pilot and the flame would be monitored by dual thermocouples. The flare pilot would be operated in a continuous mode and is re-lit automatically if the flame goes out for the wet and dry flares. The marine flare pilot would only be operated during ship loading.

2.1.6 Other Terminal Infrastructure

In addition to the facilities described above, the Terminal would also require additional facilities and infrastructure including:

- miscellaneous buildings and other structures to accommodate equipment, utilities, and support services infrastructure;
- warehouse to store spare parts and consumables for the liquefaction, regasification, and utility facilities;
- storage area for chemicals, lubricants, and hazardous substances;
- operation and maintenance building, including the control room;
- remote input/output buildings and substations;
- storage vessels for propane and ethylene refrigerants;
- storage tanks for amine make up;
- storage tanks for heavy hydrocarbons removed from the feed gas;
- spill containment facilities;
- emergency shutdown (ESD) systems;
- firewater system, including diesel driven pumps and storage tank;

- instrument air compressor packages;
- security and perimeter control systems, telecoms, information technology, closed-circuit television, and other systems;
- storage tanks for condensate, liquid nitrogen, diesel, and gasoline;
- potable water, service water, and demineralized water systems;
- pipeline interconnect for the receipt of natural gas from and export to the Pipeline;
- electric facilities, switchgear, transformers, and other electrical accessories;
- emergency diesel power backup system; and
- pipeline gas compressor.

2.2 PIPELINE FACILITIES

2.2.1 Pipeline

The Pipeline operating facilities would be designed for a maximum allowable operating pressure (MAOP) of 1,440 psig and a capacity of 2.25 Bcf/d. The Pipeline facilities would be located entirely within San Patricio County, Texas. A summary of facilities associated with the Pipeline are discussed below.

Cheniere would construct approximately 23 miles of new 48-inch-diameter natural gas pipeline, originating at the Terminal and routed primarily along an existing collocated electric transmission and gas pipeline in San Patricio County, Texas. The Pipeline would terminate north of Sinton at an interconnect with Tennessee Gas Pipeline Company, LLC (Tennessee Gas).

Six meter and regulator (M&R) stations would be installed at interconnects along the Pipeline. The Liquefaction M&R Station would be located at milepost (MP) 0.0 and would be remotely operated to feed gas to/from the Terminal. This station would include one bi-directional M&R system with a 2.6 Bcf/d capacity, filter separators, liquid handling tanks, gas chromatograph building, one pig trap on the 48-inch mainline, and pressure/flow control. The Texas Eastern Transmission, L.P. (Texas Eastern) M&R Station would be located at approximate MP 7.5 and would be located on the Taft Compressor Station parcel. This station would include one bi-directional M&R system with a 0.5 Bcf/d capacity, filter separator, and liquid handling tank. The Tejas Pipeline LLC (Tejas) M&R Station would be located at approximate MP 21.5 and would have taps on both existing Tejas pipelines (30-inch-diameter and 36-inch-diameter). This station would include a 48-inch by 36-inch ‘T’ and valve on the Pipeline, one bi-directional M&R system with a 1.0 Bcf/d capacity, filter separator, and liquid handling tank.

The Natural Gas Pipeline Company, LLC (NGPL) M&R Station would be located at approximate MP 22.4 and would have taps on both existing NGPL pipelines (26-inch-diameter and 30-inch-diameter). This station would include a 48-inch by 36-inch ‘T’ and valve on the Pipeline, one bi-directional M&R system with a 0.5 Bcf/d capacity, filter separator, and liquid handling tank. The Transcontinental Gas Pipe Line Company, LLC (Transco) M&R Station would be located at approximate MP 22.8 and would include a 48-inch by 24-inch ‘T’ and valve on the Pipeline, one bi-directional M&R system with a 0.25 Bcf/d capacity, filter separator, and liquid handling tank. The Tennessee Gas M&R Station would be located at approximate MP 23.0 and would have taps on both existing Tennessee Gas pipelines (24-inch-diameter and

30-inch-diameter). This station would include a 48-inch by 36-inch ‘T’ and valve on the Pipeline, one bi-directional M&R system with a 1.0 Bcf/d capacity, one pig trap on the 48-inch mainline, filter separator, and liquid handling tank.

In addition to the facilities listed above, Cheniere would also install five mainline valves (MLV), as well as a pig launcher and receiver.[7] MLVs would be installed at the Liquefaction M&R Station, Taft Compressor Station, MP 14.5, Sinton Compressor Station, and the Tennessee Gas M&R Station. A pig launcher would be installed at the Liquefaction M&R Station with a pig receiver installed at the Tennessee Gas M&R Station.

2.2.2 Compressor Stations

Cheniere would construct two new compressor stations associated with the Pipeline. The Taft Compressor Station would be constructed at approximate MP 7.5 and would be remotely operated. The station would be located at an interconnect with a Texas Eastern and would include two Solar Centaur 50 turbine/compressor units (6,387 horsepower [hp] each); one compressor building to house both turbine/compressor units and to include suitable noise abatement and overhead hoists; one auxiliary building with office space, bathrooms, and storage for incidental spare parts for the compressor station; emergency power generator capabilities for operation of the entire station; two suction headers (one mainline header and one for connection to the Texas Eastern pipeline); filter separators; liquid handling tanks; and discharge gas coolers associated with the Centaur 50 units.

The Sinton Compressor Station would be constructed at approximate MP 21.5. The Sinton Compressor Station would be remotely operated and would include two Solar Titan 130 turbine/compressor units (20,387 hp each), one compressor building to house both turbine/compressor units and to include suitable noise abatement and overhead hoists, one auxiliary building with office space and storage for incidental spare parts for the station, emergency power generator capabilities for operation of the entire station, two suction headers (one mainline header and one for connection to the Tejas system), filter separators, liquid handling tanks, and discharge gas coolers associated with the Titan 130 units.

2.3 LAND AND WATER REQUIREMENTS

2.3.1 Terminal Facilities

Cheniere estimates that approximately 991 acres would be affected by construction of the Terminal including the marine basin and berths. Following construction, 349 acres would continue to be impacted by operation and maintenance dredging and another 120 acres would be part of an exclusion zone. Table 2.3-1 lists the land and water requirements for the Terminal facilities. The majority of the land at the Terminal site is previously disturbed and includes areas that were used for stockpiling bauxite. Water requirements associated with the Terminal include part of the marine berths and basin, a tug dock, a construction dock, and part of the exclusion zone.

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[7] A pipeline “pig” is a device used to clean or inspect the pipeline. A pig launcher/receiver is an aboveground facility where pigs are inserted or retrieved from the pipeline.

Table 2.3-1
Land and Water Requirements for the Terminal

Facility	Land Impacted by Construction (acres)	Land Impacted During Operation (acres)	Water Impacted by Construction (acres)	Water Impacted During Operation (acres)	Total Area Impacted by Construction (acres) a/	Total Area Impacted During Operation (acres) b/
Terminal Site c/, d/	225	225	0	0	225	225
Marine Basin and Berth	5	5	121	119	126	124
Dredged Material Placement e/	437	0	0	0	437	0
Temporary Laydown Areas f/	160	0	0	0	160	0
Temporary Parking Area f/	26	0	0	0	26	0
Temporary Access Roads f/	8	0	0	0	8	0
Tool and Lunch Area f/	9	0	0	0	9	0
Exclusion Zones	0	91	0	29	0	120
Total	**870**	**321**	**121**	**148**	**991**	**469**

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a/ Construction area includes entire construction footprint, including all temporary and permanent construction areas.
b/ Operation area includes the permanent Terminal site, marine basin and berth, permanent easement, and exclusion zone.
c/ Acreage excludes the marine basin and berths and the capped Bauxite Disposal Bed 22 (52 acres). The Bauxite Disposal Bed 22 is within Project boundary but would not be disturbed by construction or operation.
d/ Bed 24 acreage is included in Terminal site (area would be filled with structural fill material and become part of the operating area).
e/ DMPA 2 and the Clay Pit Disposal Area would be used during construction.
f/ Area used during construction only and located outside of the Terminal Site.

2.3.2 Pipeline Facilities

Table 2.3-2 summarizes the land requirements for the Pipeline and associated facilities. Additional information regarding land requirements for the Pipeline facilities is provided in the following sections.

Table 2.3-2
Land Requirements for the Pipeline and Associated Facilities

Facility	Land Impacted by Construction (acres)	Land Impacted During Operation (acres)
Pipeline Right-of-Way		
Pipeline	321.1	142.3
Additional Temporary Workspace	27.0	0.0
Compressor Stations		
Taft Compressor Station (MP 7.5)	6.9	5.8
Sinton Compressor Station (MP 21.5)	17.2	7.3
M&R Stations		
Liquefaction M&R Station (MP 0.0)	2.0	1.6
Texas Eastern M&R Station (MP 7.5)	2.1	2.1
Tejas M&R Station (MP 21.5)	2.4	2.4
NGPL M&R Station (MP 22.4)	1.3	1.0
Transco M&R Station (MP 22.8)	1.0	0.9
Tennessee Gas M&R Station (MP 23.0)	2.0	2.0
Launchers/MLVs		
Terminal Pig Launcher and MLV (MP 0.0) a/	0.0	0.0
MLV at Taft Compressor Station (MP 7.5) b/	0.0	0.0
MLV (MP 14.5)	0.2	0.2
MLV at Sinton Compressor Station (MP 21.5) c/	0.0	0.0
Pig Receiver and MLV (MP 23.0) d/	0.0	0.0
Access Roads/Yards		
Access Roads	20.1	12.7
Contractor and Pipe Yard	17.4	0.0
Total:	**420.7**	**178.3**

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a/ Included with the Liquefaction M&R Station.
b/ Included within the Taft Compressor Station.
c/ Included within the Sinton Compressor Station.
d/ Included within the Tennessee Gas M&R Station.

The 48-inch-diameter Pipeline would be installed adjacent to a high voltage overhead powerline and existing natural gas pipelines along approximately 86 percent of the route. Construction of the Pipeline would require the use of a 120-foot-wide construction right-of-way consisting of 50 feet of permanent and 70 feet of temporary right-of-way in uplands. In wetlands, the construction right-of-way would be 75 feet (consisting of 50 feet permanent and 25 feet temporary right-of-way). The construction right-of-way would be collocated in some areas and may overlap with other existing rights-of-way.

The 120-foot-wide construction right-of-way would be necessary to accommodate both the increased trench depth and width necessary to install a 48-inch-diameter pipe. Due to the depth of the soils in the area, additional space would be required to store trench spoil and segregated topsoil. The right-of-way would also provide heavy equipment operators the necessary area to maintain safe and efficient separation distances between the potentially unstable trench sidewalls and their equipment. The increased construction right-of-way would also ensure adequate separation between adjacent foreign pipelines or high voltage overhead power lines and the construction activities.

Although Cheniere has routed its pipeline to be adjacent to existing utility or road rights-of-way for about 86 percent of the proposed route, it has not provided site-specific configurations for its construction right-of-way by milepost since the pipeline design has not been finalized. Cheniere would provide this information once the pipeline easement negotiation process is complete. Cheniere indicates that it may be able to collocate or overlap its construction right-of-way with other utility or road rights-of-way. Collocation of the pipeline and/or overlapping construction right-of-way would further minimize the construction footprint on properties crossed, thus minimizing impacts on affected resources. Table 2.3-3 below provides the milepost locations where pipeline construction may be adjacent to existing utilities or road rights-of-way, and the direction. Because the final pipeline design has not been provided, and to further reduce construction footprint of the pipeline construction workspace, **we recommend that**:

- **<u>Prior to construction of the pipeline</u>, Cheniere should update table 2.3-3 of the EIS to identify the existing utilities/road locations and the milepost ranges of where its construction right-of-way would overlap or collocate other utility/road rights-of-way; and revise its final alignment sheets to reflect the actual right-of-way configurations and workspace needs at these locations.**

Table 2.3-3
Locations Where the Pipeline may be adjacent to Existing Rights-of-Way

Mileposts	Segment Length (miles)	Existing Easement	Direction from Existing Right-of-Way
0.0 – 0.64	0.64	La Quinta Road	Adjacent to the west side of the road.
0.80 – 2.16	1.36	Equistar Pipeline, Koch Pipeline, Tejas Pipeline, and El Paso Pipeline	Adjacent to the north side of the Koch Pipeline.
2.36 – 2.90	0.54	Overhead power line and water line	Adjacent to north side of the water line.
2.90 – 7.90	5.00	County Road 78, overhead electric power line and water line	Adjacent to north side of the water line. County Road 78 is about 300 feet south to about MP 5.0 and about 100 feet south thereafter.
7.90 – 8.94	1.04	County Road 78	Pipeline would be about 500 feet south of County Road 78 (not adjacent).
11.05 – 13.22	2.17	Koch Pipeline	Adjacent to the north side of the Koch pipeline.
13.22 – 13.78	0.56	Koch Pipeline, private road, & water line	Adjacent to the north side of the water line. The private road is about 50 feet south.
13.79 – 14.45	0.66	El Paso Pipeline	Adjacent to the north side of pipeline.
14.45 – 16.04	1.59	County Road 2921, El Paso Pipeline, Valero Pipeline	Adjacent to the east side of Valero Pipeline. County Road 2921 is about 1,000 feet west.
16.04 – 17.80	1.76	Valero Pipeline, (2) El Paso Pipelines	Adjacent to the east side of Valero Pipeline.
18.31 – 22.72	4.41	Valero Pipeline, (2) El Paso Pipelines	Adjacent to the east side of Valero Pipeline.
Total	**19.73**		

Typical pipeline right-of-way configurations for overlapping construction rights-of-way and abutting rights-of-way are depicted in figure 2.3-1 and figure 2.3-2, respectively.

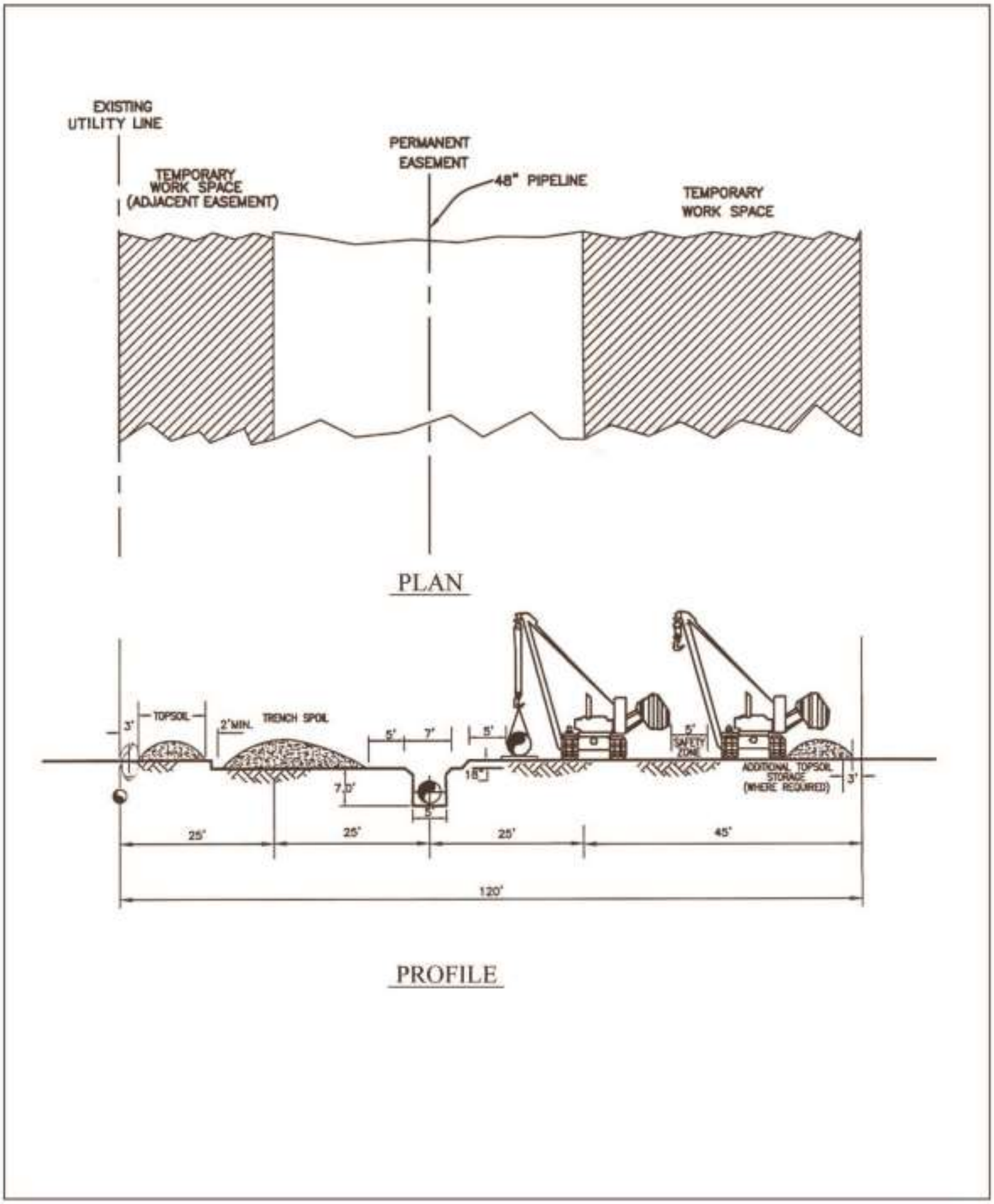

Figure 2.3-1 Typical pipeline right-of-way configuration with overlapping rights-of-way

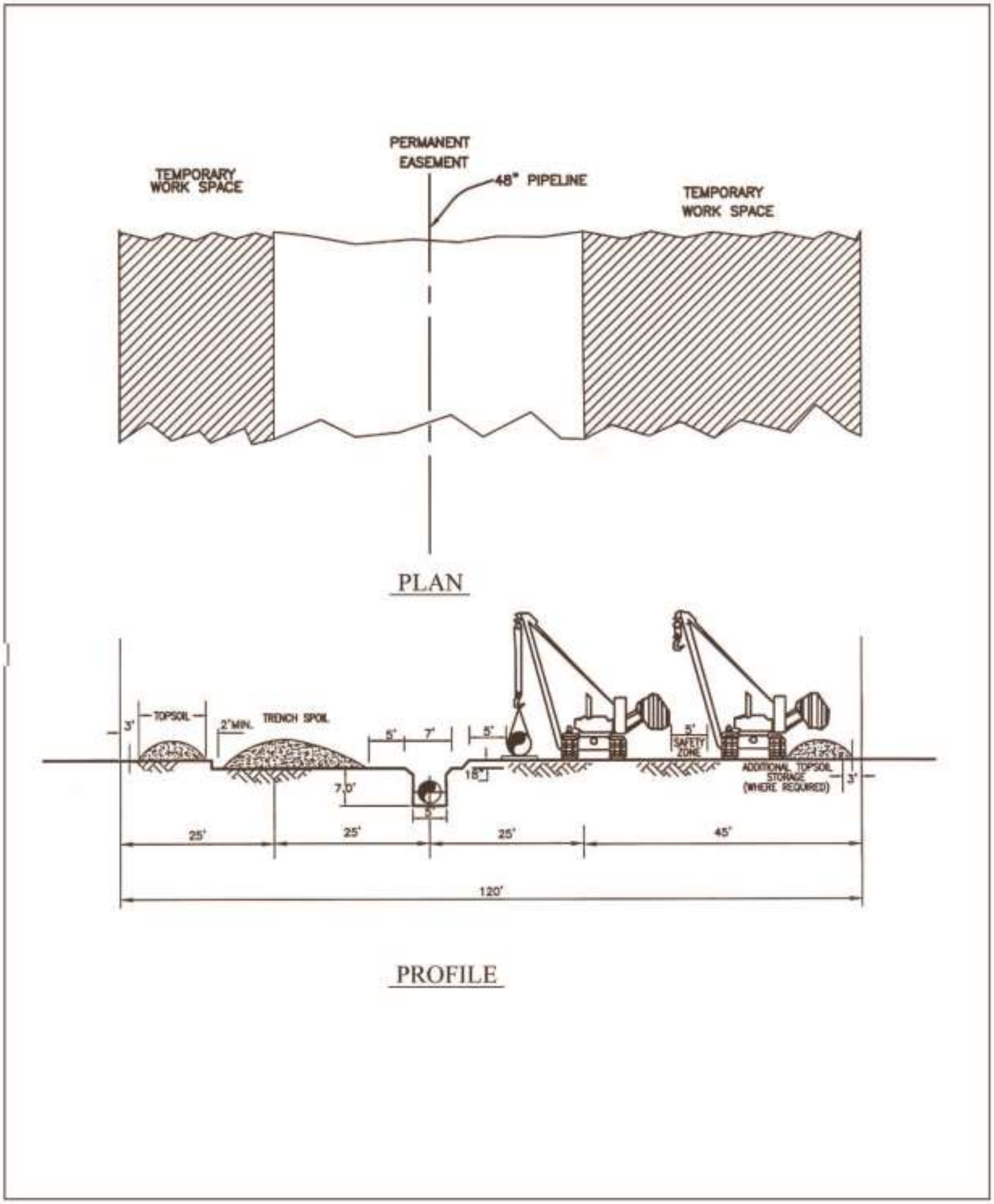

Figure 2.3-2 Typical pipeline right-of-way configuration with abutting rights-of-way

Additional temporary workspace (ATWS) would also be utilized in areas requiring specialized construction techniques such as road and waterbody crossings. Following the completion of construction, the temporary construction right-of-way and ATWS areas would be restored to preconstruction conditions and a 50-foot permanent easement would be required for operation and maintenance of the Pipeline.

The Taft Compressor Station would require approximately 6.9 acres of land for construction and 5.8 acres of land for operation. The Sinton Compressor Station would require approximately 17.2 acres of land for construction and 7.3 acres for operation. Construction of all of the M&R stations would require less than 2.5 acres for construction and operation. The specific land requirements associated with each M&R station is provided in table 2.3-2. Cheniere would also install a permanent pig launcher within the Liquefaction M&R Station and a permanent pig receiver within the Tennessee Gas M&R Station. The launcher and receiver would be entirely contained within the respective M&R station and would not require additional land.

A total of five MLVs would be placed along the Pipeline including one at MP 0.0, one at the Taft Compressor Station (MP 7.5), one at MP 14.5, one at the Sinton Compressor Station (MP 21.5), and one at MP 23.0. All of the MLVs would be contained within a proposed M&R facility or compressor station and would not require any additional temporary or permanent workspace, with the exception of the MLV at MP 14.5. This MLV would be located within the permanent easement of the Pipeline and would require a construction and operation area of 0.2 acre.

The majority of the access roads that would be used during construction and operation of the Project are existing roads that would require minor improvements, including maintenance and adding rock. Two new permanent roads would be constructed comprising approximately 0.2 acre. In total, access roads used during construction would utilize approximately 20.1 acres of land, including the approximately 12.7 acres that would be utilized during operation.

2.4 CONSTRUCTION PROCEDURES

The Project facilities would be designed, constructed, operated, and maintained in accordance with federal standards which are intended to adequately protect the public by preventing or mitigating LNG and natural gas pipeline failures or accidents, and ensure safe operation of the facilities. The Terminal would be constructed according to the standards outlined by the DOT *Federal Safety Standards for Liquefied Natural Gas Facilities* at 49 CFR 193, and the NFPA's *Standards for the Production, Storage, and Handling of LNG* (NFPA 59A). The marine areas associated with the Terminal would comply with the applicable sections of the Coast Guard regulations for *Waterfront Facilities Handling LNG* at 33 CFR 127 and Executive Order 10173.

The Pipeline facilities would comply with DOT 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, Cheniere would comply with the Commission's regulations at 18 CFR 380.15, regarding the siting and maintenance of pipeline rights-of-way.

Cheniere indicated that the Project would implement and adhere to our *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction* *and Mitigation Procedures* (Procedures) 2013 version with no alternative measures. Additionally, Cheniere has developed a *Spill Prevention, Control, and Countermeasure* (SPCC) Plan for both the Terminal and the Pipeline. We have reviewed this plan and find it acceptable.

Prior to the commencement of construction, affected landowners would be notified of the start of construction and would be provided with the contact information for Cheniere in the event that they have a construction-related concern (see section 2.5.1 for additional information on Cheniere's complaint resolution procedures).

2.4.1 Construction Schedule

On August 1, 2014, Cheniere filed a revised construction schedule stating that Cheniere anticipates construction of the Terminal would take approximately 72 months (6 years) from the onset of site preparation activities until the startup of Train 3, with substantial completion of Train 1 planned for 2019. Construction of the Pipeline and associated aboveground facilities is anticipated to take approximately one year to complete. The Pipeline is currently planned for construction in 2017.

2.4.2 Terminal Facilities

2.4.2.1 Construction of Liquefaction Facilities

During the site-works phase of construction, Cheniere would cut necessary drainage ditches in laydown areas to allow proper surface water runoff, place gravel surfaces for temporary construction facilities (i.e., parking lots, office areas, and laydown areas), install temporary construction fencing, and construct roads within the Terminal site boundaries. Activities associated with the site-works phase of construction may occur concurrently with other construction activities at the Terminal.

Cheniere would install the foundations for equipment, buildings, and pipe racks on spread footings. Following installation of the pipe racks, the pipe would be installed from multiple directions. Fabrication of pipe spools would be conducted in a covered area and structural steel members would be prefabricated off-site and erected upon arrival. The majority of the straight run pipe would be fabricated on or near the site prior to placement on the pipe racks. Pipe expansion loops would be prefabricated, transported to the site, and erected with the straight run piping. Pipe would be painted to the maximum extent practicable at the fabrication shops off-site, after all welds have been tested in accordance with applicable codes.

When practicable, large equipment would arrive at site in preassembled packages to facilitate final hook-up and testing. All equipment would be designed, fabricated, and tested by highly qualified specialist suppliers at their respective facilities. Equipment would only be shipped to the site after the necessary inspections and testing are complete. Larger equipment, such as cold boxes, acid gas absorber, and the refrigerant compressors, would be offloaded at the roll on/roll off construction dock on a multi-wheel transport crawler, and transported to their foundations. Other materials and equipment would be delivered to the site by truck.

Installation of the equipment would occur concurrently with the installation of the pipe on the pipe rack to allow for a more seamless tie-in at the main process areas. Construction of other buildings, including warehouse and control buildings, would also occur concurrently with pipe rack installation. Cheniere would coordinate the arrival of the major equipment with the completion and curing of the respective foundation so that the equipment can be placed on its foundation when it arrives, minimizing handling and the potential for intermediate storage on site.

Painting and insulation work would be completed as the piping installation, hydrostatic testing, pneumatic testing, and equipment erection is completed. After all equipment and piping has been installed, Cheniere would begin the final road paving, site grading, landscaping, and cleanup. The temporary construction facilities would be demobilized on a progressive basis as they are no longer necessary

2.4.2.2 Construction of LNG Vaporization Facilities

LNG vaporization and natural gas send-out facilities would be constructed in the same manner as the liquefaction facilities described above.

2.4.2.3 Construction of Marine Terminal and LNG Transfer Lines

The LNG berths would be dredged to a depth of -46 feet NAVD 88 with an additional 2 feet for advanced maintenance and 2 feet paid allowed overdredge to ensure minimum depth and 3:1 side slopes are met. Hydraulically dredged materials would be used to fill a portion of a former clay borrow pit and to assist in the facilitation of capping bauxite residue beds.

The primary materials that would be used in the marine berth construction are steel-pipe pilings, concrete, and reinforcing steel for concrete. Cheniere anticipates that the steel-pipe piles would be fabricated offsite and delivered to the site by barge. The concrete would either be produced in a batch at the main Terminal site or purchased from a local supplier.

Each of the two LNG carrier berths would contain at least four breasting dolphins and six mooring structures that would be constructed to provide flexibility in berthing the full size range of design vessels. One jetty platform would be constructed in each berthing area and would consist of a single level, pile-supported concrete platform with a design elevation of 37 feet. The surface of the platforms would slope towards the shore in order to drain rainwater and potential LNG discharges. Curbs would also be constructed to separate the LNG areas from the remainder of the jetty surfaces and at the perimeter of the jetty platform, where necessary, to adhere to Occupational Safety and Health Administration requirements.

The jetty platforms would each support fixed equipment including a jetty substation building, marine cryogenic liquid cargo transfer and vapor return arms, gangway tower, LNG and utility piping, fire suppression equipment, elevated access platforms, elected firewater monitors, and a jetty control building. The approach and pipe trestles would link the rear of the jetty platforms and the shore. Additionally, 4-foot catwalks would be installed to provide access to mooring and breasting dolphins and to the shore.

Work on the marine berth platforms, approach, and pipe trestles would begin first to allow installation of equipment and piping. All steel pilings would be coated with coal tar epoxy from a point 15 feet below the mudline or groundline, to the soffit of the pile cap. Pile driving would last approximately 4 to 6 months. Concrete filled high-density polyethylene pipe sleeves would be required for all piling under the pipe trestle to provide splash zone corrosion resistance.

During construction, the dredging operations around the Terminal berth that would occur over a period of months would accommodate passing commercial vessel traffic. A moving exclusion zone around the LNG carrier would be expected to limit the movements of other vessels for the relatively brief period while an LNG carrier is transiting to or from the Terminal’s berth. In other ports with LNG terminals and comparable levels of vessel traffic, such moving exclusion zones have caused inconvenience at times but have not had sustained significant impacts on other commercial users of the channel. A stationary exclusion zone around the berth, likely up to the edge of the La Quinta Channel, would limit the ability of other vessels to approach the LNG carrier but would not restrict their ability to proceed past the Terminal within the La Quinta Channel.

2.4.2.4 Temporary Construction Facilities

Main construction offices would be located on-site or in a nearby construction laydown or parking area. This area would provide common office areas for all contractors and parking areas outside the boundaries of the main construction areas. Other temporary construction facilities that would be constructed as needed include support/satellite offices, warehousing, lunchrooms, temporary access roads, parking lots, and material laydown storage. These facilities can be mobilized without significant preparation work. Additional temporary facilities, primary laydown areas, parking, and dredge disposal would be located on site or in close proximity to the site.

The permanent site grading for drainage would be directed to several outfalls on the western perimeter of the Terminal site to ensure proper drainage during construction and operation. To facilitate this, a system of drainage ditches would be constructed and would connect to a larger existing drainage ditch that runs along the western edge of the site and flows into the La Quinta Ship Channel. A *Stormwater Pollution Prevention Plan* (SWPPP) to control sediment and silt would be implemented during construction. Site preparation and laydown areas would be located in an area northwest of the Terminal and would include the installation of construction power, communications, and water. The primary employee parking area for construction personnel would be located north of the Terminal site.

Cheniere would have major construction equipment delivered primarily by barge. To accommodate these deliveries, Cheniere would construct a new roll-on/roll-off area for unloading equipment from barges to the west of the LNG carrier berths.

2.4.3 Pipeline Facilities

Prior to the start of construction, Cheniere would complete all surveys, locate the centerline and construction workspaces, and complete land or easement acquisition as needed. If the necessary easements cannot be obtained through good faith negotiations with property owners, and the Commission has issued a Certificate for the Project, Cheniere may use the right of eminent domain granted under Section 7(h) of the NGA and the *Rules of Civil Procedure* to obtain easements. Cheniere would site, construct, operate, and maintain all Pipeline facilities in accordance with all applicable federal and state regulations and industry standards. Figure 2.4-1 shows the typical construction sequence used for an overland pipeline construction spread as summarized below.

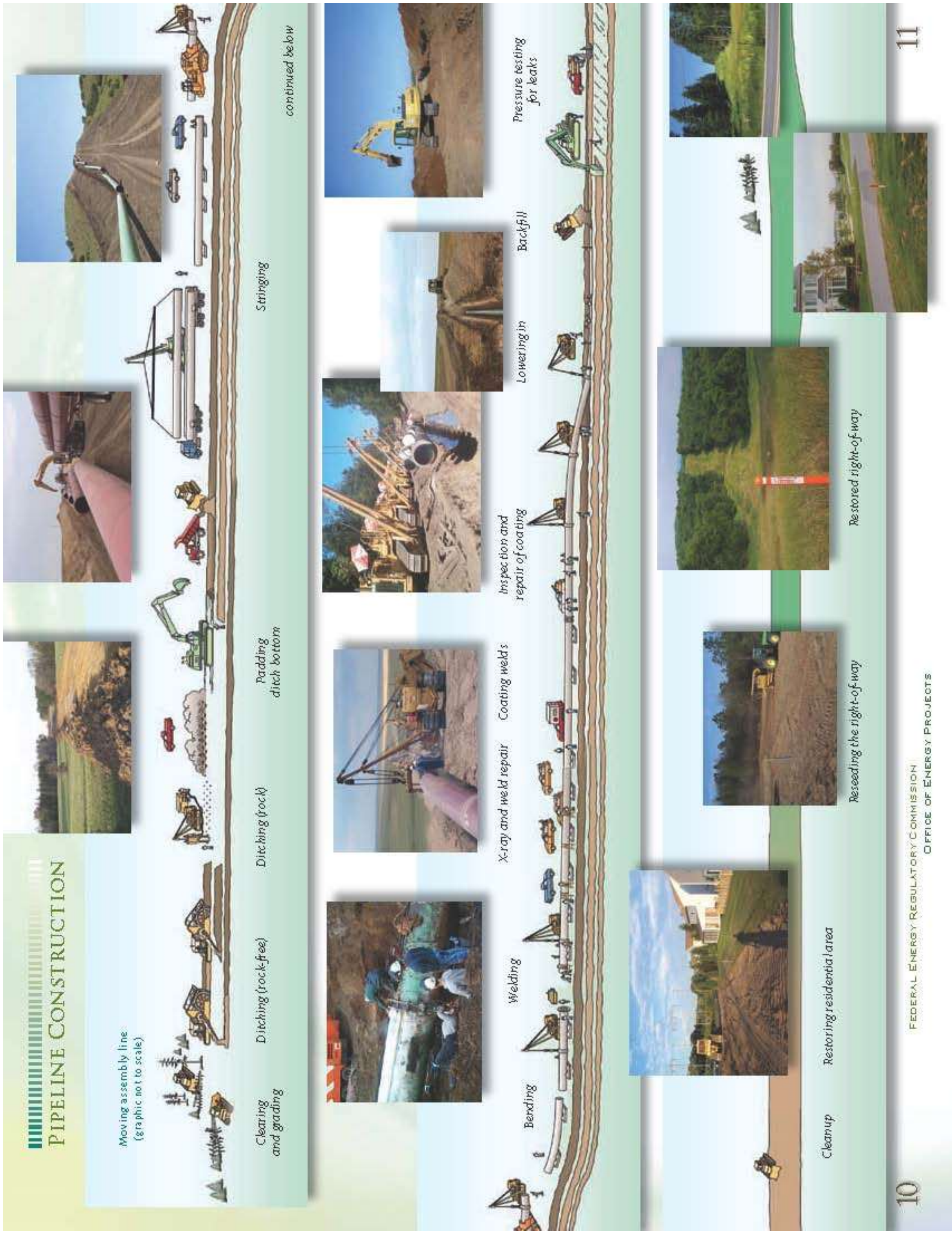

Figure 2.4-1 Typical Pipeline Construction Sequence

2.4.3.1 Standard Construction and Restoration Techniques

Clearing and Grading

Clearing operations would include removal of vegetation within the construction right-of-way and the temporary construction workspace either by mechanical means or by hand-cutting. The right-of-way limits would be identified and flagged in the field prior to clearing. If requested by a landowner, brush piles can be established along the edge of the right-of-way through land use agreements and site-specific plans. Following clearing, the construction right-of-way and ATWS would be graded as necessary to allow for safe passage of equipment and to prepare a relatively level work surface for pipeline construction. Bulldozers would typically perform grading activities.

Trenching

The pipeline ditch would be excavated to the appropriate depth to allow for burial of the pipe with at least 3 feet of cover as required by 49 CFR Part 192 of the DOT regulations. The trench would be dug with an excavator or ditching machine and the excavated material would be placed on the spoil side of the trench within the construction right-of-way. Based on available data, shallow bedrock would not be encountered within the trench depth and blasting would not be necessary. If water needs to be removed from the trench, the water would be pumped to a well-vegetated upland area off the right-of-way and/or filtered through a filter bag or siltation barrier.

Pipe Stringing, Coating, Bending, and Welding

Following excavation of the trench, the pipe would be strung along the trench. The pipe would be hauled in sections to the right-of-way via a truck from the pipe storage yard. The pipe would be off loaded and placed next to the trench using a side-boom tractor or vacuum hoe.

Following stringing the pipe sections would be bent as necessary to fit the vertical and horizontal contours of the trench. A bending engineer would survey the trench to determine the location and extent of each field bend. Appropriate bends would be made with a hydraulic pipe-bending machine. The pipe joints would then be lined up end-to-end to allow for welding into continuous lengths (strings).

All welding would be performed in accordance with API Standard No. 1104. Individual pipe sections would be welded in two steps. A front-end welding crew would perform the first step, which would be to clean and align the pipe bevels in preparation for welding and to place at least the first two passes in the welding process. Back-end welders would perform the section step, which would be to complete the welds started by the front-end crew. The pipe would be welded into long strings to minimize the number of welds that have to be made in the trench (tie-in welds). Gaps in the welding process would often be left at waterbody/wetland crossings, road crossings, and other locations where access across the work area is required.

The pipe lengths would be coated (typically with a heat applied epoxy) at a coating mill prior to being delivered to the Project site. The ends of each pipe section would be left bare to allow for welding. After welds have been inspected and approved, the weld areas would be field coated by a coating crew. The pipe coating would be inspected using equipment that emits an electrical charge, since pipeline coatings are electrically insulating.

Following welding, each weld would be inspected to ensure the structural integrity is consistent with 49 CFR Part 192 of the DOT regulations. Radiographs or ultrasonic images would be taken and processed on site for real-time results. Those welds that do not meet the requirements established by the API Standard 1104 would be marked for repair or replacement.

Lowering-In and Backfilling

The trench would be dewatered and cleared of any debris, as necessary before the pipe is lowered into the trench by side-boom tractors. Once the pipe strings have been lowered in, a tie-in crew would make the final welds in the trench. The final welds would then be inspected and coated. All suitable material excavated from the trench would be replaced during backfilling. In areas where excavated material is unsuitable for backfilling, additional fill may be brought in from offsite. In areas where topsoil was separated, the subsoil would be placed into the trench first and the topsoil would be spread over top. In non-wetland areas the top of the trench may be slightly crowned to compensate for potential settling. The soil would be inspected for compaction and scarified as necessary. After backfilling is complete, the pipe would be cleaned of any internal dirt, water, or debris by pipeline pigs that are propelled through the pipeline by air pressure.

Hydrostatic Testing

Following the completion of backfilling and cleaning, the pipeline would be pressure tested to ensure its integrity for the intended service and operating pressure. Water would be used to hydrostatically test the pipe and the water is normally obtained from water sources crossed by the pipeline, including available municipal supply lines. The water would be pumped from the water source into the pipe and would propel a pig through the pipe in a manner that fills it with water. A high pressure pump would be used to add water to the test section and to increase the test pressure. At the completion of the hydrostatic test, the pressure would be removed from the test section by propelling the pig with air and dewatering the pipe. Additional "drying" pig runs would be made, as necessary, to remove any residual water from the pipe. Hydrostatic testing is also addressed in section 4.3 of this EIS.

Cleanup and Restoration

All work areas would be final-graded and restored as closely to preconstruction conditions as possible. Prior to final grading, all construction debris would be picked up along the right-of-way. Permanent erosion control structures, such as slope breakers, would be installed during final grading in accordance with our Plan. Our Plan requires that restoration be completed within 20 days of backfilling, unless prevented by inclement weather conditions. Private property such as fences, field roads, and driveways would be restored or repaired as necessary.

Revegetation would be accomplished by seeding disturbed areas in accordance with the recommendations of the local office of the U.S. Department of Agriculture (USDA), Natural Resource Conservation Service (NRCS) or as requested by the landowner. Seeding would not be required in actively cultivated croplands, unless specifically requested by the landowner. Revegetation is further discussed in section 4.5 of this EIS.

2.4.3.2 Specialized Construction Techniques

Waterbody Construction Methods

To minimize potential impacts, waterbodies would be crossed in accordance with our Procedures and the crossings would be implemented as quickly and safely as possible. With the exception of the waterbodies that would be crossed by horizontal directional drill (HDD), waterbodies would be crossed using conventional excavator-type equipment and wet-crossing techniques, or by horizontal bore. Upland and agricultural swales, ditches, or other such conveyances would be crossed using either a wet-crossing technique if water is flowing at the time of crossing, or best management practices (BMPs) as determined by the Environmental Inspector (EI) if there is no flow at the time of crossing. Additional information regarding waterbody crossing methods is provided in section 4.3 of this EIS.

Except where reasonable alternative access is available, temporary construction equipment crossings would be installed across waterbodies to gain access along the right-of-way for construction. After equipment crossings are established, construction equipment would not be permitted to drive through a waterbody for access and the equipment crossing would be removed once access in the area is no longer needed. Only the equipment necessary to construct the crossing and install the pipe would be allowed to work in the waterbody.

To facilitate pipeline construction across waterbodies, ATWS may be needed adjacent to waterbodies to assemble and fabricate the pipe as necessary to complete the crossings. The ATWS would be located at least 50 feet away from the waterbody, except in actively cultivated croplands or other disturbed areas, as required by our Procedures. In areas where ATWS is required to be set back from the waterbody, vegetation would not be cleared between the ATWS and the waterbody.

Following installation, a minimum of 3 feet of cover would be placed over the pipe. Waterbody bed and bank contours would be restored to preconstruction conditions and the banks would be stabilized as soon as possible following construction activities. Permanent erosion control structures would be maintained to minimize erosion. Following construction, waterbodies would be inspected regularly to ensure that temporary erosion controls are functioning properly and that revegetation is progressing satisfactorily.

Horizontal Directional Drill

HDD is a pipeline construction method that minimizes surface impacts by drilling a hole and pulling the pipe through it rather than digging a trench. HDD requires drilling of a small diameter hole, or pilot hole, along a predetermined design path that originates and terminates on the surface. The pilot hole is then enlarged sufficiently to accommodate the pipe to be installed. The pipe may or may not be installed concurrently with the hole enlargement depending upon the final diameter of the enlarged hole and the soil conditions encountered. If there is an inadvertent release of drilling fluid during HDD operations, Cheniere would implement its HDD Monitoring and Contingency Plan which was approved by the COE in conjunction with issuance of the Section 10/404 permit on July 23, 2014.

Active Croplands

In accordance with our Plan, topsoil would be segregated in actively cultivated or rotated agricultural lands, pastures, and hayfields, unless otherwise approved in writing by the landowner prior to the commencement of grading activities. After the pipe has been lowered into the trench, the subsoil would be used for backfilling and the topsoil would be spread across the graded right-of-way. In active croplands, the depth of cover would be 4 feet unless otherwise specified. Soil compaction would be treated, as necessary, in accordance with our Plan.

Prior to construction, Cheniere would work with affected landowners to identify any drain tiles within the construction workspace. Any drain tiles damaged during construction would be repaired to landowner specifications or to preconstruction conditions. At this time Cheniere has not identified any existing drain tiles along the route.

Road Crossings

The crossing method used for a particular road would be dependent upon site-specific conditions and state and local statutes. Prior to construction, Cheniere would contact the "One Call" or "Call Before You Dig" system to verify and mark all utilities along the construction workspaces. Generally, Cheniere would bore under paved roadways. Boring entails drilling a hole below the roadway through which the pipe would pass. First, a bore pit is dug on one side of the roadway and a receiving pit is dug on the other side. The bore pit is excavated to a depth equal to the depth of the trench and is graded such that the bore would follow the grade of the pipe. A boring machine is lowered into the bore pit and placed on supports. The machine cuts a shaft under the roadway using a cutting head mounted on an auger. The pipe is then pushed through the hole.

During the open cut method of crossing a roadway, at least one lane of traffic would be kept open when constructing on or across residential streets. During the brief period when the 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 necessary for installing the pipe.

2.4.3.3 Aboveground Facilities

Aboveground facilities associated with the Project would include M&R stations, MLVs, pig launchers and receivers, and compressor stations. Sites for the aboveground facilities would be cleared and graded as described above for the pipeline installation. The area would be cleared of trees, brush, and debris, and would be graded and compacted to surveyed elevations.

Where foundations are required for the aboveground facilities, the ground would be excavated and improved as needed for the installation of building foundations and pipe supports. Forms and reinforcing bars would be installed in the excavated areas, as necessary, and high strength concrete would be poured to the appropriate levels for the major equipment. Concrete pours would be randomly sampled and tested to verify compliance with specifications. All concrete would then be properly cured to the desired strength.

After the foundations have sufficiently cured, installation of buildings and machinery would begin. At compressor station sites, installation of the machinery, buildings, and piping would be concurrent. The steel frames of the buildings would be erected first, followed by interior walls, insulation, exterior walls, and the roof. Cut-outs that allow for protrusion for inlet and exhaust vents through the siding would be flashed to ensure that the buildings are weather tight. Each building would be acoustically insulated and silencers would be installed on the engine exhaust stacks and the air intakes to abate noise.

Installation of aboveground piping systems would begin concurrently with the foundation work. Piping would require welding except where the piping is connected to flanged or threaded components. Aboveground piping would be installed on concrete or metal pipe supports and would be painted. Electrical conduit systems would also be installed. Once the structures and equipment are set on foundations, they would be connected to the piping and electrical conduit systems. Electrical wiring would be installed to provide power and connect instrumentation to control systems.

As each system is completed, they would be tested and calibrated to ensure proper operation. Aboveground piping would be hydrostatically tested. Controls and safety devices such as the emergency shutdown system, relief valves, gas and fire detection facilities, and other safety devices would be checked and tested. The compressor units would be operated on a trial basis following completion of the piping and mechanical work to ensure proper operation of the safety and protective devices. The trial operation would involve several short duration runs conducted over the course of several days. Start-up of the compressor units would commence once all testing is complete.

2.5 OPERATION AND MAINTENANCE

The Terminal would employ approximately 250 full-time staff. All permanent personnel would be trained in LNG safety, with applicable personnel trained in cryogenic operations and proper operation of relevant equipment. Operators would meet all of the training requirements of the DOT minimum federal safety standards specified in 49 CFR Parts 192 and 193. The standards imposed are in accordance with the Natural Gas Pipeline Safety Act of 1969, as amended.

The Terminal would be a bidirectional facility capable of loading and unloading LNG cargoes to/from the LNG carriers, liquefying natural gas from the Pipeline to produce LNG, and vaporizing stored LNG and sending the resultant natural gas into the Pipeline. Market factors would determine whether the facility would be in liquefaction or vaporization mode.

Operating procedures would be developed for the facilities, and extensive training would be provided for operational personnel to ensure that they are familiar with and understand the importance of adherence to safety procedures. These procedures would provide functional requirements for the control and safeguarding systems, to include addressing safe start-up, normal shutdowns, emergency shutdowns, fire, gas, and spills, as well as routine operation and monitoring.

The LNG carriers would enter Corpus Christi Bay from the Gulf and transit between the Terminal and the Gulf under the command of the ship’s master with local pilots to provide specialized navigational-related advice. Together, they would decide whether the existing and anticipated environmental conditions allow safe entry and transit between the Gulf and the Terminal via the Aransas Pass Channel, Corpus Christi Channel, and the La Quinta Channel. The pilots would be assigned by the ship’s master to direct the maneuvering of the LNG carrier in the harbor with the assistance of accompanying tugboats as necessary. The pilots would continue to advise the ship’s master during the berthing and securing of the ship’s mooring lines until the LNG carrier is securely moored at the Terminal’s berth.

The cargo transfer arms would be coupled to the LNG carrier’s manifold by the Terminal’s personnel. A communications and linked ESD system umbilical cable deployed between the ship and the Terminal would connect these critical functions between cargo control systems during the period that the cargo transfer arms remain connected. The emergency shutdown system would be tested from both the ship and Terminal control rooms before cargo transfer operations begin.

The ship and Terminal operators would prepare and align their respective side's cargo systems and valves after performing the required safety checks and procedures so that LNG cargo transfer between the ship and the Terminal can begin. During all cargo transfer operations, the LNG carrier's manifold would be continuously visually monitored by the ship duty personnel and also remotely by video cameras mounted on the jetty platform which transmit real-time video to display monitors located in both the jetty and main control rooms. Additionally, a security guard would be located at the facility entrance and continuously staffed 24 hours a day, seven days a week.

Facility maintenance would be conducted in accordance with 49 CFR 193 Subpart G. The full-time maintenance staff would conduct routine maintenance and minor overhauls. Major overhauls and other major maintenance would be handled by soliciting the services of trained contract personnel to perform the maintenance. All scheduled and unscheduled maintenance would be entered into a computerized maintenance management system. Only applicable personnel would be trained on the use of this system.

Scheduled maintenance, such as preventive and predictive maintenance of equipment would be input into the system to automatically print out work orders either on a time basis or on hours of operation, depending on the requirement. Scheduled maintenance would be performed on safety and environmental equipment, instrumentation, and any other equipment that requires maintenance on a routine basis. When a problem is detected that requires unscheduled maintenance attention, the person that detects the problem would enter it into the computerized maintenance management system. If a problem requires immediate attention, the appropriate person would be notified.

The Pipeline would be patrolled on a routine basis and personnel qualified to perform both emergency and routine maintenance on interstate natural gas pipeline facilities would handle all maintenance.

The Pipeline and associated facilities would be operated and maintained in a manner such that pipeline integrity is maintained in the interest of assuring that a safe, continuous supply of natural gas reaches its ultimate destination. Maintenance activities would include regularly scheduled gas leak surveys and measures necessary to repair any potential leaks. The latter may include repair or replacement of pipe segments. All fence posts, signs, marker posts, aerial markers, and decals would be painted or replaced to ensure that the pipeline locations would be visible from the air and ground. All valves would be periodically inspected and greased.

Additionally, the Pipeline would be patrolled from the air periodically which would provide information on possible leaks, construction activities, erosion, exposed pipe, population density, possible encroachment, and other potential problems that may affect the safety or integrity of the Pipeline. Cathodic protection units installed along the Pipeline would be regularly maintained.

Other maintenance functions would include periodic seasonal mowing of the permanent easement in accordance with our Plan and Procedures, terrace repair, backfill replacement, and periodic inspection of water crossings. During pipeline easement maintenance, Cheniere would not use herbicides or pesticides within 100 feet of a wetland or waterbody unless approved by the appropriate state and local agencies.

2.5.1 Environmental Compliance and Monitoring

Cheniere would implement environmental compliance and monitoring requirements from our Plan and Procedures during construction of the Terminal and Pipeline. They would also incorporate compliance and monitoring requirements from federal, state, and local permits obtained for the Project. To ensure environmental compliance, Cheniere would provide all contractors with copies of all construction procedures, plans and specifications, a construction drawing package, and all environmental permits, certificates, and/or clearances associated with the Project prior to construction.

Additionally, Cheniere would conduct environmental training for its field personnel and contractors. This training would focus on the implementation of Cheniere's construction procedures, techniques and plans, other Project-specific permit conditions, and impact minimization measures. Cheniere would ensure that training personnel provide thorough training sessions regarding the environmental requirements, all individuals receive environmental training prior to starting work, adequate training records are kept, and refresher training is provided as needed to maintain high awareness of environmental requirements.

Cheniere would employ one or more EI(s) to ensure that environmental conditions associated with permits or authorizations are satisfied. The EI(s) would be onsite daily to monitor and document environmental compliance and report to the Commission on a monthly basis regarding Terminal activities and a weekly basis regarding Pipeline activities. The EI(s) duties would include, but not be limited to, ensuring compliance with all environmental commitments, construction procedures, techniques and plans, and all permit conditions and requirements. The EI(s) would also verify construction workspaces prior to use, confirm that all sensitive resources are properly marked, and ensure proper installation and maintenance of all erosion control devices. The EI(s) would have peer status with all other inspectors, would have the authority to enforce permit and FERC environmental conditions, to issue stop-activity orders, and impose corrective actions to maintain environmental compliance.

In addition to the EI(s), contractors and construction work areas would be subject to periodic inspections throughout construction and restoration phases of the Project, by federal, state, and local agencies including the Commission. Representatives of these agencies could require the implementation of additional and/or corrective environmental measures. These representatives could also issue work stoppages, impose fines, and recommend additional actions in response to environmental compliance failures. Inspection reports prepared by us would be entered into the Commission's public record. Inspection reports prepared by other agencies would be made available per their respective policies and guidelines.

Cheniere has developed protocols, in complaint resolution procedures, to handle complaints received from landowners. Cheniere would designate one Issues Resolution Coordinator, who would be responsible for making sure that all reported complaints and issues are communicated internally and that timely responses are provided to the callers. In addition, right-of-way agents or other staff of Cheniere receiving phone calls from landowners identifying complaints or other issues would log the calls into a file that contains the specific information about the complaint. The Project personnel would notify the Issues Resolution Coordinator with the details of the call. The Issues Resolution Coordinator would then contact the construction field office and discuss the issue with the appropriate individual, (e.g., Right-of-Way Representative, Chief Inspector, or Lead EI) and determine the necessary steps and timeframe to resolve the issue. In addition, landowners would be supplied with a copy of the FERC's helpline information in the event they need to contact FERC. The Issues Resolution Coordinator would then contact the original caller as soon as practicable, but no later than 48 hours after the initial call, to explain how the issue is to be resolved and the expected timeframe for the resolution to occur. The Issues Resolution Coordinator would then follow up with the appropriate construction representative to ensure that the resolution has been or is scheduled to be implemented as indicated to the caller. The Issues Resolution Coordinator would notify the Project Director, Right-of-Way Manager, and Environmental Manager of the issue and the agreed upon resolution and anticipated timeframe. The Issues Resolution Coordinator would record the resolution plan and would track and report all calls received and the resolution plans on a regular basis to coincide with the construction reporting schedule for the FERC. A final phone call would be made to the caller within 24 hours after completion of the resolution plan.

Parties concerned with environmental compliance may contact the Commission's Dispute Resolution Service (DRS). The DRS is a professional team that promotes timely and high quality resolution of disputes. DRS specialists are highly trained in mediation, negotiation, and facilitation and are able to assist parties with the resolution of environmental compliance matters.

2.6 FUTURE PLANS AND ABANDONMENT

There are no plans for future abandonment or expansion of facilities.

ALTERNATIVES

SECTION 3

3.0 ALTERNATIVES

As required by NEPA and Commission policy, we evaluated a number of alternatives to the Project to determine if any would be reasonable and environmentally preferable to the proposed action. Below, we discuss alternative actions for the Terminal facilities and Pipeline facilities. The alternative actions include the no-action alternative, energy alternatives, systems alternatives, and alternatives sites and pipeline routes for the Project.

The evaluation criteria for selecting potentially reasonable and environmentally preferable alternatives include the following:

- technical and economic feasibility;
- significant environmental advantages over the proposed Project or segments of it; and
- ability to meet the Project objectives for providing facilities necessary to import and export LNG and deliver natural gas into the existing interstate and intrastate natural gas pipeline system in the Corpus Christi, Texas area.

With respect to the first criterion, it is important to recognize that not all conceivable alternatives are technically and economically feasible. Some alternatives may be impracticable because of the cost, existing technologies, constraints of existing system capacities, and logistics in light of the overall project objectives. In conducting an alternatives analysis, it is also important to consider the environmental advantages and disadvantages of the proposed action and to focus the analysis on those alternatives that reduce impacts or offer a significant environmental advantage.

DOE requested an alternatives analysis of Project components in a floodplain per Executive Order 11988[8] be included in the final EIS. Table 3.1-1 and section 3.2.3.3 have been revised to include information regarding the proximity of alternative Terminal sites with respect to floodplains. No alternative Terminal sites were evaluated outside of a floodplain because, as discussed in section 4.1.1.5, the Terminal facilities would be placed above predicted storm surge elevations, and siting of these Terminal locations are necessarily tied to marine/port locations. Similarly, no Pipeline route alternatives outside of floodplains were evaluated because, as discussed in section 4.1.2.4, Cheniere has proposed to implement acceptable mitigation measures at waterbody crossings and areas subject to flooding to compensate for negative buoyancy. This includes use of concrete coated pipe which is an acceptable construction practice and in accordance with DOT regulations. Both the Sinton and Taft Compressor Stations would be located outside of floodplains.

Through the application of the evaluation criteria and subsequent environmental comparisons, each alternative was considered until it was clear that the alternative was not preferable to the proposed action because it would result in significantly greater environmental or social impacts that could not be readily mitigated. Alternatives that appear to be the most reasonable with similar levels of environmental impact are reviewed below.

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[8] The provisions of Executive Order 11988 of May 24, 1977, appear at 42 FR 26951, 3 CFR, 1977 Comp., p.177.

3.1 TERMINAL FACILITIES

3.1.1 No-Action Alternative

Under the No-Action Alternative, the objectives of the Project would not be met and Cheniere would not provide the proposed natural gas transportation capacity for import or export. In addition, the potential adverse and beneficial environmental impacts identified in section 4.0 of this EIS would not occur.

Development of and production from conventional and unconventional gas formations are occurring throughout many of areas of the U.S. and are projected to continue for many years. Cheniere indicated it could provide LNG to foreign countries at a competitive price and, therefore, replace higher-cost shipments from other sources. Additionally, should market demands shift in the future, the Project would have vaporization capabilities to allow LNG to be imported, vaporized, and sent out for delivery to U.S. customers.

With or without the No-Action Alternative, other LNG export/import projects could also be developed elsewhere in the Gulf Coast region or in other areas of the U.S. resulting in both adverse and beneficial environmental impacts to those of the proposed Project. Development of any new LNG export terminals on previously undeveloped sites would likely result in similar or greater environmental impacts, in both magnitude and duration, than those of the proposed Project.

The No-Action Alternative could also require that potential end users make other arrangements to obtain natural gas service, make use of alternative fossil fuel energy sources (e.g., coal or fuel oil), or possibly make use of other traditional long-term fuel source alternatives (e.g., nuclear power) and/or renewable energy sources (e.g., solar power) to compensate for the reduced availability of natural gas that would otherwise be supplied by the proposed Project. Although international energy conservation could also result from the No-Action Alternative, that option is beyond the scope of this analysis.

3.1.2 Alternative Energy Sources

It is important to consider alternative energy sources as part of the alternative selection process. As noted above, implementing the No-Action Alternative could force potential natural gas customers to seek other forms of energy. Traditional energy alternatives to natural gas include coal, oil, hydroelectric, and nuclear power. Renewable energy resources such as solar, ocean energy, biomass, wind, landfill gas, and municipal solid waste represent new, advanced energy alternatives. Conceivably, each of these energy alternatives could support the generation of new electric power, which is a major consumer of natural gas along with residential heating, commercial, and industrial uses.

The International Energy Agency (IEA) (2012b) reported that coal exports are increasing and in the United States several new coal export projects were recently proposed, suggesting that in many international markets coal will remain competitive with natural gas in spite of coal's greater air emissions. EPA (2013) stated that compared to the average air emissions from coal-fired generation, natural gas produces half as much CO_2, less than a third as much nitrogen oxides, and 1 percent as much sulfur oxides at power plants. Similarly, fuel oil is commonly used for power generation in many countries and will continue to compete with natural gas as a fuel source in spite of greater emissions. As a result, if the No-Action Alternative is selected, it could result in a greater use of other fossil fuels and a potentially substantial increase of environmental impacts as compared to the use of natural gas. However, many countries are cognizant of the greater environmental impact of coal and fuel oil and prefer to use natural gas as a fuel source.

There has been a recent renewed interest in electric power generation by nuclear energy. However, because of the increasing demand in electricity consumption worldwide, the U.S. Energy Information Administration (2012) estimates that the proportion of electricity generated by nuclear power will decrease from 19 percent to 15 percent. In addition, regulatory hurdles, public concern over nuclear power and nuclear waste disposal, construction costs, and plant construction lead times make it unlikely that nuclear generating capacity could be available to serve all the markets targeted by the Project on a similar timeline. Further, plans for nuclear power generation have been scaled back as countries reconsidered policies after the accident at the Fukushima Daiichi nuclear power plant near Fukushima, Japan, but capacity is still projected to rise, led by China, Korea, India, and Russia (IEA, 2012a).

Renewable energy may become an increasingly significant factor in meeting future energy demands worldwide. As reported by IEA (2012a; 2012b), renewables are projected to become the world’s second largest source of power generation by 2015, and are expected to close in on coal as the primary source by 2035. However, this rapid increase hinges critically on continued subsidies. In 2011, these subsidies (including for biofuels) amounted to $88 billion, but to reach the projection noted above, the subsidies would need to increase to $4.8 trillion by 2035 (IEA 2012a).

Hydropower is currently the largest source of renewable electric power generation worldwide, and IEA expects this trend to continue through 2030. However, as with nuclear power generation, there are high costs associated with developing substantial hydropower projects and long time periods between project conception and the production of electric power.

Other compromising renewable energy resources include solar, ocean energy, and biomass. However, the cost of these types of renewable energy projects is currently high per energy output unit in comparison to natural gas-fired power generation. Photovoltaic production in support of solar energy is increasing, and the cost of photovoltaic systems is decreasing, with photovoltaic cells potentially able to greatly supplement electrical generation resources.

Ocean energy is a largely unexplored renewable resource. Technologies to capture ocean energy are in their infancy, and environmental and engineering considerations are being studied to better understand the implications of placement of power generating facilities in the ocean.

Entrepreneurs and scientists are exploring the emerging use of algae for biofuels and other renewable energy applications, and are working to accelerate the development of applications to use algal biomass. IEA (2012b) projected electric power generation from biomass technology to increase four-fold through 2035, but that time frame is well beyond the planned startup and the currently requested authorization lifetime of proposed Project.

Further generation of electrical power by wind would require construction of new wind turbines and additional electric transmission lines. Although this is likely to occur in many parts of the world, it is also likely that such development will be slow-paced in most countries due to the high cost of construction. In addition, wind power cannot be used for constant and reliable energy production because of the variability in winds, and other power generation facilities are commonly in place as backup facilities.

Electric generation from municipal waste and landfill methane are growing trends in developed countries. Again, the cost of these facilities, including operating costs, is beyond the means of many countries.

With regard to these renewable sources of energy, natural gas is often considered a “bridge fuel”; a fuel that bridges the time between the dominant use of fossil fuels today and the greater use of renewable energy sources in the future. Natural gas is cleaner burning than other fossil fuels and can also reliably serve as backup fuel to renewable energy facilities, which often provide power intermittently.

There is currently considerable momentum behind advancing renewable energy technologies and moving toward more diversified energy sources. These advanced technologies, either individually or in combination, will likely be important in addressing future energy demands. Presumably, new energy technologies will continue to offset an increasing amount of fossil fuels to meet growing energy demands, and that situation is not expected to change in the next decade.

Although it is speculative and beyond the scope of this analysis to predict what action might be taken by policy makers or end users in response to the No-Action Alternative, it is possible that without the proposed Project, the energy needs may be met by alternative energy sources, likely resulting in impacts on the environment. Alternative energy forms such as coal and oil are available and could be used to meet increased demands for energy; however, natural gas is a much cleaner-burning fuel. These other fossil fuels emit greater amounts of particulate matter, sulfur dioxide (SO_2), carbon monoxide (CO), CO_2, hydrocarbons, and non-criteria pollutants. The use of nuclear energy as replacement of other fuel sources also carries undesirable consequences, such as negative public perception of the safety of electric generation through nuclear plants and the disposal of waste products created. Renewable energies, such as solar, hydroelectric, and wind are not always reliable or available in sufficient quantities to support most market requirements and would not necessarily be an appropriate substitute for natural gas in all applications. Therefore, we have dismissed alternative energy sources as a reasonable alternative to meet the Project objectives.

3.1.3 System Alternatives

System alternatives are alternatives to the proposed action which would make use of other existing, modified, or proposed facilities that would meet the stated purpose and need of the proposed action. By definition, implementation of a system alternative would make it unnecessary to construct part or all of the proposed action. However, additions or modifications to the system alternatives may be required to increase capacity or provide receipt and delivery capability consistent with that of the proposed Project. These additions or modifications could result in environmental impacts that are less than, similar to, or greater than the environmental impacts of the proposed facility.

Our analysis of system alternatives considers existing, or recently authorized or proposed[9] LNG import, export, and storage facilities located in the continental U.S. to replace all or part of the Project. We considered whether any of the existing, recently authorized, proposed, or planned LNG import and export terminal projects could be viable system alternatives to the Project. To be considered a viable system alternative, the existing or proposed project would need to provide LNG carrier unloading, storage, and send-out capacities similar to Cheniere's proposal, in addition to current or planned expansion capacities for the terminals. Facilities outside of the Gulf Region were not considered, because they do not meet the purpose and need of the Terminal (due to the geographic region from which they are sourced).

For a system alternative to be viable, it must be technically and economically feasible. It must also be compatible with any contractual agreements Cheniere may have relating to the export of LNG. In addition, a viable system alternative would offer a significant environmental advantage over the Project. The system alternatives considered in this analysis are depicted on figure 3.1-1 and described below. Although we have considered each of the planned, proposed, or recently authorized projects below as potential system alternatives, the market would ultimately decide which and how many of these facilities are built.

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[9] Proposed projects are projects for which the proponent has submitted a formal application with the FERC; planned projects are projects that have been announced but for which no formal application has been submitted.

Figure 3.1-1 **System alternatives for the Terminal**

3.1.3.1 Existing LNG Import Terminals with Planned, Proposed, or Authorized Liquefaction Projects

There are six existing LNG import terminals in the southeastern United States along the Gulf of Mexico:

- Cameron LNG, LLC (Cameron LNG) Terminal;
- Freeport LNG Development, LP (Freeport LNG) Terminal;
- Golden Pass Products, LLC (Golden Pass) Terminal
- Gulf LNG Energy, LLC (Gulf LNG) Terminal;
- Sabine Pass LNG, LP (Sabine Pass LNG) Terminal; and
- Trunkline LNG Company, LLC (Trunkline LNG) Lake Charles LNG Terminal.

The Sabine Pass Liquefaction Project is under construction and the other import terminals are in regulatory review and permitting process for adding liquefaction and export capabilities. Each of these facilities was considered as a system alternative to Cheniere's proposed Project.

<u>Cameron LNG Terminal</u>

Cameron LNG is proposing to construct and operate a LNG liquefaction and export facility adjacent to the existing Cameron LNG Import Terminal in Cameron Parish, Louisiana approximately 240 miles northeast of the proposed Terminal site (see figure 3.1-1). The Cameron LNG Liquefaction Project would include three liquefaction trains and related facilities and would be capable of exporting 12 million metric tons per year (mtpy) of LNG. Cameron LNG entered the pre-filing process on May 9, 2012[10] and filed an application with the FERC on December 7, 2012[11] (Docket No. CP13-25). Cameron LNG expects to begin delivering LNG to international markets in 2017. A final EIS was issued for the Cameron LNG Liquefaction Project on April 30, 2014.

Although the Cameron LNG Liquefaction Project is estimated to start operations around the same time as Cheniere's Project, it would require additional capacity to meet Cheniere's objectives and any customer commitments. Cameron has not requested authorization for the increased capacity and receipt of permits and approvals for the additional facilities that would be needed to meet Cheniere's objectives. The increased time to acquire the necessary permits would not meet Cheniere's timeline of initial export in 2017. Cameron LNG's application states that Cameron LNG has executed long-term agreements for all of the proposed facility capacity, which would make it a nonviable alternative for the planned capacity at the Terminal. In addition, as proposed, the natural gas feedstock for the Project would be sourced from the south Texas region and transporting this gas to Cameron LNG would require far greater transportation costs, potential additional facilities, and the associated additional environmental impacts. Therefore, the Cameron LNG Liquefaction Project was not considered to be a reasonable alternative to the proposed Project and was removed from further consideration.

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[10] Docket No. PF12-12

[11] Docket No. CP13-25

Freeport LNG Terminal

The Freeport LNG Terminal is on Quintana Island in Brazoria County, Texas. The import terminal, which started operations in 2008, includes two 160,000 m^3 LNG storage tanks and a single berth capable of handling LNG carriers in excess of 200,000 m^3. It has a peak send out capability of approximately 1.5 Bcf of natural gas.

Freeport LNG Expansion, LP and FLNG Liquefaction, LLC (collectively, FLEX) propose to add liquefaction facilities to its existing terminal to provide export capacity of approximately 13.2 mtpy of LNG. The existing Freeport LNG Terminal is about 150 miles northeast of the proposed Terminal site (see figure 3.1-1). This project would require approximately 86 acres for three proposed trains, each with a capacity of 4.4 mtpy. FLEX filed two separate applications to the DOE/FE to export LNG to Free Trade Agreement countries, each for export of 511 Bcf per year. The DOE/FE approved the applications in February 2011 and 2012. On December 17 2010, FLEX submitted an application to the DOE/FE to export LNG to non-Free Trade Agreement nations, and the DOE/FE authorized such export on May 17, 2013. FLEX filed its application with the FERC in August 2012[12]. The final EIS for the Freeport LNG Expansion Project was issued on June 16, 2014.

On July 31, 2012, Freeport LNG Expansion signed a 20-year agreement with Osaka Gas and Chubu Electric for 100 percent of the first train (4.4 mtpy), and in February 2013 signed a 20-year agreement with BP for all of the second train (4.4 mtpy). In September 2013, FLEX signed separate liquefaction tolling contracts with Japan’s Toshiba Corp and South Korea’s SK E&S for all of the third train (4.4 mtpy).

FLEX anticipates start-up for the first liquefaction train in November 2016, with full service anticipated 48 to 54 months after initiation of construction, or 2020 to 2021. Although the Freeport LNG Expansion is estimated to start operations prior to Cheniere’s Project, it would not produce at full capacity until after the planned full capacity date of the Terminal. In addition, the full capacity of the Freeport LNG Expansion is contracted and use of the Freeport LNG Terminal as a system alternative to meet Cheniere’s objectives and any customer commitments would require that FLEX construct and operate three additional liquefaction trains and associated facilities, as well as additional import facilities, similar to those of the Project which would likely result in similar environmental impacts. However, FLEX has not requested authorization for the increased capacity and receipt of permits and approvals for the additional facilities that would be needed to meet Cheniere’s objectives. The increased time to acquire the necessary permits would not meet Cheniere’s timeline of initial export in 2017. Therefore, the Freeport Liquefaction Project was not considered to be significantly environmentally preferable or a reasonable alternative to the proposed Project and was removed from further consideration.

Golden Pass Terminal

The Golden Pass Terminal is near the town of Sabine Pass, Texas, on the western shore of Sabine Pass Channel, about 240 miles northeast of the proposed Terminal site (see figure 3.1-1). Operations started in 2010 on the approximately 477-acre site. The import terminal includes five 155,000 m^3 LNG storage tanks and two LNG carrier berths. It has a maximum send-out capacity of 2.5 Bcf/d of natural gas. The planned export facility would use

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[12] Docket Nos. CP12-509 and CP12-29

the existing storage tanks, berthing facilities, and pipeline infrastructure of the import terminal and would have a send-out capacity of 15.6 mtpy of LNG.

Golden Pass received approval from DOE/FE to export LNG to Free Trade Agreement countries on October 7, 2012. On October 26, 2012, Golden Pass submitted an application to export LNG to non-Free Trade Agreement nations.

On May 16, 2013, Golden Pass requested that the FERC initiate the pre-filing process for the project[13]. At the time this EIS was prepared, Golden Pass was still early in our pre-filing process. As a result, the Golden Pass LNG Terminal is substantially behind Cheniere in the permitting and review schedule and therefore, would likely not be permitted for service in time to meet any customer commitments of the Project, beginning in 2017. In addition, the environmental impacts of constructing and operating the facilities needed to expand beyond the planned capacity would likely be similar to those of the Project. Therefore, this project would not provide a significant environmental advantage to the proposed Project and was not considered further.

Gulf LNG Terminal

The Gulf LNG Terminal is on a 40-acre site in Pascagoula, Mississippi, about 550 miles northeast of the proposed Terminal site (see figure 3.1-1). The terminal started operations in October 2011 and has a send-out capacity of 1.3 Bcf/d of natural gas. The import terminal includes two 160,000 m^3 LNG storage tanks and a single LNG carrier berth designed to receive LNG carriers up to 250,000 m^3 in capacity. On June 15, 2012, Gulf LNG received authorization from DOE/FE to export to Free Trade Agreement countries.

Gulf LNG would construct its export facilities at its existing terminal to export up to 11.5 mtpy of LNG. On May 9, 2014, Gulf LNG requested to use the FERC pre-filing process[14], and on May 21, 2014, the FERC approved the request and initiated the pre-filing process.

The Gulf LNG Terminal is substantially behind the Project in the permitting and review schedule and therefore, could not be permitted for service in time to meet any customer commitments of the Project beginning in 2017. As a result, the planned Gulf LNG Liquefaction Project does not meet the Project objective and was not further evaluated.

Sabine Pass LNG Terminal

The Sabine Pass LNG Terminal is in Cameron Parish, Louisiana, on the eastern shore of the Sabine Pass Channel, approximately 240 miles northeast of the proposed Terminal site (see figure 3.1-1). The terminal is on approximately 853 acres and includes five LNG storage tanks with a total storage capacity of 16.9 Bcf and two LNG carrier berths. The facility has a send-out capacity of 4 Bcf/d of natural gas.

On April 16, 2012, the FERC authorized Sabine Pass LNG to receive, process, and export 16 mtpy of domestically produced natural gas as part of its liquefaction project[15]. The Sabine Pass Liquefaction Project is permitted for up to four liquefaction trains, each with an average liquefaction capacity of approximately 4 mtpy, and in August 2013, Sabine Pass LNG applied to the FERC to construct and operate two additional trains. The project is under construction and

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[13] Docket No. PF13-14

[14] Docket No. PF13-4

[15] Docket No. CP11-72

will involve the permanent use of about 191 acres as well as temporary disturbance of about 97 acres within the existing Sabine Pass LNG Terminal site. All 16 mtpy of LNG of the first four trains is fully committed to Sabine Pass LNG customers. In early 2013, Sabine Pass LNG announced that Total Gas and Power North America had signed up to take gas volumes equivalent to 2 mtpy from the fifth train and United Kingdom-based Centrica had contracted for an additional 1.75 mtpy. Therefore, additional import and export facilities would be needed to meet Cheniere's objectives, likely resulting in similar environmental impacts to the proposed Project. The permitting and authorization processes from constructing these additional facilities would preclude Sabine Pass LNG from meeting Cheniere's schedule, including any customer commitments. As a result, the Sabine Pass Liquefaction Project was not considered to provide a significant environmental advantage or be a reasonable system alternative to the Project and was not evaluated further.

Lake Charles LNG Terminal

The Lake Charles LNG Terminal is in Lake Charles, Louisiana, and started operations in 1977. The import terminal is situated on approximately 125 acres about 280 miles northeast of the proposed Terminal site (see figure 3.1-1) and has a peak send-out capacity of 2.1 Bcf/d of natural gas. Two LNG carrier berths provide loading and unloading capacity.

On July 22, 2011, Lake Charles Exports, LLC received authorization from DOE/FE to export LNG to Free Trade Agreement countries from the Lake Charles LNG Terminal. On March 25, 2014, Trunkline LNG filed an application with the FERC for authorization to construct and operate the Lake Charles Liquefaction Project[16]. Trunkline LNG would construct the project on an approximately 400-acre parcel, about 0.5 mile west of the existing Lake Charles LNG Terminal. The facility would include three liquefaction trains, each capable of producing 5 mtpy for a total output capacity of 15 mtpy. Trunkline LNG anticipates an in-service date of August 2018.

Although the Lake Charles Liquefaction Project would provide approximately 1.5 mtpy more LNG send-out capacity than the Project, its export capacity is solely contracted to one customer, BG LNG. Additional import and export facilities would be necessary to meet Cheniere's objectives. Trunkline LNG has not requested authorization for the increased capacity, and receipt of permits and approvals for the additional facilities required to meet Cheniere's schedule, including any customer commitments. Therefore, this alternative was not further evaluated.

3.1.3.2 Proposed and Planned Stand-Alone LNG Export Terminals

In addition to the six existing LNG import facilities described above, are six planned or proposed stand-alone liquefaction projects along the Gulf Coast:

- planned Gulf Coast LNG Exports, LLC (Gulf Coast) Liquefaction Project;
- proposed Excelerate Liquefaction Solutions, LLC (ELS) Lavaca Bay LNG Project;
- proposed Magnolia LNG Project;
- planned Gasfin Development USA, LLC (Gasfin) LNG Project;

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[16] Docket No. CP14-120

- planned Waller Point LNG (Waller Point) Project;
- planned CE FLNG, LLC (CE FLNG) LNG Project; and
- planned Mississippi River LNG Project.

These projects are new or "greenfield" projects that are not associated with existing LNG Import terminals that were considered as potential system alternatives.

Gulf Coast Liquefaction Project

The Gulf Coast Liquefaction Project would export LNG from a planned export terminal at the Port of Brownsville in Brownsville, Texas, about 130 miles south of the proposed Terminal site (see figure 3.1-1). On October 16, 2012, Gulf Coast received authorization from DOE/FE to export LNG to Free Trade Agreement countries. At the time this EIS was prepared, Gulf Coast had not requested that the FERC initiate the pre-filing process.

The project, as proposed to the DOE/FE, would include a new terminal on about 500 acres, four liquefaction trains capable of liquefying a total of 2.8 Bcf/d of natural gas, an unspecified number of LNG storage tanks, a marine berth, and a pipeline connecting the terminal to existing natural gas transportation lines. Rather than enter into long-term natural gas supply or LNG export contracts, Gulf Coast would set up liquefaction tolling agreements allowing individual gas customers to deliver gas and receive LNG from the terminal. Gulf Coast anticipates in service in 2018.

As a greenfield facility, the environmental impacts associated with development on an undisturbed site would likely be comparable in both magnitude and duration to the proposed Project. Therefore, the Gulf Coast Liquefaction Project would not provide a significant environmental advantage over the proposed Terminal. In addition, the Gulf Coast Liquefaction Project would not be completed in Cheniere's schedule, including any customer commitments. Therefore, this system alternative was not considered further.

Lavaca Bay LNG Project

The proposed Lavaca Bay LNG Project includes two floating liquefaction, storage, and offloading (FLSO) units that would produce LNG from North American natural gas. The project would also include onshore pre-treatment facilities and infrastructure associated with the FLSOs. LNG would be stored, as needed, prior to transferring the LNG to carriers for export. The FLSOs would be permanently moored at a proposed shore-side dock in Port Lavaca in Calhoun County, Texas, approximately 60 miles north of the proposed Terminal site (see figure 3.1-1).

The Lavaca Bay LNG Project would include a total of eight liquefaction trains, storage of up to 500,000 m^3 of LNG, and a send-out capacity of 10 mtpy of LNG. On October 23, 2012, ELS submitted a Letter of Intent and a preliminary WSA to the Coast Guard for consideration in its assessment of the waterway and issuance of a LOR regarding the suitability of the waterway for LNG carrier marine traffic. On February 6, 2014, ELS filed an application with the FERC, with a planned in service date of December 31, 2017[17]. Additional facilities would be needed to meet Cheniere's export objectives, including the creation of two new berthing areas and turning basins as well as additional other onshore facilities, resulting in similar or greater environmental impacts. Therefore, the Lavaca Bay LNG Project would not provide a significant environmental

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[17] Docket Nos. CP14-71, CP14-72, and CP14-73

advantage to the Project. Additionally, receipt of permits and approvals for the additional facilities necessary to meet Cheniere's objectives, which ELS has not requested, would likely not meet Cheniere's schedule. Therefore, this system alternative was not considered further.

Magnolia LNG Project

Magnolia LNG would construct its liquefaction and LNG export project at the Port of Lake Charles in Calcasieu Parish, Louisiana, at the port's Industrial Canal, off the Calcasieu Ship Channel, about 280 miles northeast of the proposed Terminal site (see figure 3.1-1). The Magnolia LNG Project would be a stand-alone LNG export facility, not associated with an existing LNG terminal, and constructed on a 90-acre site. At full capacity, the project would export 8 mtpy of LNG using four liquefaction trains, each with a capacity of 2 mtpy of LNG.

In December 2012, Magnolia LNG filed an application with DOE/FE requesting long-term authorization to export LNG to foreign countries with which the U.S. has existing Free Trade Agreements. On April 30, 2014, Magnolia LNG filed its application at FERC with planned commercial operations beginning with the first train in 2017 and the second train in 2018. The third and fourth trains would be constructed and operated if market conditions are favorable.[18]

To meet Cheniere's objectives, Magnolia LNG would need to commit all of the capacity of the four trains to Cheniere and construct additional trains. Magnolia LNG has not requested authorization for the increased capacity and receipt of permits and approvals for the additional facilities that would be needed to meet Cheniere's objectives, and would likely not meet Cheniere's schedule, including any customer commitments. Additionally, as proposed, the natural gas feedstock for Cheniere's Terminal would be sourced from the south Texas region. Transporting gas to the Magnolia LNG terminal, located significantly further from the south Texas region, would require greater transportation costs, potential facilities, and associated additional environmental impacts, as compared to the Cheniere Terminal. Therefore, this system alternative was not considered further.

Gasfin LNG Project

The planned Gasfin LNG Project is a liquefaction and LNG export project in Cameron Parish, Louisiana on the east side of the Calcasieu Ship Channel, approximately 280 miles northeast of the proposed Terminal site (see figure 3.1-1). The project would be a stand-alone LNG export facility that is not associated with an existing LNG terminal and would have an export capacity of 1.5 mtpy.

On March 7, 2013, DOE/FE granted Gasfin long-term authorization to export LNG to countries with which the U.S. has existing Free Trade Agreements. The Gasfin LNG Project is in the initial development phase and an anticipated schedule has not yet been released. At the time this EIS was prepared, Gasfin had not requested that the FERC initiate the pre-filing process. We do not consider the Gasfin LNG Project to be a reasonable alternative to the Project because it would not be completed in time to meet Cheniere's schedule, including any customer commitments, and as a greenfield project, would likely not provide a significant environmental advantage to the Project. Therefore, this system alternative was not considered further.

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[18] Docket No. CP14-347

Waller Point LNG Project

The planned Waller Point LNG Project is a stand-alone liquefaction and LNG export facility in Cameron Parish, Louisiana on the western shore of the Calcasieu Ship Channel from the Gulf of Mexico, approximately 280 miles northeast of the proposed Terminal site (see figure 3.1-1). The project would have an LNG export capacity of about 1.25 mtpy. On December 20, 2012, DOE/FE granted long-term authorization to Waller Point LNG for LNG export to countries with which the U.S. has existing Free Trade Agreements.

The project is in the initial development phase and Waller Point LNG has not announced a planned schedule. Further, at the time this EIS was prepared, Waller Point LNG has not requested that the FERC initiate the pre-filing process. We do not consider the Waller Point LNG Project to be a reasonable system alternative to the Project because it would not be completed in time to meet Cheniere’s schedule, including any customer commitments, and as a greenfield project, would likely not provide a significant environmental advantage to the Project. Therefore, this system alternative was not considered further.

CE FLNG LNG Project

CE FLNG announced plans for developing a floating LNG liquefaction and export terminal on the east bank of the Mississippi River north of the confluence of Baptiste Collette Bayou in Plaquemines Parish, Louisiana, approximately 490 miles east of the proposed Terminal site. Project facilities include two FLSO vessels, each capable of producing up to 4 mtpy of LNG. The FLSOs would have an LNG storage capacity of 250,000 m^3. LNG carriers would berth next to the units to load LNG. The project would include a 45-mile-long pipeline to connect the terminal with two sources of natural gas: (1) the existing Enterprise Products natural gas processing plant in Bernard Parish, (2) and the existing Targa Venice natural gas processing plant in Plaquemines Parish. CE Pipeline, LLC plans to construct and operate the pipeline.

The project would be a stand-alone liquefaction and LNG export facility that is not associated with an existing terminal. On November 21, 2012, DOE/FE granted long-term export authorization to CE FLNG for LNG export to countries with which the U.S. has existing Free Trade Agreements. At the time this EIS was prepared, CE FLNG was in the early phases of the FERC pre-filing process[19]. CE FLNG anticipates that the first FLSO vessel would be in service in March 2018, with the second FLSO starting up in October 2018.

To meet Cheniere’s objectives, CE FLNG would need to commit its entire capacity of the project to Cheniere and install two additional FLSO vessels which would require establishing additional berthing facilities, turning basins, and associated onshore facilities. We do not consider the CE FLNG LNG Project to be a reasonable system alternative to the Project because would not be completed in time or have the send out capacity to meet Cheniere’s schedule, including any customer commitments, and as a greenfield project, would likely not provide a significant environmental advantage to the Project. Therefore, this system alternative was not considered further.

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[19] Docket No. PF13-11

Mississippi River LNG Project

Louisiana LNG Energy, LLC (LLNGE) is planning to construct and operate the Mississippi River LNG Project[20]. Under this proposal, LLNGE would construct, own, and operate a liquefaction terminal for the export of LNG near mile marker 46 on the east bank of the Mississippi River. The terminal would include four liquefaction trains, each with a capacity of 74,380 cubic feet per day; two 100,000 m^3 full containment LNG storage tanks; 1.9 miles of 24-inch-diameter pipeline; and 1.6 miles of 12-inch-diameter pipeline. This project would be located more than 450 miles from this proposed Project. Therefore, we find that impacts would not have a cumulative effect on the resources in the Project area, including air quality impacts as discussed in section 4.13.5.

LLNGE requested initiation of our pre-filing process on July 11, 2014 and was approved on July 18, 2014. On August 28, 2014, DOE/FE granted LLNGE long-term authorization to export LNG to countries with which the U.S. has existing Free Trade Agreements. The planned Mississippi LNG Project would only be capable of exporting LNG, and would thus not meet the Project's stated purpose and need to provide regasification capabilities for import of LNG, in addition to export. We do not consider the Mississippi LNG Project to be a reasonable system alternative to the Project because as a greenfield project that would require additional facilities and capacity in order to meet the proposed Project's purpose and need, it would not provide a significant environmental advantage to the Project. Therefore, this system alternative was not considered further.

3.1.4 Alternative Terminal Sites

Alternative aboveground facility sites considered for the Terminal are described below. The proposed Terminal would occupy an industrial area with access to a deep water channel. We performed a thorough site alternative evaluation for the Terminal facilities. An analysis and conclusion of the alternative sites is presented below.

A large number of alternative sites were evaluated along the Gulf Coast. A total of 17 potential port alternative sites were evaluated for channel depth (greater than 40 feet) and proximity to existing natural gas pipeline systems, which are the primary criteria applicable to the Terminal. Three sites were selected for further evaluation based on access to a channel greater than 40 feet deep, access to major natural gas pipelines, industrial zoning, and availability of sufficient open land for construction and operation of the facility. These sites were previously proposed or planned for three LNG import projects that have not been built: Vista del Sol LNG, Eos FLNG, and Ingleside Energy Center LNG projects. Figure 3.1-2 shows the sites which are further discussed below.

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[20] Docket No. PF14-17-000

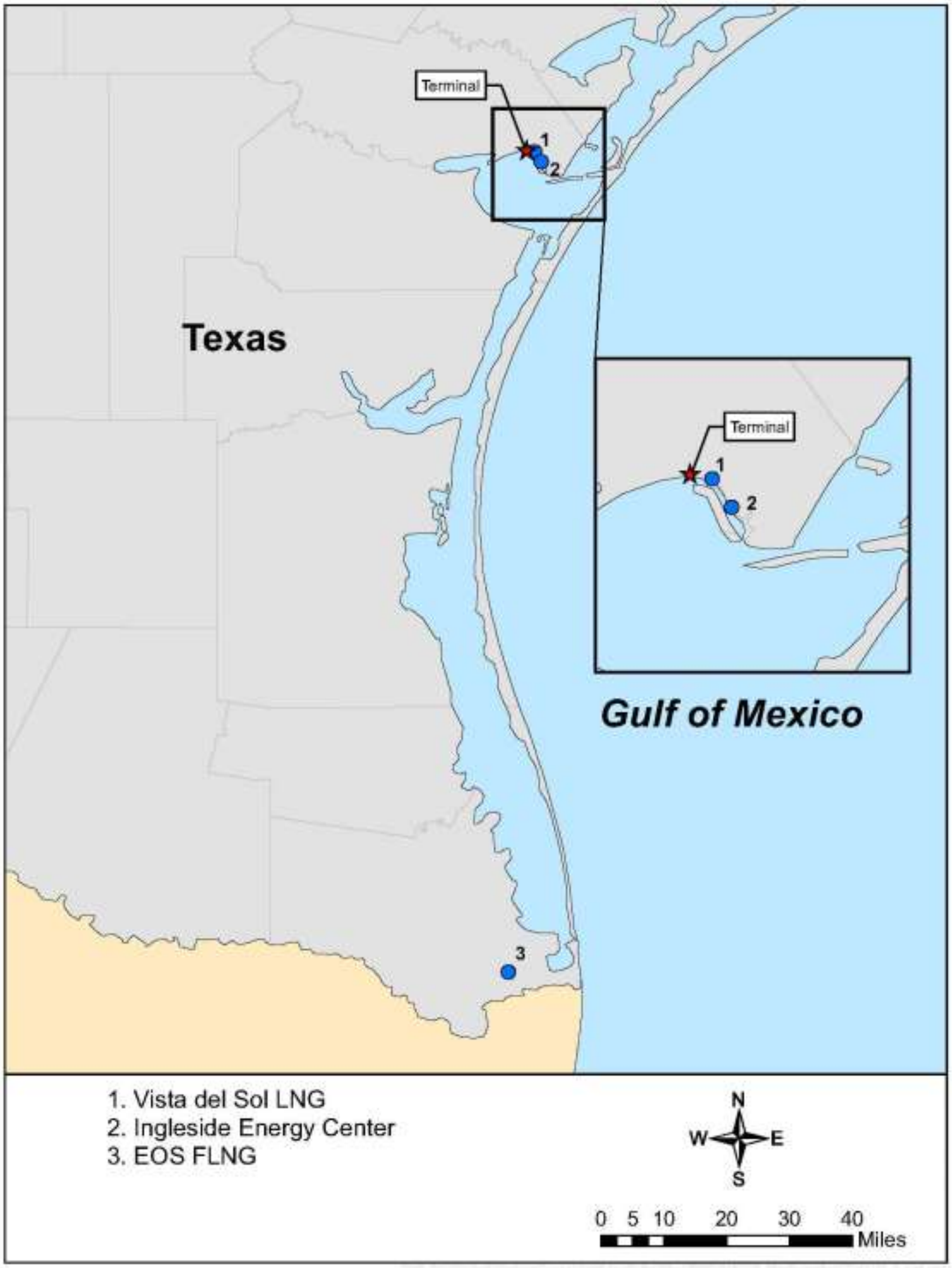

Figure 3.1-2 **Terminal Site Alternatives**

In order to assess the suitability of each site, we developed a set of four major objectives including site-specific criteria, marine operations, access to existing pipeline systems, and permitting, which were then subdivided into site selection criteria.

1. The site-specific criteria are as follows:
    - the ease of acquisition, with preference given to parcels of land in industrial areas or dredge disposal areas;
    - sufficient space for the land-based and marine components of the Terminal, including the required spacing between equipment and tanks, as specified by the NFPA 59A; and
    - existing infrastructures capable of providing reliable sources of power as well as suitable roads and barge access for delivery of materials during construction.
2. The criteria of the marine operations objective include:
    - vessel traffic volume must comply with potential restrictions that a LNG carrier in transit may pose on traffic in conjunction with other vessels;
    - ease and efficiency of channel access, as the more expeditiously a vessel is able to reach the terminal, unload, and depart on its ballast voyage, the better the economics of the terminal;
    - availability of a channel with sufficient depth, width, and air draft for the operation of a typical LNG carrier is essential; and
    - adequate maneuvering area amplitude and proximity (a minimum diameter of 1,200 feet and greater than 40 foot depth is required for a typical LNG carrier maneuvering area.).
3. The criteria for access to existing pipeline systems include:
    - proximity of existing pipeline systems for importation (it is assumed that the routing issues and construction techniques would be similar for all onshore sites.); and
    - adequate supply/send-out capacity with sufficient available capacity, and ability to maintain consistent demand for the pipeline system.
4. Criteria of the permitting objective include:
    - avoidance of impacts on residential areas including noise and light impacts;
    - environmental consequences, including maximizing the use of previously disturbed areas in order to reduce potential impacts;
    - compatibility with region/port development plans and those of adjacent properties;
    - land use zoning to support the above two criteria (zoning does not preclude industrial development); and
    - avoidance of populated areas to ensure compliance with the siting requirements of NFPA 59A and 49 CFR Part 193. The sites were evaluated by comparison of their distance to populated areas. Scores are relative to these distances.

Refer to table 3.1-1 below for a summary of the investigation results.

Table 3.1-1
Alternate Site Location Comparisons

Criteria	Proposed Site	Eos FLNG	Vista del Sol LNG	Ingleside Energy Center LNG
Site Specific				
Ease of Acquisition	Owned by Corpus Christi Liquefaction, LLC	Unknown	Owned by Occidental Petroleum Corp	Owned by Occidental Petroleum Corp
Area Available (acres)	600+	Unknown	430	82
Infrastructure	Minimal improvement required	Minimal improvement required	Minimal improvement required	Minimal improvement required
Marine Operations				
Vessel traffic volume	Acceptable	Acceptable	Acceptable	Acceptable
Channel Access	Acceptable	Acceptable	Acceptable	Acceptable
Maneuvering	Dredging required	Dredging required	Dredging required	Dredging required
Access to Pipeline				
Distance to pipeline	~23 miles	40+ miles	~23 miles	~26 miles
Pipeline capacity	Intrastate & interstate available	Limited	Intrastate & interstate available	Intrastate & interstate available
Permitting				
Compatibility with region/port development plans	Development of adjacent Port property	Port Authority is promoting growth	Development of adjacent Port property	Development of adjacent Port property
Land Use Zoning	None	Industrial	None	None
Distance to populated areas	>1 mile	5 miles	>1 mile	>1 mile
Environmental Factors [a]				
Wetland Impacts (acres)	25.7	Unknown	24.5	5.5
Open Water Impacts	150	Unknown	62.4	40
Land Impacts (acres)	321	Unknown	247.1	74
Floodplain	Marine berth and transfer arms within 100-year floodplain	Entire site within 100-year floodplain	Partially within 100-year floodplain	Mostly within 100-year floodplain

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a/ Environmental factors were determined based on information provided in Vista del Sol LNG and Ingleside Energy Center LNG EISs, that were issued on April 15, 2005 and June 10, 2005, respectively. These acreages are based on constructing import facilities only, not taking into consideration liquefaction facilities required for export. No acreages are calculated for the Eos FLNG as no data is available.

The Vista del Sol LNG and the Ingleside Energy Center LNG site locations are both on the La Quinta Ship Channel and are nearby to the proposed Terminal site. Infrastructure and environmental impacts at these sites would be similar to the proposed Terminal site but would require additional investigation as to whether liquefaction facilities can be accommodated at the site. Environmental impacts associated with developing either alternative site would likely result in impacts either similar or greater than those of the proposed site. In addition, the properties are now owned by Occidental Petroleum Corporation and are no longer available to Cheniere. Occidental Petroleum Corporation has also recently acquired the Naval Station Ingleside site from the Port of Corpus Christi Authority (POCCA) and thus, it is no longer available. Therefore, these alternative sites were dismissed and not considered further.

The Eos FLNG site is more than 40 miles from an existing pipeline system which has limited available capacity and lacks access to interstate pipeline networks. Construction of additional pipeline to reach the Eos site would likely result in greater environmental impacts than those of the proposed project. Therefore, this alternative was dismissed and not considered further.

The proposed site for the Terminal is selected because it offered the following advantages over the other alternative sites:

- the Terminal is compatible with the existing industrial land use;
- the channel has a history of accommodating international vessels delivering liquid products;
- the site has potential for barge access for the delivery of construction materials;
- the site is isolated from residential communities;
- the distance from the Terminal required to reach open water is short;
- existing pipeline systems with available take-away capacity are proximal to the site; and
- the property is owned/leased and available for development by Cheniere.

Significant site preparation earthwork was conducted at the Terminal site from 2006 to 2008 to prepare the proposed site for construction of the previously approved Import Terminal. Furthermore, some environmental permits, such as the COE Section 404/10 Permit, are valid for the Terminal but are being amended to include additional impacts from the proposed layout.

There has been industrial development in the vicinity surrounding the Terminal site. Two wind power projects as well as the Copano Pipeline Project occur within the vicinity of the Terminal; however, they do not impact the site. The ongoing construction of the La Quinta Channel Extension Project, being conducted by the COE and the POCCA, could potentially impact the Terminal site or surrounding resources. This project involves an extension of the La Quinta Channel by approximately 7,400 feet to the area directly south of the POCCA's property, located west of the Terminal. The collective effects from construction of these projects in conjunction with the Terminal could be significant; however, it is anticipated that cumulative impacts would be temporary or minor, as the listed projects would not be constructed concurrently with the Terminal. Cumulative impacts associated with the proposed Project and projects in the regional geographic area are further discussed in section 4.13.

The proposed Terminal site is the most environmentally preferable and practical alternative, as it is the only considered site that fully satisfies the Project's purpose and need, while minimizing impacts on agricultural land and would not adversely impact other existing land uses or protected resources (see sections 4.0 and 5.0).

We received a comment on the draft EIS from the COE regarding evaluation of an alternative Terminal site that does not involve siting within special aquatic sites, such as wetlands. The COE stated in its comment that "where the proposed project does not require access or proximity to, or siting within a special aquatic site, such as a wetland, to fulfill its basic purpose, practicable alternatives that do not involve special aquatic sites are presumed to be available." For the reasons previously discussed in sections 1.2 and 3.0 of the EIS, siting the Terminal near marine/port locations would be necessary; therefore an alternative Terminal site that does not involve siting within special aquatic sites was not considered.

3.1.5 Alternative Dredge Disposal Locations

As currently proposed, dredged materials would be utilized to fill a portion of a former 90-acre clay borrow pit northeast of the Terminal site. The remainder of the dredged material would be deposited in a 385-acre area, known as DMPA 2 (old bauxite disposal beds), located immediately north of the Terminal site in order to assist in the capping of those beds (see figure 2.1-1). The dredge material would be transported by a slurry pipe approximately 11,000 feet long and would be distributed across the large bauxite beds north of the Terminal. The water would be decanted and monitored as it leaves the DMPA to permitted outfalls. The resulting soil would provide a cap over the old bauxite beds, which would allow vegetation to occur and reduce the red dust in the area.

There are two alternative locations for the placement of dredged materials from the marine facilities that were evaluated. These locations, referred to as DMPA 13 and DMPA 14, (see figure 3.1-3) are located on property owned by the POCCA to the west and south of the Terminal. DMPA 13 is located south of the Terminal and La Quinta Channel and is an existing spoil island created from dredging and maintenance activities along the Channel. Environmental impacts from the placement of additional dredge material on DMPA 13 would be minimal. DMPA 14 is located to the west of the Terminal at an area where the POCCA has created a berm for dredge material placement; therefore, environmental impacts from placement of dredge material within DMPA 14 would be minimal. However, DMPAs 13 and 14 would not allow capping of former bauxite disposal beds or revegetation in the area. Therefore, the proposed location of DMPA 2 would be preferred, because it provides minimal environmental impact as well as providing minor beneficial environmental restoration.

Figure 3.1-3 Alternative Dredge Disposal Areas

3.1.6 Alternative to Elevated Flares

During the public meeting on the draft EIS, we received a comment regarding evaluation of alternatives to the proposed elevated flares.

Elevated flares are the most commonly utilized flare systems in hydrocarbon processing facilities. Ground flares may also be used in instances where the 500 British thermal units per cubic foot per hour (Btu/hr-ft^2) radiation level cannot be contained within the plant boundary, where there would be concerns regarding seismic issues, or to mitigate for impacts from noise and on visual resources in the surrounding areas. In the case of the Terminal, there would be adequate space available for elevated flares such that the 500 Btu/hr-ft^2 radiation level remains within the plant boundary and there would be no seismic issues that would prohibit elevated structures. Impacts from noise and on visual resources are discussed below and in section 4.8.1.4.

Ground flares vary in complexity and may consist either of conventional flare burners discharging horizontally with no enclosure or of multiple burners in a refractory-lined steel enclosure. Because the flame is very close to ground level, it is necessary to have a barrier around the unit to avoid any flame propagation outside of the flare perimeter.

Visual impacts associated with the elevated flares would typically be greater than ground flares; however, the majority of these events would not significantly contribute to visual impacts as they would be rare occurrences or of short duration. Noise resulting from a flare event is generated at the process valve where the release into the flare header occurs and at the flare tip. For the elevated flare, Cheniere's Noise Modeling Report (see section 4.11.2) indicated that during normal operation there would be no significant noise generated from the flares, and emergency reliefs would be infrequent and of short duration.

Air emissions quantities are essentially the same for both elevated flares and ground flares, as both provide adequate destruction of the hydrocarbons released to flare. However, elevated flares provided better dispersion of air emissions.

With proper design both ground flares and elevated flares can be operated safely. Due to the potential increased air emissions dispersion associated with the elevated flares, and only minor impacts on visual resources and noise are anticipated, we have determined that the proposed elevated flares would be the most environmentally preferred alternative.

3.1.7 Alternative to Gas Turbines

We received a comment on the draft EIS from the Sierra Club regarding the evaluation of an alternative design that would replace the 18 gas turbines driving liquefaction compressors with electric motors.

If the Project were to be redesigned with electric motors to replace the gas turbines driving the liquefaction compressors, Cheniere has indicated that a significant amount of electricity would be needed from the regional power transmission grid to run the electric motors. The use of electric motors would result in offsite criteria pollutant and GHG emissions by the power plants supplying the incremental electricity. Whether those emissions would be greater or less than projected emissions associated with the Project would be a function of load growth in the Electric Reliability Council of Texas market overtime and the types of new capacity that would be built to meet that load, among other factors.

In addition to trading air emissions impacts from the Terminal to other sources, routing of the electricity to the Terminal would result in additional other environmental impacts that the current design of the Terminal would not create. Cheniere has indicated that additional facilities that would be needed include: constructing a minimum new 7-mile, 345 kV electrical line to the nearest location where ample electrical supply is available; expansion of a nearby electrical substation to accommodate the new power; and electrical system upgrades across a large area. The additional facilities that would be needed to supply the electricity to the Terminal would result in the creation of new or expanded rights-of-way and cause impacts on people, wildlife, and vegetation.

The proposed gas turbines would provide 100 percent of the plant heating needs (hot oil and regeneration services) through waste heat recovery units installed on the gas turbine exhausts for the ethylene compressors. Cheniere has indicated that if electric motors were substituted for the gas turbines, new and additional direct-fired heaters would be required at the plant to make up for that lost heating service. Gas would be required to fuel those direct-fired heaters, which would create emissions of GHGs and criteria pollutants. Plant heating needs would not result in additional emissions under Cheniere's proposed design.

Furthermore, Cheniere has stated that the use of electric motors would also require variable frequency drive (VFD) system to control the motors, and this would require construction of an additional large building adjacent to each LNG train to house the VFD system. Electric motors and the VFD systems may also require water cooling. The current layout of the plant and the available property do not allow sufficient plot space to add these buildings and the other infrastructure that would be required to support the electric motors. The plot plan for a facility using electric motors would be larger than currently proposed and designed; and the larger footprint would result in additional land use and environmental impacts.

Finally, electric motors used as the main drivers for LNG refrigeration compressors are currently in operation only on one LNG plant, in Norway, and have not yet demonstrated the reliability necessary to sustain base load LNG production such that the technology could be recommended over the proposed design. We recognize that the Freeport LNG facility, which is located in the Houston-Galveston-Brazoria ozone nonattainment area, has been authorized with electric motors as well. However, this facility was required to meet more restrictive air permitting requirements for emissions control, which likely was an important factor in designing the facility with electric driven motors for compression. In contrast, the Project would be located in an ozone attainment area and has performed air quality modeling demonstrating compliance with applicable standards; and therefore, we find no compelling reason to not follow the precedent for BACT established by both the TCEQ (as permit developer for non-GHG PSD-regulated emissions) and EPA (as permit developer for GHG emissions) for Project permitting, with regard to the consideration of electric motor-driven compression. The BACT analysis is a PSD permitting requirement and the EIS summarizes the BACT and/or mitigation measures to reduce emissions from the gas turbines.

For the reasons discussed above, an alternative design to replace the 18 gas turbines with electric motors was not considered an environmentally preferable alternative.

3.2 PIPELINE FACILITIES

3.2.1 No-Action Alternative

Under the No-Action Alternative, the objectives of the Project would not be met and Cheniere would not provide the proposed natural gas transportation capacity for import or export. In addition, the potential adverse and beneficial environmental impacts identified in section 4.0 of this EIS would not occur.

3.2.2 System Alternatives

We considered whether any of the existing, recently authorized, or currently proposed pipeline routes in the U.S. could be reasonable system alternatives to the proposed Pipeline. To be considered a viable system alternative, the existing or approved pipeline facilities would need to: 1) transport all or part of the volume of gas required for liquefaction at the Terminal; and 2) cause significantly less impact on the environment than the proposed Pipeline.

3.2.2.1 Pipeline System Alternatives

Numerous natural gas pipelines operate in San Patricio County, Texas. The pipeline infrastructure in the county dates to the mid-20th century and is comprised of gathering and midstream pipelines, upstream processing, and transmission or distribution pipelines downstream of processing. Several interstate pipelines transport south Texas production to the east, feeding long-haul transmission systems that serve the Midwest and Northeast U.S. Alternatively, intrastate pipelines aggregate and deliver supplies for local consumption within Texas. Over the years, certain pipelines have switched from transmission and distribution to gathering or midstream service. Many have done so recently, given high production volumes. Regardless, only processed, pipeline quality gas is considered for liquefaction.

Our analysis of pipeline system alternatives includes evaluation of existing interstate pipeline systems to meet the objectives of the proposed Pipeline. Table 3.2-1 lists the natural gas pipelines identified in San Patricio County and their relative distances from the Terminal. The table also indicates which pipelines, to date, have been considered commercially for connection to the proposed Pipeline and the character of service. Five pipelines in table 3.2-1 have planned connections to the proposed Cheniere Pipeline. However, these pipelines would not serve as suitable alternatives to the Cheniere Pipeline, as additional construction of pipeline to connect to the Terminal would be required, resulting in similar or greater environmental impacts than the proposal. In addition, interconnections would also be required and it is not known whether additional pipeline length would be required by those companies at proposed pipeline interconnects.

Table 3.2-1
Natural Gas Pipelines Identified in San Patricio County, Texas

Pipeline	Miles from Cheniere Terminal	Planned Connection to Cheniere Pipeline	Description of Pipeline Service
Houston Pipeline a/	Adjacent	No	Intrastate, low pressure distribution line
Gulf South Pipeline b/	On site	No	Interstate, in gathering or midstream service
Crosstex Energy c/	On site	No	Gathering or midstream service
KM Tejas	Adjacent	No	Intrastate distribution line
Texas Eastern	7.5	Yes	Interstate, high pressure line
Gulf South Pipeline	11.6	No	Interstate, in gathering or midstream service
Channel Industries d/	14.6	No	Intrastate, distribution line
Florida Gas e/	16.7	No	Interstate, high pressure line
KM Tejas	21.0	Yes	Intrastate, high pressure line
NGPL	22.4	Yes	Interstate, high pressure line
Transco	22.8	Yes	Interstate, high pressure line
Tennessee Gas	23.0	Yes	Interstate, high pressure line

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a/ Houston Pipeline Company, LP
b/ Gulf South Pipeline Company, LP
c/ Crosstex Corpus Christi Natural Gas Transmission
d/ Channel Industries Gas Pipeline Company
e/ Florida Gas Transmission Company, LLC

The overall purpose of the Project is to provide facilities that would allow imported LNG to be vaporized and transferred to U.S. markets via existing interstate and intrastate natural gas pipeline systems, or deliver and liquefy natural gas for export. Under present conditions, no existing pipelines would satisfy the purpose and need of the Project because these lines have gas volumes committed to existing customers. Any additional volumes would require construction of additional loop, compression, or new greenfield facilities. The closest interstate pipeline that would connect with the proposed pipeline is Texas Eastern at 7.5 miles away, as depicted in table 3.2-1. Therefore, expansion of an existing interstate or intrastate pipeline to connect with the proposed Terminal would result in environmental impacts similar to or greater than those associated with the proposed Pipeline. Because a pipeline alternative using another system would provide no environmental advantage over the proposed Pipeline, we have dismissed these from consideration.

3.2.3 Pipeline Route Alternatives

In evaluating Pipeline route alternatives, we examined variations that could minimize or avoid impacts on environmentally sensitive resources such as population centers, special use areas, waterbodies, wetlands, existing or planned residences, or specific landowner concerns. We looked for a suitable Pipeline route that would result in minimal environmental and social impacts.

Paramount in the development of the alternative pipeline route analysis was the presence of existing infrastructure (utility rights-of-way, corridors, or previously developed areas). Significant emphasis was placed on the incorporation of guidelines set forth in 18 CFR Part 380.15.

The routing criteria used to develop the proposed Pipeline route included:

- utilization of existing corridors;
- minimal creation of new corridors;
- potential impacts on sensitive resources;
- land use issues;
- proximity to residential/congested areas;
- engineering/construction issues;
- operation and maintenance considerations; and
- supporting infrastructure.

Existing utility corridors generally provide opportunities to minimize impacts on the environment. Constructing new pipelines along existing corridors reduces the need for establishment of new corridors and thus, the involvement of additional landowners, clearing of new rights-of-way, and potential environmental impacts.

When establishing the final proposed route, the only substantial development has been the construction of the Papalote Creek Wind Farm, located in agricultural lands east of Taft, Texas. There are several wind turbines that have been constructed and would operate in close proximity to the Pipeline route; however, none these turbines are expected to directly impact the Pipeline or associated aboveground facilities.

3.2.3.1 Major Route Alternative

The proposed Pipeline route was primarily based on the approved route of Cheniere's initial filing, which received an Order (FERC Docket No. CP04-37-000) but was never constructed. Three major alternative routes as well as the proposed Pipeline route were evaluated to determine which would produce minimal environmental impacts while meeting the Pipeline's objective. The proposed Pipeline route, at a length of approximately 23.0 miles, provides the shortest distance from the proposed Terminal to existing high pressure natural gas pipeline systems in the South Texas region. The Pipeline would be installed adjacent to a high voltage overhead power line as well as existing natural gas pipelines along portions of the proposed route. As such, the proposed route minimizes environmental impacts by maximizing the use of existing corridors in the area. The evaluations of the three major route alternatives are discussed below. Table 3.2-2 compares significant environmental factors of each of the route alternatives with the proposed route.

Table 3.2-2
Environmental Comparison of the Proposed Pipeline Route with Route Alternatives

Environmental Factor	Proposed Route	Route Alternative A	Route Alternative B	Route Alternative C
Total Length of Mainline Pipeline (miles)	23.0	24.0	27.4	26.4
Length Adjacent to Existing Right-of-Way (miles)	19.73	16.5	23.6	22.9
Construction Disturbance (acres)	321.1 a/	350.6 a/	332.1 b/	320.0 b/
Waterbodies Crossed	9	7	9	9
Wetland Impacts (acres)	<0.01	4.5	2.8	<0.01
Railroad Crossings	3	3	2	2
Road Crossings	18	14	33	22
Residences within 50 feet of Construction Work Area	0	23	0	0

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a/ Construction disturbance based on nominal right-of-way width of 120 feet
b/ Construction disturbance based on nominal right-of-way width of 100 feet

Route Alternative A

Route Alternative A (see figure 3.2-1) would begin at the proposed Terminal and proceed west for approximately 1 mile across open land owned by the POCCA. It would then turn northwest, cross the Southern Pacific Railroad and SH 35, skirt the west side of the city of Gregory, and cross CR 2986. Alternative A would then parallel Boykin Road between MPs 4.0 and 11.0, skirting the west of the city of Taft. It would follow local farm roads between MPs 14.0 and 15.0, then turn northeast, parallel to CR 1074, crossing U.S. Highway (US) 181, to MP 17.0, where it would turn northwest again. Following an existing pipeline corridor, Alternative Route A would cross Oliver Creek at MP 18.0, Chiltipin Creek at MP 19.0, and US 77 at MP 21, before terminating at MP 24.0.

This route would be 1.0 mile longer than the proposed route, and would be 4.5 miles less collocated with existing rights-of-way. It would affect 29.5 acres more land including 4.5 acres more wetlands and would be within 50 feet of 23 residences. The proposed route does not impact residential lands. The primary disadvantage of the alternative is that it would cross a greater portion of the POCCA property located west of La Quinta Road. The POCCA property is the proposed site for both the La Quinta Trade Gateway Terminal as well as the Voestalpine DRI Plant, both of which are further discussed in section 4.13. Alternative Route A also crosses a residential area that had not been constructed when the route alternative was originally proposed and evaluated under FERC Docket No. CP04-37-000.

Therefore, Route Alternative A would not offer an environmental advantage over the proposed route and we do not recommend the use of this alternative.

Route Alternative B

Route Alternative B (see figure 3.2-1) would begin at ExxonMobil’s previously approved, but never constructed, Vista del Sol LNG terminal, located south of the DuPont chemical plant approximately 2 miles southeast of the proposed Terminal. It would then proceed northward past the DuPont plant, crossing Edwards Road and a railroad, avoiding an existing pond, and crossing SH 361 and the Southern Pacific Railroad at MP 2.3. It would then follow existing ExxonMobil and Koch pipelines heading northwest across agricultural land, crossing SH 35 at MP 5.5. At MP 17.7 Route Alternative B would leave the existing pipeline corridor and become a greenfield route, crossing Chiltipin Creek at MP 19.0 and proceeding over open scrubland to MP 20.8, where it would follow another existing pipeline. It would cross US 77 at MP 24.8 and terminate at MP 27.4.

This route would be 4.4 miles longer than the proposed route, would impact 2.8 acres more wetlands, and would cross 15 more roadways than the proposed route. Thus, Route Alternative B would not offer a significant environmental advantage over the proposed route and therefore we do not recommend the use of this alternative.

Route Alternative C

Route Alternative C (see figure 3.2-1) would begin at the previously approved, but never constructed, Ingleside Energy Center LNG terminal and would proceed northward, past the Occidental chemical plant, crossing SH 361 and the Southern Pacific Railroad at MP 1.5. It would continue northwesterly, crossing SH 35 at about MP 4.0, skirting the east side of the city of Gregory near MP 6.5, and the east side of the city of Taft near MP 14.5. This route would cross Chiltipin Creek at MP 21.5, and terminate at MP 26.4.

Route Alternative C would be 3.4 miles longer than the proposed route and would include four more road crossings thus resulting in greater land impacts. All other environmental factors evaluated would be similar to the proposed route, thus, Route Alternative C would not offer an environmental advantage over the proposed route and therefore we do not recommend the use of this alternative.

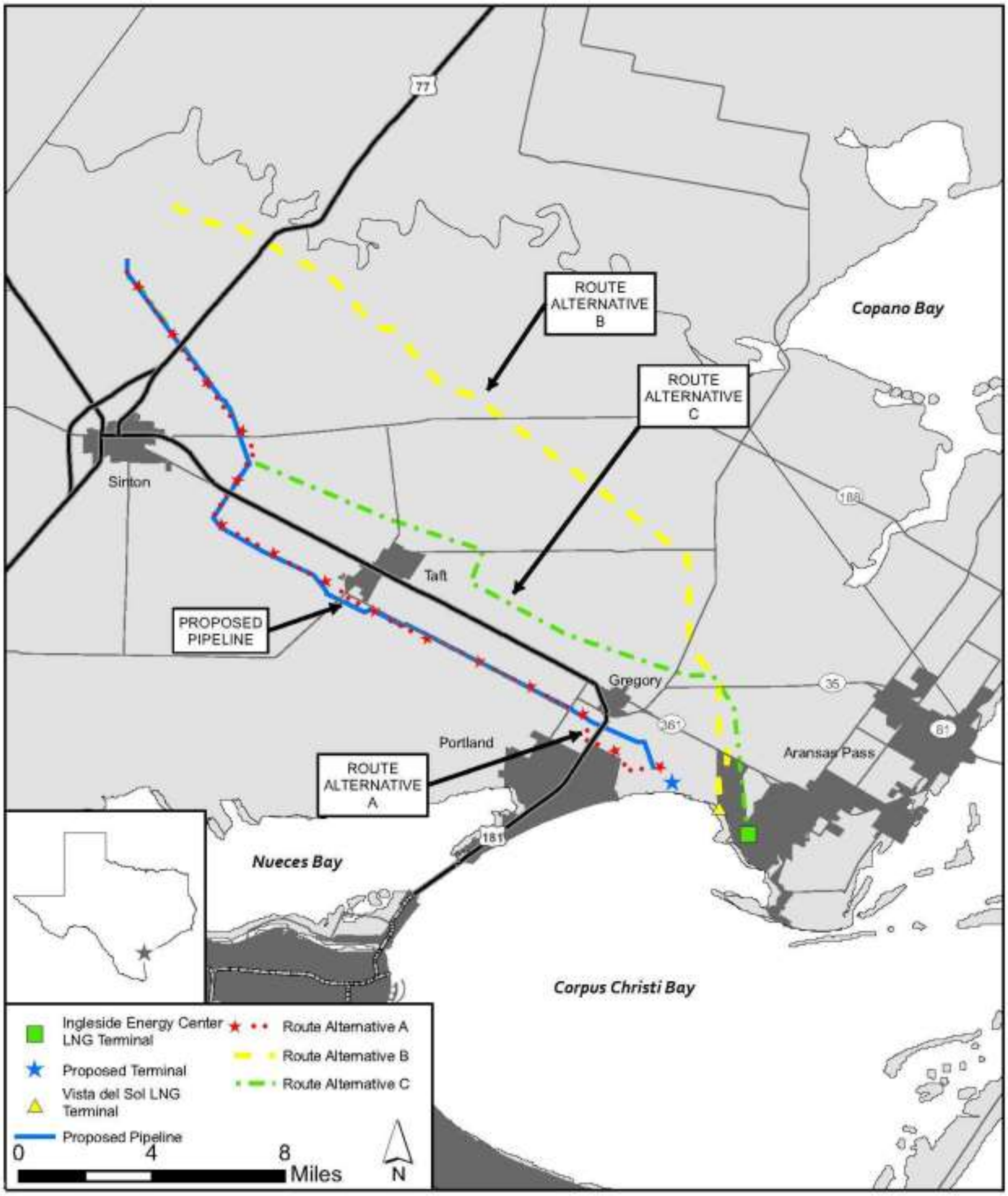

Figure 3.2-1 **Pipeline Route Alternatives**

3.2.3.2 Other Appurtenant Aboveground Facilities

Proposed aboveground facilities for the Pipeline would include MLVs, one pig launcher and receiver, and six M&R stations. These facilities all occur on agricultural land along the Pipeline right-of-way. These facilities are small, would not impact environmentally sensitive areas, are not located near residences, and their locations are tied to the locations of other foreign pipeline facilities, with the exception of the MLV at MP 14.5. As noted throughout section 4.0, the potential impacts of construction and operation of the aboveground facilities would be adequately minimized, and therefore we did not identify alternative sites that would provide a significant environmental advantage to the proposed aboveground facility sites.

3.2.3.3 Compressor Stations Site Alternatives

The Pipeline would require compression at two locations along the proposed route. In order to meet the natural gas supply throughput requirements for the Pipeline, compressor stations would be required at locations southeast of the city of Taft and northeast of the city of Sinton. Additional information on the location of the proposed compressor stations and alternative sites, are provided in the following sections.

Taft Compressor Station

The proposed Taft Compressor Station would be located on an approximately 30-acre land parcel along the north side of County Road 78 at approximate MP 7.5. An alternative 30-acre parcel is located on an adjacent tract to the southeast of the proposed site. Cheniere owns the land of the proposed location of the Taft Compressor Station. Both sites are located on agricultural land and neither site would have impacts on environmentally-sensitive resources such as waterbodies, wetlands, public roads, floodplains, or utility crossings (see table 3.2-3). However, the proposed site is 474 feet further away from noise sensitive areas (NSAs) than the alternative site. Additionally, the existing Texas Eastern pipeline crosses the property of the proposed site obviating the need for construction of a lateral pipeline thus eliminating associated environmental impacts. Therefore, the alternative site is not recommended since it has no environmental advantage over the proposed site. The proposed and alternative Taft Compressor Station sites are depicted in figure 3.2-2.

Table 3.2-3
Environmental Comparison of Cheniere's Proposed and Alternative Taft Compressor Station Sites

Environmental Factor	Proposed Site	Alternative Site
Total Area (acres)	30	30
Distance to Nearest NSA (feet)	3,099	2,625

The proposed and alternative Taft compressor station sites would not have an impact on public road and utility crossings, floodplains, waterbodies, or wetlands.

Figure 3.2-2 Taft Compressor Station Site Alternative

Sinton Compressor Station

The proposed Sinton Compressor Station is located on an approximately 30-acre parcel north of US 77 and northeast of the City of Sinton at approximate MP 21.5. Cheniere has secured leases for the proposed Sinton Compressor Station. The proposed site provides easy access to US 77 and the site is located in scrub/shrub habitat that is devoid of sensitive environmental resources, such as waterbodies, wetlands, public roads, and utility crossings. Table 3.2-4 compares significant environmental factors of the proposed Sinton Compressor Station site as well as the evaluated alternative sites.

All four alternative sites would be located in scrub/shrub habitat and would have the same acreages as the proposed site. Three alternative sites east of US 77 (Alternative Sites 1, 2, and 3) would require a new access road that crosses a railroad track along US 77, resulting in a potential safety concern for vehicular traffic. Alternative Sites 1, 2, and 3 were eliminated from further consideration for the Sinton Compressor Station since they provided no environmental advantage over the proposed site, and Alternative Site 3 is partially located within a 100-year floodplain.

Alternative 4 is located west of US 77 on property owned by the same landowner who owns the property of the proposed site. Alternative 4 was not selected because it is closer to the nearest NSA by 828 feet, and also offers no environmental advantages. The proposed and alternative Sinton Compressor Station sites are depicted in figure 3.2-3.

Table 3.2-4
Environmental Comparison of Cheniere's Proposed and Alternative Sinton Compressor Station Sites

Environmental Factor	Proposed Site	Alternative Site 1	Alternative Site 2	Alternative Site 3	Alternative Site 4
Total Area (acres)	30	30	30	30	30
Distance to Nearest NSA (feet)	2,367	3,871	5,192	6,354	1,539
Public Road/Utility Crossings a/	0	1	1	1	0

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a/ Public road and utility crossings include those crossed by new permanent access roads. The proposed and alternative Sinton compressor station sites would not have an impact on waterbodies and wetlands.

Figure 3.2-3 Sinton Compressor Station Site Alternatives

3.2.4 Pipeline and Compressor Alternatives Conclusions

Evaluation of the Pipeline route and compressor station alternatives determined that the proposed Pipeline would fully satisfy the Project's objective with minimal or temporary impacts, with implementation of appropriate mitigation, as presented in section 4.0. None of the alternative pipeline routes or compressor station alternatives offer a significant advantage over Cheniere's proposal.

ENVIRONMENTAL IMPACT ANALYSIS

SECTION 4

4.0 ENVIRONMENTAL ANALYSIS

This section describes the affected environment as it currently exists and discusses the environmental consequences of the Project. The discussion is organized by the following major resource topics: geology, including foundation conditions, and natural hazards; soils; water resources; vegetation; wetlands; fisheries and wildlife resources; threatened, endangered, and other special status species; land use, recreation, and visual resources; socioeconomics; cultural resources; air and noise; safety and reliability; and cumulative impacts.

The environmental consequences of constructing and operating the Project would vary in duration and significance. Four levels of impact duration were considered: temporary, short-term, long-term, and permanent. Temporary impacts generally occur during construction with the resource returning to preconstruction condition almost immediately afterward. Short-term impacts could continue for up to 3 years following construction. Impacts were considered long-term if the resource would require more than 3 years to recover. A permanent impact could occur as a result of any activity that modifies a resource to the extent that it would not return to preconstruction conditions during the life of the Project. We considered an impact to be significant if it would result in a substantial adverse change in the physical environment and the relationship of people with the environment.

As part of its proposal, Cheniere developed certain mitigation measures to reduce the impact of the Project. In some cases, we determined that additional mitigation measures/recommendations could further reduce the Project's impacts. Our additional mitigation measures/recommendations appear as bulleted, boldfaced paragraphs in the text of this section and are also included in section 5.0. We will recommend to the Commission that these measures be included as specific conditions in any Authorization the Commission may issue to Cheniere for this Project.

The conclusions in the EIS are based on our analysis of the environmental impact and the following assumptions:

- Cheniere would comply with all applicable laws and regulations;
- the proposed facilities would be constructed as described in section 2.0 of this EIS; and
- Cheniere would implement the mitigation measures/conditions included in its application and supplemental submittals to the FERC and cooperating agencies, and in other applicable permits and approvals.

4.1 GEOLOGIC RESOURCES

4.1.1 Terminal Facilities

4.1.1.1 Geologic Setting

The Terminal would be located within the Coastal Prairie region of the Gulf Coastal Plain physiographic province. 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 topography in the area is nearly flat, with subsurface sediments gently dipping toward the Gulf, and is dissected by highly sinuous streams. The minimum elevation at the Terminal is sea level, and the maximum elevation is approximately 36 feet above mean sea level (AMSL).

The Terminal would be located within a modern bay-estuary system that formed upon the Nueces River fluvial-deltaic system. The depositional environment in the Terminal area has been significantly impacted by Pleistocene–aged glacial and interglacial events which resulted in sea level changes. Broad deltas with meandering distributary channels of fluvial sands and interdistributary floodplains with overbank mud deposits were formed during interglacial periods when rivers carried large sediment loads towards the coast. The modern estuary system was formed approximately 2,500 years before present, when sea levels rose and filled the Nueces River valley with fluvial sediments and tidally transported Gulf sediments as the shoreline receded to its current position. The upper Corpus Christi Bay is a shallow estuarine delta characterized by prodelta muds and sandy channel-mouth bars.

The Terminal would be located within Holocene-aged alluvial and floodplain deposits underlain by the Pleistocene-aged Beaumont Formation. The Beaumont Formation consists of sands, silty sands, and clayey sands deposited in a tidally influenced back-bay environment in the upper layers and interbedded sands and clays deposited in a barrier bar setting in the lower section. The Beaumont Formation is underlain by the Pleistocene-aged Lissie Formation consisting of alluvial clay and lenticular sandstone deposits.

4.1.1.2 Mineral Resources

There are five abandoned oil and gas wells located within the Terminal site. The La Prade well, located in the northwest section of the site was a non-producing well that was abandoned in 1945. The Reynolds, Green, and State Tract No. 1 wells are located in the south-southeast section of the site and were all abandoned in 1972. The State Tract No. 15 well, also located in the south-southeast section, was abandoned in 2011. All five abandoned wells were plugged with cement and mud.

A review of the U.S. Geological Survey (USGS) Mineral Resource Data System indicated that there are no active or potential surface mines located within the vicinity of the Terminal. According to the oil and gas well database maintained by the RRC, the five abandoned oil and gas wells located within the Terminal site are wells that were plugged and abandoned in accordance with applicable RRC requirements. There is no surface evidence to visually verify locations of the well casings, and there is no indication of the presence of other oil and gas wells at the Terminal site.

In the event an unidentified oil and gas well is unexpectedly encountered during construction, Cheniere would stop all work in the area, contain any spillage of product, secure the area, and notify the EI, the RRC, and the FERC. Cheniere would consult with the RRC to determine the operator or owner on record for the subject well. RRC Statewide Rule 14 (TAC Title 16, Part 1, Chapter 3) requires operators of record to plug abandoned oil and gas wells in accordance with specifications set forth within. If the well operator cannot be identified, the RRC maintains and administers an Oil Field Cleanup Fund which may be utilized to properly plug wells. Cheniere would likely request a variance from the FERC, if necessary, and adjust equipment location to avoid the well.

Although the Project is not anticipated to affect any active or abandoned oil or gas wells and active or potential surface mines, if an unidentified well is encountered, Cheniere would implement the measures outlined above. Therefore, construction and operation of the Terminal facilities would not significantly affect mineral resources.

4.1.1.3 Paleontological Resources

No sensitive paleontological resources have been identified within the Terminal area. Therefore, no impacts are anticipated by constructing and operating the Terminal facilities.

4.1.1.4 Foundation Conditions

Cheniere has performed a geotechnical investigation of the site. The soils profiles at the LNG tank locations reveal a layered stratigraphy of sands and clays extending to a depth of approximately 180 feet. Below this lies a massive sand layer reaching a depth of approximately 300 feet. The sand and clay layers above the massive sand layer vary in thickness from approximately 10 to 30 feet. Consistency of the clay layers was generally very stiff to hard, while the upper most sand stratum had a variable density but was mostly medium dense. The eastern half of the proposed liquefaction facility process area has a similar layer soil profile as the proposed LNG tank locations, but the massive sand layer underlying the western facilities occurs at elevations of approximately -40 to -80 feet. The clay layers in this process area above elevation -40 feet are generally thicker than the sand layers, ranging between 10 to 40 feet for the clay layers and 10 to 20 feet for the sand layers. As in the proposed LNG tank locations, the upper sand is medium dense and the lower sands are very dense. The groundwater table ranges between elevation 6 and 12 feet.

Site preparation would result in the high point of finished surface at an elevation of approximately 25 feet AMSL. The foundations are planned to be reinforced concrete spread footing and mats. The net allowable recommended soil bearing ranges between 4,000 and 6,000 pounds per square foot (psf).

During the period between 1965 and 2000, most of the liquefaction plant site was covered with bauxite up to a depth of 60 feet and imposing area surcharge loads of as much as 7,500 psf. Removal of this overburden started in 2000 and was completed in 2005. In areas of the proposed liquefaction plant site covered by the bauxite stockpile, the shapes of the stockpile and the current condition of the soils generally would have a beneficial effect on foundation conditions. The LNG tanks, however, would be located in areas within and outside the previously stockpiled area causing concerns of differential surcharge conditions on the middle tank foundation, which could result in detrimental differential foundation settlements. Therefore, the tank design would include settlement analyses of the LNG tank foundation for three bounding conditions: tank area full preloaded, partially loaded, and outside of preload. Based on the settlement analyses, it may be necessary to remove and re-compact the low blow count layer near the bottom of the LNG storage tank foundations as part of the site grading and compaction.

Terminal must be constructed to satisfy the design requirements of 49 CFR 193, NFPA 59A-2001, 2006 International Building Code, and ASCE 7-05. For seismic design, the facility would also be designed to satisfy the requirements of NFPA 59A-2006 and ASCE 7-05.

The design of the facility is currently at the Front End Engineering Design (FEED) level of completion. Cheniere has proposed a feasible design and it has committed to conducting a significant amount of detailed design work for the Terminal if the Project is authorized by the Commission. Information regarding the development of the final design, as detailed below would need to be reviewed by FERC staff in order to ensure that the final design addresses the requirements identified in the FEED. Further, the timing of the production of this information should occur prior to the stage Cheniere has indicated in its application and subsequent filings. Therefore, **we are recommending that**:

- **Prior to construction, Cheniere should file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary of the Commission (Secretary):**
  - **a. site preparation drawings and specifications;**
  - **b. LNG tank and foundation design drawings and calculations based on the seismic design ground motions in Cheniere's Resource Report 13, Appendix I (URS Report – *Seismic and Tsunami Evaluation for the LNG Export Facility* dated August 7, 2012) and the settlement analyses prepared during detailed design as indicated in the response to question 4f provided in the Supplemental Responses filed by Cheniere on September 23, 2013;**
  - **c. LNG Liquefaction facility structures and foundation design drawings and calculations (including prefabricated and field constructed structures); and**
  - **d. quality control procedures to be used for civil/structural design and construction.**

4.1.1.5 Natural Hazards

Geologic hazards that can potentially affect the Terminal facility include earthquake ground motions and faulting, soil liquefaction and subsidence, and slope stability. Other natural hazards of concern include hurricane winds as well as storm surge-related flooding.

Earthquake Ground Motions and Faulting

The Gulf Plains physiographic province is characterized by low seismic hazard potential. Cheniere conducted a site-specific hazard evaluation to address this effect. The evaluation determined that the peak ground acceleration, with consideration of site amplification effects, would be 0.013 gravity (g) for a 10 percent probability of exceedance in 50 years and 0.052 g for a 2 percent probability in 50 years. Results of this evaluation indicate very low level of ground motion predicted at the Terminal area; therefore, earthquake hazards were not considered a controlling factor in facility design.

Several hundred faults exist in the Gulf Coast region and are primarily Gulf-facing listric normal faults that developed in thick sedimentary sequences over a rifted margin. These faults developed as growth faults underlying thick sediment loads and in relation to salt movement. In modern times, movement along these faults is primarily the result of petroleum production and groundwater pumping. Although numerous Quaternary surface faults are present in the Gulf Coast region, earthquakes with epicenters within the coastal areas of Texas are rare and typically of low magnitude. Subsurface salt movement can also influence faulting; however, the Terminal would not be located near any salt domes. The closest salt dome is located approximately 70 miles west of the Terminal. Stratigraphic units over 40,000 years old are found at relatively common elevations in several soil borings. There was no identified evidence that the site occurs within the zone of influence or within 0.5 mile of an active (Holocene-aged) fault. A low risk of seismic activity and faulting effects can be reasonably anticipated for the Terminal area. Therefore, the potential for large-magnitude seismic activity in the vicinity of the Terminal is low and is not considered a significant hazard.

Soil Liquefaction

Soil liquefaction is the transformation of loosely packed sediment, or cohesionless soil, from a solid to a liquid state as a result of increased pore pressure and reduced effective stress, such as intense and prolonged ground shaking from seismic events. The Terminal area would have underlying water-saturated sediments and could be susceptible to liquefaction under sufficiently strong ground motion. However, due to the relatively low levels of seismic activity and potential ground motion anticipated at the Terminal site, there is little risk for liquefaction of soils to occur. Therefore, it is not anticipated that soil liquefaction would present a significant hazard at the Terminal site.

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 oil, natural gas, or groundwater. 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 Terminal, and while there are several oil and gas fields in San Patricio County, there is no significant petroleum extraction near the proposed Terminal. Compaction of soft sediments under load can also lead to subsidence; however, the Terminal would be underlain by consolidated stiff to hard clays and medium to dense sands, minimizing the risk of subsidence. The only incidence of significant subsidence is located more than 20 miles southwest of the site. Therefore, it is not anticipated that subsidence would present a significant hazard to the Terminal site.

Slope Stability

Cheniere analyzed slope stability at the Terminal site to evaluate the erosion potential of sand layers which would be exposed after dredging in the berth areas. The analysis revealed that although there is little wave action in the La Quinta Channel, scour from tugboat propeller wash could cause eventual slumping or slope failure. To minimize potential scour from tugboat propeller wash, Cheniere would require that tugboats pull LNG carriers off the dock from the offshore side rather than push from the inshore side. This would minimize the potential for sustained propeller wash directed towards the shoreline.

Cheniere would further protect the shoreline by installing articulated block revetments. To prevent scouring of sand layers exposed during dredging of the marine berths, Cheniere would stabilize the berth slopes using articulated mats or other suitable means of stabilization. Upland slopes within the Terminal would be stabilized but may not all be seeded and maintained in a grassy condition as a part of regular facility operations.

Cheniere would implement several preventative measures in order to avoid or minimize the potential for slumping and slope failure. Therefore, adverse impacts on the slope stability at the Terminal site after dredging would not be anticipated as a result of tugboat propeller wash.

Hurricane Winds

The Terminal site would be subject to hurricane winds. LNG facilities, including the LNG tanks and associated safety systems, would be designed for a sustained wind speed of 150 mph without the loss of structural or functional integrity.

Flooding

The Terminal would be susceptible to hurricanes and tropical storms which could produce storm surges, high winds, and flooding. A flood occurs when the water level in a stream or river channel overflows the natural or manmade bank. Storm surge and hurricanes can also cause flooding. The 100-year flood represents a river channel water level that, based on an analysis of the historic record, is likely to be equaled or exceeded every 100 years; meaning that there is a 1 percent chance that the water level will be equaled or exceeded in any individual year during a flood event. Therefore, the 100-year flood is generally used for planning purposes for building within the river channel and adjacent floodplain to assess the likelihood of inundation of areas within the floodplain over time. Flash floods typically result from intense rapid precipitation in upstream areas that leads to extensive short-duration runoff into the stream channel.

The most recent FEMA Flood Insurance Rate Map indicate that the majority of the Terminal would be located within Zone C, while shoreline areas would be located in Zones V22, A16, and B. The marine berth and LNG transfer lines would be constructed within Zones V, A, or B. Table 4.1-1 includes definitions of FEMA flood hazard zones for the Project area.

Table 4.1-1
Federal Emergency Management Agency Flood Hazard Zone Designations Within the Terminal

Zone Designation	Description
Zone A	Zone A is the flood insurance rate zone that corresponds to the 100-year floodplains that are determined in the Flood Insurance Study by approximate methods. Because detailed hydraulic analyses are not performed for such areas, no Base Flood (100-year flood) Elevations (the computed elevation to which floodwater is anticipated to rise during the base flood) or depths are shown within this zone. Mandatory flood insurance purchase requirements apply.
Zone A1 to A30	Zones A1 to A30 are the flood insurance rate zones that correspond to the 100-year floodplains that are determined in the Flood Insurance Study by detailed methods. In most instances, Base Flood Elevations derived from the detailed hydraulic analyses are shown at selected intervals within this zone. Mandatory flood insurance purchase requirements apply.
Zones B and C	Zones B and C are the flood insurance rate zones that correspond to areas outside the 100-year floodplains, including areas of 100-year sheet flow flooding where average depths are less than 1 foot, areas of 100-year stream flooding where the contributing drainage area is less than 1 square mile, or areas protected from the 100-year flood by levees. No Base Flood Elevations or depths are shown within this zone.
Zone V	Zone V is the flood insurance rate zone that corresponds to the 100-year coastal floodplains that have additional hazards associated with storm waves. Base Flood Elevations derived from the detailed hydraulic analyses are shown at selected intervals within this zone. Mandatory flood insurance purchase requirements apply.

The Digital Storm Atlas of Texas predicts that a Category 5 hurricane striking Corpus Christi Bay area could produce a storm surge of up to 21 feet AMSL. As a result, Cheniere would construct the main processing equipment, storage tanks, and administration buildings in upland areas at elevations greater than 25 feet AMSL. Additionally, the jetty platforms would be at a design elevation of 36 feet AMSL, and Cheniere would install all critical and LNG-containing equipment at or above 25 feet AMSL. The shoreline would be protected through the installation of articulated block revetments.

In the event of a Category 5 or lower hurricane, significant impacts on the Terminal facilities would not be anticipated. Cheniere would implement design measures during construction that would minimize or avoid potential damages that could occur during a hurricane.

The Project is located in an area that could present potential challenges relative to natural hazards; however, these conditions can be effectively managed through sound engineering design or shown to be minimal through additional evaluation. The overall effect of construction and operation of the Terminal on topography and geology would be minor. The recommendation included in this section ensures that impacts on geologic resources would be adequately minimized.

4.1.2 Pipeline Facilities

4.1.2.1 Geologic Setting

The Pipeline would be located in the same physiographic province as the Terminal, described above in section 4.1.1. The topography crossed by the Pipeline increases in elevation from 25 feet AMSL at MP 0.0 to 80 feet AMSL near MP 23.0. The Pipeline would also cross recent Holocene-aged alluvial deposits that are underlain by deep Pleistocene-aged deltaic and alluvial deposits. The Pipeline would be underlain by the Beaumont Formation from MP 0.0 to MP 18.9, and the Lissie Formation from MP 18.9 to MP 23.0.

4.1.2.2 Mineral Resources

Four known oil and gas fields and one sand and clay pit would be located within 0.25 mile of the Pipeline. An unnamed oil field would be crossed between MP 5.5 and MP 6.5, the Midway Oil Field would be crossed between MP 7.5 and MP 8.5, the Taft Oil and Gas Field would be crossed between MP 15.9 and MP 19.0, and the Portilla Oil and Gas Field would be crossed between MP 19.0 and MP 23.0. Oil and gas deposits contained within these fields would be significantly below the proposed depth of the Pipeline trench, at approximately 5,350 to 14,000 feet below the ground surface, and should not be disturbed during the construction and operations of the Pipeline.

The sand and clay pit is intermittently active and would be located approximately 200 feet from the Pipeline construction right-of-way between MP 1.7 and MP 1.8. Cheniere would avoid impacts from mining operations in this parcel through pit mining monitoring and terms of agreement resulting from discussions with the operator to allow an adequate easement for the Pipeline.

A total of 43 foreign pipelines would be crossed by, or in close proximity to the Pipeline or associated facilities. In order to ensure foreign pipeline integrity, Cheniere indicated that it would: 1) use databases and line locaters to identify and mark foreign pipeline locations and burial depth; 2) notify foreign pipeline operators of crossing and execute any mandatory crossing agreements; 3) obtain as-built drawings from the foreign pipeline operators where available; 4) perform a "One Call" before excavating; 5) employ best operating practices to both Cheniere's and the foreign pipeline operator's standards when excavating near an existing line, which may include prohibition of mechanical equipment within a specified distance of the line; 6) require hand digging to expose a foreign pipeline at certain critical locations; and 7) have foreign pipeline operators provide an on-site field representative as oversight to the Pipeline construction activities.

Cheniere also identified seven oil and gas wells that would be located within 150 feet of the Pipeline. One of these wells would be located within the construction right-of-way and four would be located within 50 feet of the construction right-of-way. Cheniere indicated that it would consult with the RRC prior to Pipeline construction to obtain additional information regarding oil and gas wells within 150 feet of the construction right-of-way. Additionally, field verification surveys would be conducted to confirm the location of each well prior to Pipeline construction. If an oil and gas well is unexpectedly encountered during construction Cheniere would stop work immediately, contain any spillage of product, secure the area, and notify the EI, RRC, and the FERC. The owner or operator of the well would be notified and Cheniere would route around the well if necessary. Cheniere would request a route variance from the FERC, if necessary, and adjust the centerline to avoid the well.

Although some mineral resources have been identified within close proximity to the Pipeline or may be crossed by the Pipeline, Cheniere would implement the appropriate preventative measures or mitigation to minimize or avoid impacts on these resources. Therefore, the Pipeline would not significantly impact extractive resources in the form of oil and gas fields, sand and clay pits, buried foreign pipelines, or oil and gas wells.

4.1.2.3 Paleontological Resources

No identified sensitive paleontological resources would be crossed by the Pipeline. Therefore, no impacts are anticipated by constructing and operating the Pipeline.

4.1.2.4 Natural Hazards

Geologic hazards that could potentially affect the Pipeline facilities include earthquake ground motions and faulting, soil liquefaction, subsidence, slope stability, and flooding.

Earthquake Ground Motion and Faulting

As previously discussed in section 4.1.1, impacts on the Pipeline from seismic activity and faulting are not anticipated. The nearest mapped fault is 42 miles from the northern terminus of the Pipeline and thus, the potential for large-magnitude seismic activity in the vicinity of the Pipeline is low.

Soil Liquefaction

Due to the low levels of seismic activity and potential for ground motion in the Pipeline area, there is little risk for liquefaction of soils to occur. Soil liquefaction would not be a significant hazard for the Pipeline.

Subsidence

As discussed in section 4.1.1 above, subsidence in the Gulf Coast region is primarily caused by groundwater extraction, oil and gas extraction, and slumping along growth faults. In addition, soft sediments under load can also result in subsidence. Groundwater extraction in San Patricio County is primarily for irrigation, and the amount varies by season and year. Although the nearest significant subsidence event occurred more than 20 miles southwest of the Project area, typically potential for subsidence is greatest to the northeast. San Patricio County does not experience the degree of subsidence found elsewhere along the Gulf Coast. Subsidence would not be a significant hazard for the Pipeline.

Slope Stability

The Pipeline route crosses topography that is relatively flat, with elevations gradually increasing from 25 feet AMSL to 80 feet AMSL over 23 miles. Slope stability would not be a significant hazard for the Pipeline.

Flooding

The Pipeline would be susceptible to hurricanes and tropical storms which could produce storm surges, high winds, and flooding. The most recent FEMA Flood Insurance Rate Map indicates that the Pipeline would be located within Zones A, B, and C, with both of the compressor stations located within Zone C (outside of the 100-year floodplain). Table 4.1-1 includes definitions of FEMA flood hazard zones for the Project area.

The segments of Pipeline that would be located in Zone A (100-year floodplain) would have a higher susceptibility to flooding. To offset this risk Cheniere would use concrete coated pipe at waterbody crossings and areas subject to flooding to compensate for negative buoyancy. Flooding would not be a significant hazard for the Pipeline, as Cheniere would implement measures to combat buoyancy in the event of flood or storm surge. Additionally, we have determined that because the pipeline would be buried, there would not be an increase in flooding in the area.

Overall, impacts on geologic resources resulting from the installation of the Pipeline would be minor. While flooding is a potential hazard for the area, Cheniere has adequately mitigated for this through the implementation of measures to combat pipe buoyancy in flood-prone areas. With the implementation of BMPs and our Plan and Procedures, impacts on geological resources would be adequately minimized for constructing and operating the Pipeline.

4.2 SOILS AND SEDIMENTS

4.2.1 Terminal Facilities

4.2.1.1 Soils Types and Limitations

Soil types that occur within the proposed Project area and general limitations of these soils were compiled from information presented in the USDA soil survey of San Patricio and Aransas Counties, Texas (USDA, 1979) and USDA NRCS Soil Survey Geographic Database (USDA, 2003). Soil types, general limitations, and the potential impacts on these soils from the proposed Project, are presented in this section.

4.2.1.2 Terminal Facility

Construction of the Terminal would impact each of the nine soil types mapped by the NRCS (including wasteland and urban land soil types). In total, approximately 646 acres would be temporarily impacted by construction workspace and approximately 281 acres would be permanently impacted by aboveground facility placement and operation. Table 4.2-1 summarizes the acreage impacts for each soil type.

Table 4.2-1
Soil Series Impacted by the Terminal

Soil Series	Terminal Component	Area Impacted by Construction (acres)	Area Impacted by Operation (acres)	Total
Edroy clay	Terminal, Clay Pit Disposal Area, Temporary Laydown Access, Temporary Parking	38	27	65
Monteola clay 5 to 8 percent slopes	Terminal, Marine Basin and Berth	0	37	37
Orelia sandy clay loam	Terminal, Clay Pit Disposal Area, Substation Lease Area, Temporary Laydown Access, Temporary Laydown Area, Temporary Parking	185	18	203
Papalote fine sandy loam, 0 to 1 percent slopes a/	Terminal, Temporary Laydown Area	<1	17	18
Papalote fine sandy loam, 1 to 3 percent slopes a/	Temporary Laydown Access, Temporary Laydown Area, Temporary Parking	2	0	2
Raymondville clay loam, 0 to 1 percent slopes a/	Clay Pit Disposal Area, Substation Lease Area, Temporary Laydown Access, Temporary Laydown Area	2	0	2
Urban land	Clay Pit Disposal Area	19	0	19
Victoria Clay, 0 to 1 percent slopes a/	Temporary Laydown Access, Temporary Laydown Area	<1	0	<1
Wasteland	Terminal, DMPA 2, Substation Lease Area, Tool and Lunch Area	399	182	581
	Total b/	**646**	**281**	**927**

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a/ Soils are designated as prime farmland.
b/ Impact acreages do not include open water impacts and are not comparable to table 2.3-1 and table 4.8-1 because the NRCS does not map soils in tidally influenced areas. NRCS soils mapping does not accurately follow the current shoreline where as impacts in table 2.3-1 and table 4.8-1were calculated based on a more precise, current shoreline.

Publically available information was evaluated to identify and evaluate the soils that would be most susceptible to impacts from construction of the Terminal. Major soil limitations within the Terminal are discussed below.

Hydric Soils

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. Soils that are artificially drained or protected from flooding (e.g., by levees) are still considered hydric if the soil in its undistributed state would meet the definition of a hydric soil. Cheniere would construct the Terminal in accordance with our Plan and Procedures. The Procedures include provisions for wetland crossings and special construction measures in areas of saturated soils. Cheniere's implementation of these measures, as well as use of other BMPs during construction, would minimize impacts on hydric soils and would not result in significant long-term adverse impacts.

Compaction Potential

Soil compaction reduces the porosity and moisture-holding capability of soil. The degree of compaction is dependent on moisture content and soil texture. Fine-textured soils with poor internal drainage are most susceptible to compaction. Construction equipment travelling over wet soils can disrupt soil structure, reduce pore space, increase runoff potential, and cause rutting.

Approximately 288 acres of soils that would be impacted during construction and operation of the Terminal have a high potential for severe compaction (Edroy clay; Orelia sandy clay loam; Papalote fine sandy loam, 0 to 1 percent slopes; Raymondville clay loam, 0 to 1 percent slopes; and Victoria clay, 0 to 1 percent slopes) (see table 4.2-1). The potential impacts on soils from compaction would be minimal due to the existing disturbed conditions at the Terminal site. There are no active agricultural areas within the Terminal site that would require mitigation for compacted soils.

Compacted soils have the potential to increase stormwater runoff at the site. Cheniere would minimize the potential for stormwater runoff by developing and constructing systems designed to manage stormwater runoff at the Terminal. Environmental impacts resulting from compacted soils would be minimal and temporary or short-term through site design and the implementation of mitigation measures outlined in our Plan and Procedures. Potential impacts associated with stormwater runoff are further discussed in section 4.3.

Revegetation Potential

Physical properties and characteristics of soils contribute to the likelihood and duration of successful revegetation in disturbed areas. Edroy clay and Monteola clay, 5 to 8 percent slopes were identified as having low revegetation potential. Land affected by installation of aboveground facilities would be permanently converted to industrial use, and no revegetation would occur. However, areas temporarily impacted within the Terminal during construction would be stabilized and allowed to return to preconstruction conditions. In order to ensure successful revegetation in these areas, Cheniere would implement measures in our Plan as well as recommendations of the local NRCS. Significant short- or long-term impacts on the revegetation potential of soils are not anticipated given the implementation of these mitigation measures.

Erosion Potential

Factors that influence soil erosion include soil texture, structure, length and percent of slope, vegetative cover, and rainfall or wind intensity. Soils most susceptible to erosion by water are typified by bare or sparse vegetative cover, noncohesive soil particles with low infiltration rates, and moderate to steep slopes. Wind erosion processes are less affected by slope angles. Clearing, grading, and equipment movement could accelerate the erosion process and, without adequate protection, could result in discharge of sediment to waterbodies and wetlands. Soil loss due to erosion could also reduce soil fertility and impair revegetation.

Soils within the Terminal site with high erosion potential are limited to Monteola clay, 5 to 8 percent slopes and those within the area labeled by the NRCS as “wasteland”, which have been disturbed due to previous industrial activity. Impacts on these soils would result from constructing the LNG storage tanks, marine basin and berth, as well as vaporization and related processing equipment.

While the remaining soil types that would be impacted by constructing the Terminal are designated as having low erosion potential, areas such as stream banks and the banks of drainage ditches could also be susceptible to erosion resulting from construction activities. Cheniere would implement our Procedures and incorporate the erosion and sediment control practices specified in our Plan. Implementation of these erosion control measures while constructing and operating the Terminal would minimize the potential for soil erosion and associated impacts.

The shoreline between Aransas Pass and the north boundary of the Padre Island National Seashore changes at variable rates due to engineering modifications, which impact sediment deposits by trapping sand in the littoral drift system. The shoreline at the Terminal site has been stable from about 1937 to 1982, with no net change from erosion. However, wave action has caused the shoreline west and east of the Terminal to retreat at an average rate of 1 to 3 feet per year. Dredging of the marine basin, loading dock, and maneuvering area would modify a portion of the shoreline within the Terminal site. Articulated block mats or rock breakwaters would protect the shoreline within the maneuvering area from erosion.

The soils on the 20-foot high bluff overlooking the Corpus Christi Bay shoreline could experience some erosion and slumping, but only minimal construction activities would occur in this area; therefore, significant erosion of the bluff soils is not anticipated.

All ships passing through the Corpus Christi and La Quinta channels have the potential to contribute to shoreline erosion. The severity of potential shoreline erosion bordering ship channels is dependent on the number of ships; ship size, hull shape, speed, and draft; propeller action; and channel proximity to shore, shoreline shape, and the type of material of the shoreline. LNG carriers tend to have relatively shallower drafts than some other ships that currently use the channels and are likely to have less wash effect than those other ships. For a variety of safety reasons, LNG carriers calling on the Terminal would travel at slow speeds, with the accompaniment of ship-assist tug boats, thereby minimizing the generated wave energy. Additionally, the tugs would pull the LNG carriers off the dock to avoid scour from tugboat propeller wash against the shore.

Historical shore stability at the Terminal site, use of articulated block mats or rock breakwaters along the shoreline, as well as operation practices designed to minimize shoreline scour would effectively mitigate for shoreline erosion, thus minimizing impacts.

Prime Farmland Soils

Prime farmland is land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, oilseed, and other agricultural crops with minimum inputs of fuel, fertilizer, pesticides, and labor, and without intolerable soil erosion, as determined by the U.S. Secretary of Agriculture. In addition, prime farmland includes land that possesses the above characteristics but is being used currently to produce livestock and timber. Urbanized land and open water are excluded from prime farmland. Prime farmland typically contains few or no rocks, is permeable to water and air, is not excessively erodible or saturated with water for long periods, and is not subject to frequent, prolonged flooding during the growing season. Soils that do not meet the above criteria may be considered prime farmland if the limiting factor is mitigated (e.g., artificial drainage).

Construction and operation of the Terminal would impact approximately 22 acres of soils classified as prime farmland soil. Approximately 5 acres would be restored to preconstruction conditions, and operation of the Terminal would permanently impact 17 acres (see table 4.2-1). These soils were previously in industrial use and are already impacted; therefore, loss of this acreage would not significantly impact prime farmland in the local area.

4.2.1.3 Sediments

Sediments that would be impacted by construction of the Terminal are located within the proposed marine berth, loading dock, and maneuvering area. Dredging to an elevation of -46 feet NAVD88 with an additional 2 feet paid allowed overdredge and 2 feet advanced maintenance dredge would remove approximately 4.4 mcy of sediments. The sediment types that would be dredged are described as stiff clays with interbedded sand and silt layers.

Soils located in tidally influenced areas of Corpus Christi Bay have not been mapped by the NRCS. However, in 2003, four borings were drilled near the proposed ship berths (CB-47, CB-48, CB-52, and CB-54). The sediment types observed in the borings are summarized below:

- CB-47. Lean Clay or Fat Clay from the mudline at elevation -6 feet (National Geodetic Vertical Datum of 1929 [NGVD 29]) to the depth of dredging at elevation -42 feet.
- CB-48. Predominantly Lean Clay or Fat Clay from the mudline at elevation -7 feet to the depth of dredging at elevation -42 feet; 3-foot-thick layer of silty sand at elevation -23 feet; and a 4-foot-thick layer of clayey sand at elevation -36 feet.
- CB-52. Predominantly Silty Clay or Fat Clay from elevation -7 feet to the depth of dredging at elevation -42 feet; a 5-foot-thick layer of silty sand layer at the ground surface at elevation -2 feet; and a 4-foot-thick silty sand layer at elevation -30 feet.
- CB-54. Predominantly Lean Clay, Fat Clay, or Sandy Lean Clay from elevation -6 feet to the depth of dredging at elevation -42 feet; a 5-foot-thick layer of silty sand at the ground surface at elevation -1 foot; and a 3-foot-thick clayey sand layer at elevation -18 feet.

4.2.1.4 Contaminated Soils and Sediments

The Terminal site has been used to store bauxite ore since the 1950s. From 1957 to 1984, the U.S. government arranged to have approximately 5,685,195 tons of bauxite ore from British Guyana and Jamaica stockpiled on the northern portion of the Terminal site. In addition, Sherwin and its predecessor, the Reynolds Metal Company, deposited approximately 1.6 mcy of alumina processing waste materials into two former solid waste management units designated as Beds 22 and 24 from 1954 to 1969. The EPA has determined that bauxite residue, or red mud, does not exhibit any of the characteristics of hazardous waste, and that these deposits have a low potential for danger to health and the environment. Three constituents of concern were identified in red mud (arsenic, chromium, and radium-226), but at soil concentrations which were not designated by TCEQ to be a risk. Arsenic concentrations were, however, found to exceed the TCEQ Protective Concentration Level (PCL) in groundwater within and downgradient of Bed 22 (section 4.3). A clay cap was constructed over Bed 22 in 2007 to 2008 to prevent the further infiltration of stormwater and leaching of contaminants into groundwater.

Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment can have an adverse impact on soils. The effects of contamination would typically be minor because of the low frequency and volumes of potential spills and leaks. Cheniere has developed an acceptable 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 adequately minimize the potential for soil contamination. Therefore, any impacts resulting from soil contamination would be minor and temporary.

Sediments near the surface in urban environments may be contaminated by release of various chemicals from human activities along the shoreline. In 2003, the COE reported the results for the analysis of sediments that were sampled in 2000 as part of the Corpus Christi Ship Channel Improvement Project. Three samples were analyzed for organic and metallic chemicals, as well as metals, and then compared to the Effects Range Low (ERL) values, which are used by the National Oceanic and Atmospheric Administration (NOAA) as screening levels for assessing sediment quality. These are conservative levels used to identify sediment that may require additional evaluations before decisions on disposal or beneficial re-use are made. The samples were all identified as below the ERL levels.

Three samples were also compared to the TCEQ PCL for Tier 1 commercial/industrial soil protective of Class 3 groundwater for metals. All concentrations were below the PCL levels. Samples were also collected from the La Quinta Channel in 2000 and analyzed for polychlorinated biphenyls, pesticides, and polycyclic aromatic hydrocarbons. All detections were below ERL levels. We are not aware of more recent data than that presented in the 2003 COE report.

Additional impacts on soils as a result of the Terminal would include historic soil contamination at the site, as discussed above, as well as the potential for import of contaminated soils. In order to minimize the potential for the import of contaminated soils, Cheniere would follow the guidelines outlined in *Specification for Site Preparation and Earthwork* (Document No. 25744-200-3PS-CG00-F0001) to fulfill the requirements for soils imported to the site. *Specification for Site Preparation and Earthwork* describes the measures that would be implemented to ensure these soils are not contaminated. See below for an excerpt of the fill material requirements.

General fill shall be an inorganic, non-expansive cohesive material meeting the following requirements:

Liquid Limit	30% to 60%
Plasticity Index	40% Maximum, 20% Minimum
Maximum Size	2 inch

- % Passing #200 Sieve 80% Maximum, 40% Minimum

Unless otherwise noted on design drawings, general fill shall be compacted to no less than 95 percent Maximum Dry Density as determined by American Society for Testing and Materials D698.

Granular structural fill shall not contain any significant amount of organics or debris, and shall conform to the following criteria:

- Gradation (see table 4.2-2)
- Liquid Limit = 25% maximum
- Plasticity Index =10% maximum

Table 4.2-2
Gradation Criteria for Granular Structural Fill

U.S. Standard Sieve Size	Percent Passing (By Weight)
2 inch	100
0.75 inch	70-100
No. 4	30-100
No.20	15-90
No. 50	5-30
No. 200	0-5

Structural clay fill shall be low plasticity, inorganic, non-expansive cohesive material meeting the following requirements:

- Liquid Limit = 40% maximum
- Plasticity Index = 20% maximum, 10% minimum
- Maximum Size = 1 Inch
- % Passing #200 Sieve = 80% maximum, 40% minimum

Bedding material shall be well-graded granular soils. It shall not contain any significant amounts of organics or debris, and shall conform to the gradation presented in table 4.2-3.

Table 4.2-3
Gradation Criteria for Bedding Material

U.S. Standard Sieve Size	Percent Passing (By Weight)
2 inch	100
No. 4	72-100
No. 16	26-80
No. 50	5-25
No. 200	0-7

Adherence to the guidelines described above would ensure that no contaminated soils are imported to the site for use as structural fill. As a result, we determined that impacts from the importation of contaminated soils would be negligible.

4.2.2 Pipeline Facilities

4.2.2.1 Soils

The Pipeline would cross two soil associations (Victoria-Raymondville-Orelia and Orelia-Papalote) including five soil types: Orelia sandy clay loam, Papalote fine sandy loam (0 to 1 percent slopes), Papalote fine sandy loam (1 to 3 percent slopes), Raymondville clay loam (0 to 1 percent slopes), and Victoria clay (0 to 1 percent slopes). Characteristics of these soil associations are provided in table 4.2-4.

Table 4.2-4
Characteristics of Soil Types Crossed by the Pipeline Facilities

Milepost	Soil Association Name	Hydric	Prime Farmland	Erosion Potential	Revegetation Potential	Compaction Potential
0.0-18.9	Victoria-Raymondville-Orelia	No	Yes	Low	High	High
18.9-23.0	Orelia-Papalote	No	Yes	Low	Moderate	Low

4.2.2.2 Soil Limitations

Publicly available data was evaluated to determine the most susceptible soils crossed by the Pipeline. Limitations for soils crossed by the Pipeline are summarized in table 4.2-4.

Hydric Soils

No hydric soils have been identified along the Pipeline route, except where wetlands are crossed and in isolated areas where soils with high clay content have been subjected to periods of heavy saturation. As described above, Cheniere would construct the Pipeline in accordance with the measures contained in our Procedures to minimize impacts on hydric soils. Therefore, any impacts on hydric soils would be minor and temporary.

Compaction Potential

The Victoria-Raymondville-Orelia soil association has a high potential for compaction. Mitigation for soil compaction in agricultural areas would include topsoil segregation, postponing soil disturbances when soils are saturated, and using deep tillage prior to replacement of the topsoil. Cheniere would test soils for compaction and mitigate per our Plan in active agricultural areas temporarily impacted during construction of the Pipeline. Therefore, impacts on soils from compaction would be temporary and minor given the implementation of these mitigation measures.

Revegetation Potential

The aboveground facilities along the Pipeline would cover approximately 21.5 acres of land and would be permanently maintained as fenced and graveled sites. Additionally, approximately 4.1 acres of soils crossed by the Pipeline (MP 18.9 to MP 23) were identified as having a low potential for revegetation. Cheniere would implement measures in our Plan as well as recommendations of the local NRCS to ensure successful revegetation in these areas. Some of these measures include the addition of soil additives, and seeding requirements. Therefore, short- or long-term impacts on the revegetation potential of soils are not anticipated given the implementation of these mitigation measures, which includes monitoring of the right-of-way.

Prime Farmland

There are seven aboveground facilities associated with the proposed pipeline that would be located on prime farmland (see table 4.2-5) which would result in the removal of 21.5 acres of prime farmland. The impact would be permanent since each site would be graveled and fenced. However, given the amount of available prime farmland in the area, the impact is not considered significant.

Construction of the Pipeline could also impact prime farmland. These impacts could include interference with agricultural drainage, mixing of topsoil and subsoil, and soil rutting and compaction. These impacts would result primarily from excavating and backfilling the pipeline trench and vehicular traffic along the construction right-of-way.

Impacts on soils from the Pipeline would be minor. Most impacts during construction would be short-term and would not impact the potential use of prime farmland for agricultural purposes. Cheniere has consulted with the NRCS regarding potential impacts on prime farmland soils and has agreed to segregate topsoil to a depth of 12 inches. The NRCS indicated in a letter dated December 9, 2003 (regarding the previously proposed pipeline under Docket Nos. CP04-37-000 and CP04-44-000) that it did not consider the construction of the Pipeline to represent a permanent conversion of Important Farmland, because the land could still be used for agricultural production after the Pipeline is installed and the right-of-way reclaimed. We concur with the NRCS letter.

Table 4.2-5
Aboveground Facilities Along the Pipeline Located on Prime Farmland

Facility	Milepost	Soil Classification	Land Required for Operation (Acres)
Taft Compressor Station	7.5	Victoria Clay, 0-1% slopes	5.8
Texas Eastern M&R Station	7.5	Victoria Clay, 0-1% slopes	2.1
Sinton Compressor Station	21.5	Papalote fine sandy loam, 0-1% slopes	7.3
Tejas Pipeline M&R Station	21.5	Papalote fine sandy loam, 0-1% slopes	2.4
NGPL M&R Station	22.4	Victoria Clay, 0-1% slopes	1.0
Transco M&R Station	22.8	Victoria Clay, 0-1% slopes	0.9
Tennessee Gas M&R Station and MLV	23.0	Victoria Clay, 0-1% slopes	2.0
	Total		**21.5**

Overall, adhering to the measures in our Plan would minimize impact on agricultural soils, including prime farmland. Therefore, we conclude that construction and operation of the Pipeline would not significantly impact soils.

4.2.2.3 Contaminated Soils

The Pipeline would not cross any areas with known contaminated sediments. Cheniere performed a search of environmental databases to determine if contaminated soils were present along the proposed Pipeline. No known areas of contamination were identified along the Pipeline route.

Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment can adversely impact soils. The effects of contamination would typically be minor because of the low frequency and volumes of potential spills and leaks. Cheniere has developed an acceptable 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 adequately minimize the potential for soil contamination.

4.2.2.4 Erosion Control

During construction of the pipeline, Cheniere would implement some of the erosion control measures presented in our Plan such as installing temporary slope breakers, such as silt fence or staked hay or straw bales to reduce the runoff velocity and divert water off the construction right-of-way. In addition, Cheniere would use sediment barriers to stop the flow of sediments and prevent the deposition of sediments beyond approved workspaces or into sensitive resources.

None of the soils crossed by the Pipeline would have high erosion potential; therefore, impacts on soils resulting from erosion would be negligible.

4.3 WATER RESOURCES

4.3.1 Terminal Facilities

4.3.1.1 Groundwater

The proposed Terminal is located in the Coastal Lowlands aquifer system within San Patricio and Nueces Counties. In Texas, the Coastal Lowlands aquifer system underlies about 35,000 square miles of level, low-lying coastal plain and is comprised of Miocene-age and younger unconsolidated sediments of sand, silt, and clay. These sediments were deposited in three depositional environments: continental (alluvial plain), transitional (delta, lagoon, and beach), and marine (continental shelf) (Ryder, 1996). In San Patricio and Nueces Counties, the primary water-bearing stratigraphic units are Pliocene-age Goliad sand, Pleistocene-age Lissie and Beaumont formations, and Holocene-age alluvial and beach sands in the Nueces River valley (Shafer, 1968). Within Texas, the coastal lowlands aquifer system is commonly referred to as the Gulf Coast aquifer which is separated into five permeable zones and two confining units (Ryder, 1996).

Along the Gulf Coast, 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. Water supply wells in southeastern San Patricio County are screened in the Chicot aquifer at depths typically less than 50 feet. Groundwater in the county is primarily used for irrigation; however, its use is limited by high concentrations of chloride, salinity, and alkalinity. There are no fresh-water bearing sands within the Terminal site. Saltwater intrusion in the permeable sands extends further inland along the northern shore of Corpus Christi Bay. The nearest freshwater sands are located east of the Terminal site, in the vicinity of Aransas Pass and Ingleside.

The Terminal site is not underlain by a sole-source aquifer, as designated by the EPA, and there are no locally zoned aquifer protection areas within the Terminal site. There is very little groundwater use in the county and almost no pumping in the area. Most municipal water systems in San Patricio and Nueces Counties obtain water from Lake Corpus Christi, Lake Texana, or the Nueces River.

According to Texas Water Development Board data there are no public or private water supply wells located within 150 feet of the Terminal and thus, there are no wellhead protection areas (also known as source water protection areas) crossed by the Terminal. The nearest public and private supply wells are located about 3.2 miles and 2.3 miles from the Terminal site, respectively.

As discussed in section 4.2, groundwater monitoring showed that arsenic concentrations in shallow groundwater exceeded the TCEQ PCL, within and slightly downgradient of Bed 22. Groundwater quality monitoring is the responsibility of the Reynolds Metals Company under a TCEQ-approved Remedial Action Plan which established a plume management zone for the natural attenuation monitoring of arsenic concentrations in groundwater downgradient of Bed 22.

The depth to groundwater over the majority of the Terminal site is approximately 11 feet and most excavations for construction would generally be in the range of 3 to 5 feet below ground surface. It may be necessary to dewater trenches during construction if shallow groundwater is encountered during excavations. Because of the relatively small amount of water removed, the short duration of the activity, and the local discharge of the water, groundwater levels would quickly recover after pumping stops. Cheniere would follow the measures in our Procedures, which require that dewatering structures be located so that there would be no discharge of sediments into wetlands and waterbodies.

Hammer-driven pilings would be used during the construction of the berthing docks. A potential impact associated with driven pilings is the cross contamination of lower permeable aquifer zones through downward vertical seepage from one layer to another. The anticipated maximum depth of pilings is at an elevation of approximately -80 feet. At this depth, the pilings would stay within the upper (shallow) permeable zone of the Chicot aquifer. Keeping the pilings within one layer of the Chicot aquifer system and not crossing aquifer confining layers reduces the potential for cross-contamination.

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 Terminal facilities. Cheniere has agreed to implement our Procedures, including the preparation and implementation of Spill Prevention and Response Procedures that meet state and federal requirements. 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.

Substantial impacts on the groundwater resources underlying the Terminal facilities are not anticipated due to: the non-potable saline groundwater conditions that naturally occurs at the site, lack of water supply wells in the area, depth of groundwater below land surface in relation to anticipated excavation depths, construction of the proposed pilings within the permeable zone of the Chicot aquifer and not crossing aquifer confining layers, and surficial mitigation measures that would be implemented by Cheniere in the event of a hazardous material spill.

4.3.1.2 Surface Water

The Terminal would be located on the north shore of Corpus Christi Bay, situated at the northwestern end of the La Quinta Channel. Corpus Christi Bay is designated in the National Estuary Program as an estuary of "national significance". Corpus Christi Bay is typically shallow, with an average depth of 8 feet; however, there are two shipping channels through the bay that are dredged to -45 feet mean low tide to allow passage of large cargo and tanker ships. As described previously, Cheniere would dredge a maneuvering area to a depth of -46 feet NAVD 88 (plus two feet overdredge and 2 feet advanced maintenance dredge) to allow LNG carriers access to the Terminal. These activities were previously permitted by the COE for Cheniere's LNG import terminal on October 18, 2005. The COE issued an amendment to the existing permit on July 23, 2014. On September 9, 2014, Cheniere submitted a request to the COE to amend the permit to include an additional 2 feet of dredging depth (-46 feet NAVD88 plus -2 overdredge and 2 feet advanced maintenance dredge, as reported in this EIS). The COE has informed FERC that it is evaluating this action and will keep FERC apprised of developments. Following construction, dredged material would be disposed of in the designated DMPAs. Specifically, dredged material would be put to beneficial use as fill for a portion of a former 90-acre clay borrow pit and to facilitate the capping of 385 acres of bauxite residue beds that have laid open since 1968 (DMPA 2). Post-construction maintenance dredging would be conducted on an as-needed basis; however, is not anticipated to be more than once every three years. A portion of the marine facilities approach was recently dredged by the COE as part of an extension of the La Quinta Channel.

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 (TCEQ, 2010a). Corpus Christi Bay is considered a warmwater, saline fishery.

Water quality issues currently affecting Corpus Christi Bay include reduced inflow of fresh water; wetland habitat loss; chemical, heavy metal, and nutrient increases; brown tide; and floating debris (American Oceans Campaign, 1996). Freshwater inflow to the bay has been reduced by increasing demands from upstream communities that rely on surface water for their water supply. The Corpus Christi Bay watershed supports the petrochemical, agriculture, and shipping industries, which have the potential to degrade water quality through chemical and oil spills, pesticide and fertilizer runoff, and heavy metal contamination. Corpus Christi Bay is generally considered turbid, with a long-term average of total suspended solids ranging from 20 to 100 milligrams per liter (mg/L) or higher (Corpus Christi Bay National Estuary Program, 1997). This turbidity can be attributed to the natural characteristics of the bay as well as ongoing shipping and periodic dredging activities.

As described below, construction and operation of the Terminal facilities would temporarily and permanently impact Corpus Christi Bay.

Turbidity and Sedimentation

To facilitate the construction of the terminal facilities, marine basin, and maneuvering area, Cheniere would use mechanical and hydraulic cutterhead-suction dredges to excavate nearshore waters. These dredging activities would require approximately six months to complete. Hydraulic suction dredges cut and pull dredged material into the dredge device minimizing turbidity in the water column. Although hydraulic cutterhead dredges capture the majority of sediment loosened, some sediment would become suspended in the water. Studies of cutterhead dredges indicate that elevated turbidity is limited to the lower portion of the water column and turbidity levels are at background within several hundred feet of the cutterhead. Therefore, the dispersion of sediments that would occur during dredging would be minimal. To further minimize turbidity and sedimentation impacts, Cheniere would adjust cutterhead speeds.

In addition to the use of a hydraulic cutterhead dredge to minimize turbidity and sedimentation impacts, the natural characteristics of Corpus Christi Bay would also work to minimize these impacts. Ward (1997) describes the tidal flushing in Corpus Christi Bay as a restricted flow, tidal regime switching from semi-diurnal to diurnal. The tides are wind dominated which results in relatively higher tides in summer and spring with lower tides in winter and fall because of the prevailing wind. Because of the change in the width to depth ratio of the La Quinta Channel, overall currents would be expected to be relatively low, particularly at or near the bottom where dredging would occur.

We have determined that dredging activities would result in levels of turbidity consistent with ambient total suspended solids concentrations, up to the approximately 80 mg/L that TCEQ has reported as normal within 1 foot of the water surface. Therefore, based on the general hydrologic characteristics of the site and the proposed dredging activities, we expect that most of the turbidity and sedimentation would be localized, would return to background levels a short distance from the point of disturbance, and would not significantly affect surface water quality. In addition, proper disposal of dredged materials and implementation of the measures outlined in our Plan and Procedures would further reduce or avoid significant increases in background turbidity levels in the La Quinta Channel.

Dredging activities would also result in and potential runoff from the construction/dredging equipment. Runoff impacts would be minimized through use of BMPs and active maintenance of equipment.

Maintenance dredging would only occur in areas that have been previously dredged during the initial construction of the Terminal. Maintenance dredging is presently expected to occur no more frequently than once every three years and each event is anticipated to last for no more than 30 days. Hydraulic cutterhead dredges would also be used to limit resuspension, and sediments would be sampled and tested for priority pollutants prior to each maintenance dredging event according to the methodology described in the Inland Testing Manual (EPA/COE, 1998).

Cheniere is required to obtain several permits that would address dredging and dredged material management, including permits from the COE under Section 404 of the CWA and Section 10 of the RHA. Permits for water discharges into the bay from the Terminal would be obtained from the EPA, RRC, and/or the TCEQ under Section 401 of the CWA. A NPDES permit under Section 402 of the CWA issued by the RRC would be necessary to regulate return water flowing from the DMPA. The issuance of these permits takes into consideration impacts on environmental resources; therefore, the permits may contain operational limitations designed to minimize or avoid environmental impacts.

Several permit applications were submitted to the COE including the Section 404/10 Individual Permit application, as well as a Request for 401 Water Quality Certification and Request for Coastal Zone Management Consistency Determination submitted to the RRC. The COE issued the Section 404/10 Individual Permit on July 23, 2014 and the RRC issued the 401 Water Quality Certification as well as the Coastal Zone Consistency determination on November 14, 2013.

Ship and Boat Traffic

Ship and boat traffic associated with constructing and operating the Terminal could impact surface water resources as a result of ship movements, including propeller use, and ballast water exchanges. Increased wave action from ship and boat movements could increase turbidity and sedimentation. Additional impacts on surface water resources would result from LNG carrier operations requiring ballast water discharge at the Terminal. Discharge of ballast water at the Terminal site could also increase turbidity in the immediate area, as well as alter the salinity levels and water temperature. Impacts on water resources resulting from ballast water would be temporary and minor, only affecting a relatively small area. Additional information regarding impacts associated with ballast water is provided in section 4.6.2.

Ship and boat traffic has the potential to adversely impact water quality in the event of an accidental release of a hazardous substance such as fuel, lubricants, coolants, or other materials on board the vessel. Cheniere would implement the measures outlined in their SPCC in the event of a spill, as well as measures outlined in our Procedures. Cheniere would minimize the risk of a spill by implementing general preventative BMPs, including personnel training, equipment inspection, and refueling procedures.

Stormwater Runoff

Stormwater run-off collecting at the Terminal would be discharged into Corpus Christi Bay directly or, via the La Quinta Ditch which runs alongside La Quinta Road. Stormwater removal from within the LNG storage tank dikes must conform to 49 CFR 193.2173, 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. Cheniere would follow our Procedures which require that prior to construction Cheniere must prepare a SWPPP that complies with the EPA’s National Stormwater Program General Permit requirements.

Water Use

The potable water supply for the Terminal facilities would be obtained from a San Patricio Municipal Water District 24-inch-diameter main water line at the junction of SH 35 and SH 361. The San Patricio Municipal Water District obtains its water from the Nueces River and Lake Texana (TCEQ, 2010b). The water supply for the compressor stations would also be procured from the San Patricio Municipal Water District. The volumes of water required to construct and operate the Terminal are provided in tables 4.3-1 and 4.3-2.

Table 4.3-1
Water Requirements to Construct the Terminal

Activity	Quantity (millions of gallons)
Craft and Subcontractor Use	20
Line Hydrostatic Test	5
LNG Tank Hydrostatic Test	127
Site Preparation	15
Total	**167**

Table 4.3-2
Water Requirements to Operate the Terminal

Activity	Gallons per Minute	Quantity (millions of gallons per day)
Demineralized Water for Injection to Turbines for Nitrogen Oxides and Amine System	1,171	1.69
Service Water for LNG Trains	50	0.07
Potable Water for Turbine Inlet Air Humidification	306	0.44
Potable Water for Remote Building	13	0.02
Reject Water from Treatment and Design Margins	1,086	1.56
Total	**2,626**	**3.78**

Hydrostatic Testing

Prior to being placed into service, the LNG storage tanks would be tested to ensure structural integrity. The LNG piping would be pneumatically tested and therefore, would not require hydrostatic testing. Other piping and equipment associated with the Terminal would require hydrostatic testing. The total cumulative volume of water required for construction and hydrostatic testing of this equipment would be approximately 167 million gallons.

Upon completion of construction, the inner tank of each of the LNG storage tanks would be tested hydrostatically, in accordance with API Standard 620, Q.8.3. Hydrostatic testing would involve filling each of the inner tanks with approximately 42,270,000 gallons of fresh water. Test water would be purchased from the San Patricio Municipal Water District, and discharged to a drainage ditch that flows into Corpus Christi Bay or the Sherwin Alumina raw water reservoir (just north of the Terminal) for use in their facilities.

Pumps in each tank would control the discharge rate of the test water from the LNG storage tanks while discharge structures, such as a splash plate or hay bale structures, would be used to dissipate energy during discharge of the hydrostatic test water. These energy dissipation devices aid in preventing scouring and erosion. No chemicals would be added to the hydrostatic test water before or after testing. Cheniere would adhere to the testing requirements of the EPA and RRC hydrostatic test water permits.

Conclusion

Construction and operation of the Terminal would temporarily decrease water quality within the vicinity of the site as a result of dredging, maintenance dredging, and stormwater runoff. As described previously, impacts on water quality from dredging activities would be short-term and localized to within a few hundred feet of the activity. Through implementation of Cheniere's BMPs, NPDES permitting, our Procedures, and Cheniere's SPCC Plan, potential impacts resulting from stormwater runoff or the discharge of hydrostatic test water would be adequately minimized or avoided.

4.3.2 Pipeline

4.3.2.1 Groundwater

As discussed above for the Terminal, the Pipeline area is underlain by the Gulf Coast aquifer, characterized as an unconfined aquifer with unconsolidated sand, silt, and clay (Ryder, 1996). There are no locally protected aquifers, public or private water supplies, or wellheads in the vicinity of the Pipeline.

The greatest potential for impacts on groundwater would be an accidental release of a hazardous substance, such as fuels, lubricants, and coolants while constructing and operating the Pipeline. Cheniere would implement the measures contained in our Procedures, as well as its SPCC Plan which provides measures to minimize the potential impacts associated with spills of hazardous materials.

4.3.2.2 Surface Water

The Pipeline would cross ten waterbodies. There are no potable water intakes within 3 miles downstream of any waterbody crossing. No waterbody segments crossed by the Pipeline are included on the list of impaired waterbodies under Section 303(d) of the CWA nor do they contain contaminated sediments. Table 4.3-3 provides a list of the waterbodies that would be crossed by the Pipeline, including location by MP, waterbody name, type, crossing width, water quality classification, fishery type, and proposed crossing method. The pipeline would cross only two natural, permanently flowing waterbodies; Oliver Creek (MP 16.6) and Chiltipin Creek (MP 17.9).

We received several comments from the COE regarding discrepancies between the number of waterbodies initially reported in the draft EIS and that reported by the COE in its Section 10/404 permit. Cheniere addressed and clarified these discrepancies in its August 22, 2014 response to comments received on the draft EIS. Several changes were made to our analysis to reflect the information provided by Cheniere, as detailed in appendix I.

Table 4.3-3
Waterbodies Crossed by the Pipeline

Waterbody	Milepost a/	Stream Type b/	Stream Designation c/	State Water Quality Classification	Fishery Type	Crossing Method d/
Drainage Ditch	0.5	C	Intermediate	N/A	Warmwater	Bore
Drainage Ditch	1.2	C	Intermediate	N/A	Warmwater	Open Cut
Drainage Ditch	2.3	I	Intermediate	N/A	Warmwater	Open Cut
Drainage Ditch	4.7	I	Intermediate	N/A	Warmwater	Open Cut
Drainage Ditch	12.5	I	Intermediate	N/A	Warmwater	Open Cut
Oliver Creek	16.6	P	Intermediate	N/A	Warmwater	HDD
Chiltipin Creek	17.9	P	Intermediate	N/A	Warmwater	HDD
Tributary to Chiltipin Creek	18.0	I	Intermediate	N/A	Warmwater	HDD
Drainage Ditch	18.5	I	Minor	N/A	Warmwater	Open Cut
Drainage Ditch	18.6	E	Minor	N/A	Warmwater	Open Cut

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a/ Milepost at canal/creek centerline.
b/ P = Perennial, I = Intermittent, C = Canal
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

Cheniere would use the HDD method to cross Oliver and Chiltipin Creeks, as well as a tributary to Chiltipin Creek. Crossing these waterbodies via HDD would significantly reduce potential impacts on these 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, also known as a “frac-out”. Drilling mud primarily consists of water and bentonite clay. If a frac-out were to occur, it could temporarily impact water quality; however, Cheniere would implement numerous measures as identified in its *Horizontal Directional Drilling (HDD) Drilling Mud/Frac-out Contingency Plan* to minimize this impact. We have reviewed this plan and find it to be acceptable.

With the exception of one drainage ditch, the remaining waterbodies are typically dry with little or no flow. Waterbodies crossed via the open cut method could experience a decrease in water quality due to increased turbidity and sedimentation. However, due to the duration of disturbance, these impacts would be short-term. In addition, we anticipate that most drainage ditches would not be flowing during construction of the Pipeline and thus a decrease in water quality due to excess turbidity would not occur. 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.

To minimize impacts on waterbodies, Cheniere would implement measures described in our Procedures. These measures would include:

- restoring stream banks and natural contours to preconstruction conditions to the maximum extent practicable using the measures contained in our Plan and Procedures;
- stabilizing banks and installing temporary erosion sediment barriers within 24 hours; and
- vegetating disturbed riparian areas with conservation grasses and legumes or native plant species.

Additionally, lubricant, hydraulic fluid, and fuel spills from refueling construction equipment, fuel storage, or equipment failure in or near a waterbody could flow or migrate to the waterbody and impact water quality and other aquatic resources. Cheniere would implement the measures outlined in its SPCC Plan to minimize the potential impacts of spills and hazardous materials in waterbodies.

An adverse impact on waterbodies as a result of a hazardous materials spill would not be anticipated, as Cheniere would implement preventative and mitigation measures as outlined in its SPCC Plan and our Procedures.

Prior to being placed into service, the Pipeline would be hydrostatically tested to ensure structural integrity. The Pipeline would be filled with approximately 11,400,000 gallons of water for hydrostatic testing. Cheniere would likely obtain the water from an existing 30-inch-diameter raw water line owned and operated by the San Patricio Municipal Water District.

After testing is complete, water would be discharged at an average rate of approximately 4,000 gallons per minute into the Sherwin Alumina raw water reservoir located approximately 400 feet north of the south end of the Pipeline. Alternatively, the water may be discharged into the drainage ditch along La Quinta Road where it would flow into the La Quinta Channel. Cheniere would use appropriate energy dissipation and erosion control measures to prevent scouring during dewatering. No chemicals would be added to the test water. As described for the Terminal in Section 4.3.1 the raw water reservoir would have enough volume to accommodate the one time discharge of hydrostatic test water from the Pipeline.

Conclusion

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.

4.4 WETLANDS

As defined by the COE, wetlands are areas inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and under normal conditions do support, a prevalence of vegetation typically adapted for life in saturated soil conditions.

Cheniere identified wetlands within the Project area by field delineation (no federal lands would be impacted by the Project; therefore, compliance with Executive Order 11990[21], Protection of Wetlands, would not be applicable). Delineations followed the Routine On-Site Determination Methodology presented in the COE Wetland Delineation Manual (Technical Report Y-87-1) and the Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Atlantic Gulf Coastal Plain, Version 2.0 released in November 2010 (ERDC/EL TR-10-20).

4.4.1 Terminal Facilities

Five wetland/special aquatic sites were identified at the Terminal site; cordgrass salt marsh (estuarine intertidal emergent [E2EM] wetland), black mangrove (estuarine intertidal scrub/shrub [E2SS] wetland), unvegetated sand flat (estuarine intertidal flat [E2US]), vegetated sand flat/high marsh (E2US), and seagrass (estuarine submerged aquatic bed [E1AB]). Table 4.4-1 provides the approximate acreages of each wetland type located at the Terminal site. Typically, smooth cordgrass (*Spartina alterniflora*) is the only species found within this wetland type, however in the low marshes other species often include: saltmarsh bulrush (*Scirpus maritimes* var. *macrostachyus*), perennial glasswort (*Salicornia virginica*), and sea lavender (*Limonium carolinianum*). Black mangrove (*Avicennia germinans*) is the dominant species in the black mangrove wetland type, but buttonwood (*Conocarpus erectus*), leather fern (*Acrostichum aureum*), perennial glasswort, and bay marigold (*Borrichia arborescens*) may also be found. The dominant species among sparsely vegetated sand flat often includes various glasswort species (*Salicornia* spp.), saltwort (*Batis maritima*), mud plantain (*Heteranthera reniformis*), and false pimpernel (*Lindernia dubia*). Seagrass consists predominantly of shoal grass (*Halodule wrightii*), manatee grass (*Syringodium filiforme*), turtle grass (*Thalassia testudinum*), clover grass (*Halophila engelmanni*), and widgeon grass (*Ruppia maritima*).

Table 4.4-1
Wetland/Special Aquatic Sites Impacted by the Terminal

Vegetation Community	Wetland Classification a/	Construction Impact Acreage	Operation Impact Acreage
Cordgrass Salt Marsh	E2EM	6.19	5.91
Black Mangrove	E2SS	7.35	6.72
Unvegetated Sand Flat	E2US	3.25	2.87
Vegetated Sand Flat / High Marsh	E2US	1.37	1.00
Seagrass	E1AB	9.29	9.17
Total		**27.45**	**25.67**

Construction and operation of the Terminal facilities would temporarily and permanently impact wetlands. As identified in table 4.4-1, approximately 6.19 and 5.91 acres of cordgrass salt marsh, 7.35 and 6.72 acres of black mangrove, 4.62 and 3.87 acres of unvegetated and vegetated sand flats, and 9.29 and 9.17 acres of seagrass would be impacted by construction and

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[21] The provisions of Executive Order 11990 of May 24, 1977, appear at 42 FR 26961, 3 CFR, 1977 Comp., p.121.

operation, respectively. A total of approximately 27.45 and 25.67 acres of wetlands would be temporarily and permanently impacted by the construction and operation of the Terminal facilities, respectively.

Temporary wetland impacts would be those associated exclusively with construction activities. Once construction is complete, wetlands which were temporarily disturbed by construction activities would be restored to preconstruction contours and allowed to naturally revegetate. Unlike temporary impacts, permanently impacted wetlands would not be restored to preconstruction conditions following the completion of construction activities, but would be maintained as part of the Project.

To avoid and minimize impacts on wetlands, the Terminal facilities were sited in a manner that would result in less wetland impact. To mitigate unavoidable impacts on wetlands, Cheniere submitted an Aquatic Resources Mitigation Plan (ARMP) for the Project to the COE. This plan was submitted to the COE as part of the CWA Section 404 permitting process and approved in 2005 (DA Permit 23561). Since 2005, Cheniere has continued to work with the COE to finalize the ARMP to account for additional wetland impacts associated with the proposed Project.

Cheniere's proposed conceptual wetland mitigation plan at Shamrock Island was approved by the COE in 2005 to mitigate for impacts to waters of the U.S. associated with the previous proposal to construct an LNG import terminal and associated pipeline (Docket Nos. CP04-37-000, CP04-44-000, CP04-45-000, and CP04-46-000). Mitigation measures for the previously permitted 12.88 acres of wetland impacts were completed in 2013 and included the installation of 16 breakwaters bordering the north-western end of Shamrock Island. Construction of these breakwaters would assist in the preservation of existing habitats including cordgrass, mangroves, unvegetated sand flats, vegetated sand flats, hard substrates, and uplands.

In order to mitigate for the additional acres of wetland impacts associated with the proposed Project, Cheniere revised its ARMP in its Section 404/10 Permit Application submitted on August 31, 2013. In the revised ARMP, Cheniere proposed to construct approximately 3,500 feet of segmented rock breakwaters at Ransom Point. Ransom Point is located within the Redfish Bay State Scientific Area and is susceptible to erosion forces including wind-driven waves and ship wakes. Installation of breakwaters at Ransom Point aims to preserve and enhance existing habitats threatened by continued erosion.

The EPA expressed concern regarding Cheniere's ARMP. The COE addressed this concern and determined that 50 years to achieve an 8.9:1 preservation ratio, as proposed in Cheniere's ARMP, is not an appropriate period to evaluate preservation values. The COE recommended evaluating the preservation values during a 10-year period, during which time, conditions affecting the site would be relatively consistent and less likely to be influenced by sudden episodic events, such as hurricanes. Use of a shorter time period would lower Cheniere's estimated preservation ratio and potentially change the habitat types preserved by the proposed ARMP. The COE determined that in order to quantitatively evaluate Project impacts on wetland habitats, it was in the public's best interest to perform a functional assessment of wetlands impacted by the Project. A functional assessment would quantify, in a scientifically sound, reproducible and reasonably rapid manner, the wetland functions lost and those that would be mitigated for by the Project. This would allow the COE to verify if the Project is consistent with the COE-EPA Memorandum of Understanding of Mitigation under the CWA Section 404(b)(1)

Guidelines and 33 CFR 332.3(f)(1), and determine if the anticipated impacts would be adequately compensated by the proposed mitigation.

Cheniere revised its ARMP in response to comments received from the COE. Cheniere's revised ARMP (appendix C) was approved by the COE concurrent with issuance of the Section 404/10 permit on July 23, 2014.

Cheniere would evaluate ecological performance at Ransom Point based on demonstration of successful preservation and enhancement of habitats. Preconstruction habitat surveys would serve as a baseline from which comparisons with annual post-construction surveys can be made. Annual seagrass surveys would be completed during the 5-year monitoring period following construction. Habitat enhancement would be determined based on a comparison of preconstruction and post-construction survey data. Enhancement would be considered successful if seagrass density, characterized by percent cover, between the breakwater and the Ransom Point shoreline increases by at least 30 percent at the end of 5 years.

Based on the functional assessment completed for the proposed mitigation plan, the COE concluded in its Statement of Findings (issued with the approval of Cheniere's Section 404/10 Permit on July 23, 2014) that within 10 years of the mitigation plan's enhancement and preservation of tidal fringe wetlands at Ransom Point would replace and exceed the tidal fringe wetland functional capacity lost due to construction and operation of the Project.

Based on Cheniere's proposed impact mitigation measures as well as preparation of the functional assessment and ARMP approved by the COE, we have determined that constructing and operating the Terminal would not have a significant impact on wetlands.

4.4.2 Pipeline Facilities

The Pipeline would cross three palustrine emergent wetlands (PEM), one of which would be impacted during construction, as identified in table 4.4-2. PEM wetlands are characterized by a dominance of rooted herbaceous (non-woody) emergent wetland plants such as grasses and short, shrubby vegetation. Dominant species which occur in the PEM wetland impacted by the Pipeline include: locust (*Gleditsia triacanthos*), sedges (*Carex* spp.), spikerushes (*Eleocharis* spp.), and red fescue (*Festuca rubra*). Table 4.4-2 also provides the milepost location, wetland ID, temporary and permanent areas of impact, and wetland classification for each wetland crossed by the Pipeline facilities.

Table 4.4-2
Approximate Acreages of Wetland Vegetation Communities that would be Impacted by the Pipeline

Wetland ID	Milepost	Wetland Classification a/	Temporary Area of Impact (Acres) b/	Permanent Area of Impact (Acres) c/
MP-18-2 d/	18.03	PEM	0.00	0.00
MP-20-1 d/	20.13	PEM	0.00	0.00
MP-21-1	21.34	PEM	<0.01	<0.01

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a/ PEM = Palustrine emergent wetland
b/ Temporary impacts based on 75-foot construction right-of-way
c/ Permanent impacts based on 50-foot wide permanent right-of-way
d/ Areas where no impacts would occur because area would be crossed via bore or HDD

We received a comment from the COE regarding a discrepancy between the number of wetlands crossed by the Pipeline reported in the draft EIS and that reported by the COE in its Section 10/404 permit. The COE stated that only two wetlands would be crossed by the Pipeline. However, Cheniere clarified this discrepancy in its response to comments received on the draft EIS stating that the wetlands reported in the EIS are correct and that the COE did not include the wetland at MP 20-1.

Impacts on wetlands would include the temporary disturbance of wetland vegetation, soils, and hydrology. Additionally, soil disturbance and removal of wetland vegetation would temporarily impact wetland functions. Failure to properly segregate topsoil over the Pipeline trenchline would result in the mixing of topsoil with subsoil. This mixing can affect the success of post-construction reestablishment and the natural recruitment of native, wetland vegetation.

To avoid and minimize impacts on wetlands crossed by the Pipeline, Cheniere has reduced workspaces wherever possible. Cheniere has also routed the proposed Pipeline in several locations to avoid crossing wetlands entirely. Additionally, two of the three wetlands crossed by the Pipeline would be bored or crossed via HDD, thus avoiding or minimizing impacts. Though there is one PEM wetland that is located within the proposed permanent right-of-way, this wetland would be restored following completion of construction activities. In accordance with our Procedures, the wetland does not need to be actively revegetated; however, preconstruction contours must be restored following construction. Cheniere would also implement impact minimization measures identified in our Procedures. Major components of our Procedures which are applicable to wetland construction include:

- limiting construction equipment operating within the right-of-way to the equipment necessary for clearing, excavating, pipe installation, backfilling, and restoration activities;
- using upland access roads for all non-essential equipment to the maximum extent practicable;
- operating low-ground-weight equipment or operating from prefabricated construction mats in saturated wetlands;
- installing temporary erosion and sediment control measures immediately after the initial disturbance of wetland soils, and inspecting and maintaining the temporary erosion and sediment control measures until final stabilization;
- refueling and parking equipment at least 100 feet from a wetland boundary;
- installing sediment controls across the construction right-of-way, as needed, to contain trench spoil within wetlands; and
- segregating the uppermost foot of wetland topsoil from the underlying subsoil in areas disturbed by trenching, except in areas with standing water or saturated soils, or where no topsoil layer is evident.

Following construction, Cheniere would also monitor all temporarily impacted wetlands and adjacent wetlands, in accordance with the ARMP and our Procedures. Based on the amount and type of wetlands impacted along the Pipeline route and Cheniere's proposed impact minimization measures, we have determined that constructing and operating the Pipeline would not significantly impact wetlands.

4.5 VEGETATION

4.5.1 Terminal Facilities

The Terminal would be located within the southeastern portion of the Gulf Prairies and Marshes Ecoregion (Gould, 1975). The TPWD has defined area-specific vegetation types that characterize the state by vegetative cover and habitat types (McMahan et al., 1984). The Terminal would be located within an area TPWD has characterized as crops (McMahan et al., 1984). However, due to past disturbances, we have characterized the vegetation at the Terminal site as industrial/disturbed (grasslands and scrub/shrub). The marine component of the Terminal site also contains submerged aquatic vegetation (SAV).

Vegetation at the Terminal site was identified on the 2004 wetland delineation data sheets filed by Cheniere with the previous FERC filing in 2005 (Docket No. CP04-37-000) and as supplemented by the 2011/2012 delineation. Cheniere indicated that it had resurveyed for SAV as part of its Section 10/404 permitting process and that the COE had verified this data during its permitting process.

4.5.1.1 Industrial/Disturbed Vegetation

Much of the Terminal site would be located on highly disturbed land that supports little or no vegetation. A significant portion of the site has been previously graveled, paved, compacted or used for storage of bauxite and bauxite tailings. Grasslands and scrub/shrub uplands have been identified along the edges of the disturbed industrial areas. Coastal grasses and forbs exist as a narrow band between the tidal flats and the scrub/shrub communities within the Terminal site. Grass and forb species in these areas include: marshhay cordgrass (*Spartina patens*), saltgrass (*Distichlis spicata*), Bermuda grass (*Cynodon dactylon*), camphor daisy (*Rayjacksonia phyllocephalla*), sea ox-eye (*Borrichia frutescens*), coastal dropseed (*Sporoblous virginicus*), and sea oats (*Uniola paniculata*). Both woody and herbaceous vegetation also exist within the minimal scrub/shrub communities at the Terminal site. Typical species of the herbaceous undergrowth at the Terminal site include: western ragweed (*Ambrosia psilostachya*), common sunflower (*Helianthus annus*), prickly pear (*Optunis* spp.), scarlet sage (*Salvia coccinca*), silver-leaf night-shade (*Solanum elegnifolium*), Indian blanket-flower (*Gaillardia grandiflora*), and various grasses. Species of the woody overstory include mesquite (*Prospis juliflora*), saltcedar (*Tamarix ramosissima*), sugarberry (*Celtis laevigata*), yaupon (*Ilex vomitoria*), Georgia holly (*Ilex longipes*), and various palm species.

4.5.1.2 Submerged Aquatic Vegetation

As identified in section 4.4.1, submerged seagrasses occur as discontinuous patchy seagrass beds in shallow water at the Terminal site. Specifically, these seagrass beds are found along the margin of Corpus Christi Bay and consist predominantly of shoal grass, manatee grass, turtle grass, clover grass, and widgeon grass.

Construction and operation of the Terminal facilities would temporarily and permanently impact industrial/disturbed vegetation and SAV. The construction and operation of Terminal buildings and facilities would result in the permanent loss of vegetation. Additionally, the construction of the marine facilities would result in the permanent loss of 9.17 acres of SAV (see table 4.4-1). Additionally, SAV that occurs near the proposed marine facilities could be impacted by turbidity and sedimentation resulting from dredging activities. The TPWD recommended the use of turbidity curtains to minimize impacts on SAV associated with dredging.

To avoid and minimize impacts on vegetation at the Terminal, Cheniere would implement measures described in our Plan and Procedures and its ARMP as described in section 4.4.1. Dredging would be within mostly virgin stiff clays with interbedded sand and silty layers, which typically do not create high turbidity levels during dredging, as stated in Cheniere's Application. In addition, dredging would be conducted with a hydraulic cutterhead dredge, which further minimizes turbidity. As such, we expect that dredging turbidity and sedimentation impacts would be minimal and limited to within several hundred feet of the Terminal site. Cheniere would also comply with all Project-specific recommendations and mitigation requirements associated with their Section 404/10 permit.

Based on the disturbed nature of the Terminal site, the amounts and types of vegetation impacted, and Cheniere's proposed impact minimization and mitigation measures, we have determined that constructing and operating the Terminal facilities would not significantly impact vegetation.

4.5.2 Pipeline Facilities

The Pipeline associated with the Terminal would also be located within the Gulf Prairies and Marshes Ecoregion (Gould, 1975). It would be located within two distinct vegetation types as characterized by TPWD; agricultural crops and Mesquite-Live Oak-Bluewood Parks (McMahan et al., 1984). These vegetation types have been further characterized as agricultural, herbaceous and scrub/shrub vegetation, as was verified by Cheniere during surveys for the preparation of its application. Crops grown in the area that would be crossed by the Pipeline include: cotton, sorghum, soybeans, and corn. Herbaceous vegetation includes: western ragweed (*Ambrosia psilostachya*), common sunflower (*Helianthus annuus*), Indian blanket-flower (*Gaillardia pulchella*), prickly pear (*Opuntia* spp.), silver-leaf night-shade (*Solanum elaeagnifolium*), and a variety of grasses such as king ranch bluestem (*Bothriochloa ischaemum*), Texas windmill grass (*Chloris texensis*), Bermuda grass (*Cynodon dactylon*), Johnson grass (*Sorghum halepense*), and buffelgrass (*Pennisetum ciliare*). Scattered scrub/shrub species such as huisache (*Acacia smallii*), retama (*Parkinsonia aculeata*), bluewood condalia (*Condalia hookeri*), and honey mesquite (*Prosopis glandulosa*) also occur scattered throughout the herbaceous vegetation (Gould, 1975; Hatch et al., 1990). The TWPD indicated that live oak (*Quercus virginiana*) is also a common scrub-shrub species found in San Patricio County.

The TWPD provided comments on the draft EIS to avoid the removal of large trees (greater than 12 inches diameter breast height) that may occur within the boundaries of the pipeline construction right-of-way and recommended preparation of a mitigation plan for permanent impacts on mature trees. The majority of the Project is located within agricultural or open areas and is collocated with other utility corridors. Therefore, we have concluded that any impacts on large diameter trees within the Project area, should they occur, would be minor.

Construction and operation of the pipeline would temporarily impact vegetation, specifically, resulting in the temporary loss of vegetation. The right-of-way would be seeded in accordance with local NRCS requirements and therefore, vegetation would be allowed to revert to preconstruction conditions following construction.

To minimize impacts on vegetation, Cheniere would implement measures described in our Plan which specifically addresses reseeding, revegetation, and monitoring of vegetation. Vegetation would be considered successful if the right-of-way surface condition is similar to adjacent undisturbed land, and damage has been properly restored. Additionally, in order to restore vegetative cover quickly in non-crop areas, Cheniere would reseed using the seed mixtures identified in table 4.5-1

Table 4.5-1
Seed Mixtures for Terrestrial Vegetation Restoration Following Construction

Seed Mixture	Application Rate (pounds per acre)
Temporary Seed Mixture	
Oats	64
Hairy vetch	16
Foxtail millet	25
Rye	25
Permanent Seed Mixture	
Green sprangletop	8
Little bluestem	15
Indiangrass	20
Switchgrass	16

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

4.6 WILDLIFE AND AQUATIC RESOURCES

4.6.1 Wildlife Resources

4.6.1.1 Terminal Facilities

Marine Mammals and Sea Turtles

As identified in table 4.6-1, 27 species of marine mammals are commonly found in the Gulf of Mexico, seven of which are also protected by the federal and/or state governments. Additionally, five of the world's seven sea turtle species have been recorded in the Gulf of Mexico including: green (*Chelonia mydas*), hawksbill (*Eretmochelys imbricate*), Kemp's ridley (*Lepidochelys kempii*), leatherback (*Dermochelys coriacea*), and loggerhead (*Caretta caretta*). All five species are listed as threatened or endangered under the ESA and are managed jointly by the FWS and NMFS. These species are also listed as threatened or endangered by TPWD. Threatened and endangered species are addressed in section 4.7.

Table 4.6-1
Marine Mammals Observed in the Gulf of Mexico

Common Name	Scientific Name
Humpback whale	*Megaptera novaeangliae*
Fin whale	*Balaenoptera physalus*
Sei whale	*Balaenoptera borealis*
Minke whale	*Balaenoptera acutorostrata*
Blue whale	*Balaenoptera musculus*
Sperm whale	*Physeter macrocephalus*
Dwarf Sperm whale	*Kogia simus*
Pygmy Sperm whale	*Kogia breviceps*
Killer whale	*Orcinus orca*
Pygmy Killer whale	*Feresa attenuate*
Cuvier's Beaked whale	*Ziphius cavirostris*
Gervais' Beaked whale	*Mesoplodon europaeus*
Blainville's Beaked whale	*Mesoplodon densirostris*
Bryde's whale	*Balaenoptera edeni*
Short-finned Pilot whale	*Globicephala macrorhynchus*
False Killer whale	*Pseudorca crassidens*
Melon-headed whale	*Peponocephala electra*
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*

Construction of the Terminal on an upland site would not impact marine mammals or reptiles. However, construction and operation of the Terminal, specifically the dredging and LNG carrier's calling on the Terminal, could impact marine mammals and reptiles. LNG carriers could strike marine mammals and reptiles resulting in an increase in stress, injury and/or mortality. The measures that Cheniere would implement to minimize impacts on marine mammals are described in section 4.7.1.

Based on the modest increase in LNG carrier traffic over current conditions resulting from operation of the Terminal, the current commonality of such activities in the vicinity of the Terminal, and vessel strike avoidance measures that would be communicated by Cheniere to LNG carriers, we have determined that impacts on marine mammals would not be significant.

<u>Aquatic Wildlife</u>

The Terminal site contains open bay, seagrass, coastal marsh, sand flats, and black mangrove habitats, as well as coastal grasses and forbs, and scrub/shrub habitats. Open Bay and other aquatic habitat species are described in section 4.6.2.

Seagrass beds are inhabited by a variety of birds. Representative families include waders (*Ardeidae*), sandpipers (*Scolopacidae*), plovers and allies (*Charadriidae*), gulls and terns (*Laridae*), pelicans (*Pelecanidae*), cormorants (*Phalacrocoracidae*), grebes (*Podicipedidae*), loons (*Gaviidae*), rails and allies (*Rallidae*), eagles and ospreys (*Accipitridae*), and waterfowl (*Anatidae*) (Tunnell et al., 1996).

Due to salinity stress, few species of reptiles and amphibians are likely to occur in the coastal marshes at the Terminal site (Tunnell et al. 1996). However, some species, such as the diamondback terrapin (*Malaclemys terrapin littoralis*) and Gulf salt marsh snake (*Nerodia fasciata clarki*), are known to inhabit brackish marshes along the Gulf Coast (Carr, 1952; Garrett and Barker, 1987). The American alligator (*Alligator mississipiensis*) utilizes low-salinity coastal marshes as both feeding and nesting areas (Garrett and Barker, 1987). Many species of wading and aquatic shorebirds feed on the emergent plants, benthic invertebrates, and small fishes found in coastal marshes (Bellrose, 1976). Some of the common bird species likely to inhabit coastal marshes near the Terminal include mottled ducks (*Anas fulvigula*), lesser snow geese (*Chen caerulescens*), willets (*Cataptrophorus semipalmatus*), clapper rails (*Rallus longirostris*), great blue herons (*Ardea herodias*), tricolored herons (*Egretta tricolor*), black-crowned night herons (*Nycticorax nycticorax*), great egrets (*Casmerodius albus*), snowy egrets (*Egretta caerulea*), lesser scaups (*Aythya affinis*), buffleheads (*Bucephala albeola*), white pelicans (*Pelecanus erythrorhynchos*), and cormorants (Bent, 1929; Daiber, 1982; Stutzenbaker, 1988; Ruth, 1990; Tunnell et al., 1996). Herbivorous mammals, such as nutria (*Coypus coypu*) and white-tailed deer (*Odocoileus virginianus*) feed on marsh vegetation (White, 1973; Tunnell et al., 1996). Few carnivorous rodents actually reside within coastal marshes. However, the rice rat (*Oryzomys palustris*) is considered a predominantly carnivorous wetland species (Hamilton, 1976; Shard, 1967) that is common within the vicinity of the Terminal site. Other mammals that occasionally forage in coastal marshes include the cotton rat (*Sigmodon hispidus*), fulvous harvest mouse (*Reithrodonomys fulvescens*), house mouse (*Mus musculus*), and raccoon (*Procyon lotor*) (Linscombe and Kinler, 1985).

Sand flats provide excellent habitat for numerous invertebrate species, including benthic invertebrates, brown shrimp (*Penaeus aztecus*), and grass shrimp (*Paleaemonetes* spp.). Vertebrates include a variety of birds such as gulls, terns, herons, shorebirds, and wading birds. Some common species known to occur in the vicinity of the Terminal site include the laughing gull (*Larus atnicilla*), ring-billed gull (*Larus delawarensis*), royal tern (*Sterna maxima*), sandwich tern (*Sterna sandvicensis*), great blue heron, snowy egret, sanderlings (*Calidnis alba*), least sandpiper (*Calidnis minutilla*), roseate spoonbill (*Ajaia ajaja*), and white ibis (*Eudocimus albus*) (Tunnell et al. 1996).

Species likely to occur within the areas characterized by coastal grasses, forbs, and scrub/shrub at the Terminal site include the gray fox (*Urocyon cineroargentatus*), raccoon, coyote (*Canis latrans*), white tailed deer, and eastern cottontail (*Sylvilagus floridanus*) (Tunnell et al. 1996).

The Terminal would be located on a site that was used for industrial purposes for 50 years and has since been reclaimed. As described previously, the north shore of Corpus Christi Bay is highly industrial and the properties adjacent to the site are commercial and industrial in nature. Construction and operation of the Terminal would result in the permanent loss and conversion of disturbed coastal grasses and scrub/shrub habitats which would result in the permanent relocation of wildlife and an increase in stress, injury, and/or mortality. To avoid and minimize impacts on wildlife, Cheniere has reduced the size of construction areas to the maximum extent practicable and would implement measures described in our Plan and Procedures.

Based on the disturbed nature of the Terminal site as well as the characteristics of the wildlife known to occur or potentially occur in the Project area, and Cheniere's implementation of its proposed mitigation measures, we have determined that construction and operation of the Terminal would not significantly impact wildlife.

4.6.1.2 Pipeline Facilities

The Pipeline route would cross four different general habitat types: industrial, agricultural, open, and wetland. The Pipeline would not cross any areas that have been identified as sensitive habitats. Most of the Pipeline-related construction activities would occur in previously disturbed agricultural areas.

Industrial land consists of highly disturbed and modified areas at the south end of the Pipeline near the Terminal and at road crossings. These areas do not support much vegetation, and most wildlife would only occasionally be expected to use or traverse these areas.

Agricultural land consists of active cropland. Agricultural fields planted with a variety of legumes and row crops provide food and cover for several species of commonly observed wildlife. These areas provide an important food source in the form of seeds, foliage, and insects for a variety of songbirds, waterfowl, and game birds. The northern mockingbird (*Mimus polyglottos*) and mourning dove (*Zenaida macroura*) are common birds found in agricultural habitats (Tveten, 1993; Kaufman, 2000). Small mammals such as the hispid cotton rat are common in this agricultural habitat as well (Davis and Schmidly, 1994). Reptiles such as the Great Plains rat snake (*Elaphe guttata emoryi*) can also be found in this cover type (Dixon, 2000).

Wildlife species found within open land habitats include reptiles such as the western glass lizard (*Ophisaurus atenuatus*), six-lined racerunner (*Cnemidophorus sexlineatus*), keeled earless lizard (*Holbrookia propinqua*), Texas spotted whiptail (*Cnemidophonus gulanis*), western coachwhip (*Masticophis flagellum tesaceus*), ground snake (*Sonora semiannulata*), and western diamondback rattlesnake (*Crotalus atrox*) (Dixon, 2000). Bird species associated with this habitat type would include Nelson's sharp-tailed sparrow (*Ammodramus nelsoni*), prairie warbler (*Dendroica discolor*), buff-breasted sandpiper (*Tryngites subruficollis*), loggerhead shrike

(*Lanius ludovicianus*), and short-eared owl (*Asio flammeus*). Mammals likely to occur within this habitat type include the black-tailed jackrabbit (*Lepus californicus*), Gulf Coast kangaroo rat (*Dipodomys compactus*), marsh rice rat (*Orozomys palustris*), fulvous harvest mouse (*Reithrodontomys fulvescens*), raccoon, striped skunk (*Mephitis mephitis*), and coyote (Davis and Schmidly, 1994).

As described previously, the Pipeline would cross PEM wetlands at three locations. Typical wildlife species found within PEM wetlands include the Woodhouse's toad (*Bufo woodhousii*), Gulf coast toad (*Bufo nebulifer*), red-eared slider (*Trachemys scripta*), speckled king snake (*Lampropeltis getulus*), diamondback water snake (*Nerodia rhombifer*), red-winged blackbird (*Agelaius phoeniceus*), American widgeon (*Anas americana*), black-crowned night-heron (*Nycticorax nycticorax*), white ibis (*Eudocimus alba*), great egret (*Casmerodius albus*), marsh hawk (*Circus cyaneus*), rice rat, and eastern cottontail (*Sylvilagus floridanus*)..

Construction and operation of the Pipeline facilities would result in minimal and short-term impacts on wildlife because no sensitive habitats would be impacted, and much of the area affected by construction would be allowed to revert to preconstruction conditions following construction. Some smaller, less mobile wildlife, such as small mammals, amphibians and reptiles, would likely be taken during clearing and grading activities. Other wildlife, such as birds and larger mammals, would leave the immediate construction area when construction activities approach, and would move to similar habitats nearby. Areas adjacent to the Pipeline area provide similar and ample habitats for wildlife displaced temporarily during construction of the Pipeline. Wildlife would return to the majority of the Project area following construction and restoration. To minimize construction related impacts from Pipeline installation on wildlife habitats, Cheniere would implement measures contained in our Plan and Procedures, including the use of temporary erosion controls, restoration of all disturbed areas, and restricting vegetation clearing between March 1 and August 31, as further discussed in section 4.6.3.

TPWD provided comments on the draft EIS indicating that trenches left open overnight should be inspected by the EI each day prior to the commencement of work (appendix I). Additionally, TPWD recommended that if any state-listed species are trapped in the trenches, personnel permitted by TPWD would remove it. Cheniere indicated in its response to comments received on the draft EIS that it would comply with this TPWD recommendation.

Based on the types of available habitat within the Project area and with the implementation of the described mitigation measures, the Project would not have a significant impact on terrestrial wildlife, and impacts would be short-term and minor.

4.6.2 Fisheries Resources

4.6.2.1 Terminal

The Terminal facilities would be located adjacent to and in Corpus Christi Bay. The following sections describe the fisheries resources potentially impacted by construction and operation of the Project.

Open Water and Intertidal Habitats

Corpus Christi Bay was designated as an “estuary of national significance” by the EPA in 1992 and it contains over 200 fish species. The Terminal would be located across five aquatic/intertidal habitats: open bay, seagrass, coastal marsh, sand flats, and black mangroves.

Open Bay

Open bay communities provide habitat for a variety of benthic (living on or in bottom substrate) invertebrates, including, but not limited to, nematodes, harpacticoid copepods, gastrotrichs, clams, snails, polychaete worms, amphipods, and crabs. Epibenthos which typically prefer protected areas such as seagrass beds and salt marshes also occur in the open bay communities. Penaeid shrimp, roughback shrimp (*Trachypenaeus similis*), mantis shrimp (*Squilla empusa*), and blue crabs (*Callinectes sapidus* and *C. similis*) are the most abundant epifauna in these areas (Murray and Jinnette, 1976; Armstrong, 1987). Other epifaunal crustaceans that occur in open bay habitats include amphipods (*Gammarus mucronatus*), mud crabs (*Rhithropanopeus* spp.), hermit crabs (*Pagurus annulipes*), and grass shrimp (*Palaemonetes pugio*) (Tunnell et al., 1996; Armstrong, 1987). The nektonic community (occupying the water column above the substrate) of open bays includes a variety of invertebrates and fishes. Common nektonic invertebrates include: zooplankton, a variety of cnidarians (jellyfish, coral, and hydra) and the bay squid (*Lolliguncula brevis*) (Britton and Morton, 1989). Fish species common in open bay habitats include the Atlantic croaker (*Micropogonias undulatus*), spot (*Leiostomus xanthurus*), bay anchovy (*Anchoa mitchilli*), hardhead catfish (*Arius felis*), pinfish (*Lagodon rhomboides*), sand seatrout (*Cynoscion arenarius*), star drum (*Stellifer lanceolatus*), spotted seatrout (*Cynoscion nebulosus*), red drum (*Sciaenops ocellatus*), black drum (*Pogonias cromis*), southern flounder (*Paralichthys lethostigma)*, gafftopsail catfish (*Bagre marinus*), and striped mullet (*Mugil cephalus*).

Seagrass

Seagrasses provide habitat for a variety of invertebrates, including various annelids, polychaetes, crustaceans, gastropods and bivalves. Seagrass habitats also support a number of fish species including seatrout and red drum. Additionally, seagrasses provide habitat for tidewater silversides (*Menidia peninsulae*), rainwater killifish (*Lucania parva*), pinfish, bay anchovy, striped mullet, menhaden (*Brevoortia* spp.), silver perch (*Bairdiella chrysura*), dusky pipefish (*Syngnathus floridae*), speckled worm eel (*Myrophis punctatus*), and other associated species. Seagrass beds also serve as important feeding grounds for larger invertebrates and predatory fish that are attracted to these areas in pursuit of smaller prey species (Gulf of Mexico Fishery Management Council, 1998). Such predatory species include: hardhead catfish, spotted seatrout, red drum, southern flounder, spot, and various sharks and rays.

Coastal Marsh and Vegetated Flats

Coastal marshes provide habitat for a variety of filter-feeding mollusks, oligochaetes, polychaetes, nematodes, fiddler crabs (*Uca* spp.), mud crabs, grass shrimp, penaeid shrimp, and amphipods (*Orchestia* spp.). The abundance of emergent and epiphytic vegetation (plants that grow on other vegetation) found in coastal marshes supports a variety of grazing invertebrates, such as snails and various insects. Invertebrate predators, including crustacean larvae, adult copepods (Marshall and Orr, 1960), odonates, coleopterans, dipterans, and blue crabs (Tunnell et al. 1996) also are common inhabitants of coastal marshes. Similar to seagrass, coastal marshes provide nursery habitat for a variety of marine and estuarine fishes. Additionally, coastal marshes support several small, resident fish, including killifishes, menhaden, bay anchovy, striped mullet, and mosquito fish (*Gambusia affinis*), and a variety of larger predatory fishes, such as tarpon (*Megalops atlanticus*).

Tidal Flat

Tidal flats provide habitat for a variety of benthic invertebrates. Representative organisms include polychaetes, gastropods, and crustaceans such as blue crabs (Withers, 1994). Small fish often move into these areas to feed; common fish species include sheepshead minnow (*Cyprinodon variegatus*), Gulf killifish (*Fundulus grandis*), rough silversides (*Membras martinica*), larval inshore lizard fish (*Synodus foetens*), southern flounder, red drum, and spotted sea trout (Harrington and Harrington, 1972; Pfeifer and Wiegert, 1981; Pulich et al., 1982).

Black Mangrove

Black mangroves provide habitat to wildlife along protected shorelines, intertidal salt marshes, and marshy barrier islands. Black mangrove also effectively stabilizes interior tidal mudflats, dredge-fill, and other artificial sites commonly associated with wetland restoration (NRCS, 2005). Species found in black mangroves include goliath grouper (*Epinephelus itajara*), lane snapper (*Lutjanus sunagris*), and yellowmouth grouper (*Mycteroperca interstitialis*) (Gulf of Mexico Fishery Management Council, 2004).

Fisheries of Special Concern

Fisheries of special concern in Corpus Christi Bay include federal and state listed threatened and endangered species, fish with designated EFH, and those of commercial and recreational value. Corpus Christi Bay is designated in the National Estuary Program as an estuary of “national significance”.

Essential Fish Habitat

In the MSA, Congress defines EFH as consisting of “waters and substrate necessary to fish for spawning, breeding, feeding or growth to maturity” (16 USC 1802[10]). Specific habitats include all estuarine water and substrate (mud, sand, shell, and rock), and all associated biological communities, such as sub-tidal vegetation (seagrasses and algae), and the adjacent inter-tidal vegetation (marshes and mangroves). In addition to ecological significance, EFH represents areas of high economic importance due to the dependence of recreational and commercial fisheries that are directly and indirectly associated with them.

The fish species known to occur in Corpus Christi Bay, most of which are temperate in biogeographic distribution with a few tropical species (Tunnell et al., 1996), can be classified as warmwater marine or estuarine.

Construction and operation of the Terminal would impact EFH for juvenile white and brown shrimp; larval, post-larval, juvenile, and adult red drum; adult gray snapper (*Lutjanus griseus*); post-larval and juvenile Goliath grouper; post-larval and juvenile lane snapper; and juvenile yellowmouth grouper. These habitats have also been designated as EFH for highly migratory species including neonate, juvenile, and adult blacktip (*Carcharhinus limbatus*), bull (*Carcharhinus leucas*), bonnethead (*Sphyrna tiburo*), and Atlantic sharpnose (*Rhizoprionodon terranovae*) sharks; neonate and juvenile scalloped hammerhead (*Sphyrna lewini*) and lemon

(*Negaprion brevirostris*) sharks; and neonate fine tooth (*Carcharhinus isodon*) sharks (NOAA Fisheries, 2009a; Gulf of Mexico Fisheries Management Council, 2004).

A full EFH assessment has been performed for the Terminal site which outlines life history information, and relative abundance of all species with EFH identified in the Terminal area of impact. Potential impacts and conservation measures, as determined through correspondence with NOAA Fisheries, to avoid and/or minimize impacts are also included in the assessment. The EFH assessment has been included as appendix B of this EIS.

Recreational and Commercial Fisheries

Table 4.6-2 identifies the recreational and commercial fisheries known to occur in Corpus Christi Bay.

Table 4.6-2
Recreational and Commercial Fisheries in Corpus Christi Bay

Common Name	Scientific Name	Fishery Classification
Brown shrimp	*Farfantepenaeus aztecus*	Warmwater marine/estuarine
Pink shrimp	*Farfantepenaeus duorarum*	Warmwater marine/estuarine
White shrimp	*Litopenaeus setiferus*	Warmwater marine/estuarine
Red drum	Sciaenops ocellatus	Warmwater marine/estuarine
Spanish mackerel	*Scomberomorus maculatus*	Warmwater marine
Atlantic croaker	*Micropogonias undulatus*	Warmwater marine/estuarine
Black drum	*Pogonias cromis*	Warmwater marine/estuarine
Gafftopsail catfish	*Barge marinus*	Warmwater marine/estuarine
Sand seatrout	*Cynoscion arenarius*	Warmwater estuarine
Sheepshead	*Archosargus probatocephalus*	Warmwater marine/estuarine
Southern flounder	*Paralichthys lethostigma*	Warmwater marine/estuarine
Spotted seatrout	*Cynoscion nebulosus*	Warmwater estuarine
Striped mullet	*Mugil cephalus*	Warmwater marine/estuarine

Impacts and Mitigation

Constructing and operating the Terminal would impact fisheries resources including EFH and recreation and commercial fisheries. Specifically; dredging, dredge disposal, and pile driving activities would impact fish and other aquatic organisms. These activities would also impact recreational and commercial fisheries in a similar manner. Additionally, LNG carriers calling on the Terminal and other ship-related marine traffic and operations could also impact fisheries resources. Impacts on EFH resulting from construction and operation of the Project are described in more detail in appendix B, and further described below in the appropriate impact headings.

Dredge and Dredge Disposal

Dredging activities necessary for the construction of the Terminal would permanently impact open bay, seagrass, salt marsh, sand flat, and black mangrove habitats. Maintenance dredging required for operation of these facilities could periodically impact fisheries. As described in section 2.3.1, a total of 124 acres of open water habitat would be impacted by operation of the Terminal, including approximately 95.4 acres of aquatic/intertidal habitat that would be permanently converted into deep water habitat (23.8 acres of the site is currently classified as deep water and 5 acres of open land will be converted to deep water). Of the 95.4 acres of shallow, open water habitat that would be dredged, approximately 9.17 acres are currently submerged aquatic seagrass beds, 5.91 acres are cordgrass salt marsh, 1.00 acre is coastal marsh and vegetated sand flats, 2.87 acres are unvegetated sand flats, 6.72 acres are black mangrove, and the remaining 69.73 acres are unvegetated shallow open water.

Dredging activities during construction of the Terminal, including the disturbance and resuspension of sediments, would temporarily increase turbidity which could impact water quality, fish, and other aquatic organisms. Turbidity resulting from dredging activities could further be impacted by wind influenced tides. Increased turbidity could clog fish gills and irritate epithelia tissue. Increased turbidity could also impact seagrasses and other aquatic vegetation which could also impact fish and other aquatic organisms. Impacting fish habitat could impact fish behavior (avoidance), foraging, breeding, and migration. Increased stress, injury, and mortality could result from dredging activities. Additionally, dredging equipment could also entrain fish and other aquatic organisms.

Maintenance dredging would periodically increase turbidity; however, this impact would be temporary. Impacts on fisheries would be similar to those described above, but the intensity of these impacts would be significantly less. Additionally, the Project area is already subject to maintenance dredging and, as a result, fish in the area have become accustomed to this type of disturbance.

Despite other highly variable physiochemical parameters (e.g., salinity, temperature, oxygen) marine, coastal pelagic, and estuarine finfish and shellfish species are abundant in the Project area and are well adapted to highly turbid conditions. Overall, motile organisms would be capable of avoiding highly turbid areas (Hirsch et al., 1978). Under most conditions, fish and other motile organisms are only exposed to localized suspended-sediment plumes for short durations (minutes to hours) (Clarke and Wilber, 2000). COE studies have also demonstrated that benthic organisms actively repopulate dredged areas quickly after completion of dredging activities. Studies also show that many benthic organisms have capabilities to vertically migrate through substantial overburdens caused by sedimentation and turbidity (Wilber et al., 2005; Maurer et al., 1978, 1986).

As described previously, Cheniere proposes to dispose of all dredged material in an upland DMPA immediately north of the Terminal site. Run-off and return water from the DPMA would flow into an existing drainage canal along the western boundary of the Terminal and back into Corpus Christi Bay. This run-off and return water would increase turbidity at the point of entry into Corpus Christi Bay. Increased turbidity could impact fish and other aquatic organisms as described above.

To minimize impacts on fish including EFH and other aquatic organisms, Cheniere would adhere to measures outlined in our Plan and Procedures, its Section 10/404 permit (issued by the COE on July 23, 2014) and implement its ARMP. Cheniere would further minimize impacts from stormwater runoff through implementation of its SPCC Plan, construction of drainage ditches on site, and adherence to measures contained in the NPDES requirements. In addition, Cheniere received its state Water Quality Certification from the RRC on November 14, 2013.

Pile Driving

Pile driving activities would generate sound pressure waves and underwater noise levels that could impact fish and other aquatic organisms. These impacts include stress, injury, avoidance, and/or other behavior changes.

Although the impacts of pile driving are poorly studied and there is substantial variation in species response to sound, intense sound pressure waves can change fish behavior or injure/kill fish through rupturing swim bladders or causing internal hemorrhaging. The intensity of the sound pressure levels produced during pile driving depends on a variety of factors including, but not limited to, the type and size of the pile, the firmness of the substrate into which the pile is being driven, the depth of water, and the type and size of the pile-driving hammer. The degree to which an individual fish exposed to sound waves would be affected is dependent upon variables such as the peak sound pressure level and frequency as well as the species, size, and condition of the fish (e.g., small fish are more prone to injury by intense sound waves than are larger fish of the same species).

Depending on the specific conditions at the site, pile driving activities could generate underwater sound levels great enough to injure some fish or cause them to be more susceptible to predation. Underwater noise levels are commonly referred to as a ratio of the underwater sound pressure to a common reference pressure of 1 micropascal (μPa) root mean-square pressure, which is expressed in decibels (dB) of sound intensity as dB re: 1 μPa. There are insufficient peer reviewed reliable data available for the onset of behavior disturbance in fish; however, as a conservative measure, NOAA Fisheries generally uses 150 dB re: 1 μPa as the threshold for behavior effects to fish species of particular concern, citing that noise levels in excess of 150 dB re: 1 μPa can cause temporary behavior changes (startle and stress) that could decrease a fish's ability to avoid predators. The current interim thresholds protective of injury to fish are 206 dB re: 1 μPa (peak) and 187 dB re: 1 μPa (cumulative) sound exposure level for fish 2 grams or greater and 183 dB re: 1 μPa (cumulative) sound exposure level for fish of less than 2 grams (ICF Jones and Stokes and Illingworth and Rodkin, Inc., 2009).

Driving tubular steel piles has been known to generate sound levels from 192 to 194 dB, above the level that is thought to injure some fish. Depending on the specific conditions at the Terminal, these sounds can have a transmission loss rate of 0.021 to 0.046 dB per foot (Nedwell and Edwards, 2002; Nedwell et al., 2003). Based on these values, the use of an impact hammer at the Terminal could generate underwater sound levels great enough to injure some fish and otherwise affect some fish as far as 1,860 feet from a steel pile (i.e., 155 dB). Although the sound waves of the greatest intensity would be limited to the immediate vicinity of the piles within the slip, sound levels of 155 dB could extend to the far shore of the La Quinta Channel while piles for some of the mooring dolphins are being driven. In a review of studies documenting fish kills associated with pile driving, NOAA Fisheries (2003) reported that all have occurred during use of an impact hammer on hollow steel piles. The type of hammer that would be used to drive piles during construction of the Project has not yet been identified.

Measures implemented to minimize impacts on aquatic organisms from pile driving activities are further discussed in section 4.7.1.

Ship and Boat Traffic

Ship and boat traffic associated with constructing and operating the Terminal would also impact fish and other aquatic organisms. Specifically, ship movements, noise and resulting wave actions could impact fisheries resources. Ship movements could directly impact fisheries and other aquatic organisms. These movements could result in strikes and cause avoidance which could result in increased rates of stress, injury and/or mortality experienced. Although ship noise would not generally be of the intensity produced from driving steel piles, vessels operating in the La Quinta Channel could cause sounds that elicit responses in fish. Some research suggests that fish exhibit avoidance behavior in response to engine noise (International Council for Exploration of the Sea, 1995). At the same time, research conclusions tend to suggest that since the impacts are transient (i.e., once the ship passes, behavior returns to normal), that the long-term impacts on fish populations are negligible (Stocker, 2001). Increased wave action resulting from ship and boat traffic could increase turbidity which could impact fish and other aquatic organisms.

Ship Operations – Ballast Water

LNG carrier operations at the Terminal site would require the discharge of ballast water. As described previously in section 2.1.4, the Terminal has been designed to load approximately 200 to 300 LNG carriers per year. LNG carriers arriving at the Terminal could include the largest presently existing LNG carriers with the capacity to discharge approximately 9 million to 30 million gallons of ballast water at a rate up to 1.7 million gallons per hour. A 138,000 m^3 capacity LNG carrier could discharge approximately 50,000 m^3 of ballast water at the berth during each LNG cargo loading operation. Approximately 12,000,000 m^3 of ballast water would be discharged at the Terminal per year.

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 LNG carrier 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 LNG carrier upon its arrival at the Terminal. 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 non-indigenous aquatic species which could also impact fish and other aquatic organisms.

To minimize and avoid impacts on fish and other aquatic organisms resulting from ballast water discharges, the Coast Guard, which has jurisdiction over inspection and regulatory enforcement for all shipping in U.S. waters, would require all LNG carriers calling on the Terminal to adhere to all applicable ballast water management rules and regulations. Coast Guard regulations require that all vessels equipped with ballast water tanks which enter or operate in U.S. waters maintain a ballast water management plan that is specific for that vessel and assigns responsibility to the master or appropriate official to understand and execute the ballast water management strategy for that vessel. Under these requirements, vessels must implement strategies to prevent the spread of exotic aquatic nuisance species in U.S. waters. Examples of these strategies include retaining ballast water on board, minimizing discharge or uptake at certain times and locations, and exchanging ballast water with mid-ocean seawater. Ships that have operated outside of the U.S. Exclusive Economic Zone (EEZ) must either retain their ballast water on board or undergo a mid-ocean (greater than 200 nm from shore/water depth greater than 2,000 meters) ballast water exchange in accordance with applicable regulations. Applicable U.S. laws, regulations, and policy documents related to ballast water include the following:

- Nonindigenous Aquatic Nuisance Prevention and Control Act of 1990 (NANPCA) that established a broad federal program "to prevent introduction of and to control the spread of introduced aquatic nuisance species…" FWS, Coast Guard, EPA, COE, and NMFS all were assigned responsibilities.
- National Invasive Species Act of 1996 that reauthorized and amended the NANPCA because "Nonindigenous invasive species have become established throughout the waters of the U.S. and are causing economic and ecological degradation to the affected near shore regions." The Secretary of Transportation was charged with developing national guidelines to prevent import of invasive species from ballast water of commercial vessels, primarily through mid-ocean ballast water exchange, unless the exchange threatens the safety or stability of the vessel, its crew, or its passengers.
- National Aquatic Invasive Species Act of 2003 (NAISA), amended in 2005 and again in 2007, established a mandatory National Ballast Water Management Program. The primary requirements established under NAISA are: 1) all ships operating in U.S. waters are required to have on board an Aquatic Invasive Species Management Plan; 2) the Coast Guard was made responsible for the development of standards for mid-ocean ballast water exchange and ballast water treatment for vessels operating outside of the EEZ; and 3) implementing the BMPs and available technology related to ballast water treatment.
- National Ballast Water Management Program, originally established by NANPCA and further amended by NISA 1996 and NAISA 2003, made the ballast water management program mandatory, including ballast water exchange, with reporting to the Coast Guard.
- Shipboard Technology Evaluation Program, a program authorized under the Coast Guard Ballast Water Management Program and designed to facilitate the development of "effective ballast water treatment technologies, through experimental systems, thus creating more options for vessel owners seeking alternatives to ballast water exchange."
- Navigation and Vessel Inspection Circular 07-04, Change 1, a program developed by the Coast Guard for the management and enforcement of ballast water discharge into U.S. ports and harbors.
- Vessels Carrying Oil, Noxious Liquid Substances, Garbage, Municipal or Commercial Waste, and Ballast Water, implementing regulations for the Act to Prevent of Pollution from Ships of 1980, which applies to all U.S.-flagged ships anywhere in the world and to all foreign-flagged vessels operating in navigable waters of the U.S. or while at port under U.S. jurisdiction.

In addition to discharging ballast water, operation of LNG carriers while at the Terminal would require the intake of water. Ship cooling water would be withdrawn and discharged below the water line on the sides of the ship through screened water ports, known as "sea chests”. Water intakes could result in the impingement and entrainment of fish. These actions could impact the rates of stress, injury and/or mortality experienced by fish. To minimize these impacts, water intakes would be outfitted with screened sea chests that withdraw and discharge water at a relatively slow velocity.

To address the potential impacts on fisheries associated with offshore spills of fuel, lubricants, or other hazardous materials, Cheniere would implement measures contained in its SPCC Plan.

Conclusion

Based on the characteristics of the Terminal site and the adjacent waters, the fish and other aquatic organisms including their habitats that would be impacted by the Project; the dredging, dredge disposal, pile driving and shipping activities that would impact these resources; and Cheniere’s implementation of measures to avoid, minimize and mitigate these impacts; we have determined that construction and operation of the Terminal would impact fisheries, including EFH resources, but that these impacts have been sufficiently minimized.

4.6.2.2 Pipeline Facilities

As identified in section 4.3.2, the Pipeline would cross ten waterbodies. Of the ten waterbodies, two (Oliver Creek and Chiltipin Creek) are characterized as perennial, freshwater, and containing warmwater fisheries. The remaining eight crossings have been characterized as intermittent drainages, ditches, or canals that do not support sustainable fish species. No EFH, fisheries of special concern, state or federally listed threatened and endangered fish species, or fish of significant commercial and recreational value have been identified as being crossed by the pipeline facilities. Representative freshwater fish species that could occur in Oliver and Chiltipin Creeks include: central stoneroller (*Campostoma anomalum*), cypress minnow (*Hybognathus hayi*), spotted sucker (*Minytrema melanops*), yellow bullhead catfish (*Ameiurus natalis*), starhead minnow (*Fundulus excambiaei*), and green sunfish (*Lepomis cyanellus*) (Garret and Klym, 2012). Additionally, table 4.6-3 provides a list of representative game and commercial fish species with the potential to occur within Oliver and Chiltipin Creeks (Texas Natural History Collections, 2003; TPWD, 2003).

Table 4.6-3
Representative Commercial and Game Fish Species with Potential to Occur in Waterbodies Crossed by the Pipeline

Common Name	Scientific Name	Fishery Classification
Largemouth bass	*Micropterus salmoides*	Warmwater
Blue catfish	*Ictalurus furcatus*	Warmwater
Channel catfish	*Ictalurus punctatus*	Warmwater
Flathead catfish	*Pylodictis olivaris*	Warmwater
Bluegill	*Lepomis macrochirus*	Warmwater
Red ear sunfish	*Lepomis microlophus*	Warmwater
Longear sunfish	*Lepomis megalotis*	Warmwater
Green sunfish	*Lepomis cyanellus*	Warmwater
Golden shiner	*Notemigonus crysoleucas*	Warmwater
Black-tail shiner	*Cyprinella venusta*	Warmwater
Bullhead minnow	*Pimephales vigilax*	Warmwater

Construction of the 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 Oliver and Chiltipin Creeks. To minimize impacts on fish, Cheniere would cross Oliver and Chiltipin Creeks using HDDs. Because the remaining seven waterbodies do not support sustainable fisheries, constructing the Pipeline across these waterbodies would not impact fish. Additionally, Cheniere would complete all waterbody crossings in accordance with the construction and mitigation measures described in our Procedures. Though not expected, if dewatering of surface waters is necessary, Cheniere would coordinate with TPWD to determine if an Aquatic Resource Relocation Plan is required to further minimize impacts on aquatic resources.

The use of HDDs to cross Oliver and Chiltipin Creeks would significantly minimize impacts on fish. Therefore, based on the characteristics of the fisheries contained within the ten waterbodies that would be crossed, Cheniere's use of HDDs, 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.

4.6.3 Migratory Birds

Migratory birds are protected under the MBTA, originally passed in 1918. The MBTA states that it is unlawful to pursue, hunt, take, capture, kill, possess, sell, purchase, barter, import, export, or transport any migratory bird, or any part, nest, or egg of any such bird, unless authorized under a permit issued by the Secretary of the Interior. "Take" is defined in the regulations as to “pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt any of the above” (50 CFR 10).

Executive Order 13186 (January 2001) was issued, in part, to ensure that environmental analyses of federal actions assess the impacts on migratory birds. It also states that emphasis should be placed on species of concern, priority habitats, and key risk factors and it prohibits the take of any migratory bird without authorization from the FWS. On March 30, 2011, the FWS and the Commission entered into a Memorandum of Understanding that focuses on avoiding or minimizing the adverse impacts on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the Commission and the FWS by identifying areas of cooperation. This voluntary Memorandum of Understanding does not waive legal requirements under any other statutes and does not authorize the take of migratory birds.

Migratory birds follow broad routes called “flyways” between breeding grounds in Canada and the U.S. and wintering grounds in Central and South America. The Terminal site is within the Central Flyway. The Central Flyway runs through the central portion of the U.S. and includes the states of Montana, Wyoming, Colorado, New Mexico, Texas, Oklahoma, Kansas, Nebraska, South Dakota, and North Dakota, and the Canadian provinces of Alberta, Saskatchewan and the Northwest Territories. Most birds that move along the Central Flyway travel from Canada through the central states, eventually reaching the tropics of South America via the Gulf of Mexico (FWS, 2011).

The FWS published the *Birds of Conservation Concern 2008* to assess and prioritize bird species for conservation purposes. The document identifies migratory and non-migratory birds that are of conservation concern in order to stimulate conservation actions among government agencies and private partners. According to the document, the Project lies within Bird Conservation Region 37, the Gulf Coastal Prairie Region. Table 4.6-4 (see appendix D) provides a list of the species of birds of conservation concern within region 37.

4.6.3.1 Terminal Facilities

A number of migratory birds, including shore and sea birds, have the potential to fly over the Terminal. The Terminal would be located in a highly industrialized area, although several locations on the site as well as the DMPA north of the Terminal, would provide some marginal habitat. The highly industrial nature of the Terminal site and surrounding area make it an unlikely stopover area for migrants. The high amounts of activity on the properties adjacent to the Terminal likely deter migratory birds from utilizing the marginal habitat within the site. There are proposed structures within the Terminal that could pose a risk to migratory bird species that may fly through the area. These structures include the LNG tanks, the process flare tower, and the marine flare. The LNG tanks are large structures and would likely be avoided by avian species. The process flare tower would be a self-supported structure, approximately 500 feet tall, and would have aircraft warning lights installed. The marine flare would be a guy wire-supported structure, and would have visual markers affixed to the wires to prevent collisions by bird species. Though there is potential for minor impacts on migratory bird species, constructing and operating the Terminal is not expected to an impact on the population-levels of the birds. Moreover, there are several areas in the vicinity of the Terminal, including the Aransas National Wildlife Refuge, Mustang Island State Park, Lake Corpus Christi State Park, and Padre Island National Seashore that provide suitable, high quality habitat for a variety of species.

As a measure to protect any migratory birds that could be found within the Terminal site, Cheniere 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, Cheniere would survey for migratory bird nests no more than three weeks prior to commencing work. If an active migratory bird nest is found, Cheniere would consult with the FWS to identify the most appropriate measure to be taken to avoid or minimize impacts.

In addition, Cheniere would implement BMPs as described in consultation received from the FWS on September 12, 2012. Some practices outlined by the FWS include:

- using lighting systems with minimum intensity;
- using maximum off-phased white strobe lighting as per FAA regulations;
- down-shielding lights on the Terminal site as appropriate, and
- marking guy wires with visual markers and bird diverters.

Cheniere would continue to consult with the FWS prior to constructing the facilities regarding implementation of further avoidance or minimization measures to protect migratory bird species. Because of the measures described above to reduce impacts on migratory birds, including timing of activities, impacts on migratory birds would not be significant.

4.6.3.2 Pipeline Facilities

The largest impact on migratory birds from the 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 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 a substantial or long-term impact on migratory birds. This would not constitute a population-level impact given the stability of local populations and the abundance of available habitat outside of the Pipeline right-of-way.

The linear nature of the Pipeline and the use of previously and continually disturbed areas would minimize impacts on migratory bird species. Construction noise and activities could result in the temporary displacement of migratory birds. Due to the relatively short duration of construction activities and the current use of the area, the Pipeline would not have a significant impact on migratory birds. As discussed above for the Terminal, as a measure to protect any migratory birds that may be found along the Pipeline route, Cheniere 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, Cheniere would survey for migratory bird nests no more than three weeks prior to commencing work.

If an active migratory bird nest is found, Cheniere would consult with the FWS to identify the most appropriate measures to be taken to avoid or minimize impacts on migratory birds. Because of the measures described above to reduce impacts on migratory birds, including timing of pipeline construction activities, impacts on migratory birds would not be significant.

4.7 THREATENED, ENDANGERED, AND OTHER SPECIAL STATUS SPECIES

4.7.1 Federally Listed Threatened and Endangered Species

Federal agencies are required by Section 7 of the ESA to ensure that any actions authorized, funded, or carried out by the agency do not jeopardize the continued existence of a federally listed threatened or endangered species, or result in the destruction or adverse modification of designated critical habitat of a federally listed species. The FERC is required to consult with the FWS and NMFS to determine whether any federally listed endangered or threatened species or designated critical habitat are within the vicinity of the proposed Project, and to determine the proposed action's potential effects on those species or critical habitats. If the project would affect a listed species, the agency must report its findings to the FWS and NMFS in a BA. If FERC determines that the proposed action may adversely affect a listed species, the agency must submit a request for formal consultation to comply with Section 7 of the ESA. In response, the FWS and/or NMFS would issue a Biological Opinion as to whether or not the federal action would likely jeopardize the continued existence of a listed species, or result in the destruction or adverse modification of designated critical habitat.

In order to comply with Section 7 of the ESA, Cheniere, acting as the FERC's non-federal representative for purposes of complying with the ESA, consulted with the FWS and NMFS regarding the presence of federally listed and proposed threatened and endangered species and their critical or proposed critical habitats within the Project area. On October 29, 2012 NMFS notified Cheniere that it has determined that project impacts are similar to the original project and reinitiating of ESA Section 7 consultation is not required. The FWS provided concurrence with Cheniere's "not likely to adversely affect" determinations in letters dated August 8, 2013 and November 5, 2013.

Since construction of the proposed facilities may occur over several years, we and Cheniere would be responsible to ensure that any additional surveys resulting from the observation or listing of species would be conducted as appropriate and if necessary reinitiate consultation prior to allowing construction activities to commence.

The FWS and NMFS identified 17 federally listed species that occur or potentially occur within the Project area. As identified in table 4.7-1 (see appendix D), these species include two plants (south Texas ambrosia [*Ambrosia cheiranthifolia*] and slender rush-pea [*Hoffsmanseggia tenelle*]), eight mammals (blue whale [*Balaenoptera musculus*], fin whale [*Balaenoptera physalus*], humpback whale [*Megaptera novaeangliae*], sei whale [*Balaenoptera borealis*], sperm whale [*Physeter macrocephalus*], ocelot [*Leopardus pardalis*], gulf coast jaguarundi [*Herpailurus yagouaroundi*], and West Indian manatee), two birds (whooping crane [*Grus americana*] and piping plover [*Charadrius melodus*]), and five reptiles (loggerhead sea turtle, green sea turtle, leatherback sea turtle, Atlantic hawksbill sea turtle, and Kemp's ridley sea turtle).

Cheniere conducted field surveys for marine and terrestrial threatened and endangered species in June 2011 and March 2012.

Four species have been eliminated from further discussion in this EIS because suitable habitat was not identified in the vicinity of the Project based on current or protected ranges. Gulf Coast jaguarundi and ocelot are not known to occur in the Project area. Slender rush pea and south Texas ambrosia are both terrestrial species listed in Nueces County only, and terrestrial impacts associated with the Project would be outside of their known ranges. Therefore, we have determined that the Project would have no effect on these species and they are not further discussed.

4.7.1.1 Marine Mammals

Whales

Blue whales occur in all oceans of the world. They inhabit sub-polar to sub-tropical oceans and rarely occur in the Gulf of Mexico off the coast of Texas. There are only two records of blue whales from the Gulf; one stranded near Sabine Pass, Louisiana in 1926 and one stranded near Freeport, Texas in 1940 (Texas Tech University, 1997). Both identifications have been questioned. The approximate worldwide population of blue whales is 11,000-12,000, with the current North Atlantic population between 100-1,500 individuals.

Fin whales are found in the deep, off-shore waters of all major oceans but primarily at temperate to polar latitudes (NMFS, 2011). While rare in Texas one young individual was stranded on the beach at Gilchrist in Chambers County on February 21, 1951 (Texas Tech University, 1997). A highly migratory species, these whales move to high latitude feeding grounds during the spring and summer and return to southerly temperate waters for mating and calving during fall and winter.

Humpback whales occur in all oceans of the world and are distributed in the western north Atlantic from north of Iceland, Disko Bay and west of Greenland, south to Venezuela, and the tropical islands of the West Indies (Texas Tech University, 1997). The worldwide population estimate is between 5,200-5,600 individuals with approximately 800-1,000 individuals in the western North Atlantic. Humpback whales have been captured in the Florida Keys and northern Cuba with sightings occurring off the west coast of Florida and Alabama. There is only one documented observation along the Texas Coast, occurring near the Bolivar Jetty near Galveston on February 19, 1992 (Texas Tech University, 1997).

The sei whale is a medium sized baleen whale occurring primarily in offshore waters from the Gulf and Caribbean Sea northward to Nova Scotia and Newfoundland. Sei whales, like many other whales, are a migratory species that tend to occur in groups of two to five individuals. There are no known occurrences of sei whales in Texas (Schmidly, 2004).

Sperm whales typically inhabit waters 600 meters or greater in depth, and are uncommon in waters less than 300 meters deep (NMFS, 2011). Sperm whales are found in all oceans of the world in deep waters between approximately 60 degrees north and 60 degrees south latitudes. Sperm whales are the most numerous of whales in the Gulf and sightings in Texas near the coast are relatively common (Texas Tech University, 1997). Sightings of sperm whales in the Gulf are common at depths of 655 feet or greater, along submarine canyons on the edge of the continental shelf.

Although the whale species listed do not occur in relatively shallow waters such as those found near the Project, they could potentially be impacted by collisions with LNG carriers that are transiting to and from the Terminal in the open Gulf of Mexico. The probability of these species encountering LNG carriers in the open ocean would be inherently low given their ability to avoid on coming vessels coupled with their overall rarity.

Mitigation to minimize vessel strikes would be accomplished by maintaining a watch for, and taking prudent measures to avoid, impacting listed species as described in NMFS' most recent *Vessel Strike Avoidance Measures and Reporting for Mariners* (revised February 2008).

Due to the tendency for these species to remain far off-shore in very deep water, we have determined that construction and operation of the Project is not likely to adversely affect these species. NMFS affirmed its previous concurrence with this determination in a letter dated October 29, 2012.

West Indian Manatee

Manatees are found in rivers, estuaries, and coastal areas of the tropical and subtropical New World. They may be found 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. Manatees 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). Initial decline of manatee populations was a result of over hunting; however, today population declines may be attributed to collisions with power boats, entrapment in floodgates, navigation locks, fishing nets, and water pipes. Loss of warmwater habitat along with ingestion of marine debris is also a threat to the continued survival of the West Indian Manatee.

Cheniere would further minimize the impact on the manatee by implementing additional conservation measures recommended by the FWS which would include providing training on the manatee to all personnel associated with constructing and operating the Project. Manatee training information would advise contractors and staff that manatees may be found in the La Quinta Channel and include a poster to assist in identifying the mammal and instruct personnel not to feed or water the animal. Manatee training materials would include instruction to call the FWS Corpus Christi Ecological Services Field Office in the event a manatee is sighted in or near the Project area.

West Indian manatees are occasionally documented in the Corpus Christi Ship Channel, La Quinta Channel, and adjacent bays and may be attracted to warmwater outfalls associated with industrial facilities in the area during winter months (Fertl et al., 2005; Texas Marine Mammal Stranding Network, 2008). 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. With Cheniere's implementation of additional conservation measures, we have determined that construction and operation of the Project is not likely to adversely affect this species. The FWS concurred with the proposed conservation measures and the may affect, not likely to adversely affect determination in a letter dated November 5, 2013.

4.7.1.2 Sea Turtles

Five species of sea turtles inhabit the Gulf, nesting on beaches and occupying inlets and shallow bays. However, nesting sea turtles are unlikely to occur in the Project area thus, impacts on nesting turtles are unlikely. With this in mind, we determine that the Project would not adversely affect sea turtles. The most likely impact on sea turtles would be LNG carrier strikes with swimming turtles, although it would also be a rare event. Potential impacts are discussed further below.

Loggerhead Sea Turtle

In the Atlantic, the loggerhead's range extends from Newfoundland to as far south as Argentina. 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. In the eastern Pacific, loggerheads are reported from Alaska to Chile (NMFS, 2004; COE, 2003). 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, 2003).

In Texas, loggerheads are considered to be the most abundant sea turtle, favoring 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, 2003). Most loggerhead sightings have been in the northern Gulf of Mexico near jettied passes and in open water and suitable nesting habitat for this species is not available at the Project site.

Green Sea Turtle

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, 2003). Commercial harvest of eggs as food, collection of body parts to be used for leather and jewelry, and stuffing of whole small turtles are the greatest 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, and Florida. In Texas, small numbers of green sea turtles can been 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.

Adult green sea turtles forage in bays that have extensive seagrass beds and could be impacted by dredging activities when constructing the Terminal. With the exclusive use of mechanical methods and hydraulic dredges (which are not known to take sea turtles), the likelihood of a take would be significantly reduced (NMFS, 2003).

Leatherback Sea Turtle

Leatherback sea turtles 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, 2003). 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, 2003). Suitable nesting habitat for this species does not exist at the Project site. Of the five sea turtle species that occur in Texas waters, the leatherback is the species least likely to occur in the Project area.

Atlantic Hawksbill Sea Turtle

This 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, 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, 2003). 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). Although Atlantic hawksbill sightings have been recorded in Corpus Christi Bay, they are unlikely to occur in the Project area because this species prefers rocky outcroppings, coral reefs, and hard bottom areas.

The risk to hawksbill sea turtles in the Project area, while possible, would be considered unlikely due to the lack of preferred habitat (rocky shores, reefs and passes) and preferred food. With the exclusive use of mechanical methods and hydraulic dredges (which are not known to take sea turtles), the likelihood of a take would be significantly reduced (NMFS, 2003).

Kemp’s Ridley Sea Turtle

Kemp's ridley sea turtles 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, 2003). 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. This species could be a transient to the Project area between crustacean-rich feeding areas in the northern Gulf and breeding grounds in Mexico (NMFS, 2004; COE, 2003). Preferred nesting and foraging areas for this species are not found at the Project site.

The risk to a Kemp’s ridley sea turtle in the Project area would be very limited. While Kemp’s ridley sea turtles are present in the bays and could potentially be in the Terminal area, the exclusive use of mechanical methods and hydraulic dredges (which are not known to take sea turtles), would reduce the likelihood of a take significantly (NMFS, 2003).

Sea Turtle Impacts

Due to the specific nesting habitat requirements, sea turtles would not be likely to be present onshore within the Project area. In general, sea turtles would be a rare visitor to the Project area. Many of the sea turtles discussed have feeding, swimming, or resting behaviors that keep them near the surface, where they may be vulnerable to vessel strikes, especially if the turtles are cold-stunned from cold weather events. To help reduce the risk of strikes or other potential disturbances associated with the presence of LNG carriers, Cheniere would adhere to the measures outlined in the NMFS *Vessel Strike Avoidance Measures and Reporting for Mariners* (revised February 2008).

NMFS identified pile driving as having the potential to affect sea turtles. Studies have shown that the sound waves from pile driving may result in injury or trauma to fish, sea turtles, or other animals with gas-filled cavities such as swim bladders, lungs, sinuses, and hearing structures (Abbott et al., 2002). Although sea turtles would be expected to largely avoid the Project area during pile driving activities, a potential exists for sea turtles to be injured during the first several strikes of the pile driving hammer, especially if the turtles are cold-stunned from cold weather events. Cheniere would reduce impacts on listed species from pile driving by implementing the following pile driving protocols:

- An observer would be dedicated to sea turtle and marine mammal observations, responsible for monitoring species presence prior to pile driving activities;
- A 250-meter radius zone would be established and monitored for 60 minutes prior to engaging the pile driver hammer during construction. If a sea turtle or marine mammal is observed within the zone, pile driving would be delayed until the animal is observed to have left or is heading away from the established zone. If an animal dives and cannot be re-sighted, pile driving may not begin until 20 minutes after the last sighting, or until the 60-minute observation is complete, whichever is longer;
- If pile driving activity ceases for any reason, observations for sea turtles and marine mammals would resume until pile driving begins, or the 60-minute survey would be repeated;

- All animals must be allowed to exit the established zone of their own free will;
- Pile driving would not be started during nighttime hours; but if started prior to sunset, it may continue until the hammer activity ceases; and
- Cheniere would keep records of all observations and pile driving protocols, and make these records available upon request.

If the rare occurrence of the species were to overlap with the rare incidence of a spill, a turtle could be at risk due to effects on respiration, skin, blood chemistry, and salt gland function. To address the potential impacts associated with offshore spills of fuel, lubricants, or other hazardous materials, Cheniere would implement its SPCC Plan.

Dredging activities could temporarily disrupt potential foraging grounds for turtles. Cheniere proposes to dredge the marine basin and berth area using a hydraulic cutterhead dredge. Hydraulic cutterhead dredging is not known to take sea turtles by direct mortality, as with hopper dredging. Dredging activities during construction would be temporary and local in nature because dredging would be confined to the proposed turning basin and marine berth and maintenance dredging would only occur about once every three years. Dredging actions that could potentially result in injury to any sea turtles directly in the Project area would be incidental. Activities at dredge spoil placement areas would similarly not affect sea turtles since suitable nesting areas are not present in the placement areas.

With adherence to the mitigation measures identified above, we have determined that the Project is not likely to adversely affect sea turtles. The FWS concurred with this determination in a letter dated November 5, 2013 and NMFS affirmed its previous concurrence with this determination in a letter dated October 29, 2012.

4.7.1.3 Birds

Whooping Crane

The whooping crane winters in coastal Texas. Designated critical habitat for this species is located within the Aransas National Wildlife Refuge in Aransas, Calhoun, and Refugio Counties, approximately 25 miles north of the Project area. Some whooping cranes also winter on Matagorda Island, which at its closest point is approximately 13 miles from the Project area. Winter habitat consists of brackish bays, marshes, and salt flats that provide a variety of plant and animal foods such as blue crabs, clams, and berries. Whooping cranes may also occasionally use grassland swales and ponds that provide foods such as snails, crayfish, and insects. The central and eastern Panhandle also provides a major stopover area for birds migrating between summer and winter habitats.

The whooping crane has been recorded in San Patricio County, and could potentially access waters on the bay side and interior of Mustang and Padre Islands, which would be 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 in waters on the leeward side of the nearby barrier islands, we have determined that the Project is not likely to adversely affect the whooping crane. The FWS concurred with this determination in a letter dated November 5, 2013.

Piping Plover

Piping plovers inhabit shorelines along oceans, rivers, and inland lakes and nest on sandy beaches, sandbars, dunes, and silty flats. During the winter, they utilize beaches, mud and sand flats, and offshore spoil islands. The piping plover breeds on the northern Great Plains, in the Great Lakes, and along the mid- to north-Atlantic coast, and winters on the Atlantic and Gulf coasts from North Carolina to Mexico. They arrive at their Texas wintering grounds during mid- to late-July and spend a majority of their time on sand and mud flats near sandy beaches. They feed on tidal flats during low tide and Gulf beaches during high tide (COE, 2003). Decline in the piping plover population has resulted from over-hunting during the early part of the twentieth century, habitat loss or modification due to human development, alteration of river and wetland systems, and predation.

San Patricio County is one of 12 counties in Texas where concentrations of piping plover occur. Four sites in Corpus Christi Bay have been found to harbor wintering piping plover populations: Port Aransas (15 miles east of the Project area), Fish Pass (13 miles southeast of the Project area), Oso Bay (13 miles southwest of the Project area), and sites along the Gulf Intracoastal Waterway (GIWW) (COE, 2003). Several areas along the Texas coast have been identified by the FWS as essential wintering habitat for the piping plover. Essential wintering habitat for the piping plover provides the space and requisite resources necessary for the continued existence and growth of piping plover populations and consist of coastal beach, sand flat, and mud flat habitats. Critical Habitat for the wintering grounds (as opposed to breeding population Critical Habitat) has also been designated in Texas by the FWS (66 FR 36074—36078). The closest critical habitat to the Project area is Unit TX13 Sunset Lake, located approximately 4 miles southwest of the Project site.

This unit is triangle shaped, with SH 181 as the northwest boundary, and the limits of the City of Portland as the northeast boundary. The shore on Corpus Christi Bay is the third side of the triangle, with the actual boundary being mean lower low water off this shore. This unit is a large basin with a series of tidal ponds, sand spits and wind tidal flats. This unit is owned and managed by the City of Portland within a system of city parks. Some of the described area falls within the jurisdiction of the TGLO.

The piping plover habitat at the Project site would be relatively small when compared to the abundance of suitable habitat adjacent to the Terminal. Currently, piping plovers are not known to inhabit the proposed Project area and construction activities would likely result in piping plovers seeking refuge in nearby suitable habitats. To minimize impacts to piping plovers, the FWS recommended that Cheniere have a qualified biologist survey the tidal flats (piping plover habitat) at the Terminal before and after construction, submit photo documentation to the FWS that the temporarily affected tidal flats were properly restored, and have a biologist on site during construction in tidal flats to assist employees in avoiding impacts to piping plovers during construction. Cheniere would comply with these measures and would train workers through the use of a species “fact sheet” that would describe life history information, habitat characteristics, and include a photograph to help with identification.

Due to Cheniere’s implementation of the above conservation measures, we have determined that the Project is not likely to adversely affect the piping plover. The FWS concurred with the proposed conservation measures and our determination in a letter dated November 5, 2013.

4.7.2 State Listed Threatened and Endangered Species

The TPWD annotated county lists of rare species for San Patricio and Nueces Counties include 24 state listed endangered or threatened species, in addition to those species that are also federally listed and discussed above. Table 4.7-2 (see appendix D) identifies the state listed species for San Patricio and Nueces Counties. No state-protected plant species were identified within the Project area.

We have determined that 14 of these species would not be impacted by the Project because the Project is not within the known range of the species, the species has been extirpated in the Project area, there is no suitable habitat in the Project area, or the species would only occur in the Project area as an occasional transient. These species are not discussed further in the EIS. The remaining 10 state listed species could potentially occur in the vicinity of the Project. These species are discussed in the following sections.

We received several comments on the draft EIS from TPWD regarding measures to minimize impacts on state listed species including the southern yellow bat, Texas tortoise, Texas horned lizard, and indigo snake (appendix I). Comments received regarding the southern yellow bat are addressed in section 4.7.2.1 below. Cheniere indicated in its response to comments received on the draft EIS that construction personnel would receive environmental training prior to commencing work on the Project and would be instructed to notify the EI if the Texas tortoise, Texas horned lizard, or indigo snake are observed in the Project area.

4.7.2.1 Mammals

Southern Yellow Bat

The southern yellow bat (*Lasiurus ega*) is a neotropical bat that has been recorded in southern California, southern Arizona, and southern Texas in Cameron, Kleberg, and Nueces Counties. Its range may be increasing in Texas due to the rising number of ornamental palm tree plantings. This species utilizes palm trees as roosting sites and feeds on insects captured in flight. In south Texas, the southern yellow bat breeds during late winter (Davis and Schmidly, 1997).

There is potential for southern yellow bats to roost in palm trees in the Project area and forage for insects over the grasslands and coastal wetlands at night. In a comment on the draft EIS, TPWD recommended that palm trees or dead fronds in the Project area should not be cleared between May and August, to protect southern yellow bats. Cheniere indicated in its response to comments received on the draft EIS that it would endeavor to remove any palm trees between September and April and does not anticipate any removal of dead fronds. Additionally, Cheniere indicated that many of the palm trees at the Terminal site would be preserved and no palm trees occur along the Pipeline. We find these measures acceptable to minimize potential impacts. Therefore, due to the lack of contiguous habitat and the mobility of this species, we have concluded that construction and operation of the Project would not significantly impact this species.

4.7.2.2 Birds

Reddish Egret

The reddish egret (*Egretta rufescens*) is a common, permanent resident along the Texas central lower coast and is uncommon along the upper coast. It breeds along Gulf State coasts and it inhabits shallow tidal pools, saltwater bays, and marshes. Red egrets wade in shallow waters and forages for small fishes and crustaceans and commonly nests in colonies with other herons, egrets, and cormorants. Reddish egrets nest in brushy thickets of yucca and prickly pear on dry coastal islands in Texas and among mangroves in Florida (TGLO, 2004).

The Project area would be located within the reddish egret's breeding range and, potential nesting habitat does exist in the Project area. Additionally, the wetlands located in the Project area could be used for foraging; however, other abundant foraging grounds near the Project area could also be used by the species while constructing the Project. Reddish egrets were not observed in the Project area during surveys in 2011 and 2012 and their mobility would allow them to temporarily relocate to similar adjacent habitats during construction. Therefore, the Project would not significantly impact this species.

White-tailed Hawk

In Texas, population declines of white-tailed hawk (*Buteo albicaudatus*) are primarily due to grassland habitat conversion to agriculture and an increase in brushy cover within remaining open grasslands. Over the past four decades, brush removal efforts have produced more favorable habitats for this species. In the southern and central counties of Texas, and north towards Galveston, white-tailed hawk inhabit coastal grasslands. They prefer saltgrass flats near the Gulf and dry grassy mesquite-live oak savannas inland (USGS, 2004). They perch on bushes, dead trees, fence posts, and utility structures and prey on small mammals, lizards, and insects. Their breeding season is from March to May, and their nest consists of grass-lined sticks in low bushes, small trees, or cacti (National Wildlife Federation, 2004).

The white-tailed hawk is uncommon in the Project area and was not observed during field surveys in 2011 and 2012. There is potential for this species to occur in the Project vicinity; however, construction and operation of the Project would not significantly impact this species.

Wood Stork

Wood storks (*Mycteria americana*) are the largest wading birds that breed in North America. This species prefers freshwater and brackish wetlands, and nests in cypress or mangrove swamps. In Texas, the wood stork forages in prairie ponds, flooded pastures or fields, ditches and other shallow standing water including saltwater. The birds move into the Gulf States in search of mudflats and other wetlands. They formerly nested in Texas but there have been no breeding records since 1960 (TPWD, 2005). The decline of wood storks is attributed to loss of cypress swamps and also associated with a reduction in the food base (primarily small fish) necessary to support breeding colonies (FWS, 2010).

While wood storks could occur in the Project vicinity, they were not observed during field surveys conducted in 2011 and 2012. Therefore, the Project would not significantly impact this species.

4.7.2.3 Reptiles and Amphibians

Texas Tortoise

The Texas tortoise (*Gopherus berlandieri*) is a primarily vegetarian reptile that relies heavily on the fruit of the common prickly pear and other succulent plants. Its range extends from south-central Texas southward into the Mexican states of Coahuila, Nuevo Leon, and Tamaulipas. Collection of tortoises for pets led to its listing in 1977 as a protected non-game species (TPWD, 2012). This species breeds from April to September and lays its eggs deep in a hollow on the ground.

While there is marginal habitat for this species within the Project footprint, the probability of occurrence is very low due to past land disturbance including industrial and agricultural practices. Therefore, the Project would not significantly impact the Texas tortoise.

Texas Horned Lizard

The Texas horned lizard (*Phrynosoma cornutum*) or “horny toad” is found in arid and semiarid habitats in open areas with sparse vegetative cover. The horned lizard is common among loose sands or loamy soils. They range from the south-central U.S. to northern Mexico, and throughout most of Texas, Oklahoma, Kansas and New Mexico (TPWD, 2012c). They feed primarily on harvest (red) ants. The decline of the Texas horned lizard is due to multiple factors including collection for the pet trade, spread of invasive, red fire ants, changes in land use, and environmental contaminants.

The Texas horned lizard could occur in the Project area; however, due to the small amount of suitable habitat found in the Project vicinity and the large expanses of high quality habitat in adjacent areas, that the Project would not significantly impact this species.

Texas Indigo Snake

The Texas indigo snake (*Drymarchon melanurus erebennus*) is a large non-venomous snake found from southern Texas to Mexico. This species prefers sparsely vegetated areas close to permanent water sources, but is also found in mesquite savanna, open grassland area, and coastal sand dunes. They den in burrows abandoned by other animals and will eat a wide range of animals including mammals, birds, lizards, frogs, turtles, eggs, and other snakes (NatureServe, 2012). The decline of the Texas indigo snake is due primarily to habitat loss resulting from land development.

The Project area would be within the far northern range of the Texas indigo snake; however, indigo snake sightings in San Patricio County are rare. The probability of an occurrence onsite is very low and additionally, the snake is mobile, allowing it to temporarily displace to similar, adjacent habitat during Project construction. Therefore, the Project would not significantly impact this species.

Black Spotted Newt

Black-spotted newts (*Notophthalmus meridionalis*) are found along the coastal plains of south Texas and Mexico. They reside in the quiet waters of streams with abundant SAV, ponds, and ditches. Breeding habits are dependent on the amount of water available. If a water source dries up, young and adult black-spotted newts will seek shelter on land under rocks or rocky ledges (National Wildlife Federation, 2004).

In general, amphibians are sensitive to climatic factors (such as drought), habitat changes, and environmental pollutants including pesticides, petroleum hydrocarbons, and heavy metals. These factors combined with the predatory influences of non-native fish species and bullfrogs have contributed to population declines (TPWD, 2004).

The black spotted newt could occur in the Project area; however, due to the small amount of suitable habitat found in the Project vicinity and with the implementation of best management practices, as recommended by TPWD in a letter dated August 22, 2012, the Project would not significantly impact this species.

<u>South Texas Sirens</u>

South Texas sirens (*Siren* spp.) inhabit areas that are similar to the black-spotted newt, but require a year-round source of open water for aestivation (a state of dormancy) to assist in water regulation during the hottest parts of the day.

South Texas sirens could occur in the Project area; however, due to the small amount of suitable habitat found in the Project vicinity and with the implementation of best management practices, as recommended by TPWD in a letter dated August 22, 2012, the Project would not significantly impact this species.

4.7.2.4 Fish and Mollusks

<u>Opossum Pipefish</u>

The opossum pipefish (*Microphis brachyurus*) is an anadromous species, spending the majority of its time in the open ocean and returning to freshwater to spawn. The opossum pipefish can be found in low gradient creeks and medium to large rivers with dense, emergent vegetation (NatureServe, 2012). Causes of population decline include disease, poor water quality, unnatural flow, and water control structures (NMFS, 2009b). The only drainage that could provide suitable spawning and/or feeding habitat (low gradient with emergent vegetation within 30 miles of the coast) is Chiltipin Creek. However, Chiltipin Creek supports a population of longnose gar and the gars ability to thrive in turbid, warm water would be an indicator that the water quality/dissolved oxygen levels of the drainage are too poor or low to support the opossum pipefish. Additionally, downstream channel constrictions would prohibit an upstream migration. Due to this, and the fact that the Pipeline would cross Chiltipin Creek via the HDD method (avoiding direct impacts on the creek), construction and operation of the Pipeline would not significantly impact the opossum pipefish.

4.8 LAND USE, RECREATION, AND VISUAL RESOURCES

4.8.1 Terminal Facilities

4.8.1.1 Land Use

Facilities associated with the Terminal would be constructed on property located on the northern shore of Corpus Christi Bay, at the north end of the La Quinta Channel, north and east of the city of Corpus Christi in San Patricio (land-based facilities) and Nueces (marine facilities) Counties, Texas. The Terminal would be located west of the Sherwin Alumina plant on land previously used for industrial purposes.

The Terminal would be located on property owned by Cheniere that was previously an industrial site, but has since been reclaimed. Existing land uses at the site are open water and open land. Approximately 991 acres would be affected by constructing the Terminal facilities, including the marine basin and berths. Approximately 469 acres would be affected by the operation of the Terminal, Marine basin and berth, plus exclusion zones. From the total impact acreage, Terminal operations would impact approximately 225 acres and maintenance dredging would impact approximately 124 acres. Details regarding acreage impacts on land use are provided in table 4.8-1.

Table 4.8-1
Land Use Required to Construct and Operate the Terminal

Facility	Open Land		Open Water a/		Total	
	Construction (acres)	Operation (acres)	Construction (acres)	Operation (acres)	Construction b/ (acres)	Operation c/ (acres)
Terminal Site d/, e/	225	225	0	0	225	225
Marine Basin and Berth	5	5	121	119	126	124
Dredged Material Placement	437	0	0	0	437	0
Temporary Laydown Area f/	160	0	0	0	160	0
Temporary Parking Area f/	26	0	0	0	26	0
Temporary Access Roads f/	8	0	0	0	8	0
Tool and Lunch Area f/	9	0	0	0	9	0
Exclusion Zone	0	91	0	29	0	120
Total	**870**	**321**	**121**	**148**	**991**	**469**

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a/ Wetland impacts associated with the Terminal are included in open water.
b/ Construction area includes entire construction footprint, including all temporary and permanent construction areas
c/ Operational area includes the permanent Terminal site, marine basing and berth, permanent easements and exclusion zone.
d/ Acreage excludes Bauxite Disposal Bed 22 (52 acres) which is within the Project property boundary but would not be disturbed by construction or operation.
e/ Bed 24 acreage is included in the Terminal site (area would be filled with structural fill and become part of the operating area).
f/ Area used during construction only and located outside of the Terminal site.

The LNG storage tanks associated with the Terminal would be located in an area that was used for storage of bauxite ore as part of the U.S. government stockpile until 2003. Two bauxite residue beds used for the disposal of alumina processing wastes, are located on the east side of La Quinta Road for which Cheniere would have easements and lease agreements. Bauxite residues from Bed 24 were removed and placed into Bed 22. Bed 22 has been capped with clay as part of an agreement with TCEQ. There would be no direct land use impacts on Bed 22 to construct and operate the Terminal. Bed 24 would be filled with clean structural fill, purchased off-site, to planned grade and would be used as part of the Terminal facilities. The operations/maintenance building, warehouse, LNG transfer lines, and access roads to the docks would be located in a vegetated open area. Construction and operation impacts on this land would be confined to a corridor surrounding the buildings, LNG transfer piperack, and access road. The remainder of this area would remain open land. Open lands include scrub lands or unimproved lands not in use for agriculture, industry, or residences.

While constructing the Terminal, Cheniere would utilize the adjacent property to the west of the Terminal site for laydown and staging of construction materials. Additionally, a temporary employee parking area would be used to ease construction traffic congestion on La Quinta Road.

Cheniere selected two DMPAs to dispose of materials dredged during construction of the marine basin, as well as materials from maintenance dredging of the La Quinta Channel. Cheniere has indicated that they selected a site known as DMPA 2 to beneficially utilize dredged material to cap old bauxite beds which currently produce red dust under windy conditions. Cheniere would also use dredge material to fill an existing excavation area on the Alcoa property.

Construction of the Terminal would require 991 acres of land with 469 acres permanently impacted during operation. However, the majority of the Terminal facilities would be located on open land previously used for industrial purposes. The open water in the La Quinta Channel that would be utilized for the LNG marine basin would remain open water, though it would be dredged to a greater depth. The construction of the marine basin and berthing facilities would result in the conversion of approximately 5 acres of open land to open water. The mitigation of impacts on coastal marshes and wetlands as a result of the construction of the marine basin and berthing facilities is discussed in section 4.4 of this EIS. Construction of the Terminal would result in a conversion of the existing land use (open land) to industrial use. However, due to the industrial use of adjacent land and the previously disturbed nature of the area, impacts on land use from the Terminal would be minor.

4.8.1.2 Existing and Planned Residences and Commercial Developments

The Terminal would be located in an industrialized area surrounded by industrial and commercial development. There are currently no existing or planned residential developments within 0.25 mile of the Terminal.

The LNG storage tanks would be surrounded by industrial properties, and there would be no land within 0.25 mile of the Terminal site that would be available for residential development. The site would be bounded by industrial land owned by the POCCA to the west, an operating alumina facility owned by Sherwin Alumina to the east, and property owned by Alcoa to the north. All property would be zoned as industrial.

The nearest residential areas to the Terminal site are in Portland (1.3 miles west), Gregory (2.0 miles north), and Ingleside (2.9 miles east), all located in San Patricio County, Texas. The land surrounding the Terminal to the north and east has been used for processing, storage, and disposal of aluminum ore and related waste products for over 50 years. The nearest residence to any temporary construction activities is located approximately 0.6 mile northwest of the junction of La Quinta Road and SH 361. This junction is near the northwest corner of DMPA 2 that would be filled using dredged material excavated during construction. This area is not owned by Cheniere, and there would be no Project related activities at this location once the initial dredging of the marine berths were completed. Construction traffic would also use La Quinta Road to enter the Terminal site.

There are residences surrounding the Northshore Country Club in Portland, approximately 1.3 miles west of the Terminal site. Voestalpine, an Austrian steel producer, is planning to build a direct iron reduced (DRI) plant on the adjacent 1,100-acre property to the west of the Terminal site, currently owned by POCCA. The DRI plant would lie between the Terminal site and the residences near the Northshore Country Club. Due to the siting of the Terminal within an existing industrialized area and the absence of significant residential development, impacts would be consistent with the surrounding land use.

To facilitate this Project, POCCA and the COE have initiated construction work on the extension of the La Quinta Channel and began constructing a 126-acre dredge material placement area in 2010. Per website inquiry, the channel extension was completed in February 2014.

4.8.1.3 Recreation and Special Interest Areas

All of the land that would be used for the Project is privately owned. No public lands, Indian reservations, scenic areas, developed recreational facilities, parks, forests, wildlife management areas, wilderness areas, trails, or registered national landmarks have been identified in the vicinity of the proposed Terminal.

Corpus Christi Bay supports abundant marine life that drives the tourism industry in the Corpus Christi area. Recreational fishing and boating occurs in the Corpus Christi Bay and in the La Quinta 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. The recreational boating marinas closest to the Terminal include the Bahia Marina in Ingleside-on-the-Bay approximately 3 miles southeast, and the Port Aransas Municipal Marina, more than 10 miles east of the Terminal site. Common species sought by recreational anglers in the bay include redfish, speckled trout, drum, and flounder.

The Corpus Christi and La Quinta Ship Channels are actively used by commercial ship traffic, as the Port of Corpus Christi is the fifth largest commercial port in the U.S. Though total port traffic would increase (section 4.9.10), the LNG carriers would be restricted to the dredged deep water Corpus Christi and La Quinta Ship Channels while most recreational boaters utilize shallower channels of the GIWW within Corpus Christi Bay. We have determined the Project would not have any adverse impacts on recreation, including boating and fishing in Corpus Christi Bay.

4.8.1.4 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 Terminal would be constructed in a historically industrial area along the northeastern shore of Corpus Christi Bay, west of the Sherwin Alumina plant. The most prominent visual feature at the Terminal site would be three LNG storage tanks, each 181.9 feet in height from the finished grade to the top of the dome. The height from the tank floor to the top of the dome would be 177.5 feet. The outside tank diameter would be 258.5 feet. The heights of each of the three LNG storage tanks are less than the tallest structure on the adjacent Sherwin plant, which measures at 197 feet above grade.

The flare stack would be visible when in use in both day and night conditions. When flaring is not occurring, the 500-foot-high flare stack would be similar in appearance to a cell tower. The flare would be installed to accommodate emergency reliefs, facilitate maintenance purging, and start-up flaring only and would not be used during routine operation. Cheniere projects using the flare stack continuously for two to three days per year to facilitate restart of a train after a major overhaul.

The Terminal would be consistent with the industrial land use and visual resources of the area. In addition, the POCCA has plans to construct the La Quinta Trade Gateway Terminal on the property immediately west of the Terminal. The La Quinta Trade Gateway Terminal would block much or all of the visibility of the Terminal and provide a closer industrial visual feature from residences and other publicly-accessible locations. Given the existing industrial nature of this area, the limited visibility of the Terminal and the plans to develop the property west of the Terminal site, Cheniere is not proposing to implement any specific measures to further limit the visibility of the Terminal.

Impacts on visual resources resulting from the storage tanks and flare stack would be moderate and permanent; however, due to the proximity of the Terminal to other industrial structures, the storage tanks and flare stack would be consistent with the surrounding land use.

There are no residences, schools, community parks, or public areas that would be considered visually sensitive areas within 1 mile of the Terminal. The three storage tanks and elevated flare stacks would be visible on the horizon from the nearby residential subdivisions and the Northshore Country Club golf course. The current viewshed from the nearest residence is presented in figure 4.8-1. An artist rendering of the anticipated viewshed following construction of the Terminal is presented in figures 4.8-2 and 4.8-3.

The Terminal would use the minimum lighting necessary to allow personnel to safely work and inspect the equipment at the Terminal. There would be lighting along the perimeter fence as required by security regulations. Lighting on the marine jetties would be the minimum necessary for safe operation and positioned so as not to impede shipping in the channel. The lighting at the Terminal would be consistent with lighting at other industrial facilities along the La Quinta Channel and would not significantly increase light pollution in the area. Therefore, lighting and nighttime flaring would not have a significant impact on the environment. The majority of the 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 Taft Compressor Station would be located in an agricultural field with very few nearby residences. In addition, the Taft Compressor Station would be located amongst the wind turbines associated with the Papalote Creek Wind Farm and visual impacts from the station are expected to be minimal. The Sinton Compressor Station would not be visible from residences or publicly-accessible locations and is expected to have no visual impacts. Other aboveground facilities associated with the Pipeline, such as valves and meter and regulation stations, would be fairly small and not expected to have a significant impact on visual resources.

Figure 4.8-1 Current View of the Terminal Site from California Drive, Portland

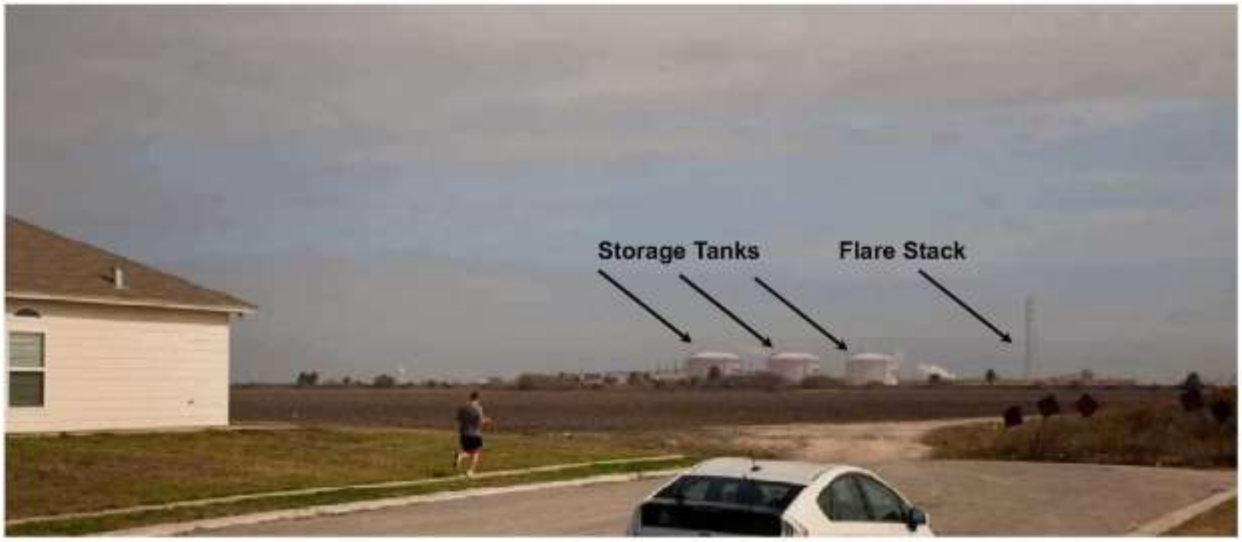

Figure 4.8-2 Post-construction Visual Simulation View of the Terminal Site from California Drive, Portland

Figure 4.8-3 Visual Simulation View of the Terminal at Night from California Drive, Portland

4.8.1.5 Coastal Zone Management

The Terminal would be located within the Texas CZMP. All activities or developments that affect Texas's coastal resources and require a federal permit or license are evaluated for compliance with the CZMA through the "federal consistency" process. In addition to the RRC, Cheniere has consulted with the TGLO's Coastal Coordination Council which determined that the Project exceeds their threshold for CZMA consistency review and deferred review to the RRC. Cheniere has received a CZMA determination for the Project in conjunction with its review and comments to the COE as part of the COE Section 10/404 permitting process (see section 1.6.9). The RRC issued Cheniere its Coastal Zone Consistency determination, along with its 401 Water Quality Certification on November 14, 2013. COE issued Cheniere a Section 10/404 permit on July 23, 2014.

4.8.2 Pipeline Facilities

4.8.2.1 Land Use

The Pipeline would originate at the proposed Terminal and would run northwest for approximately 23 miles towards the city of Sinton and would terminate at the Tennessee Gas M&R Station. The entire Pipeline would be located within San Patricio County, Texas. The Pipeline would be collocated, overlapped, or paralleled with existing rights-of-way for approximately 19.73 miles, or 86 percent of the total route. Locations where the Pipeline would be collocated with existing rights-of-way are provided in table 4.8-2.

Table 4.8-2
Locations Where the Pipeline Would be Collocated, Overlap, or Parallel with Existing Rights-of-Way

Mileposts	Existing Easement	Direction from Existing Right-of-Way	Segment Length (miles)
0.0 – 0.64	La Quinta Road	Adjacent to the west side of the road.	0.64
0.80 – 2.16	Equistar Pipeline, Koch Pipeline, Tejas Pipeline, and El Paso Pipeline	Adjacent to the north side of the Koch Pipeline.	1.36
2.36 – 2.90	Overhead power line and water line	Adjacent to north side of the water line.	0.54
2.90 – 7.90	County Road 78, overhead electric power line and water line	Adjacent to north side of the water line. County Road 78 is about 300 feet south to about MP 5.0 and about 100 feet south thereafter.	5.00
7.90 – 8.94	County Road 78	Pipeline would be about 500 feet south of County Road 78 (not adjacent).	1.04
11.05 – 13.22	Koch Pipeline	Adjacent to the north side of the Koch pipeline.	2.17
13.22 – 13.78	Koch Pipeline, private road, & water line	Adjacent to the north side of the water line. The private road is about 50 feet south.	0.56
13.79 – 14.45	El Paso Pipeline	Adjacent to the north side of pipeline.	0.66
14.45 – 16.04	County Road 2921, El Paso Pipeline, Valero Pipeline	Adjacent to the east side of Valero Pipeline. County Road 2921 is about 1,000 feet west.	1.59
16.04 – 17.80	Valero Pipeline, (2) El Paso Pipelines	Adjacent to the east side of Valero Pipeline.	1.76
18.31 – 22.72	Valero Pipeline, (2) El Paso Pipelines	Adjacent to the east side of Valero Pipeline.	4.41
	Total		**19.73**

There are no existing residences or buildings within 50 feet of the Pipeline construction work area. A Southwestern Bell fenced facility lies within 60 feet outside the proposed Pipeline, and a building within the Southwestern Bell facility lies within 75 feet of the proposed Pipeline. This building does not house permanent employees.

Constructing the Pipeline and associated aboveground facilities would impact a total of approximately 420.7 acres of land. Land use impacts associated with the Pipeline facilities would include disturbance of existing land use, the creation of new easements, and the conversion of some land to a different land use type. Construction of the Pipeline would require a 120-foot-wide construction work area, which would be comprised of a 50-foot-wide permanent easement for operation and a 70-foot-wide temporary easement for construction. ATWS would be necessary in certain locations along the Pipeline route for setup and construction across roadways, waterbodies, wetlands, and other features that require specialized construction procedures (section 2.4.3.2). Pipeline construction and operational impacts on land use are listed in table 4.8-3.

Construction of the Pipeline, including only the construction right-of-way and ATWS, would impact 348.1 acres of land. Approximately 20.1 acres of access roads would be used during construction. Details on temporary and permanent access roads to be used for the Pipeline are listed in table 4.8-4. Constructing the two compressor stations would impact approximately 24.1 acres (6.9 acres for the Taft Compressor Station and 17.2 acres for the Sinton Compressor Station). Constructing the six proposed M&R stations would impact approximately 10.8 acres of land. Cheniere would also utilize a 17.4-acre parcel of land previously used for temporary construction support as a temporary pipe storage and contractor yard. This yard would be located on the Pipeline route southeast of the City of Taft on County Road 78.

Agricultural lands would be the primary land use impacted by construction of the Pipeline and associated facilities. To accommodate deep tilling in agricultural fields, Cheniere would bury the approximately 18 miles of Pipeline that cross actively cultivated agricultural fields to a minimum depth of 4 feet. In all other areas Cheniere would bury the Pipeline to a minimum depth of 3 feet. Additional depth of cover would be provided where requested by landowners during right-of-way negotiations. Final designed burial depth would be determined during the detailed design phase based on land usage anticipated at the time of construction. The remaining land uses that would be impacted by the Pipeline consist of open lands and industrial lands.

Cheniere would obtain easements from landowners prior to constructing the Pipeline. Easements would give Cheniere access to properties and the rights to construct, operate, and maintain the Pipeline and establish a permanent right-of-way. Cheniere would compensate landowners for use of their land. The easement agreements would specify compensation for the loss of use during construction, loss of nonrenewable or other resources, and allowable uses and restrictions on the permanent right-of-way after construction. These restrictions could include prohibition of construction of aboveground structures including house additions, garages, patios, pools, or any other objects not easily removable; roads or driveways over the pipeline; or the planting and cultivating of trees or orchards within the permanent easement. The areas used as temporary construction right-of-way and ATWS would be allowed to revert to preconstruction uses with no restrictions. Land uses, including agricultural and open land, would be allowed to continue within the permanent easement and would not be permanently impacted. As discussed in the Environmental Compliance and Monitoring Section landowners would typically be notified three to five days prior to the start of construction activities, unless earlier notice is requested during easement negotiations. Landowners would be provided with written notification that would include information regarding how landowners can contact Cheniere in the event that there are complaints or incidences that need to be addressed during construction. The written notification to landowners would also provide the number for the FERC Hotline if landowners do not get an adequate response from Cheniere.

Cheniere would construct and maintain the Pipeline according to measures contained in our Plan and Procedures. Vegetation on the permanent right-of-way in non-agricultural areas would be maintained by mowing, cutting, or trimming as necessary. Agricultural areas would return to a preconstruction cultivated state, and would thus not result in a change in land use. The Pipeline right-of-way would be allowed to revegetate; however, in wetlands and in the required 25-foot vegetation maintenance buffer adjacent to waterbodies, a 10-foot strip centered on the Pipeline would be mowed. Additionally, trees within 15 feet of the pipeline with root systems that could compromise the integrity of the pipe would be selectively removed. The frequency of vegetation maintenance would depend upon the vegetative growth rate; however, it would not exceed that prescribed in our Plan and Procedures.

Table 4.8-3
Land Use Affected by Construction and Operation of the Pipeline and Associated Facilities

Facility	Agricultural		Open		Industrial		Total	
	Construction (acres)	Operation (acres)	Construction (acres)	Operation (acres)	Construction (acres)	Operation (acres)	Construction (acres)	Operation (acres)
Pipeline a/	244.6	107.0	65.1	28.7	11.4	6.6	321.1	142.3
Additional Pipeline Temporary Workspace	21.6	0.0	4.3	0.0	1.1	0.0	27.0	0.0
Liquefaction M&R Station, Pig Receiver and MLV (MP 0.0)	2.0	1.6	0.0	0.0	0.0	0.0	2.0	1.6
MLV (MP 14.5) b/	0.2	0.2	0.0	0.0	0.0	0.0	0.2	0.2
Pig Launcher and MLV (MP 23.0) c/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Taft Compressor Station	6.9	5.8	0.0	0.0	0.0	0.0	6.9	5.8
Sinton Compressor Station	0.0	0.0	17.2	7.3	0.0	0.0	17.2	7.3
Texas Eastern M&R Station	2.1	2.1	0.0	0.0	0.0	0.0	2.1	2.1
Tejas Pipeline M&R Station	0.0	0.0	2.4	2.4	0.0	0.0	2.4	2.4
NGPL M&R Station	1.3	1.0	0.0	0.0	0.0	0.0	1.3	1.0
Transco M&R Station	1.0	0.9	0.0	0.0	0.0	0.0	1.0	0.9
Tennessee Gas M&R Station	2.0	2.0	0.0	0.0	0.0	0.0	2.0	2.0
Access Roads	14.3	12.7	4.0	0.0	1.8	0.0	20.1	12.7
Contractor and Pipe Yards ^{4}	0.0	0.0	0.0	0.0	17.4	0.0	17.4	0.0
Project Total	**296.0**	**133.3**	**93.0**	**38.4**	**31.7**	**6.6**	**420.7**	**178.3**

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a/ Construction impacts include construction right-of-way and temporary workspace. Operational impacts include new permanent right-of-way and aboveground facilities.

b/ MLV would be within the construction right-of-way for the Pipeline and is already accounted for above, with a portion outside of the permanent pipeline easement.

c/ Pig launcher and MLV at MP 23.0 would be within the Tennessee Gas M&R station.

d/ The contractor and pipe yard would be located partially on the Pipeline right-of-way, and therefore this portion of the acreage is accounted for in the Pipeline acreage.

Table 4.8-4
Access Roads to be Used for Construction and Operation of the Pipeline and Associated Facilities

Access Road ID	Milepost	Temp / Perm	Existing / New	Existing Surface Type	Improvements Needed	Land Use	Length (feet)	Width (feet)	Acres
TAR #1	0.4	Temporary	Existing	Gravel	Add Rock and Maintain	Open	180	25	0.1
TAR #2	1.3	Temporary	Existing	Gravel	Add Rock and Maintain	Industrial	3,200	25	1.8
TAR #3	11.0	Temporary	Existing	Clay	Add Rock and Maintain	Agricultural	2,750	25	1.6
TAR #4	19.8	Temporary	Existing	Gravel	Add Rock and Maintain	Open	6,780	25	3.9
PAR #1	0.0	Permanent	New	N/A	Add Rock and Maintain	Agricultural	180	25	0.1
PAR #2	14.5	Permanent	Existing	Clay	Add Rock and Maintain	Agricultural	1,200	25	0.7
PAR #3	21.5	Permanent	Existing	Clay	Add Rock and Maintain	Agricultural	5,050	25	2.9
PAR #4	22.3	Permanent	Existing	Clay	Add Rock and Maintain	Agricultural	15,450	25	8.9
PAR #5	7.6	Permanent	New	N/A	Add Rock and Maintain	Agricultural	110	25	0.1
	Total								**20.1**

N/A = Not Applicable.

4.8.2.2 Existing and Planned Residences and Commercial Developments

The Pipeline would be located primarily in agricultural areas. There are currently no existing or planned residential developments within 0.25 mile of the Pipeline. Additionally, there are no existing residences or occupied buildings within 50 feet of the Pipeline construction work area. Therefore, the Pipeline would not adversely impact existing residences or planned developments.

4.8.2.3 Recreation and Special Interest Areas

All of the land that would be used for the Pipeline is privately owned. No public lands, Indian reservations, scenic areas, developed recreational facilities, parks, forests, wildlife management areas, wilderness areas, trails, or registered national landmarks have been identified in the vicinity of the proposed Pipeline; and would therefore, not be impacted.

4.8.2.4 Visual Resources

Constructing and operating the Pipeline may impact visual resources by altering the terrain and vegetation patterns during construction or right-of-way maintenance and from the presence of new aboveground facilities. The landscape setting along the proposed Pipeline route is generally flat. No designated viewing locations are present in areas overlooking the route. The majority of the Pipeline would be located within agricultural land and/or adjacent to existing rights-of-way, which would not alter the landscape of the region.

Impacts on visual resources due to the Pipeline would be primarily temporary and short-term, occurring during construction. The terrain over the majority of the Project area is flat; therefore, during construction, the cleared and graded right-of-way, as well as construction equipment would be visible from surrounding residences and local roads. Following the completion of construction activities, areas disturbed for construction would be restored and agricultural activities that previously occurred in the area would be able to resume. Therefore, the construction and operation of the Pipeline would not result in long-term visual impacts.

Cheniere would also install several aboveground facilities including M&R stations, as well as two compressor stations. M&R stations are typically small and would be expected to have only minor visual impacts. No sensitive visual resources such as schools, residential subdivisions, or public land were identified within the Project area or in the vicinity of the proposed aboveground facilities. Therefore, the visual impact of the aboveground facilities would not have a significant impact on the aesthetics of the landscape along the Pipeline route.

Taft Compressor Station

The Taft Compressor Station would be located southeast of Taft, Texas, in a rural agricultural area northwest of the intersection of County Road 78 and County Road 77. The nearest residence to the Taft Compressor Station would be located about 0.7 mile away. The compressor station would be located within the Papalote Creek Wind Farm, and the nearest wind turbine would be approximately 200 feet east of the proposed compressor station. There are several other wind turbines within 0.25 mile of the station. The wind turbines are visible from several miles away. Other man-made features on the landscape include high-tension power lines along County Road 78, grain silos, and both operating and abandoned oil and gas facility structures. The Taft Compressor Station would be consistent with other infrastructure in the area and would be less visible and noticeable than the nearby wind turbines. The compressor station would be enclosed with chain link fencing. Because the station is sited within the windfarm, visual screening measures would not be necessary.

Sinton Compressor Station

The Sinton Compressor Station would be located more than 1 mile from the nearest public access point and would not be visible to the public. Therefore, no plans are proposed to implement measures to visually screen the Sinton Compressor Station.

The majority of the land impacted by the Pipeline would be allowed to revert back to preconstruction conditions following completion of construction. Some areas, including those used for aboveground facilities, would be permanently converted to an industrial use. The implementation of the measures discussed above, including collocation of the majority of the Pipeline, would result in minimization of impacts on land use. Most impacts on visual resources would be temporary and associated with the construction phase of the Pipeline.

Construction and operation of aboveground facilities would have a minor impact on visual resources. The Taft Compressor Station would be sited in an area dominated by wind turbines and the Sinton Compressor Station would not be visible from the nearest residence or public access point. Overall, land use, recreation, and visual resource impacts associated with the Pipeline would be minor.

4.8.2.5 Coastal Zone Management

The Pipeline would be located within the Texas CZMP. Details regarding permit applications and jurisdiction over construction activities in this zone are discussed in section 4.8.1.5 above.

4.9 SOCIOECONOMICS

Due to the regional extent of socioeconomic impacts, this section discusses impacts in regards to the Project as a whole, rather than Terminal and Pipeline facilities individually. If the proposed Project was constructed, several potential socioeconomic impacts could occur as a result. Potential impacts from construction activities would include increased local population levels, and increased demands on public services and housing, increased local expenditures for materials during construction, increased payroll and sales tax revenues, local job opportunities, and increased property values. Socioeconomic impacts are detailed below.

4.9.1 Population

Both major Project components, the Terminal and the Pipeline, would be within the Corpus Christi Metropolitan Statistical Area (CCMSA), which includes Nueces and San Patricio Counties. Nearby towns and cities include Gregory, Portland, Corpus Christi, Taft, Sinton, Ingleside, Ingleside-on-the-Bay, and Aransas Pass.

Table 4.9-1 below provides a summary of selected population and socioeconomic statistics for the State of Texas. Nueces County had population growth from 2000 to 2010 of 8.5 percent, and the population of San Patricio County declined by 3.5 percent during the same time period.

Table 4.9-1
Existing Population in the Project Area

Demographic	San Patricio County	Nueces County
2010 Population	64,804	340,223
2000 Population	67,138	313,645
Percent Population Change (2000 to 2010)	-3.5	8.5

Source: U.S. Bureau of the Census 2012.

The total Project-related population change would equal the total number of non-local workers, plus any family members accompanying them. During peak construction periods (approximately 72 months), Terminal and Pipeline construction workforces, combined would include a total of approximately 2,100 workers; peaking at approximately 3,300 workers. As discussed further in sections 4.9.2 and 4.9.6, Cheniere would utilize predominantly local workers during construction, and employ a relatively small full-time operational staff at the Terminal. We determined Project-related impacts on the regional population would be short-term and negligible; however, more localized impacts on the nearby community of Portland could be significant when the workforce is at its peak.

Representatives from Cheniere met with area of Chambers of Commerce on three occasions: March 22, 2012, October 17, 2012, and December 4, 2012 to address the potential impacts of construction and operation of the Project. In addition, Cheniere representatives have met regularly since 2010 with local community officials, specifically all of the area mayors and councils (Ingleside, Port Aransas, Aransas Pass, Corpus Christi, Portland, and Gregory), the regional Economic Development Corporations, and non-governmental organizations such as environmental groups, civic organizations, and educational facilities.

Constructing the Project would result in a short-term, moderate increase to the local population and operating would result in a negligible long-term increase. Therefore, we determined the Project, as a whole, would not significantly impact local population size.

4.9.2 Economy and Employment

In 2012, the government (19 percent), trade/transportation/utility (19 percent), education/health services (17 percent), and the leisure and hospitality (12 percent) service sectors were the largest economic sectors in the CCMSA. The largest employers in the CCMSA were the petrochemical industries, health care industry, government and military, and agriculture.

The nearest municipality to the Terminal is Portland (pop. 15,099). With a civilian employed population of 7,196, Portland has no heavy industry and little commercial or retail business within the town limits; however, there are several industrial facilities located within 10 miles. The largest industries in Portland are educational services, and health care and social assistance (U.S. Census Bureau, 2012).

The 2012 American Community Survey 5-year estimate for per capita income in San Patricio County was $22,958 and the unemployment rate was 8.0 percent. According to the same 5-year estimate, the per capita income in Nueces County was $23,660 and the unemployment rate was also 8.0 percent (see table 4.9-2). The 2012 American Community Survey 5-year estimate for unemployment rate in the CCMSA was 7.9 percent, comparable to the State of Texas rate of 7.7 percent (U.S. Census, 2012). Constructing the Project would positively impact employment opportunities in both San Patricio and Nueces Counties. The Project would not have an adverse impact on the unemployment rate, and could decrease the unemployment rate due to hiring a predominantly local workforce where feasible.

Table 4.9-2
Existing Income and Employment Conditions in the Project Area

Income Characteristic	Nueces County	Corpus Christi	San Patricio County	Portland	Ingleside	Gregory
2008-2012 Per Capita Income (dollars)	$23,660	$23,692	$22,958	$27,907	$22,773	$13,545
2008-2012 Population Below Poverty Level (percent)	18.4	18.1	16.6	11.6	11.4	30.9
2008-2012 Unemployment Rate (percent)	8.0	7.9	8.0	4.3	7.7	10.1
Wholesale Trade Receipts 2010 ($1,000)	$23,402	N/A	$1,824	N/A	N/A	N/A
Retail Receipts 2010 ($1,000)	$65,139	N/A	$11,864	N/A	N/A	N/A
Accommodation and Food Service Receipts 2010 ($1,000)	$20,018	N/A	$3,347	N/A	N/A	N/A

N/A = Not Available

Sources
Census 2008 – 2012 American Community 5-Year Estimates, American Fact Finder, http://factfinder2.census.gov/.
U.S. Department of Labor, Bureau of Labor Statistics (unemployment rate at time of filing), http://www.bls.gov/data

Construction of the Terminal would require an estimated 1,800 workers over a duration of approximately 72 months. Construction of the Pipeline and associated facilities, including compressor stations, would require an estimated 300 workers over approximately 9 months. A large national or regional pipeline construction firm would likely be selected to construct the Pipeline. However, there is a substantial local pipeline construction capability that could be employed through the Pipeline contractor.

Construction schedules for the Terminal and Pipeline are planned to overlap in 2016 for a period of approximately 9 months to 1 year (the length of time that it would take to construct the Pipeline facilities). The total number of workers on the Project when the two phases overlap would be approximately 2,100; peaking at approximately 3,300 workers. Pipe and equipment for the Pipeline would be staged several miles from the Terminal and construction activities associated with the Pipeline immediately adjacent to the Terminal would be limited to the time necessary to install the Pipeline and would not encroach directly on the Terminal facility.

During operation, Cheniere anticipates adding approximately 175 full-time positions, split into three daily shifts, to operate the Terminal facilities, and approximately six full-time employees to operate the Pipeline and associated compressor stations. Cheniere estimates that staffing for operating the Terminal would result in very little relocation due to the local availability of a large, skilled workforce. This is due primarily to the local refining and petrochemical sectors as well as training programs at local colleges. Operating the Pipeline and compressor stations would also draw primarily from the local workforce. A few management level employees could relocate to the area for the operations phase. The Project workforce and anticipated construction schedules for the Terminal and Pipeline facilities are summarized in table 4.9-3.

Table 4.9-3
Number of Workers During Project Construction and Operation

Facility	Number of Workers During Construction	Number of Workers at Peak Construction	Total Duration (months)	Number of Permanent Workers During Operation
Terminal	1,800	3,000	72	250
Pipeline	300	300	9-12	6
Total	**2,100**	**3,300**	**72**	**256**

Cheniere estimates that construction and other pre-operational activities associated with the Project would result in beneficial cumulative impacts on business activity ranging from $7.4 to $10.0 billion to the local economy, $22.9 to $31.0 billion to the Texas economy, and $34.4 to $46.4 billion to the U.S. economy. Over the first 25 years of Project operation, the cumulative impacts of operations of the Project on business activity and tax receipts is estimated to contribute $27.6 billion to the local economy, $35.0 billion to the Texas economy, and $38.0 billion to the U.S. economy.

Additionally, according to Cheniere the Project is estimated to contribute indirectly to the creation of approximately 50,000 new jobs annually across the U.S. through increased natural gas exploration, drilling and production. These secondary effects are expected to result in total economic benefits of approximately $327 billion over 25 years for the U.S. economy.

4.9.3 Property Values

Construction and operation of the Project would not require the relocation or involuntary displacement of any residences or businesses. The Terminal would be constructed on property owned by Cheniere that was previously an industrial site, but has since been reclaimed. The Pipeline and compressor station facilities would be primarily on agricultural lands, and no existing residences or buildings are located within 50 feet of the Pipeline construction work area. Cheniere owns that land of the proposed location of the Taft Compressor Station. Cheniere is in negotiations to acquire the land for the proposed Sinton Compressor Station.

No significant impacts on property values are anticipated from construction and operation of the Project. The Terminal would be located in an industrialized area surrounded by industrial and commercial development, and there are currently no existing or planned residential developments within 0.25 mile of the Terminal. The LNG storage tanks would be surrounded by industrial/commercial properties, and there would be no land within 0.25 mile of the Terminal site that would be available for residential development. The Pipeline would be located primarily in agricultural areas, and there are no existing residences or buildings within 50 feet of the Pipeline construction work area. Additionally, there are currently no existing or planned residential developments within 0.25 mile of the Pipeline (see section 4.8). The proposed pipeline may have an impact on the property values of the surrounding area; however, valuation depends on many factors, including the size of the parcel, the values of adjacent properties, the presence of other utilities, the current value of the land, and the current land use. Similar pipeline rights-of-way are present in the surrounding areas; therefore, the property values in the general area of the proposed pipeline would already reflect the presence of underground facilities.

Property taxes are generally based on the actual size of the land. Construction of the pipeline would not change the general use of the land, but would preclude construction of aboveground structures on the permanent right-of-way. If landowner feels that the presence of a pipeline easement reduces the values of his or her land, resulting in an overpayment of property taxes, he/she may appeal the issue of the assessment and subsequent property taxation to the local property tax agency. This issue is beyond the scope of this EIS.

We received a comment regarding the potential for insurance premium adjustments or loss of coverage associated with the proposed Project. This landowner didn’t explicitly specify if they would be directly affected by the Pipeline, or if they reside near the Terminal. If they reside near the Terminal, no potential loss or coverage of insurance is expected. Assuming the landowner may be affected by the pipeline, we cannot assess how their property and or any insurance they hold may be affected. Research conducted and included in the Constitution Pipeline Project draft EIS[22], which consisted of the FERC staff calling insurance agents, suggested that potential for a residential action would depend on several factors, including terms of the individual landowners policy and terms of the applicant’s policy (in this case Cheniere). As indicated in the Constitution EIS, we were unable to confirm exclusively under what conditions a landowner’s insurance policy could change.

4.9.4 Construction Payroll and Material Purchases

The Project would have an estimated total construction payroll of approximately $1.0 to $1.5 billion over the 60-month construction period. The expenditures of Project personnel on local goods, services, and labor would create several cycles of income as wages are spent and re-spent by succeeding recipients. The average monthly payroll impact of the Project on local communities would be an estimated $1.4 million. Because the region supports an extensive manufacturing and processing infrastructure for the chemical and petro-chemical industries, many construction materials and equipment supplies are locally available, and Cheniere anticipates that purchases of local construction materials would range from approximately $785 million to $1.06 billion.

4.9.5 Tax Revenues

The overall sales tax on goods and services in the CCMSA is 8.25 percent. No state income tax is levied in the State of Texas. Construction of the Project would result in increased sales tax revenues for the State of Texas, San Patricio and Nueces Counties, Gregory-Portland Independent School District, Taft Independent School District, and Sinton Independent School District. The Project is estimated to contribute approximately $1.6 to $2.8 million per month in

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local tax revenues. Additionally, the total tax revenues from construction and other pre-operational activities associated with the Project is estimated to contribute $96.8 million for Corpus Christi, $578.4 million for the State of Texas, and $1.4 billion for the U.S. New revenues would provide direct and indirect benefits to local residents throughout the life of the Project.

4.9.6 Housing

A sufficient supply of temporary housing units is available in San Patricio and Nueces Counties. However, due to the size of Portland non-local workers would likely have to disperse to the surrounding communities to meet all of the housing needs during construction. The number of temporary and permanent housing units available is provided in table 4.9-4 below. The Corpus Christi area is a popular tourist destination in south Texas and there are many hotels, campgrounds, and recreational vehicle (RV) parks in the area.

Table 4.9-4
Temporary Housing Units Available in the Project Area

Housing Characteristics a/	Nueces County	Corpus Christi	San Patricio County	Portland	Ingleside	Gregory
2006-2010 Number of Vacant Housing Units b/	17,233	13,192	4,652	251	398	22
2006-2010 Vacancy Rate (percent)	12.5	10.8	17.5	8.1	11.9	17.5
2010 Number of Vacant Housing Units for Seasonal, Recreational, or Occasional Use (percent) c/	5,431	3,844	1,237	19	44	2
2006-2010 Number of Renter Occupied Housing Units	49,790	46,689	7,791	2,186	1,118	190
2012 Number of Hotels/Motels	184	126	38	8	8	0
2012 Number of Campgrounds and RV Parks	24	11	17	1	1	0

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a/ Housing Unit: *According to the U.S. Census Bureau's website glossary, a* housing unit may be a house, apartment, mobile home *or trailer*, group of rooms, or a single room occupied as separate living quarters *or vacant, intended for occupancy as separate living quarters*. Separate living quarters are those in which the occupants live separately from other individuals in the building and which have direct access from outside the building or through a common hall.

b/ Vacant Housing Unit: According to the U.S. Census Bureau*'s website glossary*, a housing unit is vacant if no one is living in it at the time of enumeration, unless its occupants are only temporarily absent. Units temporarily occupied at the time of enumeration entirely by people who have a usual residence elsewhere are also classified as vacant.

c/ Seasonal, Recreational, or Occasional Use Housing Unit: According to the U.S. Census Bureau*'s American Community Survey 2008 Subject Definitions*, seasonal, recreational, or occasional use housing units include vacant units used or intended for use only in certain seasons *or* for weekends or other occasional use throughout the year. *Seasonal units include those used for summer or winter sports or recreation, such as beach cottages and hunting cabins. Seasonal units also may include quarters for such workers as herders and loggers.* Interval ownership units, sometimes called shared ownership or time-sharing condominiums, are included in this category.

Sources

U.S. Census Bureau, Census 2010, http://factfinder.census.gov (vacant housing units and vacancy rate).
U.S. Census Bureau. 2000. Profiles of General Demographic Characteristics: 2000 Census of Population and Housing.
YellowBook 2012: Number of "Hotels and Motels" and "Campgrounds and RV Parks" as advertised on www.yellowbook.com. Actual numbers may vary.

Seasonal tourism, recreation, and port activity are major components of the local economy in the Corpus Christi metropolitan area. Because of the importance of these economic sectors, businesses, local governments, and economic development agencies have worked to ensure adequate availability of housing to accommodate these activities. Projected increases in tourism for the area are already being addressed by growth in local temporary housing capacity.

The Project is not expected to require construction of new residences. However, because of the creation of high paying direct and indirect jobs, the value of local housing is likely to increase markedly due to the demand for higher-quality, owner-occupied and rental housing. The majority of workers associated with the Project is anticipated to come from within 50 miles of the Project area and would not require temporary housing. Therefore, constructing the Project is not expected to significantly impact local market conditions.

4.9.7 Removal of Agricultural, Pasture, or Timberland from Production

Construction and operation of the Terminal would not require the removal of agricultural land, pasture, or timberland from production; therefore, no adverse impacts would occur. Although construction of the Pipeline would temporarily impact agricultural land, these lands would be allowed to revegetate and return to preconstruction conditions and uses. Therefore, no significant impact on potential revenue from agricultural lands is anticipated, as overall production should not be affected.

Some areas, including those used for the Taft Compressor Station as well as other aboveground facilities, would be permanently converted to industrial land and thus, would require the removal of agricultural land from pasture. However, these impacts would be minor, and Cheniere would compensate landowners for the use of their land and for production loss.

4.9.8 Public Services

San Patricio and Nueces Counties have well-developed infrastructure that would provide health, police, fire, emergency, and social services near the Project site. Public health infrastructure in San Patricio County includes one community hospital, five health centers, and 10 private clinics. Nueces County has seven hospitals: Care Regional Medical Center in Aransas Pass, Texas, is located approximately 7 miles from the proposed Terminal; and Christus Spohn Hospital, Corpus Christi Medical Center, Driscoll Children's Hospital, Kindred Hospital, Northwest Regional Hospital, and Doctors Regional Medical Center, are all in Corpus Christi, Texas, approximately 13 to 16 miles from the proposed Terminal.

The cities of Corpus Christi, Portland, Gregory, Ingleside, Sinton, and Taft each have a police department and fire department near the Project area. The nearest hospital, Care Regional Medical Center, is equipped with a trauma center and has 75 beds. Additional hospitals with trauma centers are located nearby in Corpus Christi. The nearest police station, located approximately 2.4 miles from the proposed Terminal, is the Portland City Police Department. Other law enforcement and emergency services are provided by the Nueces County Sheriff’s Department and San Patricio County Sheriff's Office in Sinton, Texas. The Portland City Fire Department is the nearest fire service. Emergency services, including medical, fire, and law enforcement, are available through the “911” service and can address large scale emergency responses, as needed.

The Terminal facility is located in an unincorporated area that is not served by a municipal fire department; therefore, Cheniere is exploring contracting with the Refinery Terminal Fire Company to provide firefighting and emergency services in the area.

The Terminal site lies within the Gregory-Portland Independent School District and the Pipeline crosses through Gregory-Portland Independent School District, Taft Independent School District, and Sinton Independent School District. Table 4.9-5 below provides information on the school districts and school enrollment in the Project area. For the 2010-2011 school year there were 74,517 students enrolled in 130 schools in the Project area. Most of the Project construction personnel would not be expected to relocate their entire families to the Project area; therefore, the Project would not have a significant impact on local schools.

Table 4.9-5
School Districts and School Enrollment in the Project Area

School District	Number of Schools					Enrollment	
	Total	Elementary	Middle / Jr. High	High School	Other	Total	% Change (2008/2009 to 2010/2011)
San Patricio County							
Aransas Pass ISD	5	3	1	1	0	1,784	-10.9%
Gregory-Portland ISD	7	4	2	1	0	4,291	-0.6%
Ingleside ISD	5	3	1	1	0	2,152	-3.2%
Mathis ISD	4	1	2	1	0	1,799	-0.3%
Odem-Edroy ISD	3	1	1	1	0	1,085	-6.0%
Sinton ISD	4	1	1	1	1	2,150	-0.6%
Taft ISD	3	1	1	1	0	1,136	-5.8%
Nueces County							
Agua Dulce ISD	2	1	0	1	0	342	-7.6%
Banquete ISD	3	1	1	1	0	795	-5.2%
Bishop Cons. ISD	4	2	1	1	0	1,234	+3.4%
Calallen ISD	4	2	1	1	0	3,836	-0.1%
Corpus Christi ISD	58	37	11	6	4	38,242	-0.6%
Driscoll ISD	2	1	1	1	0	294	+8.1%
Flour Bluff ISD	6	3	2	1	0	5,526	-1.3%
London ISD	2	1	0	1	0	394	+48.1%
Port Aransas ISD	3	1	1	1	0	568	+5.6%
Robstown ISD	6	3	2	1	0	3,301	-2.2%
Tuloso-Midway ISD	5	2	1	1	1	3,550	+4.6%
West Oso ISD	4	2	1	1	0	2,038	-2.3%

ISD = Independent School District

Public services and municipal programs are readily available in the Project vicinity. In addition to the emergency services described above, the area has several public libraries, museums, parks and recreation facilities. There are abundant recreational opportunities at the many national, state, and local parks in the Corpus Christi area.

The Corpus Christi area is home to several academic institutions of higher learning. Texas A&M University - Corpus Christi and Del Mar College are located in Corpus Christi. Del Mar College is a community college offering associate level and technical courses, while Texas A&M University - Corpus Christi is an institution offering both undergraduate and graduate degrees. Port Aransas hosts the University of Texas at Austin Marine Science Institute, an institution fostering both undergraduate and postgraduate oceanographic studies.

Impacts on public services would be greatest while constructing the Project, as the greatest number of workers would be present. City of Portland public services, as those closest to the Terminal, would be in highest demand during construction. While public services in Portland may not be sufficient to accommodate the increased demand when the workforce is at its peak, public services in the surrounding areas would be sufficient. Through cooperation and coordination with local law enforcement and health care providers, the Project would not significantly burden local public services.

4.9.9 Environmental Justice

Environmental justice considers disproportionately high and adverse impacts on minority or low-income populations in the surrounding community resulting from the programs, policies, or activities of federal agencies. Items considered in the evaluation of environmental justice include human health or environmental hazards, the natural physical environment, and associated social, economic, and cultural factors. Environmental justice analysis is conducted in compliance with Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations*.

Under Executive Order 12898, each federal agency must ensure that public documents, notices, and hearings are readily available to the public. The mailing list for the Project was initiated when the FERC's NOI was issued, and has been continually updated during the EIS process. All property owners affected by the Project, as identified by Cheniere, received the notices about the Project without any distinction based on minority or income status. The distribution list for the EIS included local newspapers and libraries; and all landowners, miscellaneous individuals, and environmental groups who provided scoping comments or asked to remain on the mailing list.

The majority of impacts associated with the Project would result from construction and operation of the Terminal facilities, as presented throughout this EIS. The nearest residential area is located more than 1 mile from the Terminal and consists of a golf course community (Northshore Country Club). Impacts associated with the Pipeline facilities are primarily associated with construction and operation of the compressor stations. There are no residences located within 0.5 mile of either the Sinton or Taft Compressor Stations, and the closest residential areas are more than 3 miles and 1.4 miles, respectively.

Table 4.9-6 presents the general ethnic mix and economic status of San Patricio County, and Nueces County, Texas based on data from the U.S. Census Bureau (2012). Nueces and San Patricio Counties have a lower percentage of Black and Asian populations than the State of Texas as a whole. However, both Counties have a higher percentage of people of Hispanic or Latino origin than the rest of the state.

In order to evaluate information more specific to the area affected by the Terminal and Pipeline, FERC assessed environmental justice statistics at the U.S. Census tract level, which is the smallest geographic census unit for which information was available.

Table 4.9-6
Minority Populations in Census Tracts within 0.5 mile of the Project

State/County/Census Tract	White (non-Hispanic)	Hispanic	Black	Asian	Native American	Other	Two or more races
TEXAS	45.3	37.6	11.5	3.8	0.3	0.1	0.6
NUECES COUNTY a/	32.8	60.7	3.7	1.6	0.2	0.1	0.9
SAN PATRICIO COUNTY	42.2	54.2	1.8	0.9	0.1	0.1	0.6
Census Tract 105 b/	6.0	93.3	0.0	0.0	0.0	0.0	0.7
Census Tract 107	52.6	41.5	2.1	3.4	0.0	0.0	0.5
Census Tract 108 b/	16.7	82.7	0.3	0.0	0.1	0.0	0.2
Census Tract 109	43.9	55.3	0.0	0.0	0.0	0.0	0.7
Census Tract 110	22.1	73.0	4.6	0.0	0.0	0.0	0.3

Source: U.S. Bureau of the Census 2012

a/ No tract information is presented for Nueces County, as all Project facilities would be located within Corpus Christ Bay, greater than 0.5 mile from the nearest inhabited census tract

b/ Project would be within 0.5 mile of the tract, but would not be located directly within the tract

The communities in the immediate vicinity of the Project area do not show any fundamental characteristics that would differentiate them from Nueces or San Patricio Counties, or the State of Texas as a whole (see table 4.9-7). While a relatively high percentage of the population lives below the poverty level in Census Tracts 105 and 108, these tracts would not be directly crossed by the Project. Additionally, there are no aboveground facilities within 0.5 mile of these tracts. All of the other census tracts within which the Project would be located have fewer people below the poverty level than the State of Texas or the county; therefore, low income populations would not be disproportionately impacted. Similarly, the percentage of minority populations within some of the census tracts (Census Tracts 105, 108, and 110) are higher than that for the Project counties. As stated, Census Tracts 105 and 108 are not directly crossed by the Project, and only a small portion of the Pipeline would cross Census Tract 110. All of the other tracts in which the Project would be located have fewer minority populations than the county; therefore, minority populations are not disproportionately impacted. The location of the Terminal and compressor stations in relation to the low income and minority populations in the Project area are provided in table 4.9-7.

Table 4.9-7
Poverty and Minority Populations in Census Tracts within 0.5 mile of the Project

State/County/Census Tract	Facility	Percent Below Poverty	Percent Minority
TEXAS	Terminal, Pipeline, Taft Compressor Station, Sinton Compressor Station	17.4	54.7
NUECES COUNTY a/	Terminal	18.4	67.2
SAN PATRICIO COUNTY	Terminal, Pipeline, Taft Compressor Station, Sinton Compressor Station	16.6	57.8
Census Tract 105 b/	Pipeline	30.8	94.0
Census Tract 107	Terminal, Pipeline, Taft Compressor Station	10.0	47.4
Census Tract 108 b/	Pipeline	21.6	83.3
Census Tract 109	Pipeline, Sinton Compressor Station	14.9	56.1
Census Tract 110	Pipeline	15.8	77.9

Source: U.S. Bureau of the Census 2012

a/ No tract information is presented for Nueces County, as all Project facilities would be located within Corpus Christ Bay, greater than 0.5 mile from the nearest inhabited census tract
b/ Project would be within 0.5 mile of the tract, but would not be located directly within the tract

Contractors working on the Project would be required to comply with applicable equal opportunity and non-discrimination laws and policies. The criteria for all positions would be based upon qualifications without regard to age, race, creed, or sex, and in accordance with applicable, federal, state, and local employment laws and policies. Disproportionate, adverse impacts on minority or low-income populations would not occur as a result of constructing or operating the Project. Furthermore, the Project is expected to provide a beneficial economic impact on local communities through employment opportunities, construction payroll expenditures, purchases of construction goods and materials, local expenditures by workers, and increased tax revenues, regardless of race or income group.

The FERC staff held one public scoping meeting in the Project area to provide residents, municipalities, special interest groups, and federal and state regulatory agencies an opportunity to comment on the Project. The date and location of the meeting was included in the NOI. Throughout this document we identify impacts on environmental resources that potentially may have a direct or indirect effect on the local population, including air quality (see section 4.11.1), water resources (see section 4.3), and hazardous materials (see section 4.2). We have not identified any disproportionately high or adverse human health or environmental effects on minority and low-income communities or Native American groups.

With the implementation of Cheniere's construction plans, we have determined that the construction and operation of the Project would not have a significant adverse impact on the local population including low-income and minority populations.

In a comment on the draft EIS (appendix I), the EPA recommended that FERC assess whether there are any potentially disproportionate impacts on communities within the following census block groups: 484090105002, 484090105001, 484090108004, 484090108003, 484090108001, 484090110001, 484090110004, and 484090110002. Of the block groups identified, the first five correspond to census tracts 105 and 108 which, as stated in above, are not crossed by the Project and are not located within 0.5 mile of any of the aboveground facilities. The remaining three block groups identified occur within tract 110. As stated above, a small portion of tract 110 would be crossed by the Pipeline, but impacts would not be anticipated to be disproportionate, particularly because impacts of pipeline construction are considered temporary. Therefore, FERC has determined that there would be no disproportionate impacts on low income or minority populations as a result of the Project.

4.9.10 Transportation and Traffic

4.9.10.1 Terminal Facilities

Land Transportation

The Terminal site is accessible via public roadways. It would be located on La Quinta Road, which intersects SH 35 and SH 361 in Gregory. From Gregory, US 181 provides southern access to Portland, Corpus Christi, and Interstate 37 (I-37), and northern access to Sinton and US 77. The city of San Antonio is 150 miles northwest of Gregory via I-37 and Houston is 210 miles north via US 77/59.

South of Gregory, existing roads would provide land access to the Terminal site via SH 35, SH 361, and La Quinta Road. La Quinta Road, which is a private road currently used as access to the adjacent Sherwin Alumina facility, would provide primary access to the Terminal during both construction and operation. All Terminal traffic must access La Quinta Road via the SH 35 eastbound frontage road, which requires all traffic entering the site to turn right from the SH 35 eastbound frontage road onto La Quinta Road. All traffic exiting the site would turn right from La Quinta Road onto the SH 35 eastbound frontage road. Personnel and deliveries driving from Aransas Pass would travel west on SH 35 to Portland, exit Broadway, perform a U-turn and proceed east on the SH 35 frontage road, which is the same direction as traffic from Corpus Christi. Vehicles leaving the site and traveling to Aransas Pass would proceed easterly on the SH 35 frontage road, and vehicles traveling to Corpus Christi would also travel easterly on the SH 35 frontage road, but would U-turn under SH 35 at the SH 361 intersection and travel west on SH 35.

Based on 2010 traffic data from the Texas Department of Transportation (TxDOT), approximately 32,000 vehicles per day traveled SH 35 near the exit for La Quinta Road. No official level of service ratings have been assigned to the roads in the Project vicinity.

There would be an increase in heavy truck traffic and workforce traffic to the Terminal site during the Terminal construction phase. Cheniere estimates an average of 26 to 36 deliveries of construction materials per day, with a peak of 44 to 59 trips per day. The estimated daily construction traffic would equate to approximately 1,620 to 2,268 trips to and from the Terminal during an average month of construction, including all worker vehicles, deliveries, and other construction traffic. During peak construction, Cheniere would anticipate approximately 2,700 to 3,645 vehicle trips per month to and from the site. Based on available traffic count data, constructing the Terminal would not be expected to significantly impact traffic flow on SH 35, as this volume represents a temporary daily increase in traffic of 2 to 3 percent. To help mitigate increases in traffic, a parking area for construction workers is planned near SH 361 at the Sherwin Alumina exit, from which the construction workers would be carried by a bus through the Sherwin Alumina property to the rear entrance of the Terminal site. This arrangement would reduce traffic on La Quinta Road during peak hours.

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

Cheniere would consult with the TxDOT and other local entities responsible for transportation planning, including San Patricio and Nueces Counties and the cities of Gregory and Portland, to determine if a Project-specific construction transportation plan is necessary.

Operating the Terminal would require an estimated 250 employees, split between 3 daily shifts. The additional traffic generated by operational employees would not result in a significant increase in traffic volume on area roadways because the increase would be less than 1 percent of the daily traffic volumes in the area.

Overall, impacts on land transportation would primarily occur during construction of the Terminal. During construction, Cheniere would minimize impacts on traffic via the use of busses to transport workers to the site. Additionally, the increase in traffic while constructing the Terminal would be temporary and would only slightly increase traffic in the area. During operation of the Terminal, the increase in traffic volume would be negligible and would not result in a perceptible overall increase in area traffic.

Marine Transportation

The Port of Corpus Christi is the fifth largest port in the U.S. in tonnage. In 2009, the volume of ship and barge activities (total of 5,160 ship calls) declined approximately 14 percent from 2008. In 2010, the Port of Corpus Christi handled 5,768 ship calls, including 416 ships carrying dry cargo, 992 tankers, and 4,360 barges. The top three inbound commodities in 2010 were crude oil, fuel oil, and gas oil, while the top outbound commodities were gasoline, fuel oil, and diesel.

The La Quinta Channel is the site of the Kiewit Offshore Industries marine fabrication yard, DuPont Chemical Company, Occidental Chemical Company, and the Sherwin Alumina Company. Traffic consists of rigs and platforms, tank ships and barges carrying chemicals and products to and from the chemical plants, and ore and alumina carriers (ships and barges) to and from Sherwin Alumina.

The ferries at Port Aransas operate 24 hours a day, 365 days a year, typically departing every 10 to 20 minutes. Additionally, Corpus Christi Bay is utilized by commercial fishing and shrimping boats, and recreational boaters; however, the majority of recreational boaters use the GIWW channels (see section4.8.1.3).

Commercial vessel traffic (less than 18-foot draft) traverses 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 crafts dock at Harbor Island and use either the ship channel or Aransas Channel, and the Aransas Pass Outer Bar Channel to access the Gulf of Mexico. Although this is a significant fleet of small boats, they typically do not use the Corpus Christi Channel and would only be affected by LNG carrier traffic for the period of time the

LNG carrier is in the 4 nm along Outer Bar Channel. Aransas Pass also has a shipyard, but traffic related to this facility would not be significant as compared to the normal volume of fishing boats and other small crafts in the area.

The distance from the sea buoy off Aransas Pass to the Terminal's marine berths would be about 19.7 nm. The LNG carrier total U.S. territorial water route consists of an approximately 7.0 nm Safety Fairway transit from the U.S. Territorial Sea Boundary to the Aransas Pass Sea Buoy, thence approximately 4.6 nm to the entrance of the Jetty Channel, thence approximately 1.5 nm to the Corpus Christi Channel, thence approximately 9.0 nm to the La Quinta Channel, and thence approximately 4.6 nm up the La Quinta Channel to the proposed Terminal LNG carrier marine berths.

Cheniere estimates piloted channel transit times in each direction for an LNG carrier would be between three and four hours, including docking and undocking operations, between the sea buoy of Aransas Pass and the Terminal. 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 Channel. A moving safety and security zone would be established that would essentially limit deep draft traffic to a one-way pattern when LNG carriers are in the channel, though it would not be expected to adversely impact overall traffic patterns.

The majority of vessel traffic that enters Corpus Christi Bay, via either the ship channel or the GIWW, is bound for the Port of Corpus Christi. With the ship channel entrance and the intersection with the GIWW both located east of the entrance to the La Quinta Channel, transiting LNG carriers could have a transient effect on vessel traffic flow in Corpus Christi Bay within that section of the channel. The majority of other vessel traffic consists of tug and barge tows utilizing the GIWW. Their potential to intersect with the LNG carrier route would be for a relatively short distance as the tug and barge tow route and the LNG carrier route would overlap for approximately 1.5 nm between the GIWW intersection with the ship channel and the branch to the La Quinta Channel. Ship traffic, although subject to the restrictions of the moving safety and security zone around the transiting LNG carrier, would generally share the Corpus Christi Channel between the Aransas Pass Sea Buoy and the entrance of the La Quinta Channel, a distance of approximately 15 nm.

The Port Aransas ferry system crosses the Corpus Christi Ship Channel within approximately 0.6 nm of the cut between San Jose Island and Mustang Island. Typically, four to six ferryboats operate during daylight hours. However, when LNG carriers would be transiting; one LNG carrier entering the Corpus Christi Ship Channel once every one to two days would not be anticipated to have a significant effect on the Port Aransas ferry operations. Cheniere has estimated that a single ferry trip may be potentially delayed up to a maximum of 20 minutes due to the passage of an LNG carrier. According to TxDOT, 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 LNG carriers under normal conditions.

We received a comment in response to the draft EIS from a landowner located along the Corpus Christi Ship Channel who is concerned about increased ship movement and the effect it would have on the seawall (appendix I). Cheniere responded to the comment on August 22, 2014, and indicated that it has been in contact with the landowner to discuss the concerns. We note that the landowner's comment indicates that the deterioration of the seawall and erosion of the land has been occurring over the past decade.

Industrial facilities in the Corpus Christi area accommodate a wide range of shipping activity. The Terminal is expected to receive approximately 200 to 300 LNG carrier visits each year once it becomes operational. Each LNG carrier visiting the Terminal would be under the guidance of a licensed member of the Aransas-Corpus Christi Pilots who is aboard the vessel for the entire transit between the sea buoy and the Terminal. The LNG carriers would be moving at reduced channel transit speeds determined to be safe to maintain proper maneuverability by the vessel's master and the pilot. Because LNG is a relatively light cargo due to it being less than half the density of water, LNG carriers carrying a volume of cargo equivalent to that of an oil tanker or bulk carrier of similar capacity would actually displace significantly less water than loaded vessels of similar size. Additionally, the underwater hull form design of most LNG carriers is streamlined to achieve the higher speeds necessary to minimize the at-sea voyage times. This has the further effect of reducing these vessels' comparative bow waves and wakes magnitude caused by displaced water movement during slower channel transit speeds.

The seawall deterioration and land erosion identified by the landowners is a pre-existing issue that is ongoing. Due to all of the aforementioned reasons, transiting LNG carrier traffic associated with the Terminal is not anticipated to be a perceptible contributor to this issue. Cheniere has indicated that it would continue its engagement of other users of the channel to promote responsibly safe vessel movement operations.

4.9.10.2 Pipeline Facilities

Land Transportation

The 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 pipeline and the proposed crossing method for each road are listed in table 4.9-8. The two pipeline compressor stations would be located approximately 3 miles north of Sinton and 2 miles southeast of Taft. The Sinton Compressor Station would be accessible from a private access road off of US 77 and the Taft Compressor Station would be accessible via County Road 78.

Constructing the pipeline would require approximately 300 workers. An additional six employees would be necessary to operate the Pipeline and associated compressor stations. Construction traffic in and out of compressor station sites and yards would result in localized increases in traffic volumes but existing traffic in the area is generally limited and the increased traffic from construction is expected to be minor.

Table 4.9-8
Roadways Crossed by the Pipeline

Roadway Name	Milepost	Roadway Type	Jurisdiction	Construction Crossing Method
La Quinta Road	0.0	Paved	County	Bore
US 181 / SH 35	1.9	Paved	Federal / State	HDD
CR 2986	2.9	Paved	County	Bore
CR 3667	5.0	Unpaved	County	Bore
CR 3567	6.2	Paved	County	Bore
CR 1612	7.5	Paved	County	Bore
CR 77	7.9	Paved	County	Bore
CR 3365	8.5	Unpaved	County	Bore
SH 893	9.6	Paved	State	Bore
SH 631	10.0	Paved	State	Bore
CR 1944	10.4	Paved	County	Bore
CR 2965	13.2	Unpaved	County	Bore
US 181	15.1	Paved	Federal	Bore
CR 1210	16.1	Unpaved	County	Bore
CR 2921	16.9	Unpaved	County	Bore
SH 188	17.0	Paved	State	Bore
Marathon Road	18.8	Paved	City	Bore
US 77	20.2	Paved	Federal	Bore

Constructing the Pipeline would result in some minor, short-term impacts on area roadways along the 23-mile route. Short-term impacts on traffic flow could occur where the Pipeline would be installed beneath roads due to safety precautions for workers crossing and working in the vicinity of the road crossings. However, these crossings would be constructed via bore and would have no long-term impacts on traffic patterns or road conditions.

Construction traffic in and out of the compressor station sites and 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 necessary, traffic control personnel would be utilized to manage traffic in areas of active construction, but this would typically only be required for large trucks entering or exiting the Pipeline workspaces and the traffic impacts would be of short duration. Cheniere would repair any damage to public roadways caused by construction equipment. Operation of the Pipeline and associated facilities would require an additional workforce of six people which would not have an impact on traffic in the area.

4.10 CULTURAL RESOURCES

Section 106 of the NHPA, as amended, requires that the FERC take into account the effects of its undertakings on historic properties, and afford the ACHP an opportunity to comment. The steps in the process to comply with Section 106, outlined in the ACHP's implementing regulations at 36 CFR 800, include consultations, identification of historic properties, assessment of effects, and resolution of adverse effects. Activities related to consultation and/or Project coordination for both the Terminal and Pipeline facilities are presented for the Project as a whole, below. Field survey activities and the results of investigations to identify and evaluate cultural resources that are completed to date are discussed separately below.

4.10.1 Consultations

We sent copies of our NOI for this Project to a wide range of stakeholders, including the ACHP, U.S. Department of the Interior (DOI) National Park Service, DOI Bureau of Indian Affairs (BIA), the Texas SHPO, and Indian tribes which may have an interest in the Project area. The NOI contained a paragraph about Section 106 of the NHPA, and stated that we use the notice to initiate consultations with the SHPO, and to solicit their views, and those of other government agencies, interested Indian tribes, and the public on the Project's potential effects on historic properties. No comments on cultural resources issues were received in response to our NOI.

Through a review of Cheniere's application, and independent research, we identified Indian tribes that historically used or occupied the Project area, and may attach religious or cultural significance to historic properties in the APE, in accordance with Section 101(d)(6)(B) of the NHPA. In addition to sending our NOI to potentially interested Indian tribes, we wrote letters to the 12 tribes listed on table 4.10-1 on January 9, 2013, describing the Project and requesting comments. No tribes responded to the letters.

Table 4.10-1
Indian Tribes Contacted

Tribes Contacted by the FERC Through the NOI and January 9, 2013 Letters	Tribes Contacted by Cheniere by January 13, 2012 Letters	Responses
Alabama Coushatta Tribe of Texas, c/o Carlos Bullock, Chair		No responses filed to date.
Apache Tribe of Oklahoma, c/o Louis Maynahonah, Chair		No responses filed to date.
Caddo Nation of Oklahoma, c/o Brenda Edwards, Chair	Caddo Nation, c/o Robert Cast, THPO a/	No responses filed to date.
Comanche Nation of Oklahoma, c/o Michael Burgess, Chair		No responses filed to date.
Jicarilla Apache Tribe of New Mexico, c/o Levi Pesata, President		No responses filed to date.
Kickapoo Traditional Tribe of Texas, c/o Juan Garza, Chair		No responses filed to date.
Kiowa Tribe of Oklahoma, c/o Ron Twohatchet, Chair		No responses filed to date.
Lipan Apache Tribe of Texas, c/o Bernard Barcema. Chair		No responses filed to date.
Mescalero Apache Tribe of New Mexico, c/o Mark Chino, President		No responses filed to date.
Tonkawa Tribe of Oklahoma, c/o Donald Patterson, President	Tonkawa Tribe, c/o Miranda Nax'ce Allen, Museum and NAGPRA Assistant b/	No responses filed to date.
Wichita and Affiliated Tribes of Oklahoma, c/o Stratford Williams, President	Wichita and Affiliated Tribes, c/o Leslie Standing, President	No responses filed to date.
Ysleta Del Sur Pueblo of Texas, c/o Frank Paiz, Governor		No responses filed to date.

a/ THPO = Tribal Historic Preservation Officer
b/ NAGPRA = Native American Graves Protection and Repatriation Act

In addition to our consultation program, Cheniere also communicated with Indian tribes it thought may have an interest in the Project area. On January 13, 2012, Cheniere sent a letter to the Southern Plains Regional Office of the BIA requesting information about Indian tribes that should be contacted about the Project. The BIA confirmed that the appropriate tribes that should be contacted included the Alabama-Coushatta Tribe, Caddo Nation, Tonkawa Tribe, and Wichita and Affiliated Tribes. Cheniere contends that it contacted the Alabama-Coushatta Tribe concerning its proposed LNG import terminal in 2003, at the same location as the current Project, and the tribe indicated that the Project area was outside of their ceded lands. Cheniere sent letters dated January 13, 2012 to the Caddo Nation, Tonkawa Tribe of Oklahoma, and Wichita and Affiliated Tribes requesting information about effects the Project may have on traditional cultural properties. Cheniere has not filed any responses to its communications with Indian tribes.

Cheniere also consulted with the THC, representing the SHPO. Cheniere had been communicating with the SHPO since 2003, regarding its original LNG import terminal proposal.

4.10.2 Overview and Survey Results

4.10.2.1 Terminal Facilities

On August 10, 2004, the SHPO indicated that the State Marine Archaeologist had reviewed the submerged area where Cheniere proposed to excavate and construct its marine berth for the originally proposed LNG import terminal and determined that much of the area had been previously surveyed and the rest was very shallow, therefore, "the project may proceed without further underwater archaeological survey." Cheniere's consultant, Tetra Tech, wrote a letter to the SHPO on May 21, 2012, requesting concurrence that the previous cultural review was still valid for the newly proposed LNG export proposal, because the basic location and design of the marine berth had not greatly changed. The SHPO concurred on May 25, 2012.

Upland portions of the proposed Terminal site were first surveyed by Historic Preservation Associates (Cheniere contractor), and reported in 2004. That survey identified 11 archaeological sites along the bluff edge (Klinger, 2004). A second survey report in 2004 by PBS&J (Cheniere contractor) inventoried about 79 acres within the Terminal site. Nine of the sites originally recorded by Historic Preservation Associates were relocated by PBS&J, plus three new archaeological sites and an isolated find were identified (Turner, 2004b). PBS&J tested six of the sites originally recorded by Historic Preservation Associates (Turner, 2004a). The prehistoric sites were shell middens, usually found eroding from the bluffs, with limited faunal materials and chipped stone artifacts.

One site (41SP35), however, contained an historic component, identified as the archaeological remains of the so-called Taft Ranch Mansion. The Taft Ranch began as the Fulton Cattle Company in 1871, and was controlled after 1900 by Charles Taft, half-brother to future U.S. President William Taft. In 1907, Joseph Green, the Taft Ranch foreman, oversaw the construction of a mansion and ranch headquarters, known as La Quinta, at the location of 41SP35. The mansion burned down in 1938.

PBS&J was of the opinion that none of the sites within the Terminal tract were eligible for the NRHP. The SHPO agreed on August 24, 2004.

In May 2012, Tetra Tech (Cheniere contractor) inventoried about 4.2 acres at the proposed Terminal, relocated 10 of the previously recorded sites, and found three new sites. Again, all of the sites were evaluated as not eligible for the NRHP (Tetra Tech, 2012). Tetra Tech submitted the report of these investigations to the SHPO on August 8, 2012, who accepted it and agreed with the recommendations, in a letter dated August 15, 2012.

Tetra Tech, on behalf of Cheniere, wrote a letter to the SHPO dated June 20, 2012, requesting that no additional archaeological surveys be required for two temporary extra workspace areas associated with construction of the Terminal: 1) a laydown area west of La Quinta Road; and 2) worker parking area within the former Sherwin aluminum plant area east of the Terminal. The laydown area had been previously examined for cultural resources for the proposed Corpus Christi La Quinta Container Terminal Project (Ricklis, 1999), and the parking lot would be located on former industrial land. On July 3, 2012, the SHPO stamped a copy of that letter with the statement: "No historic properties affected Project may proceed;" indicating that no additional archaeological investigations needed to done at the proposed laydown and parking areas.

On August 8, 2012, Tetra Tech wrote a letter to the SHPO, requesting permission not to conduct archaeological surveys at the proposed DMPA 2 covering 385 acres and the borrow pit covering 90 acres. It was Tetra Tech's opinion that those areas were previously disturbed and had a low potential to contain cultural resources. The SHPO agreed on August 15, 2012 that no historic properties would be affected in those areas; and work at the DMPA 2 and borrow pit could proceed as planned.

Tetra Tech wrote another letter to the SHPO on April 12, 2013, that identified five ancillary work areas proposed for use during construction of the Terminal, covering a total of about 114 acres, where additional archaeological surveys should not be required because these areas have a low potential to contain historic properties that may be adversely affected by the Project. These areas include:

- Area A – Tool and Lunch Area – covering about 9 acres on the east side of the Terminal, next to an industrial pond that is part of the aluminum plant complex;
- Area B – Temporary Laydown Area North – covering about 50 acres on the west side of La Quinta Road;
- Area C – Temporary Laydown Access – covering about 8 acres combined at four locations off of La Quinta Road;
- Area D – Temporary Parking Area – covering about 26 acres east of the Laydown Area 1 identified in the June 20, 2012 letter; and
- Area E – La Quinta Road Utility Corridor – covering about 21 acres along La Quinta Road south from South Gregory Road (SR 361).

On April 22, 2013, the SHPO stamped a copy of Tetra Tech's April 12, 2013 with the statement: "No historic properties affected Project may proceed." This means that no additional cultural resources investigations are necessary at temporary workspace Areas A, B, C, D, and E.

4.10.2.2 Pipeline Facilities

The original pipeline route proposed by Cheniere for its LNG import project, and analyzed in our March 2005 EIS in Docket Nos. CP04-37-000 and CP04-44-000, was 23-miles-long, with eight proposed M&R stations at interconnections for other existing natural gas pipeline systems. Within two reports filed in 2004, PBS&J documented surveys that covered all but 2.1 miles of that original route (Perkins and Latham 2004; Perkins 2004). No archaeological or historic sites were recorded during those surveys. The SHPO accepted those reports in letters dated March 25 and July 8, 2004 and agreed that no historic properties were identified in the areas inventoried. On May 21, 2012, Tetra Tech wrote the SHPO a letter to confirm that the previous surveys were still valid for the current Project proposed by Cheniere in Docket No. CP12-508-000, and the SHPO concurred on May 25, 2012.

The newly proposed pipeline route in Docket No. CP12-508-000 differs from the originally proposed route at about six locations, totaling approximately 3.5 miles. In May 2012, Tetra Tech conducted a cultural resources inventory of various segments along the newly proposed pipeline route from approximately MP 3.0 to 5.0, MP 9.0 to 11.0, MP 18.1 to 18.3, and MP 22.9 to 23.3; the location of the newly proposed Taft Compressor Station; and four alternative locations for the Sinton Compressor Station. No cultural resources were recorded. Tetra Tech conveyed the report to the SHPO on August 8, 2012, who accepted it and agreed with the recommendations in a letter dated August 15, 2012.

The only segment of the newly proposed pipeline route that was not surveyed by PBS&J in 2004 or by Tetra Tech in 2012 was from about MP 0.5 to 0.9. However, this segment is within the tract proposed for the La Quinta Trade Gateway Terminal that was previously investigated (Ricklis, 1999). It is also within Laydown Area #1, identified in Tetra Tech's June 20, 2012 letter to the SHPO, that the SHPO agreed did not require additional archaeological survey. .

Tetra Tech's June 20, 2012, letter to the SHPO also requested permission not to conduct archaeological surveys at the proposed Sinton Compressor Station (Alternative 5) at approximately MP 22.5 on the pipeline route. This 30-acre tract of rangeland was characterized as having a low potential to contain historic properties. The SHPO concurred on July 3, 2012, that no historic properties would be affected within this area.

4.10.3 Unanticipated Discoveries

On August 7, 2012, Tetra Tech submitted an updated *Plan and Procedures for Addressing Unanticipated Discoveries of Cultural Resources and Human Remains*. Cheniere also filed a copy of this plan with its application to the FERC. The SHPO concurred that this plan was acceptable on August 15, 2012, and we agree.

4.10.4 Compliance with the NHPA

No traditional cultural resources, burials, or sites of religious significance to Indian tribes were identified in the APE by the National Park Service, BIA, SHPO, Cheniere, Tetra Tech, or the Indian tribes contacted by the FERC. We agree with the SHPO that no historic properties would be affected within the APE at the Terminal and along the Pipeline route. Because we and the SHPO agree that the Project would have no effect on historic properties, we have completed the process of complying with Section 106 of the NHPA. The undertaking can proceed if authorized; the ACHP does not need to comment, and we do not have to submit any additional information about this Project, or further consult with the ACHP, in accordance with its implementing regulations for Section 106, at 36 CFR 800.5(b) and (c)(1). After consultations, we conclude that the Project would have no effect on Native American traditional cultural properties or religious sites, and therefore, we have completed compliance with Section 101(d)(6) of the NHPA.

4.11 AIR QUALITY AND NOISE

4.11.1 Air Quality

Air quality would be affected by construction and operation of the Project. Though 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 Terminal and compressor stations. This section of the EIS addresses the construction- and operation-based emissions from the Project, as well as projected impacts to air quality and applicable regulatory requirements.

4.11.1.1 Regional Climate

The Project area climate (humid subtropical) 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 1981 to 2010 show that daily average high temperatures range from 67°F during January to 94°F during August. Daily average low temperatures range from 47°F during January to 75°F during August. The record minimum and maximum temperatures are 11°F and 109°F, respectively. The annual average precipitation amounts to approximately 32 inches, with a monthly maximum of 5 inches in September. At least a trace of precipitation occurs on 77 days during the year, on average (NOAA, 2013a).

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, 2013b). 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 (Corpus Christi Windsurfing Association, 2013).

4.11.1.2 Existing Air Quality

Ambient Air Quality Standards

The EPA has established National Ambient Air Quality Standards (NAAQS) for six pollutants: SO_2, CO, ozone (O_3), nitrogen dioxide (NO_2), particulate matter (PM) including PM less than 10 microns in diameter (PM_{10}) and PM less than 2.5 microns in diameter ($PM_{2.5}$), 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, Rule §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 4.11-1.

Table 4.11-1
Ambient Air Quality Standards

Pollutant	Averaging Period	Primary NAAQS	Secondary NAAQS	Texas NGLC
O_3	8-hour (2008) a/	0.075 ppm	0.075 ppm	-
CO	1-hour b/	35 ppm	-	-
	8-hour b/	9 ppm	-	-
NO_2	1-hour c/	100 ppb	-	-
	Annual d/	53 ppb	53 ppb	-
$PM_{2.5}$	24-hour e/	35 µg/m^3	35 µg/m^3	-
	Annual f/	12 µg/m^3	15 µg/m^3	-
PM_{10}	24-hour g/	150 µg/m^3	150 µg/m^3	-
Lead	3-month h/	0.15 µg/m^3	0.15 µg/m^3	-
SO_2	1-hour i/, j/	75 ppb	-	-
	3-hour b/	-	0.5 ppm	-
	30-minute	-	-	0.4 ppm k/
H_2S	30-minute	-	-	0.08/0.12 ppm l/

µg/m^3 = micrograms per cubic meter; ppm = parts per million; ppb = parts per billion
NGLC = net ground-level concentration

a/ Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years.
b/ Not to be exceeded more than once per year.
c/ The 98th percentile of daily maximum 1-hour average concentrations, averaged over 3 years.
d/ Annual arithmetic mean.
e/ The 98th percentile of 24-hour concentrations, averaged over 3 years.
f/ Annual arithmetic mean, averaged over 3 years.
g/ Not be exceeded more than once per year on average over 3 years.
h/ Not to be exceeded.
i/ The 99th percentile of daily maximum 1-hour concentrations, averaged over 3 years.
j/ 24-hour and annual SO_2 NAAQS revoked in 2010 (75 FR 35520); however, standards remains in effect until one year after an area is designated attainment or nonattainment for the 1-hour standard, except in areas designated nonattainment for the 1971 standard, where the 1971 standards remains in effect until implementation plans to attain or maintain the 2010 standard are approved.
k/ Net ground-level concentration not to be exceeded at the property boundary.
l/ Net ground-level concentration of 0.08 ppm not to be exceeded on property normally occupied by people and net ground-level concentration of 0.12 ppm not to be exceeded on property that are not normally occupied by people.

GHGs occur in the atmosphere both naturally and as a result of human activities, such as the burning of fossil fuels. These gases are the integral components of the atmosphere's greenhouse effect that warms the earth's surface and moderates day/night temperature variation. In general, the most abundant GHGs are water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and O_3. On December 7, 2009, the EPA defined air pollution to include the mix of six long-lived and directly-emitted GHGs, finding that the presence of the following GHGs in the atmosphere may endanger public health and welfare through climate change: CO_2, CH_4, N_2O, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

As with any fossil fuel-fired project or activity, the Project would contribute 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. 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[23]. To obtain the CO_2e quantity, the mass of the particular compound is multiplied by the corresponding GWP, the product of which is the CO_2e for that compound. The CO_2e value for each of the GHG compounds is summed to obtain the total CO_2e GHG emissions.

Air Quality Control Regions and Attainment Status

Air Quality Control Regions (AQCRs) are areas established for air quality planning purposes in which implementation plans describe how ambient air quality standards will 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 Terminal and Pipeline) is located in the Corpus Christi-Victoria Intrastate AQCR. Likewise, 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.

Air Quality Monitoring and Existing Air Quality

Air quality monitors are located throughout the state to determine existing levels of various air pollutants. Air quality monitoring data obtained from the EPA AirData and the TCEQ Air Quality Data databases for the period 2009-2011 were reviewed by Cheniere to characterize ambient air quality for regulated criteria pollutants in the vicinity of the Project area. The assessment included the following pollutants: O_3, CO, NO_2, $PM_{2.5}$, PM_{10}, and SO_2. Data for the three-year period from representative Project area monitors are summarized in table 4.11-2. This table shows representative concentrations for the 3-year period and/or short-term averaging periods.

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[23] On November 29, 2013, EPA revised the GWPs as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904). When Resource Report No. 9 was prepared by Cheniere, the EPA-stated GWPs for CO_2, CH_4, and N_2O were 1, 21, and 310, respectively. Because the GHG emissions for the Project are primarily CO_2, associated CO_2e emissions will not change significantly as a result of EPA's revisions.

Table 4.11-2
Existing Ambient Air Concentrations for the Project Area

Pollutant	Averaging Period	Measured Concentration	Units	Monitor Information		
				Air Quality Control Region (AQCR) a/	Location - County	Site ID No.
CO	1-hour b/	2	ppm	AQCR 213	Cameron	480610006
	8-hour b/	2	ppm	AQCR 213	Cameron	480610006
NO_2	1-hour b/	26	ppb	AQCR 216	Brazoria	480391016
	Annual c/	3	ppb	AQCR 216	Brazoria	480391016
Ozone	8-hour d/	0.071	ppm	AQCR 214	Nueces	483550025
$PM_{2.5}$	24-hour e/	26	$\mu g/m^3$	AQCR 214	Nueces	483550034
	Annual c/	9.4	$\mu g/m^3$	AQCR 214	Nueces	483550034
PM_{10}	24-hour b/	67	$\mu g/m^3$	AQCR 214	Nueces	483550034
SO_2	1-hour b/	52	ppb	AQCR 214	Nueces	483550032
	3-hour b/	NA	NA	AQCR 214	Nueces	NA

$\mu g/m^3$ = micrograms per cubic meter; ppm = parts per million; ppb = parts per billion
NA = Data not available
a/ AQCRs:
AQCR 213: Brownsville-Laredo Intrastate
AQCR 216: Metropolitan Houston-Galveston Intrastate
AQCR 214: Corpus Christi-Victoria Intrastate
b/ Maximum of the 2nd highest measurements recorded in 2009, 2010, and 2011
c/ Maximum annual average measurement recorded for 2009, 2010, and 2011
d/ Average of the annual 4th highest 8-hour average measurements recorded during the years 2009, 2010, and 2011
e/ Maximum of the 98th percentile measurements recorded during the years 2009, 2010, and 2011

A review of the 2012 ambient monitoring data in the TCEQ Air Quality Data database (TCEQ, 2013) shows that, except for $PM_{2.5}$ (annual average), the measured concentrations for all pollutants for the various averaging periods are either at or below the values shown in table 4.11-2. For $PM_{2.5}$, the annual average concentration for 2012 was 9.6 $\mu g/m^3$, which was slightly higher than the annual average concentration (for 2009 and 2010) shown in table 4.11-2.

4.11.1.3 Regulatory Requirements for Air Quality

The Project would be potentially subject to a variety of federal and state regulations pertaining to the construction or operation of air emission sources. The TCEQ has the primary jurisdiction over air emissions produced by stationary sources associated with the Project. The TCEQ is delegated by the EPA to implement Federal air programs, with the exception of issuing permits for GHG emissions. However, on February 18, 2014, EPA issued a proposed rulemaking approving Texas' GHG permitting program. In anticipation of a final rulemaking, EPA offered applicants who are currently in the permitting process with EPA the choice of continuing the permitting process with EPA, or moving their applications to the TCEQ. On June 14, 2014, HB 788 authorizing the TCEQ permitting of GHG emissions became law in Texas. However, in order to implement HB 788, further rule changes in the TAC will need to be made and adopted, which must then be approved by EPA as part of revisions to the SIP. Once EPA approves the SIP revisions, the TCEQ will become the permitting authority for GHG emissions. For those applicants who transition to the TCEQ, the process will restart with a new public notice period. Although Texas' GHG permitting program is not finalized, TCEQ has begun accepting applications. If a final rulemaking fails to occur, applicants who chose to move their applications to the TCEQ would have the opportunity to return back to EPA for federal permitting at the point in the application process where EPA left off.

The June 23, 2014 U.S. Supreme Court decision addressing the application of stationary source permitting requirements to GHG (Utility Air Regulatory Group v. Environmental Protection Agency, No. 12-1146) fundamentally changed GHG permitting requirements, regardless of whether permits are issued by EPA or the states. In summary, 1) where new sources emit GHG as the only pollutant with the potential to be emitted above the major source threshold, and 2) where existing major source modifications emit GHG as the only pollutant for which there is a significant emissions increase (and a significant net emissions increase) projects no longer require PSD or Title V permits.

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

Federal Air Quality Requirements

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 following federal requirements have been reviewed for applicability to the Project.

- New Source Review (NSR) / Prevention of Significant Deterioration;
- Title V Operating Permits;
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Greenhouse Gas Reporting;
- Chemical Accident Prevention Provisions; and
- General Conformity.

New Source Review/Prevention of Significant Deterioration

Separate preconstruction 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 preconstruction permit program for new or modified major sources located in attainment areas is called PSD. 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 (the Terminal, the Sinton Compressor Station, and the Taft Compressor Station) are all located within an attainment area, 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 tons per year (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 CO_2e is 100,000 tpy. If a new source is determined to be a major source for any PSD pollutant, then other remaining criteria pollutants would be subject to PSD review if those pollutants are emitted at rates that exceed significant emission thresholds (100 tpy for CO; 40 tpy for nitrogen oxides [NO_x], VOC, and SO_2 each; 25 tpy for total suspended particulate, 15 tpy for PM_{10}, and 10 tpy for [direct] $PM_{2.5}$). Sources which exceed the major source threshold are then subject to a PSD review.

The three facilities associated with the Project are all evaluated separately for purposes of PSD applicability. As shown in table 4.11-7, the Terminal is subject to PSD review for NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, and CO_2e. According to the June 23, 2014 Supreme Court decision, as shown in table 4.11-13, the Sinton Compressor Station would not be subject to PSD review. However, Cheniere began permitting for this facility prior to that date and therefore, PSD permitting was considered for NO_x, CO, PM_{10}, $PM_{2.5}$, and CO_2e. The Taft Compressor Station is not subject to PSD review.

The PSD GHG Tailoring Rule intends to account for facilities that represent an estimated 70 percent of GHG emissions. This rule applies to all industrial sources that are major sources of any NSR-regulated pollutant other than GHGs and emit or have the potential to emit 75,000 tpy or more of CO_2e.

Major new stationary sources applying for a PSD construction permit must include a Best Available Control Technology (BACT) analysis and a detailed air quality impacts analysis in its permit application. As part of the air quality impacts analysis, the applicant must demonstrate that the proposed facilities would comply with applicable NAAQS.

One additional factor considered in the PSD permit review process is the potential impacts on protected Class I areas. Class I areas were designated specifically as pristine natural areas or areas of natural significance and have the lowest increment of permissible deterioration, which precludes development near these areas. Class I areas are given special protection under the PSD program. However, as described in section 4.11.1.4, because of the distance to the nearest Class I area, and the quantity of emissions predicted from the Project, a Class I analysis is not required for the Project.

The TCEQ issued a draft PSD permit for the Terminal's criteria pollutants on July 8, 2013. The TCEQ also issued a final PSD permit for the Sinton Compressor Station's criteria pollutants on December 20, 2013 prior to the June 23, 2014 Supreme Court decision. The Terminal and Sinton Compressor Station began GHG permitting with the EPA prior to the February 18, 2014 EPA rulemaking. The EPA issued a draft GHG permit for the Sinton Compressor Station on February 6, 2014, and the Terminal on February 27, 2014. On April 14, 2014, Cheniere notified EPA and TCEQ that it was selecting TCEQ as its GHG permitting authority for the Terminal and would be transitioning its GHG permit application. Cheniere also filed additional information indicating that it made no changes to the Terminal or BACT analysis upon submission to the TCEQ. Because the TCEQ has already issued a final PSD permit for the criteria pollutants for the Sinton Compressor Station, since the Supreme Court ruling, this facility may not require a GHG PSD permit, and EPA may not need to issue a final GHG PSD permit for the Sinton Compressor Station. Also, the GHG PSD permit for the Terminal is positioned to transition to TCEQ when it receives permitting authority or EPA may maintain permitting authority to continue the permitting process. Although the required final permit for the Sinton

Compressor Station is unknown and the permitting authority for the Terminal is unknown, we recommend that:

<u>Prior to construction of any foundations at the Terminal</u>, Cheniere should file an update on the status of GHG PSD permitting requirements for the Sinton Compressor Station and documentation of any final GHG PSD permit from the applicable permitting agency. <u>Prior to construction of the Sinton Compressor Station</u>, Cheniere should file documentation of its final GHG PSD permit obtained.

Title V Operating Permits

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 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 CO, SO_2, PM_{10}, or $PM_{2.5}$, 10 tpy for an individual hazardous air pollutant (HAP), or 25 tpy for any combination of HAPs. The recent Title V GHG Tailoring Rule also requires facilities that have the potential to emit GHGs at a threshold level of 100,000 tpy CO_2e be subject to Title V permitting requirements.

Both the Terminal and Sinton Compressor Station would be subject to the Title V program. The Terminal exceeds the major source thresholds for NO_x, CO, VOC, HAPs and GHGs. For the Sinton Compressor Station, emissions of NO_x, CO and GHGs are greater than the major source thresholds. Therefore, the Terminal and Sinton Compressor Station would need to apply for and obtain Title V operating permits. The Taft Compressor Station does not qualify as a major source under Part 70.

Cheniere submitted Title V operating permit applications for the Terminal and Sinton Compressor Station to the TCEQ in November 2012, which are still under review.

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 sources at the Terminal and Sinton and Taft compressor stations.

Subpart KKKK of 40 CFR Part 60, *Standards of Performance for Stationary Combustion Turbines,* applies to stationary combustion turbines that are modified, constructed, or reconstructed after February 18, 2005 and have maximum heat input rates greater than 10 MMBtu per hour. Turbines subject to this subpart are exempt from 40 CFR Part 60, Subpart GG emission standards for turbines. Subpart KKKK applies to the 18 natural gas-fuel turbines used to drive refrigeration compressors at the Terminal. Subpart KKKK also applies to the two natural gas-fired turbines at both the Sinton Compressor Station and the Taft Compressor Station, which are used to compress natural gas for onward transport through the pipeline. Subpart KKKK regulates emissions of SO_2 and NO_x. One method of complying with the SO_2 emission limit is to not burn any fuel in the turbine which contains total potential sulfur emissions in excess of 26 nanograms SO_2 per joule (/J) (0.060 pounds [lb] SO_2 /MMBtu) heat input. The turbines would be fueled by natural gas or boil-off gas and therefore would comply with the fuel sulfur content requirement. Based on the size of the turbines, NO_x emissions must be limited to 25 ppm by volume at 15 percent oxygen (O_2) or 1.2 lb per megawatt-hour (lb/MWh). Refrigeration turbines located at the Terminal would utilize water injection for NO_x emission control. The turbines located at the compressor stations would not employ water or steam injection to control NO_x emission, and therefore annual performance testing would be conducted to demonstrate continuous compliance. As an alternative to performance testing, continuous parameter monitoring for each turbine may be conducted to demonstrate that the units are operating in low-NO_x mode.

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.

There are storage tanks for propane and ethylene refrigerants located at the Terminal; however, these storage tanks are exempt because they qualify as pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere. The three LNG storage tanks would have a capacity of 160,000 m^3, which would meet the volume criteria for Subpart Kb. The 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°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 tanks. There is one condensate storage tank at the Terminal that stores VOCs and has a capacity greater than 75 m^3. However, this tank is subject to the requirements of 40 CFR Part 63, Subpart EEEE and therefore is not subject to Subpart Kb. Additionally, there are eight diesel fixed-roof storage tanks and one gasoline fixed-roof storage tank located at the Terminal. The tanks each have a capacity less than 75 m^3, and therefore are exempt from Subpart Kb based on size. Both the Sinton and Taft compressor stations have condensate tanks with volumes less than 75 m^3, thus exempting the tanks from Subpart Kb.

Subpart JJJJ of 40 CFR Part 60, *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*, applies to spark ignition engines with a maximum engine power greater than 25 hp for which construction commenced by July 12, 2006 and was manufactured after January 1, 2009. The 1,328-brake-hp natural gas-fired generator at the Sinton Compressor Station and the 838-brake-hp natural gas-fired generator at the Taft Compressor Station, to be used for standby electricity generation to power the facilities, meet these applicability criteria and are therefore subject to the requirements of Subpart JJJJ. In order to demonstrate compliance with the emission limits found in the rule, owners and operators may either operate a manufacturer-certified engine according to manufacturer's operation and maintenance procedures or conduct performance testing. Owners/operators of emergency engines are required to keep records of their hours of operation. Additionally, maintenance records must be kept for all engines.

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 three 422-brake-hp diesel-fired fire water pump engines and the four 2,220-brake-hp diesel-fired standby generators located at the Terminal. The recordkeeping and reporting requirements would also apply.

Subpart OOOO of 40 CFR Part 60, *Standards of Performance for Crude Oil and Natural Gas Production, Transmissions and Distributions*, applies in part to compressors that are located between the wellhead and point of custody transfer. The Sinton and Taft compressor stations are not located between the wellhead and the point of custody transfer and therefore are not subject to Subpart OOOO.

National Emission Standards for Hazardous Air Pollutants

The 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, coke oven emissions, 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 annual PTE HAP emissions from the Terminal would be 24.2 tpy in aggregate and 16 tpy for formaldehyde (the individual HAP with the greatest PTE) (see section 4.11.1.4); therefore, the Terminal would be a major source of HAPs. Although an LNG storage and process facility is not one of the source categories regulated under Part 63, NESHAP/MACT standards could still apply for specific types of sources (i.e., stationary combustion turbines) that support facility operations. The annual PTE all-HAP emissions from the Sinton Compressor Station and Taft Compressor Station are 4.1 tpy and 1.5 tpy, respectively (see section 4.11.1.4); therefore, each station is classified as an area source of HAPs. The NESHAP described in the following paragraphs have been identified as being potentially applicable to specific sources at the Terminal and Sinton and Taft Compressor Stations.

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 tank vessel loading operations at the Terminal would occur at loading berths that only transfer liquids containing organic HAPs as impurities, as that term is defined in 40 CFR §63.561, the Terminal is exempt from Subpart Y [40 CFR §63.560(d)(5)].

Subpart EEEE of 40 CFR Part 63, *NESHAP for Organic Liquids Distribution (Non-Gasoline)*, applies to owners and operators of organic liquid distribution operations located at a major source of HAP emissions. The condensate storage tank and condensate loading operation at the Terminal are subject to the requirements of this rule. The Terminal would need to comply with the operating limitations, requirements for initial compliance demonstrations, and other applicable requirements under Subpart EEEE.

Subpart YYYY of 40 CFR Part 63, *NESHAP for Stationary Combustion Turbines*, applies to owners and operators of stationary combustion turbines located at a major source of HAP emissions. The GE LM2500+G4 combustion turbines at the Terminal meet the definition of a lean premix gas-fired stationary combustion turbine as defined under this subpart, and therefore would potentially be subject to an emission limitation for formaldehyde of 91 parts per billion (ppb) by volume, at 15 percent O_2. The Terminal is a major source of HAPs and would be required to comply with the operating limitations, requirements for performance test and initial compliance demonstrations, and reporting requirements under Subpart YYYY.

Subpart CCCCCC of 40 CFR Part 63, *NESHAP for Gasoline Dispensing Facilities*, applies to the loading of gasoline storage tanks at an area source of HAP emissions. The Terminal is a major source of HAPs; therefore, Subpart CCCCCC would not apply to the loading of the gasoline storage tank at the Terminal. The Sinton and Taft Compressor Stations would not be equipped with gasoline storage tanks.

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. The Terminal is a major source of HAPs and would have four diesel-fired standby generators each rated at 2,220 brake-hp; therefore, these generators (each of which would operate less than 100 hours per year) are subject only to the initial notification requirement of Subpart ZZZZ. As discussed previously, the three 422-brake-hp diesel-fired fire water pumps at the Terminal would be required to comply with the requirements of 40 CFR Part 60, Subpart IIII. These engines satisfy the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII, per 40 CFR §63.6590(c)(6).

The Sinton and Taft compressor stations are classified as area sources of HAPs. The standby generators at these facilities are considered a new emergency reciprocating internal combustion engine at an area source and, as discussed previously, would be required to comply with the requirements of 40 CFR Part 60 Subpart JJJJ. These engines satisfy the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart JJJJ, per 40 CFR §63.6590(c)(1).

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, regasification of LNG and liquefaction of natural gas.

Emissions of GHGs associated with the construction and operation of the Project, including all direct and indirect emission sources were calculated. In addition, GHG emissions were converted to total CO_2e emissions based on the GWP of each pollutant. The reporting rule does not apply to construction emissions; however, we have included the construction emissions for accounting and disclosure purposes. GHG emissions from operation of the Terminal, the Sinton Compressor Station and the Taft Compressor Station are each anticipated to exceed the 25,000 metric ton threshold and therefore may be subject to the reporting rule. If actual GHG emissions from the Terminal or compressor stations are equal to or greater than the reporting threshold, Cheniere would need to comply with all applicable requirements of 40 CFR Part 98.

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. A risk management plan 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. The General Duty Clause is as follows:

> “The owners and operators of stationary sources producing, processing, handling and storing such substances have a general duty to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility, taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.”

Stationary sources are defined in 40 CFR 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. The Terminal would store about 514,037,299 pounds of methane as LNG, 1,956,793 pounds of propane, and 1,007,181 pounds of ethylene on site. 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 Terminal, which is subject to 49 CFR Part 193, would not be required to prepare an risk management plan. We have included an analysis of the proposed design’s compliance with Part 193, including overpressure modeling, in section 4.12 of this EIS.

General Conformity

A 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 conformity threshold levels (*de minimis*) 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 conformity emission thresholds per year in each nonattainment area.

A General Conformity Determination must show that the emissions would conform to the applicable SIP and would not degrade air quality in the nonattainment area. This can be demonstrated through acquisition of emission offsets, SIP revisions, or dispersion modeling. On-site mitigation of emissions, (i.e., controls above and beyond what is required by regulation), can also be used to demonstrate conformity. According to 40 CFR §51.853, emissions from sources subject to NSR or PSD requirements are exempt and are deemed to have conformed.

As discussed in a previous section of this report, the Project facilities (Terminal and Sinton and Taft Compressor Stations) are located in an area currently designated by EPA as better than national standards or unclassifiable or in attainment 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 PSD permitting program; therefore, these emissions are not subject to General Conformity regulations. However, during the construction phase of the Project, barges carrying equipment and materials would travel periodically from the Port of Houston to the Project construction dock via the GIWW during the 2014 to 2017 period. Specifically, one barge in 2014 and approximately six barges per year in 2015, 2016, and 2017 would travel from the Port of Houston to the construction dock. The Port of Houston is located in the Houston-Galveston-Brazoria (HGB) "severe" ozone nonattainment area (1997 8-hour NAAQS); therefore, each barge would spend part of its trip within the HGB ozone nonattainment area. The construction barge traffic emissions associated with travel in the HGB ozone nonattainment area would be subject to evaluation under General Conformity regulations.

The relevant general conformity pollutant thresholds for the HGB ozone nonattainment area are 25 tpy of NO_x and VOC (ozone precursors) for the portions of the Project located in the nonattainment area.

Cheniere estimated emissions from tug vessels that push the barges using the methodology and emission factors described in EPA's *Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories* (ICF International, 2009). 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.

Cheniere estimated that the total potential direct and indirect emissions of NO_x and VOC from the Project construction-related activity (i.e., construction barge travel in HGB ozone nonattainment area) would be less than 25 tpy for each year of the construction period (2014 to

2017), as shown in table 4.11-3. Based on these emissions, a General Conformity Determination is not required for the Project.

Table 4.11-3
Construction Barge NOx and VOC Emissions Subject to Evaluation for General Conformity

Pollutant	Annual Emissions (tpy)			
	2014	2015	2016	2017
NO_x	0.64	3.85	3.85	3.85
VOC	0.02	0.14	0.14	0.14

Applicable 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.
- 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 applicable requirements for storage tanks, process vents, and loading operations, including the standards and recordkeeping and reporting requirements.
- 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. Unlike the Terminal and Sinton Compressor Station, the Taft Compressor Station construction and operation would be authorized by the TCEQ Standard Permit for Installation and/or Modification of Oil and Gas Facilities, per 30

TAC §116.620. Cheniere intends to apply for the Standard Permit at a date closer in time to the anticipated construction date for the Taft Compressor 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.

4.11.1.4 Construction Emissions and Mitigation

Construction of the Terminal, Sinton and Taft Compressor Stations, and Pipeline 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 engines 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.);
- Installation of Terminal equipment;
- Installation of compressor stations equipment;
- Installation of pipeline and pipeline interconnection equipment;
- Operation of off-road vehicles and trucks during construction;
- Operation of marine vessels (e.g., equipment barges) during construction;
- Offshore dredging; and
- Workers' vehicles used for commuting to and from the construction site (i.e., on-road vehicles).

The total period of construction for the Terminal is estimated by Cheniere to be 72 months. The 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 at the Terminal and compressor stations. We note that there are no residential or sensitive populations within 1 mile of the Terminal site. 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 for an area under construction would depend on numerous factors including: degree of vehicular traffic; size of area disturbed, amount of exposed soil, soil properties (silt and moisture content); and wind speed. Construction of the Project would also result in fuel combustion emissions from a variety of sources, including off-road sources (e.g., bulldozers, cranes, front-end loaders, pile drivers), on-road sources (e.g., construction worker vehicles), and marine vessels (e.g., tugs, barges).

Site preparation activities for the Terminal, compressor stations, and M&R stations would include grading, cutting of drainage ditches, placement of gravel surfaces (e.g., lay-down areas), and construction of access roads within the Project site boundaries. 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. The construction equipment and vehicles would be powered by internal combustion engines that would generate PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC, and CO emissions. Site preparation equipment would include bulldozers, front-end loaders, backhoes, compactors, scrapers, dump trucks, and other mobile construction equipment.

The construction of the Terminal would include installation of three liquefaction trains, three LNG storage tanks, LNG vaporization and natural gas send-out facilities, LNG carrier berths and LNG transfer lines, major mechanical equipment, and piping and instrumentation, as well as construction of foundations, pipe racks, miscellaneous storage tanks, and buildings. The Terminal construction equipment would include cranes, forklifts, pile drivers, welders, concrete pump trucks, and generators (for various duties, such as pumping, lighting, etc.), which would result in fuel combustion and fugitive dust emissions.

The Project would include off-shore dredging of the LNG carrier berthing area at the Terminal. The emissions generated by these activities would be predominantly combustion emissions from the construction equipment and marine vessel engines. The construction equipment would include a clam shell dredge, tugboats, survey/workboats, crew boats, inspection vessels, and trucks.

Air emissions would also be generated during construction of the Pipeline. Pipeline site preparation and construction activities would generate fugitive dust from clearing, trenching, backfilling, grading, and traffic on paved and unpaved areas, as well as fuel combustion emissions from the construction equipment. 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 Pipeline construction activities would include various earthmoving equipment (bulldozers, backhoes, trenchers, graders, and compactors), cranes, forklifts, compressors, pumps, trenchers, stringing trucks, welding rigs, generators, and miscellaneous trucks.

The construction of the Sinton and Taft Compressor Stations would include installation of two compressor turbines at each station, major mechanical equipment, and piping and instrumentation, as well as construction of foundations, miscellaneous storage tanks, and buildings. The construction equipment would include cranes, forklifts, welders, pumps, and generators, which would result in fuel combustion and fugitive dust emissions.

Site truck traffic (e.g., supply trucks) and worker commuter vehicles would generate fugitive dust from travel on paved and unpaved surfaces as well as tailpipe emissions. The Terminal construction would require an average of approximately 1,800 workers over a period of approximately 72 months. The Pipeline construction would require approximately 300 workers over a period of approximately nine months. Most of the commuter vehicles would likely burn gasoline, although supply trucks and some worker pickup trucks would burn ultra-low-sulfur diesel fuel.

Fuel combustion emissions from off-road construction equipment and on-road vehicles (e.g., for commuter workers) were based on EPA emission factors. SO_2 emissions would be further mitigated by the use of ultra-low-sulfur diesel. In addition, vehicle emissions would be minimized through compliance with 30 TAC Chapter 114 – *Control of Air Pollution from Motor Vehicles*. Fugitive dust emissions generated by on-site construction equipment were based on emission factors developed by the Western Regional Air Partnership (*WRAP Fugitive Dust Handbook*). Fugitive dust emission estimates associated with construction activities for the Project assume a dust suppressant control efficiency of 50 percent. The total criteria air pollutant and GHG (as CO_2e) emissions associated with construction-related activities for the Terminal are summarized in table 4.11-4. The total criteria air pollutant and GHG (as CO_2e) emissions associated with construction-related activities for the Pipeline, compressor stations, and M&R facilities are summarized in table 4.11-5. These totals include fuel combustion emissions as well as fugitive PM emissions. For fuel combustion emissions from non-road and on-road engines, nearly all emitted PM is assumed to be $PM_{2.5}$.

Table 4.11-4
Total Construction Emissions by Year Associated with the Terminal

Year	**Annual Emissions (tpy)**						
	NO_x	**VOC**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**CO_2e a/**
2015	1,341.0	144.0	1,186.0	81.4	67.8	67.8	119,762
2016	2,587.9	235.3	1,557.5	109.3	116.5	116.4	148,534
2017	1,271.5	138.7	1,156.4	77.7	64.6	64.6	115,458
2018	793.9	106.2	974.3	66.6	39.2	39.1	92,118
2019	669.8	98.0	929.2	58.1	32.2	32.2	86,047
2020	141.3	62.1	727.7	45.7	4.0	4.0	60,2151
Total Emissions from Fuel Combustion b/	***6,805***	***784***	***6,531***	***439***	***324***	***324***	***622,135***
Total Fugitive Dust Emissions					***4,489***	***477***	
Total PM Emissions for Construction Period					***4,813***	***1,119***	

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
b/ Emissions from dredge transfer pump included in Year 2015 emissions

Table 4.11-5
Total Construction Emissions Associated with the Pipeline and M&R Facility Areas a/, b/

Sub-Project	**Annual Emissions (tpy) c/**						
	NO_x	**VOC**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**CO_2e d/**
Pipeline	64.7	8.5	90.7	0.22	178.1 e/	22.1 e/	19,201
M&R Facility Areas	28.0	6.7	132.0	0.18	28.0 f/	4.4 f/	8,597

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a/ M&R facility areas include the Sinton and Taft Compressor Stations
b/ Includes emissions from fuel combustion in non-road construction equipment and on-road worker commuter vehicles
c/ Emissions are projected by Cheniere to occur in calendar year 2016
d/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
e/ Includes fugitive dust emissions of 174.1 tpy PM_{10} and 18.2 tpy $PM_{2.5}$
f/ Includes fugitive dust emissions of 26.4 tpy PM_{10} and 2.8 tpy $PM_{2.5}$

As shown in table 4.11-4, the fugitive dust accounts for the majority of PM emissions during the construction period for the Terminal. Cheniere developed a revised Fugitive Dust Control Plan (FDCP) to mitigate these emissions (see appendix E). Measures outlined in the FDCP include the following:

- use of a dedicated water truck to apply water to heavily used unpaved areas, as needed;
- ensure that dump trucks and other open-bodied trucks hauling soil or other dusty materials to or from the Project site are covered, as needed;
- use of signage to direct construction vehicle traffic to designated (paved or gravel) roads when practical; and
- enforcing a 15-mph speed limit on unsurfaced roads.

We, and the EPA, have reviewed the FDCP and find it does not adequately address track-out onto paved roads. Therefore, **we recommend that**:

- **<u>Prior to construction</u>, Cheniere should file a revised FDCP with the Secretary for review and written approval from the Director of OEP. The revised FDCP should include the following:**

  a. the use of gravel at construction entrance and exit locations; and

  b. measures to clean paved roads upon mud or dirt track out.

Emissions over the 72-month construction period would increase pollutant concentrations in the vicinity of the Project; however, their effect on ambient air quality would vary with time due to the construction schedule, the mobility of the sources, and the variety of emission sources. Construction emissions associated with the Pipeline are considered temporary and would cease at completion of construction. Construction emissions associated with the compressor stations are considered temporary, but would transition to permanent operational-phase emissions. Construction emissions at the Terminal would occur over a five-year period in one location; therefore, the associated air quality impacts are considered short-term. In addition, following construction, air quality would not revert back to previous conditions, but would transition to operational-phase emissions after commissioning and initial start-up.

4.11.1.5 Operating Emissions and Mitigation

Operation of the Terminal would result in air emissions from stationary equipment (e.g., refrigerant compressor turbines, flares, oxidizers, and emergency generators) and mobile sources (e.g., LNG carriers and tugs). Also, operation of the Sinton and Taft Compressor Stations 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.

<u>Terminal</u>

As discussed earlier, in addition to liquefaction operations, the Terminal would be equipped to receive LNG and conduct vaporization of stored LNG using two trains of AAV and pumps, with send-out to customers through the Pipeline. The AAVs provide regasification of the LNG without requiring combustion, eliminating associated air emissions. This section focuses on the Terminal emission sources associated with the operating liquefaction process.

The Terminal would operate up to three natural gas liquefaction trains continuously. Sources of air emissions associated with operation of the Terminal include:

- 18 GE LM2500+G4 natural gas-fired combustion turbines or equivalent (43,013 hp each; six per train);
- Seven diesel-fired engines for emergency use (four standby power generators and three fire water pumps);
- Five flares (for control of vented organic compound emissions);
- Three thermal oxidizers (for control of acid gas emissions);
- Miscellaneous storage tanks (condensate, gasoline, amine, and distillate/no. 2 oil);
- Maneuvering and hoteling LNG carriers; and
- Fugitive VOC and GHG emission sources (e.g., valves, flanges, connectors, and marine vessel offloading equipment).

Criteria pollutant emissions of NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, and SO_2 would be generated primarily by the fuel combustion sources at the Terminal. The main emission sources at the Terminal, the 18 combustion turbines, would be fueled with boil-off (natural) gas.

Table 4.11-6 provides a summary of the estimated annual criteria air pollutant, GHG (as CO_2e), and HAP emission rates for operating stationary sources associated with the Terminal. The annual emissions are based on continuous operation (8,760 hours per year), except for standby generators and fire water pumps, which are based on no more than 27 and 52 hours per year, respectively. As discussed above, the Terminal is a major source under the PSD program and a major source of HAPs.

Cheniere submitted updated values for table 4.11-6 with its comments on the draft EIS on August 1, 2014. The values in the table have been updated; however, the annual SO_2 emission rate total for the flares should be 0.52 tpy (shown in the table 4.11-6), and not 0.23 tpy as suggested by Cheniere. The total of 0.52 tpy is based on the SO_2 emission rates given in Attachment 1 of the report provided in Attachment 26A of Cheniere’s September 16, 2013 response to FERC’s July 16, 2013 Environmental Information Request. In Attachment 1 of that report, Cheniere shows an annual SO_2 emission rate of 0.28 tpy for planned flare maintenance. As indicated table 4.11-6, the total annual emission rate for the flares includes emissions associated with planned maintenance.

Table 4.11-6
Annual Emissions Associated with Operation of On-Shore Emission Sources at the Terminal

Emission Source	**Annual Emissions (tpy)**								
	NO_x	**VOC**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**CO_2e a/**	**HAPs**	
								Total HAPs	**Single HAP**
Refgn. Comp. Turbines (18)	2,261	47.4	1,658	24.2	56.4	56.4	2,640,000	23.2	16.0 b/
Flares (5) c/	38.7	64.5	332.1	0.52	-	-	106,000	0.60	0.35 d/
Thermal Oxidizers (3)	18.2	0.43	19.7	8.85	2.71	2.71	589,000	0.36	0.30 d/
Standby Diesel Generators (4)	0.46	0.03	0.07	0.02	0.007	0.007	140	0.002	0.001 e/
Fire Water Pump Engines (3)	0.21	0.005	0.05	0.0004	0.007	0.007	37.7	0.001	0.0006 e/
Storage Tanks	-	1.09	-	-	-	-	-	-	-
Fugitives	-	29.7	-	-	-	-	9,090	-	-
Total Emissions:	***2,319***	***143.1***	***2,010***	***33.6***	***59.1***	***59.1***	***3,340,000 f/***	***24.2***	***16.0 a/***
PSD Signif. Emission Rate g/	*40*	*40*	*100*	*40*	*15*	*10 h/*	*100,000*		
Subject to PSD Review	*Yes*	*Yes*	*Yes*	*No*	*Yes*	*Yes*	*Yes*		

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
b/ Worst-case individual HAP emissions from the Project are presented for formaldehyde
c/ One marine flare, two wet gas flares, and two dry gas flares (normal operation, including planned MSS activities and ship inert gas venting)
d/ Worst-case individual HAP emissions from the Project are presented for benzene
e/ Worst-case individual HAP emissions from the Project are presented for propylene
f/ CO_2 emissions account for approximately 99 percent of the total CO_2e emissions
g/ Emissions of other PSD-regulated air pollutants – lead, fluorides, sulfuric acid mist, H_2S, total reduced sulfur, and reduced sulfur compounds – are negligible
h/ 10 tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; 40 tpy of NO_x emissions unless demonstrated not to be a $PM_{2.5}$ precursor

Short-term emission rates are considered a separate operating scenario for the Terminal and are the basis of short-term impact analyses presented in section 4.11.1.6. Table 4.11-7 provides a summary of the estimated short-term (pounds per hour [lb/hr]) controlled criteria air pollutant and HAP emission rates for operating stationary sources associated with the Terminal.

Cheniere submitted updated values for table 4.11-7 with its comments on the draft EIS on August 1, 2014. The values in the table have been updated; however, the short-term SO_2 emission rate total for the flares should be 4.55 lb/hr (shown in the table 4.11-7), and not 0.33 lb/hr as suggested by Cheniere. The total of 4.55 lb/hr is based on the SO_2 emission rates given in Attachment 1 of the report provided in Attachment 26A of Cheniere's September 16, 2013 response to FERC's July 16, 2013 Environmental Information Request. In Attachment 1 of that report, Cheniere shows a short-term SO_2 emission rate of 4.22 lb/hr for planned flare maintenance. Because the planned maintenance activities are characterized as "intermittent" sources for the purposes of modeling, the short-term emission rate was "annualized" to 0.08 lb/hr for the 1-hour SO_2 impacts analysis; however, for the purposes of emissions inventory presentation purposes, the short-term emission rate of 4.22 lb/hr is unchanged. As indicated in in table 4.11-7, the total short-term emission rate for the flares includes emissions associated with planned maintenance.

Table 4.11-7
Short-Term Emissions Associated with Operation of On-Shore Emission Sources at the Terminal

Emission Source	Short-Term Emissions (lb/hr)							
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	HAPs	
							Total HAPs	Single HAP
Refgn. Comp. Turbines (18)	516.2	10.8	378.5	5.53	12.9	12.9	5.29	3.66 a/
Flares (5) b/	524.5	2,032	4,497	4.55	-- c/	-- c/	7.67	4.67 d/
Thermal Oxidizers (3)	4.15	0.10	4.50	2.22	0.62	0.62	0.08	0.07 d/
Standby Diesel Generators (4)	37.7	2.05	5.92	1.29	0.54	0.54	0.15	0.10 e/
Fire Water Pump Engines (3)	8.70	0.23	2.06	0.02	0.30	0.29	0.04	0.03 e/
Storage Tanks	--	18.0	--	--	--	--	0.015	0.010 f/
Fugitives	--	6.78	--	--	--	--	0.022	0.019 f/
Total Emissions	***1,091***	***2,070***	***4,888***	***13.6***	***14.4***	***14.4***		

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a/ Highest individual HAP emission rate for this source is for formaldehyde
b/ One marine flare, 2 wet gas flares, and 2 dry gas flares (normal operation, including planned MSS)
c/ Assumed to be zero or negligible based on EPA's AP-42 emission factor for non-smoking flares of 0 µg/l in exhaust
d/ Highest individual HAP emission rate for this source is for benzene
e/ Highest individual HAP emission rate for this source is for propylene
f/ Highest individual HAP emission rate for this source is for hexane

The TCEQ reviewed and approved Cheniere's PSD BACT analysis for the Terminal, including the refrigeration compressor turbines, internal combustion engines (standby generators), flares, and thermal oxidizers. Methods for reducing emissions of NO_x, CO, and VOCs for each of these sources were evaluated based on technical feasibility. Cheniere would reduce emissions of NO_x from the refrigeration compressor turbines through use of water-injection and good combustion practices; CO and VOC emissions would be controlled through the use of good combustion practices. The limited-use standby generators/engines would utilize good combustion practices and ultra-low-sulfur diesel fuel to reduce emissions, especially PM and SO_2 emissions. Emissions from the flares and thermal oxidizers would be reduced through good combustion practices. The resulting BACT-based emission rates are equal to or better than any NSPS, NESHAP, and/or Reasonably Available Control Technology (RACT) emission standards applicable to the Terminal emission sources.

Once constructed, the Terminal would undergo an initial start-up process before it could be fully operational. This process would result in larger emissions than under normal operating conditions and would last for several months. After initial startup, Cheniere plans to continuously operate the liquefaction facility, thus limiting start-up/shutdown events to those associated with periodic routine maintenance or the need to shut down due to equipment malfunction. Table 4.11-8 summarizes the estimated criteria pollutants, GHGs, and HAP emissions for initial startup activities.

Table 4.11-8
Annual Emissions Associated with Initial Start-Up of the Terminal

Emission Source	**Annual Emissions (tpy)**								
	NO_x	**VOC**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**CO_2e a/**	**HAPs**	
								Total HAPs	**Single HAP**
Terminal Start-Up – All Sources	198.2	52.8	1.699	2.19	-- b/	-- b/	32,900 c/	4.12 d/	2.35 e/

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
b/ Assumed to be zero or negligible based on EPA's AP-42 emission factor for non-smoking flares of 0 µg/l in exhaust
c/ CO_2 emissions account for approximately 13 percent of the total CO_2e emissions
d/ Flares emissions
e/ Highest individual HAP emission rate for flares is for benzene

Outside of scheduled routine maintenance events, complete shutdown of an LNG train is not anticipated. A routine maintenance shutdown of each LNG train would occur every three years for turbine engine replacement, amine vessel inspection, and molecular sieve replacement. The maintenance schedule would be staggered such that one of the three trains per year would undergo the maintenance activities. When an LNG train is shut down for these maintenance events, there would be no need to vent or flare the refrigerants stored in the equipment, though there would be some minor venting to flare to depressure compressors to facilitate inspection. Higher turbine emissions during start-up and shutdown are not expected during these infrequent maintenance events.

Flaring emissions would occur during the regularly scheduled maintenance event on an LNG train. Shutdown of the LNG train would require depressurization of the acid gas removal unit and dehydration unit. The encompassed feed gas within the system would be pressure purged to the process flare stack (526,000 lb per 12-hour period). After the maintenance event, the LNG train would be purged, with a total of approximately 18,343,000 lb of feed gas vented to the process flare stack over a 72-hour period.

During operation of the Terminal, LNG carriers and supporting marine vessels, namely tugboats and security vessels, would routinely generate air emissions. Cheniere assessed the emissions associated with various potential LNG carrier operating scenarios, in terms of engine duty and fuel type, in determining the highest emissions-generating scenario. All scenarios assumed a main engine size rating of 30,000 kilowatt, based on available engine data on the existing fleet of LNG carriers.

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

Ship emissions are quantified along the entire length of the reduced speed zone (RSZ). Cheniere's emission calculations for the LNG carriers transiting through the RSZ are based on the use of residual oil with a sulfur content of 2.7 percent in the ship's main engine. This calculation is conservative in that International Maritime Organization Marine Pollution standards will require the use of oil with a maximum sulfur content of 0.10 percent, effective January 1, 2015. Therefore, we re-calculated the RSZ emissions based on the use of oil with a sulfur content of 0.10 percent to more accurately represent main engine emissions.

LNG carrier maneuvering for each LNG carrier call would take place within the security zone over a four-hour time period (two hours arriving and two hours departing). Cheniere assumed that three tugboats and one security vessel would be deployed for each ship call. While the LNG carrier is docked and LNG is being loaded to the ship, emissions would be generated by hoteling operations on the ship for a 20-hour period. Cheniere examined various on-board power generating scenarios for the maneuvering and hoteling phase of LNG carrier calls at the Terminal. Based on projections for the type/class of LNG carriers calling at the Terminal in the future, Cheniere selected a set of emission rates representative of the anticipated fleet profile. Emissions may also be generated in the case of the potential future operating scenario whereby LNG is being offloaded from a docked LNG carrier to the Terminal (i.e., LNG import operations).

Table 4.11-9 presents a summary of the estimated highest annual criteria air pollutant and GHG (as CO_2e) emissions associated with the operation of marine vessels within the security zone at the Terminal. Marine vessel operations within the security zone would result in emissions associated with maneuvering and hoteling LNG carriers, and could include emissions from offloading operations on LNG carriers (under a potential future LNG import operating scenario). Table 4.11-10 presents a summary of the estimated highest annual criteria air pollutant and GHG (as CO_2e) emissions associated with the operation of marine vessels outside the security zone. Marine vessel operations outside the security zone would include LNG carriers traversing the RSZ (i.e., the route between the security zone and pilot boarding zone). These emissions, which are not subject to review under the PSD program, are based on 300 LNG carrier calls per year.

Emission Source	Annual Emissions (tpy)						
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2e a/
Maneuvering and Hoteling by LNG carriers b/	20.44	8.06	28.30	3.48	0.19	0.19	1,319
Offloading LNG carriers	36.90	1.07	12.52	0.77	0.44	0.42	1,939
Tug Boat Support	3.49	0.37	9.70	0.082	0.08	0.08	1,380
Security Vessel Support	2.11	0.22	5.85	0.049	0.05	0.05	831.8
Total Emissions (LNG Export)	***26.0***	***8.7***	***43.9***	***3.6***	***0.32***	***0.32***	***5,470***
Total Emissions (LNG Import) c/	***62.9***	***9.7***	***56.4***	***4.4***	***0.76***	***0.74***	***3,531***

Table 4.11-9
Annual Emissions Associated with Operation of Marine Vessels within the Security Zone at the Terminal

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
b/ Includes emissions from operation of main engine (for maneuvering) and auxiliary engines (for maneuvering and hoteling)
c/ LNG import scenario conservatively assumes on-board generator(s) operation for both hoteling and LNG offloading purposes

Table 4.11-10
Annual Emissions Associated with Operation of Marine Vessels Outside the Security Zone

Emission Source	Annual Emissions (tpy)						
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2e a/
RSZ Travel by LNG carriers	79.76	7.33	12.79	2.48	1.42	1.27	3,958
Tug Boat Support	46.19	4.88	128.3	0.12	1.03	1.03	18,253
Security Vessel Support	3.01	0.32	8.35	0.07	0.07	0.07	1,188
Total Emissions	***129***	***12.5***	***149***	***2.7***	***2.5***	***2.4***	***23,399***

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O

The marine vessel short-term emission rates are considered a separate operating scenario for the impact analyses in section 4.11.1.6. Table 4.11-11 presents a summary of the estimated short-term (lb/hr) criteria air pollutant emissions associated with the operation of marine vessels within the security zone at the Terminal.

The air quality impacts that could occur during normal Terminal operation and ship maneuvering within the security zone, ship hoteling, ship LNG loading, and ship LNG cargo offloading are assessed as part of the air quality impacts analysis presented below.

Table 4.11-11
Short-Term Emissions Associated with Operation of Marine Vessels within the Security Zone

Emission Source	Short-Term Emissions (lb/hr)					
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
Maneuvering and Hoteling by LNG carriers a/	9.17	3.07	11.01	1.37	0.09	0.09
Offloading LNG carriers	27.06	0.78	11.21	0.82	0.35	0.33
Tug Boat Support	6.37	0.67	17.69	0.15	0.14	0.14
Security Vessel Support	6.01	0.63	16.71	0.14	0.13	0.13

a/ Includes emissions from operation of main engine (for maneuvering) and auxiliary engines (for maneuvering and hoteling)

Pipeline Facilities: Sinton and Taft Compressor Stations

Sources of air emissions associated with operation of the Sinton and Taft Compressor Stations would include:

- Combustion turbines for gas compression:
  a. Sinton: two Solar Titan 130-2050S turbine/compressor units (20,794 hp each);
  b. Taft: two Solar Centaur 50 turbine/compressor units (6,387 hp each);
- Emergency generators for standby power (one generator at each station);
- Condensate storage and truck loading (one tank at each station);
- Fugitive VOC and GHG emission sources (e.g., valves, flanges, and connectors); and
- VOC and GHG emissions associated with limited blowdown events.

Criteria pollutant emissions of NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, and SO_2 would be generated primarily by the fuel (natural gas) combustion sources at the terminal. The main emission sources at the compressor stations are the natural gas-fired combustion turbines.

Table 4.11-12 provides a summary of the estimated annual criteria air pollutant, GHG (as CO_2e), and HAP emissions for the Sinton and Taft Compressor Stations. For the combustion turbines at each station, the annual emissions are based on continuous operation (i.e., 8,760 hours per year). For the standby generators, annual emissions are based on operation of 100 and 500 hours per year for the Sinton and Taft Compressor Stations, respectively. As discussed in section 4.11.1.3, the Sinton Compressor Station is a new major source under the PSD program and the Taft Compressor Station is not a major source. Neither compressor station is a major source of HAP emissions. Fugitive emissions associated with the M&R Stations would be negligible, and no air emissions would be directly generated by the Pipeline during normal operation. 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 are VOC and GHG. Emissions associated with “blow-down” events at the compressor stations are included in the fugitive emissions category in table 4.11-12 and table 4.11-13.

Table 4.11-12
Annual Emissions Associated with Operation of the Sinton and Taft Compressor Stations

Emission Source	Annual Emissions (tpy)								
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	CO_2e a/	HAPs	
								Total HAPs	Single HAP b/
Sinton Compressor Station									
Compressor Turbines (2) c/	128.6	9.41	194.9	17.5	26.9	26.9	150,254		
Standby Diesel Generator	0.29	0.06	0.26	0.01	0.005	0.005	57.1		
Fugitives	-	2.69	-	-	-	-	4,970		
Storage Tank	-	0.37	-	-	-	-	-		
Total Emissions	***128.9***	***12.5***	***195.1***	***17.5***	***26.9***	***26.9***	***155,281***	***4.06***	***3.12***
PSD Signif. Emission Rate d/	*40*	*40*	*100*	*40*	*15*	*10^e*	*100,000*		
Subject to PSD Review	*Yes*	*No*	*Yes*	*No*	*Yes*	*Yes*	*Yes*		
Taft Compressor Station									
Compressor Turbines (2) c/	46.2	3.34	66.6	6.28	9.68	9.67	53,950		
Standby Diesel Generator	0.92	0.17	0.60	0.02	0.01	0.01	167.8		
Fugitives	-	0.97	-	-	-	-	3,604		
Storage Tank	-	0.37	-	-	-	-			
Total Emissions	***47.1***	***4.9***	***67.2***	***6.3***	***9.7***	***9.7***	***57,722***	***1.47***	***1.19***

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a/ CO_2e emissions based on GWPs of 1 for CO_2, 21 for CH_4, and 310 for N_2O
b/ Worst-case individual annual HAP emissions from each station are formaldehyde emissions from fuel combustion
c/ Includes MSS (start-up and shutdown) emissions
d/ Emissions of other PSD-regulated air pollutants – lead, fluorides, sulfuric acid mist, H_sS, total reduced sulfur, and reduced sulfur compounds – are negligible
e/ 10 tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; 40 tpy of NO_x emissions unless demonstrated not to be a $PM_{2.5}$ precursor

Short-term emission rates are considered a separate operating scenario for the Sinton Compressor Station and are the basis of the impacts analysis presented in section 4.11.1.6. Table 4.11-13 provides a summary of the estimated short-term (lb/hr) criteria air pollutant and HAP emissions for the Sinton Compressor Station.

Table 4.11-13
Short-Term Emissions Associated with Operation of the Sinton Compressor Station

Emission Source	Short-Term Emissions (lb/hr)						
	NO_x	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$	HAP a/
Compressor Turbines (2)	29.3	28.6 b/	2,491 b/	4.0	6.14	6.14	
Standby Diesel Generator	5.85	1.15	5.27	0.13	0.10	0.10	
Fugitives	-	0.02	-	-	-	-	
Storage Tank	-	28.4	-	-	-	-	
Total Emissions	***35.2***	***58.2***	***2,496***	***4.1***	***6.2***	***6.2***	***150***

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a/ Worst-case individual short-term HAP emissions from each station are fugitive hexane emissions associated with blow-down processes
b/ Emissions associated with turbine shutdown

The TCEQ reviewed and approved Cheniere's PSD BACT analysis for the Sinton Compressor Station, including the compressor turbines and the standby generator. Methods for reducing emissions of NO_X, CO, and VOCs for each of these sources were evaluated based on technical feasibility. Cheniere would reduce emissions of NO_X and CO from the compressor turbines through use of dry low-NO_X combustors and good combustion practices; VOC emissions would be controlled through use of good combustion practices. The natural gas-fired, limited-use standby generator would be equipped with a turbocharger and use good combustion practices to reduce emissions. The resulting BACT-based emission rates are equal to or better than any NSPS, NESHAP, and/or RACT emission standards applicable to the compressor station emission sources.

Emissions from the Taft Compressor Station would be below PSD and Title V permitting thresholds; therefore, the facility is classified as a minor source. As a result of triggering PSD review, the air quality impacts that could occur during normal operation of the Sinton Compressor Station are assessed below.

4.11.1.6 Operational Impact 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 from operation of both the Terminal and the Sinton Compressor Station. The assessment included air dispersion modeling to predict off-site (i.e., ambient) concentrations in the vicinity of the Project.

We considered five separate air quality impacts analyses in our review for the Terminal and Sinton Compressor Station.

Air quality impact analyses for the Terminal include:

- Analysis 1: NAAQS modeling analysis, including associated marine activities;
- Analysis 2: PSD increment consumption and additional impacts analyses;

- Analysis 3: Ozone impacts analysis; and
- Analysis 4: Additional state-specific modeling.

Air quality impact analysis for the Sinton Compressor Station includes:

- Analysis 5: PSD permitting analyses.

Overall Modeling Methodology

With the exception of Analysis 3, all modeling was conducted using the American Meteorological Society/EPA Regulatory Model. This model is the preferred guideline model for predicting impacts from new and modified stationary sources. Analysis 3 was conducted using the EPA-approved Comprehensive Air Quality Model with Extensions (CAMx). Data sets input to these models include emission source parameter values (e.g., stack height and diameter, stack exhaust temperature and gas flow, and pollutant emission rate), building/structure dimensions for determining the effects of the buildings/structure on dispersion of emissions, receptor locations, terrain elevation data, and meteorological data, as appropriate. Emission rates for stationary and marine vessel sources are shown above. No receptors were placed within the facility fence line, because these are not considered “ambient air” locations in accordance with modeling guidance. Background concentrations and NAAQS were converted to units of $\mu g/m^3$ to be consistent with the model-predicted units of concentration.

Analysis 1: Terminal - NAAQS Modeling Analysis

Cheniere conducted a cumulative NAAQS analysis addressing emissions from the Terminal, marine activities associated with Terminal (including LNG carrier maneuvering, hoteling and unloading, tugboat maneuvering and standby, and security vessel standby), existing off-site emission sources (e.g., TCEQ-provided inventory of industrial/commercial facilities), and representative background concentrations.

For the emissions from marine vessel activities, Cheniere considered two representative operating scenarios: 1) one LNG carrier hoteling and offloading while a tug is on standby within the security zone; and 2) one LNG carrier hoteling and offloading, a second LNG carrier being maneuvered by two tugs, a third tug on standby nearby, and one security vessel on standby nearby, all within the security zone. For these operating scenarios, Cheniere examined three different combustion fuel options for the main and auxiliary engines used for the maneuvering and hoteling phases. One of these options included main engine operation on oil with a 0.1 percent sulfur content maximum. Cheniere established LNG carrier emission rates for modeling based on the anticipated future LNG carrier fleet mix profile for the three options.

Cheniere initially modeled the Terminal alone (with the marine activities included) and compared the maximum concentrations against the Significant Impact Levels (SILs), which are defined as a *de minimis* impact level below which a source is presumed not to cause or contribute to an exceedance of a NAAQS. Table 4.11-14 shows the SIL analysis modeling results, demonstrating that only the 1-hour NO_2 and SO_2 and annual NO_2 impacts would be greater than the SILs. Therefore, a cumulative NAAQS analysis was conducted only for NO_2 and SO_2.

Table 4.11-14
Terminal - SIL Analysis Modeling Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	SIL ($\mu g/m^3$)
NO_2	1-hour	**130.84**	7.5
	Annual	**8.33**	1
CO	1-hour	334.69	2,000
	8-hour	166.10	500
PM_{10}	24-hour	1.10	5
$PM_{2.5}$	24-hour	1.01	1.2
	Annual	0.29	0.3
SO_2	1-hour	**19.06**	7.8 a/
	3-hour	11.61	25
	24-hour	3.76	5
	Annual	0.49	1

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a/ Interim SIL

For the cumulative NAAQS analysis, the Terminal (including associated marine activities) and other off-site sources (including the Taft Compressor Station) were modeled. To account for additional sources not explicitly modeled but that contribute to background pollutant levels in the vicinity of the Terminal, monitoring data from TCEQ-approved representative monitoring sites also were added to the modeling results prior to comparison to the NAAQS. The monitoring site for NO_2 was the Lake Jackson Monitor (EPA Monitor 48-039-1016), located in the southern part of Brazoria County. The monitoring site for SO_2 was in Corpus Christi, Texas (EPA Monitor 48-355-0032). Table 4.11-15 shows the results for the cumulative NAAQS analysis.

Table 4.11-15
Terminal - Cumulative NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	543.34	39.55	**582.89**	188
	Annual	23.35	6.32	29.67	100
SO_2	1-hour	21.80	114.50	136.30	196

The modeled concentrations for annual NO_2 and 1-hour SO_2, when combined with representative background concentrations, were predicted to be below the corresponding NAAQS. However, modeled impacts of 1-hour NO_2, when combined with representative background concentrations, were predicted to be greater than their applicable NAAQS. Further review of these results indicated that only one receptor, at another industrial site, is predicted to have a concentration greater than the 1-hour NO_2 NAAQS. A source culpability analysis demonstrated that the Terminal's contribution to this predicted industrial-site exceedance is below the SIL; therefore, the Terminal would not cause or significantly contribute to this exceedance.

Analysis 2: Terminal - PSD Increment Consumption and Additional Impacts Analyses

In addition to the cumulative NAAQS analysis discussed above, Cheniere submitted to the TCEQ a PSD increment consumption analysis and an Additional Impacts Analysis to satisfy PSD permitting requirements for the Terminal. The results of these analyses are provided below to disclose further impacts associated with the Terminal.

PSD increment is the amount of pollution an area is allowed to increase. PSD increments are intended to prevent the air quality in attainment areas from deteriorating to the level set by the NAAQS. The PSD increment analysis is used to determine whether a proposed project would cause or contribute to an exceedance of the allowable decrease in air quality in conjunction with other existing sources. Federal PSD guidelines specify allowable changes in air pollutant concentrations due to industrial expansion in an area.

The PSD SIL modeling results submitted to the TCEQ showed that the predicted maximum 1-hour and annual NO_2 concentrations exceed the respective SILs. There is no 1-hour NO_2 PSD increment; however, a comprehensive PSD increment analysis was required for annual NO_2 emissions as part of the PSD permit application submitted to the TCEQ.

For the NO_2 PSD increment consumption analysis, the analysis considered Terminal sources as well as off-site emission sources. Off-site sources within an area defined by the Radius of Influence (the maximum distance in kilometers at which a modeled concentration is predicted to be above a SIL) plus 50 kilometers were included. Emission rates/release parameters for the off-site sources were obtained from the TCEQ Point Source Database. The modeled annual NO_2 concentration of 9.88 $\mu g/m^3$ is below the PSD increment of 25 $\mu g/m^3$.

Cheniere also submitted to the TCEQ an Additional Impact Analysis as required by the PSD regulations. For the growth analysis, no significant commercial, residential, or industrial growth is expected as a result of construction/operation of the Terminal.

Secondary air quality standards are set under the CAA for the protection of public welfare, including protection against decreased visibility and damage to animals and vegetation, including crops. The NAAQS analysis demonstrated that the Terminal would comply with applicable secondary NAAQS; therefore, any impacts on vegetation, animals, and other public welfare concerns would not be significant.

In Texas, if a facility complies with visibility and opacity requirements specified in 30 TAC Chapter 111, no additional visibility impact analyses are required. Cheniere would comply with visibility and opacity requirements specified in 30 TAC Chapter 111. Because the main combustion units at the Terminal would use only natural gas as fuel, we do not anticipate significant impacts to regional visibility.

Analysis 3: Terminal - Ozone Modeling

The TCEQ and FERC staff requested an assessment of the Terminal's impact on local ozone concentrations. Cheniere conducted this analysis using both the two-step screening process established by the TCEQ as well as the refined photochemical model CAMx.

The two-step TCEQ screening process begins by first identifying a representative ozone background concentration from a nearby ambient monitor. Step 2 of the screening procedure involves calculating the ratio of annual VOC to NOx emissions. The results of this screening process demonstrated that Cheniere's emissions were considered ozone neutral, and therefore are not expected to have a meaningful impact on local ozone levels.

Based on discussions with EPA and the TCEQ, Cheniere conducted refined modeling using CAMx to further support the conclusion drawn from the two-step TCEQ screening process. Unlike air quality analyses conducted for other criteria pollutants, there is not specific guidance from EPA or the TCEQ concerning how to conduct ozone modeling. However, there is precedent from recent permitting actions as to how to determine whether or not a permitting action will have a meaningful impact on ozone levels.

The CAMx modeling was conducted for the May 31, 2006 through July 1, 2006 ozone episode, because this episode has been used for local air quality planning. The use of CAMx and this ozone episode was based on discussions with both EPA and the TCEQ. CAMx was run using a "base case" scenario of emissions as well as an emissions scenario that included the Project (added to the base case), thus allowing for a comparison of ozone levels before and after the Project is permitted.

The results of the CAMx modeling analysis were evaluated in the same manner as had been done for the Sabine Pass LNG Project. This evaluation demonstrates that the Terminal is not expected to cause or contribute to an exceedance of an ozone NAAQS violation.

We received a comment on the draft EIS from the Sierra Club regarding the conclusions drawn from the CAMx modeling (appendix I). In particular the Sierra Club states that FERC "does not explain how it interprets this modeling which shows that the Project will increase ozone levels beyond 75 ppb, to support the DEIS's conclusion that the terminal is not expected to cause or contribute to exceedance of the ozone NAAQs." The modeling results demonstrate that emissions from the Project are not likely to cause adverse impacts on 8-hour ozone levels. Cheniere's analysis was conducted in consideration of the current NAAQS of 75 ppb. After reviewing the modeling analysis results as well as recent ambient monitoring data for the Corpus Christi area, we agreed with Cheniere's study findings, and find that emissions from the Project would not adversely affect the ozone attainment designation status of the Corpus Christi area. Consistent with FERC, the EPA did not dispute the results of Cheniere's ozone impact analysis.

To clarify, the model-simulated ground-level ozone concentrations do not represent 8-hour ozone design values. The magnitude of an ozone design value, not an individual 8-hour average measurement, determines an area's attainment status relative to the NAAQS. An ozone design value is based on the average of the 4th-highest daily maximum 8-hour ozone concentrations over a 3-year period measured by a qualified ambient air quality monitor. For an area to be designated nonattainment for ozone, the average 4th-highest concentration must exceed the NAAQS (75 ppb). Therefore, it is possible that a monitor could measure one or more individual maximum 8-hour concentrations that exceed 75 ppb over a 3-year period; however, the average of the fourth highest values may still be well below 75 ppb. Although Cheniere's modeling may have indicated that a historical, individual ozone event/episode could yield a maximum 8-hour ozone concentration greater than 75 ppb, such a temporally-limited (episode-specific) worst-case result cannot be used to categorize an area as not in attainment of the NAAQS, with or without an ozone impact contribution from the Project.

As shown by Cheniere's CAMx modeling, the maximum 8-hour ozone impact from Project emissions is predicted to be 1.47 ppb. A review of regulatory ozone monitoring data for the most recent three complete years of data (2011-2013) for the Corpus Christi area indicates that an incremental worst-case ozone contribution of 1.47 ppb would not potentially cause or contribute to a change in the attainment designation status of the area, as the highest ozone design value is 70 ppb.

It should also be noted that the analysis conducted by Cheniere was based on maximum allowable emissions for the Project (i.e., all emission sources operating at full capacity), which is an unlikely operating condition, but was modeled nonetheless because this represents the Project as permitted. Therefore, the results associated with modeling allowable emissions likely overestimate the impact on ambient ozone levels from the Project.

The Sierra Club also commented that the draft EIS does not consider marine vessel ozone precursor emission impacts. The Project is located within an ozone attainment area. However to address emissions of precursor ozone pollutants from the Terminal sources, the final EIS incorporates the results of the ozone impact modeling analysis, conducted as part of the CAA PSD permitting process for the TCEQ. Further, marine vessel emissions within the security zone would result in a 1.4 percent increase in total ozone precursor emissions for the Project, beyond those included in the modeling. These additional emissions would not result in a meaningful increase in additional ozone precursor emissions not already modeled.

Analysis 4:Terminal - Additional State-Specific Modeling

Although the Terminal's SO_2 emissions increase did not trigger PSD review, the TCEQ requested an air dispersion modeling analysis for SO_2 emissions to assess compliance with the SO_2 NAAQS as well as the State Property Line Standards for SO_2 and H_2S as specified in 30 TAC §112.3(a). The modeling conducted by Cheniere considered stationary sources associated with the Terminal.

Table 4.11-16 shows the modeling results for the SO_2 NAAQS analyses. All modeled concentrations of SO_2 were predicted to be less than the applicable SILs. Therefore, this modeling analysis demonstrates compliance with the SO_2 NAAQS.

Table 4.11-16
Terminal - SO2 NAAQS Analysis Modeling Results

Averaging Period	Maximum Concentration ($\mu g/m^3$)	SIL ($\mu g/m^3$)
1-hour	4.14	7.8 a/
3-hour	2.44	25
24-hour	1.49	5
Annual	0.22	1

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a/ Interim SIL

Table 4.11-17 shows the modeling results for the State Property Line Standards analysis. The modeled concentrations were predicted to be less than the State Property Line Standards for SO_2 and H_2S. Therefore, this modeling analysis demonstrates compliance with the State Property Line Standards.

Table 4.11-17
Terminal - State Property Line Standards Modeling Results

Pollutant	Maximum Concentration ($\mu g/m^3$) a/	Chapter 112 Standard ($\mu g/m^3$)
SO_2	16.17	1,021
H_2S	0.02	162

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a/ 1-hour average concentration

Cheniere submitted to the TCEQ a State Effects Evaluation assessing emitted compounds' potential to cause adverse health effects, odor nuisances, vegetation effects, or materials damage. Following TCEQ procedures, a comparison against Effects Screening Levels (ESLs) was required for only three compounds: benzene, gasoline, and ethylene.

The modeling conducted by Cheniere considered stationary sources associated with the Terminal. Table 4.11-18 shows the modeling results of the State Effects Evaluation analysis. Because the maximum predicted concentrations for ethylene were found to be less than their corresponding ESLs, no further analysis of ethylene emissions was necessary. Although predicted concentrations of benzene and gasoline were found to be greater than their respective ESLs, TCEQ's guidance deems the benzene and gasoline modeling results acceptable. Therefore, no further State Effects Evaluation modeling is necessary.

Table 4.11-18
Terminal - State Effects Evaluation Modeling Results

Pollutant	**Averaging Period**	**Maximum Concentration ($\mu g/m^3$)**	**ESL ($\mu g/m^3$)**
Benzene	1-hour	184.35	170
	Annual	2.41	4.5
Ethylene	1-hour	11.54	1,400
	Annual	0.96	34
Gasoline	1-hour	6,769.33	3,500
	Annual	54.93	350

Analysis 5: Sinton Compressor Station - PSD Permitting Analyses

Cheniere submitted to the TCEQ a PSD modeling analysis for the Sinton Compressor Station, including a SIL analysis, cumulative NAAQS analysis, and PSD increment consumption analysis. Tables 4.11-19 through 4.11-21 show the results of these analyses.

Table 4.11-19
Sinton Compressor Station – SIL Analysis Modeling Results

Pollutant	**Averaging Period**	**Maximum Concentration ($\mu g/m^3$)**	**SIL ($\mu g/m^3$)**
NO_2	1-hour	**59.1**	7.5
	Annual	**1.5**	1
CO	1-hour	**6,341.0**	2,000
	8-hour	**5,543.5**	500
PM_{10}	24-hour	**9.2**	5
	Annual	0.4	1
$PM_{2.5}$	24-hour	**7.6**	1.2
	Annual	**0.4**	0.3

As shown in table 4.11-19, the maximum predicted concentrations for all pollutants and averaging times were found to be greater than the SILs, except for the annual PM_{10} concentration. Therefore, cumulative NAAQS and PSD increment consumption modeling analyses were conducted for 1-hour and annual NO_2, 1-hour and 8-hour CO, 24-hour PM_{10}, and 24-hour and annual $PM_{2.5}$.

For the cumulative NAAQS analysis, the Sinton Compressor Station and off-site emission sources (including the Taft Compressor Station) were modeled. To account for additional sources not explicitly modeled but that contribute to background pollutant levels in the vicinity of the station, monitoring data from a representative monitoring site was added to the modeled results prior to comparison to the NAAQS. The representative monitoring site for NO_2 was the Lake Jackson Monitor (EPA Monitor 48-039-1016), located in the southern part of Brazoria County. The representative monitoring site for CO was located in Brownsville, Texas (EPA Monitor 48-061-0006). The representative monitoring site for PM_{10} and $PM_{2.5}$ was the Dona Park monitor (EPA Monitor 48-355-0034), located in Nueces County. Table 4.11-20 shows the results for the cumulative NAAQS analysis. The modeled concentrations for NO_2, CO, PM_{10}, and $PM_{2.5}$, when combined with representative background concentrations, were predicted to be below their corresponding NAAQS.

Table 4.11-20
Sinton Compressor Station - Cumulative NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	102.02	42.45	144.47	188
	Annual	3.77	6.78	10.55	100
CO	1-hour	6,325.14	2,125.48	8,450.62	40,000
	8-hour	4,836.42	1,125.26	5,961.68	10,000
PM_{10}	24-hour	12.81	67.0	79.81	150
$PM_{2.5}$	24-hour	13.35	20.67	34.02	35
	Annual	1.38	9.37	10.75	15

For the PSD increment consumption analysis, the Sinton Compressor Station sources as well as off-site emission sources were modeled. Per the request of TCEQ, only increment consuming sources were included (i.e., reductions in emissions from shutdown sources could not be accounted for in the modeling). As shown in table 4.11-21, the modeled impacts for NO_2, PM_{10}, and $PM_{2.5}$ were predicted to be below their corresponding PSD increments.

Table 4.11-21
Sinton Compressor Station - PSD Increment Consumption Modeling Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
NO_2	Annual	3.77	25
PM_{10}	24-hour	19.72	30
$PM_{2.5}$	24-hour	8.72	9
	Annual	0.55	4

An Additional Impact Analysis was conducted, as required by the PSD regulations. For the growth analysis, no significant commercial, residential, or industrial growth is expected as a result of construction/operation of the Sinton Compressor Station.

In Texas, if a facility complies with visibility and opacity requirements specified in 30 TAC Chapter 111, no additional visibility impact analyses are required. Cheniere would comply with visibility and opacity requirements specified in 30 TAC Chapter 111. Because the combustion units at the Sinton Compressor Station would use only natural gas as fuel, we do not anticipate significant impacts to regional visibility.

4.11.2 Noise

Noise would affect the local environment during both the construction of the Project facilities and operation of each of the proposed compressor stations associated with the Project. At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions, the effects of seasonal vegetative cover, and man-made activities.

Two measures used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the equivalent sound level (L_{eq}) and the day-night average sound level (L_{dn}). The L_{eq} is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the L_{eq} with 10 decibels on the A-weighted scale (dBA) added to nighttime sound levels between the hours of 10:00 PM and 7:00 AM to account for people's greater sensitivity to sound during nighttime hours. The A-weighted scale is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies. A person's threshold of perception for a perceivable change in loudness on the A-weighted sound level is on average 3 dBA, whereas a 5 dBA change is clearly noticeable and a 10 dBA change is perceived as twice or half as loud.

4.11.2.1 Regulatory Requirements

In 1974, the EPA published Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety (EPA, 1974). This document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has determined that, to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an L_{dn} of 55 dBA. We have adopted this criterion and use it to evaluate the potential noise impacts from the Project at NSAs, such as residences, schools, or hospitals. Due to the 10 dBA nighttime penalty added prior to calculation of the L_{dn}, for a facility to meet the L_{dn} 55 dBA limit, it must be designed such that actual constant noise levels on a 24-hour basis do not exceed 48.6 dBA L_{eq} at any NSA.

Based on a review of state regulations, there are no noise quality regulations or ordinances at the state or county level that are 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, the City of Corpus Christi ordinance requirements are not applicable to the Project. The City of Portland's Municipal Code of Ordinances provides a noise limit of 63 dBA at the residential property line:

The ordinance listed above is generally less stringent for residences than the FERC limit. However, in the unusual situation of a house set back on a very large parcel of land, the FERC sound level limit could be satisfied at the house and the Portland City Ordinance limit exceeded at the property line. Upon review of the site and existing NSAs for the Project, this unusual condition is not expected to occur.

4.11.2.2 Existing Noise Levels

Impacts at the Terminal, two compressor stations, and three HDD crossings have been evaluated for adjacent NSAs and surrounding ambient noise levels.

Terminal

There are no NSAs within a 1-mile radius of the proposed Terminal. For the purposes of studying noise impacts for the proposed Terminal and dredging activities, the nearest five NSAs were identified. These NSAs are shown on figure 4.11-1 and are located about 1.6 to 3.2 miles from the noise-producing equipment at the Terminal. The NSAs include residential communities, Ingleside High School, two churches, and a hotel.

Cheniere's consultant, Tetra Tech, conducted a noise survey from February 16 to February 17, 2012 to characterize the existing acoustic environment in the vicinity of the Terminal site. Principal contributors to the acoustic environment include existing industrial facilities, motor vehicle traffic on local roadways, periodic aircraft flyovers and rail movements, and natural sounds such as birds, insects, and leaf or vegetation rustle during elevated wind conditions. Table 4.11-23 summarizes the results of the baseline sound measurements for the Terminal. The measured L_{dn} sound levels ranged from 51 to 54 dBA, indicating a relative acoustic consistency across the area in the vicinity of the Terminal site, with NSAs exposed to both similar sound sources and overall background sound levels.

Table 4.11-22
Terminal - Baseline Measurement Results

NSA	Distance from site to NSA (miles)	Direction from site to NSA	Monitoring Location ID	Sound Level L_{dn} dBA
1	1.6	SW	ST-1	53
2	2.1	W	ST-2	54
3	2	NW	ST-3	53
4	2.5	NW	ST-4	54
5	3.2	E	ST-5	51

Figure 4.11-1 Terminal and Dredging NSA Locations and Distances

Pipeline

Baseline sound measurements were conducted in the vicinity of the two proposed compressor station sites near the towns of Taft and Sinton from May 22 to May 24, 2012. The NSAs identified for the compressor station sound surveys are shown in figure 4.11-2 and figure 4.11-3. Table 4.11-24 summarizes the results of the baseline sound measurements for the Sinton and Taft Compressor Stations. The measured L_{dn} sound levels ranged from 55 to 64 dBA.

Figure 4.11-2 Sinton Compressor Station NSA Locations and Distances

Figure 4.11-3 Taft Compressor Station NSA Locations and Distances

Table 4.11-23
Compressor Stations - Baseline Measurement Results

Site	NSA	Distance from site to NSA (miles)	Direction from site to NSA	Monitoring Location ID	Sound Level L_{dn} dBA
Sinton CS	1	0.6	SE	S-1	55
Taft CS	1	0.7	E	T-2	59
	2	0.9	NW	T-2	59
	3	1.4	N	T-1	64
	4	1.0	NE	T-1	64

At the Sinton Compressor Station site, one NSA was identified, representative of a grouping of privately owned cabins approximately 3,300 feet southeast of the proposed Sinton Compressor Station site. A representative monitoring location was selected approximately 0.5-mile from the intersection of Edwards Road and US 77. The ambient acoustic environment included sounds from distant highway traffic on US 77, birds, distant air conditioning units at one of the cabins, insects, and a night-time train pass-by and horn.

At the Taft Compressor Station site, four NSAs were identified within 1.5 miles; all were residences. Two monitoring locations were selected to represent the ambient sound level environment. The T-1 monitoring location was positioned northeast of the intersection of US 181 and County Road 3465. The T-2 monitoring location was positioned southwest of the intersection of US 181 and County Road 79 (Midway Road). The acoustic environment included sounds from roadway traffic on US 181, wind turbine generators, wind during both daytime and nighttime monitoring, and insect and rodent noise only at night.

Horizontal Directional Drills

Cheniere conducted baseline sound measurements at NSAs in the vicinity of the three proposed HDD crossings. The NSAs identified for the HDD site baseline sound surveys are shown in figures 4.11-4 and 4.11-5. Cheniere has not finalized the entry and exit sides of the crossing points, so the two sites associated with each crossing are labeled as (a) and (b).

Measurements were conducted during the same time period as those conducted for the compressor stations. Table 4.11-25 summarizes the results of the baseline sound measurements for the HDD sites. The results of the baseline sound survey show varying ambient sound levels throughout the HDD areas. The measured daytime sound levels (L_d) ranged from 42 to 58 dBA.

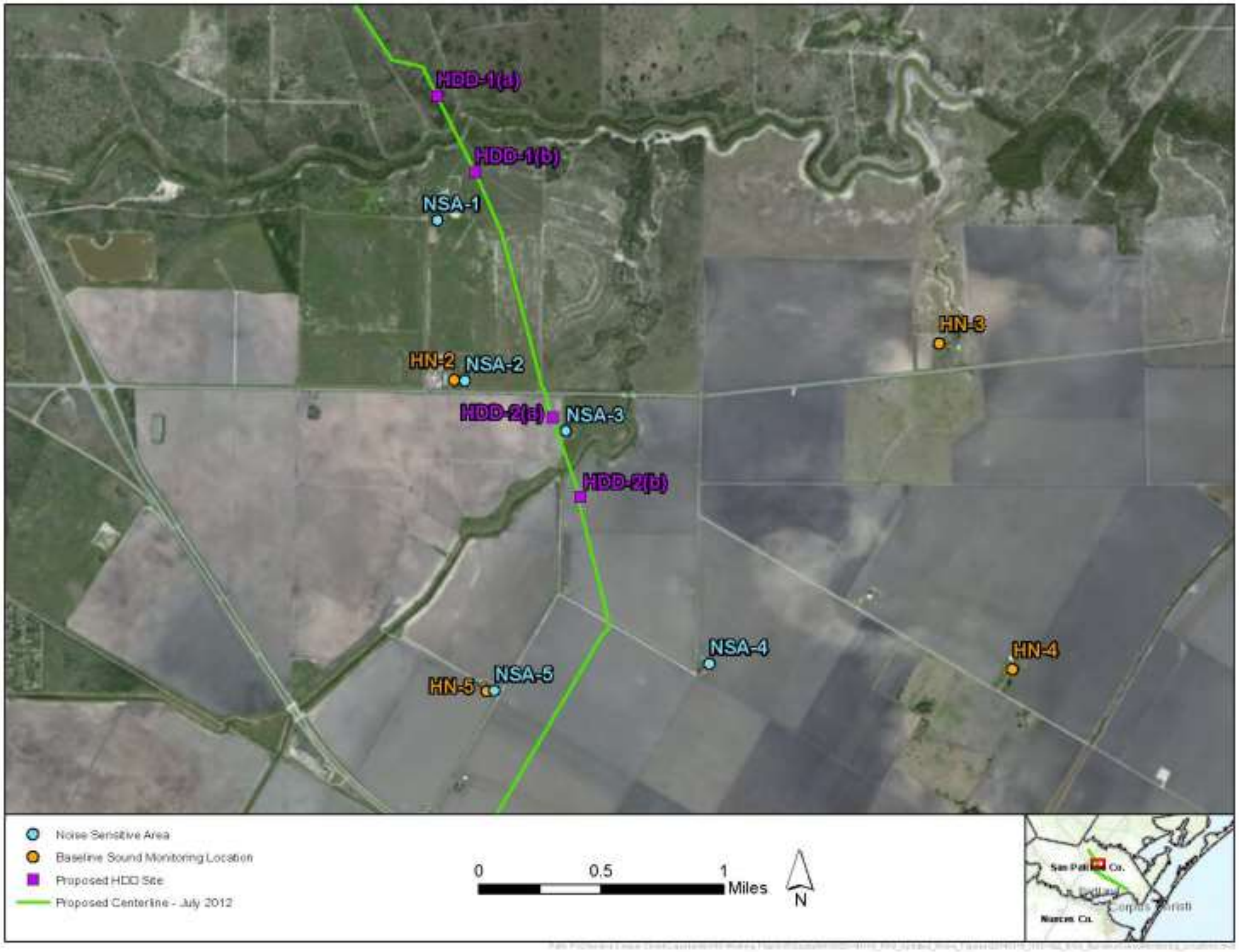

Figure 4.11-4 US 181/SH 35 HDD (HDD-1) and Oliver Creek HDD (HDD-2) NSA Locations and Distances

Figure 4.11-5 Chiltipin Creek HDD (HDD-3) NSA Locations and Distances

The ambient acoustic environments of the Chiltipin Creek HDD crossing and the Oliver Creek HDD crossing sites have similar sound source contributors, including traffic noise on SH 188, birds, insects, and distant traffic noise on U.S. Highway 181.[26] The NSAs at these two HDDs are all residential. The ambient acoustic environment of the US 181/SH 35 HDD crossing sites were influenced by traffic on US 181, SH 35, and local roads; birds, insects, wind, and aircraft fly-overs. The nearest NSAs included residential communities, a hotel and a church.

Table 4.11-24
HDD Locations - Baseline Measurement Results

Crossing	Site	NSA	Distance from site to NSA (miles)	Direction from site to NSA	Monitoring Location ID	L_d
Chiltipin Creek	HDD-1(a)	1	0.4	S	HN-2	57
	HDD-1(b)	1	0.2	SW	HN-2	57
Oliver Creek	HDD-2(a)	3	0.1	SE	HN-2	57
		2	0.3	W	HN-2	57
	HDD-2(b)	3	0.2	N	HN-2	57
		4	0.8	SE	HN-5	42
		5	0.8	SW	HN-5	42
US 181/SH 35	HDD-3(a)	6	0.4	NE	HS-1	58
		7	0.5	S	HS-2	52
		8	0.9	SW	HS-3	53
		9	0.8	NW	HS-4	57
	HDD-3(b)	10	0.4	NE	HS-1	58
		7	0.4	SW	HS-2	52

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[26] The NSAs for the Chiltipin Creek HDD are located farther from both SH 188 and US 181 than the NSAs for the Oliver Creek HDD. It is possible that the measured sound levels at the NSAs for the Chiltipin Creek HDD (HDD 1) are less than the reported values.

4.11.2.3 Noise Quality Impacts and Mitigation

Construction Noise

Construction noise would be generated over an extended period at the Terminal and for a short-term period along the pipeline, compressor stations, and HDD work areas.

Terminal Facilities

The four-year construction activities at the Terminal site would generate increases in sound levels. 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, weather conditions or other unusual circumstances may necessitate nighttime work. Construction noise is highly 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 Terminal construction (consisting of excavation, filling and grading using heavy earth-moving equipment, pile driving for docks, and dredging), would generate the highest sound levels. In general, heavy equipment would be used during this phase of construction. Sound levels at the nearest NSA for each construction phase were calculated. The results ranged from 43 to 48 dBA L_{eq}.

Noise generated during pile-driving for installation of the LNG carrier docks was considered as a separate case of construction noise because activities could occur 24 hours per day. There may be two pile driving machines working simultaneously during construction. One pile driving machine would be located at the west jetty and the other would be located at the east jetty. Assuming two pile drivers in simultaneous 24-hour operation, the predicted L_{dn} value at the nearest NSA (NSA 1) is 47.7 dBA, which is less than the existing ambient sound level.

Dredging noise is not expected to cause a significant environmental noise impact. There are no NSAs located within 0.5 miles of the dredge proposed area, as shown on figure 4.11-1. NSAs and the ambient acoustic environment closest to Project dredging activities are the same at those NSAs identified near the Terminal site. The noise would vary as the activities move nearer or farther from the NSAs, but even at the closest approach using the noisiest dredge option, the temporary dredging contributions are not expected to exceed the FERC noise level criterion. Dredging activities would require approximately six months to complete. Total daily activity work time would vary from 16 to 20 hours, and may occur at any time of day or night, 7 days per week.

Construction noise levels for the Terminal (including pile driving of the LNG carrier docks and dredging activities) are projected below the FERC criterion at the closest NSAs and are not expected to cause a significant impact.

Pipeline Facilities

Compressor Stations

Construction of the Pipeline would result in short-term noise impacts, primarily due to heavy equipment used in clearing and grading, pipe trenching, pipe welding, trench backfill, and right-of-way restoration activities. These activities are temporary and of short duration at any given point along the linear pipeline route.

Noise levels from compressor station construction were conservatively evaluated considering equipment usage factors and construction hours. The estimated noise level from the Sinton Compressor Station would be 50 dBA L_{eq} at the nearest NSA (NSA-1) at 0.6 miles. The estimated noise level from the Taft Compressor Station is projected to be 47 dBA L_{eq} at the nearest NSA (NSA-1) at 0.7 miles. Actual received sound levels would fluctuate, depending on the construction activity, equipment type, and separation distances between source and receiver.

Construction noise may be periodically audible at several residential receptor locations. In order to minimize noise levels associated with compressor station construction, Cheniere identified the following mitigation measures may be implemented to the extent practical:

- Construction site and access road speed limits may be established and enforced during the construction period;
- Electrically-powered equipment may be used instead of pneumatic or internal combustion powered equipment, where feasible;
- Material stockpiles and mobile equipment staging, parking, and maintenance areas may be located as far as practicable from noise-sensitive receptors;
- The use of noise-producing signals, including horns, whistles, alarms, and bells, would be for safety warning purposes only.

Additionally, all noise-producing construction equipment and vehicles using internal combustion engines should be equipped with mufflers, air-inlet silencers where appropriate, and any other shrouds, shields, or other noise-reducing features in good operating condition that meet or exceed original factory specification.

Horizontal Directional Drills

Cheniere proposes three HDD crossings on the Project. Each HDD would require eight days or more to complete. Cheniere has also committed to performing all HDD activities, except potentially the pipe pullback, during daylight hours. HDD operations would occur at one site at a time.

HDD equipment consists of an HDD drilling 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. Sound levels at NSAs resulting from HDD entry and exit operations were calculated using sound power levels of typical equipment. The calculation also assumes the worst case condition that the entry would be nearest the NSA. The results of this analysis are presented in table 4.11-25.

Noise levels from the Chiltipin Creek and US 181/SH 35 HDDs would be below existing noise levels at the nearest NSAs. Potential noise impacts may occur at the Oliver Creek HDD where noise levels would be at or above existing noise levels for several NSAs and would be perceived as twice as loud as existing noise levels at a residence located 300 feet from one site. However, noise levels during daytime hours would not be any louder than other typical construction noise and would not impact night-time sound levels.

Table 4.11-25
Summary of HDD Acoustic Modeling Results

Crossing	Site	NSA	Distance from site to NSA (feet)	Direction from site to NSA	Existing Ld (dBA)	HDD Contribution Ld (dBA)	Combined Ld (dBA)	Net Increase (dBA)
Chiltipin Creek	HDD-1(a)	1	2200	S	57	54.5	59	2
	HDD-1(b)	1	1100	SW	57	54.5	59	2
Oliver Creek	HDD-2(a)	1	300	SE	57	65.7	66	9
		2	1800	W	57	50.2	58	1
	HDD-2(b)	1	1300	N	57	53.2	59	2
		2	4000	SE	42	43.3	46	4
		3	4000	SW	42	43.3	46	4
US 181/ SH 35	HDD-3(a)	1	2400	NE	58	47.8	58	0
		2	2600	S	52	48.6	54	2
		3	4700	SW	53	42.0	53	0
		4	4400	NW	57	42.5	57	0
	HDD-3(b)	1	2200	NE	58	48.6	58	0
		2	2200	SW	52	48.6	54	2

Operational Noise

Terminal Facilities

The Terminal would include the following major noise-producing sources:

- LM2500+G4 gas turbine driven refrigerant compressors;
- Gas treatment facilities;
- Waste heat recovery systems;
- Induced draft air coolers;
- Piping;
- Recycle boil-off gas compressors; and
- Instrument air compressor packages.

Noise contributions for the Terminal were calculated using environmental noise prediction software Cadna/A version 4. The model calculates the total sound pressure level at a specified receiver location or over a grid from all sources.

The following equipment noise mitigation measures are included in this study:

- large air-cooled heat exchangers with a sound power level limit of 99 dBA and a sound pressure level limit of 85 dBA at 1 meter;
- Each gas turbine for refrigerant compression requires a silencer for the gas turbine inlet, gas turbine enclosure, inlet duct, inlet intake, filter house, gas turbine ventilation and auxiliaries, resulting in an average 85 dBA sound pressure level at 1 meter;
- noise hood on gearboxes; and
- compressor suction, discharge and recycle piping are assumed to have 4 inch acoustic insulation.

Predicted L_{dn} values from the Terminal are shown in table 4.11-26 for the five noise sensitive areas identified on figure 4.11-1. Based on results of the noise model summarized above, the Terminal (with the aforementioned noise control measures) would result in a maximum sound level contribution of 51.3 dBA L_{dn} at the nearest NSA. Based on these results, operation of the Terminal would comply with the FERC 55 L_{dn} criterion and City of Portland noise requirements. Therefore, we find that noise impacts due to operation of the Terminal would not be significant. However, to ensure that the actual noise resulting from operation of the Terminal facilities is not significant, **we recommend that:**

- **Cheniere should file a noise survey with the Secretary no later than 60 days after placing each liquefaction train and the entire Terminal in service. If a full load condition noise survey is not possible, Cheniere should provide an interim survey at the maximum possible load and provide the full load survey within six months. If the noise attributable to the operation of all of the equipment for a liquefaction train or at the Terminal, under interim or full load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, Cheniere should file a report on what changes are needed and should install the additional noise controls to meet the level within one year of the in-service date. Cheniere 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.**

Table 4.11-26
Terminal Operational Noise Impact Results

NSA	Distance (miles) and Direction to NSA from CCL Terminal	Existing Ambient L_{dn} (dBA)	Calculated L_{dn} of Proposed Noise Sources (dBA)	Combined L_{dn} (dBA)	Expected Increase (dBA)
NSA-1	1.6	53	50.8	55.0	2.0
NSA-2	2.1	54	49.0	55.2	1.2
NSA-3	2.0	53	49.9	54.7	1.7
NSA-4	2.5	54	50.8	55.7	1.7
NSA-5	3.2	51	48.0	52.8	1.8

Pipeline Facilities

Compressor Stations

Operation of the Sinton and Taft Compressor Stations has the potential to result in noise impacts at nearby NSAs. The facilities for both compressor stations are similar but the Taft Compressor Station would utilize two Solar Centaur 50 turbine/compressor units (6,387 hp each) whereas the Sinton Compressor Station would utilize two Solar Titan 130 turbine/compressor units (20,794 hp each). The following noise sources would be present at the compressor stations:

- Two Solar Centaur 50 turbine/compressor units (6,387 hp each) at the Taft Compressor Station;
- Two Solar Titan 130 turbine/compressor units (20,794 hp each) at the Sinton Compressor Station;
- Discharge gas coolers;
- Lube oil coolers;
- Air compressor;
- Electrical transformer; and
- Aboveground compressor station piping.

Similar to the modeling methodology of the Terminal, Cadna/A was used to model noise generated during Compressor Station operation. Site-specific topography was imported into the model and ground absorption characteristics within the Project area were also considered. Sound attenuation through foliage and diffraction was ignored. Octave band sound power data from the equipment manufacturer were used as inputs to the model wherever possible. In the absence of manufacturer data, reasonable and appropriate assumptions were derived from engineering guidelines and literature.

Cheniere is in the initial engineering phases for each compressor station and has not finalized specific noise mitigation measures. Common vendor information has been applied to each compressor station's acoustic model when available. Final design would be inclusive of a number of noise mitigation measures which may include acoustical enclosures, barriers, silencers, and lagging, in addition to low noise equipment. The principal noise mitigation measures which have been included in the noise analysis are as follows:

- Acoustically insulated compressor station buildings;
- Combustion air inlet silencers;
- Combustion turbines equipped with exhaust silencers; and
- Aboveground piping outside the compressor station building covered with acoustic pipe insulation.

The modeled operational sound from the Taft and Sinton Compressor Stations considers simultaneous operation of all sound sources at their maximum rated loads under normal operating conditions. Results are presented in table 4.11-28, which contains a comparison of the calculated levels with existing levels, the combined future levels, and the expected net increase. The modeling results indicate that the calculated sound levels resulting from compressor station operation at the NSAs are all below the FERC criterion of L_{dn} of 55 dBA. Also, the expected increases in noise levels at the NSAs around both compressor station sites are shown to be negligible. However, to ensure that the actual noise levels resulting from operation of the Sinton and Taft Compressor Stations are not significant, **we recommend that:**

- **Cheniere should file noise surveys with the Secretary <u>no later than 60 days</u> after placing the Sinton and Taft Compressor Stations in service. If a full load condition noise survey is not possible, Cheniere should provide an interim survey at the maximum possible horsepower load and provide the full load survey <u>within six months</u>. If the noise attributable to the operation of all of the equipment at the Sinton or Taft Compressor Station, under interim or full horsepower load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, Cheniere should file a report on what changes are needed and should install the additional noise controls to meet the level <u>within one year</u> of the in-service date. Cheniere 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.**

Table 4.11-27
Operational Noise Impact Results - Compressor Stations

Compressor Station	NSA	Distance (feet) and Direction to NSA from Compressor Station	Existing Ambient L_{dn} (dBA)	Calculated L_{dn} of Proposed Noise Sources (dBA)	Combined L_{dn} (dBA)	Increase Over Existing (dBA)
Sinton	NSA-1	3200 - SE	55	44	55	<1
Taft	NSA-1	3800 - ENE	59	39	59	<1
	NSA-2	4400 - WNW	59	38	59	<1
	NSA-3	7200 - NW	64	33	64	<1
	NSA-4	5300 - NE	64	37	64	<1

Blowdowns

The sound levels associated with high pressure gas venting vary based on initial blowdown pressure, the diameter and type of blowdown valve, and the diameter and arrangement of the downstream vent piping. Blowdown sound levels are loudest at the beginning of the blowdown event and they decrease as the blowdown pressure decreases. There are typically two types of gas blowdown events at compressor stations:

- unit blowdown: a routine gas blowdown that can occur when a compressor is stopped and gas between the suction/discharge valves and compressor(s) is vented to the atmosphere through a blowdown silencer; and

- station blowdown: a gas blowdown, vented via a silencer that occurs when all of the station piping is depressurized.

The blowdown silencers at the stations have been designed to produce no more than 60 dBA at 300 feet, during standard blowdown events in order to reduce the potential for adverse noise impacts. Due to the short duration and infrequent timing of station blowdowns, these events would not influence the 24-hour L_{dn} values projected for these facilities.

Meter and Regulator Stations

Six M&R stations would be installed at interconnects along the Pipeline. Facilities at the M&R stations generally consist of filter separators, liquid handling tank, one bi-directional M&R system, and a 48-inch by 36-inch “T” and valve on the Pipeline. Sound generated from M&R stations is expected to be low level resulting in minimal impacts at NSAs.

4.12 RELIABILITY AND SAFETY

4.12.1 LNG Facility Regulatory Oversight

Three federal agencies share regulatory authority over the siting, design, construction and operation of LNG import and export terminals: the Coast Guard, the DOT, and the FERC. The Coast Guard has authority over the safety of an LNG facility’s marine transfer area and LNG marine traffic, as well as over security plans for the entire LNG facility and LNG marine traffic. Those standards are codified in 33 CFR parts 105 and 127. The DOT establishes federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities, as well as for the siting of marine cargo transfer systems at waterfront LNG plants. Those standards are codified in 49 CFR 193. Under the NGA and delegated authority from the DOE, the FERC authorizes the siting and construction of LNG import and export facilities.

In 1985, the FERC and DOT entered into a memorandum of understanding regarding the execution of each agency’s respective statutory responsibilities to ensure the safe siting and operation of LNG facilities. In addition to FERC’s existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the memorandum of understanding specified that FERC may, with appropriate consultation with DOT, impose more stringent safety requirements than those in Part 193.

In February 2004, the Coast Guard, DOT, and 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, including terminal facilities and tanker 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 DOT and Coast Guard participate as cooperating agencies.

As part of the review required for a FERC authorization, Commission staff must ensure that all proposed facilities would operate safely and securely. The design information that must be filed in the application to the Commission is specified by 18 CFR 380.12 (m) and (o). The level of detail necessary for this submittal requires the Project sponsor to perform substantial front-end engineering of the complete facility. The design information is required to be site-specific and developed to the extent that further detailed design would not result in changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs which we considered during our review process.

The FERC's filing regulations also require each applicant to identify how its proposed design would comply with DOT's siting requirements in 49 CFR 193, Subpart B. As part of our NEPA review, we use this information from the applicant to assess whether or not a facility would have a public safety impact. As a cooperating agency, DOT assists FERC staff in evaluating whether an applicant's proposed siting meets the DOT requirements. If a facility is constructed and becomes operational, the facility would be subject to DOT's inspection program. Final determination of whether a facility is in compliance with the requirements of 49 CFR 193 would be made by DOT staff.

Section 4.12.2 discusses the principal properties and hazards of the materials stored, processed, and handled at the LNG Facility; section 4.12.3 discusses our technical review of the preliminary design of the LNG Facility; section 4.12.4 discusses siting requirements for the LNG Facility; section 4.12.5 discusses the siting analysis of the LNG Facility; section 4.12.6 discusses the safety and security requirements of the LNG carriers associated with the LNG Facility. section 4.12.7 discusses emergency response and evacuation planning for the LNG Facility and along the LNG Carrier Route; and section 4.12.9 discusses the safety of the Pipeline associated with the Project.

4.12.2 LNG Facility Hazards

With the exception of the October 20, 1944, failure at an LNG facility in Cleveland, Ohio, 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. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people[27]. The failure of the LNG storage tank was due to the use of materials inadequately suited for cryogenic temperatures. LNG migrating through streets and into underground sewers due to the lack of adequate spill impoundments at the site was also a contributing factor. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used and that spill impoundments are designed and constructed properly to contain a spill at the site.

Another operational accident occurred in 1979 at the Cove Point LNG facility in Lusby, Maryland. A pump seal failure resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to better ensure that the situation would not occur again.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction facility, which 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 to the 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

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[27] 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.

adjacent liquefaction process and liquid petroleum gas (LPG) separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard would be addressed at the proposed Project, Cheniere would install hazard detection devices at all combustion and ventilation air intake equipment to enable isolation and deactivation of any combustion equipment whose continued operation could add to, or sustain, an emergency.

On March 31, 2014, an explosion and fire occurred at Northwest Pipeline Corporation's LNG peak-shaving facility in Plymouth, Washington. The facility 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. The accident investigation is still in progress. Once developed, measures to address any causal factors which led to this incident will be applied to all facilities under Commission jurisdiction.

4.12.2.1 Hazards Associated with the Proposed Equipment

Before liquefaction, Cheniere would pre-treat the feed gas for removal of mercury, H_2S, and CO_2. The removal of these substances from the feed gas stream can be hazardous as a result from the physical, chemical, flammability, and/or toxicity properties of the substances used or produced during the pretreatment process.

The CO_2 and H_2S would be removed using an activated methyldiethanolamine (a-MDEA or amine) system. Amine is commonly used to remove CO_2 and H_2S in natural gas. The amine solution would be clear or pale yellow with an ammonia odor and is completely soluble in water. The amine solution could result in eye and skin irritation or burns if contacted, upper respiratory tract irritation or death if inhaled, and can be toxic if swallowed. Amine vapor is also flammable in concentrations between approximately 1.4 and 8.8 percent, but would be handled at temperatures below the point at which it could produce enough vapors to form a flammable mixture. The piping and equipment containing amine would be contained if spilled, as discussed under "Impoundment Sizing" in section 4.12.5. Due to its low vapor pressure, the amine solution would not pose a significant hazard to the public, which would have no access to the on-site areas.

Carbon dioxide is a common component of natural gas. The CO_2 would be in its gaseous state and would be colorless and odorless. Carbon dioxide could result in eye and skin irritation if contacted, and respiratory irritation or death if inhaled. Carbon dioxide is non-flammable. Cheniere proposes a design capacity to handle up to 2 percent by volume (% vol) CO_2, in the natural gas stream. The CO_2 would be removed from the natural gas stream to prevent fouling in the liquefaction process and would be accumulated to concentrations exceeding 93% vol during regeneration of the amine. After regeneration, the CO_2 would eventually be vented to the atmosphere after passing through scavenger beds and a thermal oxidizer. Due to the limited amount of CO_2 processed and high concentrations needed to cause asphyxiation, safety hazards associated with the release of CO_2 would be localized at the exit of the thermal oxidizer stack, and therefore, the CO_2 would not pose a significant safety hazard to the public, which would have no access to the on-site areas.

Hydrogen sulfide may also exist in the natural gas stream. Hydrogen sulfide would be in its gaseous state and would be colorless with a rotten egg odor. Hydrogen sulfide could result in eye and skin irritation if contacted, and is toxic and can result in death if inhaled. Cheniere proposes a design capacity to handle up to 4 parts per million by volume (ppm-v) H_2S, however lower concentrations would be expected in the natural gas stream. The H_2S would be removed from the natural gas stream from the amine system to prevent downstream corrosion and fouling in the liquefaction process. During this process, H_2S may accumulate to concentrations up to approximately 0.016% vol during regeneration of the amine. After regeneration, the H_2S would be sent through scavenger beds to be removed. The spent scavenger would be disposed of offsite at a licensed facility and would not pose a significant safety hazard to the public. In the case of a release of H_2S prior to reaching the scavenger beds, Cheniere has provided hazard modeling, as described in section 4.12.5.

Mercury may exist in the natural gas stream, but is not expected to be present. Mercury would be in a liquid state and would be a metallic silver color and is odorless. Mercury could result in toxic effects, including death, if contacted, ingested, or inhaled in certain doses. Cheniere proposes a design capacity to handle up to 20 micrograms per standard cubic meter ($\mu g/Sm^3$) of mercury. Mercury would be removed to prevent corrosion and potential liquid metal embrittlement of downstream aluminum heat exchangers through the use of sulfur-impregnated activated carbon beds to form mercuric sulfide, which is stable and insoluble. The sulfur impregnated carbon beds would have enough capacity to last at least four years before the beds would need to be replaced. Maintenance and safety procedures would cover the proper replacement and disposal of the mercuric sulfide within the carbon beds and would not pose a safety hazard to the public, which would have no access to the on-site areas.

In addition to the removal of H_2S, CO_2, and mercury, Cheniere would also install a heavy hydrocarbon removal system to remove hydrocarbons that may be present in the natural gas stream and could freeze and foul the liquefaction process. The hydrocarbons heavier than methane would be separated out through a series of distillation columns. The lighter hydrocarbons that exist as liquids under elevated pressures often present in a natural gas transmission pipeline, such as ethane, propane, and butane, are often referred to as natural gas liquids (NGLs). The NGLs would not freeze during the liquefaction process and would be recycled back into the natural gas stream before liquefaction. The NGLs are not toxic, but are flammable and can present overpressure hazards if ignited. The heavier hydrocarbons that exist as liquids near atmospheric pressure, such as pentane, hexane, benzene, toluene, ethylbenzene, and xylene, are referred to as condensates. These components would freeze during the liquefaction process and damage or foul equipment. Therefore, these components would be removed from the natural gas stream as liquids and sent to floating roof storage tanks where they would be either pumped into an existing condensate pipeline or transferred to tanker trucks for removal in the event that the stabilized condensate does not meet the applicable quality specifications of the pipeline. Most of the stabilized condensate components are flammable and some are toxic. Any liquid spill would be contained in impoundments, as discussed under “Impoundment Sizing” in section 4.12.5. Cheniere has provided modeling in the case of an accidental release of NGLs and stabilized condensate, also described in section 4.12.5.

After pre-treatment, the treated natural gas would then be liquefied into LNG through a series of heat exchangers utilizing ethylene, propane, and methane as refrigerants. The LNG would then be stored on-site in atmospheric storage tanks before being transferred to LNG carriers for export. The refrigerants would also be stored on-site and periodically re-filled as needed. The LNG and refrigerants are not toxic, but are flammable and some can present overpressure hazards if ignited. Any liquid spill would be contained in impoundments, as discussed under "Impoundment Sizing" in section 4.12.5. Cheniere has provided modeling in the case of an accidental release of LNG and refrigerants, also described in section 4.12.5.

Loss of Containment

A loss of the containment is the initial event that results in all other potential hazards. The initial loss of containment can result in a liquid and/or gaseous release with the formation of vapor at the release location, as well as from any liquid that pooled. The fluid released may present low or high temperature hazards, and may result in the formation of toxic and flammable vapors. The extent of the hazard will depend on the material released, the storage and process conditions, and the volumes released.

Cheniere would store LNG at atmospheric pressure and at a cryogenic temperature of approximately -260°F; liquid ethylene at approximately 45 psig and a cryogenic temperature of approximately -110°F; and liquid propane at ambient temperature and elevated pressures of approximately 125 psig, similar to the conditions typically used in propane storage and distribution. However, lower temperatures of propane would exist during the refrigeration process and upon a release the rapidly expanding gas may further cool. The NGLs would vary from approximately -88°F to 316°F and at approximately 40 psig to 620 psig. Condensate storage would be at near atmospheric pressure and temperature.

Due to the temperature and pressure conditions under which these liquids would be handled onsite, loss of containment of these liquids could lead to the release of both liquid and vapor into the immediate area. Contact with either cold liquid or vapor could cause freeze burns or frostbite for personnel in the immediate area or more serious injury or death depending on the length of exposure. However, spills would be contained to on-site areas and the cold state of these releases would be greatly limited due to the continuous mixing with the warmer air. The cold temperatures from the release would not present a safety hazard to the public, which would not have access to on-site areas.

These releases may also quickly cool any materials contacted by the liquid on release, causing extreme thermal stress in materials not specifically designed for such conditions. These thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength. These temperatures, however, would be accounted for in the design of equipment and structural supports, and would not be substantially different from the hazards associated with the storage and transportation of liquid oxygen (-296ºF) or several other cryogenic liquids that have been routinely produced and transported in the United States.

A rapid phase transition (RPT) can occur when a cryogenic liquid is spilled onto water and changes from liquid to gas, virtually instantaneously. Unlike an explosion that releases energy and combustion products from a chemical reaction, an RPT is the result of heat transferred to the liquid inducing a change to the vapor state. RPTs have been observed during LNG test spills onto water. In some test cases, the overpressures generated were strong enough to damage test equipment in the immediate vicinity of the LNG release point. The sizes of the overpressure events have been generally small and are not expected to cause significant damage. The average overpressures recorded at the source of the RPTs during the Coyote tests have ranged from 0.2 pounds per square inch (psi) to 11 psi[28]. These events are typically limited to

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[28] The Lawrence Livermore National Laboratory conducted seven tests (the Coyote series) on vapor cloud dispersion, vapor cloud ignition, and RPTs at the Naval Weapons Center in China Lake, California in 1981.

the area within the spill and are not expected to cause damage outside of the area engulfed by the LNG pool. However, a RPT may affect the rate of pool spreading and the rate of vaporization for a spill on water.

Vapor Dispersion

In the event of a loss of containment, LNG, ethylene, propane, and NGLs would vaporize on release from any storage or process facilities. Depending on the size of the release, they may also form a liquid pool and vaporize. Additional vaporization would result from exposure to ambient heat sources, such as water or soil. When released from a containment vessel or transfer system, LNG will generally produce 620 to 630 standard cubic feet (ft^3) of natural gas for each cubic foot of liquid. Ethylene will produce approximately 375 ft^3 of gas for each cubic foot of liquid. Propane will produce approximately 250 ft^3 of gas for each cubic foot of liquid. The composition of NGL would vary throughout the heavy hydrocarbon removal process and may produce up to 380 ft^3 of gas for each cubic foot of liquid. In the event of a loss of containment of stabilized condensate, the stabilized condensate would spill primarily as a liquid and form a pool, but would vaporize much more slowly than NGL.

The vapor may form a toxic or flammable cloud depending on the material released. The dispersion of the vapor cloud will depend on the physical properties of the cloud, the ambient conditions, and the surrounding terrain and structures. Generally, a denser-than-air vapor cloud would sink to the ground due to the relative density of the vapor to the air and would travel with the prevailing wind, while a lighter-than-air vapor cloud would rise and travel with the prevailing wind. The density will depend on the material releases and the temperature of the material. For example, a LNG release would initially form a denser-than-air vapor cloud and transition to lighter-than-air vapor cloud as the vapor disperses downwind and mixes with the warm surrounding air; a liquid ethylene release would form a denser-than-air vapor cloud and transition to a neutrally buoyant vapor cloud as it mixes with the warm surrounding air; and a propane, NGL, or condensate release would form a denser-than-air vapor cloud and would remain denser than the surrounding air, even after warming to ambient temperatures. However, experimental observations and vapor dispersion modeling indicate a LNG vapor cloud would not typically be warm, or buoyant, enough to lift off from the ground before the LNG vapor cloud disperses below its lower flammable limit (LFL).

The vapor cloud would continue to be hazardous until it dispersed below toxic levels and/or flammable limits. Toxicity is primarily dependent on the concentration of the vapor cloud in the air and the exposure duration, while flammability of the vapor cloud is primarily dependent just on the concentration of the vapor when mixed with the surrounding air. In general, higher concentrations within the vapor cloud would exist near the spill, and lower concentrations would exist near the edge of the cloud as it disperses downwind.

Toxicity is defined by a number of different agencies for different purposes. Acute Exposure Guideline Levels (AEGLs) and Emergency Response Planning Guidelines (ERPGs) are recommended for use by federal, state, and local agencies, as well as the private sector for emergency planning, prevention, and response activities related to the accidental release of hazardous substances[29]. Other federal agencies, such as the Department of Energy, EPA, and NOAA, use AEGLs and ERPGs as the primary measure of toxicity[30,31,32].

There are three AEGLs and ERPGs which are distinguished by varying degrees of severity of toxic effects with AEGL-1 and ERPG-1 (level 1) being the least severe to AEGL-3 and ERPG-3 (level 3) being the most severe. AEGL-1 is the airborne concentration of a substance that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, these effects are not disabling and are transient and reversible upon cessation of the exposure. AEGL-2 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape. AEGL-3 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death. ERPG levels have similar definitions, but are based on the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to 1 hour without experiencing similar effects defined in each of the AEGLs. The EPA provides ERPGs (1 hour) and AEGLs at varying exposure times (10 minutes, 30 minutes, 1 hour, 4 hours, and 8 hours) for a list of chemicals. AEGLs are used preferentially as they are more inclusive and provide toxicity levels at various exposure times. The preferential use of AEGLs is also done by DOE and NOAA. The toxic properties for the various material components stored and processed on-site are tabulated in table 4.12-1.

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[29] U.S. Environmental Protection Agency, *Sources of Acute Dose Response Information*, http://www.epa.gov/ttn/atw/toxsource/acutesources.html, December 3, 2013.

[30] U.S. Department of Energy, *Temporary Emergency Exposure Limits for Chemicals: Methods and Practice*, DOE Handbook, DOE-HDBK-1046-2008, August 2008.

[31] U.S. Environmental Protection Agency, *40 CFR 68 Final Rule: Accidental Release Prevention Requirements: Risk Management Programs Under Clean Air Act Section 112(r)(7)*, 61 Federal Register 31667-31732, Vol. 61, No. 120, Thursday, June 20, 1996.

[32] U.S. National Oceanic and Atmospheric Administration, *Public Exposure Guidelines*, http://response.restoration.noaa.gov/oil-and-chemical-spills/chemical-spills/resources/public-exposure-guidelines.html, December 3, 2013.

Table 4.12-1
Toxicity Levels (in ppm) [33,34]

Compound	AEGL Level	10 min	30 min	60 min	4 hr	8 hr
H2S	AEGL 1	0.75	0.60	0.51	0.36	0.33
	AEGL 2	41	32	27	20	17
	AEGL 3	76	59	50	37	31
n-Hexane	AEGL 1	-	-	-	-	-
	AEGL 2	4,000 a/	2,900 a/	2,900 a/	2,900 a/	2,900 a/
	AEGL 3	12,000 c/	8,600 b/	8,600 b/	8,600 b/	8,600 b/
Benzene	AEGL 1	130	73	52	18	9
	AEGL 2	2,000 a/	1,100	800	b/	200
	AEGL 3	9,700 b/	5,600 a/	4,000 a/	2,000 a/	990
Toluene	AEGL 1	200	200	200	200	200
	AEGL 2	3,100 a/	1,600	1,200	790	650
	AEGL 3	13,000 b/	6,100 a/	4,500 a/	3,000 a/	2,500 a/
EthylBenzene	AEGL 1	33	33	33	33	33
	AEGL 2	2,900	1,600	1,100	660	580
	AEGL 3	4,700	2,600	1,800	1,000	910
Xylenes	AEGL 1	130	130	130	130	130
	AEGL 2	2,500 a/	1,300 a/	920 a/	500	400
	AEGL 3	7,200 b/	3,600 a/	2,500 a/	1,300 a/	1,000 a/

a/ =≥10% LFL
b/ =≥50% LFL
c/ =≥100%LFL

In addition, methane and heavier hydrocarbons are classified as simple asphyxiants and may pose extreme health hazards, including death, if inhaled in significant quantities within a limited time. Very cold methane and heavier hydrocarbons vapors may also cause freeze burns. However, the locations of concentrations where cold temperatures and oxygen-deprivation effects could occur are greatly limited due to the continuous mixing with the warmer air

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[33] U.S. Environmental Protection Agency, *Acute Exposure Guideline Levels*, http://www.epa.gov/oppt/aegl/pubs/chemlist.htm, December 3, 2013.

[34] American Industrial Hygiene Association, *2013 ERPG/WEEL Handbook*, http://www.aiha.org/get-involved/AIHAGuidelineFoundation/EmergencyResponsePlanningGuidelines, 2013.

surrounding the spill site. For that reason, exposure injuries from contact with releases of methane and heavier hydrocarbons normally represent negligible risks to the public.

Flammable vapors can develop when a flammable material is above its flash point and concentrations are between the LFL and the upper flammable limit (UFL). Concentrations between the LFL and UFL can be ignited, and concentrations above the UFL or below the LFL would not ignite. The flammable properties for the various material components stored and processed on-site are tabulated in table 4.12-2.

Table 4.12-2
Flammable Properties[35]

Material Component	**Flash Point**	**LFL** (% vol)	**UFL** (% vol)
Methane	-283°F	5.0	15.0
Ethylene	-250°F	2.7	36
Ethane	-211°F	3.0	12.5
Propane	-155°F	2.1	9.5
n-Butane	-76°F	1.8	8.5
i-Butane	-105°F	1.8	8.4
n-Pentane	-56°F	1.4	7.8
i-Pentane	-60°F	1.4	7.6
CycloPentane	-35°F	1.35	9.4
n-Hexane	-7.6°F	1.2	7.5
i-Hexane	-20°F	1.2	7.0
CycloHexane	-20°F	1.3	8.0
n-Heptane	30°F	1.05	7.0
i-Heptane	0°F	1.05	7.0
n-Octane	63°F	0.80	6.5
i-Octane	10°F	1.0	5.6
n-Nonane	99°F	0.70	5.6
n-Decane	126°F	0.75	5.4
n-Undecane	149°F	0.70	4.8
n-Dodecane	162°F	0.60	4.7
Benzene	11°F	1.4	7.1
Toluene	45°F	1.2	7.1
EthylBenzene	75°F	1.0	6.7
m-Xylene	77°F	1.1	7.0
o-Xylene	75°F	1.1	6.0
p-Xylene	77°F	1.1	7.0
H_2S	-116°F	4.0	44

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[35] Society of Fire Protection Engineers, *The SFPE Handbook of Fire Protection Engineering*, Fourth Edition, 2008.

The extent of the affected area and the severity of the impacts on objects within a vapor cloud would primarily be dependent on the material, quantity, and duration of the initial release, the surrounding terrain, and the environmental conditions present during the dispersion of the cloud. Cheniere has modeled the extent of the potential vapor dispersion hazards for the Project, which is discussed in section 4.12.5.

Flammable Vapor Ignition

If the flammable portion of a vapor cloud encounters an ignition source, a flame would propagate through the flammable portions of the cloud. In most circumstances, the flame would be driven by the heat it generates. This process is known as a deflagration, or a flash fire because of its relatively short duration. However, exposure to a deflagration, or flash fire, can cause severe burns and death, and can ignite combustible materials within the cloud. Cheniere has modeled the extent of the potential flammable vapor dispersion hazards for the Project, which is discussed in section 4.12.5.

If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves that can cause damage would be generated. As a deflagration accelerates to super-sonic speeds, the large shock waves produced, rather than the heat, would begin to drive the flame, resulting in a detonation. The flame speeds are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance. Cheniere has modeled the extent of the potential overpressure hazards for the Project, which is discussed in section 4.12.5.

Once a vapor cloud is ignited, the flame front may propagate back to the spill site if the vapor concentration along this path is sufficiently high to support the combustion process. When the flame reaches vapor concentrations above the UFL, the deflagration could transition to a fireball and result in a pool or jet fire back at the source. A fireball would occur near the source of the release and would be of a relatively short duration compared to an ensuing jet or pool fire. The extent of the affected area and the severity of the impacts on objects in the vicinity of a fire would primarily be dependent on the material, quantity, and duration of the fire, the surrounding terrain, and the environmental conditions present during the fire. Cheniere has modeled the extent of the potential radiant heat hazards for the Project, which is discussed in section 4.12.5.

Cascading Events

Fires and overpressures may also cause failures of nearby storage vessels, piping, and equipment if not properly mitigated. These failures are often termed cascading events or domino effects and can exceed the consequences of the initial hazard.

The failure of a pressurized vessel could cause fragments of material to fly through the air at high velocities, posing damage to surrounding structures and a hazard for operating staff, emergency personnel, or other individuals in proximity to the event. In addition, failure of a pressurized vessel when the liquid is at a temperature significantly above its normal boiling point could result in a boiling-liquid-expanding-vapor explosion (BLEVE). BLEVEs can produce overpressures when the superheated liquid rapidly changes from a liquid to a vapor upon the release from the vessel. BLEVEs of flammable fluids may also ignite upon its release and cause a subsequent fireball.

Failures of nearby storage vessels, piping, and equipment and the potential for cascading events are discussed in this section 4.12.5. Cheniere has mitigated the risk for cascading event hazards for the Project, which is also discussed in section 4.12.5.

4.12.3 Technical Review of the Facility Preliminary Engineering Design

Operation of the proposed facility poses a potential hazard that could affect the public safety if strict design and operational measures to control potential accidents are not applied. The primary concerns are those events that could lead to an LNG spill of sufficient magnitude to create an off-site hazard as discussed in section 4.12.2. However, it is important to recognize the stringent requirements in place for the design, construction, operation, and maintenance of the facility, as well as the extensive safety systems proposed to detect and control potential hazards.

In general, we consider an acceptable design to include various layers of protection or safeguards in the facility design to reduce the risk of a potentially hazardous scenario from developing into an event that could impact the off-site public. These layers of protection are independent of one another so that any one layer would perform its function regardless of the action or failure of any other protection layer or initiating event. Such design features and safeguards typically include:

- A facility design that prevents hazardous events through the use of inherently safer designs; suitable materials of construction; operating and design 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 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 structural fire protection, to prevent escalation to a more severe event;
- Site security measures for controlling access to the facility, including security inspections and patrols; response procedures to any breach of security and liaison with local law enforcement officials; and
- On-site and off-site 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.

The inclusion of such protection systems or safeguards in a facility design can minimize the potential for an initiating event to develop into an incident that could impact the safety of the off-site public. In addition, siting of the facility with regard to potential off-site consequences can be further used to minimize impacts to public safety. As discussed in section 4.12.4, DOT's regulations in 49 CFR 193, Subpart B require a siting analysis be performed by Cheniere.

As part of the application, Cheniere provided a FEED for the Project. In developing the FEED, Cheniere conducted a hazard identification study of the process flow diagram (PFD) to identify potential risk scenarios. This helped to establish the required safety control levels and identify whether additional process and safety instrumentation, mitigation, and/or administrative controls would be needed. We have analyzed the information filed by Cheniere to determine the extent that layers of protection or safeguards to enhance the safety, operability, and reliability of the facility are included in the FEED.

The objectives of our FEED review focused on the engineering design and safety concepts of the various protection layers, as well as the projected operational reliability of the proposed facilities. The design would use materials of construction suited to the pressure and temperature conditions of the process design. Piping would be designed in accordance with ASME B31.3. Pressure vessels would be designed in accordance with ASME Section VIII and the storage tanks would be designed in accordance with American Petroleum Institute (API) Standard 620, per 49 CFR 193 and the National Fire Protection Association's Standard 59A (NFPA 59A). All LNG storage tanks would also include boil-off gas compression or re-liquefaction to prevent the release of boil-off to the atmosphere in accordance with NFPA 59A for an inherently safer design. Valves and other equipment would be designed to recommended and generally accepted good engineering practices. Cheniere states that its facility would be designed to withstand a sustained wind of 150 mph in accordance with 49 CFR 193.2067(b)(2)(i), which would also exceed the 10,000 year mean return interval or 0.5 percent probability of exceedance in a 50-year period requirement in federal regulations of 49 CFR 193.2067(b)(2)(ii)[36]. The base plant elevation would be at a height of 25 feet or greater NAVD 88 or 25.59 feet NGVD 29 to minimize the risk of flooding. This elevation would be able to withstand surge and tide equivalent to 10,000 year mean return interval hurricanes, which would exceed the 100 year mean return interval Base Flood Elevation of 13 feet NVGD 29 as well as a potential storm surge elevation defined by NOAA for a Category 5 hurricane of 20.3 feet NGVD 29[37]. As discussed in Section 4.1.4, we also examined the seismic and structural design of the facility and provided recommendations to deal with the issues identified. In addition, FAA issued Aeronautical Study 2012-ASW-5296-OE[38], indicating there is no substantial adverse effect on the safe and efficient utilization of the navigable airspace. The report concluded that there would be no substantial adverse impact for heights of 529 feet above ground level or 550 feet AMSL. No facilities or equipment would exceed this height. The tallest structures that would be installed would be the flare stacks, LNG storage tanks, and the gas turbine stacks. The LNG storage tanks would be outfitted with lighting and aircraft warning lights and the flare stacks and gas turbine stacks would be marked and lighted in accordance with

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[36] A 150 mph sustained wind speed would correspond to a 183 mph 3-second gust using the Durst Curve in ASCE 7-05 and a 185 mph 3-second gust using a 1.23 gust factor for onshore winds at a coast line recommended in World Meteorological Organization, Guidelines for Converting Between Various Wind Averaging Periods in Tropical Cyclone Conditions. These wind speeds are equivalent to approximately a 14,000 year mean return interval or 0.36 percent probability of exceedance in a 50-year period for the site based on ASCE 7-05 wind speed return period conversions,

[37] Surge and tide of 1 in 10,000 year hurricane (21 feet) and sudden hurricane (14 feet) based on a 30 ft mean lower low water depth in Figure 4.5.1-4and Figure 7-4B, respectively, in API-2INT, Interim Guidance on Hurricane Conditions in the Gulf of Mexico. A sudden hurricane may not allow for evacuation.

[38] Federal Aviation Administration, Determination of no Hazard to Air Navigation, https://oeaaa.faa.gov/oeaaa/external/letterViewer.jsp?letterID=182024301, Aeronautical Study No. 2012-ASW-5296-OE, January 29, 2013.

the FAA Advisory Circular 70/7460-1K, "Obstruction Marking and Lighting." Cheniere would need to extend the FAA determination before the expiration date of July 29, 2014.

Cheniere would install process control valves and instrumentation to safely operate and monitor the facility. Alarms would have visual and audible notification in the control room to warn operators that process conditions may be approaching design limits. Operators would have the capability to take action from the control room to mitigate an upset.

Cheniere would develop facility operation procedures after completion of the final design; this timing is fully consistent with accepted industry practice. We have made recommendations for Cheniere to provide more information on the operating and maintenance procedures as they are developed, including safety procedures, hot work procedures and permits, abnormal operating conditions procedures, and personnel training. In addition, we have recommended measures such as labeling of instrumentation and valves, piping, and equipment and car-seals/locks, to address human factor considerations and improve facility safety. An alarm management program would also be in place to ensure effectiveness of the alarms.

Safety valves and instrumentation would be installed to monitor, alarm, shutdown, and isolate equipment and piping during process upsets or emergency conditions. Safety instrumented systems would comply with International Society for Automation (ISA) Standard 84.01 and other recommended and generally accepted good engineering practices. We also made recommendations on the 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 valves in the facility control system.

Safety relief valves and flares would be installed to protect the process equipment and piping. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per NFPA 59A and ASME Section VIII, and would be designed based on API 520, 521, 527, and other recommended and generally accepted good engineering practices. In addition, we made recommendations to ensure the design and installation of pressure and vacuum relief devices are adequate.

The security requirements for the Project are governed by 49 CFR 193, Subpart J - Security. This subpart includes 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. Requirements for maintaining safety of the liquefaction facility are in the Coast Guard regulations in 33 CFR 127. Requirements for maintaining security of the terminal are in 33 CFR 105.

Title 49, CFR, Part 193, Subpart J – Security, specifies security requirements for the onshore component of LNG facilities. This subpart includes 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. Security at the facility would be provided by both active and passive systems. The site would be surrounded by a protective enclosure (i.e., a fence or natural barrier). The enclosure would be illuminated with not less than 2.2 lux between sunset and sunrise. Title 33 CFR 127 would require even higher intensity lighting at any loading flange and at each work area. Intrusion detection systems and day/night camera coverage would identify unauthorized access. A separate security staff would conduct periodic patrols of the plant, and screen visitors and contractors. The security staff may also assist in maintaining security of the marine terminal during cargo unloading. If the facility is constructed and operated, compliance with the security requirements of 49 CFR 193, including the adequacy of the protective enclosure and illumination intensity, would be subject to the DOT inspection and enforcement program. Compliance with the requirements of 33 CFR 127 would be subject to the Coast Guard inspection and enforcement program.

In addition to the requirements of Part 193, there are also requirements for maintaining security of a marine terminal contained in Coast Guard regulations. Title 33, CFR, Part 105, as authorized by the MTSA, requires all terminal owners and operators to submit a Facility Security Assessment and a Facility Security Plan to the Coast Guard for review and approval. 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, risk assessment methodology, and the responsibility for implementing the Facility Security Assessment and Facility Security Plan and performing an annual audit for the life of the project;
- conducting a Facility Security Assessment to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures;
- developing a Facility Security Plan based on the Facility Security Assessment, with procedures for: responding to transportation security incidents; notification and coordination with local, state, and federal authorities; prevention of unauthorized access; measures and equipment to prevent or deter dangerous substances and devices; training; and evacuation;
- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, vessel stores and bunkers, and monitoring;
- ensuring the Transportation Worker Identification Credential program is properly implemented; and
- reporting all breaches of security and security incidents to the National Response Center.

Under 33 CFR 105, Cheniere would be required to submit a Facility Security Plan to the Coast Guard for review and approval before commencement of operations.

In the event of a release, drainage systems from LNG storage and liquefaction process facilities would direct a spill away from equipment in order to minimize flammable vapors from dispersing to confined, occupied, or public areas and to minimize heat from impacting adjacent equipment and public areas if ignition occurs. Spacing of vessels and equipment between each other, from ignition sources, and to the property line would comply with NFPA 59A and NFPA 30. We also made recommendations to ensure the spacing and designs of impoundments reduce the thermal radiation distances and reduce the risk of cascading failure of future condensate tanks. Impoundment systems are further discussed in section 4.12.5.

Cheniere performed a preliminary fire protection evaluation to ensure that adequate hazard detection, hazard control, and firewater coverage would be installed to detect and address any upset conditions. Structural fire protection, proposed to prevent failure of structural supports of equipment and pipe racks, would comply with NFPA 59A and other recommended and generally accepted good engineering practices. Cheniere would also install hazard detection systems to detect, alarm, and alert personnel in the area and control room to initiate an emergency shutdown and/or initiate appropriate procedures, and would meet NFPA 72, ISA 12.13, and other recommended and generally accepted good engineering practices. Hazard control devices would be installed to extinguish or control incipient fires and releases, and would meet NFPA 59A and NFPA 10, 12, 15, 17, and other recommended and generally accepted good engineering practices. Cheniere would provide automatic firewater systems and monitors for use during an emergency to cool the surface of storage vessels, piping, and equipment exposed to heat from a fire, and would meet NFPA 59A, 20, 22, and 24 requirements. We have made recommendations for Cheniere to provide more information on the design, installation, and commissioning of hazard detection, hazard control, and firewater systems as Cheniere would further develop this information during the final design phase.

Cheniere would also have emergency procedures in accordance with 49 CFR 193 and 33 CFR 127. The emergency procedures would provide for protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the facility. Cheniere would also be required to develop an emergency response plan (ERP) in accordance with the Energy Policy Act of 2005 (EPAct 2005), as discussed further in section 4.12.7.

The use of these protection layers would minimize the potential for an initiating event to develop into an incident that could impact the safety of the off-site public. As a result of the technical review of the information provided by Cheniere in the submittal documents, we identified a number of concerns in information data requests issued on April 8, April 22, and August 16, 2013 relating to the reliability, operability, and safety of the proposed design. Cheniere provided written responses on April 26, May 9, May 30, June 5, June 19, September 23, 2013 in response to staff's questions. However, some of these responses indicated that Cheniere would correct or modify its design in order to address issues raised in the information request. As a result, **we recommend that:**

- **Prior to construction of the final design, Cheniere should file with the Secretary, for review and written approval by the Director of the OEP, information/revisions pertaining to Cheniere's responses, as listed in Table 4.12-3 of the EIS, which indicated features to be included in the final design and documentation.**

Table 4.12-3
Cheniere Responses Indicating Features to be Included in the Final Design of the Projects

FERC Data Request Filing Date	Cheniere Response Filing Date	Data Request Response Number(s)
February 1, 2013	February 21, 2013	60, 73, 77, 78, 80, 81, 82, and 85
February 1, 2013	May 3, 2013	60, 78, and 79
April 8, 2013	April 26, 2013	1, 2, 3, 10, 14, 15, 18, 20, 21, 22, 23, 24, 26, 28, 30, 50, 51, 52, 53, 54, 55, 57, 63, and 79
April 22, 2013	May 9, 2013	5
August 16, 2013	September 5, 2013	2 and 3
August 16, 2013	September 23, 2013	4

The FEED and specifications submitted for the proposed facilities to date are preliminary, but would serve as the basis for any detailed design to follow. If authorization is granted by the Commission, the next phase of the Project would include development of the final design, including final selection of equipment manufacturers, process conditions, and resolution of some safety-related issues. We do not expect that the detailed design information to be developed would result in changes to the basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs that were presented as part of the FEED.

A more detailed and thorough hazard and operability review (HAZOP) analysis would be performed by Cheniere during the final design phase to identify the major hazards that may be encountered during the operation of 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 effects which may result from the design or operation of the facility. Recommendations to prevent or minimize these hazards would be generated from the results of the HAZOP review.

Once the design has been subjected to a HAZOP review, the design development team tracks changes in the facility design, operations, documentation, and personnel. Cheniere would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled. Resolutions of the recommendations generated by the HAZOP review would be monitored by FERC staff. We have included a recommendation that Cheniere should file a HAZOP study on the completed final design.

Information regarding the development of the final design, as detailed below, would need to be filed with the Secretary for review and written approval by the Director of the OEP before equipment construction at the site would be authorized. To ensure that the concerns we've identified relating to the reliability, operability, and safety of the proposed design are addressed by Cheniere, and to ensure that the facility is subject to the Commission's construction and operational inspection program, **we recommend that the following measures should apply to the Cheniere Project. Information pertaining to these specific recommendations should be filed with the Secretary for review and written approval by the Director of OEP either: <u>prior to initial site preparation</u>; <u>prior to construction of final design</u>; <u>prior to commissioning</u>; <u>prior to introduction of hazardous fluids</u>; or <u>prior to commencement of service</u>, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, should be submitted as critical energy infrastructure information pursuant to 18 CFR 388.112. See Critical Energy Infrastructure Information, Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. 31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements, would be subject to public disclosure. All information should be filed <u>a minimum of 30 days</u> before approval to proceed is requested.**

- **<u>Prior to initial site preparation</u>, Cheniere should provide quality assurance and quality control procedures for construction activities.**
- **<u>Prior to initial site preparation</u>, Cheniere should file an overall project schedule, which includes the proposed stages of the commissioning plan.**

- **Prior to initial site preparation, Cheniere should provide procedures for controlling access during construction.**
- **Prior to initial site preparation, Cheniere should provide a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**
- **Prior to initial site preparation, Cheniere should file a complete specification of the proposed LNG tank design and installation.**
- **The final design should include 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.**
- **The final design should include change logs that list and explain any changes made from the FEED provided in Cheniere'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.**
- **The final design should provide an up-to-date equipment list, process and mechanical data sheets, and specifications.**
- **The final design should include three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion.**
- **The final design should include up-to-date PFDs and Piping and Instrument Diagrams (P&IDs). The PFDs should include heat and material balances. The P&IDs should include the following information:**
  - **a. equipment tag number, name, size, duty, capacity, and design conditions;**
  - **b. equipment insulation type and thickness;**
  - **c. storage tank pipe penetration size or nozzle schedule;**
  - **d. piping with line number, piping class specification, size, and insulation type and thickness;**
  - **e. piping specification breaks and insulation limits;**
  - **f. all control and manual valves numbered;**
  - **g. valve high pressure sides and cryogenic ball valve external and internal vent locations;**
  - **h. relief valves with set points; and**
  - **i. drawing revision number and date.**
- **The final design should include a list of all car-sealed and locked valves consistent with the P&IDs.**
- **The final design should include a hazard and operability review 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.**
- **The final design should include spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments.**

- **The <u>final design</u> should provide electrical area classification drawings.**
- **The <u>final design</u> should include 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.**
- **The <u>final design</u> should provide 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; should alarm the hazardous condition; and should shut down the appropriate systems.**
- **The <u>final design</u> should include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control.**
- **The <u>final design</u> should specify fire protection systems, uninterruptable power supply, emergency power generators, emergency lighting, radio communications system, control valves, instrumentation, and shutdown systems associated with the LNG storage tanks and their isolation as Seismic Category 1.**
- **The <u>final design</u> should specify that for hazardous fluids, piping and piping nipples 2 inches or less in diameter are to be no less than schedule 160 for carbon steel and no less than schedule 80 for stainless steel, and are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.**
- **The <u>final design</u> should include 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 required by 49 CFR 193 and should provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing.**
- **The <u>final design</u> should specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses.**
- **The <u>final design</u> should include any isolation valves necessary for initial startup, operation, shutdown, restart, and maintenance procedures.**
- **The <u>final design</u> should include LNG tank fill flow measurement with high flow alarm.**
- **The <u>final design</u> should include boil-off gas (BOG) flow and temperature measurement for each tank.**
- **The <u>final design</u> should include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire.**
- **The <u>final design</u> should specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the BOG Recondenser**

should be the same pressure and temperature rating as the piping at the discharge of the LNG Send-out pumps.

- **The final design should specify that a check valve is provided in the LNG send-out pump minimum flow recycle piping.**
- **The final design should specify discharge valving to allow the pumps to be recirculated without flowing LNG to the vaporizer control valve during initial startup and provide a cooldown bypass valve to pressurize and cool the vaporizer inlet piping.**
- **The final design of the LNG vaporization system should specify that a check valve, vent valve, and manual isolation valve are to be provided downstream of the outlet shut-off valve 00XV-56015.**
- **The final design should specify that the LNG loading arms are equipped with a manual isolation valve at the base of each arm.**
- **The final design should specify the minimum distance required for valve maintenance, between the LNG loading header and the first valve in the discharge piping to the loading arm.**
- **The final design should specify that all drains from high pressure hazardous fluid systems are to be equipped with double isolation and bleed valves.**
- **The final design of the wet gas flare should include a drain or should justify why a drain is not included.**
- **The final design should provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 CFR 193.**
- **The final design should include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, storage tanks, and vent stacks.**
- **The final design should specify that a pressure relief valve is to be provided on the upstream side of the vaporizer outlet shutoff valve. The valve should be sized in accordance with the requirements of NFPA 59A (2001 ed.) Section 5.4.1.**
- **The final design of the LNG vaporization system should include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A (2001 ed.) Section 5.4.1 and should be set at a lower pressure.**
- **The final design should specify that ethylene storage vessels be equipped with redundant full capacity relief valves.**
- **The final design should specify that propane storage vessels be equipped with redundant full capacity relief valves.**
- **The final design should specify that LNG relief valves and LNG drains should not discharge into the boil-off-gas (BOG), vapor return, or fuel gas systems.**

- **The final design should include pressure relieving protection for flammable liquid piping (i.e., condensate products) which can be isolated by valves.**
- **The final design should demonstrate there would not be a potential hazard of a liquid release from LNG reliefs routed to the dry flare and specify that LNG from all other relief valves and drains are to be returned to storage.**
- **The final design should specify that all Emergency Shutdown (ESD) valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS)/Safety Instrumented Systems (SIS).**
- **The final design should include complete plan drawings of the security fencing and of facility access and egress.**
- **The final design should include the cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and setpoints.**
- **The final design should include a plant-wide ESD button with proper sequencing.**
- **The final design should specify that the truck fill line be equipped with an automatic shutoff valve.**
- **The final design should include an updated fire protection evaluation of the proposed facilities carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2 as required by 49 CFR 193. A copy of the evaluation, a list of recommendations, and actions taken on the recommendations and supporting justifications should be filed.**
- **The final design of the hazard detectors should account for the calibration gas when determining the LFL set points for methane, propane, and ethylene, and condensate.**
- **The final design should include complete plan drawings and a list of the hazard detection equipment. Plan 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 proposed hazard detection equipment.**
- **The final design should provide a technical review of its proposed facility design that:**
    a. **identifies all combustion/ventilation air intake equipment and the distances to any possible hazardous fluid release (LNG, flammable refrigerants, flammable liquids and flammable gases); and**
    b. **demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.**
- **The final design should include smoke detection in occupied buildings.**

- **The <u>final design</u> should include hazard detection suitable to detect high temperatures and smoldering combustion in electrical buildings and control room buildings.**
- **The <u>final design</u> should include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable.**
- **The <u>final design</u> should include clean agent systems in the electrical switchgear and instrumentation buildings.**
- **The <u>final design</u> should provide complete plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Drawings should clearly show the location by tag number of all fixed, wheeled, and hand-held extinguishers. The list should include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units.**
- **The <u>final design</u> should include facility plans and drawings showing the proposed location of the firewater and any foam systems. Plan drawings should clearly show the planned location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam generator, and sprinkler. The drawings should also include piping and instrumentation diagrams of the firewater and foam systems.**
- **The <u>final design</u> should specify that the firewater pump shelter is designed with a removable roof for maintenance access to the firewater pumps.**
- **The <u>final design</u> 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. The firewater main header pressure transmitter, 00PT-33091, should also be connected to the DCS and recorded.**
- **<u>Prior to commissioning</u>, Cheniere should file plans and detailed 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>, Cheniere should provide 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. Cheniere should file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued.**
- **<u>Prior to commissioning</u>, Cheniere should tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**
- **<u>Prior to commissioning</u>, Cheniere should file Operation and Maintenance procedures and manuals, including safety procedures, hot work procedures and**

permits, abnormal operating conditions reporting procedures, and management of change procedures and forms.

- **<u>Prior to commissioning</u>, Cheniere should maintain a detailed training log to demonstrate that operating staff has completed the required training.**
- **<u>Prior to commissioning</u>, Cheniere should file a tabulated list and drawings of the proposed hand-held fire extinguishers. The list should include the equipment tag number, extinguishing agent type, capacity, number, and location. The drawings should show the extinguishing agent type, capacity, and tag number of all hand-held fire extinguishers.**
- **<u>Prior to commissioning</u>, Cheniere should file results of the LNG storage tank hydrostatic test and foundation settlement results. At a minimum, foundation settlement results should be provided thereafter annually.**
- **<u>Prior to introduction of hazardous fluids</u>, Cheniere should complete 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.**
- **<u>Prior to introduction of hazardous fluids</u>, Cheniere should complete 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).**
- **<u>Prior to commencement of service</u>, Cheniere should label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A.**
- **<u>Prior to commencement of service</u>, Cheniere should develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Cheniere staff.**
- **<u>Prior to commencement of service</u>, Cheniere should notify FERC staff of any proposed revisions to the security plan and physical security of the facility.**
- **<u>Prior to commencement of service</u>, Cheniere should file progress on construction of the Terminal in <u>monthly</u> reports. Details should include a summary of activities, problems encountered, contractor nonconformance/ deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude should be reported to the FERC <u>within 24 hours</u>.**

In addition, we recommend that the following measures should apply throughout the life of the facility:

- **The facility should be subject to regular FERC staff technical reviews and site inspections on at least an <u>annual</u> basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Cheniere 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 piping and instrumentation diagrams 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 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 (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities should include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site 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, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving natural gas 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 should also 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 also be included in the semiannual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.**
- **In the event the temperature of any region of any secondary containment, including imbedded pipe supports, 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., hazardous fluid releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) should be reported to FERC staff. In the event 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 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 fluid for five 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 facility that contains, controls, or processes a hazardous fluid;

h. any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes a hazardous fluid 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 a facility that contains or processes a hazardous fluid 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 operation of a pipeline or a facility that contains or processes a hazardous fluid;

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

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

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

In addition to the final design review, we would conduct inspections during construction and would review additional materials, including quality assurance and quality control plans, nonconformance reports, and cooldown and commissioning plans, to ensure that the installed design is consistent with the safety and operability characteristics of the FEED. We would also conduct inspections during operation to ensure that the facility is operated and maintained in accordance with the filed design throughout the life of the facility. Based on our analysis and recommendations presented above, the FEED presented by Cheniere would include acceptable layers of protection or safeguards which would reduce the risk of a potentially hazardous scenario from developing into an event that could impact the off-site public.

4.12.4 LNG Facility Siting Requirements

The principal hazards associated with the substances involved in the liquefaction, storage and vaporization of LNG result from cryogenic and flashing liquid releases, flammable and toxic vapor dispersion, vapor cloud ignition, pool fires, BLEVEs, and overpressures. As discussed in section 4.12.3, our FEED review indicates that sufficient layers of protection would be incorporated into the facility design to mitigate the potential for an initiating event to develop into an incident that could impact the safety of the off-site public. Siting of the facility with regard to potential off-site consequences is also required by DOT's regulations in 49 CFR 193, Subpart B as to ensure that impact to the public would be minimized. The Commission's regulations under 18 CFR 380.12(o)(14) require Cheniere to identify how the proposed design complies with the siting requirements of DOT's regulations in 49 CFR 193, Subpart B. As part of our review, we used Cheniere's information, developed to comply with DOT's regulations, to assess whether or not the facility would have a public safety impact. The Part 193 requirements state that an operator or government agency must exercise control over the activities that can occur within an "exclusion zone," defined as the area around an LNG facility that could be exposed to specified levels of thermal radiation or flammable vapor in the event of a release. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The 2001 edition of NFPA 59A, an industry consensus safety standard for the siting, design, construction, operation, maintenance, and security of LNG facilities, is incorporated into Part 193 by reference, with regulatory preemption in the event of conflict. The following sections of Part 193 specifically address the siting requirements applicable to each LNG container and LNG transfer system:

- Part 193.2001, Scope of part, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the marine vessel and the last manifold or valve immediately before a storage tank.
- Part 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). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.
- Part 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).
- Part 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).

For the LNG facilities proposed for the Project, these Part 193 siting requirements would be applicable to the following equipment:

- Three 47,000,000 gallon (160,000 m^3) nominal full containment LNG storage tanks and associated piping and appurtenances - Parts 193.2057 and 2059 require the establishment of thermal and flammable vapor exclusion zones for LNG tanks. NFPA 59A (2001), Section 2.2.3.2 specifies four thermal exclusion zones based on the design spill and the impounding area. NFPA 59A (2001), Sections 2.2.3.3 and 2.2.3.4 specify a flammable vapor exclusion zone for the design spill which is determined with Section 2.2.3.5.

- Two 30-inch-diameter and three 20-inch-diameter LNG transfer lines for the proposed ship (un)loading docks – Parts 193.2001, 2057, and 2059 require thermal and flammable vapor exclusion zones for the marine cargo transfer system. NFPA 59A (2001) does not address LNG transfer systems.
- Twelve in-tank pumps (three 8,806-gallon-per-minute (gpm) pumps and one 4,403-gpm pump for each of the LNG storage tanks) and associated piping and appurtenances; six 6,569-gpm LNG transfer pumps (one operating and one spare for each liquefaction train) and associated piping and appurtenances; and two 1,834-gpm LNG sendout pumps (both operating, no spare common to the facility) and associated piping and appurtenances - Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) Section 2.2.3.2 specifies the thermal exclusion zone and Sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spills for containers and process areas.
- Two 200 MMscf per day of natural gas trains of AAVs (both operating, no spare) with eighteen to twenty fan assisted fin-fan heat exchangers and associated piping and appurtenances common to the facility - Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) Section 2.2.3.2 specifies the thermal exclusion zone and Sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spills for containers and process areas.
- Three liquefaction heat exchangers and associated piping and appurtenances, including a telescoping 16-inch, 24-inch, 30-inch-diameter LNG rundown line, for each of the proposed 4.5 million tons per annum (mtpa) (approximately 700 MMscf per day of natural gas) liquefaction trains - Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) Section 2.2.3.2 specifies the thermal exclusion zone and Sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spills for containers and process areas.

Previous FERC environmental assessments/impact statements for past projects have identified inconsistencies and areas of potential conflict between the requirements in Part 193 and NFPA 59A (2001). Sections 193.2057 and 193.2059 require exclusion zones for each LNG container and LNG transfer system, and an LNG transfer system is defined in Section 193.2007 to include cargo transfer system and transfer piping (whether permanent or temporary). However, NFPA 59A (2001) requires exclusion zones only for "transfer areas," which is defined as the part of the plant where the facility introduces or removes the liquids, such as truck loading or ship-unloading areas. The NFPA 59A (2001) definition does not include permanent plant piping, such as cargo transfer lines. Section 2.2.3.1 of NFPA 59A (2001) also states that transfer areas at the water edge of marine terminals are not subject to the siting requirements in that standard.

The DOT has addressed some of these issues in a March 2010 letter of interpretation.[39] In that letter, DOT stated that: (1) the requirements in the NFPA 59A (2001) for transfer areas

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[39] PHMSA Interpretation "Re: Application of the Siting Requirements in Subpart B of 49 CFR Part 193 to the Mount Hope Bay Liquefied Natural Gas Transfer System" (March 25, 2010).

for LNG apply to the marine cargo transfer system at a proposed waterfront LNG facility, except where preempted by the regulations in Part 193; (2) the regulations in Part 193 for LNG transfer systems conflict with NFPA 59A (2001) on whether an exclusion zone analysis is required for transfer piping or permanent plant piping; and (3) the regulations in Part 193 prevailed as a result of that conflict. The DOT has determined that an exclusion zone analysis of the marine cargo transfer system is required.

In FERC environmental assessments/impact statements for past projects, we have also noted that when the DOT incorporated NFPA 59A into its regulations, it removed the regulation that required impounding systems around transfer piping. As a result of that change, it is unclear whether Part 193 or the adopted sections of NFPA 59A (2001) require impoundments for LNG transfer systems. We note that Part 193 requires exclusion zones for LNG transfer systems, and that those zones were historically calculated based on impoundment systems. We also note that the omission of containment for transfer piping is not a sound engineering practice. For these reasons, we generally recommend containment for all LNG transfer piping within a plant's property lines.

Federal regulations issued by the Occupational Safety and Health Administration (OSHA) under 29 CFR 1910.119 (*Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents* (PSM)), and the EPA under 40 CFR 68 (*Risk Management Plans*) cover hazardous substances, such as methane, propane, and ethylene at many facilities in the U.S. However, OSHA and EPA regulations are not applicable to facilities regulated under 49 CFR 193. On October 30, 1992, shortly after the promulgation of the OSHA Process Safety Management regulations, OSHA issued a letter of interpretation that precluded the enforcement of PSM regulations over gas transmission and distribution facilities. In a subsequent letter on December 9, 1998, OSHA further clarified that this letter of interpretation applies to LNG distribution and transmission facilities.

In addition, EPA's preamble to its final rule in Federal Register, Volume 63, Number 3, 639-645, clarified that exemption from the requirements in 40 CFR 68 for regulated substances in transportation, including storage incident to transportation, is not limited to pipelines. The preamble further clarified that the transportation exemption applies to LNG facilities subject to oversight or regulation under 49 CFR 193, including facilities used to liquefy natural gas or used to transfer, store, or vaporize LNG in conjunction with pipeline transportation. Therefore, the above OSHA and EPA regulations are not applicable to facilities regulated under 49 CFR 193. As stated in Section 193.2051, LNG facilities must be provided with the siting requirements of NFPA 59A (2001 edition). The siting requirements for flammable liquids within an LNG facility are contained in NFPA 59A, Chapter 2:

- NFPA 59A, Section 2.1.1 requires consideration of clearances between flammable refrigerant storage tanks, flammable liquid storage tanks, structures and plant equipment, both with respect to plant property lines and each other. This section also 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 Section 2.2.2.2 requires impoundments serving flammable refrigerants or flammable liquids to contain a 10-minute spill of a single

accidental leakage source or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the DOT. In addition, NFPA Section 2.2.2.5 requires impoundments and drainage channels for flammable liquid containment to conform to NFPA 30, Flammable and Combustible Liquids Code.

- NFPA 59A 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 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 LNGFIRE or using models that have been validated by experimental test data appropriate for the hazard to be evaluated and that are acceptable to DOT.
- NFPA 59A 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 alternative models that take into account physical factors influencing LNG vapor dispersion. Alternative models must have been validated by experimental test data appropriate for the hazard to be evaluated and must be acceptable to DOT. Section 2.2.3.5 requires the design spill for impounding areas serving vaporization and process areas to be based on the flow from any single accidental leakage source.

For the following liquefaction facilities that are proposed for the Project, FERC staff identified that the siting requirements from Part 193 and NFPA 59A would be applicable to the following equipment:

- Three liquefaction heat exchangers and associated piping and appurtenances for each of the proposed 4.5 mtpa (approximately 1.9 billion standard cubic feet per day) liquefaction trains;
- Three 75,961-gallon ethylene storage vessels and associated piping and appurtenances common to the facility;
- Two 235,597-gallon propane storage vessels and associated piping and appurtenances common to the facility;
- One 144,000-gallon stabilized condensate storage tank and associated piping and appurtenances common to the facility;
- Three 65-gpm ethylene pump (one per liquefaction train) and associated piping and appurtenances;
- Three 200-gpm propane pump (one per liquefaction train) and associated piping and appurtenances;
- Two 100-gpm condensate send-out pumps and associated piping and appurtenances;
- Twenty-seven reflux pumps (nine per liquefaction train), ranging from 152- to 358-gpm, and associated piping and appurtenances;

- Three 2,340-gpm hot oil pumps and associated piping and appurtenances; and
- Six 53-gpm pentane charge pump (two per liquefaction train) and associated piping and appurtenances.

4.12.5 LNG Facility Siting Analysis

Suitable sizing of impoundment systems and selection of design spills on which to base hazard analyses are critical for establishing an appropriate siting analysis. Although impoundment capacity and design spill scenarios for storage tank impoundments are well described by Part 193, a clear definition for other impoundments is not provided either directly by the regulations or by the adopted sections of NFPA 59A (2001). 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 DOT. However, no definition of single accidental leakage source is provided in the regulations.

We recommend impoundments to be sized based on the greatest flow capacity from a single transfer pipe for 10 minutes, while recognizing that different spill scenarios may be used for the single accidental leakage sources for the hazard calculations required by Part 193. A similar approach is used with impoundments for process vessels. We recommend these to be able to contain the contents of the largest process vessel served, while recognizing that smaller design spills may be appropriate for Part 193 calculations.

4.12.5.1 Impoundment Sizing

Part 193.2181 references NFPA 59A (2001) for siting, which specifies 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. We also consider it prudent design practice to provide a barrier to prevent liquid from flowing to an unintended area (i.e., outside the plant property) in the event that the full containment storage tank primary and secondary containers have a common cause failure. 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.

Table 4.12-4 shows the spill volumes and their corresponding impoundment systems. Cheniere proposes three full containment LNG storage tanks where the outer tank wall would serve as the impoundment system. The proposed LNG storage tanks would have a design maximum volume of 47,463,327 gallons with a maximum potential capacity of 48,030,856 gallons. As shown in Table 4.12-4, the outer tank would have a volumetric capacity of 56,444,124 gallons, which exceeds the 110 percent requirement by 4,234,465 gallons. The outer tank would contain 119 percent of the design maximum volume and 112 percent of the maximum potential capacity of the inner tank, meeting the Part 193 requirements. Cheniere would install a raised access road around the perimeter of the facility, which also serves to limit liquid from flowing off the plant property in the case of a common cause failure of the existing full containment storage tank primary and secondary containers. The raised access road surrounding the proposed LNG storage tanks would meet our recommendation that a barrier be provided to prevent liquid from flowing off plant property.

Potential spills occurring from the LNG Tank withdrawal lines, liquefaction trains, LNG vaporization, and associated pumps, vessels, equipment, piping and appurtenances would drain toward trenches and would be directed to the outside battery limit (OSBL) Impoundment. The trenches would have a rectangular cross-sectional area with a minimum slope of 0.1 percent, and were confirmed to handle the maximum volumetric flow from any single line. The OSBL Impoundment would be a cylindrical impoundment, 70 feet in diameter by 19 feet deep, with a usable capacity of approximately 547,000 gallons. The largest spill to the OSBL Impoundment would be a 10 minute spill volume of 528,340 gallons from a guillotine rupture of the 30-inch-diameter ship transfer (un)loading line. The OSBL Impoundment would also contain spills from the in-tank pump withdrawal header and the LNG rundown line. The proposed LNG storage tank would be equipped with four in-tank pumps, three rated at 8,806 gpm and one at 4,403 gpm. With all four in-tank pumps operating at full rated capacity, the volume for a 10-minute spill from the in-tank pump withdrawal header would be 308,210 gallons. Any spills from the LNG rundown line of the liquefaction trains would include two 6,569 gpm LNG transfer pumps (one operating and one spare) and would be sloped toward trenches leading to the OSBL Impoundment. A 10 minute spill volume from the LNG rundown line assuming three pumps running (one operational per train) would be approximately 197,070 gallons. The OSBL Impoundment would also contain spills from the send-out pump header to the vaporizers. Send-out equipment would include two trains utilizing 1,834-gpm send-out pumps. A 10-minute spill from one of the send-out trains would be 18,340 gallons. These spills would all be contained in the OSBL Impoundment. The proposed OSBL Impoundment would also be able to contain spills from the largest vessels in these areas, including three 75,961-gallon ethylene storage vessels, two 235,597-gallon propane storage vessels, two approximately 176,000-gallon capacity dry gas flare knockout vessels.

Potential spills occurring from the ship transfer line and associated vessels, equipment, piping and appurtenances would drain toward troughs, trenches, and swales and would be directed to the Jetty Impoundment. The swales would have trapezoidal cross-sectional areas with a minimum slope of 0.1 percent, and were confirmed to handle the maximum volumetric flow of 52,384 gpm from the transfer line. The Jetty Impoundment would also be a cylindrical impoundment, 70 feet in diameter by 19 feet deep, with a usable capacity of approximately 547,000 gallons. The largest spill to the Jetty Impoundment would be a 10-minute spill volume of 528,340 gallons from a guillotine rupture of the 30-inch-diameter ship transfer (un)loading line.

Cheniere proposes to install a stabilized condensate product storage tanks with a maximum design volumetric capacity of 237,945 gallons. Containment for the stabilized condensate storage tank would be provided by a concrete pad and wall with dimensions of 150 feet-long by 90 feet-wide by 4 feet-high, and a usable volume of approximately 403,948 gallons.

Cheniere proposes to install a 30,551-gallon amine storage tank within a 50-foot-long by 48-foot-wide by 4-foot-high diked area and a 149,905-gallon amine surge tank within a 70-foot-long by 50-foot-wide by 6-foot, 6-inch-high diked area. The diked areas would have usable volumetric capacities of 71,813 gallons and 170,812 gallons, respectively. The Solvent Regenerator, Solvent Flash Drum, Scavenger Tank, Spent Scavenger Tank, Thermal Oxidizer

KO Drum, and Hot Oil Surge Drum would also have separate containment, as shown in table 4.12-4.

Table 4.12-4
Impoundment Area Sizing

Source	Spill Size (gallons)	Impoundment System	Impoundment Size (gallons)
LNG Storage Tank	48,030,856	Outer Tank Concrete Wall	56,444,124
Ship Transfer line (north)	528,340	OSBL Impoundment	547,000
In-Tank Pump Withdrawal Header	308,210	OSBL Impoundment	547,000
LNG Rundown Line	197,070	OSBL Impoundment	547,000
Sendout Pump Discharge/Vaporizer Inlet	18,340	OSBL Impoundment	547,000
Ethylene Storage Tank	75,961	OSBL Impoundment	547,000
Propane Storage Tank	235,597	OSBL Impoundment	547,000
Dry Gas Flare Knockout Drum	304,581	OSBL Impoundment	547,000
Ship Transfer line (south)	528,340	Jetty Impoundment	547,000
Condensate Storage Tank	237,945	Condensate Containment	403,948
Amine Storage Tank	30,551	Amine Storage Diked Area	71,813
Amine Surge Tank	149,905	Amine Surge Diked Area	170,812
Solvent Regenerator and Solvent Flash Drum	120,400	Solvent Diked Area	205,714
Scavenger Tank	25,814	Scavenger Tanks and Waste Water Dike	161,908
Spent Scavenger Tank	31,412	Scavenger Tanks and Waste Water Dike	161,908
Waste Water Tank	81,694	Scavenger Tanks and Waste Water Dike	161,908
Thermal Oxidizer KO Drum	3,470	Thermal Oxidizer Curbed Area	22,255
Hot Oil Surge Drum	105,983	Hot Oil Surge Drum Dike	158,210

4.12.5.2 Design Spills

Design spills are used in the determination of the hazard calculations required by Part 193. Prior to the incorporation of NFPA 59A in 2000, the design spill in Part 193 assumed the full rupture of "a single transfer pipe which has the greatest overall flow capacity" for not less than 10 minutes (old Part 193.2059(d)). With the adoption of NFPA 59A, the basis for the design spill for impounding areas serving only vaporization, process, or LNG transfer areas became the flow from any single accidental leakage source. Neither Part 193 nor NFPA 59A (2001) defines "single accidental leakage source."

In a letter to FERC staff, dated August 6, 2013, DOT requested that LNG facility applicants contact the Office of Pipeline Safety's Engineering and Research Division regarding the Part 193 siting requirements[40]. Specifically, the letter stated that DOT required a technical review of the applicant's design spill criteria for single accidental leakage sources on a case-by-case basis to determine compliance with Part 193.

In response, Cheniere provided DOT with its design spill criteria and identified leakage scenarios for the proposed equipment. DOT reviewed the data and methodology Cheniere used to determine the single accidental leakage sources for the design spills based on the flow from various leakage sources including piping, containers, and equipment containing LNG, refrigerants, and other hazardous fluids. On February 10, 2014, DOT provided a letter to FERC staff stating that DOT had no objection to Cheniere's methodology for determining the single accidental leakage sources for candidate design spills to be used in establishing the Part 193 siting requirements for the proposed LNG liquefaction facilities[41,42]. The design spills produced by this method were identified in the documents reviewed by DOT and have been filed in the FERC docket for this project. These are the same design spills described in the following sections. However, DOT has indicated in subsequent communications that the design spills should assume all pumps are running unless a mechanical interlock or passive preventive measure is installed and that the design spills should use pump run-out flow rate conditions in failure calculations. Cheniere has not provided sufficient evidence that they have met this criteria for all failure calculations. Inclusion of multiple pumps and pump runout conditions could result in changes to the design spills described in the siting analysis, but may also be mitigated to prevent changes to the conclusion of the siting analyses described. As a result, **we recommend that:**

<u>Prior to initial site preparation</u>, Cheniere should file with the Secretary for review and approval by the Director of OEP, evidence that demonstrates the inclusion of multiple pumps and pump run-out flow rates would not result in any changes to the conclusions of the siting analyses. In the event that any modifications alter the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Cheniere should consult with DOT on any actions necessary to comply with Part 193.

DOT's conclusions on the candidate design spills used in the siting calculations required by Part 193 was based on preliminary design information which may be revised as the engineering design progresses. If Cheniere's design or operation of the proposed facility differs from the details provided in the documents on which DOT based its review, then the facility may not comply with the siting requirements of Part 193. As a result, **we recommend that:**

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[40] August 6, 2013 Letter from Kenneth Lee, Director of Engineering and Research Division, Office of Pipeline Safety to Terry Turpin, LNG Engineering and Compliance Branch, Office of Energy Projects. Filed in Docket Number CP12-507 on August 13, 2013. Accession Number 20130813-4005

[41] February 10, 2014 Letter "Re: Corpus Christi Liquefaction, LLC, A Subsidiary of Cheniere Energy, Inc., Docket No. CP12-507-000, Design Spill Determination" from Kenneth Lee to Lauren H. O'Donnell. Filed in Docket Number CP12-507 on February 10, 2014. Accession Number 20140210-4008

[42] PHMSA based this decision on the following documents: (1) DOT letter to FERC notifying applicants to contact PHMSA for siting requirements, FERC Docket Accession Number 20130813-4005; (2) Corpus Christi Liquefaction response to FERC/PHMSA Data Request, FERC Docket Accession Numbers 20140128-5154 and 20140128-5155; (3) Corpus Christi Liquefaction supplemental response to PHMSA, FERC Docket Accession Numbers 20140207-5085 and 20140207-5086; and (4) Corpus Christi Liquefaction supplemental response to PHMSA, FERC Docket Accession Numbers 20140210-5100 and 20140210-5101 .

- **Prior to the construction of the final design, Cheniere should file with the Secretary for review and approval by the Director of OEP, certification that the final design is consistent with the information provided to DOT as described in the design spill determination letter dated February 10, 2014 (Accession Number 20140210-4008). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Cheniere should consult with DOT on any actions necessary to comply with Part 193.**

As design spills vary depending on the hazard (vapor dispersion, overpressure or radiant heat), the specific design spills used for the Cheniere siting analysis are discussed under "Vapor Dispersion Analyses", "Overpressure Analysis", and "Thermal Radiation Analysis".

4.12.5.3 Vapor Dispersion Analyses

As discussed in section 4.12.2, a release may form a toxic or flammable cloud depending on the material released. A large quantity of flammable material released without ignition would form a flammable vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limit or encountered an ignition source. In order to address these hazards, 49 CFR §193.2051 and 193.2059 require vapor dispersion evaluation of potential incidents and exclusion zones in accordance with applicable sections of NFPA 59A (2001). NFPA 59A, Section 2.1.1 requires consideration of clearances between flammable refrigerant storage tanks, flammable liquid storage tanks, structures and plant equipment, both with respect to plant property lines and each other. This section also 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, Section 2.2.3.4 also 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. Taken together, Part 193 and NFPA 59A (2001) require that flammable vapors either from an LNG tank impoundment or a single accidental leakage source do not extend beyond a facility property line that can be built upon and that other potential incidents (e.g., toxic releases) must also be considered.

Title 49 CFR §193.2059 requires that dispersion distances be calculated for a 2.5 percent average gas concentration (one-half the LFL of LNG vapor) under meteorological conditions which result in the longest downwind distances at least 90 percent of the time. Alternatively, maximum downwind distances may be estimated for stability Class F, a wind speed of 4.5 mph, 50 percent relative humidity, and the average regional temperature. Similar safety factors (i.e., one half the LFL of other flammable materials and one half the AEGL of toxic materials) and similar parameters (i.e., F stability, 2 meters per second wind speed, 50 percent relative humidity, average regional temperature, and 0.03 meter surface roughness) have also been specified for other hazardous fluids.

The regulations in Part 193 specifically approve the use of two models for performing these dispersion calculations, DEGADIS and FEM3A. The use of alternative models is also allowed, but must be specifically approved by the DOT. Although Part 193 does not require the use of a particular source term model, modeling of the spill and resulting vapor production is necessary prior to the use of vapor dispersion models. In August 2010, the DOT issued Advisory

Bulletin ADB-10-07 to provide guidance on obtaining approval of alternative vapor-gas dispersion models under Subpart B of 49 CFR 193. In October 2011, two dispersion models were approved by DOT for use in vapor dispersion exclusion zone calculations: PHAST-UDM Version 6.6 and Version 6.7 (submitted by Det Norske Veritas) and FLACS Version 9.1 Release 2 (submitted by GexCon). PHAST 6.7 and FLACS 9.1, with their built-in source term models, were used to calculate dispersion distances.

As discussed under "Design Spills" in section 4.12.5, failure scenarios must be selected as the basis for the Part 193 dispersion analyses. Process conditions at the failure location would affect the resulting vapor dispersion distances. In determining the spill conditions for these leakage sources, process flow diagrams for the proposed design, used in conjunction with the heat and material balance information (i.e., flow, temperature, and pressure), can be used to estimate the flow rates and process conditions at the location of the spill. In general, higher flow rates would result in larger spills and longer dispersion distances; higher temperatures would result in higher rates of flashing; and higher pressures would result in higher rates of jetting and aerosol formation. Therefore, two scenarios may be considered for each design spill:

1. The pressure in the line is assumed to be maintained by pumps and/or hydrostatic head to produce the highest rate of flashing and jetting (i.e., flashing and jetting scenario); and
2. The pressure in the line is assumed to be depressurized by the breach and/or emergency shutdowns to produce the highest rate of liquid flow within a curbed, trenched, or impounded area (i.e., liquid scenario).

Alternatively, a single scenario for each design spill could be selected if adequately supported with an assessment of the depressurization calculations and/or an analysis of process instrumentation and shutdown logic acceptable to DOT.

In addition, the location and orientation of the leakage source must be considered. The closer a leakage source is to the property line, the higher the likelihood that the vapor cloud would extend off-site. As most flashing and jetting scenarios would not have appreciable liquid rainout and accumulation, the siting of impoundment systems would be driven by liquid scenarios, while siting of piping and other remaining portions of the plant would be driven by flashing and jetting scenarios.

Cheniere reviewed multiple releases for the liquid scenarios and for the flashing and jetting scenarios. Cheniere used the following conditions, corresponding to 49 CFR §193.2059, for the vapor dispersion calculations: ambient temperature of 72°F, relative humidity of 50 percent, wind speeds of 1 to 2 meters per second in various directions, atmospheric stability class of F and a ground surface roughness of 0.03 meter. In addition, a sensitivity analysis to the wind speed and direction was provided to demonstrate the longest predicted downwind dispersion distance in accordance with the PHAST and FLACS Final Decisions.

Cheniere accounted for the facility geometry, including the impoundment and trench geometry details as established by available plant layout drawings. The plant geometry accounts for any on-site wind channeling that could occur. The releases were initiated after sufficient time had passed in the model simulations to allow the wind profile to stabilize from effects due to the presence of buildings and other on-site obstructions.

Vapor Dispersion Design Spill Analyses for LNG

According to table 2.2.3.5 of NFPA 59A, design spills from containers with over the top withdrawal lines and no bottom penetrations should be the largest flow from the container (i.e., storage tank) withdrawal pumps for a 10-minute duration at full-rated capacity. Design spills from process areas should be single accidental leakage sources for a 10-minute duration.

Cheniere evaluated more than 440 different piping segments, vessels, valves, and other equipment. Based on the failure frequency, total vapor flow rate, and location of the release, Cheniere considered different LNG releases with varying release conditions, orientations, wind speeds, and wind directions as described below. In order to address the highest rate of LNG flow (i.e., liquid scenario), Cheniere evaluated multiple scenarios, including: a) full guillotine ruptures of the 30-inch withdrawal lines of LNG Storage Tanks 1 and 2, b) a hole equivalent to 10-inch-diameter (⅓-diameter) and a full guillotine rupture at various locations in the 30-inch transfer line from the LNG storage tanks to the Jetty Areas, c) a hole equivalent to 10-inch-diameter (⅓-diameter) in the 30-inch transfer line from Liquefaction Train 1 to the LNG storage tanks, and d) a hole equivalent to 5.33-inch-diameter (⅓-diameter) in the 16-inch transfer line from the LNG storage tanks to Liquefaction Train 3.

The full guillotine rupture of the withdrawal line from the LNG storage tanks was assumed to be at the maximum sendout flow rate of 52,834 gpm for a 10-minute duration based on two of the three tanks operating three of its four pumps at the rated capacities of 8,806 gpm (or three tanks operating two of its four pumps). This exceeds the maximum flow rate from a withdrawal line from a single tank with all four pumps running at their maximum pump runout. This design spill was evaluated at LNG Storage Tank 1 (closest LNG storage tank to the property line) and at LNG Storage Tank 2 prior to its change in dimensions and relocation farther away from the property line. LNG Storage Tank 3 would be the farthest from the property line and LNG vapors would be expected to disperse no farther than LNG Storage Tank 1 or 2. The spills were assumed to be completely liquid.

The 10-inch-diameter (⅓-diameter) equivalent hole in the 30-inch transfer line from the storage tanks to the Jetty Areas was calculated to produce a 17,119 gpm flow rate based on the orifice equation and process conditions. This spill was evaluated at the send-out equipment nearest to the property line, at the transition in the direction of the trenchway nearest to the occupied buildings, and at the West and East Jetty Areas. A full guillotine rupture in the 30-inch transfer line was also modeled and assumed to be at the be at the maximum sendout flow rate of 52,834 gpm for a 10-minute duration based on two of the three tanks operating three of its four pumps at the rated capacities of 8,806 gpm (3 pumps for export) and 4,403gpm (1 pump for sendout). This spill was evaluated at various locations along the transfer line, including at the OSBL Impoundment, at the send-out equipment nearest to the property line, at the transition in direction of the spillway nearest to the occupied buildings, and at the Jetty Sump. All spills were assumed to be completely liquid.

The 10-inch-diameter (⅓-diameter) equivalent hole in the 30-inch transfer line from Liquefaction Train 1 to the LNG storage tanks was assumed to be at a maximum flow rate of 19,677 gpm for a 10-minute duration based on three trains running one of their two pumps at full rated capacity of 6,569 gpm. The spill was evaluated at Liquefaction Train 1 and was assumed to be completely liquid.

The 5.33-inch-diameter (⅓-diameter) equivalent hole in the 16-inch transfer line from Liquefaction Train 3 to the storage tanks was calculated to produce a 6,374 gpm flow rate based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Train 3 and was assumed to be completely liquid.

Cheniere used PHAST Version 6.7 to perform diameter, wind, and elevation sensitivity studies in order to address the highest rate of LNG vapor flow (i.e., flashing and jetting scenario). The sensitivity analysis led Cheniere to evaluate multiple scenarios, including: a) a full guillotine rupture of a 3-inch-diameter cooldown line attached to a 16-inch transfer pump discharge, b) a full guillotine rupture of a 4-inch-diameter line attached to a 16-inch transfer pump discharge, c) a full guillotine rupture of a 4-inch-diameter line attached to a 10-inch-diameter high pressure sendout pump discharge, d) a hole equivalent to 8-inch-diameter in the 20-inch transfer line from the shoreline to the East Jetty, and e) a hole equivalent to 2.23-inch-diameter in the LNG storage tank withdrawal line.

The full guillotine of a 3-inch diameter line was calculated to produce 2,209 gpm flow rate based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Train 1 and was determined to produce no liquid rainout (i.e., all vapor).

The full guillotine of a 4-inch-diameter cooldown line was calculated to produce 3,927 gpm flow rate based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Train 3 and was determined to produce no liquid rainout (i.e., all vapor).

The full guillotine of a 4-inch-diameter line was assumed to produce 2,180 gpm flow rate for a 10-minute duration based on the pump operating at the maximum flow of 2,180 gpm. The spill was evaluated at the send-out pump area and was determined to produce no liquid rainout (i.e., all vapor).

The 8-inch-diameter equivalent hole in the 20-inch transfer line from the shoreline to the East Jetty was calculated to produce 10,955 gpm based on the design flow rate of the line. The release was evaluated at the East Jetty and was determine to produce. Shrouds were installed to minimize jetting effects and resulted in 97 percent rainout.

The 2.23-inch-diameter equivalent hole in the LNG storage tank withdrawal line representative of a gasket failure was calculated to produce 1,226 gpm based on the orifice equation. The release was evaluated at the top of the northern most LNG storage tank.

The LNG releases are summarized in table 4.12-5. DOT staff reviewed the methodology used to select these design spills and had no objection at the time of its review.

Table 4.12-5
LNG Design Spills

Scenario	Hole Diameter	Release location	Pressure (psig)	Temperature (^{o}F)	Total Flow Rate (gpm)	Liquid Fraction (%)
1	30-inch	Storage Tank 1	5	-250	52,834	100
2	30-inch	Storage Tank 2*	5	-250	52,834	100
3	30-inch	OSBL Impoundment	5	-250	52,834	100
4	30-inch, 10-inch	Sendout Pump Area	5, 35	-250	52,834, 17,119	100
5	30-inch, 10-inch	Spillway Transition Near Buildings	5, 35	-250	52,834, 17,119	100
6	30-inch	Jetty Impoundment	5	-250	52,834	100
7	10-inch	West Jetty	35	-250	17,119	100
8	10-inch	East Jetty	35	-250	17,119	100
9	10-inch	Liquefaction Train 1	50	-245	19,677	100
10	5.33-inch	Liquefaction Train 3	60	-245	6,374	100
11	3-inch	Liquefaction Train 1	72	-245	2,209	0
12	4-inch	Liquefaction Train 3	72	-245	3,927	0
13	4-inch	Sendout Pump Area	1,530	-206	2,180	0
14	8-inch	East Jetty	35	-250	10,995	97
15	2.23-inch	Storage Tank 1	80	-250	1,226	0

Vapor Dispersion Design Spill Analyses for Other Hazardous Fluids

In addition to the 13 LNG releases evaluated, Cheniere considered 14 other hazardous fluid releases after using PHAST Version 6.7 to perform diameter sensitivity, wind sensitivity, and elevation sensitivity studies. The sensitivity analysis led Cheniere to evaluate multiple scenarios, including: a) a full guillotine rupture of a 3-inch-diameter line attached to a 24-inch-diameter ethylene line from the Ethylene Surge Drum to the Ethylene Economizer at the Ethylene Cold Box b) a full guillotine rupture of the 2-inch-diameter line attached to a 36-inch propane line from the Propane Condensers to the Propane Accumulator c) a hole equivalent to 1-inch-diameter in the 4-inch-diameter discharge of the Heavy Reflux Pumps, d) a hole equivalent to 1-inch-diameter in a 24-inch acid gas line from the Solvent Regenerator Reflux Drum to the Hydrogen Sulfide Removal Skids at the Acid Gas Removal Unit, e) a hole equivalent to 1-inch-diameter in the 4-inch-diameter discharge of the Condensate Pumps at the Condensate Storage Area, f) a full guillotine rupture of the 2-inch-diameter ethylene transfer hose at the Refrigerant Storage Area, g) a full guillotine rupture of the 2-inch-diameter propane transfer hose at the Refrigerant Storage Area, and h) a full guillotine rupture of the 2-inch-diameter valve on the condensate transfer line at the Condensate Storage Area.

The full guillotine rupture of the 3-inch-diameter line at the Ethylene Cold Box was calculated to produce 4,571 gpm for a 10-minute duration based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Trains 1, 2, and 3, and was determined to produce no liquid rainout (i.e., all vapor).

The full guillotine rupture of the 2-inch-diameter line at the Propane Accumulator was calculated to produce 1,520 gpm for a 10-minute duration based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Trains 1, 2, and 3, and was determined to produce no liquid rainout (i.e., all vapor).

The 1-inch-diameter equivalent hole at the discharge of the Heavy Reflux Pumps was determined to be at a flow rate of 199 gpm for a 10-minute duration based on one of two pumps operating at maximum flow rate of 199 gpm. The spill was evaluated at Liquefaction Train 3, and was determined to produce the largest amount of vapor.

The 1-inch-diameter equivalent hole at the Acid Gas Removal Unit was calculated to produce a flow rate of 1,221 gpm based on the orifice equation and process conditions. The spill was evaluated at Liquefaction Trains 1, 2, and 3, and would produce all vapor.

The 1-inch-diameter equivalent hole at the discharge of the Condensate Pumps was determined to be at a flow rate of 100 gpm for a 10-minute duration based on one of two pumps running at rated capacity of 100 gpm. The spill was evaluated at the Condensate Storage Area, and was determined to produce the largest amount of vapor.

The full guillotine rupture of the 2-inch-diameter ethylene transfer hose was determined to be at a flow rate of 50 gpm for a 10-minute duration based on the design flow rate from a delivery truck. The spill was evaluated at the Refrigerant Storage Area, and was determined to produce no liquid rainout (i.e., all vapor).

The full guillotine rupture of the 2-inch-diameter propane transfer hose was determined to be at the maximum pump flow rate of 50 gpm for a 10-minute duration based on the design flow rate from a delivery truck. The spill was evaluated at the Refrigerant Storage Area, and was determined to produce no liquid rainout (i.e., all vapor).

The full guillotine rupture of the 2-inch-diameter valve on the condensate transfer line was determined to be at the maximum pump flow rate of 100 gpm for a 10-minute duration based on the design flow rate from a delivery truck. The spill was evaluated at the Condensate Storage Area, and was determined to produce no liquid rainout (i.e., all vapor). The LNG releases are summarized in table 4.12-6. DOT staff reviewed the methodology used to select these design spills and had no objection at the time of its review.

Table 4.12-6
Other Hazardous Design Spills

Scenario	Hole Diameter	Release location	Pressure (psig)	Temperature (°F)	Total Flow Rate (gpm)	Liquid Fraction (%)
1	3-inch	Ethylene Cold Box of Liquefaction Train 1	323	-18	4,571	0
2	3-inch	Ethylene Cold Box of Liquefaction Train 2	323	-18	4,571	0
3	3-inch	Ethylene Cold Box of Liquefaction Train 3	323	-18	4,571	0
4	2-inch	Propane Accumulator of Liquefaction Train 1	190	105	1,520	0
5	2-inch	Propane Accumulator of Liquefaction Train 2	190	105	1,520	0
6	2-inch	Propane Accumulator of Liquefaction Train 3	190	105	1,520	0
7	1-inch	Heavy Reflux Pumps at Liquefaction Train 3	643	-23	199	94
8	1-inch	Acid Gas Removal Unit of Liquefaction Train 1	12.9	122	1,221	0
9	1-inch	Acid Gas Removal Unit of Liquefaction Train 2	12.9	122	1,221	0
10	1-inch	Acid Gas Removal Unit of Liquefaction Train 3	12.9	122	1,221	0
11	1-inch	Condensate Storage Pumps of Condensate Storage Area	128	116	100	62
12	2-inch	Ethylene Transfer Hose of Refrigerant Storage Area	45	-109	50	0
13	2-inch	Propane Transfer Hose of Refrigerant Storage Area	115	71	50	0
14	2-inch	Condensate Transfer Valve of Condensate Storage Area	125	119	100	0

FLACS was used to predict the extent of the ½ LFL vapor cloud. Since the acid gas would contain the toxic component, H_2S, and the stabilized condensate would contain toxic components of benzene, toluene, ethylebenzene, and xylene, Cheniere also calculated the dispersion distances to toxic threshold exposure limits based on the toxicity levels that were at or below ½ AEGLs.

Vapor Dispersion Analyses for LNG and Other Hazardous Fluids

Cheniere proposes to install a series of 20-foot, 12-foot, and 10-foot-high vapor fences, as shown in figure 4.12-1, as well as a shroud surrounding a portion of their transfer lines near their East and West Docks to limit the vapor cloud dispersion distances.

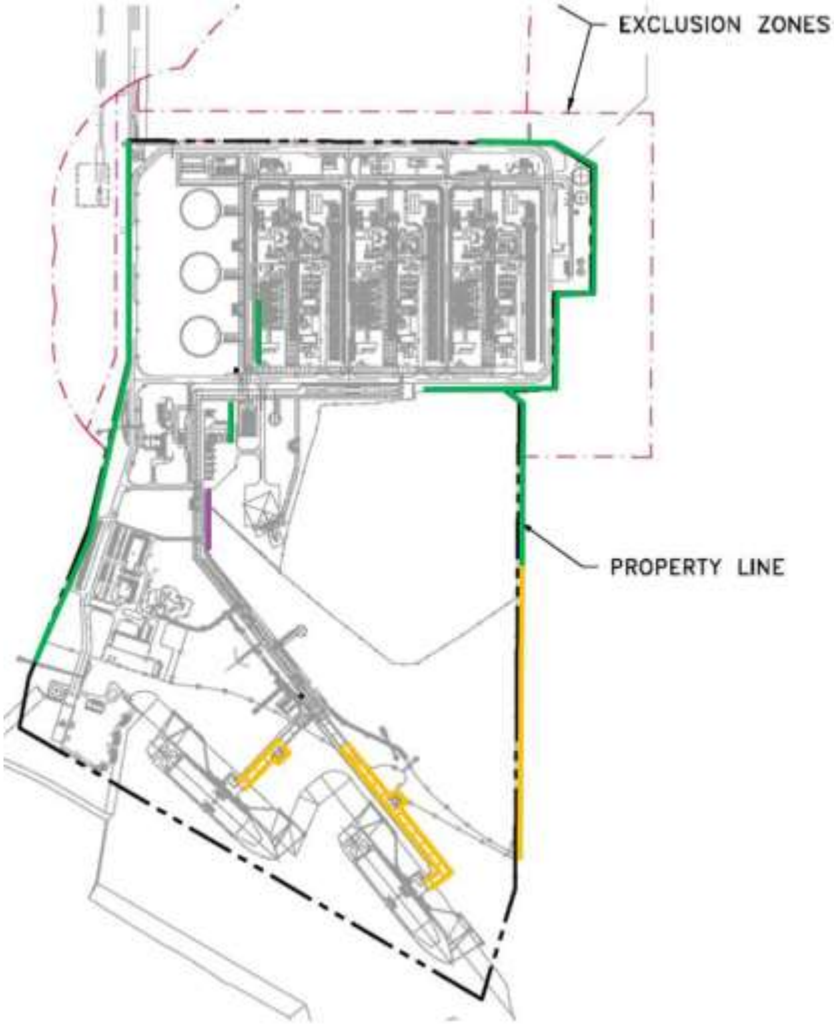

Figure 4.12-1 Vapor Fences (20 feet high in green; 12 feet high in yellow; 10 feet high in purple)

Cheniere stated that the vapor fences would be routinely inspected by personnel and repaired as necessary. The design of the vapor fences would be completed during detailed engineering. In order to ensure that the vapor barriers are maintained throughout the life of the facility, **we recommend that:**

- **<u>Prior to construction of the final design,</u> Cheniere should file with the Secretary for review and written approval by the Director of OEP, the details of the vapor fences** as **well as procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR § 193.2059. This information should be filed a minimum of 30 days before approval to proceed is requested.**

As shown in figure 4.12-2, the FLACS results indicated that the vapor dispersion hazards would primarily remain within the Cheniere property line with the exception of limited areas that would still remain within areas of legal control by Cheniere through exclusion zone agreements with Alcoa, Sherwin, and the Port. These exclusion zone agreements have been reviewed by DOT staff, who raised no objections at the time of review.

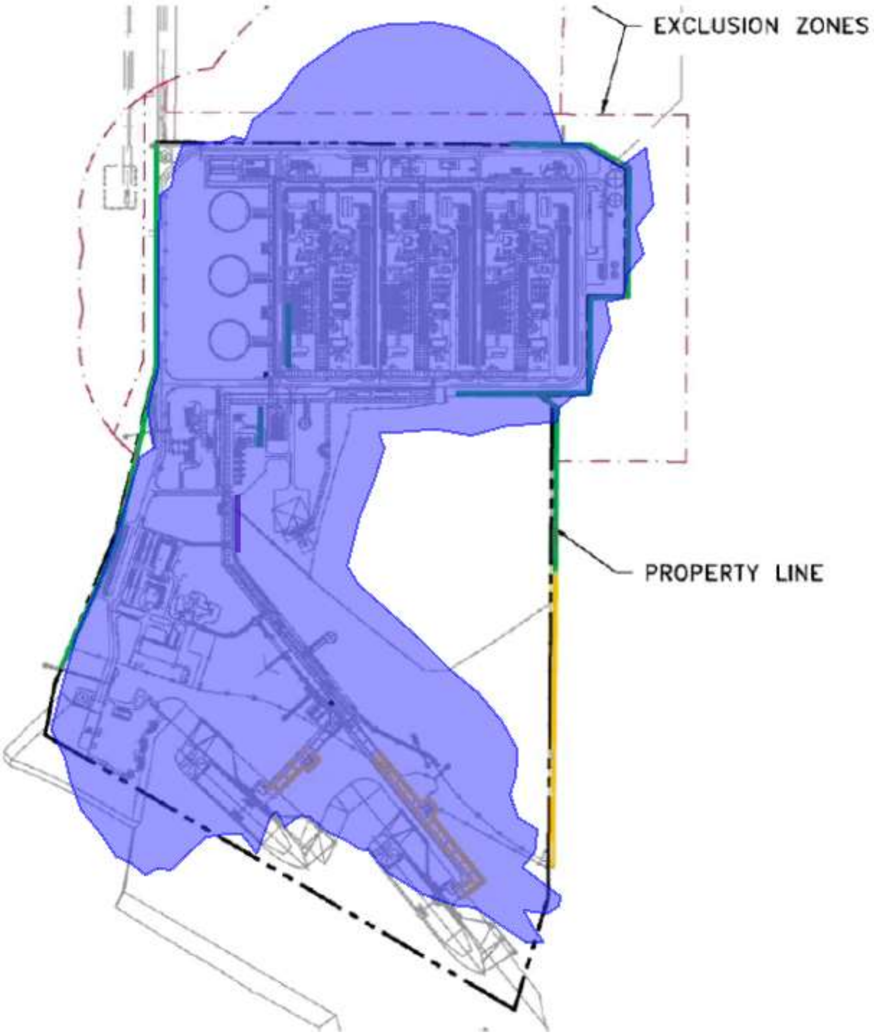

Figure 4.12-2 **Flammable and Toxic Vapor Cloud Dispersion Contours**

As a result, we conclude that the siting of the proposed Project would not have a significant impact on public safety. If the facility is constructed and operated, compliance with the requirements of 49 CFR 193 would be addressed as part of DOT's inspection and enforcement program. All vapor fences would be required to meet 49 CFR 193 regulations.

4.12.5.4 Overpressure Analysis

As discussed in section 4.12.2, the propensity of a vapor cloud to detonate or produce damaging overpressures is influenced by the reactivity of the material, the level of confinement and congestion surrounding and within the vapor cloud, and the flame travel distance. It is possible that the prevailing wind direction may cause the vapor cloud to travel into a partially confined or congested area.

<u>LNG Vapor Clouds</u>

As adopted by Part 193, Section 2.1.1 of NFPA 59A (2001) requires an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility be considered. As discussed under "Flammable Vapor Ignition" in section 4.12.2, unconfined LNG vapor clouds would not be expected to produce damaging overpressures.

The potential for unconfined LNG vapor cloud detonations was investigated by the Coast Guard in the late 1970s at the Naval Weapons Center in China Lake, California. Using methane, the primary component of natural gas, several experiments were conducted to determine whether unconfined LNG vapor clouds would detonate. Unconfined methane vapor clouds ignited with low-energy ignition sources (13.5 joules), produced flame speeds ranging from 12 to 20 mph. These flame speeds are much lower than the flame speeds associated with a deflagration with damaging overpressures or a detonation.

To examine the potential for detonation of an unconfined natural gas cloud containing heavier hydrocarbons that are more reactive, such as ethane and propane, the Coast Guard conducted further tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane. The tests indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined natural gas vapor cloud to detonate. Less processed natural gas with greater amounts of heavier hydrocarbons would be more sensitive to detonation.

The Coast Guard indicated overpressures of 4 bar and flame speeds of 78 mph were produced from vapor clouds of 86 percent to 96 percent methane in near stoichiometric proportions using exploding charges as the ignition source. The 4 bar overpressure was the same overpressure produced during the calibration test involving exploding the charge ignition source alone, so it remains unclear that the overpressure was attributable to the vapor deflagration.

Additional tests were conducted to study the influence of confinement and congestion on the propensity of a vapor cloud to detonate or produce damaging overpressures. The tests used obstacles to create a partially confined and turbulent scenario, but found that flame speeds developed for methane were not significantly higher than the unconfined case and were not in the range associated with detonations.

Although it has been possible to produce damaging overpressures and detonations of unconfined LNG vapor clouds, the Project would be designed to receive feed gas with methane concentrations as low as 90 percent, which are not in the range shown to exhibit overpressures and flame speeds associated with high-order explosions and detonations. Although Cheniere did not identify any specific LNG imports with methane concentrations below 89 percent, Cheniere had stated that the Project may receive LNG from various foreign sources, and has considered methane concentrations as low as 84 percent in the design of the facility. These concentrations could provide a higher propensity to produce damaging overpressures if ignited, but would be less reactive than propane or ethylene stored onsite and handled in areas with less congestion and confinement. In addition, the substantial amount of initiating explosives needed to create the shock initiation during the limited range of vapor-air concentrations also renders the possibility of detonation of these vapors at an LNG plant as unrealistic.

Ignition of a confined LNG vapor cloud could result in higher overpressures. In order to prevent such an occurrence, Cheniere would take measures to mitigate the vapor dispersion and ignition into confined areas, such as buildings. Building would be located away from process areas and combustion and ventilation air intake equipment would be required to have hazard detection devices that enable isolation of the air dampers. Hazard detection with shutdown capability would also be installed at air intakes of combustion equipment whose continued operation could add to, or sustain, an emergency. In general, the primary hazards to the public from an LNG spill that disperses to an unconfined area, either on land or water, would be from dispersion of the flammable vapors or from radiant heat generated by a pool fire.

Vapor Clouds from Other Hazardous Fluids

In comparison with LNG vapor clouds, there is a higher potential for unconfined propane clouds to produce damaging overpressures, and an even higher potential for unconfined ethylene vapor clouds to produce damaging overpressures. Unconfined ethylene vapor clouds also have the potential to transition to a detonation much more readily than propane. This has been shown by multiple experiments conducted by the Explosion Research Cooperative to develop predictive blast wave models for low, medium, and high reactivity fuels and varying degrees of congestion and confinement[43]. The experiments used methane, propane, and ethylene, as the respective low, medium, and high reactivity fuels. In addition, the tests showed that if methane, propane, or ethylene is ignited within a confined space, such as in a building, they all have the potential to produce damaging overpressures. The refrigerant streams would contain all three of these components (i.e., methane, propane, and ethylene). Therefore, a potential exists for unconfined vapor clouds that could produce damaging overpressures in the event of a release of propane or ethylene.

In order to evaluate this hazard, Cheniere used FLACS to perform an overpressure analysis. Cheniere used the vapor dispersion results, previously discussed in “Vapor Dispersion Analyses”. Due to the highest reactivity, releases of ethylene from the liquefaction process area dispersing to the most confined and congested regions of the plant were evaluated in the overpressure analyses. Various ignition locations and times were evaluated to predict the worst case overpressure distances. Releases of methane and propane and subsequent ignition would be less severe due to their lower reactivity. The overpressure scenarios evaluated are summarized in table 4.12-7.

Table 4.12-7
Overpressure Scenarios

Scenario	Material	Release Locations	Ignition Location
1	Ethylene	Ethylene Cold Box of Liquefaction Train 1	SE Corner underneath Compressor Building Deck
2	Ethylene	Ethylene Cold Box of Liquefaction Train 1	NE Corner underneath Compressor Building Deck
3	Ethylene	Ethylene Cold Box of Liquefaction Train 3	SW Corner underneath Compressor Building Deck
4	Ethylene	Ethylene Cold Box of Liquefaction Train 3	NW Corner underneath Compressor Building Deck

As shown in Figure 4.12-3, the FLACS results indicated that the maximum extent of 1 psi overpressures with a safety factor of 2 (i.e., ½ psi overpressure) would remain within property that Cheniere owns or legally controls through covenants.

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[43] Pierorazio, A.J., Thomas, J.K., Baker, Q.A., Kethcum, D.E, "An Update to the Baker-Strehlow-Tang Vapor Cloud Explosion Prediction Methodology Flame Speed Table", American Institute of Chemical Engineers, Process Safety Progress, Vol. 24., No. 1, March 2005.

Figure 4.12-3 Vapor Cloud Explosion Overpressure Contours

Overpressures were also evaluated at the proposed LNG storage tanks, which would be as high as 9 psi. Cheniere indicated that the LNG storage tank would be designed for this external blast loading. Cheniere indicated that the LNG storage tanks would be designed to withstand this overpressure. Project specifications have been included that reflect this. In order to ensure that the LNG storage tanks can withstand this overpressure, **we recommend:**

- **<u>Prior to construction of the final design,</u> Cheniere should file with the Secretary for review and approval by the Director of OEP, the details of the LNG storage tank structural design that demonstrates the tanks can withstand overpressures from ignition of design spills. This information should be filed a minimum of 30 days before approval to proceed is requested.**

As a result, we conclude that the siting of the proposed Project would not have a significant impact on public safety. If the facility is constructed and operated, compliance with the requirements of 49 CFR 193 would be addressed as part of DOT's inspection and enforcement program.

4.12.5.5 Thermal Radiation Analysis

As discussed in section 4.12.2, if flammable vapors are ignited, the deflagration could propagate back to the spill source and result in a pool fire causing high levels of thermal radiation (i.e., heat from a fire). In order to address this, 49 CFR §193.2051 and §193.2057 require evaluation of thermal radiation hazards of potential incidents and exclusion zones in accordance with applicable sections of NFPA 59A (2001). Together, Part 193 and NFPA 59A (2001) specify different hazard endpoints for spills into LNG storage tank containment and spills into impoundments for process or transfer areas. For LNG storage tank spills, there are three radiant heat flux levels which must be considered:

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

The requirements for spills from process or transfer areas are more stringent. For these impoundments, the 1,600 Btu/ft^2-hr flux level cannot extend beyond the facility's property line that can be built upon. Other potential incidents that could have a bearing on the safety of plant personnel or surrounding public are also required to be evaluated under NFPA 59A, Section 2.1.1.

Part 193 requires the use of the LNGFIRE3 computer program model developed by the Gas Research Institute to determine the extent of the thermal radiation distances. Part 193 stipulates that the wind speed, ambient temperature, and relative humidity that produce the maximum exclusion distances must be used, except for conditions that occur less than 5 percent of the time based on recorded data for the area. Cheniere selected the following ambient conditions to produce the maximum exclusion distances: wind speeds of 15 to 28 mph, ambient temperature of 34°F, and 40 percent relative humidity. We agree with Cheniere's selection of atmospheric conditions.

For its LNG storage tank analysis, Cheniere calculated thermal radiation distances using LNGFIRE3 for the 1,600-, 3,000-, and 10,000-Btu/ft^2-hr incident radiant heat levels using an inner tank concrete wall inner diameter (261 feet) as the pool diameter. This diameter was based on the initial LNG storage tank design, which is larger than the updated outer concrete wall outer diameter (258.5 feet) and therefore would be conservative. The flame base was set equal to an approximate height of the concrete wall (150 feet) above the surrounding terrain. This flame height was based on the initial LNG storage tank design, which is lower than the updated outer concrete container height (169.5 feet) and therefore would be conservative. Target heights were set at the ground level.

For its Impoundment analysis, Cheniere calculated thermal radiation distances using LNGFIRE3 for the 1,600-Btu/ft^2-hr incident radiant heat level centered on the OSBL and Jetty

Impoundments. The OSBL and Jetty Impoundments are both 70 feet in diameter. The fire base is conservatively assumed to be at ground elevation.

For other potential incidents, such as ethylene, propane, or NGL spills or a pool fire within the condensate storage tank impoundment, Cheniere also calculated thermal radiation distances using LNGFIRE3 for the 1,600-, 3,000-, and 10,000-Btu/ft^2-hr incident radiant heat levels. Although LNGFIRE3 is specifically designed to calculate thermal radiation flux levels for LNG pool fires, LNGFIRE3 could also be used to conservatively calculate the thermal radiation flux levels for flammable hydrocarbons such as ethylene, propane, NGL, and condensate. Two of the parameters used by LNGFIRE3 to calculate the thermal radiation flux are the mass burning rate of the fuel and the surface emissive power (SEP) of the flame, which is an average value of the thermal radiation flux emitted by the fire. The mass burning rate and SEP of an ethylene, propane, NGL, or condensate fire would be less than an equally sized LNG fire. Since the thermal radiation from a pool fire is dependent on the mass burning rate and SEP, the thermal radiation distances required for ethylene, propane, NGL, and condensate fires would not extend as far as the exclusion zone distance previously calculated for an LNG fire in the same sump. For condensate spills into the condensate impoundment, Cheniere modeled a pool fire within the impoundment, which measures 150ft by 90ft. The flame base was conservatively assumed to be at ground level.

As shown in table 4.12-8 and figure 4.12-4, the 10,000-, 3,000-, and 1,600-Btu/ft^2-hr heat fluxes from the LNG storage tank, OSBL Impoundment, Jetty Impoundment, and condensate storage impoundment would remain within the facility property lines. In addition, as shown in figure 4.12-1, radiant heat flux from the flares would not impact personnel or the public.

Table 4.12-8
Thermal Radiation Exclusion Zones for Impoundment Basins

Flux Level (Btu/ft^2-hr)	LNG Storage Tank Outer Containment (ft) a/	OSBL Impoundment (ft) a/	Jetty Impoundment (ft) a/	Condensate Storage Tank Dike (ft) a/	
				Front	Side
10,000	358	200	200	335	338
3,000	748	269	269	457	440
1,600	955	317	317	530	501

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a/ from center of impoundment

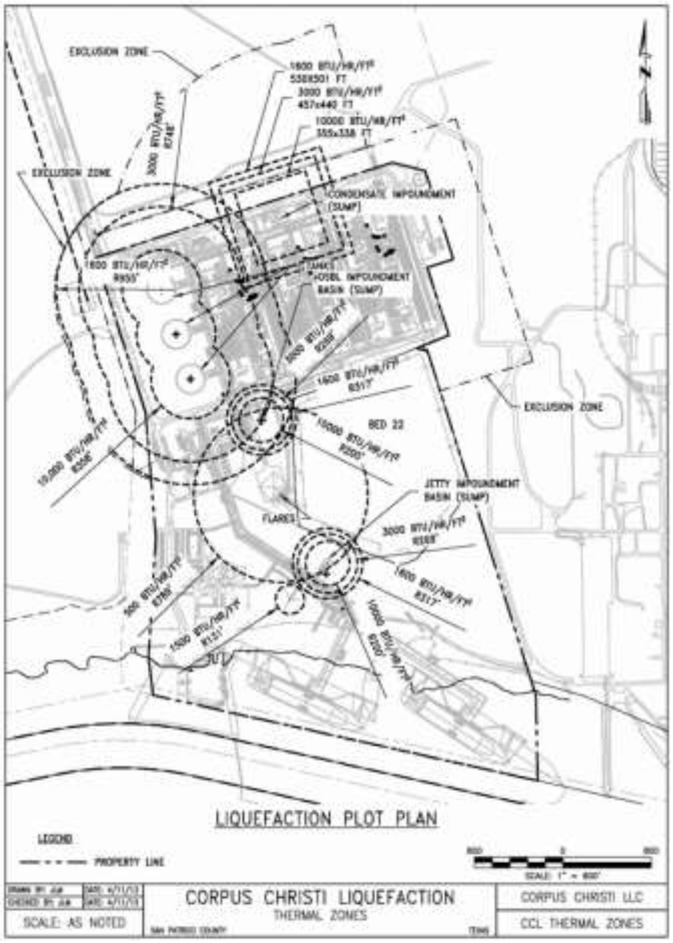

Figure 4.12-4 Thermal Radiation Exclusion Zones 1,600-BTU for Storage Tank and Impoundments

Fires from trenches would not be expected to extend beyond the vapor dispersion distances from the trenches and would not be expected to be of sufficient duration to warrant a hazard to the public. FERC staff also evaluated jet fires from various piping and found that the jet fires radiant heat to 5 kiloWatts per square meter (kW/m^2) would extend a limited extent beyond the property line, and not onto any structures. In addition, it is possible that the vapor fences may in fact block the radiant heat from extending beyond the property line.

As a result, we conclude that the siting of the proposed Project would not have a significant impact on public safety. If the facility is constructed and operated, compliance with the requirements of 49 CFR 193 would be addressed as part of DOT's inspection and enforcement program.

4.12.5.6 Cascading Events

Although Cheniere proposes to install the propane and ethylene storage vessels away from other equipment, the propane and ethylene storage vessels could be subject to radiant heat exposure from a LNG storage tank roof top fire. In order to mitigate this potential, Cheniere proposes to install radiant heat shields to protect the ethylene and propane storage vessels. The radiant heat shields would result in negligible risk of a BLEVE occurring at the refrigerant storage area from a LNG storage tank roof top fire.

In addition, Cheniere would have pressure and level instrumentation, fire detection, emergency isolation and depressurization valves, passive fire protection, fire suppression units, and remotely activated firewater monitors to mitigate the potential of a BLEVE from an adjacent jet fire. As a result, we conclude that the siting of the proposed Project would not have a significant impact on public safety.

4.12.6 LNG Carrier Hazards

Since 1959, ships have transported LNG without a major release of cargo or a major accident involving an LNG carrier. There are more than 370 LNG carriers 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 more than 2,600 individual LNG carrier 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.

Cheniere has not identified specific source(s) for LNG import or export destinations for the proposed Project. LNG could be obtained from terminals throughout the world and delivered by LNG carriers to the proposed Terminal. There are 19 countries which provide LNG for export: Algeria; Angola, Australia, Brunei, Egypt, Equatorial Guinea, Indonesia, Libya, Malaysia, Nigeria, Norway, Oman, Peru, Qatar, Russia, Trinidad & Tobago, United Arab Emirates, United States, and Yemen with another 5 countries intending to develop export facilities: Columbia, Canada, Iran, Papua New Guinea, and Venezuela. Cheniere has stated that the proposed Terminal would be for a wide range of LNG import compositions, including from Trinidad & Tobago (lean LNG) and Nigeria (rich LNG)

LNG from the Terminal may also be exported to any importing terminal throughout the world for which Cheniere has authorization to export.[44] There are 29 countries which have facilities to receive LNG: Argentina, Belgium, Brazil, Canada, Chile, China, Dominican Republic, England, France, Greece, India, Indonesia, Italy, Japan, Kuwait, Malaysia, Mexico, Netherlands, Portugal, Singapore, South Korea, Spain, Sweden, Taiwan, Thailand, Turkey, United Arab Emirates, United States, and Wales with another 9 planned or under construction: Albania, Croatia, Cyprus, Germany, Ireland, Lithuania, Pakistan, Philippines, and Poland. Although LNG could be sent to any of these, Cheniere has stated that its export would likely be to Latin America, Asia, and Europe.

4.12.6.1 Past LNG Carrier Incidents

A review of the history of LNG maritime transportation indicates that there has not been a serious accident at sea or in a port which resulted in a spill due to rupturing of the cargo tanks. However, insurance records, industry sources, and public websites identify a number of incidents involving LNG carriers, 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 occurrences, representing the range of incidents experienced by the worldwide LNG carrier fleet, are described below:

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[44] Cheniere has authorization to export LNG to Free-Trade Agreements. Authorization to export LNG to Non-Free-Trade Agreement nations are subjected to DOE approval.

- **El Paso Paul Kayser** grounded on a rock in June 1979 in the Straits of Gibraltar during a loaded voyage from Algeria to the United States. Extensive bottom damage to the ballast tanks resulted; however, no cargo was released because no damage was done to the cargo tanks. The entire cargo of LNG was subsequently transferred to another LNG carrier 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 vessel and shore piping. The cargo loading had been secured just before the wind struck, but the loading arms had not been drained. Consequently, the LNG remaining in the loading arms spilled onto the deck, causing fracture of some plating.
- **Mostefa Ben Boulaid** had an electrical fire in the engine control room during unloading at Everett, Massachusetts. The ship crew extinguished the fire and the ship completed unloading.
- **Khannur** had a cargo tank overfill into the vessel's vapor handling system on September 10, 2001, during unloading at Everett, Massachusetts. Approximately 100 gallons of LNG were vented and sprayed onto the protective decking over the cargo tank dome, resulting in several cracks. After inspection by the Coast Guard, the Khannur was allowed to discharge its LNG cargo.
- **Mostefa Ben Boulaid** had LNG spill onto its deck during loading operations in Algeria in 2002. The spill, which is believed to have been caused by overflow rather than a mechanical failure, caused significant brittle fracturing of the steelwork. The vessel was required to discharge its cargo, after which it proceeded to dock for repair.
- **Norman Lady** was struck by the USS Oklahoma City nuclear submarine while the submarine was rising to periscope depth near the Strait of Gibraltar in November 2002. The 87,000 m^3 LNG carrier, 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 vessel was refloated, repaired, and returned to service.
- **Golar Freeze** moved away from its docking berth during unloading on March 14, 2006, in Savannah, Georgia. The powered emergency release couplings on the unloading arms activated as designed, and transfer operations were shut down.
- **Catalunya Spirit** lost propulsion and became adrift 35 miles east of Chatham, Massachusetts on February 11, 2008. Four tugs towed the vessel to a safe anchorage for repairs. The Catalunya Spirit was repaired and taken to port to discharge its cargo.

- **Al Gharrafa** collided with a container ship, Hanjin Italy, in the Malacca Strait off Singapore on December 19, 2013. The bow of the Al Gharrafa and the middle of the starboard side of the Hanjin were damaged. Both ships were safely anchored after the incident. No losses of LNG, fatalities, or injuries were reported.

4.12.6.2 LNG Carrier Regulatory Oversight

The Coast Guard exercises regulatory authority over LNG carriers under 46 CFR 154, which contains the United States safety standards for vessels carrying LNG in bulk. The LNG carriers visiting the proposed facility would also be constructed and operated in accordance with the International Maritime Organization (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 LNG carriers 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 vessel is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG carriers under Title 46 CFR Part 154.

The LNG carriers which would deliver or receive LNG to or from the proposed facility would also need to comply with various U.S. and international security requirements. The IMO adopted the *International Ship and Port Facility Security Code* in 2003. This code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships; improve security aboard ships and ashore; and reduce the risk to passengers, crew, and port personnel on board ships and in port areas. All LNG carriers, as well as other cargo vessels 500 gross tons and larger, and ports servicing those regulated vessels, must adhere to the IMO standards. Some of the IMO requirements for ships are as follows:

- ships must develop security plans and have a Vessel Security Officer;
- ships must have a ship security alert system. These alarms transmit ship-to-shore security alerts identifying the ship, its location, and indication that the security of the ship is under threat or has been compromised;
- ships must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with ships; and
- ships may have equipment onboard to help maintain or enhance the physical security of the ship.

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 resulting Coast Guard regulations, contained in 33 CFR 104, require vessels to conduct vulnerability assessments and develop corresponding security plans. All LNG carriers servicing the facility would have to comply with the MTSA requirements and associated regulations while in U.S. waters.

The Coast Guard also exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the

Magnuson Act (50 USC Section 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC Section 1221, et seq.); and the MTSA of 2002 (46 USC Section 701). The Coast Guard is responsible for matters related to navigation safety, carrier 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 Title 33 CFR Part 105.

The Coast Guard regulations in 33 CFR 127 apply to the marine transfer area of waterfront facilities between the LNG carrier and the first manifold or valve located inside the containment. Title 33 CFR 127 regulates the design, construction, equipment, operations, inspections, maintenance, testing, personnel training, firefighting, and security of LNG waterfront facilities. The safety systems, including communications, emergency shutdown, gas detection, and fire protection, must comply with the regulations in 33 CFR 127. Under § 127.019, Cheniere would be required to submit two copies of its Operations and Emergency Manuals to the Coast Guard Captain of the Port (COTP) for examination.

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 import facility to submit a Letter of Intent to the Coast Guard at the same time the pre-filing process is initiated with the Commission.

In addition to the Letter of Intent, 33 CFR 127 and FERC regulations require each LNG project applicant to submit a WSA to the cognizant COTP no later than the start of the FERC pre-filing process. Until a facility begins operation, applicants must annually review their WSAs and submit a report to the COTP as to whether changes are required. The WSA must include the following information:

- port characterization;
- risk assessment for maritime safety and security;
- risk management strategies; and
- resource needs for maritime safety, security, and response.

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).

As described in 33 CFR 127 and in NVIC 01-11, the applicant develops the WSA in two phases. The first phase is the submittal of the Preliminary WSA, which begins the Coast Guard’s review process to determine the suitability of the waterway for LNG marine traffic. The second phase is the submittal of the Follow-On WSA. This document is reviewed and validated by the Coast Guard and forms the basis for the agency’s recommendation to the FERC.

The Preliminary WSA provides an outline which characterizes the port community and the proposed facility and transit routes. It provides an overview of the expected major impacts LNG operations may have on the port, but does not contain detailed studies or conclusions. This document is used to start the Coast Guard's scoping process for evaluating the suitability of the waterway for LNG marine traffic.

The Follow-On WSA must provide a detailed and accurate characterization of the LNG facility, the LNG tanker route, and the port area. The assessment should identify appropriate risk mitigation measures for credible security threats and safety hazards. The Follow-on WSA provides a complete analysis of the topics outlined in the Preliminary WSA. It should identify credible security threats and navigational safety hazards for the LNG marine traffic, along with appropriate risk management measures and the resources (federal, state, local, and private sector) needed to carry out those measures.

NVIC 01-11 directs the use of the three concentric Zones of Concern, based on LNG carriers 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 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 LFL 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 in the port.

As required by its regulations (33 CFR 127.009), the Coast Guard is responsible for issuing a LOR to the FERC regarding the suitability of the waterway for LNG marine traffic with respect to the following items:

- physical location and description of the facility;
- the LNG carrier's characteristics and the frequency of LNG shipments to or from the facility;
- waterway channels and commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by LNG carriers 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 vessels from the channel and the width of the channel.

The Coast Guard may also prepare an LOR Analysis, which serves as a record of review of the LOR and contains detailed information along with the rationale used in assessing the suitability of the waterway for LNG marine traffic.

4.12.6.3 Cheniere's Waterway Suitability Assessment

In a letter to the Coast Guard dated December 13, 2011, Cheniere submitted a Letter of Intent and a Preliminary WSA to the COTP, Sector Corpus Christi to notify the Coast Guard that it proposed to construct an LNG terminal. In the development of the Follow-On WSA, Cheniere consulted with the Coast Guard, the Area Maritime Security Committee, and other port stakeholders. As part of its assessment of the safety and security aspects of this project, the COTP Sector Corpus Christi consulted various safety and security working groups, including the Area Maritime Security Committee, Harbor Safety Committee, and Corpus Christi Port Security Working Group. In addition, the Coast Guard participated in meetings with the Port of Corpus Christi Authority, the Aransas-Corpus Christi Pilots, a focused La Quinta user group, and other federal, state, and local agencies.

Cheniere submitted the Follow-On WSA to the Coast Guard on August 30, 2012 with an Addendum submitted on January 28, 2013.

LNG Carrier Routes and Hazard Analysis

An LNG carrier's transit to and from the 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 LNG carrier would head north by Quinta Island before reaching its final destination at the Cheniere Project. Pilotage is compulsory for foreign vessels and U.S. vessels under registry in foreign trade when in U.S. waters. All deep draft ships 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 LNG carrier port time with pilotage would be approximately three to four 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 LNG carriers proceed along the intended track line, Hazard Zone 1 would encompass coastal areas along Port Aransas, including University of Texas Marine Science Institute, US 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, recreational and fishing vessels may also fall within Zone 1, depending on their course. Transit of such vessels through a Zone 1 area of concern can be avoided by timing and course changes, if conditions permit.

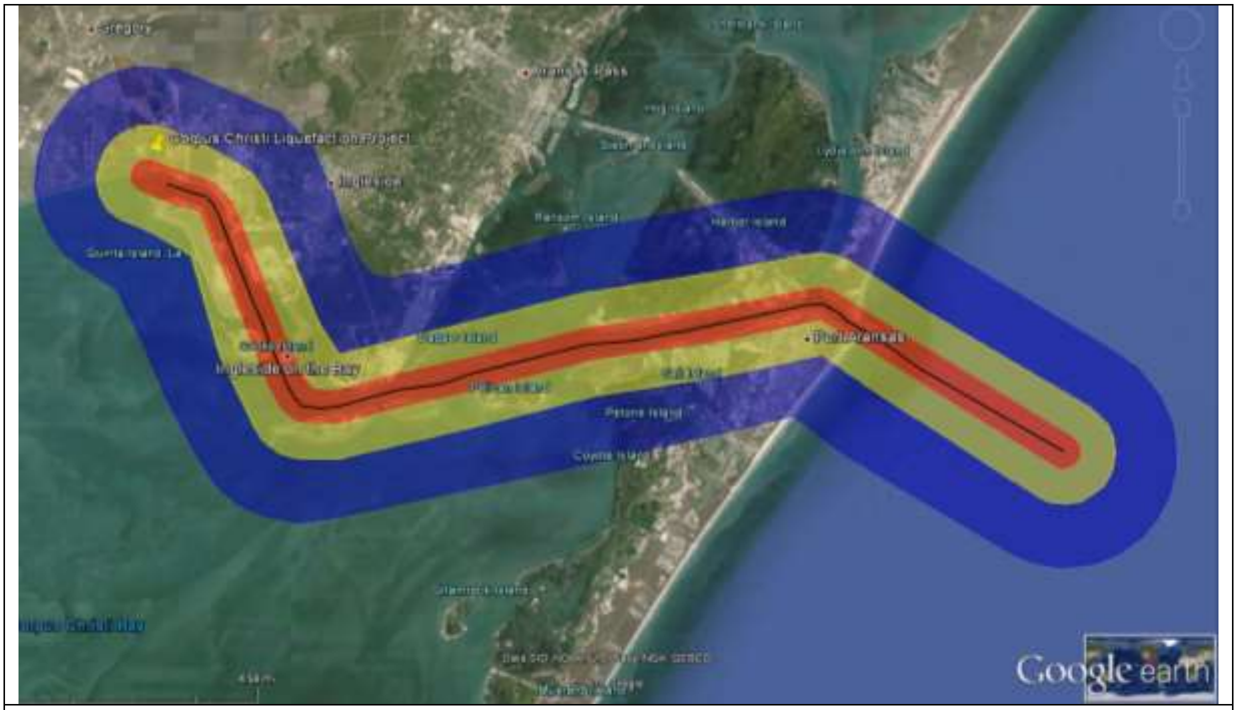
Zone 2 would cover a wider swath of coastal areas along Port Aransas and Ingleside, including Port Aransas Fire Department and Police Department, and multiple residential, commercial, industrial, and institutional (e.g., church, school, etc.) buildings. Pelican Island, Cooks Island, and La Quinta Island 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 4.12-6 and 4.12-7.

🟥 Accidental Sandia Hazard Zone 1 (0-250m)
🟨 Accidental Sandia Hazard Zone 2 (250-750m)
🟦 Accidental Sandia Hazard Zone 3 (750-1700m)

Figure 4.12-5 Accidental Hazard Zones Along LNG Carrier Route



🟥 Intentional Sandia Hazard Zone 1 (0-500m)
🟨 Intentional Sandia Hazard Zone 2 (500-1600m)
🟦 Intentional Sandia Hazard Zone 3 (1600-3500m)

Figure 4.12-6 Intentional Hazard Zones Along LNG Carrier Route

4.12.6.4 Coast Guard Letter of Recommendation and Analysis

In a letter dated March 21, 2013, the Coast Guard issued a LOR and LOR Analysis to FERC stating 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 accommodating the type and frequency of LNG marine traffic associated with this Project. The recommendation was based on full implementation of the strategies and risk management measures identified to the Coast Guard by Cheniere in its WSA.

Although Cheniere has suggested mitigation measures for responsibly managing the maritime safety and security risks associated with LNG marine 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. Accordingly, Cheniere is required to submit a report to the Coast Guard identifying any changes in conditions, such as changes to the port environment, the LNG facility, or the tanker route, that would affect the suitability of the waterway. The Coast Guard has indicated that Cheniere has provided its annual update, which is currently under review of the Coast Guard.

The Coast Guard's LOR is a recommendation on 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 ERP or the Cost Sharing Plan (see section 4.12.7). 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 are necessary to safeguard the public health and welfare, critical infrastructure and key resources, the port, the marine environment, and the vessel.

Under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA, and the Safety and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG carrier movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port or marine environment. If this Project is approved and if appropriate resources are not in place prior to LNG carrier 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. Therefore, **we recommend that:**

- **Cheniere should receive written authorization from the Director of OEP before commencement of service at the Terminal. 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, and the Safety 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 Cheniere or other appropriate parties.**

4.12.7 LNG Facility and LNG Carrier Emergency Response

As required by 49 CFR §193.2059, Cheniere would need to prepare emergency procedures manuals that provide for: a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordination and cooperation with appropriate local officials. Specifically, § 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…"

Section 3A(e) of the NGA, added by Section 311 of the EPAct 2005, stipulates that in any order authorizing an LNG terminal, the Commission must require the LNG terminal operator to develop an ERP in consultation with the Coast Guard and state and local agencies. The FERC must approve the ERP prior to any final approval to begin construction. Therefore, **we recommend that:**

- **Cheniere should develop an ERP (including evacuation) 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 LNG carrier to activate sirens and other warning devices.**

The ERP should be filed with the Secretary for review and written approval by the Director of OEP prior to initial site preparation. Cheniere should notify the FERC staff of all planning meetings in advance and should report progress on the development of its ERP at 3-month intervals.

A number of organizations and individuals have expressed concern that the local community would have to bear some of the cost of ensuring the security and emergency management of the LNG facility and the LNG carriers while in transit and unloading at the berth. Section 3A(e) of the Natural Gas Act (as amended by EPAct 2005) specifies that the ERP must include a Cost-Sharing Plan that contains a description of any direct cost reimbursements the applicants agree to provide to any state and local agencies with responsibility for security and safety at the LNG terminal and in proximity to LNG carriers that serve the facility. Therefore, **we recommend that:**

- **The ERP should include a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. Cheniere should file the Cost-Sharing Plan for review and written approval by the Director of OEP prior to initial site preparation.**

The Cost-Sharing Plan must specify what the LNG terminal operator would provide to cover the cost of the state and local resources required to manage the security of the LNG terminal and LNG carrier, and the state and local resources required for safety and emergency management, including:

- direct reimbursement for any per-transit security and/or emergency management costs (for example, overtime for police or fire department personnel);
- capital costs associated with security/emergency management equipment and personnel base (for example, patrol boats, firefighting equipment); and
- annual costs for providing specialized training for local fire departments, mutual aid departments, and emergency response personnel; and for conducting exercises.

The cost-sharing plan must include the LNG terminal operator's letter of commitment with agency acknowledgement for each state and local agency designated to receive resources.

4.12.8 Conclusions on Facility Reliability and Safety

As part of the NEPA review, Commission staff must assess whether the proposed facilities would be able to operate safely and securely to minimize potential public impact. Based on our technical review of the preliminary engineering designs, we have made a number of recommendations to be implemented prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility to enhance the reliability and safety of the facility and to mitigate the risk of impact to the public.

In addition, we analyzed whether Cheniere would be sited consistently with federal regulations promulgated by DOT in 49 CFR 193. As a cooperating agency, DOT assisted FERC staff in evaluating whether an applicant's proposed siting meets the DOT requirements. DOT reviewed the data and methodology Cheniere used to determine the design spills from various leakage sources, including piping, containers, and equipment containing hazardous liquids. Cheniere used those design spills to model hazardous releases, which extended beyond their property line, but under their legal control through covenants with the adjacent property owners. On February 10, 2014, DOT provided a letter to FERC staff stating that DOT had no objection to Cheniere's methodology for determining the single accidental leakage sources for candidate design spills to be used in establishing the Part 193 siting requirements for the proposed LNG liquefaction facilities. If a facility is constructed and becomes operational, the facility would be subject to DOT'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 DOT staff.

We also analyzed the potential impacts along the waterway from LNG marine traffic. As a cooperating agency, the Coast Guard analyzed the suitability of the waterway for LNG marine traffic. In a letter dated March 21, 2013, the Coast Guard issued a LOR and LOR Analysis to FERC stating 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 accommodating the type and frequency of LNG marine traffic associated with this Project. The recommendation was based on full implementation of the strategies and risk management measures identified to the Coast Guard by Cheniere in its WSA. Under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA, and the Safety and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG carrier 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 appropriate resources are not in place prior to LNG carrier 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. FERC staff recommends Cheniere receive written authorization from the Director of OEP before commencement of service at the Terminal to ensure the Coast Guard has determined that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Cheniere or other appropriate parties.

Based on our engineering design analysis and recommendations presented in section 4.12 for the Terminal, the no objection by DOT to the design spill methodology and our subsequent review of the siting analysis for the Terminal, the LOR issued by the Coast Guard concluding the LNG vessel transit is suitable for LNG marine traffic, and the regulatory requirements for the design, construction, and operation of the Pipeline and Terminal, we conclude that the Project would not result in significantly increased public safety risks.

4.12.9 Pipeline Safety Standards

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 an 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°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.

The DOT is mandated to provide adequate protection against risks to life and property posed by pipeline transportation under Title 49, USC Chapter 601. The DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety 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 strives 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.

The DOT 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 DOT's agent to inspect interstate facilities within its boundaries; however, the DOT is responsible for enforcement actions. Federal inspectors from the DOT Office of Pipeline Safety perform inspections on interstate natural gas pipeline facilities in Texas.

The DOT 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 Memorandum of Understanding on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993, between the DOT and the FERC, the DOT has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of our 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 DOT 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 DOT. 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 DOT's Technical Pipeline Safety Standards Committee which determines if proposed safety regulations are reasonable, feasible, and practicable.

The facilities associated with the Pipeline must be designed, constructed, operated, and maintained in accordance with the DOT 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 DOT specifies material selection and qualification; minimum design requirements; and protection from internal, external, and atmospheric corrosion.

The DOT 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.
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; MAOP; inspection and testing of welds; and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas. Once the pipeline route has been finalized, Cheniere would identify the pipeline centerline with respect to other structures or manmade features and determine the class locations along the Pipeline.

If a subsequent increase in population density adjacent to the right-of-way results in a change in class location for the pipeline, Cheniere would reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness, if required to comply with the DOT requirements for the new class location.

The DOT Pipeline Safety Regulations require operators to develop and follow a written integrity management program that contains all the elements described in 49 CFR 192.911 and address the risks on each transmission pipeline segment. The rule requires operators to establish an integrity management program which applies to all high consequence areas (HCA).

The DOT has published rules that define HCAs where a gas pipeline accident could do considerable harm to people and property and requires an integrity management program to minimize the potential for an accident. This definition satisfies, in part, the Congressional mandate for DOT 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[45] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle[46], 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 DOT regulations specify the requirements for the integrity management program at Section 192.911. Of the 23 miles of proposed pipeline route, Cheniere has identified approximately 2.9 miles that would be classified as an HCA. The pipeline integrity management rule for HCAs requires inspection of the pipeline HCAs at intervals specified in § 192.939, but at least every seven years.

The DOT 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

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[45] 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.

[46] The potential impact circle is a circle of radius equal to the potential impact radius.

- protecting people first and then property, and making them safe from actual or potential hazards.

The DOT 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. Cheniere would provide the appropriate training to local emergency service personnel before the pipeline is placed in service.

4.12.9.1 Pipeline Accident Data

The DOT requires all operators of natural gas transmission pipelines to notify the DOT of any significant incident at the earliest practicable moment and to submit a report within 30 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)[47].

During the 20 year period from 1994 through 2013, a total of 1,237 significant incidents were reported on the more than 300,000 total miles of natural gas transmission pipelines nationwide.

Additional insight into the nature of service incidents may be found by examining the primary factors that caused the failures. Table 4.12-8 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 constituting 48.2 percent of all significant incidents. The pipelines included in the data set in table 4.12-8 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 pipelines have a higher frequency of corrosion incidents and material failure, since corrosion and pipeline stress/strain is a time-dependent process.

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[47] $50,000 in 1984 dollars is approximately $115,000 as of March, 2014 (CPI, Bureau of Labor Statistics, February 2014)

Table 4.12-9
Natural Gas Transmission Pipeline Significant Incidents by Cause
1994-2013 a/

Cause	No. of Incidents	Percentage e/
Corrosion	292	23.6
Excavation b/	211	17.0
Pipeline material, weld or equipment failure	304	24.6
Natural force damage	142	11.5
Outside force c/	74	6.0
Incorrect operation	33	2.7
All other causes d/	181	14.6
TOTAL	1,237	-

a/ All data gathered from PHMSA Significant incident files, March 25, 2014. http://primis.phmsa.dot.gov/comm/reports/safety/
b/ Includes third party damage
c/ Fire, explosion, vehicle damage, previous damage, intentional damage
d/ Miscellaneous causes or unknown causes
e/ Due to rounding, column does not total 100%

The use of both an external protective coating and a cathodic protection system[48], required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe.

Outside force, excavation, and natural forces are the cause in 34.5 percent of significant pipeline incidents. These 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. Table 4.12-9 provides a breakdown of outside force incidents by cause.

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 programs in populated areas to minimize unauthorized excavation activities in the vicinity of pipelines. The "One Call" program is a service used by public utilities and some private sector companies (e.g., oil pipelines and cable television) to provide preconstruction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts.

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[48] 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 4.12-10
Outside Forces Incidents by Cause
(1994-2013) a/

Cause	**No. of Incidents**	**Percent of all Incidents**
Third party excavation damage	176	41.2
Operator excavation damage	25	2.0
Unspecified excavation damage/previous damage	10	0.8
Heavy rain/floods	72	5.8
Earth movement	35	2.8
Lightning/temperature/high winds	21	1.7
Natural force (other)	14	1.1
Vehicle (not engaged with excavation)	45	3.6
Fire/explosion	8	0.6
Previous mechanical damage	5	0.4
Fishing or maritime activity	7	0.6
Intentional damage	1	0.1
Electrical arcing from other equipment/facility	1	0.1
Unspecified/other outside force	7	0.6
TOTAL	427	--

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a/ Excavation, Outside Force, and Natural Force from table 4.12-8

4.12.9.2 Impact on Public Safety

The service incidents data summarized in table 4.12-8 include pipeline failures of all magnitudes with widely varying consequences.

Table 4.12-10 presents the average annual injuries and fatalities that occurred on natural gas transmission lines for the 5-year period between 2009 and 2013. The majority of fatalities from pipelines are due to local distribution pipelines not regulated by FERC. These are natural gas pipelines 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 which are more susceptible to damage. Local distribution systems do not have large right-of-ways and pipeline markers common to the FERC regulated natural gas transmission pipelines.

Table 4.12-11
Injuries and Fatalities - Natural Gas Transmission Pipelines

Year	Injuries	Fatalities
2009	11	0
2010 a/	61	10
2011	1	0
2012	7	0
2013	2	0

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a/ All of the public injuries and fatalities in 2010 were due to the Pacific Gas and Electric pipeline rupture and fire in San Bruno, California on September 9, 2010.

The nationwide totals of accidental fatalities from various anthropogenic and natural hazards are listed in table 4.12-11 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, however, because individual exposures to hazards are not uniform among all categories. The data nonetheless indicate a low risk of death due to incidents involving natural gas transmission pipelines compared to the other categories. Furthermore, the fatality rate is much lower than the fatalities from natural hazards such as lightning, tornados, or floods.

Table 4.12-12
Nationwide Accidental Deaths a/

Type of Accident	Annual No. of Deaths
All accidents	117,809
Motor Vehicle	45,343
Poisoning	23,618
Falls	19,656
Injury at work	5,113
Drowning	3,582
Fire, smoke inhalation, burns	3,197
Floods b/	89
Lightning b/	52
Tornado b/	74
Natural gas distribution lines c/	14
Natural gas transmission pipelines c/	2

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a/ All data, unless otherwise noted, reflects 2005 statistics from U.S. Census Bureau, Statistical Abstract of the United States: 2010 (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 (1983-2012) http://www.weather.gov/om/hazstats.shtml
c/ PHMSA significant incident files, March 25, 2014. http://primis.phmsa.dot.gov/comm/reports/safety/, 20 year average.

The available data show that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 1994 to 2013, there were an average of 62 significant incidents, 10 injuries and 2 fatalities per year. 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 would represent a slight increase in risk to the nearby public.

4.13 CUMULATIVE IMPACTS ANALYSIS

NEPA requires the lead federal agency to consider the potential cumulative impacts of proposals under review. Cumulative impacts may result when the environmental effects associated with the proposed action are superimposed on or added to impacts associated with past, present, and reasonably foreseeable future projects. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over a period of time. Generally, cumulative impacts could result only from the construction of other projects in the same vicinity and impacting the same resource areas as the proposed facilities. In such a situation, although the impact associated with each project might be minor, the cumulative impact resulting from all projects being constructed in the same general area could be greater.

Our analysis includes other projects in the vicinity of the proposed Project that affect the same resources as the proposed Project in the same approximate time frame. Specifically, actions included in the cumulative impact analysis must:

- impact a resource area potentially affected by the proposed Project
- cause the impact within all or part of the same area affected by the proposed Project for that resource; and
- cause the impact within all or part of the time span as that of the potential impact from the proposed Project.

Using this approach, the potential for cumulative impacts was assessed by combining the potential environmental impacts of the proposed Project with the impacts of identified projects. The cumulative impact area for each resource is defined in section 4.13.2.

We received comments on the draft EIS from the EPA and the Sierra Club suggesting that FERC consider the potential for increased natural gas production as a result of the proposed Terminal and the potential environmental impacts associated with these potential increases (appendix I). With regard to environmental impacts associated with natural gas production and pipeline transportation, no specific shale-gas play has been identified as a source of natural gas. The Project does not depend on additional shale gas production, which may occur for reasons unrelated to the Project and over which FERC has no control, such as state permitting for additional gas wells. The development of natural gas in shale by hydraulic fracturing is not the subject of this EIS, nor is the issue directly related to the Project. Determining the well and gathering line locations and the environmental impacts associated with their development and operation is not feasible, as the market and gas availability at any given time would determine the source of the natural gas. Further, future shale production is not reasonably foreseeable, because local governments make the decisions concerning siting and timing of wells and gathering lines. Consequently, we cannot know the specifics of when, where, or even if natural gas production would occur. Therefore, an environmental analysis of increased natural gas production would be too speculative for inclusion in the final EIS, because the impact cannot be described with sufficient specificity to make its consideration useful to reasoned decision makers.

While the DOE *Draft Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the Unites States* provides certain general estimates about the environmental impacts associated with natural gas production, those impacts have no particular relationship to Cheniere’s proposed project. In its notice of the Draft Addendum, DOE stated that the discussion of natural gas production activities went beyond what NEPA requires. “While DOE has made broad projections about the types of resources from which additional production may come, DOE cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced. Therefore, DOE cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature.” We agree with DOE that the use of this report, in NEPA, for a specific project and anticipated project induced upstream impacts is not appropriate.

We agree that the end users of exported LNG would cause environmental impacts; however, neither the location(s) nor the footprint of these impacts is known. Consequently, an analysis would be speculative and provide no meaningful data for decision makers to consider.

Further, the impacts of end use in foreign, likely non-adjacent, countries is beyond the scope of a project proposed within the United States and evaluated under NEPA and CEQ regulations.

Consideration of impacts related to increased exports of LNG is not included in the final EIS; however, we note that studies conducted by National Economic Research Associates indicate that LNG exports is self-limiting, in that little or no natural gas would be exported if the price of natural gas in the United States increases much above current expectations (National Economic Research Associates, 2014).

4.13.1 Projects Potentially Contributing to Cumulative Impacts

The Pipeline would receive and deliver domestic natural gas via interconnections with a number of existing intrastate and interstate pipeline systems. These interconnecting pipeline systems (Texas Eastern, Tejas, NGPL, Transco, and Tennessee Gas) span states from Texas to Illinois to Tennessee and Pennsylvania and cross multiple shale gas plays, as well as conventional gas plays. In addition, each of these interconnecting pipeline systems has a developed network of additional interconnects with other gas transmission pipeline companies that may cross additional gas plays. However, Cheniere does not identify and we cannot estimate how much of the export volumes would come from current shale gas production and how much, if any, would be new production or development attributable to the Project. The Project does not depend on additional shale gas production which may occur for reasons unrelated to the Project and over which the Commission has no control, such as state permitting for additional gas wells. An overall increase in nationwide production of shale gas may occur for a variety of reasons, but the location and subsequent activity is unknown and is too speculative to assume based on the interconnected interstate natural gas pipeline system. Additionally, the factors necessary for a meaningful analysis of when, where, and how the development of shale gas would occur are unknown at this time.

Wells which could produce gas that might ultimately flow to this Project might be developed in any of the shale plays that exist in nearly the entire eastern half of the United States. Accordingly, it is simply impractical for the Commission to consider impacts associated with additional shale gas development as cumulative indirect impacts resulting from the Project which must, under CEQ regulations, be meaningfully analyzed by the Commission. For purposes of this cumulative impact analysis, impacts which may result from additional shale gas production is not considered reasonably foreseeable, as defined by CEQ regulations, nor is such an additional production or any correlative potential impacts, an effect of the Project. Therefore, we find that the EIS appropriately considers cumulative impacts on the areas surrounding the Project and appropriately focuses on potential impacts associated with the Project. The analysis of the potential impacts of the Project on geology and soils, water resources, fisheries, vegetation, wildlife, land use, recreation, visual resources, socioeconomics, cultural resources, air quality, and noise, indicates that the Project would result in little to no incremental contribution to impacts on resources in the Project area; therefore, the Project’s incremental contribution to impacts on resources well beyond the Project area would likewise be negligible.

Table 4.13-1 (see appendix D) provides a list of projects considered in our cumulative impacts analysis, including the proposed Project, and a general summary of potential impacts associated with each project. Included in our analysis are those known projects with potential impacts on the same resources for which some impact has been evaluated for the Project. Figure 4.13-1 shows the general locations of the projects included in our cumulative impacts analysis.

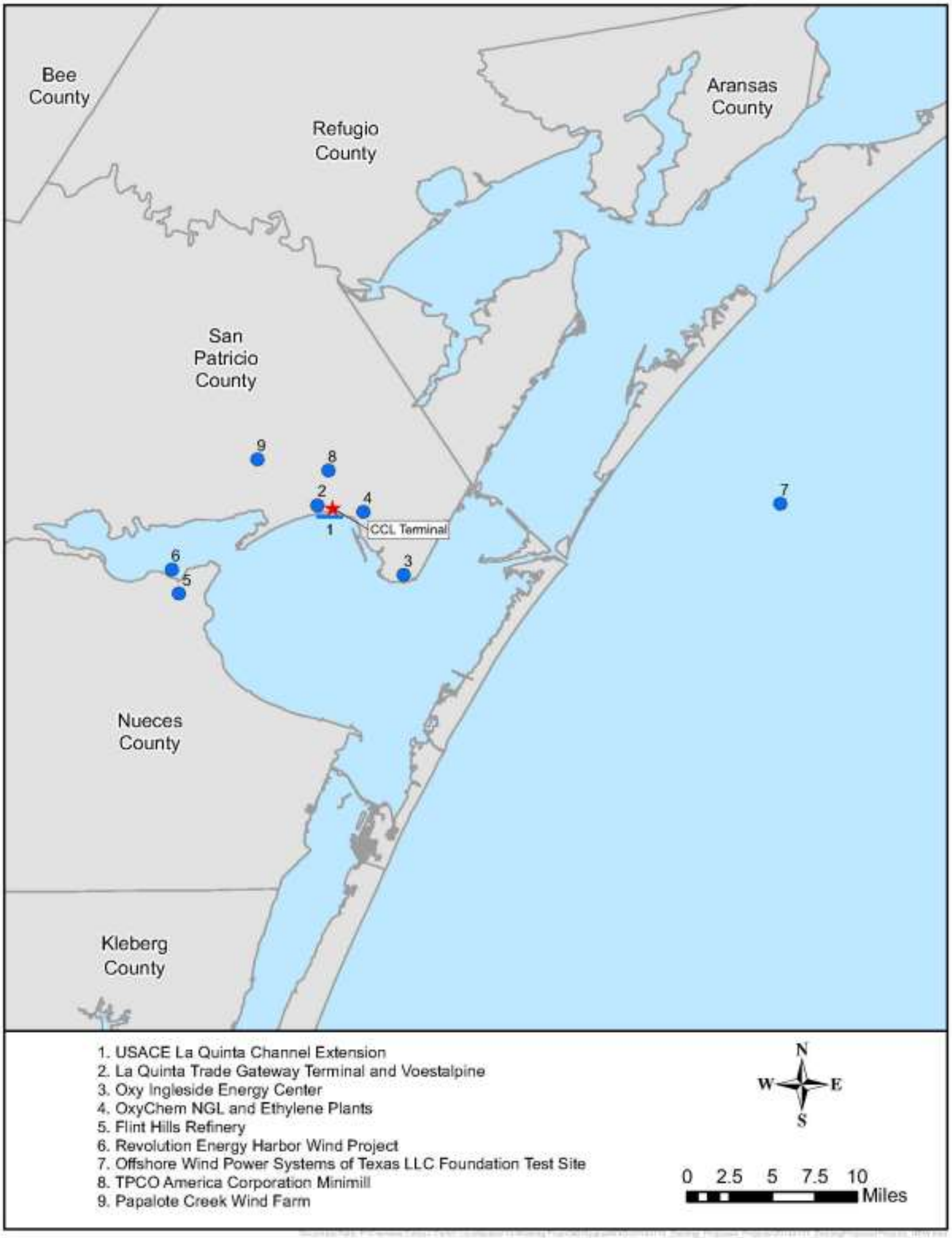

Figure 4.13-1 **General Locations of Projects Potentially Contributing to Cumulative Impacts**

4.13.1.1 U.S. Army Corps of Engineers La Quinta Channel Extension

The COE, Galveston District, awarded a contract on September 22, 2011 in the amount of $33,537,027 to King Fisher Marine Service, LP for dredging of the Corpus Christi Ship Channel's La Quinta extension located less than 1 mile southeast of the Terminal in Nueces County, Texas. Commencement of dredging began in December 2011, and will be completed by the summer of 2014. Construction activities have included dredging of approximately 7,400 feet of the La Quinta Channel extension to a depth of -39 feet mean low tide (equivalent to -40 feet NAVD 88) (plus 2 feet paid overdredge, plus 2 feet advanced maintenance dredge).

The project, for navigation and ecosystem restoration, is part of the Corpus Christi Ship Channel - Channel Improvement Project as authorized by Section 1001(40) of the Water Resources Development Act of 2007. Funding for the construction contracts was approved on May 17, 2011 by the COE as part of its 2011 work plan for the Army Civil Works program. The projects include the following navigation and ecosystem restoration elements:

- extend the La Quinta Ship Channel approximately 7,400 feet;
- construct an ecosystem restoration feature; and
- create a beneficial use site.

4.13.1.2 Port of Corpus Christi Authority La Quinta Trade Gateway Terminal

The proposed La Quinta Trade Gateway Terminal comprises a major component of the POCCA's proposed long-term development plan and would be located immediately west of the Terminal on a 1,100-acre site on the north side of Corpus Christi Bay. Once complete, this fully permitted project would provide a state-of-the-art multi-purpose dock and container facility. Project features consist of the extension of the La Quinta Channel (see description for COE La Quinta Channel Extension), construction of a 3,800-foot-long, 3-berth ship dock with nine ship-to-shore cranes, utilizing 250 acres of container/cargo storage yards, an intermodal rail yard, and over 400 acres for on-site distribution and warehouse centers. The facility would have the capacity to handle approximately 1 million 20-foot equivalent units annually. The La Quinta Trade Gateway Terminal would be located adjacent to US 181/SH 35 and immediately to the west of the proposed Project site.

The federal authorization to construct the extension of the La Quinta Ship Channel has been a key factor for moving forward with the construction of the La Quinta Trade Gateway Terminal. With the authorization and initial appropriation to construct the channel extension, the Port Commission signed a Project Partnership Agreement with the COE in October 2009 in order to authorize and construct the extension. The COE began work at the site in 2010 through construction of a 126-acre dredge material placement area as well as the dredging of the La Quinta Channel extension as discussed above. The completion of the La Quinta Channel extension by the summer of 2014 would facilitate the initiation of construction of the La Quinta Trade Gateway Terminal, beginning with additional dredging of the Ship Channel. A start date has not yet been set for construction of the cargo terminal.

4.13.1.3 Revolution Energy Harbor Wind Project

Revolution Energy, LLC has developed and constructed the Harbor Sunrise wind farm on the north side of the Inner Harbor along Nueces Bay. Feasibility study results have indicated that a wind power project located within the inner harbor is viable. Under a lease agreement, additional scoping studies have been conducted to determine the exact number and size of the wind turbines that would be installed.

Project development commenced in the 2006 and began transmitting power to the grid in February 2012. The project consists of six, 1.5-megawatt offshore wind turbines that can supply up to 30 million kilowatt-hours a year to the local grid, supplying enough energy to power about 2,500 homes. The turbines have been installed along the perimeter of the port, out of the way of cargo operation areas.

4.13.1.4 Offshore Wind Power Systems of Texas Foundation Test Site

Offshore Wind Power Systems of Texas, LLC (Offshore Wind), is a privately owned Texas corporation that has developed an offshore platform (the Titan Wind Turbine Platform) for use by wind turbines installed along off-shore wind farms. In September 2011 Offshore Wind solicited turbine manufacturers/suppliers to utilize the "Titan 200" foundation at the fully permitted test site located approximately 10 miles off the shore of the former Naval Station Ingleside site, and approximately 26 miles east of the Terminal.

4.13.1.5 Tianjin Pipe Corporation America Corporation Minimill

Tianjin Pipe Corporation (TPCO) America Corporation began construction on its Texas Mill Project in Gregory, Texas in September, 2011. Phase I of the project was completed in early 2013 and the entire facility is scheduled to be operational in late 2014.

The Texas Mill Project is a seamless steel pipe manufacturing facility on a 253-acre site, which will be located between SH 35 and SH 361, approximately 1.5 miles north of the proposed Project site. The 1.6 million square-foot facility would produce 500,000 metric tons per year of pipe principally for use in the energy industry. The seamless pipe would be used in both the U.S. and abroad, utilizing an electric arc furnace to convert recycled scrap steel and pig iron. Once fully operational, the TPCO America facility would be the largest single investment by TPCO, a Chinese company, in a U.S. manufacturing facility.

4.13.1.6 Oxy Ingleside Energy Center Propane Export Facility

Oxy Ingleside Energy Center purchased the former Naval Station at Ingleside property from the POCCA in 2012. The property is located along the Corpus Christi Ship Channel, approximately 6 miles southeast of the Project site. The Naval station property encompasses approximately 483 acres and contains more than 70 state-of-the-art buildings, such as warehouse facilities, office and administrative facilities, barracks, fitness and recreation facilities, a capital-class pier and wharf area, and several others.

Oxy Ingleside Energy Center has recently announced plans to construct a propane export facility within this property and anticipates the facility to be operational by January 2015. The company has also indicated that it could potentially export other fuels from the proposed facility, such as butanes, natural gas, and condensate. Construction and operation plans for this project have not been made available to the public; therefore, reasonable approximations of potential impacts were used in the cumulative impacts analysis.

4.13.1.7 Papalote Creek Wind Farm

The Papalote Creek Wind Farm is located on actively cultivated agricultural land near the communities of Taft and Gregory. Portions of the wind farm would be crossed by the Cheniere Pipeline between approximate MPs 7 to 10. Papalote Creek Wind Farm complex is a two-phase project consisting of 87 Siemens 2.3 megawatt (MW) turbines and 109 Vestas V82 1.65 MW turbines capable of generating nearly 380 MW. The first phase of the wind farm went into service in fall 2009 and the second phase began operations in 2011.

4.13.1.8 Occidental Chemical Corporation Natural Gas Liquids Fractionation Facility

Occidental Chemical Corporation (OxyChem) proposes to construct and operate a new 87,000 barrel per day NGL Fractionation Facility within its existing site along the La Quinta Channel, located 2 miles west of Ingleside, Texas and approximately 1.2 miles east of the Terminal. The proposed project also includes the installation of four hydrocarbon pipelines, which would be constructed within the existing 18.5-mile-long and 100-foot-wide San Patricio Pipeline Corridor. These pipelines would serve to transport NGL to the proposed 470-acre facility where they would be fractionated into ethane, propane, butane, and natural gasoline. The products would then be stored on-site before being transferred via pipeline, tank truck, rail car, or barge to various markets or the proposed OxyChem Ethylene Plant located immediately adjacent to the fractionation facility.

In May 2012, OxyChem submitted a GHG PSD permit application to the EPA for their proposed fractionation facility. OxyChem identified two thermal oxidizers, one flare, one cooling tower, fugitive sources for five operating areas, one emergency generator, and four firewater pump engines as new sources of GHG emissions. The public comment period for the GHG PSD permit closed as of August 9, 2013.

OxyChem recently released an anticipated construction schedule, with project activities estimated to be completed by December 2014. However, this schedule is currently under review and a final in-service date has not yet been determined.

4.13.1.9 OxyChem Ethylene Plant

OxyChem proposes to construct and operate a new 1.2 billion pounds per year (lb/y) ethylene plant within its existing site along the La Quinta Channel, located approximately 2 miles west of Ingleside, Texas and approximately 1.2 miles east of the Terminal. The plant would receive ethane feed via pipeline or from the proposed NGL Fractionation Facility to be constructed on adjacent property. Once fully operational, the plant would produce 1.2 billion lb/y of market grade ethylene. Construction on this project is expected to commence in 2014, with the facility becoming fully operational in early 2017.

In December 2012, OxyChem submitted a GHG PSD permit application to the EPA for their proposed ethylene plant. OxyChem identified five cracking furnaces, two thermal oxidizers, one high pressure ground flare, one emergency generator engine, one low pressure enclosed flare, one cooling tower, and fugitive sources for six operating areas as new sources of GHG emissions. OxyChem is currently in the early development and permitting stages for the project, and an updated construction schedule has not been released.

4.13.1.10 Voestalpine DRI Plant

Voestalpine proposes to construct and operate a DRI plant on land adjacent to the west side of the Project in San Patricio County, Texas. The proposed DRI plant would be constructed on approximately 475 acres of upland property and approximately 11 acres of submerged land owned by the POCCA. Additionally, the facility would also include the construction of a 1,060-foot-long high performance dock.

Project features consist of a reformer and reactor necessary for the conversion of Canadian or Brazilian ore into highly metallized iron, either in the form of DRI or hot briquetted iron. The DRI Plant is expected to require approximately 150 people for the annual production of 2 million metric tons of iron, which would be distributed to Austrian steel mills as well as other international and domestic markets. It is anticipated that the project would begin operations in late 2015 and would be in full production by early 2016. Voestalpine submitted a GHG PSD permit application to the EPA for their proposed DRI Plant in January 2013.

4.13.1.11 Flint Hills West Refinery Expansion

Flint Hills Resources Corpus Christi, LLC (FHR) proposes to expand their existing crude oil refinery located on the north eastern shore of Nueces Bay, approximately 15 miles east of the Terminal. The expansion of their currently operating West Refinery would allow the refinery to process a larger percentage of domestic crude oil and increase the total crude processing capacity.

Construction of new facilities for this project would include a process unit called the Saturates Gas Plant No. 3, one cooling tower, and equipment piping fugitive components in several existing process units. The existing equipment affected by construction would include increasing the firing duty of the CCR Hot Oil Heater, physical changes to the Mid Plant Cooling Tower, and conversion of the current Gas Oil Hydrotreating Unit to a Distillate Hydrotreating Unit.

In December 2012, FHR submitted a GHG PSD permit application to the EPA, as the proposed refinery expansion will increase emissions at the site. The application was incomplete and FHR has since submitted updated information; however, the application has not been deemed complete to date.

4.13.2 Existing, Proposed, and Planned LNG Terminals and Projects

We identified one existing LNG terminal in the general Project vicinity (Freeport Liquefaction Project), one proposed LNG terminal (Lavaca Bay LNG Project), and one planned LNG terminal (Gulf Coast Liquefaction Project) that could contribute to cumulative impacts with those of the proposed Project. Other existing or proposed LNG terminals were identified but dismissed from this analysis as they are located approximately 300 miles away. Brief descriptions of the projects are provided below. This cumulative impacts analysis considered the impacts of operation of the existing terminal as well as the potential construction and operation impacts of the planned or proposed projects.

4.13.2.1 Freeport Liquefaction Project

FLEX has proposed the Freeport Liquefaction Project in Brazoria County, Texas, which includes the addition of liquefaction facilities to its existing terminal located on Quintana Island to provide export capacity of approximately 13.2 mtpy of LNG. This project would require approximately 86 acres for three proposed trains, each with a capacity of 4.4 mtpy, and associated facilities. FLEX anticipates start-up for the first liquefaction train in November 2016, with full service anticipated 48 to 54 months after initiation of construction. This project is located more than 150 miles from the proposed Project. .

4.13.2.2 Lavaca Bay LNG Project

The proposed Lavaca Bay LNG Project (Docket Nos. CP14-71-000, CP14-72-000, and CP14-73-000) consists of two floating liquefaction, storage, and offloading (FLSO) units that would produce LNG from North American natural gas. The Lavaca Bay LNG Project would include a total of eight liquefaction trains, storage of up to 500,000 m^3 of LNG, and a send-out capacity of 10 mtpy of LNG and has a planned in service date of December 31, 2017. The project would also include onshore pre-treatment facilities and infrastructure associated with the FLSOs. LNG would be stored, as needed, prior to transferring the LNG to carriers for export. The project is located more than 60 miles north of the proposed Project. .

4.13.2.3 Gulf Coast Liquefaction Project

The planned Gulf Coast Liquefaction Project would include a new export terminal located in Brownsville, Texas (more than 130 miles south of the proposed Project) consisting of four liquefaction trains capable of liquefying 2.8 Bcf/d of natural gas. Gulf Coast anticipates in service in 2018.

4.13.3 Currently Operating Oil and Gas Facilities

There are various oil and gas wells in the vicinity of the proposed Project site (see section 4.1), primarily located near the Pipeline, and many of these are oil and gas gathering and transmission pipelines and related facilities. Those facilities are in place and generally would not contribute to the cumulative impacts associated with construction of the Project; however, the operation of the wells permanently removed both wetlands and vegetation. There are no major storage or processing facilities in the vicinity.

The Pipeline would be adjacent to portions of other rights-of-way including those with which the proposed Pipeline would interconnect. These pipelines have been in service for a number of years and the only impacts relating to the cumulative impact analysis include maintenance for permanent rights-of-way in the vicinity of the interconnections and emissions from compressor stations associated with the pipelines.

4.13.4 Other Projects and Activities Considered

4.13.4.1 Non-Jurisdictional Power Lines and Substations

As discussed in section 1.6.1, Cheniere identified an electrical power line extension and substation that would be required for construction and operation of the Terminal. An overhead powerline would extend from the junction of SH 35 and SH 361 to a new facilities substation located at the Terminal site. The power line and electrical substation would be built, owned, and operated by AEP. Cheniere would also build, own, and operate an underground power line that would extend from the AEP substation to the facilities substation at the Terminal.

4.13.4.2 Non-Jurisdictional Waterline

As discussed in section 1.6.2, the construction and operation of the Terminal would require a waterline connection to the San Patricio Municipal Water District potable water system at the north end of La Quinta Road. The waterline would be constructed within the same corridor as the power lines discussed above.

4.13.4.3 Removal of Non-Jurisdictional Natural Gas Pipelines

Two existing natural gas pipelines located in the Project area (Crosstex Corpus Christi Natural Gas Transmission [Crosstex] and Royal Production Company [Royal] were removed by their respective operators following Cheniere's receipt of the 2005 Order. Descriptions of the locations of the pipeline segments previously present at the Terminal are provided below.

Crosstex Corpus Christi Natural Gas Transmission - approximately 0.3 mile of 10-inch-diameter natural gas pipeline owned and operated by Crosstex was located within the Terminal site boundary. Portions of this pipe would have been impacted during dredging activities associated with the marine berth, as well as the La Quinta Channel Extension, further discussed in section 4.13.1.

Royal Production Company - approximately 0.6 mile of 6-inch-diameter offshore natural gas pipeline extending from a well in Corpus Christi Bay, a 4-inch tie-in, and a tank battery, all owned and operated by Royal, was located within the Terminal site boundary.

These two existing natural gas pipelines were abandoned, removed, or relocated following Cheniere's receipt of the Order issued by the Commission on April 18, 2005. The exact nature of the abandonment, removal, or relocation activities is not known to Cheniere or FERC, as each of the individual operators permitted and conducted these operations on their own. Environmental impacts associated with the removal of those three pipelines are anticipated to have occurred within previously disturbed areas and were not significant.

In addition to the two pipelines that were previously present at the Terminal site, Gulf South Pipeline Company, LP currently maintains an approximately 1.2-mile 6-inch diameter natural gas pipeline at the Terminal site. Cheniere has indicated that the Pipeline would be relocated prior to commencement of construction at the Terminal site. Because this relocation would be permitted and conducted by Gulf South, the exact scope of the relocation is not known to Cheniere or FERC.

4.13.5 Potential Cumulative Impacts by Resource

The following sections address the potential cumulative impacts from Cheniere's Project on each environmental resource.

4.13.5.1 Geologic Resources

The cumulative impact area for geologic resources and natural hazards was considered to be the area adjacent to the Terminal and the Pipeline construction areas. Although the topography in the area is nearly flat, construction of the Terminal would require some modification of existing contours to safely accommodate the facilities and maintain drainage in the area. These modifications would not differ substantially from the existing topography in adjacent areas. The LNG tanks would be located in areas that may be subject to differential surcharge conditions, which could result in detrimental differential foundation settlements;

however, this would be investigated with settlement analysis of the tank foundation and by implementing preventative measures as necessary.

The projects in the cumulative impact area for geologic conditions at the Terminal would include the COE La Quinta Channel Extension, the POCCA La Quinta Trade Gateway Terminal, and the Voestalpine DRI Plant, all of which may require dredging activities. The three non-jurisdictional facilities associated with the proposed Project occur within the cumulative impact area for geologic conditions at the Terminal; however, construction of these non-jurisdictional facilities is not expected to result in noticeable changes in topography. Scouring of sand layers exposed during dredging of the shoreline and La Quinta Channel could increase the erosion potential of exposed sand layers and may cause eventual slumping or slope failure. Although the Terminal is located in an area that may present challenges relative to slope stability, mitigation plans and implementation of erosion controls would reduce or minimize any significant cumulative impacts on these resources in the Corpus Christi Bay area.

Construction and operation of the Pipeline would primarily occur within previously disturbed areas and would result in minimal impacts on geological resources. Cheniere would restore topographic contours along the right-of-way to preconstruction conditions to the maximum extent practicable.

4.13.5.2 Soils and Sediments

The cumulative impact area for soils was considered to be the area adjacent to the Terminal and the Pipeline construction areas. Past impacts on soils resources in the vicinity of the Project have resulted from agriculture and industrial developments as well as construction and maintenance of existing roads, railroads, utility lines, and transmission lines. Clearing, grading, and equipment movement associated with construction of the Terminal and the Pipeline could result in soil loss due to erosion, which could reduce soil fertility and impair revegetation, and discharge of sediment to waterbodies and wetlands. However, Cheniere would implement mitigation measures outlined in our Plan and Procedures as well as recommendations of the local NRCS to minimize erosion and aid in the reestablishment of vegetation in areas temporarily impacted during construction.

The planned non-jurisdictional facilities, including the electrical power line extensions and substations as well as the waterline, would be constructed within and adjacent to the Terminal site. All of the non-jurisdictional facilities would be constructed within existing, previously disturbed areas and would not contribute significantly to a cumulative impact on soils.

4.13.5.3 Water Resources

The cumulative impact area for groundwater was limited to the aquifers that Project is located within. The cumulative impact area for surface water resources extends approximately 2 miles upstream and downstream of the Terminal site boundaries and the pipeline stream crossings. Cumulative impacts on water resources at the Terminal site, when combined with other projects in the area, would be limited primarily to the waters of the La Quinta Channel and the Corpus Christi Ship Channel, as the majority of other identified projects are located along those waterways. Although the non-jurisdictional waterline to the San Patricio Municipal Water District potable water system would be installed at the Terminal site, the waterline would be constructed entirely within previously disturbed areas and would not result in adverse impacts on water resources or local water quality.

Some of the projects would require dredging in order to deepen, widen, or maintain marine channels, turning basins, or to install pilings or footings. As a result of initial dredging activities, construction of new channels and turning basins, and during future maintenance dredging, increased turbidity and sedimentation would temporarily decrease water quality in the vicinity of each project. Water resources may have been previously impacted during dredging activities associated with the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines located at the Terminal site. However, dredging and construction activities associated with the abandonment, removal, or relocation of these pipelines would have been similar to those discussed above but would have occurred on a much smaller scale.

If dredging associated with the Terminal could add to the cumulative impact on water quality if it were to occur concurrently with dredging for the other projects identified in the area. However, the negative impacts on water quality as a result of dredging in and adjacent to the existing La Quinta and Corpus Christi Channels would be temporary, and water quality would be expected to return to ambient conditions soon after completion of activities.

The design of the offshore platforms for the Offshore Wind Foundation Site offers a relatively small area of impact using a reduced footprint on the sea floor. Although some turbidity in the water column could occur as a result of installation of the platforms at the test site, it is likely that this impact would be minor and temporary in nature. In addition, turbidity would remain isolated to the area directly adjacent to the platform.

Installation of the Pipeline associated with the Project would not have a significant impact on the freshwater waterbodies that would be crossed. Even if the other projects identified in the area have concurrent impacts on the same waterbodies, significant cumulative impacts would not be anticipated. Each company would implement crossing methods and erosion and sediment control measures that would comply with local, state, and, federal permit requirements for each crossing. The impacts on waterbodies that would occur as a result of the installation of the Pipeline would be short-term, and full restoration of stream banks, pipeline right-of-ways, and all other natural horizons would be restored to preconstruction contours to the maximum extent practicable.

In the event of a spill of hazardous materials during construction or operation of any of the projects identified, water resources could potentially be impacted. However, the Project is not likely to contribute significantly to cumulative impacts on water resources due to spills. In the event of a spill of hazardous materials, Cheniere would implement its SPCC Plan. Additionally, the location of the Terminal site occurs on previously disturbed, highly industrialized lands including old bauxite tailing storage areas. Best management practices would be utilized during installation of the Pipeline in order to prevent contamination of waterbodies being crossed in the event of a hazardous materials spill.

4.13.5.4 Wetlands and Submerged Aquatic Vegetation

The cumulative impact area for wetlands was considered to be the area adjacent to the proposed Project construction area.

Several of the projects identified in table 4.13-1 (see appendix D) could have a significant cumulative impact on wetlands and submerged aquatic vegetation. In the case of the Pipeline, impacts on wetlands would be mostly temporary, as they would be restored after construction, with less than 0.01 acre of anticipated permanent impacts. However, construction of the

Terminal is expected to contribute more significantly to cumulative impacts on wetlands in the region. Each of the project proponents would be required by the terms and conditions of their respective Section 404 permit to provide compensatory mitigation for these unavoidable wetland impacts. These impacts are detailed by the COE in its Statement of Findings for the Section 404 permit issued for the Project on July 23, 2014 and filed with the FERC on August 5, 2014.

Additionally, the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines would have impacted wetlands and SAV at the Terminal site. Although the exact nature of the abandonment, removal, or relocation activities is not known to Cheniere or the FERC, it is assumed that impacts associated with dredging activities as well as mitigation measures would have been similar to those associated with the marine berth and the La Quinta Channel Extension.

Both temporary and permanent impacts on SAV are expected as a result of dredging and other construction activities from each of the identified projects, including the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines. Additional mitigation plans have been proposed by the POCCA to compensate for adverse impacts on SAV communities, including the creation of nearly 900 acres of shallow-bottom habitat, 15 acres of SAV, and 26 acres of marsh using dredged material from the La Quinta Ship Channel Extension Project; and construction of an Ecosystem Restoration Feature to protect approximately 45 acres of existing SAV, an existing bird island, and 400 acres of wetlands.

While impacts on wetlands and SAV are anticipated, mitigation plans and activities would reduce or minimize cumulative impacts on these resources in Corpus Christi Bay area. Therefore, the Project would not contribute significantly to cumulative impacts on wetlands and SAV.

4.13.5.5 Vegetation, Wildlife, and Aquatic Resources

The cumulative impact area for vegetation and wildlife was considered to be the area adjacent to and near the proposed Project construction zones. The cumulative impact area for aquatic resources was considered to be the same as that for water resources.

When projects are constructed concurrently, the combination of construction activities could have cumulative impact on vegetative, wildlife, or aquatic resources. All of the projects considered in this cumulative impacts analysis would be within or adjacent to previously, highly disturbed, industrial areas or developed sites. These areas do not typically offer high quality habitat for diverse vegetation or wildlife species. In addition, while constructing these projects, mobile wildlife species would be able to temporarily displace to similar adjacent habitats. These species would later be able to return to the open project lands following restoration. Therefore, we determined impacts on wildlife species would be short-term and not significant.

Dredging activities associated with several of the identified projects would impact a significant amount of shallow-bottom habitat considered EFH. Deepening shipping channels, maneuvering areas, and docks would result in a permanent conversion of shallow-bottom habitat to deeper water habitat, maintained as such through periodic maintenance dredging. Dredging associated with the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines would have resulted in impacts on shallow-bottom habitat and other aquatic resources similar to those associated with construction of the marine berth, but on a much smaller scale. Therefore, cumulative impacts on vegetative, wildlife, or aquatic resources from the abandonment, removal, or relocation of these non-jurisdictional pipelines would not be significant. Most other impacts associated with dredging would be short-term, such as localized turbidity resulting in reduced water quality and potential temporary impacts on local fish species. Compensatory mitigation for loss of vegetated components of EFH (seagrass and coastal marsh habitats) would be addressed through Section 404 permitting, and consultation with NOAA Fisheries.

The construction and operation of large turbines associated with wind farm projects could potentially affect bird and bat species through collision-related fatalities. However, a Phase I Avian Risk Assessment conducted for the Revolution Energy Wind project determined that fatalities among birds in the area are not likely to be biologically significant. Additionally, the project has been constructed in a highly industrialized area which does not provide high quality bird habitat. The Project would not be likely to contribute significantly to cumulative impacts on flying species, as the tallest structures (storage tanks, marine flare, and process flare tower located at the Terminal facilities) would have visual markers and aircraft warning lights installed on guy-wires and tall, free-standing structures. Additionally, the heights of the tallest structures associated with the Project would be similar or less than those located on neighboring properties. Although some collisions with these structures could potentially occur it is not likely that these fatalities would be of biological significance.

4.13.5.6 Threatened and Endangered Species

Of the projects listed in table 4.13-1 (see appendix D), only the La Quinta Channel Extension, OxyChem NGL Fractionation Facility, FHR West Refinery Expansion, and Freeport Liquefaction projects had results of threatened and endangered species impact assessments that are publicly available. Seventeen federally listed species were identified as occurring or potentially occurring within the Project area, including two plants (south Texas ambrosia and slender rush-pea), nine mammals (five whales, ocelot, gulf coast jaguarundi, and West Indian manatee), two birds (whooping crane and piping plover), and five reptiles (loggerhead sea turtle, green sea turtle, leatherback sea turtle, Atlantic hawksbill sea turtle, and Kemp’s ridley sea turtle). We have determined the Project would not be likely to adversely affect any of these federally listed threatened and endangered species. An additional 24 state listed species were identified in San Patricio and Nueces Counties, 14 of which would not be impacted and 10 which would not likely be impacted by the Project.

According to the Environmental Assessment for the La Quinta Channel Extension, the project would either have no effect or would not be likely to adversely affect the species listed in Nueces and San Patricio Counties. Dredging of the Ship Channel may indirectly impact EFH due to increased turbidity and suspended sediment load in the estuarine water column; however, these impacts on EFH are expected to be temporary and minor. OxyChem developed a draft BA to assess any potential impacts from its NGL Fractionation Facility on the listed threatened and endangered species. The results of this BA determined that the project would have no effect on four of these listed species and may affect, but would not be likely to adversely affect the remaining listed species. Additionally, the BA states that the NGL Fractionation Facility would have no adverse impacts on EFH. The GHG PSD permit application for FHR’s West Refinery Expansion indicates that no listed threatened and endangered species or their critical habitats occur within the project’s potential impact area and thus, no impacts on listed species are expected. Freeport LNG indicated in its application to the FERC that the project would have no effect, or would be not likely to adversely affect any threatened or endangered species in the area.

No adverse impacts on threatened and endangered species are expected occur as a result of the Project and the projects identified in table 4.13-1 (see appendix D) (with publicly available species impact assessments); therefore, no cumulative impacts are anticipated. However, dredging associated with the Project; the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines; and the La Quinta Channel Extension could result in adverse cumulative impacts on EFH. However, dredging activities for the La Quinta Channel Extension and the abandonment, removal, or relocation of the non-jurisdictional natural gas pipelines would not be performed in conjunction with the Project and thus, cumulative impacts on EFH would not be significant.

4.13.5.7 Land Use, Recreation, and Visual Resources

The cumulative impact area for land use was considered to be the area adjacent to and in the vicinity of the proposed Project. The cumulative impact area for recreation was considered to be GIWW, the Corpus Christi and La Quinta Ship Channels, and Corpus Christi Bay. The cumulative impact area for visual resources was considered to be the area within the viewsheds of the Project facilities.

Almost all projects identified (on land) in the vicinity of the Project, including the non-jurisdictional electrical power line extensions and waterline, would be or have been, constructed on, or adjacent to, highly disturbed industrial or agricultural lands. A significant, additional cumulative loss of unique or special interest lands would not occur as a result of constructing or operating the projects. The installation of the Pipeline and other pipelines across agricultural lands would result only in short-term impacts on agricultural and open, herbaceous lands, as land use would be restored following completion of construction activities.

The Corpus Christi Bay is actively utilized for recreation activities such as boating and fishing; therefore, it is probable that the construction or operation of the identified projects could have a significant, negative impact on the area’s recreational value. However, the Corpus Christi and La Quinta Ship Channels are already actively used by commercial ship traffic, as the Port of Corpus Christi is the fifth largest commercial port in the U.S. Though total port traffic would increase, large ships would be restricted to the deep water-dredged Corpus Christi and La Quinta Ship Channels, while most recreational boaters would utilize shallower channels of the GIWW and many shallow water bays within the Corpus Christi Bay area.

The visual character of the existing landscape is defined by historic and current land uses such as recreation, conservation, and development. The visual qualities of the landscape are further influenced by existing installations such as highways, railroads, pipelines, and electrical transmission and distribution lines and facilities. Cumulatively, the identified projects’ infrastructure facilities and their construction would have some visual impact on the immediate surroundings. However, the identified projects would be consistent with ongoing industrial activities and existing facilities along the Corpus Christi and La Quinta Ship channels.

The proposed non-jurisdictional underground power line and waterline would be buried from the AEP substation to the Project substation at the Terminal site and would not affect the visual character of the area after construction is complete. The overhead power line and supporting structures would alter visual quality and expand the industrial character of the area to the north of the Terminal site. However, the visual quality would be consistent with the industrial character of the surrounding area and consistent with electrical transmission lines that parallel many roadways in the area.

Impacts on visual resources resulting from the storage tanks and flare stack would be moderate and permanent; however, due to the proximity of the Terminal to other industrial structures, the storage tanks and flare stack would be consistent with the surrounding land use.

There are no residences, schools, community parks, or public areas that would be considered visually sensitive areas within 1 mile of the Terminal. The Terminal would use the minimum lighting necessary to allow personnel to safely work and inspect the equipment at the Terminal. The lighting at the Terminal would be consistent with lighting at other industrial facilities along the La Quinta Channel and would not significantly increase light pollution in the area. Therefore, cumulative impacts from lighting and nighttime flaring on the environment would not be significant.

4.13.5.8 Socioeconomics

The cumulative impact area for socioeconomics included San Patricio and Nueces Counties. The construction period for the Project would likely be concurrent with those of several of the major La Quinta Channel projects and the non-jurisdictional electrical power line extensions and waterline. Combined, the projects identified would generate several thousand temporary construction jobs and many permanent jobs associated with various operational duties. Many of the workers would likely reside locally and would not require temporary housing. However, if temporary housing would be required for multiple projects occurring concurrently, Corpus Christi offers a relatively large number of temporary housing facilities such as hotels, campgrounds, and RV parks.

Positive benefits of the new jobs and workers in the area would include lowering local unemployment rates, increasing revenue for local business owners, and generating new tax revenue to the Corpus Christi area. No identified minority or low-income populations would be disproportionately impacted by the projects (see section 4.9.9); therefore, the Project would not contribute to cumulative impacts on these populations.

A cumulative impact on land transportation would be dependent on the construction schedules and amount of overlap between the construction phases for all of the identified projects in the geographic region. Construction of the non-jurisdictional electric power lines and substations and the non-jurisdictional waterline would contribute to cumulative impacts on traffic along portions of US 361 and in the vicinity of the Terminal site, primarily at the beginning and end of each construction shift. Although we recognize concurrent construction of the proposed Project and other projects in the vicinity of the Terminal site would result in increased workers in the area, periods of increased traffic, and impacts on public services, we are not recommending additional mitigation at this time. Therefore, we have determined that with the implementation of Cheniere’s mitigation measures, the impacts of the Project when added with other projects’ impacts would not result in significant cumulative impacts.

Currently, the Port accommodates more than 6,000 vessels and 80 million tons of cargo annually. The amount of vessel traffic in the Nueces Bay area would not significantly increase as a result of construction and operation of the Cheniere Terminal and other identified projects. However, it is not anticipated that the Corpus Christi and La Quinta Ship Channels Port would be adversely impacted, as the Port has been maintained in such a way as to handle significant increases in docking a maneuvering capacity.

4.13.5.9 Cultural Resources

Because no historic properties have been identified to date that would be adversely effected by Cheniere's proposal, that project would not be adding incrementally to cumulative regional impacts on cultural resources which are listed or eligible for listing on the NRHP. Any other projects with a federal nexus would have to adhere to section 106 of the NHPA, and follow the regulatory requirements of 36 CFR 800. Under those regulations, the lead federal agency, in consultation with the SHPO, would have to identify historic properties in the APE, assess potential project effects, and resolve adverse effects through an agreement document that outlines a treatment plan. The NHPA and its implementing regulations ensure that projects that require a federal permit, license, or approval would not have significant cumulative impacts on historic properties.

4.13.5.10 Air Quality and Noise

The cumulative impact area for air quality during construction of the Project is the area adjacent to and near the boundary of the Terminal site and along the Pipeline. The cumulative impact area for air quality during operation of the project was established based on the Project's PSD Area of Impact, as described in section 4.11.1

Construction of the Project and many of the past, present, or future projects listed in table 4.13-1 (see appendix D) would involve the use of construction equipment that generates air pollution, including fugitive dust. Operation of construction equipment would be primarily restricted to daylight hours and would be minimized through typical controls and practices, some of which are required under TCEQ rules. The emissions from construction activities for the Project and other projects in the region would result in short-term emissions that would be localized to each project area; therefore, construction emissions are not expected to have a significant cumulative impact on regional air quality.

Operation of the Project, including LNG carriers and associated support vessels in the vicinity of the Terminal, would contribute cumulatively to air pollutant levels in combination with some of the other projects identified as part of the cumulative impacts analysis. As discussed in section 4.11.1.4, detailed air quality impact analyses were conducted by Cheniere to quantitatively evaluate the combined impacts from operation of the Project and other emission sources in the region, including pollutant background concentrations. Those combined impacts were compared against the NAAQS, which are designed to be protective of human health and the environment. The results of the NAAQS analyses demonstrated that there would be no significant impact on regional air quality from operation of the Project.

Newly proposed (future) projects in the area (e.g., Voestalpine DRI Plant) would contribute cumulatively to air quality 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 federal and state permits and approvals. Thus, the Project is not anticipated to contribute to the cumulative impact on regional air quality as a result of operation.

Noise levels typically attenuate quickly as the distance from the noise source increases. Therefore, the cumulative impact area considered for noise is within about 1.5 miles of the Terminal, 1 mile of the pipeline route, and a 1-mile radius of the Sinton and Taft Compressor Stations. The only projects in the cumulative impact area that may be constructed at the same time as the Terminal are the OxyChem NGL Fractionation Facility and Ethylene Plant, and Voestalpine DRI Plant. Noise produced during the construction of these identified projects could create some short-term impacts on nearby residences and could have short-term impacts on some aquatic species. However, Noise impacts during construction of these projects would be localized and would attenuate as the distance from the noise source increases. The nearest NSAs in the vicinity of the Terminal site are over one mile away. Therefore, cumulative noise impacts associated with construction would be unlikely to be noticeable, unless one or more of the projects were constructed concurrently at the same location.

Operation of the identified projects with land-based facilities would also generate noise. For the Project, the FERC would require that noise generated during operation would not exceed the 55 decibel limit established by the EPA for protection of public health and welfare. The combined operation of the identified projects, should they all be authorized, could result in the raising of the average ambient noise level at the nearest NSAs but not by a significant measure. Cumulative operational noise would be audible at the Terminal, but should not be significantly greater than current measured ambient noise due to noise attenuation.

4.13.5.11 Climate Change

Climate change is the change in climate over an extended period of 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 an indication of climate change, while a series of severe droughts or hot summers that statistically alter the trend in average precipitation or temperature over decades may indicate climate change.

The IPCC is the leading international, multi-governmental scientific body for the assessment of climate change. The U.S. is a member of the IPCC and participates in the IPCC working groups studying various aspects of climate change. The leading U.S. scientific body on climate change is the U.S. Global Change Research Program (USGCRP). Thirteen federal departments and agencies[49] participate in the USGCRP, which began as a presidential initiative in 1989 and was mandated by Congress in the Global Change Research Act of 1990 (GCRA). The USGCRP coordinates and supports U.S. participation in the IPCC assessments.

The IPCC and USGCRP have recognized that:

- globally, GHGs have been accumulating in the atmosphere since the beginning of the industrial era (circa 1750);

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[49] 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.

- combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture and clearing of forests, is primarily responsible for the accumulation of GHG;
- anthropogenic GHG emissions are the primary contributing factor to climate change; and
- impacts extend beyond atmospheric climate change alone, and include changes to water resources, transportation, agriculture, ecosystems, and human health.

The USGCRP issued the report, *Global Climate Change Impacts in the United States*, in June 2009 summarizing the impacts climate change has already had on the U.S. and the projected future impacts due to continued climate change (USGCRP, 2009). The report describes the effects of global change on different regions of the U.S. (e.g., Southeast) and on various societal and environmental sectors, such as water resources, agriculture, energy use, and human health. Building on the findings presented in this report as well as other recent research, the USGCRP issued the report, *The National Global Change Research Plan 2012-2021: A Strategic Plan for the U.S. Global Change Research Program*, which outlines specific goals and objectives for the Program to generate and disseminate scientific knowledge that is readily available and directly useful to decision-makers and the general public (USGCRP, 2012). These efforts are intended to fulfill the Congressional mandate of the GCRA. Although climate change is a global concern, for this analysis, the focus is on the cumulative impacts of climate change in the Project area.

The USGCRP's report notes the following observations of environmental impacts that may be attributed to climate change in the Southeast region:

- average temperatures have risen about 2°F since 1970 and are projected to increase another 4.5 to 9°F during this century;
- increases in illness and death due to greater summer heat stress;
- the destructive potential of Atlantic hurricanes increased since 1970 and the intensity (with higher peak wind speeds, rainfall intensity, and storm surge height and strength) is likely to increase during this century;
- within the past century in the U.S., relative sea level changes ranged from falling several inches to rising about 2 feet and are projected to increase another 3 to 4 feet this century;
- sea level rise and human alterations have caused coastal wetland loss during the past century, reducing the capacity of those wetlands to protect against storm surge, and projected sea level rise is anticipated to result in the loss of a large portion of the nation's remaining coastal wetlands;
- declines in dissolved oxygen in streams and lakes have caused fish kills and loss of aquatic species diversity;
- moderate to severe spring and summer drought areas have increased 12 to 14 percent (with frequency, duration and intensity also increasing and projected to increase);
- longer periods of time between rainfall events may lead to declines in recharge of groundwater and decreased water availability;
- responses to decreased water availability, such as increased groundwater pumping, may lead to stress or depletion of aquifers and a strain on surface water sources;

- increases in evaporation and plant water loss rates may alter the balance of runoff and groundwater recharge, which would likely to lead to saltwater intrusion into shallow aquifers;
- coastal waters temperature rose about 2°F in several regions and are likely to continue to warm as much as 4 to 8°F this century; and
- coastal water warming may lead to the transport of invasive species through ballast water exchange during ship transit.

Climate Change in the Project region would have two effects which may cause increased storm surges; increase temperatures of Gulf Waters which would increase storm intensity, and a rising sea level. Even with the increased sea levels due to climate change, and increased storm surge, the critical structure elevations of 25-feet above mean sea level at the Liquefaction Plant would provide a significant barrier to a 100-year climate change-enhanced storm surge.

The GHG emissions associated with construction and operation of the Project were identified and quantified in section 4.11.1.4. Based on the total annual potential emissions for the constructed Terminal and Sinton and Taft Compressor Stations, Project operations would increase CO_2 emissions in Texas by approximately 0.5 percent (based on 2010 emissions for the State [DOE, 2013]).

GHG emissions from sources located at Project facilities (Terminal and Sinton Compressor Stations) would be minimized by application of EPA-approved BACT under the PSD permitting program. Cheniere prepared a BACT analysis for the proposed refrigeration compressor turbines, standby generators, flares, thermal oxidizers, and fugitive emissions at the Terminal which was submitted to EPA for review. CO_2 emissions from the turbines would be minimized through use of natural gas as fuel, design energy efficiency, and operational energy efficiency (i.e., good combustion practices) as BACT. The aeroderivative-class GE LM2500+G4 SAC model turbines selected by Cheniere have a higher thermal efficiency than the heavy-duty frame-class turbines. Also, natural gas for fuel yields the lowest CO_2 emissions, on a lb/MWh basis, of any fuel available for the turbines. Cheniere's design also includes a waste heat recovery system on the exhaust of two ethylene turbines for each liquefaction train to provide the required heat for gas treatment, thus avoiding the need for new CO_2-emitting gas-fired heaters. After evaluation of Cheniere's analysis, EPA stipulated a BACT emission limit for the turbines of 8,041 lb CO_2e MMscf of LNG, 12-month rolling average (U.S. EPA, 2014a). BACT for the thermal oxidizers is the implementation of design measures and good combustion and maintenance practices, along with a BACT emission limit of 57.8 ton CO_2 per MMscf of gas burned. BACT for the flares is use of clean fuel for pilots and good flare design, along with mass emission limits. BACT for the standby generators and fire water pump engines is the selection of a fuel efficient engine and good combustion, operating, and maintenance practices, along with limited annual operating hours and mass emission limits. BACT for fugitive emissions from natural gas components is a gas leak detection and repair (LDAR) program compliant with TCEQ 28LAER and 28M LDAR programs, supplemented with an audio/visual/olfactory program.

Cheniere also prepared a BACT analysis for the proposed compressor turbines, standby generator, and gas blowdowns at the Sinton Compressor Station, which was reviewed by EPA. After evaluation of Cheniere's analysis, EPA stipulated a BACT emission limit for each turbine of 1.18 lb CO_2 per hp hour, 12-month rolling average (EPA 2014b). BACT for the standby generator is the use of good combustion, operating, and maintenance practices, along with limited annual operating hours and mass emission limits. BACT for the gas blowdowns is the use of an additional seal gas booster system for the gas compressors and the capability to burn potential blowdown gases as fuel, as well as mass emission limits.

Cheniere provided an assessment of the feasibility of a carbon capture and storage (CCS) system to TCEQ as part of the GHG permit application BACT analysis. Cheniere provided information on the technical and economic feasibility of developing and using CCS for the Terminal and Sinton Compressor Stations. This technology involves deploying a method to capture carbon from the exhaust stream of the combustion units and then finding a method for permanent storage (injecting the recovered CO_2 underground through various means, including enhanced oil recovery, saline aquifers, and un-mineable coal seams). EPA evaluated the information provided by Cheniere and deemed CCS to be technically infeasible for the Project, on the following basis (EPA, 2014). Under the current design of the Terminal, Cheniere would not be creating any excess heat or excess steam to produce or export electricity. The Terminal design relies on simple-cycle combustion turbines that can be powered up quickly to provide process heat on a consistently reliable basis. Six of the 18 combustion turbines would be equipped with a Waste Heat Recovery Unit, but would still be operated as simple cycle combustion turbines. The potential transient loading of combined-cycle combustion turbines together with the considerable capital costs involved with this combustion turbine configuration make the combined cycle option a non-viable design alternative. Because combined-cycle combustion turbines are not technically feasible for the Project, CCS is also technically infeasible for the Project. EPA has noted that there have been no CCS demonstrations on simple-cycle combustion turbines. In the GHG BACT analysis, Cheniere stated that there is no commercially available carbon capture system of the scale that would be required to control the CO_2 emissions from compressor turbines, thermal oxidizers, and flares, such as those typically located at an LNG terminal or compressor station. The Sierra Club commented that the technology does exist for affordable capture of carbon from the pretreatment systems. However, Cheniere has also stated that no long-term CO_2 storage facilities are located near the Project, as the region does not have geological formations that support sequestration. Therefore, even if Sierra Club is correct in the ability to capture the carbon, the costs and environmental impacts associated with additional infrastructure to send the carbon to a region where it could be properly stored or used for enhanced oil recovery are not a feasible or preferable alternative. Based on the magnitude of the estimated capital and annualized costs, Cheniere demonstrated that CCS is not economically feasible. Even if feasibility could be demonstrated, Cheniere noted that any CCS system would cause significant adverse energy and environmental impacts due to the additional water and energy needs for system operation, with the associated generation of additional GHGs and other criteria pollutants from natural gas firing in combustion units. EPA and TCEQ are still evaluating the GHG permit applications for the Terminal and Sinton Compressor Station.

Climate Change in the region would have two effects which may cause increased storm surges; increase temperatures of Gulf Waters which would increase storm intensity, and a rising sea level. Even with the increased sea levels due to climate change, and increased storm surge, the critical structure elevations of 25-feet above mean sea level at the Liquefaction Plant would provide a significant barrier to even a 100-year climate change-enhanced storm surge.

Currently, there is no standard methodology to determine how the Project's incremental contribution to GHGs would result in physical effects on the environment, either locally or globally. However, estimated emissions associated with the Project would incrementally increase the atmospheric concentrations of GHGs, in combination with GHG emissions from other sources identified in the cumulative impacts analysis. Because we cannot determine the Project's incremental physical impacts due to climate change on the environment, we cannot determine whether or not the Project's contribution to cumulative impacts on climate change would be significant.

4.13.5.12 Safety

For the proposed Terminal, we considered the cumulative impact area for marine vessel traffic to include the water route from the Aransas Pass Sea Buoy, through the entrance of the Jetty Channel, Corpus Christi Channel, and the La Quinta Channel, terminating at the Terminal marine berths. The cumulative impact area for the Terminal is the area adjacent to and in the vicinity of the Terminal site, and the cumulative impact area for the Pipeline was considered to be within about 660 yards of the pipeline centerline. The cumulative impact area for emergency services includes the area in the general vicinity of the Terminal and the Pipeline.

Cheniere would mitigate impacts on public safety through the implementation of applicable federal, state, and local rules and regulations for the proposed Project as described in section 4.12. Those rules and regulations would ensure that the applicable design and engineering standards are implemented to protect the public and avoid or minimize the potential for accidents and failures.

As noted in section 4.12, the risk associated with the Pipeline would be small. In addition, the proposed Pipeline is adjacent to several pipelines and crosses several other pipelines. Although operation of the proposed Pipeline would increase the risk of a pipeline accident, the increase in risk would be small. As a result, cumulative impact on risk for the Pipeline would not be significant.

Emergency response time is a key aspect of public health and safety. Key emergency services would be provided by the existing services in San Patricio and Nueces Counties. In accordance with our regulations, Cheniere would prepare a comprehensive plan that identifies the cost sharing mechanisms for funding these emergency response costs. Therefore, the cumulative impact of each project's comprehensive plans would not result in a significant impact on public safety.

4.13.6 Conclusions for Overall Cumulative Impacts

A thorough determination regarding the significance of cumulative impacts for specific environmental resources is difficult due to a lack of access to the details of activities for many identified projects. Additionally, distinct threshold values for most environmental resources are typically undetermined. The most significant cumulative impacts would occur should all identified projects in the area be constructed concurrently with the Project; however, this is not anticipated. However, construction of the Terminal, in addition several of the identified projects, would result in the permanent loss of various wildlife habitats and natural land use types. As a result, construction of the Project would cumulatively contribute to the increasing industrialization of agricultural and/or open lands in the area.

Most of the cumulative environmental impacts identified would be short-term and minor, such as impacts on geology, soils, water, threatened and endangered species, and terrestrial vegetation. The Project and several of the identified projects would increase vessel traffic within the Port; however, the large port would more than likely be capable to adequately accommodate such an increase and thus, would not contribute significantly to cumulative impacts on marine traffic.

Wetlands and SAV within the region would sustain the most significant impacts, as dredging and other activities associated with the Project and others would result in the degradation and permanent loss of these resources. Compensatory and voluntary mitigation plans and procedures for many of the projects would offset the severity of cumulative permanent impacts on wetlands and SAV. Cheniere would comply with the terms and conditions of the Section 404 permit by creating new wetland habitat and protect existing habitat, and would not significantly contribute to the loss of wetlands.

Cumulative benefits would be realized from the creation of new wetlands, seagrass, and marsh habitats through compensatory and voluntary mitigation programs. Additionally, the Project and identified projects would enhance the local economy through jobs and wages, purchases of goods and materials, and tax revenues.

CONCLUSIONS AND RECOMMENDATIONS

SECTION 5

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 SUMMARY OF THE ENVIRONMENTAL ANALYSIS

The conclusions and recommendations presented in this section are those of the FERC environmental staff. Our conclusions and recommendations are based on input from the COE, Coast Guard, DOE, DOT, and EPA as cooperating agencies in the preparation of this EIS. However, the cooperating agencies will present their own conclusions and recommendations in their respective Records of Decision and determinations, and can adopt this EIS consistent with 40 CFR 1501.3 if, after an independent review of the document, they conclude that their requirements have been satisfied. Otherwise, they may elect to conduct their own supplemental environmental analysis.

We conclude that construction and operation of the Corpus Christi LNG Project would result in temporary and short-term impacts on numerous resources. However, the Project would result in permanent impacts on wetlands, EFH, agricultural lands, and visual resources; and long-term impacts on air quality. As part of our analysis, we developed specific mitigation measures that are practical, appropriate, and reasonable for construction and operation of the Project. We are, therefore, recommending that these mitigation measures be attached as conditions to any authorization issued by the Commission. Implementation of the mitigation proposed by Cheniere and our recommended mitigation would ensure that impacts in the Project area would be avoided or minimized and would not be significant. A summary of the Project impacts and our conclusions are presented below by resource.

5.1.1 Geologic Resources

Construction and operation of the Project would not significantly alter the geologic conditions of the Project area or affect mining of resources. Additional information is required on the geology and seismology of the Terminal site to adequately design the facilities to prevent any safety risks. Therefore, we are recommending that Cheniere file design calculations and drawings stamped and sealed by the professional engineer-of-record for the LNG facility structures and foundations, including the LNG tanks. The Pipeline would not cross any significant geologic hazards, including areas of seismic activity or subsidence. Cheniere has committed to conducting geotechnical investigations for the HDDs to determine general subsurface conditions prior to constructing the Pipeline. Blasting is not anticipated during construction of either the Terminal or the Pipeline. Based on Cheniere’s proposal, including implementation of our Plan and Procedures and our recommended mitigation measures, impacts on geological resources would be adequately minimized and would not be significant. The potential for impacts on the Project from geologic hazards would also be minimal.

5.1.2 Soils

Construction of the Project facilities would disturb soils, resulting in increased potential for erosion, compaction, and mixing of topsoil. Soils within the Terminal site have high erosion potential. Additional areas susceptible to erosion within the Project area include stream banks and the banks of drainage ditches crossed by the Pipeline. Cheniere would implement the erosion and sediment control measures outlined in our Plan and Procedures. Cheniere would further minimize potential for shoreline erosion at the Terminal by installing articulated block mats or rock breakwaters to protect the shoreline within the marine vessel maneuvering area from erosion.

Construction of the Terminal would not significantly impact prime farmlands, as the area was previously disturbed. However, construction of the Pipeline would result in the loss of 21.5 acres of prime farmland due to the installation of permanent aboveground facilities. Most impacts during pipeline construction would be short-term and would not impact future use of prime farmland for agricultural purposes. Implementation of measures outlined in our Plan would adequately minimize the impacts from the Project on prime farmland.

Due to the historic industrial use of the Terminal site and surrounding areas, there would be potential for contaminated soils to be discovered during construction. However, no areas of contamination have been identified at the Terminal site. In order to ensure that no contaminated soils are imported to the site for use as structural fill, removed from the site, or discovered during construction, Cheniere would follow guidelines outlined in its *Specification for Site Preparation and Earthwork* to fulfill the requirements for soils imported to the site.

5.1.3 Water Resources

Due to the non-potable saline groundwater conditions that naturally occur at the Terminal, lack of water supply wells in the area, depth of groundwater below land surface in relation to anticipated excavation depths, construction of the proposed pilings within the permeable zone of the Chicot aquifer rather than crossing the aquifer confining layers, and surficial mitigation measures that would be implemented by Cheniere including those described in its SPCC Plan and our Procedures, no significant impact on the groundwater resources underlying the Terminal facilities is anticipated.

Impacts on groundwater as a result of the Pipeline would be similar to that discussed for the Terminal. The greatest potential for impacts on groundwater would be an accidental release of a hazardous substance, such as fuels, lubricants, and coolants while constructing and operating the Pipeline. We have determined that the implementation of measures outlined in Cheniere’s SPCC Plan and our Procedures would adequately minimize potential impacts on groundwater resources resulting from construction and operation of the Pipeline.

Construction and operation of the Terminal would result in decreased water quality of Corpus Christi Bay within the vicinity of the site as a result of initial dredging and maintenance dredging, as well as stormwater runoff and dewatering. Impacts on water quality from dredging activities would be short-term and localized to within a few hundred feet of the activity. Impacts on water quality from dredging would be minimized by the use of a hydraulic cutterhead dredge which effectively captures most sediment disturbed during dredging. Through implementation of NPDES regulations, our Procedures, and Cheniere’s SPCC Plan, potential impacts resulting from stormwater runoff or the discharge of hydrostatic test water would be adequately minimized or avoided. We have determined that with implementation of the measures outlined above, impacts on surface water resources as a result of the construction and operation of the Terminal would not be significant.

Waterbodies crossed by the Pipeline via the open cut method would experience short-term impacts on water quality including increased turbidity, sedimentation, and overall stream bed and bank disturbance. Cheniere would avoid significantly impacting water quality in three of the ten waterbodies crossed by the Pipeline, Chiltipin and Oliver Creeks and an unnamed tributary to Chiltipin Creek, by utilizing HDD crossing methods. We have determined that implementation of Cheniere's SPCC Plan, the HDD crossing method, and the measures outlined in our Procedures would adequately minimize impacts on surface water resources associated with the construction and operation of the Pipeline.

5.1.4 Wetlands

Construction and operation of the Terminal would result in the disturbance of 27.45 acres of wetlands, including 25.67 of permanent wetland loss. Wetlands within the Terminal consist of cordgrass salt marsh, black mangrove, unvegetated sand flat, vegetated flats/high marsh, and seagrass. To mitigate unavoidable impacts on wetlands at the Terminal, Cheniere submitted to the COE an ARMP for the Project. As part of the Section 404 permit process, the COE required that Cheniere conduct a functional assessment to more adequately evaluate wetland impacts and mitigation associated with the Project. Since issuance of the draft EIS, the COE approved Cheniere's revised ARMP addressing its comments and issued Cheniere's Section 404/10 Permit on July 23, 2014. Compensatory mitigation for the loss of 25.67 acres of wetlands are addressed in Cheniere's ARMP (appendix C) and include the installation of 16 breakwaters at Shamrock Island, as well as installation of 3,500 feet of segmented rock breakwaters at Ransom Point. The installation of the breakwaters would protect and enhance sensitive wetland resources from significant erosion forces currently degrading and depleting the area. Additionally, Cheniere would monitor all temporarily impacted wetlands in accordance with the FERC's Procedures until restoration is complete.

The Pipeline would cross three PEM wetlands, two of which would be crossed by HDD and would not result in any impacts. One remaining wetland (less than 0.01 acre) is located within the proposed permanent pipeline easement and would be restored to preconstruction conditions in accordance with our Procedures following the completion of construction activities.

Based on Cheniere's proposed impact mitigation measures as well as preparation of the functional assessment and ARMP approved by the COE, we have determined that constructing and operating the Terminal and Pipeline would not have a significant impact on wetlands.

5.1.5 Vegetation

Land-based facilities at the Terminal would not significantly impact vegetation, as the site is highly disturbed and sparsely vegetated. Construction and operation of the marine berths would permanently impact approximately 9.17 acres of SAV (seagrass beds). Mitigation for the permanent conversion of SAV to deep water habitat would be mitigated by Cheniere through implementation of its ARMP as discussed in section 4.4.1. Approximately 0.12 acre of SAV would be temporarily impacted. Cheniere would adhere to our Procedures, including post-construction monitoring, to ensure restoration of these areas following construction.

Based on the disturbed nature of the Terminal site, the amounts and types of vegetation impacted, and Cheniere's proposed impact minimization and mitigation measures, we have determined that constructing and operating the Terminal facilities would not significantly impact vegetation.

No sensitive vegetation would be impacted by the Pipeline. Vegetation impacted by the Pipeline would be predominantly agricultural crops with some herbaceous and scrub-shrub vegetation in open land. All areas impacted by installation of the Pipeline, with the exception of the MLVs and two compressor stations, would be restored to preconstruction conditions. Due to the abundance of similar vegetation in the area, permanent impacts on vegetation from the aboveground facilities would not be significant.

5.1.6 Wildlife and Aquatic Resources

Construction and operation of the Terminal would result in the removal and/or conversion of wildlife habitats at the site. Land-based facilities would result in the permanent conversion of open land to industrial land. However, due to the previous industrial use of the site and its proximity to other industrial areas, we conclude that this would not constitute a significant impact on terrestrial wildlife habitat. To minimize impacts on wildlife, Cheniere would restrict the size of construction areas to the maximum extent practicable and implement measures described in our Plan and Procedures to avoid or minimize off-site impacts.

Construction and operation of the marine berths could impact aquatic reptiles and mammals, as well as fisheries resources, as a result of dredging and pile driving during construction and from LNG carrier traffic during operation. Impacts from pile driving and other construction activities would be temporary. Operation impacts would be permanent; however, because such activities are already common in the vicinity of the Terminal, and Cheniere would inform LNG carriers about vessel strike avoidance measures, we have determined that impacts on marine mammals and reptiles would not be significant.

Impacts on fisheries and other aquatic resources, including EFH would primarily result from dredging, dredge disposal, and pile driving activities. These activities would also similarly impact recreational and commercial fisheries. Additionally, LNG carriers calling on the Terminal and other ship-related marine traffic and operations could also impact fisheries resources. Impacts on EFH are further discussed in the EFH Assessment in appendix B.

Cheniere would adhere to measures outlined in our Plan and Procedures as well as its ARMP to minimize and mitigate for impacts on fish and other aquatic resources. Potential impacts associated with stormwater runoff would be minimized or avoided through implementation of Cheniere's SPCC Plan, construction of drainage ditches at the Terminal, and adherence to NPDES regulations. The COE issued the Section 404/10 Individual Permit on July 23, 2014 and the RRC issued the 401 Water Quality Certification as well as the Coastal Zone Consistency determination on November 14, 2013.We have determined that construction and operation of the Terminal would impact fisheries and other aquatic resources; however, based on Cheniere's implementation of the measures outlined above and in its ARMP, these impacts have been sufficiently minimized.

No sensitive wildlife habitats would be impacted by construction or operation of the Pipeline. The majority of the area disturbed during construction would be agricultural land and open land that would revert back to preconstruction condition and use following the completion of construction activities. Areas adjacent to the Pipeline area provide similar and ample habitats for wildlife displaced temporarily during construction of the Pipeline. Wildlife would return to the majority of the Pipeline area following construction and restoration. Impacts on wildlife during construction and operation of the Pipeline would be minimized by the implementation of our Plan and Procedures as well as restriction of vegetation clearing between March 1 and August 31 to avoid impacts on migratory birds. If vegetation clearing must be conducted during this time, Cheniere would survey for migratory bird nests no more than three weeks prior to commencing work. If an active migratory bird nest is found, Cheniere would consult with the FWS to identify the most appropriate measure to be taken to avoid or minimize impacts.

Impacts on aquatic resources associated with construction and operation of the Pipeline would consist of loss of aquatic habitat, disturbance of the stream bed, and increased turbidity and sedimentation. Two of the ten waterbodies crossed by the Pipeline support sustainable fisheries (Oliver and Chiltipin Creeks); however, Cheniere would cross both of these waterbodies via HDD, avoiding direct impacts to fisheries and other aquatic resources. Additionally, Cheniere would complete all remaining waterbody crossings in accordance with the construction and mitigation measures described in our Procedures.

Based on the characteristics of the fisheries contained within the ten waterbodies that would be crossed and Cheniere's use of HDDs 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 aquatic resources.

5.1.7 Threatened, Endangered, and Other Sensitive Species

Based on consultations with the FWS and NMFS, as well as Cheniere's habitat surveys, 13 federally listed species potentially occur in the general Project area. We have determined that construction and operation of the Project is not likely to adversely affect the blue whale, fin whale, humpback whale, sei whale, sperm whale, West Indian manatee, whooping crane, piping plover, loggerhead sea turtle, green sea turtle, leatherback sea turtle, Atlantic hawksbill sea turtle, and Kemp's ridley sea turtle at the Terminal, and that the Pipeline would have no effect on federally listed species. Regarding federally listed threatened and endangered species, NMFS notified Cheniere on October 29, 2012 that initiation of Section 7 consultation would not be required; and in letters dated August 8, 2013 and November 5, 2013, the FWS concurred with determinations that the Project is not likely to adversely affect species under its jurisdiction.

Ten state listed species were identified as potentially occurring within the Project area. Based on the presence of potential habitat, we conclude that Cheniere's collocation with existing utility corridors and constructing primarily within previously disturbed areas would avoid or minimize potential impacts on state listed species by reducing the overall extent of new land disturbance.

In summary, implementation of Cheniere's mitigation measures and use of our Plan and Procedures during construction and operation of the Project would adequately minimize impacts on federally and state listed species.

5.1.8 Land Use, Recreation, and Visual Resources

Construction of the Terminal would occur within a previous industrial site that has since been reclaimed and would result in permanent impacts on 321 acres of open land and 148 acres of open water. The majority of the open land area used for operation would be permanently converted to industrial land (approximately 5 acres would be converted to open water). Open water areas impacted by operation would remain open water, but would be dredged to a greater depth.

Construction and operation of the Pipeline, including permanent access roads, would result in approximately 133.3 acres of permanent operation impacts on agricultural land (including areas impacted by the permanent pipeline easement that would return to agricultural use), 38.4 acres of permanent operation impacts on open land (including areas impacted by the permanent pipeline easement that would return to open land), and 6.6 acres of industrial land for operation.

Impacts on visual resources near the Terminal resulting from the storage tanks and elevated flare stack would be permanent. However, due to the proximity of the Terminal to other industrial structures, the storage tanks and elevated flare stack would be consistent with the surrounding viewshed. Visual impacts from facility lighting at the Terminal would be permanent, but would be the minimum amount necessary to allow personnel to safely work and inspect the equipment at the Terminal.

The construction of the Pipeline would temporarily impact visual resources along the route due to the presence of construction personnel and equipment. Operation of the Taft and Sinton Compressor Stations would permanently impact the viewshed in the area. However, the Taft Compressor Station would be located in a rural area near a wind farm and the Sinton Compressor Station would not be visible from the nearest public area minimizing and avoiding impacts on the surrounding viewshed.

5.1.9 Socioeconomics

Construction of the Project would require a workforce of 2,100 workers, peaking at approximately 3,300 workers. Cheniere would utilize predominantly local workers during construction and employ a relatively small full-time operations staff at the Terminal. Project-related construction impacts on the regional population would result in a short-term, moderate increase to the local population, and Project operation would result in a negligible, long-term increase.

Construction and operation of the Project would increase local and state tax revenues from sales taxes, payroll taxes, and would likely increase local employment. Additionally, the Project would not impact any urban or residential areas, and no disproportionately high and adverse human health or environmental effects on minority, low-income communities, or Indian tribes have been identified.

Impacts on traffic in the Project area would primarily occur during construction of the Terminal. During construction, Cheniere would minimize impacts on traffic via the use of busses to transport workers to the site. Additionally, traffic during construction would only slightly increase overall traffic in the area. During operation, the increase in traffic would be negligible and would not result in a perceptible increase in area traffic.

Construction and operation of the Terminal would result in an increase in marine traffic in the area. During operation, Cheniere anticipates receiving approximately 300 LNG carriers annually. Although LNG carriers would require a moving safety and security zone that would limit deep draft traffic while LNG carriers are in the channel, the LNG carriers would only be in the channel for about 1.25 hours and are not anticipated to adversely impact overall vessel traffic patterns.

5.1.10 Cultural Resources

Cultural resource evaluations were conducted for the entire Project area. No traditional cultural resources, burials, or sites of religious significance to Indian tribes were identified in the APE by the National Park Service, BIA, SHPO, Cheniere, or the Indian tribes contacted by the

FERC. We agree with the SHPO's determination in letters dated May 25, July 3, and August 15, 2012, and April 22, 2013, that no historic properties would be affected in areas that have been inventoried.

5.1.11 Air Quality and Noise

Air quality impacts associated with construction of the Project would include emissions from fossil-fueled construction equipment and fugitive dust. Construction emissions associated with the Pipeline and compressor stations would be temporary and localized; however, compressor station emissions would transition to operational-phase emissions. The 6-year construction period at the Terminal would result in short-term air quality impacts which would transition to permanent operational-phase emissions after commissioning and initial start-up. Cheniere would incorporate fugitive dust control measures during construction to minimize emissions. However, we and the EPA find that Cheniere has not adequately addressed track-out onto paved roads as part of its fugitive dust controls. Therefore, we are recommending that Cheniere file a revised FDCP that incorporates additional mitigation measures to address track-out, prior to the start of construction.

Operation of the Terminal and the Sinton and Taft Compressor Stations would result in permanent air quality impacts. Cheniere would minimize operation emissions through implementation of Best Available Control Technology, as required by Cheniere's operating air permits. Cheniere has applied for all applicable air permits and would comply with all air permit requirements for those facilities. However, because some permitting requirements and applicable permitting authorities regarding the Terminal and Sinton Compressor Station are still being determined, we are recommending that Cheniere file additional status information related to its potential GHG PSD permits for these facilities. The Taft Compressor Station would be below PSD and Title V permit thresholds and would be classified as a minor source. In addition, air dispersion modeling, which included LNG carriers and other nearby emission sources, demonstrated that operation of the Terminal would not result in an exceedance of the NAAQS at any location, with the exception of NO_2. An expanded analysis determined that operation of the Terminal would not contribute significantly to exceedances of the 1-hour NO_2 NAAQS. Air dispersion modeling also demonstrated that the Sinton Compressor Station would not result in any exceedances of the NAAQS at any location.

Impacts on noise levels associated with construction of the Project would generally be temporary, minor, and limited to daylight hours. The highest noise levels would be generated during the four to six months of pile driving activities, which are estimated to be well below significant at all NSAs. Based on the detailed noise assessments for each of the proposed HDD locations, noise levels from the Chiltipin Creek and US 181/SH 35 HDDs would be below the existing noise levels at the nearest NSAs. Noise levels may be perceived as twice as loud as the existing noise levels at one residence located near the Oliver Creek HDD. Cheniere has committed to performing all HDD activities, except potentially the pipe pullback, during daylight hours to mitigate significant noise impacts at NSAs.

The Terminal and Sinton and Taft Compressor Stations would generate noise on a continuous basis during operation. However, the predicted noise levels attributable to operation of these facilities should not result in significant impacts on the NSAs nearest to those facilities. To ensure that actual noise levels resulting from Project operation would not exceed significant levels, we are recommending that Cheniere file post-construction noise survey reports for each facility.

5.1.12 Safety

We evaluated the safety of the proposed Terminal facility, the related LNG carrier transit, and the bi-directional Pipeline. As part of our evaluation of the Terminal, we performed a technical review of the preliminary engineering design to ensure sufficient layers of protection would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the public. The DOT reviewed the initial data and methodology Cheniere used to determine the design spills from various leakage sources, including piping, containers, and equipment containing hazardous liquids, and stated it had no objection to Cheniere's methodology for determining the candidate design spills used to establish the required siting for its proposed Terminal. The Coast Guard reviewed the suitability of the Corpus Christi Ship Channel from the entrance approach at Port Aransas to the La Quinta Junction and the entire length of La Quinta Channel, and issued a LOR indicating the waterway would be suitable for the type and frequency of the marine traffic associated with the proposed Project. In addition, Cheniere would be required to comply with all regulations in 49 CFR 192 for its Pipeline and 33 CFR 105, 33 CFR 127, and 49 CFR 193 for its Terminal facilities. Based on our engineering design analysis and recommendations presented in section 4.12 for the Terminal, the design spill methodology reviewed by DOT for the Terminal, the LOR issued by the Coast Guard for the LNG carrier transit, and the regulatory requirements for the Pipeline and Terminal, we conclude that the Project would not result in significant increased public safety risks.

5.1.13 Cumulative Impacts

We considered the contributions of the proposed Project in conjunction with other projects in the Project area to determine the potential for cumulative impact on the resources affected by the Project. As a part of that assessment, we identified existing projects, projects under construction, projects that are proposed or planned, and reasonably foreseeable projects including existing and proposed LNG import and export terminals, other development projects, and non-jurisdictional facilities associated with the Project. Our assessment considered the impacts of the proposed Project combined with the impacts of the other projects on resources within all or part of the same area and time. We conclude that although cumulative impacts on some resources would occur, those impacts would not be significant.

Most of the identified cumulative impacts would be temporary and minor. However, construction of the Terminal, in addition to several of the identified projects, would result in the permanent loss of various wildlife habitats and natural land use types. As a result, construction of the Project would contribute to the increasing industrialization of agricultural and/or open lands in the area. Additionally, several of the identified projects, as well as the proposed Project would contribute to an increase in vessel traffic in the Port. This would be a long-term impact; however, due to the size of the Port, this would not contribute significantly to cumulative impacts on marine traffic.

Other temporary and minor cumulative environmental impacts identified include impacts on water and air quality, threatened and endangered species, and terrestrial vegetation. Additionally, several of the identified projects, as well as the proposed Project would contribute to an increase in vessel traffic in the Port; however, due to the size of the Port, this would not contribute significantly to cumulative impacts on marine traffic.

Additionally the Project would result in cumulative impacts on wetlands and SAV within the region when combined with dredging and degradation from other projects in the area. Compensatory and voluntary mitigation plans for many of the projects would offset the severity of permanent cumulative impacts on wetlands and SAV. Alternatively, there would also be beneficial cumulative impacts from the creation of new wetlands, seagrass, and marsh habitats through the compensatory and voluntary mitigation programs as well as beneficial use of dredged material. Other beneficial cumulative impacts would be enhancement of the local economy from increased tax revenues, jobs and wages, and purchases of goods and materials.

5.2 ALTERNATIVES

Our analysis of alternatives for the Terminal and the Pipeline included, alternative Terminal sites, alternative dredge disposal locations, alternative Pipeline aboveground facility sites, and major alternatives for the Pipeline. While the No-Action Alternative would avoid the environmental impacts identified in this EIS, the objectives of the Project would not be met. However, any need for the import and export of natural gas could potentially be met by LNG export and import projects developed elsewhere, which would result in similar or greater impacts at other locations. Potential end users could make other arrangements to obtain natural gas service, or use alternative fossil fuel energy sources, other traditional long-term fuel source alternatives, and/or renewable energy sources to compensate for the reduced availability of natural gas that would otherwise be supplied by the Project. Similarly, natural gas capacity holders on the Pipeline would have to find other outlets for getting natural gas to market, which could include other pipelines or LNG terminals, each with their own environmental impacts.

We evaluated 12 Terminal system alternatives including 6 existing LNG import terminals with planned, proposed, or authorized LNG export projects and 6 planned, proposed, or authorized LNG terminals dedicated solely to export of LNG. All of the systems would require the need for substantial construction beyond that currently proposed, production volume limitations, in-service dates scheduled significantly beyond Cheniere's schedule and environmental impacts that were considered comparable to or greater than those of the proposed Project. As a result, we eliminated them from further consideration.

We evaluated 17 alternative Terminal sites at existing ports along the Gulf Coast. Three of these sites were selected for further evaluation based on access to a channel greater than 40 feet deep, access to major natural gas pipelines, industrial zoning, and availability of sufficient open land for construction and operation of the Terminal. Each of these three evaluated sites was previously proposed as a site for an LNG project, but the projects were never built. We conclude the use of two of those areas would no longer be feasible, as the properties are now owned by Occidental Petroleum Corporation and are no longer available to Cheniere. The third site was removed from consideration as a viable alternative, as it did not meet the Project's criteria for access to an existing pipeline system. In addition, the location of the Terminal site was selected because it is compatible with the existing industrial land use, would minimize impacts on agricultural land, and would not adversely impact protected resources. As a result, we conclude that development of the Terminal on the alternative sites would not be environmentally preferable or fully satisfy the Project's purpose and need. We considered two alternative dredge disposal locations, but found that neither of these locations were environmentally preferable to the proposed sites.

We evaluated 12 existing pipeline systems as system alternatives to the proposed Pipeline, including five pipelines that have planned connections to the Cheniere Pipeline. We determined that those system alternatives would not have sufficient capacity to meet the natural gas requirements of the Terminal without substantial expansion. Construction impacts of expanding those pipeline systems would be similar to or greater than those of the proposed Pipeline. Consequently, we conclude that none of the pipeline system alternatives would be environmentally preferable to the proposed Pipeline.

We evaluated three major pipeline route alternatives in addition to the proposed Pipeline route to determine which would produce minimal environmental impacts while meeting the Pipeline's objective. The proposed Pipeline route would provide the shortest distance from the Terminal to existing high pressure natural gas pipeline systems in the South Texas region. In addition, the proposed route minimizes environmental impacts by maximizing the use of existing corridors in the area. We determined that the major route alternatives would not offer a significant environmental advantage over the proposed route. Consequently, we conclude that none of the major pipeline route alternatives would be environmentally preferable to the proposed Pipeline route.

We evaluated one site alternative to the proposed Taft Compressor Station site. Although both sites are located on agricultural land that lack environmentally-sensitive resources, the proposed site is further away from NSAs than the alternative site. Consequently, we conclude that the alternative site would not provide a significant environmental advantage to the proposed Taft Compressor Station site.

We evaluated four site alternatives to the proposed Sinton Compressor Station site. Three of these alternative sites would require crossing an existing railroad track along US Highway 77, resulting in a safety concern for vehicle traffic. The remaining alternative site is closer to the nearest NSA than the proposed site, which was also preferred by the landowner. Therefore, we conclude that the alternative sites would not provide a significant environmental advantage to the proposed Sinton Compressor Station site. No alternative sites were identified that would be environmentally preferable to the other proposed aboveground facilities associated with the Pipeline.

5.3 FERC STAFF'S RECOMMENDED MITIGATION

If the Commission authorizes the Project, we are recommending that the following measures be included as specific conditions in the Commission's Order. These measures would further mitigate the environmental impacts associated with the construction and operation of the proposed Project. The section number in parentheses at the end of a condition corresponds to the section number in which the measure and related resource impact analysis appears in the EIS.

1. Cheniere shall follow the construction procedures and mitigation measures described in its applications and supplemental filings (including responses to staff data requests), and as identified in the EIS, unless modified by the Order. Cheniere must:
    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;

b. justify each modification relative to site-specific conditions;

c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

d. receive approval in writing from the Director of OEP **before using that modification**.

2. For LNG facilities, the Director of the OEP has delegated authority to take all steps necessary to ensure the protection of life, health, property, and the environment during construction and operation of the Terminal. This authority shall include:

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

   b. the design and implementation of any additional measures deemed necessary to ensure compliance with the intent of the Order.

3. The Director of OEP has delegated authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the Pipeline. This authority shall allow:

   a. the modification of conditions of the Order; and

   b. the design and implementation of any additional measures deemed necessary (including stop-work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance of mitigation of adverse environmental impact resulting from the Project construction and operation.

4. **Prior to any construction,** Cheniere shall file affirmative statements with the Secretary, certified by senior company officials, that all company personnel, EI's, 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 depicted in the EIS, 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.

   Cheniere'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. Cheniere'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 detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or

disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

This requirement does not apply to extra workspaces allowed by FERC's Plan or minor field realignments per landowner needs and requirements that 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 a single Implementation Plan for the review and written approval by the Director of OEP. Cheniere must file revisions to their plan as schedules change. The plan shall identify:

a. how Cheniere will implement the construction procedures and mitigation measures described in its respective application and supplements (including responses to staff data requests), identified in the EIS, 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 per spread and aboveground facility sites, 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 materials;

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 noncompliance occurs; and
- h. for each discrete facility, a Gantt or PERT chart (or similar Project scheduling diagram), and dates for:
    1. the completion of all required surveys and reports;
    2. the environmental compliance training of onsite personnel;
    3. the start of construction; and
    4. the start and completion of restoration.

8. Cheniere shall employ at least one EI for the Terminal and at least one EI per construction spread for the Pipeline. Each EI shall be:
    - a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or 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 on a **monthly** basis for the Terminal and on a **weekly** basis for the Pipeline until all construction and restoration activities are complete. 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. the construction status at the Terminal site and of each spread of the Pipeline, 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 and each instance of noncompliance observed by each 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 actions implemented in response to all instances of noncompliance, and their cost;

e. the effectiveness of all corrective 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. **Prior to receiving written authorization from the Director of OEP to commence construction of any Project facilities**, Cheniere shall file with the Secretary documentation that each has received all applicable authorizations required under federal law (or evidence of waiver thereof).

11. Cheniere must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the Terminal 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. Cheniere must receive written authorization from the Director of OEP **before placing the Terminal facilities into service**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval and applicable standards, can be expected to operate safely as designed, and the rehabilitation and restoration of the areas affected by the Terminal are proceeding satisfactorily.

13. Cheniere must receive written authorization from the Director of OEP **before placing the Pipeline 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 Pipeline 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 authorization conditions 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 Pipeline**, Cheniere shall update table 2.3-3 of the EIS to identify the existing utilities/road locations and the milepost ranges of where its construction right-of-way would overlap or collocate other utility/road rights-of-way;

and revise its final alignment sheets to reflect the actual right-of-way configurations and workspace needs at these locations. (*section 2.3.2*)

16. **Prior to construction,** Cheniere shall file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary:

    a. site preparation drawings and specifications;

    b. LNG tank and foundation design drawings and calculations based on the seismic design ground motions in Cheniere's Resource Report 13, Appendix I (URS Report – Seismic and Tsunami Evaluation for the LNG Export Facility dated August 7, 2012) and the settlement analyses prepared during detailed design, indicated in the response to question 4f provided in the Supplemental Responses filed by Cheniere on September 23, 2013;

    c. LNG liquefaction facility structures and foundation design drawings and calculations (including prefabricated and field constructed structures); and

    d. quality control procedures to be used for civil/structural design and construction. (*section 4.1.1.4*)

17. **Prior to construction** of any foundations at the Terminal, Cheniere shall file an update on the status of GHG PSD permitting requirements for the Sinton Compressor Station and documentation of any final GHG PSD permit from the applicable permitting agency. **Prior to construction of the Sinton Compressor Station,** Cheniere should file documentation of its final GHG PSD permit obtained. (*section 4.11.1.3*)

18. **Prior to construction,** Cheniere shall file a revised FDCP with the Secretary for review and written approval from the Director of OEP. The revised FDCP shall include the following:

    a. the use of gravel at construction entrance and exit locations; and

    b. measures to clean paved roads upon mud or dirt track out. (*section 4.l1.1.4*)

19. Cheniere shall file a noise survey with the Secretary **no later than 60 days** after placing each liquefaction train and the entire Terminal in service. If a full load condition noise survey is not possible, Cheniere shall provide an interim survey at the maximum possible load and provide the full load survey **within six months**. If the noise attributable to the operation of all of the equipment for a liquefaction train or at the Terminal, under interim or full load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, Cheniere shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within one year** of the in-service date. Cheniere 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 4.11.2.3*)

20. Cheniere shall file noise surveys with the Secretary **no later than 60 days** after placing the Sinton and Taft Compressor Stations in service. If a full load condition noise survey is not possible, Cheniere shall provide an interim survey at the maximum possible horsepower load and provide the full load survey **within six months**. If the noise attributable to the operation of all of the equipment at the Sinton or Taft Compressor

Station, under interim or full horsepower load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, Cheniere shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within one year** of the in-service date. Cheniere 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 4.11.2.3*)

Recommendations 21 through 104 shall apply to the Cheniere Terminal. Information pertaining to the specific recommendations shall be filed with the Secretary for review and written approval by the Director of OEP either: **prior to initial site preparation; prior to construction of final design**; **prior to commissioning; prior to introduction of hazardous fluids; or prior to commencement of service**, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, shall be submitted as critical energy infrastructure information pursuant to 18 CFR 388.112. See Critical Energy Infrastructure Information, Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. 31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements, would be subject to public disclosure. All information shall be filed **a minimum of 30 days** before approval to proceed is requested. (*section 4.12.3*)

21. **Prior to initial site preparation**, Cheniere shall file evidence that demonstrates the inclusion of multiple pumps and pump run-out flow rates would not result in any changes to the conclusions of the siting analyses. In the event that any modifications alter the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Cheniere should consult with DOT on any actions necessary to comply with Part 193. (*section 4.12.5*)

22. **Prior to initial site preparation**, Cheniere shall provide quality assurance and quality control procedures for construction activities. (*section 4.12.3*)

23. **Prior to initial site preparation**, Cheniere shall file an overall project schedule, which includes the proposed stages of the commissioning plan. (*section 4.12.3*)

24. **Prior to initial site preparation**, Cheniere shall provide procedures for controlling access during construction. (*section 4.12.3*)

25. **Prior to initial site preparation**, Cheniere shall provide a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. (*section 4.12.3*)

26. **Prior to initial site preparation**, Cheniere shall file a complete specification of the proposed LNG tank design and installation. (*section 4.12.3*)

27. **Prior to initial site preparation**, Cheniere shall develop an ERP (including evacuation) 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 LNG carrier to activate sirens and other warning devices.

Cheniere shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals**. (*section 4.12.7*)

28. **Prior to initial site preparation**, Cheniere shall file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. (*section 4.12.7*)

29. The **final design** shall include 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 4.12.3*)

30. The **final design** shall include change logs that list and explain any changes made from the FEED provided in Cheniere'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 4.12.3*)

31. The **final design** shall provide information/revisions pertaining to Cheniere's responses, as listed in Table 4.12.3-1 of the EIS, which indicated features to be included in the final design and documentation. (*section 4.12.3*)

32. The **final design** shall provide an up-to-date equipment list, process and mechanical data sheets, and specifications. (*section 4.12.3*)

33. The **final design** shall include three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion. (*section 4.12.3*)

34. The **final design** shall include up-to-date PFDs and P&IDs. The PFDs shall include heat and material balances. The P&IDs shall include the following information:

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

    b. equipment insulation type and thickness;

    c. storage tank pipe penetration size or nozzle schedule;

   d. piping with line number, piping class specification, size, and insulation type and thickness;
   e. piping specification breaks and insulation limits;
   f. all control and manual valves numbered;
   g. valve high pressure sides and cryogenic ball valve external and internal vent locations;
   h. relief valves with set points; and
   i. drawing revision number and date. (*section 4.12.3*)

35. The **final design** shall include a list of all car-sealed and locked valves consistent with the P&IDs. (*section 4.12.3*)

36. The **final design** shall include a hazard and operability review 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 4.12.3*)

37. The **final design** shall include spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments. (*section 4.12.3*)

38. The **final design** shall provide electrical area classification drawings. (*section 4.12.3*)

39. The **final design** shall include 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. (*section 4.12.3*)

40. The **final design** shall provide 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; shall alarm the hazardous condition; and shall shutdown the appropriate systems. (*section 4.12.3*)

41. The **final design** shall include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control. (*section 4.12.3*)

42. The **final design** shall specify fire protection systems, uninterruptable power supply, emergency power generators, emergency lighting, radio communications system, control valves, instrumentation, and shutdown systems associated with the LNG storage tanks and their isolation as Seismic Category 1. (*section 4.12.3*)

43. The **final design** shall specify that for hazardous fluids, piping and piping nipples 2 inches or less in diameter are to be no less than schedule 160 for carbon steel and no less than schedule 80 for stainless steel, and 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 4.12.3*)

44. The **final design** shall include 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 required by 49 CFR 193 and shall provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing. (*section 4.12.3*)

45. The **final design** shall specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses. (*section 4.12.3*)

46. The **final design** shall include any isolation valves necessary for startup, operation, shutdown, restart, and maintenance procedures . (*section 4.12.3*)

47. The **final design** shall include LNG tank fill flow measurement with high flow alarm. (*section 4.12.3*)

48. The **final design** shall include BOG flow and temperature measurement for each tank. (*section 4.12.3*)

49. The **final design** shall include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire. (*section 4.12.3*)

50. The **final design** shall include the details of the LNG storage tank structural design that demonstrates the tanks can withstand overpressures from ignition of design spills. (*section 4.12.5*)

51. The **final design** shall specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the BOG Recondenser shall be the same pressure and temperature rating as the piping at the discharge of the LNG Send-out pumps. (*section 4.12.3*)

52. The **final design** shall specify that a check valve is provided in the LNG send-out pump minimum flow recycle piping. (*section 4.12.3*)

53. The **final design** shall specify discharge valving to allow the pumps to be recirculated without flowing LNG to the vaporizer control valve during initial startup and provide a cooldown bypass valve to pressurize and cool the vaporizer inlet piping. (*section 4.12.3*)

54. The **final design** of the LNG vaporization system shall specify that a check valve, vent valve, and manual isolation valve are to be provided downstream of the outlet shut-off valve 00XV-56015. (*section 4.12.3*)

55. The **final design** shall specify that the LNG loading arms are equipped with a manual isolation valve at the base of each arm. (*section 4.12.3*)

56. The **final design** shall specify the minimum distance required for valve maintenance, between the LNG loading header and the first valve in the discharge piping to the loading arm. (*section 4.12.3*)

57. The **final design** shall specify that all drains from high pressure hazardous fluid systems are to be equipped with double isolation and bleed valves. (*section 4.12.3*)

58. The **final design** of the wet gas flare shall include a drain or shall justify why a drain is not included. (*section 4.12.3*)

59. The **final design** shall provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 CFR 193. (*section 4.12.3*)

60. The **final design** shall include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, storage tanks, and vent stacks. (*section 4.12.3*)

61. The **final design** shall specify that a pressure relief valve is to be provided on the upstream side of the vaporizer outlet shutoff valve. The valve shall be sized in accordance with the requirements of NFPA 59A (2001 ed.) Section 5.4.1. (*section 4.12.3*)

62. The **final design** of the LNG vaporization system shall include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A (2001 ed.) Section 5.4.1 and shall be set at a lower pressure. (*section 4.12.3*)

63. The **final design** shall specify that ethylene storage vessels be equipped with redundant full capacity relief valves. (*section 4.12.3*)

64. The **final design** shall specify that propane storage vessels be equipped with redundant full capacity relief valves. (*section 4.12.3*)

65. The **final design** shall specify that LNG relief valves and LNG drains shall not discharge into the boil-off gas (BOG), vapor return, or fuel gas systems. (*section 4.12.3*)

66. The **final design** shall include pressure relieving protection for flammable liquid piping (i.e., condensate products) which can be isolated by valves. (*section 4.12.3*)

67. The **final design** shall demonstrate there would not be a potential hazard of a liquid release from LNG reliefs routed to the dry flare and specify that LNG from all other relief valves and drains are to be returned to storage. (*section 4.12.3*)

68. The **final design** shall specify that all Emergency Shutdown (ESD) valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS)/Safety Instrumented System (SIS). (*section 4.12.3*)

69. The **final design** shall include complete plan drawings of the security fencing and of facility access and egress. (*section 4.12.3*)

70. The **final design** shall include the cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and setpoints. (*section 4.12.3*)

71. The **final design** shall include a plant-wide ESD button with proper sequencing. (*section 4.12.3*)

72. The **final design** shall specify that the truck fill line be equipped with an automatic shutoff valve. (*section 4.12.3*)

73. The **final design** shall include an updated fire protection evaluation of the proposed facilities carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2 as required by 49 CFR 193. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. (*section 4.12.3*)

74. The **final design** of the hazard detectors shall account for the calibration gas when determining the LFL set points for methane, propane, and ethylene, and condensate. (*section 4.12.3*)

75. The **final design** shall include complete plan drawings and a list of the hazard detection equipment. Plan 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 proposed hazard detection equipment. (*section 4.12.3*)

76. The **final design** shall provide a technical review of its proposed facility design that:

    a. identifies all combustion/ventilation air intake equipment and the distances to any possible hazardous fluid release (LNG, flammable refrigerants, flammable liquids and flammable gases); and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency. (*section 4.12.3*)

77. The **final design** shall include smoke detection in occupied buildings. (*section 4.12.3*)

78. The **final design** shall include hazard detection suitable to detect high temperatures and smoldering combustion in electrical buildings and control room buildings. (*section 4.12.3*)

79. The **final design** shall include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable. (*section 4.12.3*)

80. The **final design** shall include clean agent systems in the electrical switchgear and instrumentation buildings. (*section 4.12.3*)

81. The **final design** shall provide complete plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Drawings shall clearly show the location by tag number of all fixed, wheeled, and hand-held extinguishers. The list shall include the equipment tag number, type, capacity,

equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units. (*section 4.12.3*)

82. The **final design** shall include facility plans and drawings showing the proposed location of the firewater and any foam systems. Plan drawings shall clearly show the planned location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam generator, and sprinkler. The drawings shall also include piping and instrumentation diagrams of the firewater and foam systems. (*section 4.12.3*)

83. The **final design** shall specify that the firewater pump shelter is designed with a removable roof for maintenance access to the firewater pumps. (*section 4.12.3*)

84. The **final design** 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. The firewater main header pressure transmitter, 00PT-33091, shall also be connected to the DCS and recorded. (*section 4.12.3*)

85. The **final design** shall include certification that the final design is consistent with the information provided to DOT as described in the design spill determination letter dated February 10, 2014 (Accession Number 20140210-4008). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR Part 193 siting analysis was based, Cheniere shall consult with DOT on any actions necessary to comply with Part 193. (*section 4.12.5*)

86. The **final design** shall include the details of the vapor fences as well as procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR § 193.2059. (*section 4.12.5*)

87. **Prior to commissioning**, Cheniere shall file plans and detailed procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. (*section 4.12.3*)

88. **Prior to commissioning**, Cheniere shall provide 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. Cheniere 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 4.12.3*)

89. **Prior to commissioning**, Cheniere shall tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. (*section 4.12.3*)

90. **Prior to commissioning**, Cheniere shall file Operation and Maintenance procedures and manuals, including safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, and management of change procedures and forms. (*section 4.12.3*)

91. **Prior to commissioning**, Cheniere shall maintain a detailed training log to demonstrate that operating staff has completed the required training. (*section 4.12.3*)

92. **Prior to commissioning**, Cheniere shall file a tabulated list and drawings of the proposed hand-held fire extinguishers. The list shall include the equipment tag number, extinguishing agent type, capacity, number, and location. The drawings shall show the extinguishing agent type, capacity, and tag number of all hand-held fire extinguishers. (*section 4.12.3*)

93. **Prior to commissioning**, Cheniere shall file results of the LNG storage tank hydrostatic test and foundation settlement results. At a minimum, foundation settlement results should be provided thereafter annually. (*section 4.12.3*)

94. **Prior to introduction of hazardous fluids**, Cheniere shall complete 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 4.12.3*)

95. **Prior to introduction of hazardous fluids**, Cheniere shall complete 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 4.12.3*)

96. **Prior to commencement of service**, Cheniere shall label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A. (*section 4.12.3*)

97. **Prior to commencement of service**, Cheniere shall develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Cheniere staff. (*section 4.12.3*)

98. **Prior to commencement of service**, Cheniere shall notify FERC staff of any proposed revisions to the security plan and physical security of the facility. (*section 4.12.3*)

99. **Prior to commencement of service**, Cheniere shall file progress on construction of the Terminal in **monthly** reports. Details shall include a summary of activities, problems encountered, contractor non-conformance/ deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude shall be reported to the FERC **within 24 hours**. (*section 4.12.3*)

100. **Prior to commencement of service**, Cheniere shall receive 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, and the Safety 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 Cheniere or other appropriate parties. (*section 4.12.6*)

In addition, recommendations 101 through 104 shall apply throughout the **life of the facility**:

101. 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, Cheniere 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 piping and instrumentation diagrams 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 annual report, shall be submitted. (*section 4.12.3*)

102. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site 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, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving natural gas 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 shall also 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 also be included in the semiannual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility. (*section 4.12.3*)

103. In the event the temperature of any region of any secondary containment, including imbedded pipe supports, 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 4.12.3*)

104. Significant non-scheduled events, including safety-related incidents (e.g., hazardous fluid releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) shall be reported to FERC staff. In the event 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 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 fluid for five 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 facility that contains, controls, or processes a hazardous fluid;

h. any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes a hazardous fluid 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 a facility that contains or processes a hazardous fluid 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 operation of a pipeline or a facility that contains or processes a hazardous fluid;

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

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

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports shall include investigations results and recommendations to minimize a reoccurrence of the incident. (*section 4.12.3*)

Appendix A

ALIGNMENT SHEETS

RIGHT-OF-WAY

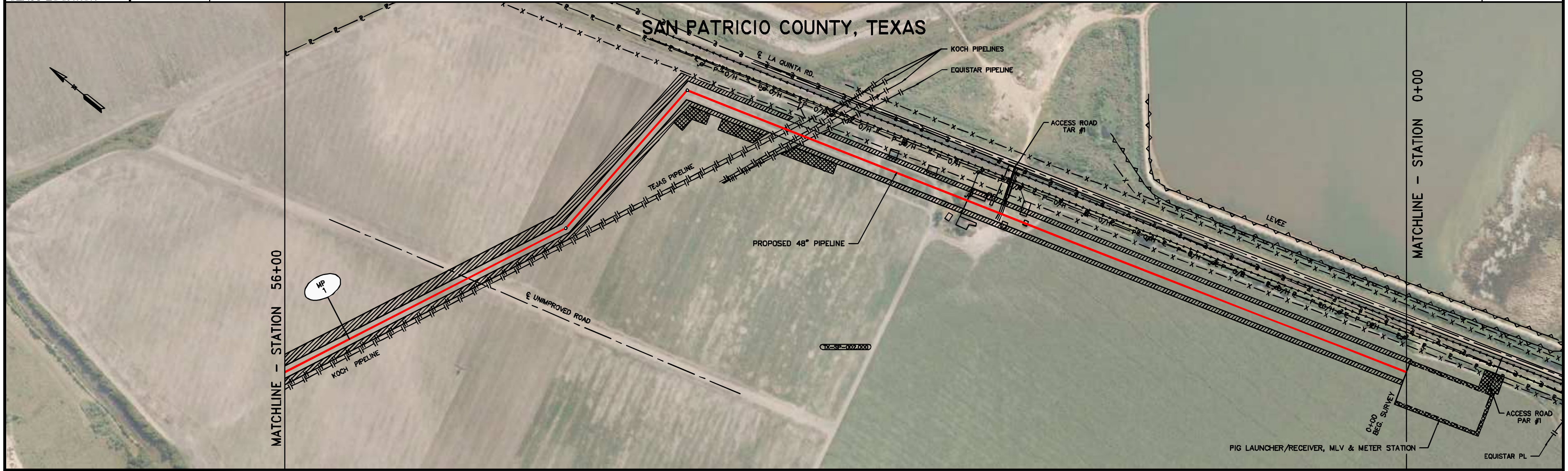
TRACT NUMBER: TX-SP-002.000

OWNERSHIP/AGENCY: PORT OF CORPUS CHRISTI

5600.0 FT

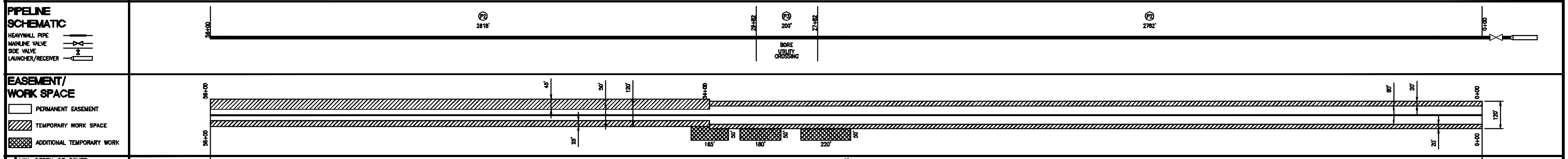
56+00 | 0+00

CLASS LOCATION: CLASS 1



STATION/ DESCRIPTION

46+82 UNIMPROVED ROAD C.L.
42+09 P.I. < 21°25'14" RT.
34+00 P.I. < 70°05'07" LT.
29+43 FOREIGN PIPELINE
29+18 FOREIGN PIPELINE
28+65 FOREIGN PIPELINE
28+49 FOREIGN PIPELINE
28+22 FOREIGN PIPELINE
20+77 O.H. POWERLINE
20+76 POWER POLE, 25.4' RT.
19+27 ROAD EDGE, GRAVEL
19+19 ROAD EDGE, GRAVEL
19+12 ROAD EDGE, GRAVEL
18+10 BUILDING
17+91 BUILDING
0+01 SURFACE SITE
0+00 BEGIN STA.



ENVIRONMENTAL MITIGATION/RECLAMATION

MIN. DEPTH OF COVER		3'
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	[illegible]	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P2	48" O.D. x 0.823" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5400
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	200

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/18/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

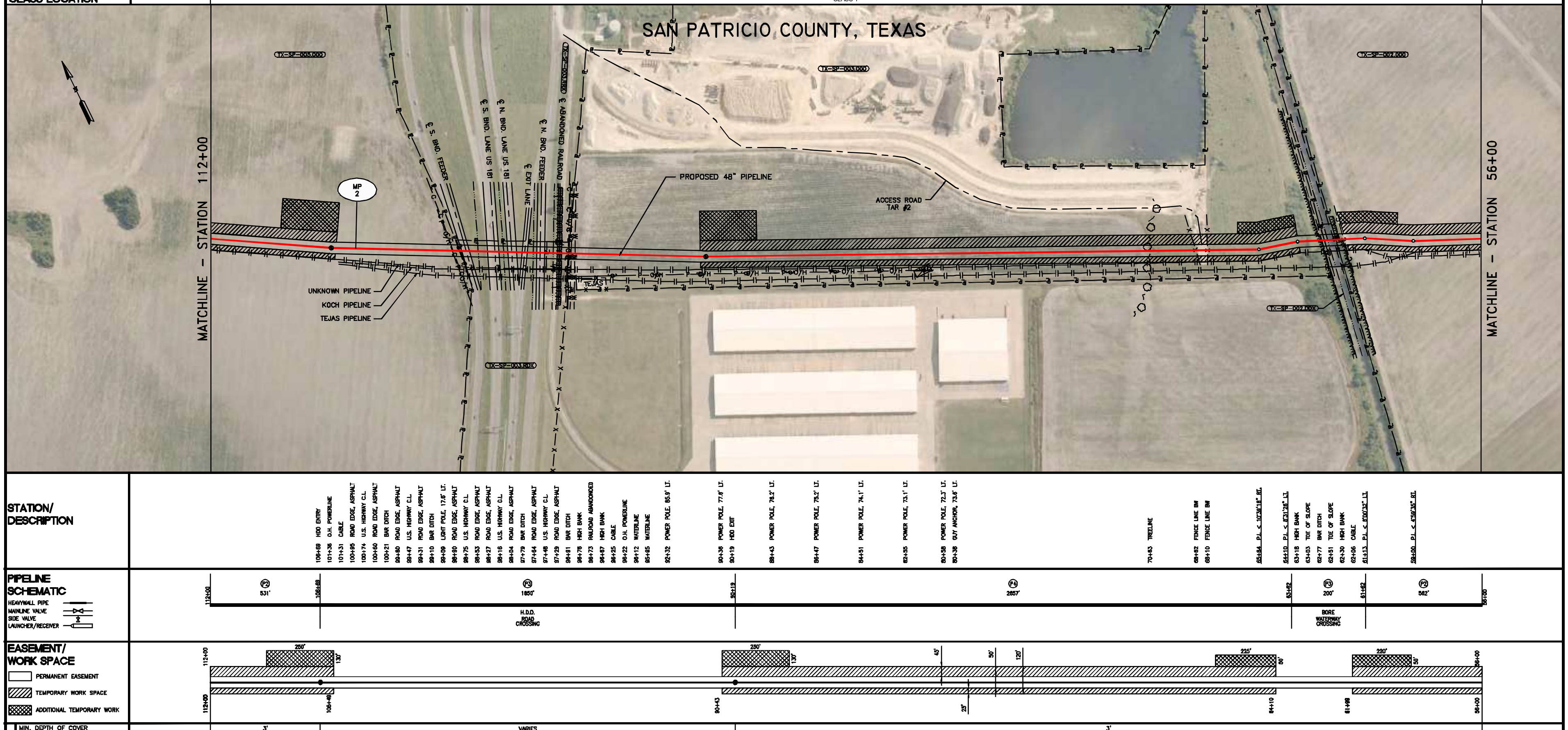
CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 0+00 TO STA. 56+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1101	1 OF 22

07-18-12 15:42 12054_FERC ALIGNMENTS 8 RAM

RIGHT-OF-WAY TRACT NUMBER OWNERSHIP/AGENCY	112+00	TX-SP-005.000 DON CABLE. JOE GARRETT. GJW PARTNERSHIP 1097.6 FT	101+02	TX-SP-003.RDX US HIGHWAY 181 382.1 FT	97+20	TX-SP-003.RRX UNION PACIFIC RAILROAD 97.3 FT	96+23	TX-SP-003.000 BDJ PROPERTIES LLC. PHIL BERRYMAN 3331.4 FT	62+92	TX-SP-002.DDX DRAINAGE DITCH 50.7 FT	62+41	TX-SP-002.000 PORT OF CORPUS CHRISTI 640.9 FT	56+00
CLASS LOCATION								CLASS 1					



ENVIRONMENTAL MITIGATION/RECLAMATION		
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	EROSION CONTROL CODE	
	SLOPE BREAKER CODE	
	TRENCH BREAKER CODE	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

PIPELINE

PROPOSED ROUTE 05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P2	48" O.D. x 0.823" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	1093
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	1850
			P4	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	2857

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE

CORPUS CHRISTI PIPELINE, LP

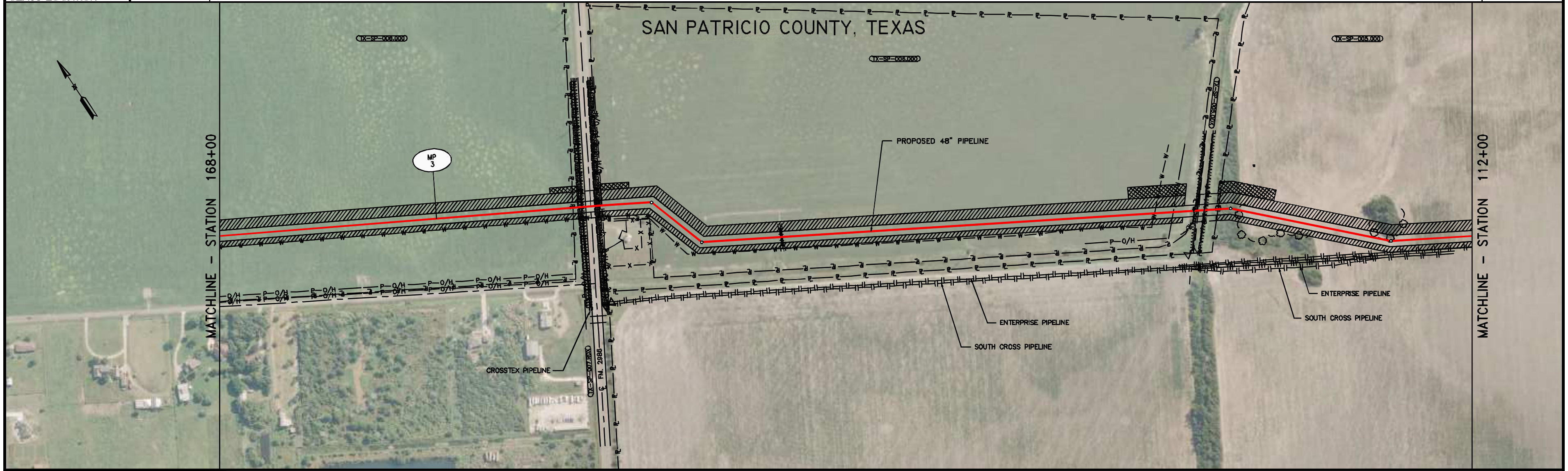
PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 56+00 TO STA. 112+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1102	2 OF 22

07-10-12 12:25 12054_FERC ALIGNMENTS 6 RAM

RIGHT-OF-WAY TRACT NUMBER OWNERSHIP/AGENCY	TX-SP-008.000 DIANE DECOU, MARTHA MCKAMEY DECOU, DECOU FAMILY PARTNERSHIP, LTD, SUSAN DECOU LAMB, CORINNE LILLIAN MCKAMEY, JEFFREY RANDALL MCKAME 1560.6 FT	TX-SP-007.RDX FM ROAD 2986 118.4 FT	TX-SP-006.000 ELDT INVESTMENTS, LTD, DARYL HASS 2684.8 FT	TX-SP-005.DDX DRAINAGE DITCH 103.0 FT	TX-SP-005.000 DON CABLE, JOE GARRETT, GJW PARTNERSHIP 1133.2 FT
CLASS LOCATION	CLASS 1				

168+00 · 152+39 · 151+21 · 124+36 · 123+33 · 112+00

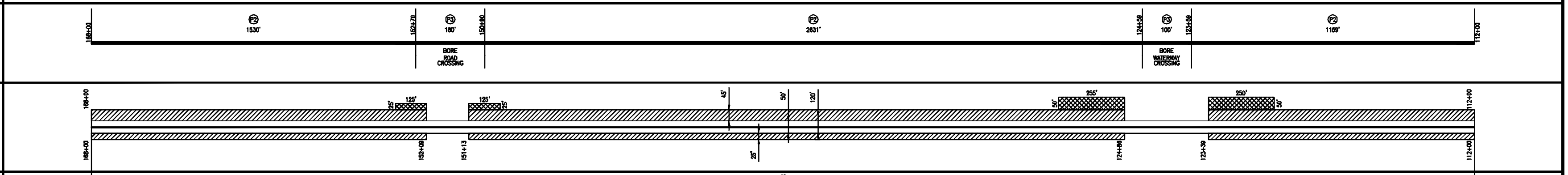


STATION/ DESCRIPTION

152+09 O.H. POWERLINE
152+05 HIGH BANK
152+03 FOREIGN PIPELINE
151+97 BAR DITCH
151+90 HIGH BANK
151+82 ROAD EDGE, ASPHALT
151+60 FARM TO MARKET C.L.
151+38 ROAD EDGE, ASPHALT
151+31 HIGH BANK
151+25 BAR DITCH
151+21 HIGH BANK
151+19 CABLE
151+11 O.H. POWERLINE
148+92 P.I. < 42°08'32" LT.
146+10 P.I. < 42°05'21" RT.
142+67 HIGH BANK
142+58 BAR DITCH
142+50 HIGH BANK
126+13 WATERLINE
125+31 O.H. POWERLINE
124+40 INT. STREAM
124+37 HIGH BANK
124+18 TOE OF SLOPE
123+95 INT. STREAM
123+94 TOE OF SLOPE
123+81 HIGH BANK
122+78 P.I. < 15°07'19" LT.
122+43 TREELINE
116+02 TREELINE
115+92 TREELINE
115+57 P.I. < 14°55'27" RT.

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION		
MIN. DEPTH OF COVER		3'
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	EROSION CONTROL CODE	
	SLOPE BREAKER CODE	
	TRENCH BREAKER CODE	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

PIPELINE
PROPOSED ROUTE 05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P2	48" O.D. x 0.823" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5320
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	280

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 112+00 TO STA. 168+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1103	3 OF 22

07-10-12 12:26 12054_FERC ALIGNMENTS 6 RAM

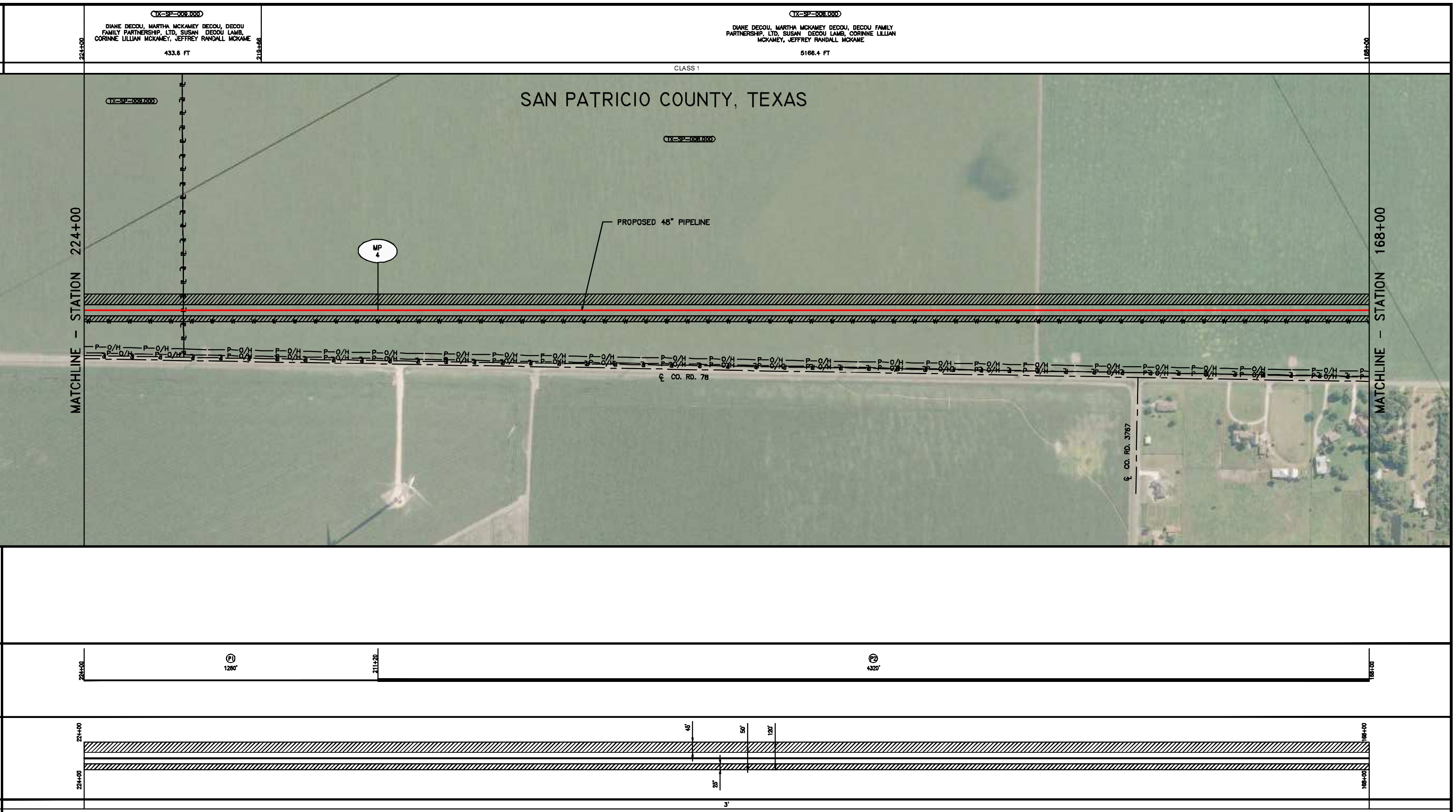
RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

CLASS LOCATION

STATION/ DESCRIPTION

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION	MIN. DEPTH OF COVER	
	UPLAND	CLEAR AND GRADE
		TOPSOIL SALVAGE METHOD
	WATERBODY CROSSINGS	
	WETLAND CROSSINGS	TYPE
		℄ LENGTH
	MILEPOSTS	
	PERMANENT EROSION CONTROL	EROSION CONTROL CODE
		SLOPE BREAKER CODE
		TRENCH BREAKER CODE
	REVEGETATION	
	DRAINAGE & IRRIGATION SYSTEMS	
	MISCELLANEOUS	
	RESTRICTED WORK	TIMING CONSTRAINTS
		DATES

PIPELINE
PROPOSED ROUTE
05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	1280
			P2	48" O.D. x 0.823" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	4320

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

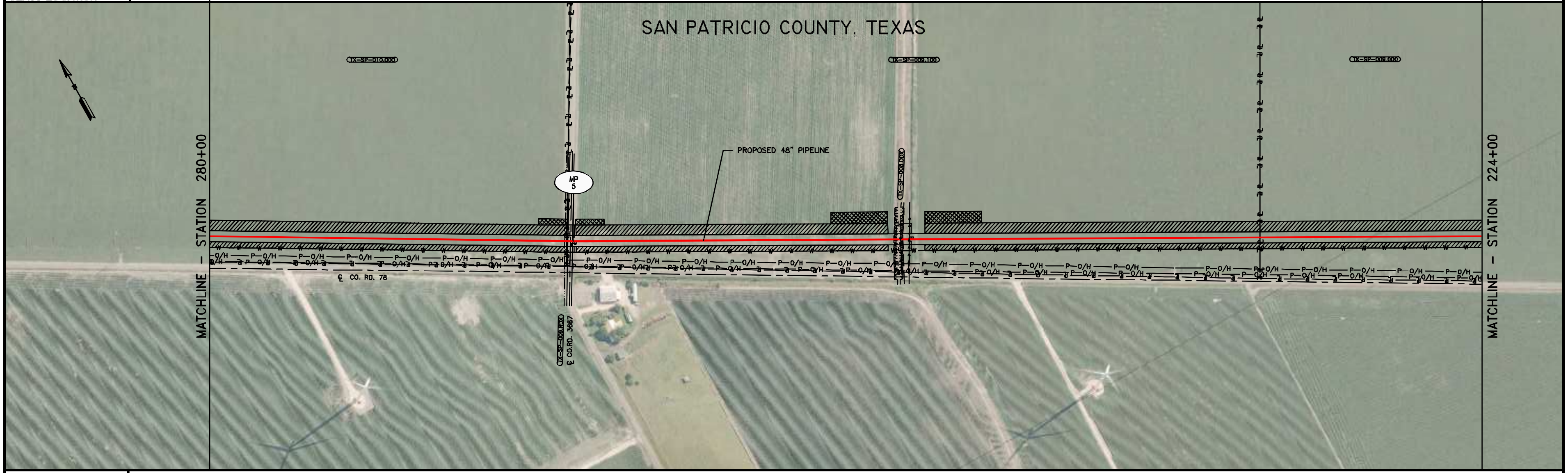
CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 168+00 TO STA. 224+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1104	4 OF 22

07-10-12 12:28 12054_FERC ALIGNMENTS 6 RAM

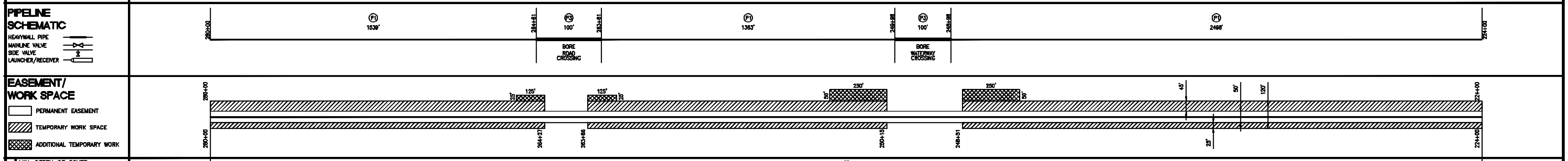
RIGHT-OF-WAY TRACT NUMBER OWNERSHIP/AGENCY	280+00	TX-SP-010.000 ROY JAMES FLOERKE AND ORA MARIE FAMILY LIMITED PARTNERSHIP 1573.4 FT	264+27	TX-SP-009.RDX COUNTY ROAD 3667 32.2 FT	263+94	TX-SP-009.100 DIANE DECOU, MARTHA MCKAMEY DECOU, SUSAN DECOU LAMB, CORINNE LILLIAN MCKAMEY, JEFFREY RANDALL MCKAMEY, KARA MARIE MCKAMEY, KENNETH 1416.1 FT	249+78	TX-SP-008.DDX DRAINAGE DITCH 67.0 FT	249+11	TX-SP-009.100 DIANE DECOU, MARTHA MCKAMEY DECOU, SUSAN DECOU LAMB, CORINNE LILLIAN MCKAMEY, JEFFREY RANDALL MCKAMEY, KARA MARIE MCKAMEY, KENNETH 1534.7 FT	233+77	TX-SP-009.000 DIANE DECOU, MARTHA MCKAMEY DECOU, DECOU FAMILY PARTNERSHIP, LTD, SUSAN DECOU LAMB, CORINNE LILLIAN MCKAMEY, JEFFREY RANDALL MCKAME 976.6 FT	224+00
CLASS LOCATION		CLASS 1											



STATION/ DESCRIPTION

264+35 BAR DITCH
264+22 ROAD EDGE, ASPHALT
264+11 COUNTY ROAD C.L.
264+01 ROAD EDGE, ASPHALT
264+01 ROAD EDGE, ASPHALT

249+76 HIGH BANK
249+62 HIGH BANK
249+57 INT. STREAM
249+48 TOE OF SLOPE
249+20 INT. STREAM
249+18 TOE OF SLOPE



MIN. DEPTH OF COVER		3'
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	EROSION CONTROL CODE	
	SLOPE BREAKER CODE	
	TRENCH BREAKER CODE	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

ENVIRONMENTAL MITIGATION/RECLAMATION

PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5400
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	200

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 224+00 TO STA. 280+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1105	5 OF 22

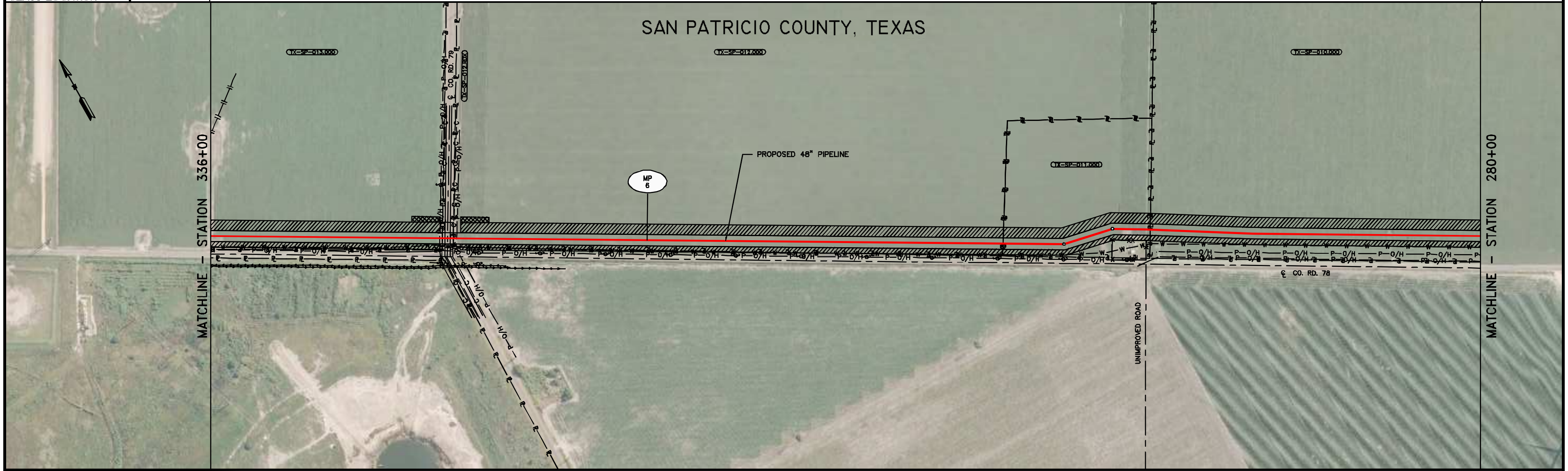
07-10-12 12:29 12054_FERC ALIGNMENTS 6 RAM

RIGHT-OF-WAY

TRACT NUMBER	TX-SP-013.000	TX-SP-012.RDX	TX-SP-012.000	TX-SP-011.000	TX-SP-010.000
OWNERSHIP/AGENCY	JEAN IVEY	COUNTY ROAD 79	NEAL L. FLOERKE	SAN PATRICIO MUNICIPAL WATER DISTRICT	ROY JAMES FLOERKE AND ORA MARIE FAMILY LIMITED PARTNERSHIP
	1019.4 FT	48.4 FT	2419.5 FT	657.6 FT	1455.1 FT

336+00 325+81 325+32 301+13 294+55 280+00

CLASS LOCATION CLASS 1



STATION/ DESCRIPTION

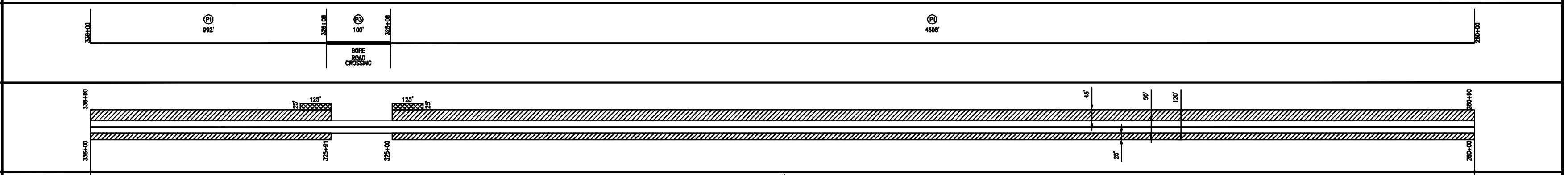
334+58	TOWER PWR POLE, 60.2' LT.
331+37	TOWER PWR POLE, 61.1' LT.
328+14	TOWER PWR POLE, 61.9' LT.
325+92	POWER POLE, 53.4' LT.
325+92	O.H. POWERLINE
325+81	CABLE
325+69	ROAD EDGE, ASPHALT
325+56	COUNTY ROAD C.L.
325+46	ROAD EDGE, ASPHALT
325+32	CABLE
325+25	TOWER PWR POLE, 52.6' LT.
325+18	O.H. POWERLINE
325+11	TOWER PWR POLE, 50.6' LT.
324+47	GUY ANCHOR, 61.6' LT.
324+19	POWER POLE, 62.5' LT.
321+50	POWER POLE, 63.0' LT.
318+62	POWER POLE, 63.2' LT.
315+76	POWER POLE, 64.1' LT.
312+89	POWER POLE, 64.3' LT.
310+01	POWER POLE, 65.2' LT.
307+13	POWER POLE, 65.0' LT.
304+26	POWER POLE, 65.3' LT.
301+37	POWER POLE, 66.3' LT.
298+46	POWER POLE, 67.1' LT.
298+45	P.I. < 16°04'38" RT.
296+21	P.I. < 16°24'21" LT.

PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE

☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION

MIN. DEPTH OF COVER		3'
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	EROSION CONTROL CODE	
	SLOPE BREAKER CODE	
	TRENCH BREAKER CODE	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS S/N	W.T.	ANGLE	MATERIAL SUMMARY NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5500
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 – 35 MILS ARO COATING	100

REFERENCE DRAWINGS NO.	DESCRIPTION	DWG. NO.

REVISION NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

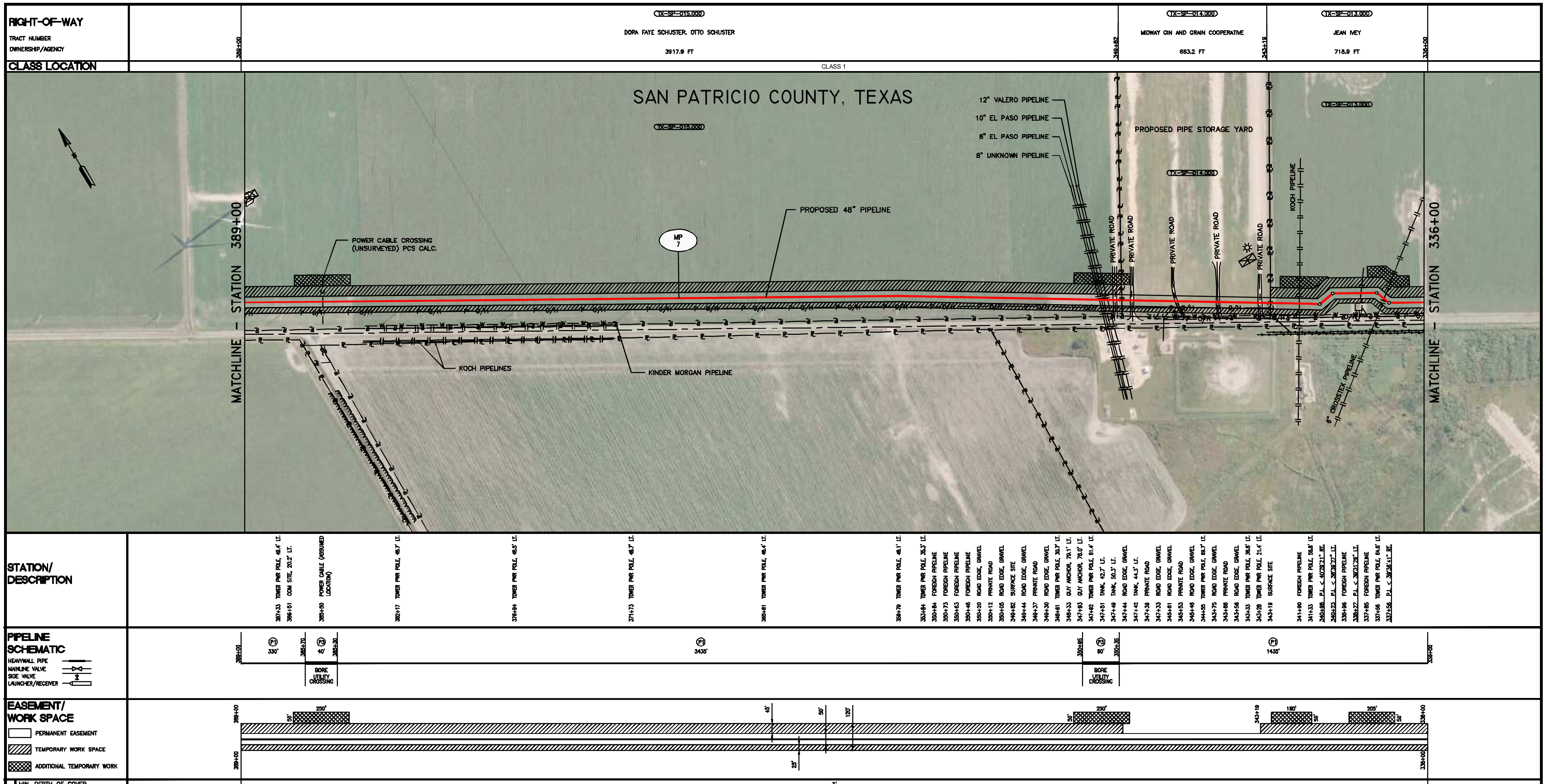
DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 280+00 TO STA. 336+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1106	6 OF 22

07-10-12 12:30 12054_FERC ALIGNMENTS 5 RAM



ENVIRONMENTAL MITIGATION/RECLAMATION	UPLAND	CLEAR AND GRADE
		TOPSOIL SALVAGE METHOD
	WATERBODY CROSSINGS	
	WETLAND CROSSINGS	TYPE
		℄ LENGTH
	MILEPOSTS	
	PERMANENT EROSION CONTROL	EROSION CONTROL CODE
		SLOPE BREAKER CODE
		TRENCH BREAKER CODE
	REVEGETATION	
	DRAINAGE & IRRIGATION SYSTEMS	
	MISCELLANEOUS	
	RESTRICTED WORK	TIMING CONSTRAINTS
		DATES

PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5200
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	100

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

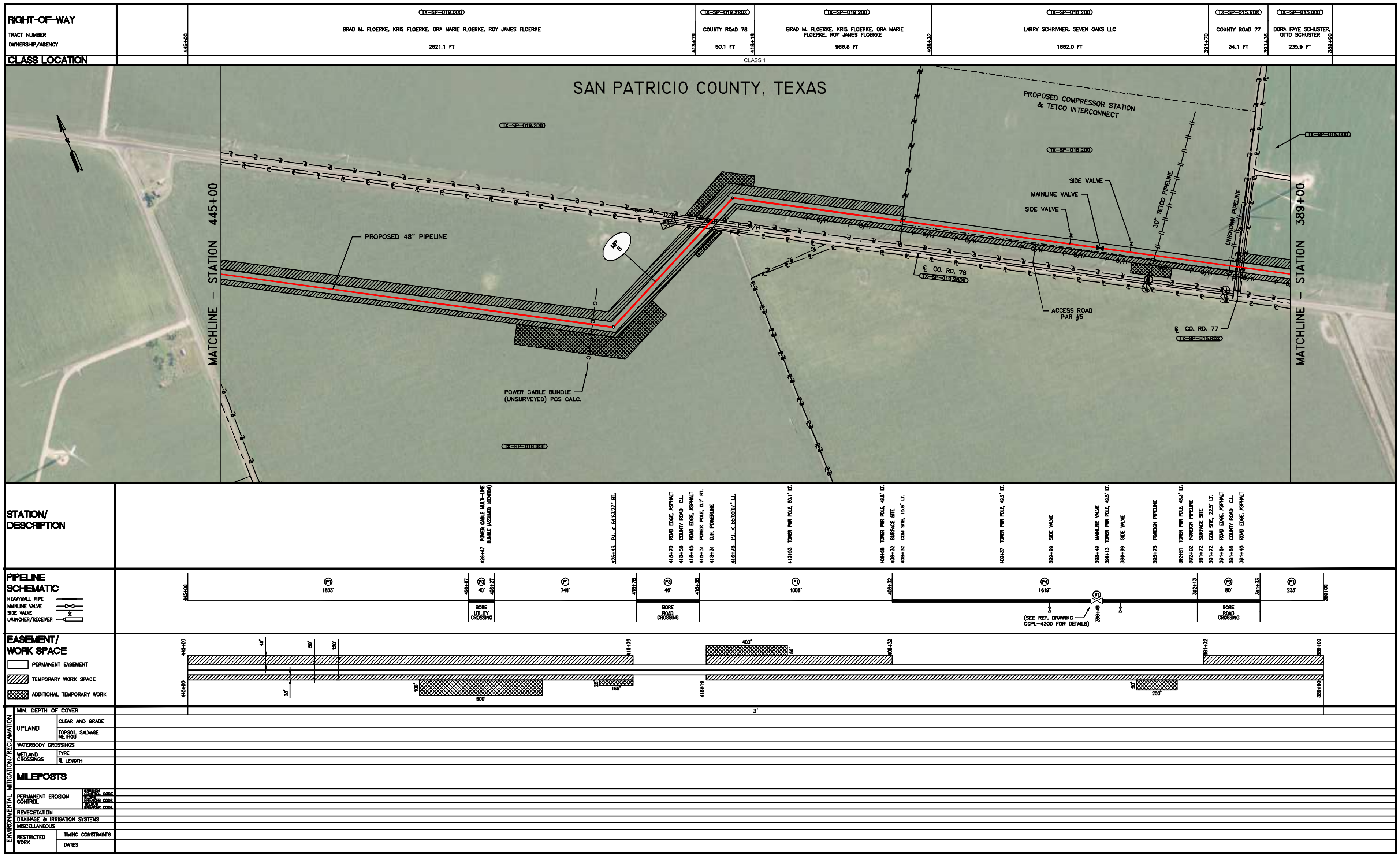
DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 336+00 TO STA. 389+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1107	7 OF 22

07-10-12 12:31 12054_FERC ALIGNMENTS 5 RAM



PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	3821
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	160
			P4	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	1619
			V1	MAINLINE VALVE (SEE REF. DRAWING CCPL-4200 FOR DETAILS)	1

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/18/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 389+00 TO STA. 445+00
FERC ALIGNMENT SHEET

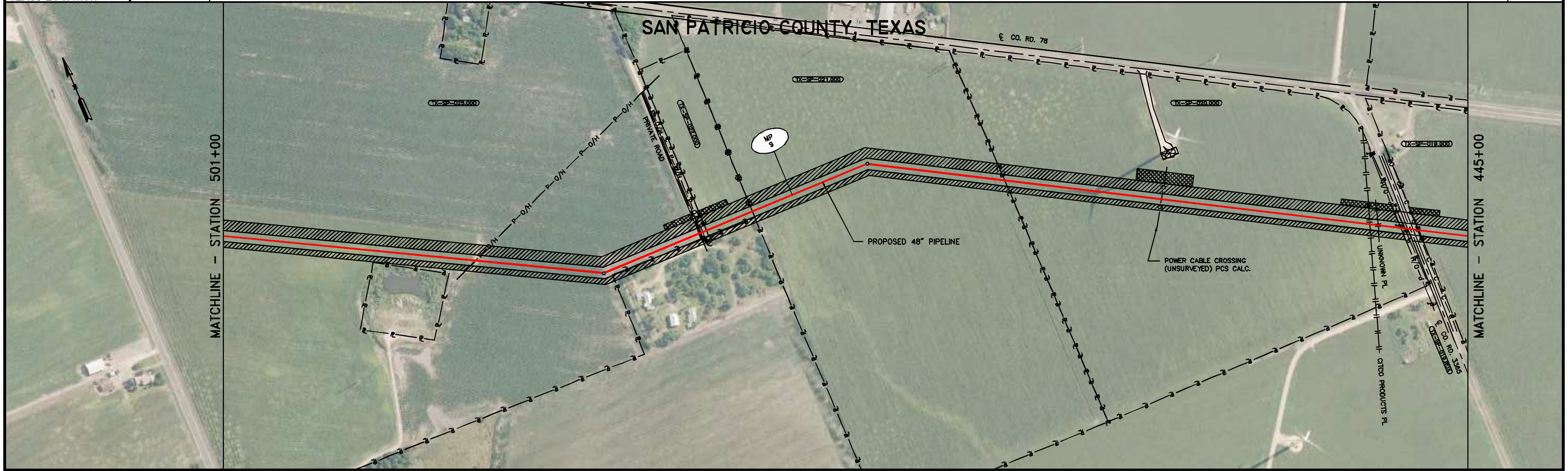
REVISION	DRAWING NUMBER	SHEET
C	CCPL-1108	8 OF 22

07-18-12 15:44 12054_FERC ALIGNMENTS 7 RAM

RIGHT-OF-WAY

TRACT NUMBER / OWNERSHIP/AGENCY	TX-SP-025.000	TX-SP-022.000	TX-SP-021.000	TX-SP-020.000	TX-SP-019.RDX	TX-SP-019.000
	E. C. PUSTEJOVSKY, JANIECE PUSTEJOVSKY, JIM PUSTEJOVSKY, MARGARET PUSTEJOVSKY, MARGIE PUSTEJOVSKY, PAUL PUSTEJOVSKY	THE ESTATE OF RAFAEL AND URSULA GARZA, DECEASED	THE MAX M. FLOERKE FAMILY LIMITED PARTNERSHIP	BRAD M. FLOERKE, KRIS FLOERKE, ORA MARIE FLOERKE, ROY JAMES FLOERKE	COUNTY ROAD 3365	BRAD M. FLOERKE, KRIS FLOERKE, ORA MARIE FLOERKE, ROY JAMES FLOERKE
	2171.4 FT	218.9 FT	1156.2 FT	1772.4 FT	62.4 FT	218.7 FT
	501+00 – 479+28	479+28 – 477+10	477+10 – 465+53	465+53 – 447+81	447+81 – 447+19	447+19 – 445+00

CLASS LOCATION CLASS 1



STATION/ DESCRIPTION

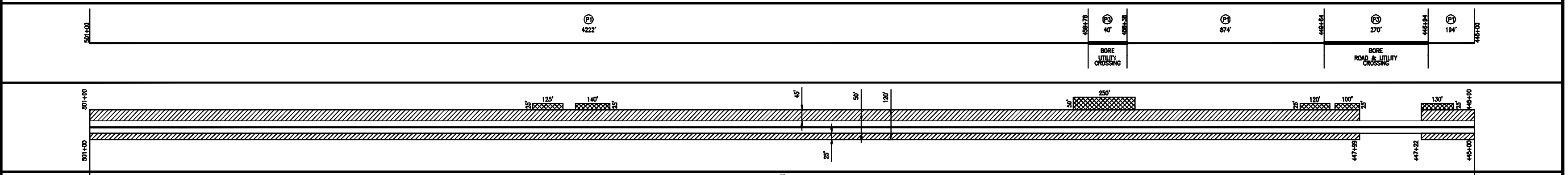
489+93 TOWER PWR POLE, 9.1' LT.
489+86 O.H. POWERLINE
484+17 P.I. < 28°07'24" RT.
479+64 ROAD EDGE, GRAVEL
479+59 PRIVATE ROAD
479+55 ROAD EDGE, GRAVEL
479+48 GUY ANCHOR, 60.9' LT.
479+47 O.H. POWERLINE
479+47 POWER POLE, 39.7' LT.
479+28 GUY ANCHOR, 40.2' LT.
471+63 P.I. < 28°24'27" LT.
458+58 POWER CABLE (ASSUMED LOCATION)
448+35 FOREIGN PIPELINE
448+98 FOREIGN PIPELINE
448+02 POWER POLE, 8.1' RT.
447+98 O.H. POWERLINE
447+67 ROAD EDGE, ASPHALT
447+54 COUNTY ROAD C.L.
447+43 ROAD EDGE, ASPHALT
447+24 CABLE

PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE

☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER 3'

ENVIRONMENTAL MITIGATION/RECLAMATION

UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE

PROPOSED ROUTE 05/2012

INDUCTION BENDS S/N	W.T.	ANGLE	MATERIAL SUMMARY NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5290
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 36 MILS ARO COATING	310

REFERENCE DRAWINGS NO.	DESCRIPTION	DWG. NO.

REVISION NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/18/12
B	CHANGED SCALE TO 1:200	6/29/12
C	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

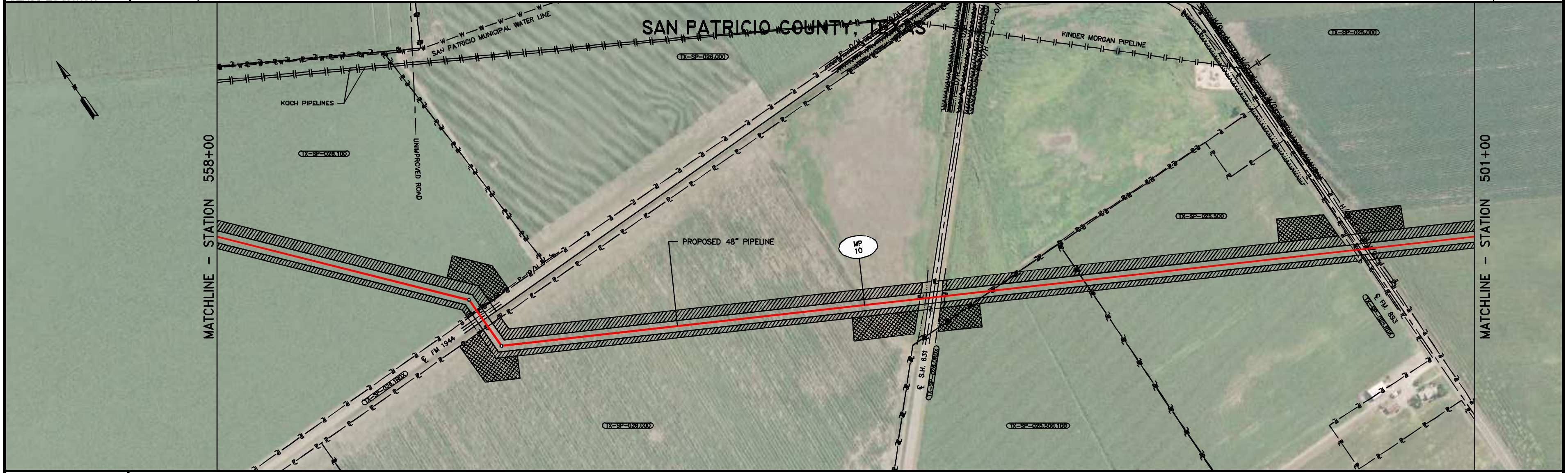
CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 445+00 TO STA. 501+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
C	CCPL-1109	9 OF 22

07-10-12 12:34 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY TRACT NUMBER OWNERSHIP/AGENCY	TX-SP-026.100 THE MAX M. FLOERKE FAMILY LIMITED PARTNERSHIP 1206.8 FT	TX-SP-026.1RDX FM ROAD 1944 79.9 FT	TX-SP-026.000 BETTY ANN PAMPLIN 1957.0 FT	TX-SP-026.0RDX STATE HIGHWAY 631 112.4 FT	TX-SP-026.000 BETTY ANN PAMPLIN 203.0 FT	TX-SP-025.500.100 CORNELIA ANN MOORE PHILLIS 410.6 FT	TX-SP-025.500 MARGIE M. SHELBURNE 1217.8 FT	TX-SP-025.RDX FM ROAD 893 38.6 FT	TX-SP-025.000 E. C. PUSTEJOVSKY, JANIECE PUSTEJOVSKY, JIM PUSTEJOVSKY, MARGARET PUSTEJOVSKY, MARGIE PUSTEJOVSKY, PAUL PUSTEJOVSKY 473.9 FT
Station	558+00 – 545+93	545+93 – 545+13	545+13 – 525+56	525+56 – 524+44	524+44 – 522+41	522+41 – 518+30	518+30 – 506+12	506+12 – 505+74	505+74 – 501+00
CLASS LOCATION	CLASS 1								



STATION/ DESCRIPTION

546+57 P.I. < 40°46'45" LT.
546+01 POWER POLE, 27.4' LT.
546+01 O.H. POWERLINE
545+72 ROAD EDGE, ASPHALT
545+60 FARM TO MARKET C.L.
545+48 ROAD EDGE, ASPHALT
544+08 P.I. < 61°13'54" RT.

525+28 BAR DITCH
525+15 ROAD EDGE, ASPHALT
524+98 STATE HIGHWAY C.L.
524+82 ROAD EDGE, ASPHALT
524+56 BAR DITCH

506+19 ROAD EDGE, ASPHALT
506+02 FARM TO MARKET C.L.
505+85 ROAD EDGE, ASPHALT
505+78 POWER POLE, 38.8' RT.
505+57 O.H. POWERLINE

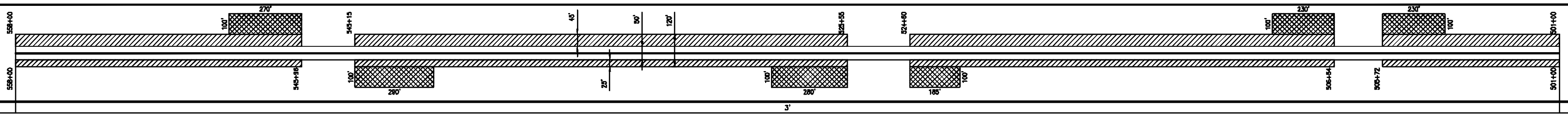
PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

Stations	Pipe	Length	Note
558+00 – 546+03	P1	1197'	
546+03 – 545+03	P3	100'	BORE ROAD CROSSING
545+03 – 525+70	P1	1933'	
525+70 – 524+30	P3	140'	BORE ROAD CROSSING
524+30 – 506+32	P1	1798'	
506+32 – 505+72	P3	60'	BORE ROAD CROSSING
505+72 – 501+00	P1	472'	

EASEMENT/ WORK SPACE

PERMANENT EASEMENT
TEMPORARY WORK SPACE
ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER 3'

ENVIRONMENTAL MITIGATION/RECLAMATION

UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH
MILEPOSTS
PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE

PROPOSED ROUTE 05/2012

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INDUCTION BENDS

S/N	W.T.	ANGLE

MATERIAL SUMMARY

NO.	DESCRIPTION	QTY.
P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5400
P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	300

REFERENCE DRAWINGS

NO.	DESCRIPTION	DWG. NO.

REVISION

NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 501+00 TO STA. 558+00
FERC ALIGNMENT SHEET

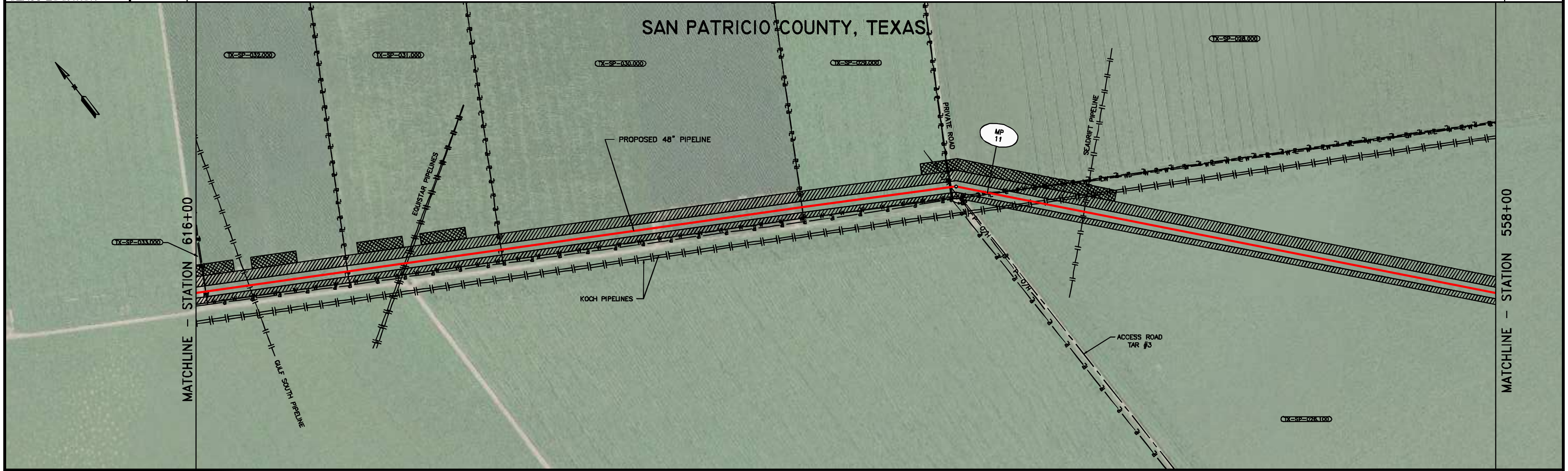
REVISION	DRAWING NUMBER	SHEET
B	CCPL-1110	10 OF 22

07-10-12 12:41 12054_FERC ALIGNMENTS 6 RAM

RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

STATION	TRACT NUMBER	OWNERSHIP/AGENCY	LENGTH
616+00 – 615+55	TX-SP-033.000	JERRY LEA MOORE, NANCY DANIEL SIMMONS, PAXTON HOLT DANIEL, ROBERT SCOTT MOORE	45.2 FT
615+55 – 609+24	TX-SP-032.000	ESTATE OF DONALD FRANK SWANN, KAY P. HART SWANN	630.5 FT
609+24 – 602+43	TX-SP-031.000	ESTATE OF DONALD FRANK SWANN, KAY P. HART SWANN	681.6 FT
602+43 – 589+04	TX-SP-030.000	ESTATE OF DONALD FRANK SWANN, KAY H. SWANN	1338.3 FT
589+04 – 582+49	TX-SP-029.000	DOUGLAS RAY HART, MARILYN C. HART	655.2 FT
582+49 – 580+59	TX-SP-028.000	BETTY JO PYRON	190.5 FT
580+59 – 558+00	TX-SP-026.100	THE MAX M. FLOERKE FAMILY LIMITED PARTNERSHIP	2258.7 FT

CLASS LOCATION CLASS 1

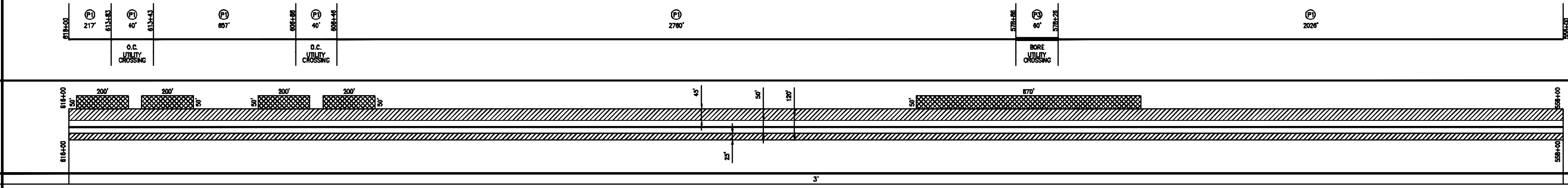


STATION/ DESCRIPTION

613+63 FOREIGN PIPELINE
606+72 FOREIGN PIPELINE
606+60 FOREIGN PIPELINE
582+43 O.H. POWERLINE
582+41 PRIVATE ROAD
582+21 P.I. < 15°45'19" LT.
581+85 GUY ANCHOR, 60.0' LT.
581+78 POWER POLE, 66.9' LT.
581+77 POWER POLE, 65.2' LT.
580+77 WATERLINE
578+71 FOREIGN PIPELINE
578+40 FOREIGN PIPELINE
576+47 FOREIGN PIPELINE

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
PERMANENT EASEMENT
TEMPORARY WORK SPACE
ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION
MIN. DEPTH OF COVER 3'
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH
MILEPOSTS
PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

INDUCTION BENDS S/N	W.T.	ANGLE

MATERIAL SUMMARY

NO.	DESCRIPTION	QTY.
P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5740
P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	60

REFERENCE DRAWINGS

NO.	DESCRIPTION	DWG. NO.

REVISION

NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

Project Consulting Services, Inc.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

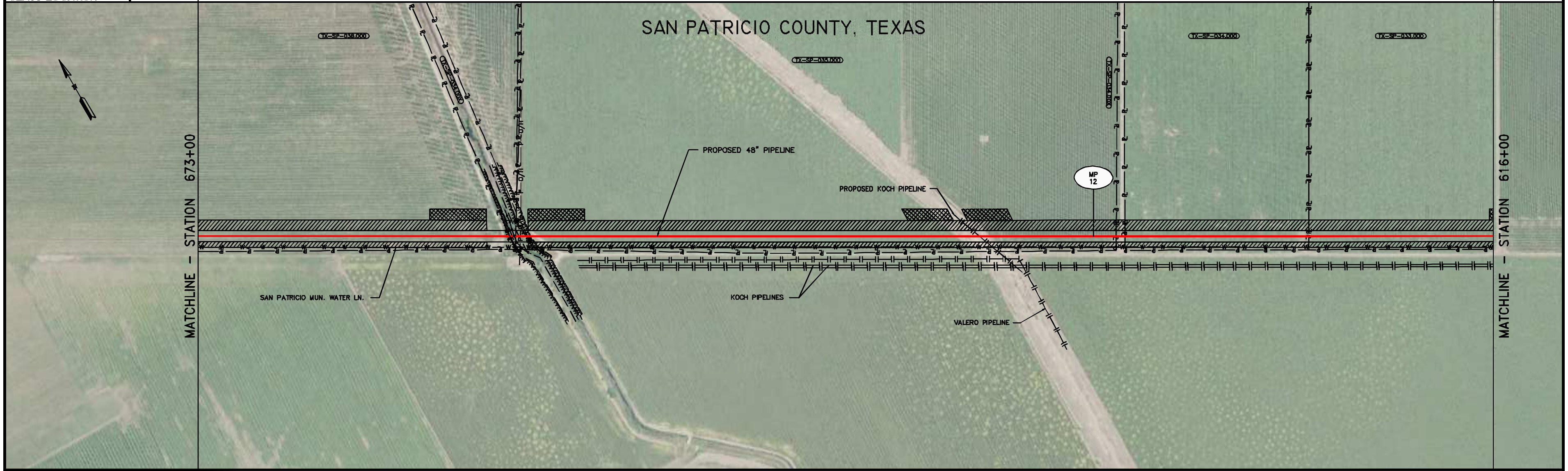
CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 558+00 TO STA. 616+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL–1111	11 OF 22

07–10–12 12:47 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY	673+00		659+28		658+51		632+61		632+23		624+13		616+00
TRACT NUMBER		TX-SP-036.000		TX-SP-034.DDX		TX-SP-035.000		TX-SP-034.DDX		TX-SP-034.000		TX-SP-033.000	
OWNERSHIP/AGENCY		JULIA DRISCOLL, ROBERT DRISCOLL, ROBERT DRISCOLL, JR. FOUNDATION		DRAINAGE DITCH		CHARLES A. BROWN, LINDA D. BROWN		DRAINAGE DITCH		ESTATE OF A. H. MOORE, ESTATE OF G. H. MCCANN, OLA MCCANN, KATHLEEN YOUNG MOORE		JERRY LEA MOORE, NANCY DANIEL SIMMONS, PAXTON HOLT DANIEL, ROBERT SCOTT MOORE	
		1371.6 FT		77.8 FT		2589.8 FT		38.2 FT		809.5 FT		813.1 FT	
CLASS LOCATION		CLASS 1											



STATION/ DESCRIPTION

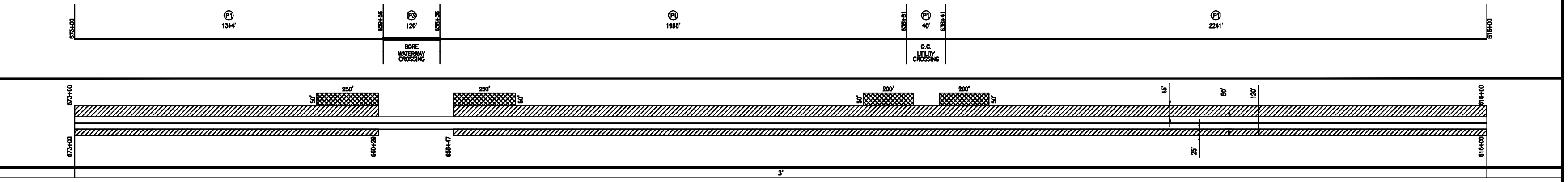
659+41 HIGH BANK
659+27 INT. STREAM
659+17 TOE OF SLOPE
659+08 INT. STREAM
658+88 TOE OF SLOPE
658+82 O.H. POWERLINE
658+64 HIGH BANK
658+50 HIGH BANK
638+61 FOREIGN PIPELINE

PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE

☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION

MIN. DEPTH OF COVER		3'
UPLAND	CLEAR AND GRADE	
	TOPSOIL SALVAGE METHOD	
WATERBODY CROSSINGS		
WETLAND CROSSINGS	TYPE	
	℄ LENGTH	
MILEPOSTS		
PERMANENT EROSION CONTROL	CONTROL CODE	
	SLOPE BREAKER CODE	
	TRENCH BREAKER CODE	
REVEGETATION		
DRAINAGE & IRRIGATION SYSTEMS		
MISCELLANEOUS		
RESTRICTED WORK	TIMING CONSTRAINTS	
	DATES	

PIPELINE

PROPOSED ROUTE
05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5580
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 36 MILS ARO COATING	120

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

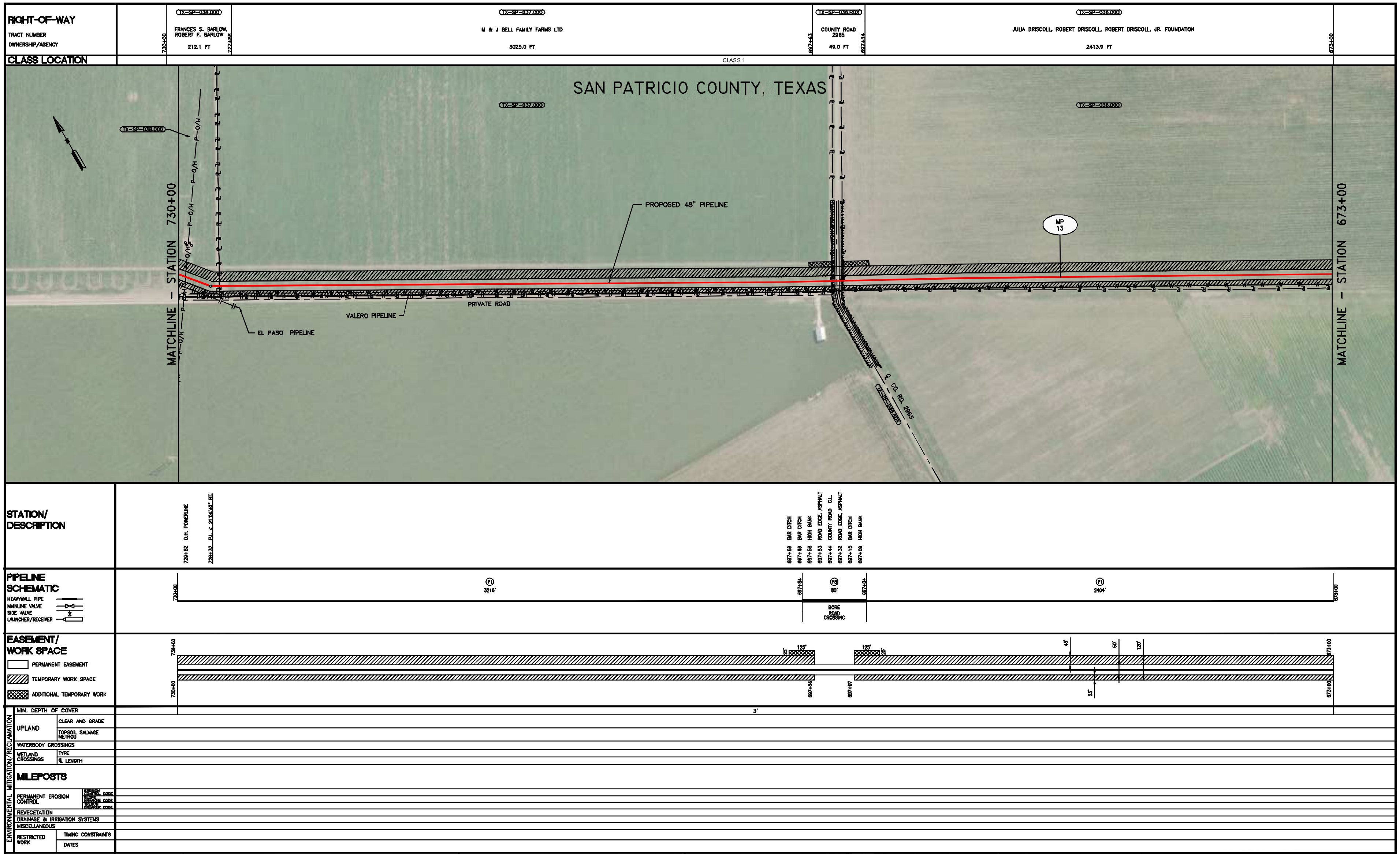
DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 616+00 TO STA. 673+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1112	12 OF 22

07-10-12 12:48 12054_FERC ALIGNMENTS 6 RAM



PIPELINE

PROPOSED ROUTE
05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5620
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	80

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 673+00 TO STA. 730+00
FERC ALIGNMENT SHEET

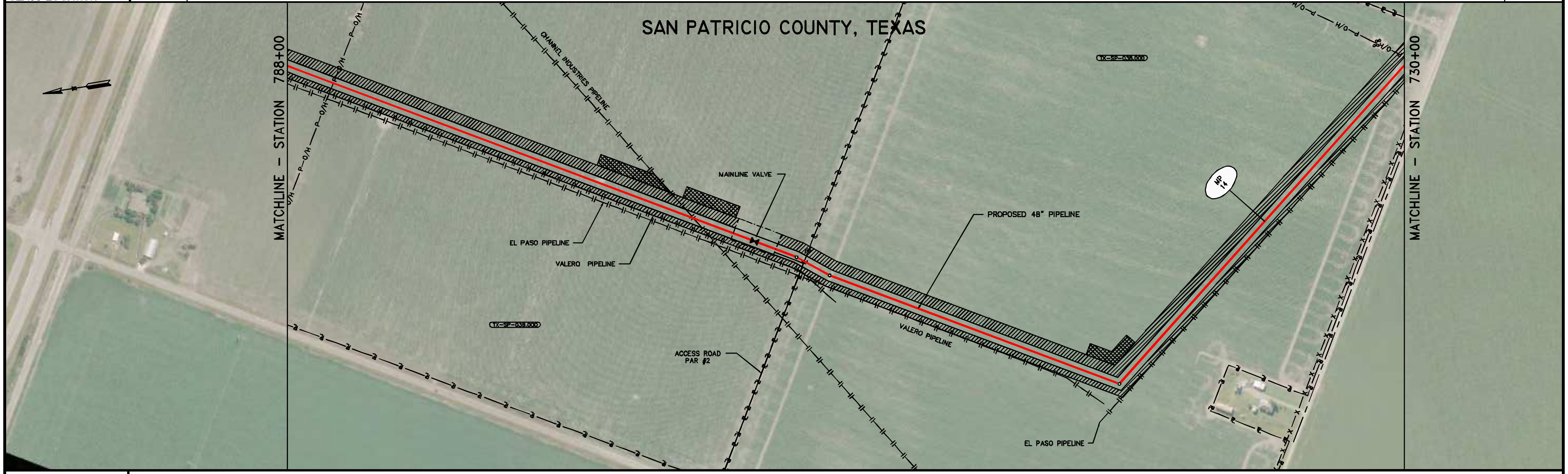
REVISION	DRAWING NUMBER	SHEET
B	CCPL-1113	13 OF 22

07-10-12 12:50 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

788+00 | TX-SP-039.000 JACQUELINE ARNOLD, JOYCE ANN BRONAUGH, LINDA FAY GANT, DAWNA JEAN KUNZE, EDITH LILLIAN SCHMALSTIEG, JOHN H. SCHMALSTIEG 2433.0 FT | 763+67 | TX-SP-038.000 FRANCES S. BARLOW, ROBERT F. BARLOW 3387.0 FT | 730+00

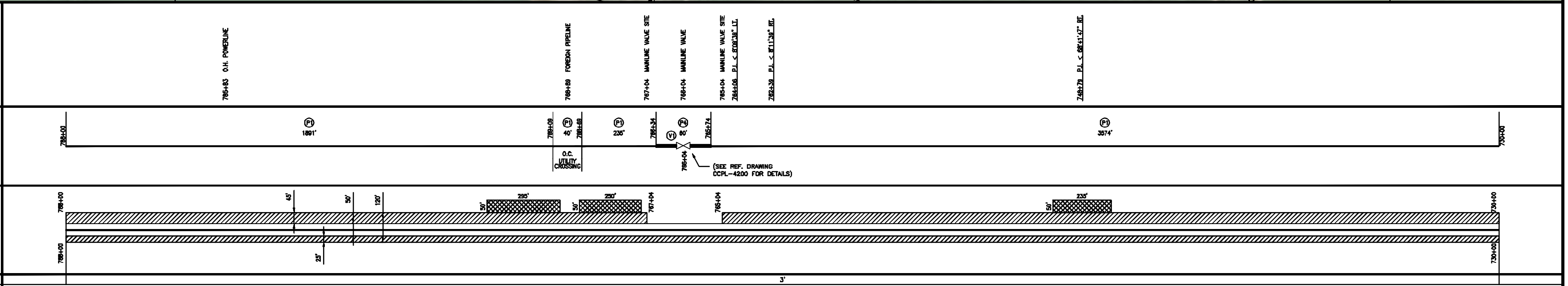
CLASS LOCATION
CLASS 1



STATION/ DESCRIPTION

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

ENVIRONMENTAL MITIGATION/RECLAMATION
PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

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2012 CHENIERE ENERGY

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5740
			P4	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	60
			V1	MAINLINE VALVE (SEE REF. DRAWING CCPL-4200 FOR DETAILS)	1

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 730+00 TO STA. 788+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1114	14 OF 22

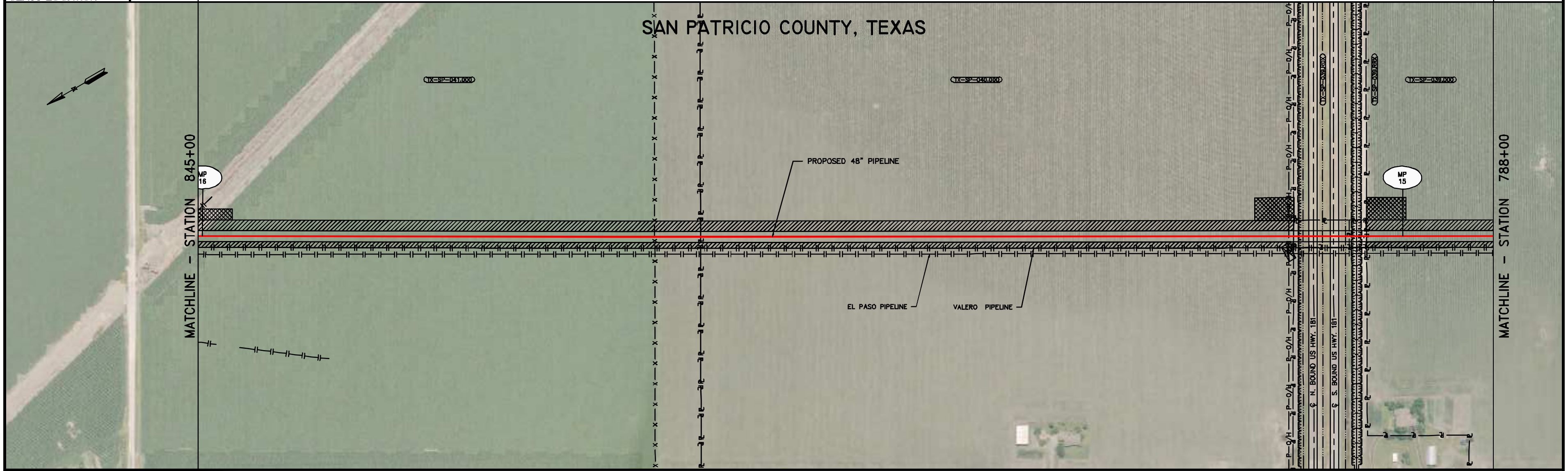
07-10-12 12:52 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

CLASS LOCATION

	845+00 – 822+89	822+89 – 796+80	796+80 – 794+34	794+34 – 793+58	793+58 – 788+00
TRACT NUMBER	TX-SP-041.000	TX-SP-040.000	TX-SP-039.RDX	TX-SP-039.RRX	TX-SP-039.000
OWNERSHIP/AGENCY	APRIL F. MAGNUSON PROTECTION TRUST, NEAL L. FLOERKE, APRIL F. MAGNUSON	MELISSA S. MIRES, LYDIA SCHMALSTIEG	US HIGHWAY 181	UNION PACIFIC RAILROAD	JACQUELINE ARNOLD, JOYCE ANN BRONAUGH, LINDA FAY GANT, DAWNA JEAN KUNZE, EDITH LILLIAN SCHMALSTIEG, JOHN H. SCHMALSTIEG
LENGTH	2211.2 FT	2609.0 FT	245.6 FT	76.1 FT	557.9 FT

CLASS 1

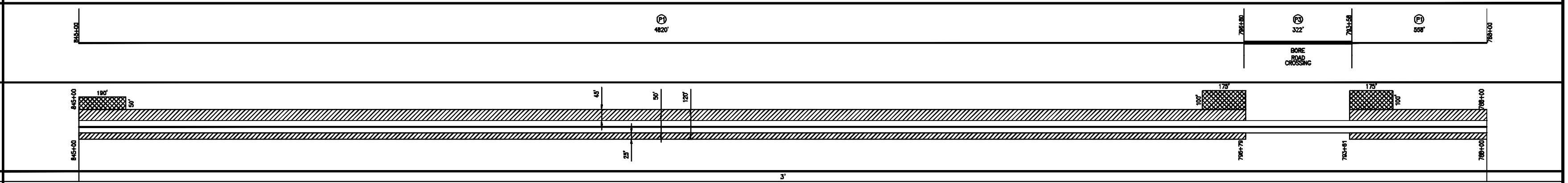


STATION/ DESCRIPTION

824+90	FENCE LINE
797+04	UTILITY POLE, 73.2' LT.
797+01	POWER POLE, 68.8' LT.
797+01	O.H. POWERLINE
796+48	HIGH BANK
796+37	BAR DITCH
796+13	ROAD EDGE, ASPHALT
795+92	U.S. HIGHWAY C.L.
795+76	ROAD EDGE, ASPHALT
795+52	BAR DITCH
795+19	ROAD EDGE, ASPHALT
795+04	U.S. HIGHWAY C.L.
794+82	ROAD EDGE, ASPHALT
794+51	BAR DITCH
794+51	BAR DITCH
794+12	HIGH BANK
794+03	RAILROAD
793+94	HIGH BANK

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
PERMANENT EASEMENT
TEMPORARY WORK SPACE
ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION
MIN. DEPTH OF COVER
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH
MILEPOSTS
PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5378
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 36 MILS ARO COATING	322

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 788+00 TO STA. 845+00
FERC ALIGNMENT SHEET

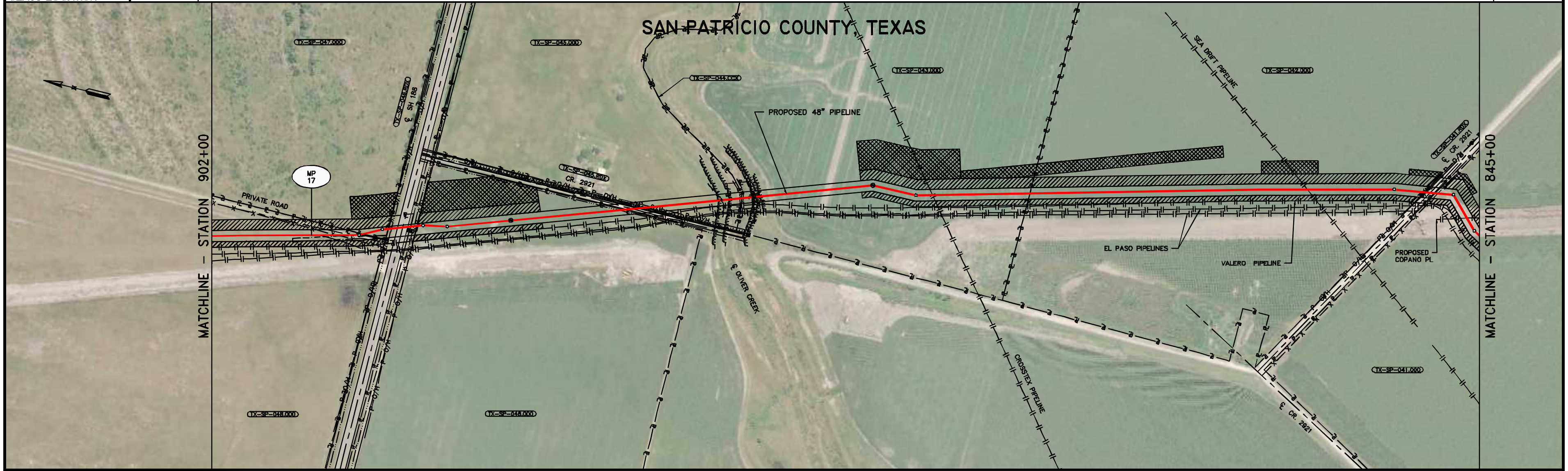
REVISION	DRAWING NUMBER	SHEET
B	CCPL-1115	15 OF 22

07-10-12 12:53 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY

TRACT NUMBER	TX-SP-048.000	TX-SP-047.000	TX-SP-046.RDX	TX-SP-046.000	TX-SP-045.RDX	TX-SP-045.000	TX-SP-044.CCX	TX-SP-043.000	TX-SP-042.000	TX-SP-041.RDX	TX-SP-041.000
OWNERSHIP/AGENCY	MARY DONNA SMOTHERS, RONALD L. SMOTHERS, SR.	ROSEMARY EILEEN HODGES, GARY WILLIAM SCHUBERT	STATE HIGHWAY 188	GAY COPELAND TAYLOR	COUNTY ROAD 2921	ALEXANDRA E. ZAFIRIOU, NIKOLAOS T. ZAFIRIOU	OLIVER CREEK	TIM PYRON	EDWIN TELTSCHIK, NORMAN TELTSCHIK	COUNTY ROAD 2921	APRIL F. MAGNUSON PROTECTION TRUST, NEAL L. FLOERKE, APRIL F. MAGNUSON
	666.4 FT	113.2 FT	98.9 FT	937.3 FT	98.9 FT	369.8 FT	102.7 FT	1231.1 FT	1738.6 FT	45.5 FT	297.6 FT
	902+00 – 895+34	895+34 – 894+20	894+20 – 893+22	893+22 – 883+84	883+84 – 882+85	882+85 – 879+15	879+15 – 878+13	878+13 – 865+82	865+82 – 848+43	848+43 – 847+98	847+98 – 845+00

CLASS LOCATION CLASS 1



STATION/ DESCRIPTION

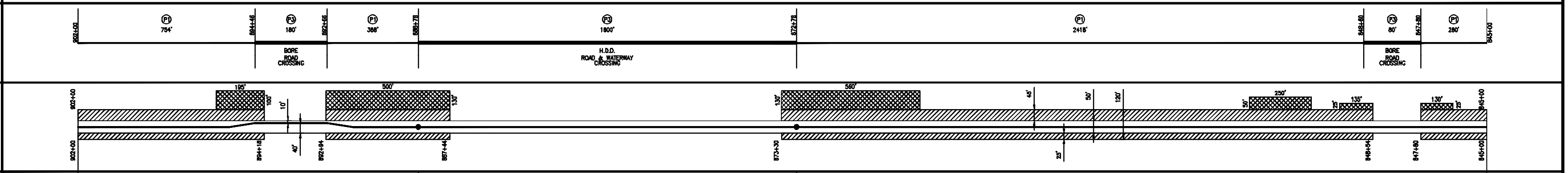
896+51 FENCE LINE BW
895+91 PRIVATE ROAD
895+52 P.I. < 13°24'35" RT.
894+46 P.I. < 8°08'56" LT.
894+20 STATE HIGHWAY ROW
894+20 FENCE LINE BW
894+20 FENCE LINE
894+20 O.H. POWERLINE
894+05 BAR DITCH
893+80 ROAD EDGE, ASPHALT
893+56 STATE HIGHWAY C.L.
893+33 ROAD EDGE, ASPHALT
893+07 BAR DITCH
893+01 POWER POLE, 17.0' LT.
892+94 O.H. POWERLINE
892+92 STATE HIGHWAY ROW
892+66 P.I. < 8°08'56" LT.
891+60 P.I. < 8°08'56" RT.
888+78 HDD ENTRY
884+03 BAR DITCH
883+71 ROAD EDGE, GRAVEL
883+44 COUNTY ROAD C.L.
883+20 ROAD EDGE, GRAVEL
882+94 BAR DITCH
882+75 HIGH BANK
882+57 O.H. POWERLINE
879+52 HIGH BANK
879+47 PERENNIAL STREAM
879+04 HIGH BANK
878+68 TOE OF SLOPE
878+52 TOE OF SLOPE
878+10 PERENNIAL STREAM
878+08 PERENNIAL STREAM
878+01 HIGH BANK
877+97 PERENNIAL STREAM
877+79 HIGH BANK
877+67 HIGH BANK
872+78 P.I. < 18°37'32" LT.
872+78 HDD EXIT
870+83 P.I. < 14°02'52" RT.
870+10 FOREIGN PIPELINE
853+61 FOREIGN PIPELINE
848+79 P.I. < 5°17'28" LT.
848+45 O.H. POWERLINE
848+44 POWER POLE, 1.0' RT.
848+36 ROAD EDGE, GRAVEL
848+20 COUNTY ROAD C.L.
848+03 ROAD EDGE, GRAVEL
847+85 FENCE LINE
847+16 P.I. < 54°57'28" LT.
845+98 FOREIGN PIPELINE
845+34 P.I. < 16°02'07" RT.

PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE

☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER	3'	VARIES	3'

ENVIRONMENTAL MITIGATION/RECLAMATION

UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE

PROPOSED ROUTE 05/2012

INDUCTION BENDS

S/N	W.T.	ANGLE

MATERIAL SUMMARY

NO.	DESCRIPTION	QTY.
P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	3840
P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	1880

REFERENCE DRAWINGS

NO.	DESCRIPTION	DWG. NO.

REVISION

NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 845+00 TO STA. 902+00
FERC ALIGNMENT SHEET

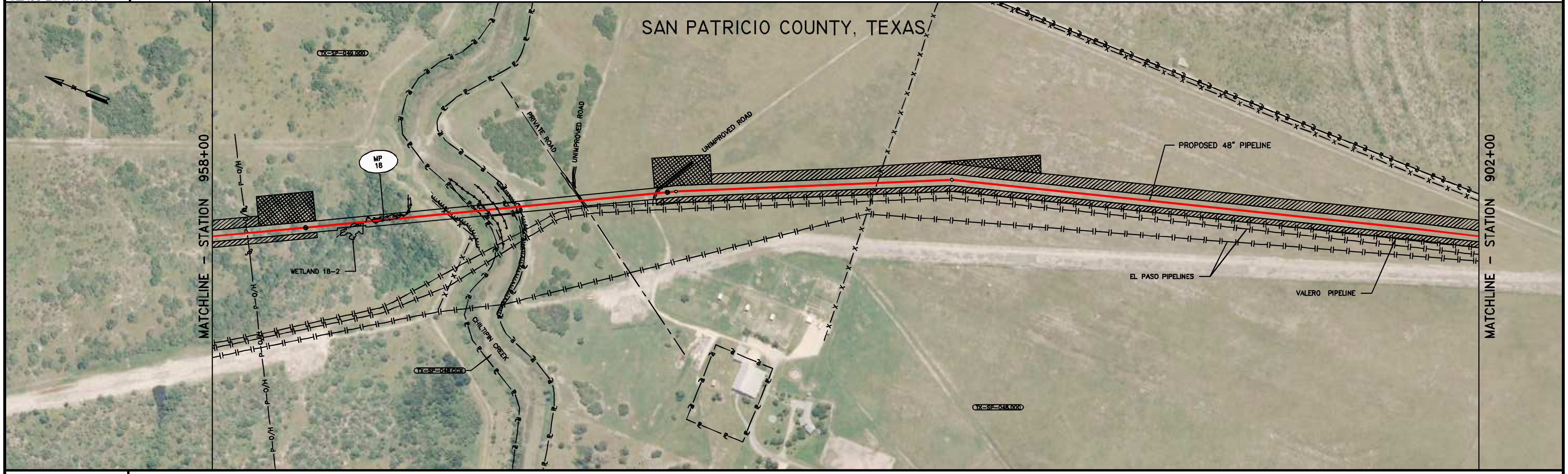
REVISION	DRAWING NUMBER	SHEET
B	CCPL-1116	16 OF 22

07-10-12 12:54 12054_FERC ALIGNMENTS 6 RAM

RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

958+00 – 946+27	TX-SP-049.000	EDWARDS 1976 TRUST "A" 1173.3 FT
946+27 – 944+57	TX-SP-048.CCX	CHILTIPIN CREEK 169.3 FT
944+57 – 902+00	TX-SP-048.000	MARY DONNA SMOTHERS, RONALD L. SMOTHERS, SR. 4257.4 FT

CLASS LOCATION CLASS 1

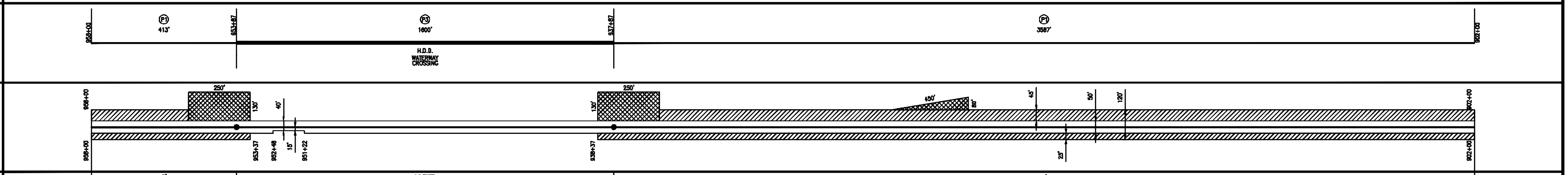


STATION/ DESCRIPTION

956+46	O.H. POWERLINE
956+43	POWER POLE, 85.8' LT.
953+87	HDD ENTRY
951+23	BAR DITCH
951+20	INT. STREAM
950+92	INT. STREAM
950+06	INT. STREAM
947+63	FENCE LINE BW
947+34	HIGH BANK
946+32	TOE OF SLOPE
945+89	PERENNIAL STREAM
945+39	PERENNIAL STREAM
944+82	TOE OF SLOPE
944+49	HIGH BANK
942+01	CULVERT FL, 84.3' RT.
941+87	CULVERT FL, 60.7' RT.
941+73	ROAD EDGE, GRAVEL
941+70	CULVERT FL, 6.7' LT.
941+68	PRIVATE ROAD
941+62	ROAD EDGE, GRAVEL
941+56	CULVERT FL, 4.9' LT.
938+43	ROAD EDGE, GRAVEL
938+38	UNIMPROVED ROAD C.L.
938+31	ROAD EDGE, GRAVEL
938+26	CULVERT FL, 28.7' RT.
938+09	CULVERT FL, 17.5' RT.
937+87	HDD EXIT
937+50	P.I. < 3°08'41" LT.
928+63	FENCE LINE BW
928+63	FENCE LINE BW
925+34	P.I. < 8°27'29" LT.

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER	3'	VARIES	3'

ENVIRONMENTAL MITIGATION/RECLAMATION
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; & LENGTH
MILEPOSTS
PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

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INDUCTION BENDS

S/N	W.T.	ANGLE

MATERIAL SUMMARY

NO.	DESCRIPTION	QTY.
P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	4000
P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	1600

REFERENCE DRAWINGS

NO.	DESCRIPTION	DWG. NO.

REVISION

NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

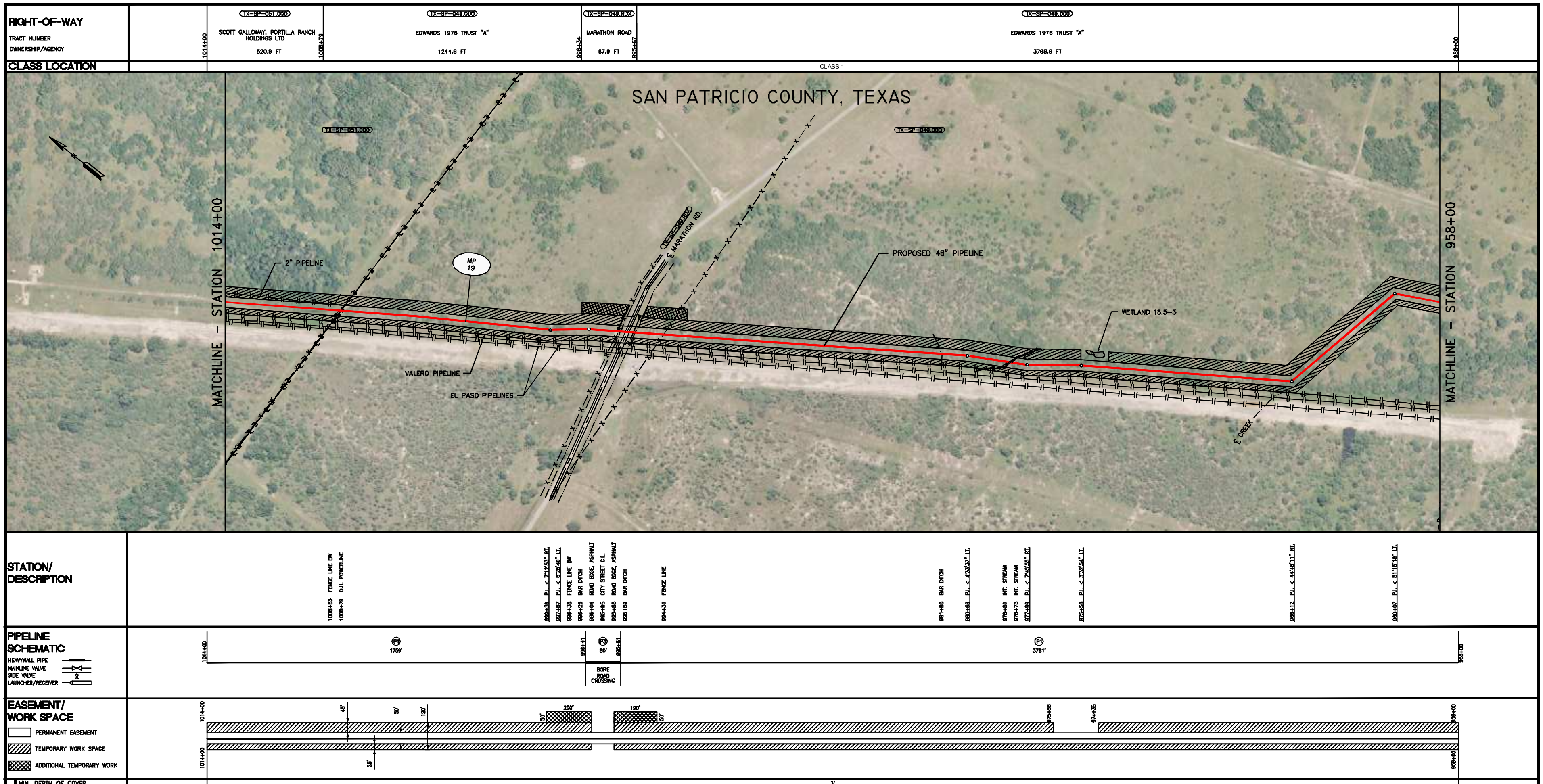
DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 902+00 TO STA. 958+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1117	17 OF 22

07-10-12 12:56 12054_FERC ALIGNMENTS B RAM



ENVIRONMENTAL MITIGATION/RECLAMATION

MIN. DEPTH OF COVER 3'

UPLAND — CLEAR AND GRADE

UPLAND — TOPSOIL SALVAGE METHOD

WATERBODY CROSSINGS

WETLAND CROSSINGS — TYPE

WETLAND CROSSINGS — ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL — EROSION CONTROL CODE

PERMANENT EROSION CONTROL — SLOPE BREAKER CODE

PERMANENT EROSION CONTROL — TRENCH BREAKER CODE

REVEGETATION

DRAINAGE & IRRIGATION SYSTEMS

MISCELLANEOUS

RESTRICTED WORK — TIMING CONSTRAINTS

RESTRICTED WORK — DATES

PIPELINE

PROPOSED ROUTE 05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5520
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	80

REFERENCE DRAWINGS		
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PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
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APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 958+00 TO STA. 1014+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
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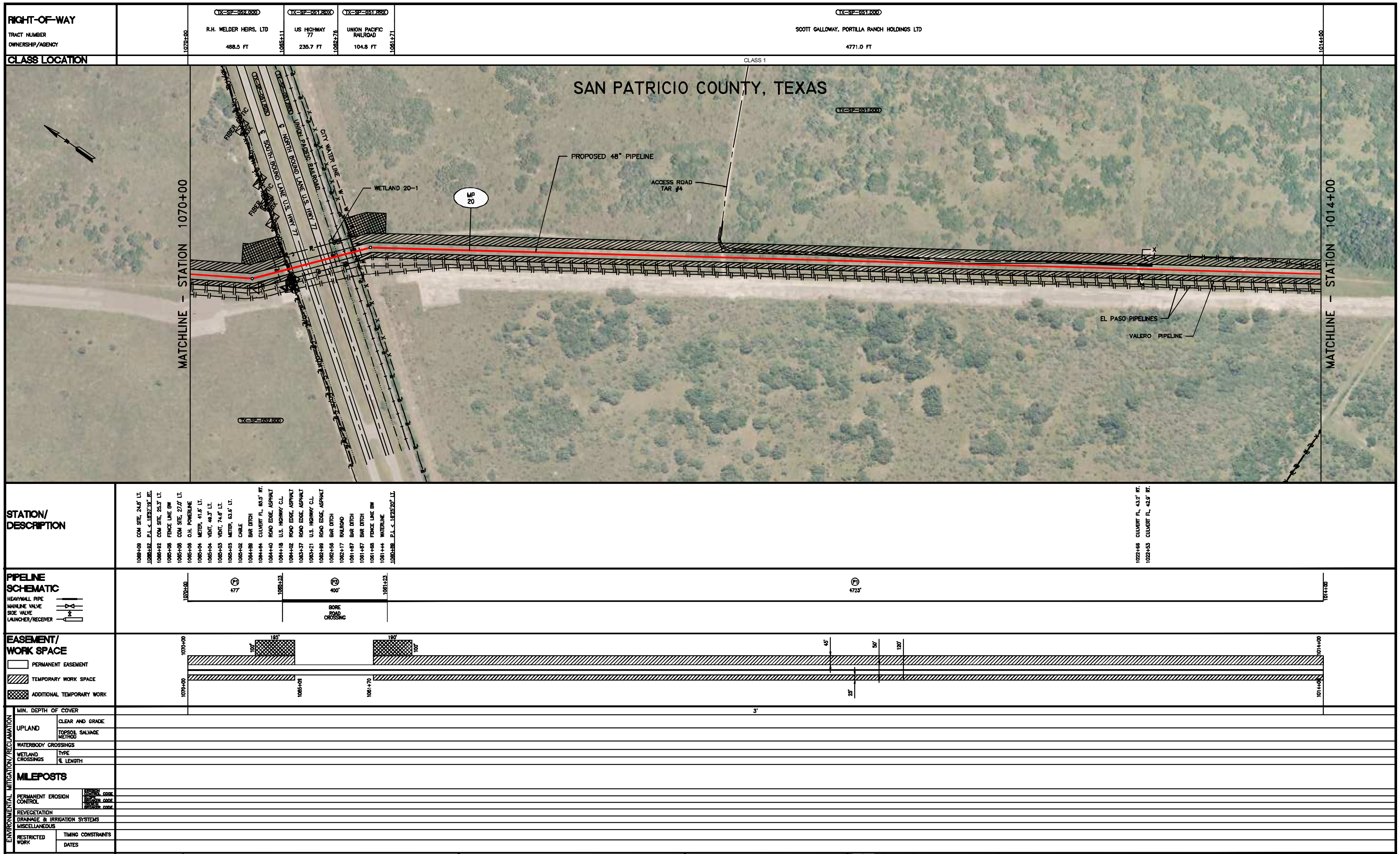

PIPELINE

PROPOSED ROUTE
05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
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			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	400

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

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NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/10/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 1014+00 TO STA. 1070+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1119	19 OF 22

07-10-12 12:58 12054_FERC ALIGNMENTS 6 RAM

RIGHT-OF-WAY

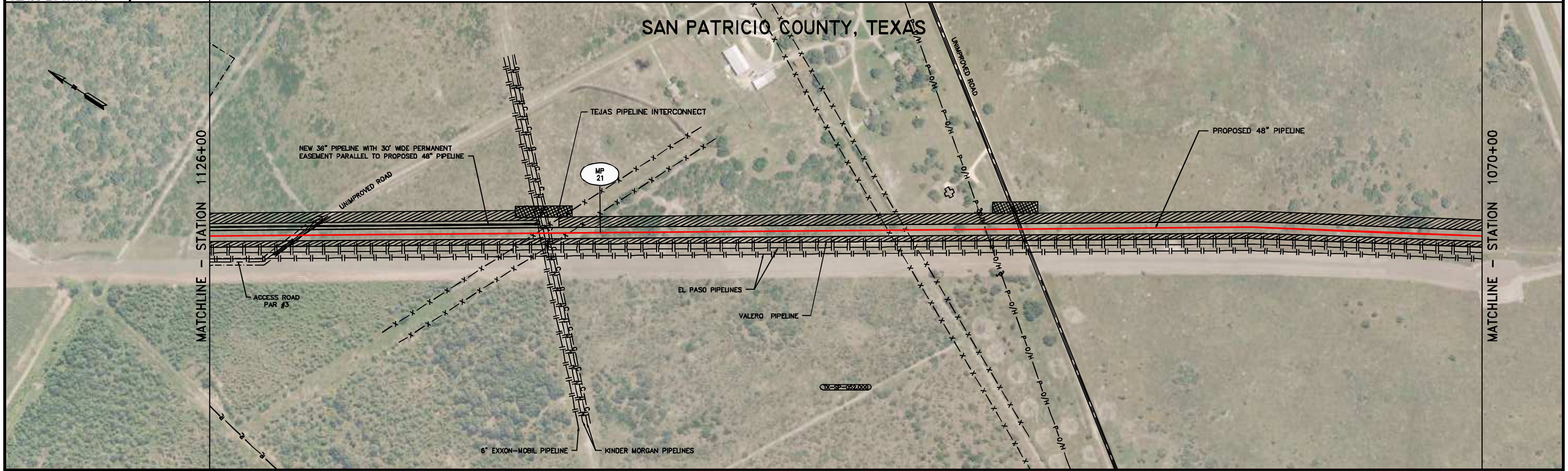
TRACT NUMBER: TX-SP-052.000

OWNERSHIP/AGENCY: R.H. WELDER HEIRS, LTD

5600.0 FT

1126+00 | 1070+00

CLASS LOCATION: CLASS 1



STATION/ DESCRIPTION

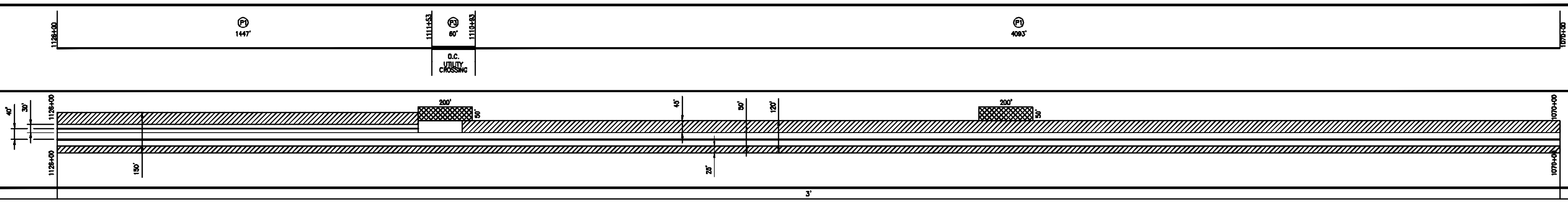
1122+37	ACCESS ROAD EASEMENT
1122+12	ROAD PERMANENT ACCESS C/L
1122+04	ROAD EDGE, DIRT
1121+95	UNIMPROVED ROAD C.L.
1121+87	ACCESS ROAD EASEMENT
1121+86	ROAD EDGE, DIRT
1111+61	FENCE LINE BW
1111+48	FOREIGN PIPELINE
1111+28	FOREIGN PIPELINE
1111+08	FOREIGN PIPELINE
1110+97	CABLE
1110+17	FENCE LINE BW
1096+15	FENCE LINE BW
1095+34	FENCE LINE BW
1092+13	POWER POLE, 80.3' RT.
1091+86	O.H. POWERLINE
1090+36	ROAD EDGE, GRAVEL
1090+30	UNIMPROVED ROAD C.L.
1090+24	ROAD EDGE, GRAVEL
1079+10	COM SITE, 25.1' LT.
1077+05	COM SITE, 25.9' LT.
1075+04	COM SITE, 25.5' LT.
1073+08	COM SITE, 25.3' LT.
1071+05	COM SITE, 25.1' LT.

PIPELINE SCHEMATIC

HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE

☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



ENVIRONMENTAL MITIGATION/RECLAMATION

MIN. DEPTH OF COVER: 3'

UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD

WATERBODY CROSSINGS

WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE

REVEGETATION

DRAINAGE & IRRIGATION SYSTEMS

MISCELLANEOUS

RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE

PROPOSED ROUTE 05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	5540
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	60

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
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PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

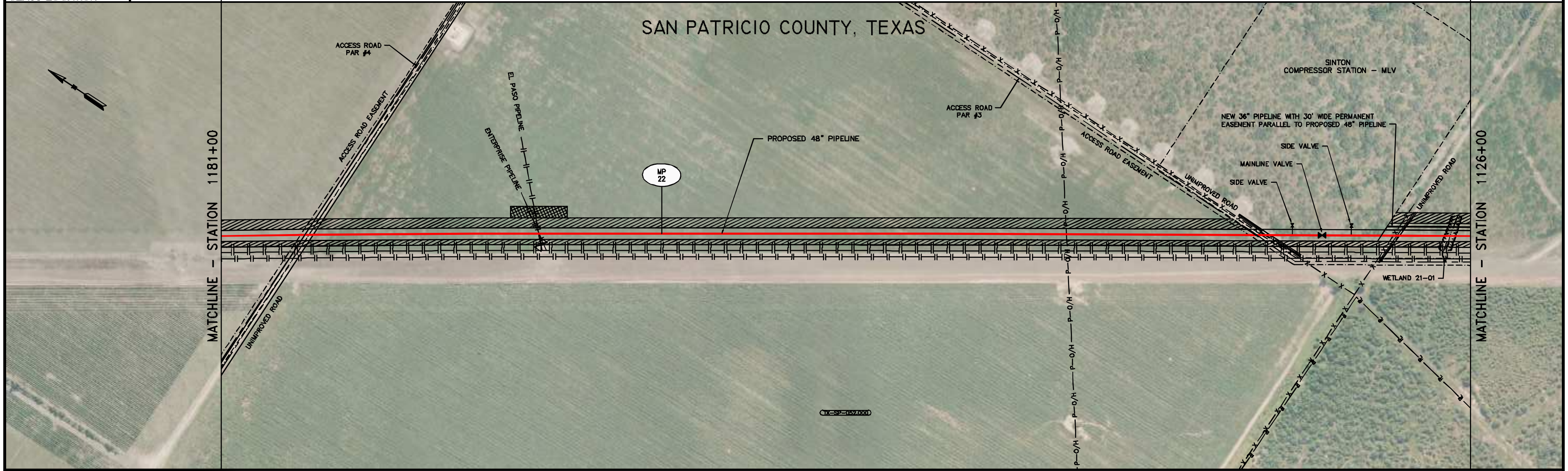
PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 1070+00 TO STA. 1126+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1120	20 OF 22

07-10-12 13:00 12054_FERC ALIGNMENTS 5 RAM

RIGHT-OF-WAY
TRACT NUMBER: TX-SP-052.000
OWNERSHIP/AGENCY: R.H. WELDER HEIRS, LTD
5500.0 FT

CLASS LOCATION: CLASS 1

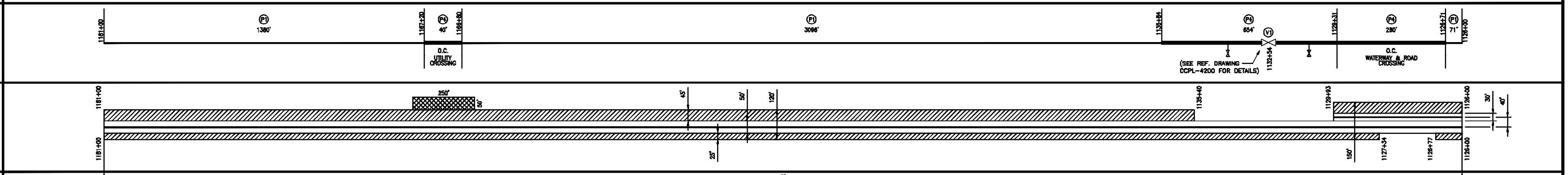


STATION/ DESCRIPTION

1177+50	ACCESS ROAD EASEMENT
1177+32	ROAD EDGE, GRAVEL
1177+32	ROAD PERMANENT ACCESS C/L
1177+13	ACCESS ROAD EASEMENT
1177+12	UNIMPROVED ROAD C.L.
1176+96	ROAD EDGE, GRAVEL
1167+01	FOREIGN PIPELINE
1167+00	FOREIGN PIPELINE
1143+78	O.H. POWERLINE
1135+74	ACCESS ROAD EASEMENT
1135+46	ROAD PERMANENT ACCESS C/L
1135+40	SURFACE SITE
1135+19	ACCESS ROAD EASEMENT
1135+07	FENCE LINE BW
1134+99	ROAD EDGE, DIRT
1134+90	UNIMPROVED ROAD C.L.
1134+80	ROAD EDGE, DIRT
1133+84	SIDE VALVE
1132+54	MAINLINE VALVE
1131+24	SIDE VALVE
1129+93	SURFACE SITE
1129+40	FENCE LINE BW
1129+24	ROAD EDGE, DIRT
1129+18	UNIMPROVED ROAD C.L.
1129+12	ROAD EDGE, DIRT
1127+03	HIGH BANK
1126+91	BAR DITCH
1126+77	HIGH BANK

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
☐ PERMANENT EASEMENT
▨ TEMPORARY WORK SPACE
▩ ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER: 3'

ENVIRONMENTAL MITIGATION/RECLAMATION
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

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INDUCTION BENDS S/N	W.T.	ANGLE	NO.	MATERIAL SUMMARY DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	4546
			P4	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	954
			V1	MAINLINE VALVE (SEE REF. DRAWING CCPL-4200 FOR DETAILS)	1

REFERENCE DRAWINGS NO.	DESCRIPTION	DWG. NO.

REVISION NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
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PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 1126+00 TO STA. 1181+00
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1121	21 OF 22

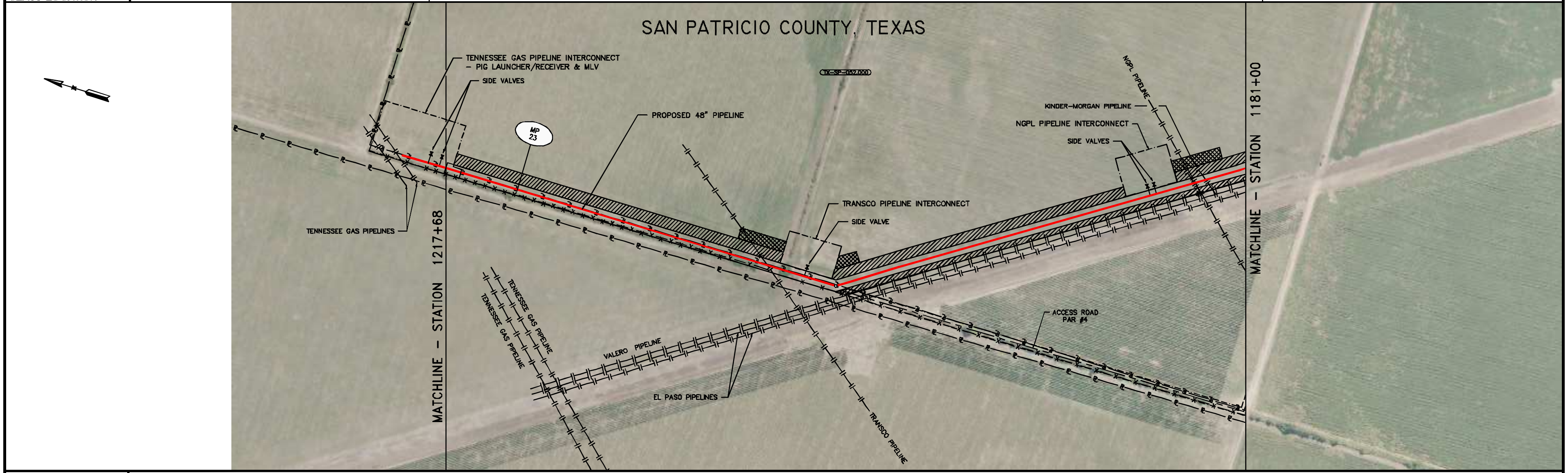
07-10-12 13:02 12054_FERC ALIGNMENTS 7 RAM

RIGHT-OF-WAY
TRACT NUMBER
OWNERSHIP/AGENCY

TX-SP-052.000
R.H. WELDER HEIRS, LTD
3668.4 FT

CLASS LOCATION
CLASS 1

1217+68
1181+00

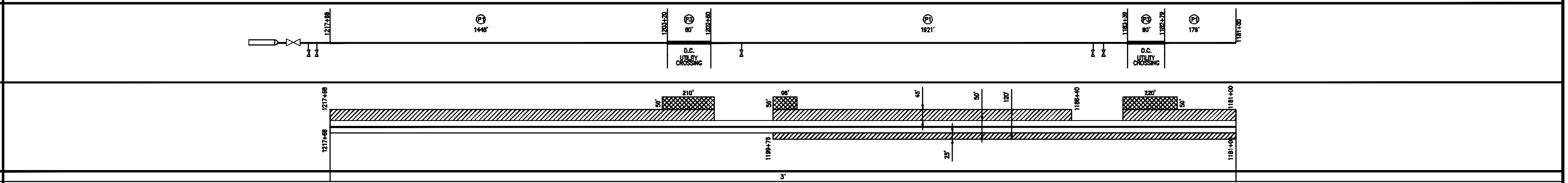


STATION/ DESCRIPTION

1202+90 FOREIGN PIPELINE
1201+20 SIDE VALVE
1199+78 P.I. < 33°18'29" RT.
1185+38 SIDE VALVE
1185+08 SIDE VALVE
1183+35 FOREIGN PIPELINE
1183+30 FOREIGN PIPELINE
1182+83 FOREIGN PIPELINE

PIPELINE SCHEMATIC
HEAVYWALL PIPE
MAINLINE VALVE
SIDE VALVE
LAUNCHER/RECEIVER

EASEMENT/ WORK SPACE
PERMANENT EASEMENT
TEMPORARY WORK SPACE
ADDITIONAL TEMPORARY WORK



MIN. DEPTH OF COVER: 3'

ENVIRONMENTAL MITIGATION/RECLAMATION
UPLAND: CLEAR AND GRADE; TOPSOIL SALVAGE METHOD
WATERBODY CROSSINGS
WETLAND CROSSINGS: TYPE; ℄ LENGTH

MILEPOSTS

PERMANENT EROSION CONTROL: EROSION CONTROL CODE; SLOPE BREAKER CODE; TRENCH BREAKER CODE
REVEGETATION
DRAINAGE & IRRIGATION SYSTEMS
MISCELLANEOUS
RESTRICTED WORK: TIMING CONSTRAINTS; DATES

PIPELINE
PROPOSED ROUTE 05/2012

INDUCTION BENDS			MATERIAL SUMMARY		
S/N	W.T.	ANGLE	NO.	DESCRIPTION	QTY.
			P1	48" O.D. x 0.750" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE COATING	3548
			P3	48" O.D. X 1.000" W.T., API 5L PSL 2, GR. X-70, DSAW W/ 16 MILS NOMINAL FBE & 30 - 35 MILS ARO COATING	120

REFERENCE DRAWINGS		
NO.	DESCRIPTION	DWG. NO.

REVISION		
NO.	DESCRIPTION	DATE
A	ISSUED FOR REVIEW	6/29/12
B	ISSUED FOR PERMITTING	7/18/12

PROJECT CONSULTING SERVICES, INC.

DESIGNED	PCS	DATE	06/12
DRAWN	PCS	SCALE	1"=200'
CHECKED	PCS	APPROVED	
APPROVED	PCS	APPROVED	

CHENIERE
CORPUS CHRISTI PIPELINE, LP

PROPOSED 48" NATURAL GAS PIPELINE
CORPUS CHRISTI PIPELINE PROJECT
STA. 1181+00 TO STA. 1217+68
FERC ALIGNMENT SHEET

REVISION	DRAWING NUMBER	SHEET
B	CCPL-1122	22 OF 22

07-18-12 15:53 12054_FERC ALIGNMENTS 7 RAM

Appendix B

ESSENTIAL FISH HABITAT ASSESSMENT

APPENDIX B

ESSENTIAL FISH HABITAT ASSESSMENT

1.0 INTRODUCTION

In 1976, the Magnuson-Stevens Act (MSA) was passed in order to promote fish conservation and management. The MSA granted the National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NOAA Fisheries) legislative authority for fisheries regulation in the United States within a jurisdictional area located between 3 miles to 200 miles offshore, depending on geographical location. NOAA Fisheries established eight regional fishery management councils, each responsible for the proper management and harvest of finfish and shellfish resources within their respective geographic regions. These fishery management councils have developed Fisheries Management Plans (FMP), which outline measures to ensure the proper management and harvest of the finfish and shellfish within these waters.

Recognizing that many marine fisheries are dependent on nearshore and estuarine environments for at least part of their life cycles, new habitat conservation provisions to the MSA (Public Law [PL] 94-265, as amended in 1996 and PL 104-297, as amended in 1998) were added, along with other goals, to promote more effective habitat management and protection of marine fisheries. The protection of the marine environments important to marine fisheries, referred to as essential fish habitat (EFH), is required in the review of projects conducted under federal permits, licenses, or other authorities that affect or have the potential to affect such habitat. EFH is defined as "those waters and substrate necessary to fish for spawning, breeding, feeding, or growth to maturity" (16 United States Code [U.S.C.] 1802(10)).

Federal agencies that authorize, fund, or undertake activities that may adversely impact EFH must consult with the NOAA Fisheries. Although absolute criteria have not been established for conducting EFH consultations, NOAA Fisheries recommends consolidated EFH consultations with interagency coordination procedures required by other statutes such as the National Environmental Policy Act (NEPA) and Endangered Species Act (ESA), in order to reduce duplication and improve efficiency. Generally, the EFH consultation process includes the following steps:

1) **Notification –** The action agency should clearly state the process being used for EFH consultations (e.g., incorporating EFH consultation into the Environmental Impact Statement (EIS) or Rivers and Harbors Act Section 10 Permit).

2) **EFH Assessment** – The action agency should prepare an EFH Assessment that includes both identification of affected EFH and an assessment of impacts. Specifically, the EFH should include: 1) a description of the proposed action; 2) an analysis of the effects (including cumulative effects) of the proposed action on EFH, the managed fish species, and major prey species; 3) the federal agency's views regarding the effects of the action on EFH; and 4) proposed mitigation, if applicable.

3) **EFH Conservation Recommendations** – After reviewing the EFH Assessment, NOAA Fisheries would provide recommendations to the action agency regarding measures that can be taken by that agency to conserve EFH.

4) **Agency Response** – The action agency must respond to NOAA Fisheries within 30 days of receiving NOAA Fisheries' recommendations to conserve EFH. The action agency may notify NOAA Fisheries that a full response to conservation recommendations will be provided by a specified completion date agreeable to all parties. The response must include a description of measures proposed by the agency for avoiding, mitigating, or offsetting the impact activity on EFH.

CONSULTATION PROCESS

Our[1] consultations with NOAA Fisheries regarding the potential impacts on EFH resulting from construction and operation of the proposed Corpus Christi LNG Project (Project) have been conducted in coordination with our NEPA review.

EFH ASSESSMENT OVERVIEW

A description of the proposed action is provided in section 2.0 of the Project draft EIS. Our analysis of the effects, including cumulative effects, of the proposed action and associated mitigation on EFH, managed fish species, and major prey species, and our views regarding the effects of the proposed action on EFH are provided in the following sections.

Based on our review of the proposed Project, including LNG marine traffic through the La Quinta Channel, and in consultation with NOAA Fisheries, we have identified EFH for various life stages of 14 species (Table 1): juvenile white (*Litopenaeus setiferus*) and brown (*Farfantepenaeus aztecus*) shrimp; larval, post-larval, juvenile, and adult red drum (*Sciaenops ocellatus*); adult gray snapper (*Lutjanus griseus*); post-larval and juvenile Goliath grouper (*Epinephelus itajara*); post-larval and juvenile lane snapper (*Lutjanus synagris*); juvenile yellowmouth grouper (*Mycteroperca interstitialis);* neonate, juvenile, and adult blacktip (*Carcharhinus limbatus*), bull (*Carcharhinus leucas*), Atlantic sharpnose (*Rhizoprionodon terranovae*), and bonnethead sharks (*Sphyrna tiburo*); neonate and juvenile scalloped hammerhead sharks (*Sphyrna lewini*) and lemon sharks (*Negaprion brevirostris*) within Corpus Christi Bay (NOAA Fisheries, 2014; Gulf of Mexico Fishery Management Council [GMFMC], 2004).

In addition to being designated as EFH for a variety of federally managed species, the Project area provides nursery, foraging, and refuge habitats that support various recreationally and economically important marine fishery species such as spotted sea trout, southern flounder, Atlantic croaker, black drum, Gulf menhaden, striped mullet, and blue crab. Such estuarine-dependent species serve as prey for other fisheries managed by GMFMC and highly migratory species managed by NOAA Fisheries (NOAA Fisheries, 2013).

---

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

Table 1.
EFH Present in Project Area
Nueces and San Patricio Counties, Texas

Species	Life Stage				
	Larval	**Post-larval**	**Neonate**	**Juveniles**	**Adults**
Invertebrates					
Brown Shrimp (*Farfantepenaeus aztecus*)			N/A **a**/	X	
White Shrimp (*Litopenaeus setiferus*)			N/A **a**/	X	
Reef Fish/Snapper-Grouper					
Red Drum (*Sciaenops ocellatus*)	X	X	N/A **a**/	X	X
Gray Snapper (*Lutjanus griseus*)			N/A **a**/		X
Lane Snapper (*Lutjanus sunagris*)		X	N/A **a**/	X	
Goliath Grouper (*Epinephelus itajara*)		X	N/A **a**/	X	
Yellowmouth Grouper (*Mycteroperca interstitialis*)			N/A **a**/	X	
Highly Migratory Species					
Bull Shark (*Carcharhinus leucas*)	N/A **b**/	N/A **b**/	X	X	X
Scalloped Hammerhead Shark (*Sphyrna lewini*)	N/A **b**/	N/A **b**/	X	X	
Bonnethead Shark (*Sphyrna tiburo*)	N/A **b**/	N/A **b**/	X	X	X
Blacktip Shark (*Carcharhinus limbatus*)	N/A **b**/	N/A **b**/	X	X	X
Finetooth Shark (*Carcharhinus isodon*)	N/A **b**/	N/A **b**/	X		
Lemon Shark (*Negaprion brevirostris*)	N/A **b**/	N/A **b**/	X	X	
Atlantic Sharpnose Shark (*Rhizoprionodon terraenovae*)	N/A **b**/	N/A **b**/	X	X	X

Source: NOAA Fisheries, 2014; GMFMC, 2004
a/ Species does not have a neonate life stage
b/ Species does not have a larval or post larval life stage

2.0 ESSENTIAL FISH HABITAT

All estuarine systems of the Gulf of Mexico (Gulf) are considered essential habitat for fish species managed by the GMFMC. In 2005 the GMFMC amended seven FMPs in accordance with Subpart J of 50 CFR Part 600. In 2004, the GMFMC completed a Final EIS for the Generic Essential Fish Habitat Amendment addressing all required EFH components included in the amendment to the MSA. The 2005 EFH Amendment delineated EFH as areas of higher species density, based on the NOAA Atlas and functional relationships analysis for the following FMPs: Red Drum, Reef Fish, Coastal Migratory Pelagics, Shrimp, Stone Crab, and Spiny Lobster, and Coral.

The FMPs managed by the GMFMC, include: all estuaries; the U.S. – Mexico border to the boundary between the areas covered by the GMFMC and the South Atlantic Fishery Management Council from estuarine waters out to depths of 100 fathoms. Additionally, sharks are managed through Amendment 1 to the Final Consolidated Highly Mobile Species FMP.

EFH is characterized as occurring within three zones: estuarine (inside barrier islands and estuaries), nearshore (60 feet or less in depth), and offshore (greater than 60 feet in depth). The GMFMC defines 12 standard habitat types, based on a combination of substrate and biogenic structure descriptions, which are present with the Gulf. These 12 standard habitat types include: submerged aquatic vegetation (e.g., seagrasses, benthic algae), mangroves, drifting algae, emergent marshes (e.g., tidal wetlands, salt marshes, tidal creeks, rivers/streams), sand/shell bottoms, soft bottoms (e.g., mud, clay bottoms, silt), hard bottoms (e.g., live hard bottoms, low-relief irregular bottoms, high-relief irregular bottoms), oyster reefs, banks/shoals, reefs (e.g., reef halos, patch reefs, deep reefs), shelf edge/slope, and pelagic (GMFMC, 2004).

All impacts associated with the Project are located within the estuarine zone. Habitat types identified within the Project area include emergent marshes, submerged aquatic vegetation, mangroves, soft bottoms (unvegetated shallow water), and sand/shell bottoms (unvegetated shallow water). In addition to providing EFH, mangroves and vegetated wetlands also provide other essential estuarine support functions, including: providing a physically recognizable structure and substrate for refuge and attachment above and below the sediment surface, binding sediments, preventing erosion, collecting organic and inorganic material by slowing currents, and providing nutrients and detrital matter to the estuary.

A detailed description of these habitats as well as the life history characteristics and habitat preferences of each federally managed species in the Project area is provided below and is based primarily on the research referenced in Cheniere’s application to FERC, both Cheniere’s and our consultation with NOAA Fisheries, and a review of the applicable FMPs, as amended.

3.0 FEDERALLY MANAGED SPECIES WITH EFH IN CORPUS CHRISTI BAY

Corpus Christi Bay is characterized as estuarine and provides habitat to a variety of animal species across several taxa including, birds, reptiles, fish, macro invertebrates, and mammals. Habitat types present within Corpus Christi Bay include, but are not limited to, submerged aquatic vegetation, mangroves, emergent marshes, oyster reefs, sand/shell bottoms, and soft bottoms (Coastal Bend Bays and Estuaries Program, 2012).

The GMFMC final EIS for EFH for the Gulf FMPs (GFMFC, 2004) and the Consolidated Atlantic Highly Migratory Species FMP (NOAA Fisheries, 2010) provide detailed information on life history and relative abundance for species identified as having potential EFH in the Project area. All species with EFH as identified by NOAA Fisheries are considered to be at least classified as “common” in the Project area (NOAA Fisheries, 2014). The habitat types utilized by each of the species for which EFH is present within the Project area are presented in Table 2 and further discussed below.

Table 2
EFH Present in Corpus Christi Bay
Nueces and San Patricio Counties, Texas

Habitat Type	Species	Life Stage
Estuarine Emergent Marsh		
	Gray snapper	Adult
	Red drum	Post larval, juvenile, adult
	Brown shrimp	Juvenile
	White shrimp	Juvenile
Estuarine Mangrove		
	Goliath grouper	Post larval, juvenile
	Lane snapper	Juvenile
	Yellowmouth snapper	Juvenile
Estuarine Sand/Shell Bottom		
	Brown shrimp	Juvenile
	Gray snapper	Adult
	Lane snapper	Juvenile
	Red drum	Post larval, juvenile, adult
Estuarine Mud/Soft Bottom		
	Gray snapper	Adult
	Lane snapper	Juvenile
	Red drum	Larval, juvenile, adult
	Brown shrimp	Juvenile
	White shrimp	Juvenile
Estuarine Submerged Aquatic Vegetation		
	Brown shrimp	Juvenile
	Goliath grouper	Juvenile
	Lane snapper	Post larval, juvenile
	Red drum	Larval, post larval, juvenile, adult

Table 2
EFH Present in Corpus Christi Bay
Nueces and San Patricio Counties, Texas

Habitat Type	Species	Life Stage
Estuarine **a**/		
	Bull shark	Neonate, juvenile, adult
	Scalloped hammerhead shark	Neonate, juvenile
	Bonnethead shark	Neonate, juvenile, adult
	Blacktip shark	Neonate, juvenile, adult
	Finetooth shark	Neonate
	Lemon shark	Neonate, juvenile
	Atlantic sharpnose shark	Neonate, juvenile, adult

Source: NOAA Fisheries, 2014; GMFMC, 2004
a/ Information regarding specific estuarine habitats utilized by highly migratory species (sharks) is not available; therefore, the habitat type is not further refined.

Shrimp Fishery of the Gulf of Mexico

Shrimp species within the Gulf use a variety of habitats as they grow from planktonic larvae to spawning adults. Habitat throughout all life stages range from estuarine to open ocean. Larvae are primarily found in the open ocean. As larvae progress into the post larval life stage, they begin to move into the benthic estuarine habitats. Adult habitat use varies between species and season but typically ranges from nearshore to offshore (GMFMC, 1981). Specific life history and habitat use descriptions for species with EFH in the Project area are provided below.

White Shrimp (*Litopenaeus setiferus*)

White shrimp are found in estuaries and out to depths of approximately 40 meters (m) offshore in the coastal waters extending from Florida to Texas and are most abundant in the central and western Gulf. Non-spawning adult white shrimp inhabit offshore waters in the winter and move inshore in the spring. Spawning generally occurs offshore in water depths of less than 27 m from spring to late fall, peaking during June and July. Eggs are demersal and share the same distribution as spawning adults. Larval white shrimp hatch within 12 hours of spawning and begin to migrate through passes toward estuaries as they develop into post-larvae. Estuarine migration peaks between June and September.

Juvenile white shrimp are most abundant in turbid estuaries along the western coast of the Gulf and, within these estuarine nurseries, reach their greatest densities in marsh edge habitats and in areas with submerged aquatic vegetation. However, juvenile white shrimp are also common in marsh ponds, channels, inner marshes, shallow subtidal areas, and oyster reefs. In non-vegetated areas, post-larvae and juveniles inhabit mostly muddy substrates with large quantities of detritus. Sub-adult white shrimp move from the estuaries to coastal areas in late August and September (GMFMC, 2004).

Brown Shrimp (*Farfantepenaeus aztecus*)

Adult brown shrimp inhabit neritic waters (over the continental shelf from low tide to a depth of approximately 110 m) throughout the Gulf, but are more abundant off the coasts of Texas, Louisiana, and Mississippi. Non-spawning adults prefer turbid waters to soft sediments (e.g., mud and sand). In the spring and fall, adult brown shrimp move to slightly deeper water (46 to 91 m) to spawn. Brown shrimp eggs are demersal and usually hatch when temperatures are greater than 24 degrees Celsius (C). Larval brown shrimp are most abundant offshore but do occur in waters that range from 0 to 82 m deep. Post-larval brown shrimp migrate toward estuaries in the spring, typically reaching their destination between February and April. Late post-larval and juvenile brown shrimp are most abundant in shallow (less than 1 m) estuarine habitats in the spring and early summer but typically are present through the fall.

Juvenile brown shrimp reach their greatest abundances in turbid estuaries but tolerate waters with less suspended material. Within the estuarine environment, juvenile brown shrimp prefer marsh edges and areas with submerged vegetation, but occur throughout the vegetated and non-vegetated portions of the estuary and in the lower reaches of its tributaries. Sub-adults are most abundant in slightly deeper waters from 1 to 18 m and prefer sand, mud, and shell substrates to the vegetated bottoms preferred by juveniles. As they develop, sub-adult brown shrimp continue to migrate toward deeper waters, eventually leaving the estuarine nurseries in mid-summer.

Red Drum Fishery of the Gulf of Mexico

Red Drum (*Sciaenops ocellatus*)

Red drum occur in a variety of habitats over different substrates throughout the Gulf. Habitats range in depth from about 40 m offshore to very shallow in estuarine wetlands with substrates that include sand, mud, and oyster reefs. Adult red drum are roving predators that opportunistically feed on a variety of invertebrate and vertebrate prey including crab, shrimp, and other fishes. Spawning occurs from September through November over deeper waters protected from currents such as the mouths of bays and inlets, and on the Gulf side of barrier islands. Eggs typically hatch between late summer and early fall in the open waters of the Gulf and are subsequently transported on tides and currents into estuarine nursery areas.

Larval red drum are most abundant in estuaries from mid-August through late November. Within these estuarine nurseries, larvae, post-larvae, and juveniles prefer habitats protected from currents with submerged and emergent vegetation and muddy substrates, but also tolerate non-vegetated hard and soft-bottomed areas. Larval and post-larval red drum feed primarily on copepods whereas juveniles feed on a wide variety of small invertebrates. Juvenile red drum become most abundant in early winter. Much like the adult red drum, late juveniles utilize a wide variety of habitats. However, they still prefer protected waters and do not become abundant in open waters until mid-September to early October. Estuarine wetlands are very important to larval and juvenile red drum and while adult red drum use estuaries they tend to spend more time offshore as they age (GMFMC, 2004).

Reef Fishery of the Gulf of Mexico

Estuarine dependent and nearshore reef fish and snapper-grouper species utilize areas inshore of the 100-foot contour, such as attached macroalgae; submerged rooted vascular plants (seagrasses); estuarine emergent vegetated wetlands (salt marshes, brackish marsh); tidal creeks; estuarine scrub/shrub (mangrove fringe); oyster reefs and shell banks; unconsolidated bottom (soft sediments); artificial and coral reefs; and live/hard bottom for all life stages. Snappers are common in all warm marine waters. Most are inshore dwellers although some occur in open-water. Some species enter estuaries and mangroves, with the latter functioning as nursery grounds. The serranids (grouper) are primarily carnivorous bottom dwellers, associated (as adults) with hard-bottomed substrates and rocky reefs (GMFMC, 2004). Specific life history and habitat use descriptions for species with EFH in the Project area are provided below.

Gray Snapper (*Lutjanus griseus*)

Gray snapper range from North Carolina to Brazil, including Bermuda, the Caribbean, and northern Gulf (GMFMC, 1998). Juveniles can occasionally be found as far north as Massachusetts (Manooch, 1988). Gray snapper are capable of inhabiting a wide variety of habitats. Offshore benthic habitats include shipwrecks, ledges, hard bottom, coral reefs, and rocky outcroppings to depths of 180 m, while inshore habitats consist of seagrasses, mangroves, and rock piles (Bortone and Williams, 1986; Manooch, 1988; Florida Museum, 2013). Smaller, younger fish are typically found utilizing more inshore habitats, such as seagrass beds and areas of soft sediments, compared to larger, older adults (Manooch, 1988; Florida Museum, 2013). Adults and juveniles are euryhaline and can tolerate a salinity range from 0 to 37 practical salinity units and have even been recorded in freshwater lakes and rivers of southern Florida (GMFMC, 1998; 2004; Florida Museum, 2013). They are also found utilizing waters with temperatures between 13 and 32.5 degrees C (Bortone and Williams, 1986). Eggs and larvae are pelagic until larvae settle at inshore nurseries consisting of seagrass beds, mangroves, jetties, or pilings, approximately three weeks after hatching, typically from July through September (Bortone and Williams, 1986; Domeier et al., 1996; GMFMC, 1998; 2004; Florida Museum, 2013).

This species does not exhibit extensive movements and remains in the same area for extended periods of time, except during spawning season (GMFMC, 1998; Florida Museum 2013). Gray snapper do demonstrate daily movement associated with feeding and schooling. Gray snapper migrate from inshore waters to offshore waters to spawn between April and November, with spawning correlated with lunar cycles (Manooch, 1988; Domeier et al., 1996; Florida Museum, 2013). Spawning locations have not been identified but are believed to be associated with reefs and shipwrecks (Domeier et al., 1996). Individuals are capable of spawning multiple times during a season (Florida Museum, 2013). This species is an opportunistic predator. Crustaceans are a primary component of the adult gray snapper's diet (Starck and Schroeder, 1971). Adult gray snapper prey nocturnally on fish, shrimp, and crab (Manooch, 1988; Florida Museum, 2013).

Lane Snapper (*Lutjanus synagris*)

Lane snapper are distributed from North Carolina to southern Brazil, including the Gulf and the Caribbean Sea. Lane snapper are abundant in the Antilles, off Panama, and the northern coast of South America (Florida Museum, 2013). These fish prefer clear nearshore water over rocky bottoms near coral reefs and in sandy areas or seagrass with abundant shrimp. Juveniles use inshore waters as nurseries. Lane snapper occur up to 400 m deep (Florida Museum, 2013). Lane snapper spawn from March to September throughout their range, and both sexes are able to spawn after the first year (GMFMC, 2004). Lane snapper are opportunistic predators feeding on a variety of prey, such as small bottom fishes as well as shrimp, crabs, and cephalopods (Florida Museum, 2013).

Goliath Grouper (*Epinephelus itajara*)

Goliath grouper are distributed from Florida to Brazil, including Bermuda, Caribbean Sea, and Gulf (Florida Museum, 2013). They are most abundant off eastern Florida south to the Florida Keys (GMFMC, 1998; 2004). This species is also found in the eastern Atlantic from Senegal to Congo, Africa and in the eastern Pacific from the Gulf of California to Peru (Florida Museum, 2013). Rocks, corals, caves, shipwrecks, ledges, and muddy substrates, in waters with depths less than 46 m, are the preferred habitat of territorial adults, while juveniles are found in estuarine areas associated with mangroves and oyster bars (Sadovy and Eklund, 1999; Florida Museum, 2013). Eggs and larvae are pelagic with larvae becoming benthic approximately 25 days after hatching (Florida Museum, 2013). Spawning events occur around shipwrecks, rock ledges, and reefs from July through September and are correlated with lunar events. Spawning aggregations containing over 100 goliath groupers have been observed with all recorded aggregations (except Bermuda) occurring between 15 degrees north and 26 degrees north latitudes (Sadovy and Eklund, 1999; Florida Museum, 2013). These aggregations primarily consist of the largest and oldest individuals of the population (Coleman et al., 2000). Goliath grouper are considered sedentary and typically do not move among reefs, except to form aggregations (Sadovy and Eklund, 1999). Goliath groupers are opportunistic feeders that prey mainly on crustaceans (spiny lobsters, shrimp, and crabs) and fishes (stingrays and parrotfishes), but also consume cephalopods and young sea turtles (Florida Museum, 2013).

Yellowmouth Grouper (*Mycteroperca interstitialis*)

Yellowmouth grouper are native to the western Atlantic from Florida to southern Brazil, including the Gulf, Florida Keys, Bahamas, Cuba, and throughout the Caribbean Sea (IUCN, 2013). In the Gulf, yellowmouth grouper occur off of the Campeche Banks, the west coast of Florida, Texas Flower Garden Banks, and the northwest coast of Cuba (GMFMC, 2004). Yellowmouth grouper prefer rocky and coral bottoms from shoreline to at least 55 m deep. Smaller yellowmouth grouper are common in mangrove areas (IUCN, 2013). Little information is available on yellowmouth grouper life history, however, yellowmouth grouper are pelagic spawners and sex-reversal is possible for this species (IUCN, 2013). Spawning occurs primarily in spring and summer, with peaks in April and May off the west coast of Florida (GMFMC, 2004). Juveniles commonly occur in mangrove-lined lagoons and move into deeper water as they grow (GMFMC, 2004). Yellowmouth grouper feed primarily on other fishes (IUCN, 2013).

Atlantic Highly Migratory Species

Highly migratory species (sharks) may utilize a variety of coastal and ocean habitats. Shark habitat can be described in four broad categories: coastal, pelagic, coastal-pelagic, and deep-dwelling. Coastal species inhabit estuaries, nearshore areas, continental slope, and continental shelf. Bull, scalloped hammerhead, bonnethead, blacktip, finetooth, lemon, and Atlantic sharpnose sharks are all considered coastal sharks (NOAA Fisheries, 2009; 1999). Adult sharks are broadly distributed as adults, but often utilize estuaries as pupping and nursery areas during pupping season and through their neonate and young-of-the-year life stages.

Specific life history and habitat use descriptions for species with EFH in the Project area are provided below.

Bull Shark (*Carcharhinus leucas*)

The bull shark is managed under the Large Coastal Shark MU through the Final Atlantic Consolidated FMP for Highly Migratory Species (NOAA Fisheries, 2006). Bull sharks are a circumglobal species and in the Atlantic are distributed from Massachusetts to Florida, including the Gulf. The bull shark is considered most common off southern Florida and within the Gulf (Castro, 1983; Compagno, 1984b). This shallow-water species is common in both tropical and subtropical regions and in marine, estuarine, and freshwater habitats and can journey long distances up large rivers (NOAA Fisheries, 1999). The bull shark typically occupies shallow coastal waters less than 30 m deep, but has been observed at depths of 152m. Adults occupy deeper waters than juveniles. Bull sharks typically stay near the bottom, rarely utilizing surface waters (Compagno, 1984b). Bull shark nurseries have been recorded in low salinity estuaries extending from North Carolina to the Gulf (McCandless et al., 2002). Bull sharks migrate north as far as Massachusetts, along the coast during the summer and then return south as waters cool (Compagno, 1984b). Mating occurs in late spring or early summer (June or July), with birth to live young occurring in estuaries and river mouths the following year, from April to June (Compagno, 1984b; Castro, 1983). Bull sharks are opportunistic feeders that prey on a wide variety of bony fishes, shark species, and invertebrates. Additionally, stomach contents have revealed that this species also consumes sea turtles, sea birds, and marine mammals (Compagno, 1984b).

NOAA Fisheries (2009) has designated EFH for neonates, juveniles, and adult bull sharks within the Project area. Neonate bull shark EFH is designated as shallow coastal waters, including inlets and estuaries in the Gulf between Texas and the west coast of Florida, with localized areas off of Mississippi and the Florida Panhandle. The mid-east coast of Florida to South Carolina is also EFH for bull sharks (NOAA Fisheries, 2009). Juvenile bull shark EFH is designated as shallow coastal waters, inlets, and estuaries in waters less than 25 m off western Florida in the Gulf from Texas through the Florida Keys (NOAA Fisheries, 2009). Adult bull shark EFH is in western Florida through the Florida Keys as well as the Texas coast and eastern Louisiana.

Scalloped Hammerhead Shark (*Sphyrna lewini*)

The scalloped hammerhead shark is managed under the Large Coastal Shark MU through the Final Consolidated Atlantic Highly Migratory Species FMP (NOAA Fisheries, 2006). Scalloped hammerhead sharks are found in warm-temperate to tropical waters worldwide over the continental shelf and slope. In the Atlantic, the scalloped hammerhead shark ranges from New Jersey to Brazil, including the Gulf and the Caribbean Sea (Florida Museum, 2013). This species inhabits waters from the surface to depths of 275 m and is found close to shore, in bays and estuaries, preferring water temperatures of at least 22 degrees C (Castro, 1983; Compagno, 1984a). Typically, scalloped hammerhead sharks spend the day close to shore and move to deeper waters at night to feed (Florida Museum, 2013). Scalloped hammerhead sharks birth once a year in the summer starting around June in shallow coastal nurseries found from Virginia to the Gulf (Castro, 1993; McCandless et al., 2002). This species forms large schools when it migrates seasonally north to south along the eastern U.S. coast (NOAA Fisheries, 1999).

Scalloped hammerhead sharks consume a wide variety of fishes, as well as invertebrates, and have been reported feeding only at night (Compagno, 1984a).

NOAA Fisheries (2009) has designated EFH for neonate and juvenile scalloped hammerhead sharks within the Project area. Neonate and juvenile scalloped hammerhead shark EFH is designated as shallow coastal areas such as bays and estuaries out to a 25 m isobath in the Gulf from Texas to the southern west coast of Florida (NOAA Fisheries, 2009).

Bonnethead Shark (*Sphyrna tiburo*)

The bonnethead shark is managed under the Small Coastal Shark Management Unit through the Final Atlantic Consolidated Highly Migratory Species FMP (NOAA Fisheries, 2006). The bonnethead shark is limited to warm waters in the Atlantic Ocean ranging from coastal southern New England south to the Gulf and Brazil, and is most common in the Caribbean Sea, including Cuba and the Bahamas. In the Pacific Ocean, the bonnethead shark ranges from southern California to Ecuador (Castro, 1983). Bonnethead sharks inhabit shallow coastal waters where they are typically associated with sandy or muddy substrates (Castro et al., 1999). This species inhabits continental and insular shelves, over reefs, estuaries, seagrass beds, and shallow bays from depths of 10 m to 80 m (Campagno, 1984b). Bonnethead shark nurseries have been identified in estuaries from South Carolina south along the Atlantic coast into the Gulf (McCandless et al., 2002). Bonnethead sharks prefer water temperatures warmer than 21 degrees C and migrate accordingly back and forth to the equator throughout the year. This species migrates to inshore areas of North Carolina, South Carolina, and Georgia during the summer and off Florida and the Gulf during spring and fall. During the winter, it moves southward to deeper waters. This species mates late summer through early fall in shallow waters (Castro, 1983; Branstetter, 2002; Lombardi-Carlson et al., 2003). Bonnethead sharks prey primarily upon benthic species, including shrimp, crab, cephalopods, and fish during the daytime (Castro, 1983; Branstetter, 2002).

NOAA Fisheries (2009) has designated EFH for neonate, juvenile, and adult bonnethead sharks within the Project area. Neonate, juvenile, and adult bonnethead shark EFH is designated as shallow coastal waters, inlets, and estuaries in the Gulf along Texas and from eastern Mississippi through the Florida Keys (NOAA Fisheries, 2009).

Blacktip Shark (*Carcharhinus limbatus*)

The blacktip shark is managed under the Large Coastal Shark Management Unit through the Final Atlantic Consolidated Highly Migratory Species FMP (NOAA Fisheries, 2006). This shark is found worldwide in predominantly tropical seas but occurs seasonally in warm-temperate coastal waters. In the Atlantic, it ranges from southern New England to southern Brazil, encompassing the Gulf and Caribbean Sea (Garrick, 1982). The blacktip shark is most abundant off South Carolina, Georgia, and Florida in the summer (Castro, 1983). The blacktip shark ranges from inshore estuarine waters, including bays and mangrove swamps, to offshore habitats, but is rarely found at depths greater than 30 m. This species often stays near the surface. Although often recorded offshore, it is not considered a true oceanic shark species. It has a wide salinity tolerance but generally does not move far into riverine systems (Compagno, 1984a). Neonate and juvenile blacktip sharks utilize nursery areas and can remain there for up to a year. Blacktip shark nurseries have been identified in nearshore and estuarine waters from North Carolina through the Gulf (Castro, 1993; NOAA Fisheries, 1999; McCandless et al., 2002). Recent analysis has determined that blacktip sharks in the Gulf and Atlantic nurseries are genetically distinct and separate from one another. Large schools of blacktip sharks off the coast of Florida seasonally migrate north to south along the coast up to 1,159 nautical miles. This species migrates to deeper waters during the winter and utilizes coastal waters of the southeastern U.S. during the summer. Blacktip sharks give birth to live young in inshore nursery grounds during late spring to early summer after a 10 to 11 month gestation period. Blacktip sharks are active mid-water hunters, feeding on benthic and pelagic fishes, cephalopods, and other invertebrates.

Finetooth Shark (*Carcharhinus isodon*)

The finetooth shark is managed under the Small Coastal Shark Management Unit through the Final Consolidated Atlantic Highly Migratory Species FMP (NOAA Fisheries, 2006). In the Atlantic, the finetooth shark is distributed from North Carolina to Cuba and southern Brazil, including the Gulf (Compagno, 1984a). Not a lot is known about habitat associations of this species. Finetooth sharks form large schools and are located in waters close to shore to depths of 10 m (Compagno, 1984a). Finetooth shark estuarine nursery areas have been documented from South Carolina to the Gulf (Castro, 1993; McCandless et al., 2002). Finetooth sharks give birth to live young from May to June. This species feeds on bony fishes, crustaceans, and cephalopods (Campagno, 1984a; Florida Museum, 2013).

NOAA Fisheries (2009) has designated EFH for neonates within the Project area. Neonate finetooth shark EFH is designated as shallow coastal areas such as bays and estuaries out to a 25 m isobath in the Gulf off of Texas, eastern Louisiana, Mississippi, Alabama, and the Florida Panhandle (NOAA Fisheries, 2009).

Lemon Shark (*Negaprion brevirostris*)

The lemon shark is managed under the Large Coastal Shark Management Unit (MU) through the Final Atlantic Consolidated Highly Migratory Species FMP (NOAA Fisheries, 2010). The species is found in the temperate/tropical regions of the Atlantic and Pacific oceans, as well as the Caribbean Sea. In the Atlantic, its distribution ranges from New Jersey to southern Brazil, including the Gulf (Compagno, 1984b; Florida Museum, 2013). Utilization of diverse habitat is characteristic of the species and includes oceanic waters, coral reefs, mangroves, bays, sounds, estuaries, and river mouths. The lemon shark is found from surface waters to depths of 90 m (Florida Museum, 2013). Young sharks are typically found utilizing habitats closer to shore than adults (Campagno, 1984b). Lemon shark nurseries have been recorded in the Florida Keys, Tampa Bay, Florida, and along the Gulf coast of Texas (McCandless et al., 2002). Lemon sharks typically inhabit deeper waters during the daytime and move to shallower waters at night (Florida Museum, 2013). Off Florida, this species also migrates south into deeper water during the winter (Compagno, 1984b). Lemon sharks mate and give birth to live young during the spring and summer, from May to September (Compagno, 1984b). Lemon sharks consume a variety of crustaceans, mollusks, and fishes located over sandy or muddy substrates (Compagno, 1984b; Florida Museum, 2013).

NOAA Fisheries (2009) has designated EFH for adult and neonate lemon sharks within the Project area. Neonate lemon shark EFH is designated as shallow coastal areas such as bays and estuaries out to a 25 m isobath in the Gulf between Texas mid-coast and the Florida Keys.

Juvenile lemon shark EFH is designated as shallow coastal areas such as bays and estuaries out to a 25 m isobath in areas along Texas and eastern Louisiana (NOAA Fisheries, 2009).

Atlantic Sharpnose Shark (*Rhizoprionodon terraenovae*)

The Atlantic sharpnose shark is managed under the Small Coastal Shark Management Unit through the Final Consolidated Atlantic Highly Migratory Species FMP (NOAA Fisheries, 2009). This shark is a subtropical-tropical species found throughout the Atlantic Ocean. The Atlantic sharpnose shark inhabits the waters of the coast of North America from New Brunswick to Florida, extending to the Yucatan area in the Gulf (Castro, 1983; Florida Museum, 2013). This species is a common year-round coastal inhabitant from South Carolina to the Gulf and is a seasonally abundant migrant off Virginia (NOAA Fisheries, 1999). The Atlantic sharpnose shark is most abundant in warm-temperate to subtropical waters of the continental shelf, from inshore areas such as estuaries to the surf zone and out over the shelf in water as deep as 280 m, but it mostly remains in waters less than 10 m deep (Florida Museum, 2013). This demersal shark has a broad salinity tolerance and has been found up rivers, such as the Pascagoula River in Mississippi (Florida Museum, 2013). This species and its nursery areas can also be found in estuarine habitats (Castro, 1993). The Atlantic sharpnose shark performs inshore-offshore movements seasonally, moving into deeper offshore waters during winter as water temperatures fall (Compagno, 1984a; Florida Museum, 2013). Atlantic sharpnose sharks typically mate in late spring and early summer with females migrating offshore during their pregnancy (Florida Museum, 2013). This species moves back inshore to give birth to live young in shallow, protected areas during the late spring to early summer of the following year, from North Carolina to central Florida (Castro, 1983; 1993). This species feeds on fishes, worms, shrimp, crabs, and mollusks (Florida Museum, 2013; Branstetter, 2002).

NOAA Fisheries (2009) has designated EFH for neonate, juvenile, and adult Atlantic sharpnose sharks within the Project area. Neonate, juvenile, and adult Atlantic sharpnose shark EFH is designated as shallow coastal areas such as bays and estuaries out to a 25 m isobath within the Gulf between Texas and the Florida Keys (NOAA Fisheries, 2009).

4.0 POTENTIAL EFFECTS ON EFH

Potential effects on EFH associated with the construction and operation of the Project would primarily consist of increased turbidity; decreased water quality; and increased sediment disturbance, suspension, and deposition in the area.

Approximately 124.0 acres of open water habitat would be impacted by operation of the Terminal. Of the 124.0 acres, approximately 95.4 acres is currently aquatic/intertidal habitat (shallow water) that would be permanently converted to deep water habitat (23.8 acres of the site is currently classified as deep water and 5.0 acres of open land will be converted to deep water). Impact on EFH species would depend on the species' use of deep water habitats. Many of the species that occupy shallow water habitats may also inhabit the deep water habitats that currently exist in the adjacent La Quinta Channel and Turning Basin sometime during their life cycle. Many species reside or migrate through both inshore and offshore areas at different life stages and during different seasons throughout the year.

Of the 95.4 acres of shallow water habitat that would be dredged, approximately 9.2 acres are currently submerged aquatic seagrass beds, 5.9 acres are cordgrass salt marsh, 1.0 acre is emergent marsh and vegetated sand flats, 2.9 acres are unvegetated sand flats, and 6.7 acres are black mangrove. The remaining 67.9 acres are unvegetated shallow water. Portions of these habitats would be permanently converted to open water habitat. These habitats are valuable habitat types relative to fish and EFH as they provide a food rich environment for productive foraging and refuge from predators for juveniles and prey species. Alteration of these habitats can cause a reduction or loss of juvenile or prey species rearing habitats and an alteration in the timing of life history stages. The primary activities associated with the Project that would result in alteration and degradation of EFH include dredging, pile driving, increased ship traffic, and ballast water intake and discharge.

Dredging

As described in section 4.3 of the EIS, Cheniere proposes to use a hydraulic cutterhead dredging system to remove approximately 4.4 million cubic yards of mostly stiff clays with interbedded sand and silt layers to create the berthing area and maneuvering basin at the Terminal. Dredging with a hydraulic cutterhead dredge generally creates less turbidity than other types of dredges (i.e., mechanical bucket or hopper dredges). With a cutterhead dredge, the cutter speed can be adjusted to match the sediment properties, thus minimizing turbidity (Herbich and Brahme, 1984). During operation of the Project, maintenance dredging may be required every three years. Cheniere estimates that 200,000 cubic yards of material would be dredged for each occurrence. During the dredging operation, water quality would be affected by the temporary increase in turbidity surrounding the hydraulic cutterhead of the dredge as well as around the mixing zone. Disturbance of bottom sediments during dredging can significantly increase turbidity and down-current deposition of sediments. Very high levels of turbidity can result in the physical impairment of estuarine species (e.g., turbidity induced clogged gills resulting in suffocation, or abrasion of sensitive epithelial tissue).

However, the turbidity and the deposition of sediments would be reduced by the tidal flushing action of Corpus Christi Bay. Tidal flushing in Corpus Christi Bay has been described as a restricted flow, tidal regime switching from semi-diurnal to diurnal (Ward, 1997). The tides are wind dominated which results in relatively higher tides in summer and spring with lower tides in winter and fall because of the prevailing wind. Because of the change in the width to depth ratio of the La Quinta Channel, overall currents would be expected to be relatively low, particularly at or near the bottom where dredging would occur.

Based on the general hydraulic characteristics of the site and the proposed depth of dredging, most of the sediment that would become suspended during the dredging process is expected to be short term and the water quality would return to background levels a short distance from the point of disturbance. Therefore, impacts to EFH due to water quality impacts from dredging are not expected to be significant.

Entrainment of aquatic organisms by dredging machinery can impact EFH species directly or indirectly through the removal of prey species (e.g., benthic invertebrates) or food species (e.g., macroalgae), disrupting energy flow and biotic interactions. Entrainment of benthic organisms during the dredging of the berthing and maneuvering areas is expected, however, entrainment would not be extensive enough to have a significant impact on the fishery resources of Corpus Christi Bay. In addition, benthic organisms typically have rapid recolonization rates that would limit impacts on the biota of these areas.

Dredging and the direct removal of suitable benthic substrates can impact EFH by removing suitable cover or settlement structure. Dredging typically homogenizes bottom substrates, reducing the structural complexity of habitats. Field surveys of the Project area revealed that the open bay habitats that would be dredged already consist of a homogenous bed of fine substrates. Dredging of these areas would, therefore, not significantly alter the existing bottom type, with the exception of vegetated areas, as discussed below.

Dredging can also result in the chemical impairment of the water column due to the suspension of contaminated sediments. The Final EIS for the Corpus Christi Ship Channel Improvement Project reported the results of sediments that were sampled and analyzed for organic and metallic chemicals (COE, 2003). The U.S. Army Corps of Engineers (COE) EIS included samples from the La Quinta Channel extension that would overlap the area of the proposed dredging. In addition, Cheniere collected three sediment cores from the proposed dredging area and had them analyzed for metals. In the COE final EIS, the results were compared to the Effects Range Low (ERL), which are used by NOAA as screening levels for assessing sediment quality. These are conservative concentration levels and are considered the lowest concentrations where effects on the marine ecology have been observed. These levels are used to identify sediment that may require additional evaluations before decisions on disposal or beneficial re-use are made.

In 1985 samples from the La Quinta Channel, arsenic ranged from 12 to 15 milligrams per kilogram (mg/kg) in all six samples, which is above the ERL of 8.2 mg/kg. Six samples were taken from the same stations in 1990 and again in 2000, and all metals were below the ERL levels. Three samples were taken in 2000 from the La Quinta extension and analyzed for metals and all metals were below the ERLs. The samples taken in 1985 were analyzed for polychlorinated biphenyls (PCBs) and pesticides and all detections were below ERL levels. The samples taken in 1990 and 2000 were analyzed for PCBs, pesticides, and polycyclic aromatic hydrocarbons, and all detections were below ERL levels. The COE concluded that, overall, there is no indication of current water quality problems in the La Quinta Channel (COE, 2003).

The results of the analysis of Cheniere's core samples were compared to the Protective Concentration Levels (PCL) for Tier 1 commercial/industrial soil protective of Class 3 groundwater. All concentrations were below the PCL.

While the existing functions of the permanently impacted seagrass, coastal marsh, cordgrass salt marsh, vegetated and unvegetated sand flats, black mangrove, and unvegetated shallow water habitats would be lost, this area would function as open water habitat. Impacts on EFH resulting from increased turbidity, decreased water quality, and increased sedimentation as a result of dredging would be short term and limited to the immediate area surrounding the activity.

Pile Driving

In addition to impacts from dredging during construction of the Project, sound pressure waves produced during pile driving activities to construct the marine terminal may result in impacts on nearby fish species with EFH designations, and their prey. Intense sound pressure waves can affect fish behavior and/or result in the rupturing of swim bladders and internal hemorrhaging. The intensity of the sound pressure levels produced during pile driving depends on a variety of factors including, but not limited to, the type and size of the pile, the firmness of the substrate into which the pile is being driven, the depth of water, and the type and size of the pile-driving hammer. The degree to which an individual fish exposed to sound waves would be affected is dependent upon variables such as the peak sound pressure level and frequency as well as the species, size, and condition of a fish (e.g., small fish are more prone to injury by intense sound waves than are larger fish of the same species). Depending on the specific conditions at the site, pile driving activities could generate underwater sound levels great enough to injure some fish or cause them to be more susceptible to predation. However, in order to reduce impacts on fish and other aquatic species from pile driving, Cheniere would perform a soft start in which they would ramp-up pile driving activities to allow mobile species in the area to relocate to adjacent habitats prior to the primary pile driving activities.

Marine Traffic

Ship and boat traffic associated with construction and operation of the Project would also generate underwater sounds. Although vessel sounds would not generally be of the intensity produced from driving steel piles, Project vessels (e.g., LNG carrier ships [LNGCs'], tugs, construction barges) operating in the La Quinta Channel could result in sounds that illicit responses in fish. Most research suggests that fish exhibit avoidance behavior in response to engine noises (International Council for Exploration of the Sea, 1995). At the same time, research conclusions tend to suggest that since the effects are transient (i.e., once the ship passes, behavior returns to normal), then the long-term effects on populations are negligible (Stocker, 2001).

Ballast Water

It is expected that any LNGC at the Terminal would be in full compliance with the domestic requirements for ballast water management as specified in the National Invasive Species Act of 1996 and international standards that were adopted on February 13, 2004. Additionally, the Terminal would comply with Port of Corpus Christi Authority (POCCA) general and specific discharge prohibitions (regulations) currently in place. While taking on LNG cargo at the Terminal, LNGCs will discharge seawater ballast to maintain stability. In accordance with International Maritime Organization regulations, LNGCs are required to undergo mid-ocean ballast water exchange during transit so that the source of the ballast water discharged at the Terminal would not be from a foreign port but would be from open ocean. Ballast water is exchanged through seachests and it is estimated to take between 25 and 72 hours to complete ballast water discharge while at dock depending on the rate of LNG cargo loading. Ballast discharge is necessary to maintain a constant draft at the berth. Adverse effects on marine life would be minimized by a number of factors. First, temporary spikes in salinity are not anticipated to adversely affect fish and other marine organisms. Second, ballast water would be discharged near the bottom of the waterway, where salinity levels are naturally higher and the ballast water can enter the saltwater wedge and move toward the open Gulf. Third, as the LNGCs move in and out of the marine berth, the amount of water displaced by the LNGC (on average 110,000 tons per vessel) would be circulated into, around, and out of the berth and would facilitate rapid mixing of any ballast water and flushing of the marine berth on a per ship basis. The net effect is enhanced and rapid dilution of any ballast water upon departure of the LNGC. Finally, the amount of freshwater flowing into the Corpus Christi Bay from the Nueces River, as well as other freshwater sources along the La Quinta Channel, exceeds anticipated ballast discharge. Thus, the ballast water would be quickly diluted to ambient salinity.

Therefore, any effects on salinity are expected to be temporary and localized, and are not expected to have any negative effects on the marine life in and around the Terminal.

If it is necessary for ballast water to be taken on at the Terminal, during cargo delivery, each LNGC would discharge its entire cargo to LNG storage tanks on shore. As with LNG export, LNGCs discharging LNG cargo would take on seawater ballast to maintain a constant draft at the berth. Aquatic species in the immediate vicinity of the ship berths could therefore be impacted by entrainment during ballast water intake.

Cumulative Impacts

Cumulative impacts result when impacts associated with a proposed project is superimposed on or added to impact associated with past, present, or reasonably foreseeable future projects within the area affected by the Project. Although individual impacts of the separate projects might be minor, the additive effects from all the projects could be significant. Additional discussion of cumulative impacts is provided in section 4.13 of the Project EIS.

Existing environmental conditions in the Project area reflect extensive changes based on past projects and activities. For example, substantial impacts have occurred and continue to occur because of water quality degradation from point and non-point source pollution within Corpus Christi Bay. Point source discharges from industry, combined with septic tank leachates, stormwater runoff, and oil and chemical spills contribute to lower water quality and degraded fishery habitats.

Cumulative effects on marine resources in the area could occur from several planned and currently in progress projects including the proposed COE La Quinta Ship Channel Extension, POCCA La Quinta Trade Gateway Terminal, Offshore Wind Power Systems of Texas, LLC Foundation Test Site, and Voestalpine DRI Plant. All of these projects would involve dredging activities, which if conducted concurrently with the Project, could result in cumulative impacts on EFH in the area. The primary short-term impact of dredging is an increase in turbidity. Turbidity impacts are primarily restricted to the area surrounding the dredging activity and are temporary. The La Quinta Ship Channel Extension is located directly across from the Terminal site, and the POCCA La Quinta Trade Gateway Terminal and Voestalpine DRI Plant are located immediately adjacent to the Terminal site. If dredging for the Terminal is conducted concurrently with these other projects, short-term impacts to EFH from increased turbidity would be significant. However, based on the projected schedules of these projects, dredging would likely not occur concurrently, minimizing the potential for cumulative effects from dredge-associated turbidity.

Construction of each of these projects, including dredging, would result in long-term impacts to EFH in the form of habitat loss or conversion. However, the COE requires mitigation for all permanent impacts to waters of the United States; therefore, similar to the proposed Project, these other projects would be required to compensate for loss of these habitats through mitigation as well. For example, the La Quinta Ship Channel Extension is beneficially utilizing dredge material by creating shallow water habitat partially planted with submerged aquatic vegetation to compensate for similar habitat lost as a result of dredging.

Although required mitigation would lessen the impacts from these projects to EFH and aquatic resources as a whole, gradual and cumulative impacts that could result from the construction and operation of the Project and other projects in the area and within the near future would result in some unavoidable adverse effects on the existing environment. For example, future projects such as the La Quinta Trade Gateway Terminal and the Voestalpine DRI Plant could potentially contribute to impacts on EFH both from dredging and the potential for increased ship traffic. However, specific impacts on EFH as a whole would be addressed for each individual project, and impacts on vegetated components of EFH would be addressed through compensatory mitigation during Section 404 permitting.

5.0 EFH MITIGATION

Cheniere has attempted to avoid or minimize impacts on coastal resources, including EFH, by identifying a site for the Terminal that is previously disturbed, adjacent to an existing deep water shipping channel, and near industrial activity. Because the proposed site is immediately adjacent to the existing La Quinta Turning Basin and Channel, the need for dredging would be limited to that required for the Terminal maneuvering basin and berths.

The permanent conversion of wetlands (EFH) as a result of the proposed dredging will require compensatory mitigation to comply with the COE Section 404(b)1 guidelines. Cheniere submitted an Aquatic Resources Mitigation Plan (ARMP) for the Project to the COE. This plan was submitted to the COE as part of the CWA Section 404 permitting process and approved in 2005 (DA Permit 23561). Since 2005, Cheniere has continued to work with the COE to finalize the ARMP to account for additional wetland impacts associated with the proposed Project.

Cheniere’s proposed conceptual wetland mitigation plan at Shamrock Island was approved by the COE in 2005 to mitigate for impacts to waters of the U.S. associated with the previous proposal to construct an LNG import terminal and associated pipeline (Docket Nos. CP04-37-000, CP04-44-000, CP04-45-000, and CP04-46-000). Mitigation measures for the previously permitted 12.88 acres of wetland impacts were completed in 2013 and included the installation of 16 breakwaters bordering the north-western end of Shamrock Island. Construction of these breakwaters would assist in the preservation of existing habitats including cordgrass, mangroves, unvegetated sand flats, vegetated sand flats, hard substrates, and uplands.

In response to the COE public notice for Cheniere’s permit application (Permit No. SWG-2007-01637), several agencies, including NOAA Fisheries, expressed concern regarding the length of time (50 years) it would take for complete compensatory mitigation to be complete. The COE addressed these concerns and determined that 50 years to achieve an 8.9:1 preservation ratio, as proposed in Cheniere’s ARMP, is not an appropriate period to evaluate preservation values. The COE recommends evaluating the preservation values during a 10-year period, during which time, conditions affecting the site would be relatively consistent and less likely to be influenced by sudden episodic events, such as hurricanes. Use of a shorter time period would lower Cheniere’s estimated preservation ratio and potentially change the habitat types preserved by the proposed ARMP.

The COE determined that in order to quantitatively evaluate Project impacts on wetland habitats, it is in the public’s best interest to perform a functional assessment of the Project. A functional assessment would quantify, in a scientifically sound, reproducible and reasonably rapid manner, the wetland functions lost and those that would be mitigated for by the Project. This would allow the COE to verify if the Project is consistent with the COE-EPA Memorandum of Understanding of Mitigation under the CWA Section 404(b)(1) Guidelines and 33 CFR 332.3(f)(1), and determine if the anticipated impacts would be adequately compensated by the proposed mitigation. We expect the COE recommendations to be included in any permit that it may issue. Pending the results of the functional assessment, increased compensation in the mitigation area could be required.

6.0 FERC'S VIEW REGARDING EFH

Construction and operation of the Project would have temporary and long-term impacts on EFH. In general, temporary impacts are not expected to be significant considering the proposed dredging method and the localized impact of the actions. Dredging of the berthing and maneuvering basin would temporarily affect EFH by disturbing bottom sediments and increasing turbidity, which can have adverse physiological effects on finfish and shellfish species. Hydraulic dredging would also directly affect some benthic species that would be entrained during dredging. However, considering the nature of the sediments that would be dredged, the use of hydraulic cutterhead dredging, and the temporary nature of the dredging, these impacts would not be significant.

Impacts on EFH from the deposition of sediments re-suspended by dredging activities are expected to be minimal. Considering the hydrologic characteristics of the site and the depth of excavation, most of the sediment that does become suspended during the dredging process is expected to settle within or near the dredging footprint as opposed to migrating to adjacent areas. Field studies of cutterhead dredges indicate that elevated turbidity is limited to the lower portion of the water column and turbidity levels are at background within several hundred feet of the cutterhead dredging operation (Herbich and Brahme, 1984). Because of the design of the channel, suspended sediments would be expected to stay within the confines of the dredged channel.

With the exception of areas of coastal wetland, dredging of open bay habitat is not expected to result in a significant alteration of habitat structure, as the area of the bay near the Terminal generally lacks habitat structure/cover. Also, considering recolonization rates of potentially affected benthic species and the relatively limited area affected by dredging, these losses would not be extensive enough to have a significant impact on the fishery resources of Corpus Christi Bay.

The primary impact on EFH would be the permanent loss of approximately 95.90 acres of shallow open water habitat, of which 25.67 acres consist of seagrass, coastal marsh, cordgrass salt marsh, vegetated and unvegetated tidal flats, and black mangrove. This habitat is valuable to EFH managed species as they provide a food-rich environment for foraging and refuge for juveniles and prey species. To compensate for this permanent loss of habitat, Cheniere would implement wetland mitigation designed to avoid a net loss of wetlands as necessary to comply with the COE's Section 404(b)1 guidelines.

Based on Cheniere's proposed impact mitigation measures as well as preparation of the functional assessment and ARMP to be approved by the COE, we have determined that constructing and operating the Terminal would not have a significant impact on EFH.

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Appendix C

AQUATIC RESOURCES MITIGATION PLAN

SWG-2007-01637

July 30, 2013
Rev. June 17, 2014

Attachment "A"

JUN 18 2014

WETLAND MITIGATION PLAN FOR THE CORPUS CHRISTI LIQUEFACTION PROJECT
San Patricio and Nueces Counties, Texas
Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P.

1. Mitigation Goals and Objectives

Corpus Christi Liquefaction, LLC (CCL) and Cheniere Corpus Christi Pipeline, L.P. (CCPL) propose to construct and operate a natural gas liquefaction and export plant and liquefied natural gas (LNG) import facilities with regasification capabilities (CCL Terminal) and an associated 23-mile pipeline (collectively referred to as the 'CCL Project'). CCL and CCPL are currently authorized by the U.S. Army Corps of Engineers (DA Permit 23561) for impacts to waters of the U.S. associated with a previous proposal to construct a LNG import terminal and an associated pipeline. The CCL Project is to be located at the previously authorized, but not constructed, LNG import terminal site and pipeline route in San Patricio and Nueces Counties, Texas (authorized under DA Permit 23561).

The original permit (DA Permit 23561) authorized compensatory mitigation at Shamrock Island for 12.88 acres of impacted jurisdictional wetlands. On August 31, 2012, CCL and CCPL submitted a request to the U.S. Army Corps of Engineers to amend DA Permit 23561 to reflect additional impacts to wetlands due to necessary design changes between the previously authorized LNG import terminal project and the current CCL Project. These proposed additional impacts to wetlands are due entirely to design changes at CCL's proposed Terminal. All impacts to wetlands from CCPL's pipeline are included in the 12.88 acres of previously authorized compensatory mitigation at Shamrock Island. Therefore, the supplemental mitigation described in this plan is entirely the obligation of CCL.

CCL proposes to construct the following key features at the terminal site that will impact jurisdictional waters of the U.S.:

1. Dredging of a basin.
2. Construction of two piers with associated mooring and breasting structures.
3. Construction of tug dock.
4. Construction of approach roads.

Construction of these facilities will impact a total of approximately 27.45 acres of wetlands, of which 25.67 acres will be permanently impacted (see Sheet 1 of 8). Of this total, the original permit (DA Permit 23561) authorized compensatory mitigation at Shamrock Island for 12.88 acres of impacted jurisdictional areas. The newly proposed permanent impacts (by habitat type) are listed below:

Seagrass:	3.82 acres
Mangroves:	5.13 acres
Smooth Cordgrass:	3.53 acres
Vegetated Flats:	-0.13 acres (reduction of impact from originally permitted plan)
Unvegetated Flats:	2.64 acres
Total	**14.99 acres**

In addition to the currently authorized mitigation at Shamrock Island for 12.88 acres of wetland impacts (which include impacts associated with the CCL's currently authorized import terminal and CCPL's currently authorized pipeline), CCL is proposing to provide mitigation at Ransom Point in Corpus Christi Bay for the additional 14.99 acres of proposed impacts to wetland habitats. The Ransom Point to Dagger Island area is exposed to erosional forces created by a combination of wind-driven waves and wakes of ships transiting the Corpus Christi Ship Channel. The area's small islands, seagrass beds, and marsh habitats are being eroded at an average rate of 5.2 ft./yr., placing a large area of seagrass and marsh habitat at risk. Texas Parks and Wildlife Department (TPWD) presently has a master plan to preserve Redfish Bay area habitats including Dagger Island, Dagger Point, and Ransom Point, which are all located within the Redfish Bay State Scientific Area. CCL is proposing to construct approximately 3,500 feet of segmented rock breakwaters to preserve the existing habitats on Ransom Point as well as the habitats within Redfish Bay that Ransom Point protects. This proposed mitigation has been coordinated with TPWD, other resource agencies, and USACE, and is consistent with the goals and objectives of TPWD's master plan. Further, implementation of this mitigation plan represents a potential catalyst for additional mitigation projects throughout the important Redfish Bay area.

2. Site Selection Information

The primary criteria for selection of the mitigation site are ability to permit (site offers adequate compensation for the proposed 14.99 acres of impact), ability to construct, and likelihood of long-term success. In an attempt to provide a successful mitigation project in perpetuity, CCL is proposing to construct a 3,500-foot segmented rock breakwater at Ransom Point in addition to the work previously done at Shamrock Island.

Shamrock Island

The authorized mitigation for the initial 12.88 acres of impacted wetlands (associated with the currently authorized import terminal and pipeline) is located at Shamrock Island, where 16 rock breakwaters were successfully constructed by CCL and CCPL during late 2012 and early 2013 (see Sheet 2 of 8). The construction of the authorized mitigation at Shamrock Island has been completed.

Ransom Point

The CCL Project will impact an additional 14.99 acres of seagrass and marsh habitat (see Sheet 1 of 8). Mitigation for these additional impacts will be located at Ransom Point in the form of a 3,500-foot segmented break water (see Sheet 3 of 8). Ransom Point comprises over 92 acres of high quality wetland mosaic and protects many acres of adjacent seagrass and saltmarsh habitat.

A study to identify rates of erosion at Dagger and Ransom Islands was conducted for TPWD by HDR in 2009. The results of the study indicate that Ransom Point is eroding along its southeastern shore at an average rate of 5.2 ft/yr. Projecting the erosion rates at 10-year intervals indicates that approximately 17.8 acres of marsh and upland habitat will be lost in 50 years (see Sheet 4 of 8 and Table 1 below).

Table 1 - Ransom Point Habitat Loss

Interval (Years)	Marsh Lost (Acres)	Mangroves Lost (Acres)	Shallow Water Habitat Lost (Acres)	Uplands Lost (Acres)	Total Habitats Lost per Interval (Acres)	Cumulative Wetland Habitat Lost (Acres)
10	1.32	0.59	0.26	1.73	3.90	3.90
20	1.82	0.57	0.82	0.52	3.73	7.63
30	1.68	0.66	0.85	0.36	3.55	11.18
40	1.54	0.53	0.62	0.70	3.39	15.57
50	1.47	0.61	0.66	0.49	3.23	17.80

**Based on observed average rate of erosion (5.2 feet/year).*

Installation of breakwaters at Ransom Point aims to halt the observed ongoing erosion at Ransom Point, thereby preserving over 90 acres (approximate) of at-risk habitat (see Sheet 5 of 8). Preservation of Ransom Point habitats will provide a secondary benefit to the adjacent shallow water and saltmarsh habitats by offering protection from the same forces that are currently putting Ransom Point at risk (see Sheet 7 of 8).

3. Site Protection Instrument

CCL will enter into a lease agreement with the Texas General Land Office (TGLO) for construction of the segmented rock breakwater. CCL will coordinate with TPWD, TGLO, and the City of Aransas Pass in an attempt to establish a conservation easement, deed restriction, or similar instrument that limits uses of Ransom Point to those that are consistent with this mitigation plan.

4. Baseline Information

Shamrock Island

As described previously, 16 rock breakwaters have been constructed at Shamrock Island to compensate for originally permitted impacts totaling 12.88 acres.

Ransom Point

Habitats on Ransom Point comprise (see Sheet 4 of 8):

- 26.20 acres of Borrichia-dominated marsh with a plant community comprised of *Borrichia frutescens, Distichlis spicata, Spartina spartinae* and *Salicornia virginica*.
- 23.13 acres of mangrove marsh with a plant community comprised of *Avicennia germinans, Batis maritima, Salicornia virginica, Borrichia frutescens* and *Distichlis spicata*.
- 0.32 acres of *Sesuvium maritima* marsh.
- 0.28 acres of *Spartina alterniflora* marsh.
- 8.14 acres of open water.
- 7.90 acres of uplands with a plant community comprised of *Opuntia sp., Yucca* sp., *Spartina spartinae*, and *Helianthus argophyllus.*

- 0.18 acres of oyster reef.
- 26.57 acres of submerged aquatic vegetation.

The southern portion of Redfish Bay contains over 2,000 acres of shallow water, seagrass, and marsh habitat. Ransom Point provides protection from wind-driven waves and ship wakes to extensive seagrass beds and marsh habitats to the northwest. While these habitats are currently protected by Ransom Point and adjacent islands, threats to Ransom Point from erosion put these habitats at risk.

5. Number of Credits to be Provided

A summary of the mitigation provided at Shamrock Island for the previously permitted 12.88 acres of impacts is provided in Table 2.

Table 2 - Shamrock Island Mitigation Totals

Habitat Types	Mitigation Ratio	CCL Impact (acres)	Required Mitigation (acres)	Total Habitats (acres)		
				Created	Preserved	Total
Submerged aquatic vegetation (SAV)	3 to 1	6.04	18.12	13.93	38.728	66.528
Smooth cordgrass (Spartina)	2 to 1	2.76	5.2	---	4.41	4.41
Mangroves	3 to 1	2.01	6.03	---	0.567	0.567
Unvegetated Tidal Flats	1 to 1	0.45	0.45	---	1.652	1.652
Vegetated Tidal Flats	1 to 1	1.62	1.62	---	13.076	13.076
Hard Substrate	N/A	---	---	1.299	0.049	1.348
Uplands	---	---	---	---	10.441	10.441

A summary of the mitigation proposed at Ransom Point (for the proposed additional 14.99 acres of permanent wetland impacts) is provided in Table 3.

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Table 3 - Ransom Point Mitigation Totals

Ransom Point Mitigation							
Habitat Type	**Impacted Area (Ac)**	**Mitigation Alternative**		**In-Kind/Out-of-Kind**	**Type of Habitat**	**Mitigation Area (Ac)**	**Mitigation Ratio**
		Preservation	**Enhancement**				
Seagrass	3.82	Yes	Yes	In-Kind	Seagrass	23.26	6.1 to 1
Mangroves	5.13	Yes	Yes	In-Kind	Mangrove	22.95	4.5 to 1
Unvegetated Sandflats	2.64	Yes	Yes	Out-of-Kind	Isolated Uplands Borichia Marsh	7.9 5	3.0 to 1 1.9 to 1
Smooth Cordgrass	3.53	Yes	Yes	In-Kind	Smoth Cordgrass	0.28	0.1 to 1
				Out-of-Kind	Borrichia Marsh Sesuvium Marsh Oyster Reef Open Water (Ponds)	21.2 0.32 0.18 8.14	6.0 to 1 0.1 to 1 0.05 to 1 2.3 to 1
				Long-Term Enhancement	Marsh Complex*	65.97	18.7 to 1
Shallow Water Habitat**	69.7	Yes	Yes	In-Kind	Shallow Water Habitat	48.5	0.7 to 1
				Long-Term Preservation	Shallow Water Habitat	261	3.7 to 1

*Marsh Complex within the Ransom Point mitigation area includes a mosaic comprising borrichia marsh, mangrove marsh, sesuvium marsh, smooth cordgrass marsh open water (ponds), and uplands.

**Shallow water habitat will be converted to deep water habitat.

Seagrass
3.82 acres of seagrass impacts are being mitigated in-kind with 23.26 acres of seagrass preservation at 6.1 to 1. Construction of the proposed breakwaters will result in reduced wave energy, reduced currents, and decreased turbidity. Reduction of these detrimental forces will result in improved site conditions for seagrass colonization and survival. Thus, the proposed mitigation is also considered an enhancement of existing habitat (6.1 to 1).

Mangroves
5.13 acres of mangrove impacts are being mitigated in-kind with 22.95 acres of mangrove preservation at 4.5 to 1. In addition to the 22.95 acres of mangrove preservation, the Applicant is proposing to preserve 23.26 acres of seagrass, 7.9 acres of uplands, 26.20 acres of borrichia marsh, 0.28 acre of Spartina alterniflora, and 0.32 acre of sesuvium marsh. All of these adjacent and surrounding habitats contribute toward the stability of the Ransom Point mosaic, which includes the existing mangroves. Thus, protection of the various communities within the mosaic will likely increase the resilience of the existing mangroves from wind, waves, and other erosive forces and improve conditions by improvement long-term stability. This factor suggests that the proposed mitigation plan is not just preserving 22.95 acres, but is enhancing the 22.95 acres as well.

In addition to many other ecological functions, the adjacent and surrounding plant communities provide valuable foraging and nesting habitat for a multitude of avian species. Many of these communities occur slightly above elevations considered suitable for black mangroves, which means that in the context of relative sea level rise, these areas are likely to allow for future recruitment of black mangroves. While difficult to quantify, permanent long term protection of Ransom Point is likely to result in propagation (creation) of new mangroves on Ransom Point.

Smooth Cordgrass
3.53 acres of Spartina alterniflora impacts are being mitigated in-kind with 0.28 acre of Spartina alterniflora preservation at 0.1 to 1. As a result of breakwater construction, surrounding protective

habitats such as uplands (7.9 acres), black mangroves (22.95 acres), borrichia marsh (26.20 acres) , sesuvium marsh (0.32 acres), and open water (8.14 acres) will remain intact, thereby allowing stands of S. alterniflora opportunities to not only survive but to expand. Thus, the proposed out-of-kind mitigation is likely to result in an enhancement of the existing S. alterniflora onsite. In addition to enhancement of the 0.28 acre of S. alterniflora currently onsite, the Applicant anticipates natural recruitment of S. alterniflora along approximately 4,700 LF (approx. 0.43 acres) of perimeter shoreline that is currently exposed to erosive wind waves and ship wakes but will be protected by the proposed breakwater. Further, many of the communities onsite occur slightly above elevations considered suitable for S. alterniflora, which means that in the context of relative sea level rise, these areas are likely to allow for future recruitment of S. alterniflora. While difficult to quantify, permanent long term protection of Ransom Point is likely to result in propagation (creation) of new smooth cordgrass on Ransom Point. In this case, the Applicant is proposing preservation and enhancement of 65.97 acres of marsh complex, which provides multiple estuarine functions, highly valuable habitat for numerous avian species, and a variety of other ecological functions.

Unvegetated Flats
2.64 acres of unvegetated flats are being mitigated out-of-kind with 7.9 acres of uplands (3.0 to 1) and 5 acres of borrichia marsh preservation at 1.9 to 1. Past attempts to create and/or preserve (over the long term) unvegetated sand flats have been for the most part unsuccessful. Common practice over the past several years has been to mitigate for this resource with creation, protection, or enhancement of other communities.

Shallow Water Habitat
The Applicant proposes to compensate for conversion of approximately 69 acres of shallow water habitat to deep water habitat via preservation and enhancement of 48.5 acres (approximate) of existing shallow water habitat that occurs between the proposed breakwaters and Ransom Point. Installation of the proposed breakwaters will reduce wave energy, reduce damaging currents, and reduce turbidity. This reduction of detrimental forces will improve conditions within the shallow water habitat area. Thus, the protection of the 48.5 acre area is considered an enhancement as well as preservation. In addition to the protection of 48.5 acres, approximately 261 acres of shallow water habitat within a secondary preservation area will be protected via protection of Ransom Point (which serves as a protective buffer between Corpus Christi Bay and the shallow waters of Redfish Bay) (see Sheet 7 of 8).

Secondary Preservation
269 acres of high quality shallow water habitat, seagrass, and coastal saltmarsh occur within the secondary preservation area that is currently buffered from Corpus Christi Bay and the Corpus Christi Ship Channel by Ransom Point (see Sheet 7 of 8).

6. Mitigation Work Plan

Construction of mitigation at Shamrock Island was completed in February of 2013.

Construction of mitigation at Ransom Point will begin within 6 months of beginning work in jurisdictional areas at the CCL Project. CCL will be responsible for constructing the project.

Key elements of the Ransom Point plan are as follows:

- Construct 3,500 feet of segmented rock breakwater.
- Construction to commence within 6 months of the beginning of work in jurisdictional areas.
- Breakwater construction duration will be one year or less.
- Breakwaters will be positioned along 5-foot contour or along seaward limit of existing seagrass beds, whichever is shallower (see Sheet 6 of 8).
- Breakwater crest elevation will be 3.5 feet Mean Low Tide (MLT), which should provide for long-term protection in the context of Relative Sea Level Rise (see Sheet 8 of 8).
- A post-construction survey will be conducted, with results provided to USACE.

7. Maintenance Plan

CCL will be responsible for maintaining the constructed breakwater so that it remains in compliance with respect to permitted dimensions and locations. The site will be inspected annually to ensure that appropriate navigational aids and other signage are in place.

8. Ecological Performance Standards

A. Shamrock Island

Ecological performance at Shamrock Island will be based on 1) demonstration of successful creation of seagrass habitat and hard substrate, and 2) preservation of other habitats. Demonstration of habitat creation will be provided via annual monitoring, following the protocol described in Section 9. Demonstration of successful preservation will be provided via annual habitat assessments, following the protocol described in Section 9. The authorized mitigation plan dated August 17, CCL is not responsible for protection of habitats from hurricanes or other major events that are beyond their control.

B. Ransom Point

Ecological performance at Ransom Point will be based on 1) demonstration of successful preservation of habitats and 2) demonstration of enhancement of habitats. Demonstration of successful preservation will be provided via annual habitat assessments, following the protocol described below. A pre-construction habitat survey will serve as a baseline, from which comparisons with annual post-construction surveys can be made. Enhanced habitats will result from improved site conditions via reduced wave energy, currents, and turbidity. A pre-construction (prior to breakwater construction) seagrass survey will be conducted to establish baseline conditions. Annual post-construction seagrass surveys will be conducted during the five year monitoring period. Comparison of pre- and post-construction seagrass surveys is to be used as a means for documenting habitat enhancement. Enhancement is to be deemed successful if seagrass density (percent cover) between the breakwater and Ransom Point shoreline increases by 30 percent at the end of five years post-construction. CCL is not responsible for protection of habitats from hurricanes or other major events that are beyond their control.

C. Temporary Impacts

The Applicant is proposing to temporarily impact 1.78 acres of jurisdictional areas. Restorative success will be based on demonstration that the impacted areas have been restored to near preconstruction contours and that plant species assemblages and densities are equivalent to those observed in the pre-construction condition. Additional mitigation may be required if restorative efforts are deemed unsuccessful by USACE. See Section 9, monitoring requirements for additional detail.

9. Monitoring Requirements

A. Shamrock Island

A delineation of created habitats within the Shamrock Island mitigation area will be conducted annually for five years following construction. Habitats to be delineated include seagrass beds only (created hard substrate is represented by the constructed breakwater that was completed in early 2013). A cursory assessment of preserved habitats and comparison with observed pre-construction conditions will also be conducted annually for five years. Reports on each annual survey will be provided to USACE and will include descriptions of methodology, results (including photographs), and conclusions. Most notably, discussion of observed changes from previous years (if any) will be included in each monitoring report. Monitoring and reporting will be conducted in accordance with USACE Regulatory Guidance Letter 08-03.

B. Ransom Point

Within 60 days of completion of construction of breakwaters, CCL will submit a report to USACE describing pre-construction and post-construction conditions.

A delineation of habitats within the primary protection area will be conducted annually for 5 years following construction. Habitats to be delineated include those described in Section 4 of this plan, including seagrass and various saltmarsh communities. Reports on each annual survey will be provided to USACE and will include descriptions of methodology, results (including photographs), and conclusions. Most notably, discussion of observed changes (if any) from previous years will be included in each monitoring report. Monitoring and reporting will be conducted in accordance with USACE Regulatory Guidance Letter 08-03. Monitoring of the 269-acre secondary preservation area will not be conducted.

C. Temporary Impacts

The Applicant is proposing 1.78 acres of temporary jurisdictional impacts. Areas to be temporarily impacted will be monitored prior to construction (baseline monitoring) and then again after the areas have been restored. Monitoring of restored areas is to continue for five years or until USACE has concluded that the areas have been successfully restored.

10. Long-Term Management Plan

Management responsibilities for the mitigation site will be incorporated into CCL's overall management of the CCL Project.

11. Adaptive Management Plan

If results of the monitoring indicate that the mitigation is not successful, CCL will coordinate with USACE to discuss an appropriate course of action. Example remedies may include, but are not limited to, planting efforts, alternative sites, etc.

12. Financial Assurances

CCL is a well-established entity that has demonstrated (through delivery of the Shamrock Island mitigation and other projects) financial capability and reliability.

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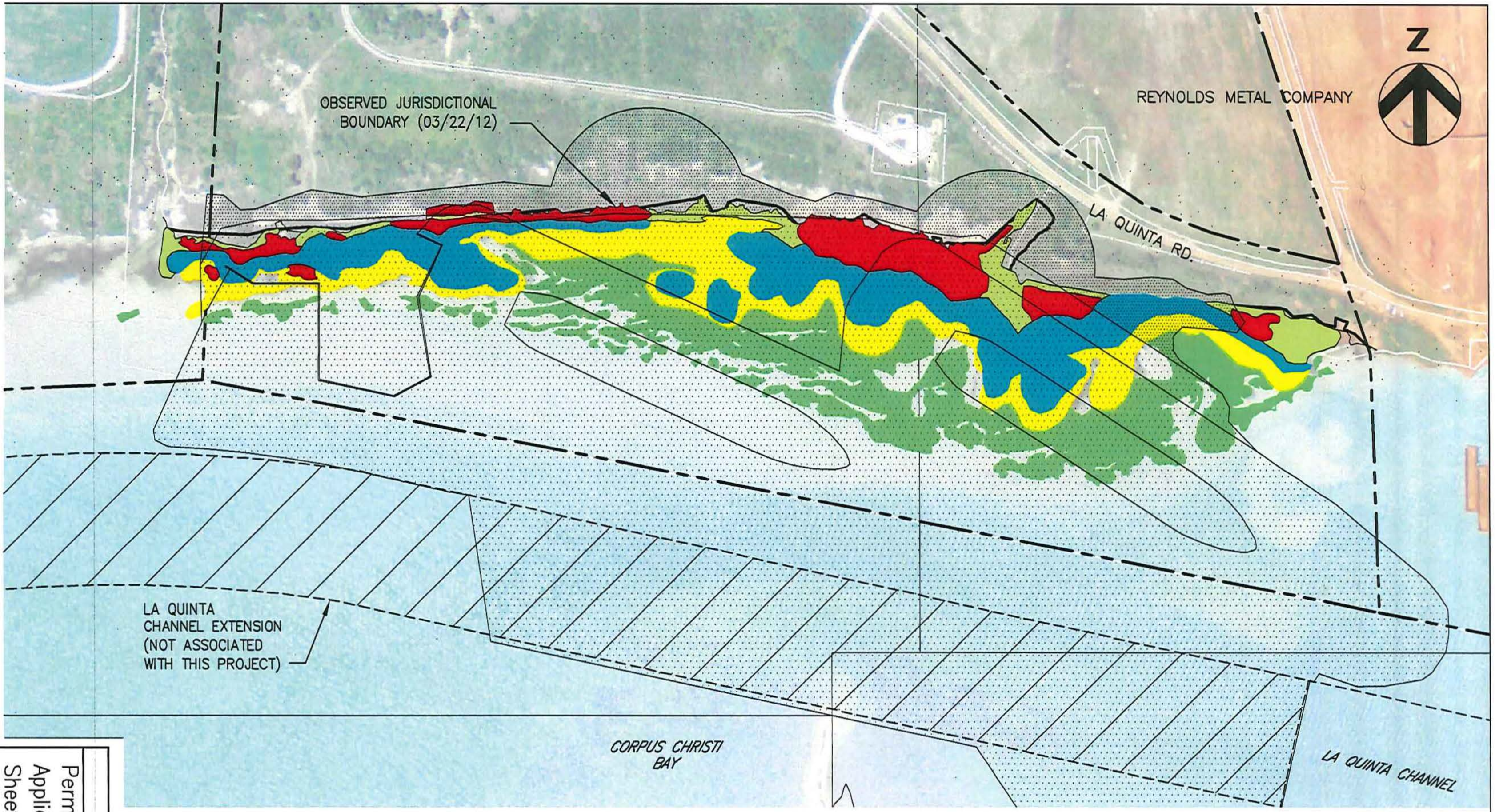

PROPOSED IMPACTS

SCALE: 0 250' 500'

CORPUS CHRISTI LIQUEFACTION - IMPACT SUMMARY TABLE

	Resource Type	Total Previously Permitted Project Impacts			Additional Impacts Over Previous Permit			Total Impacts - Previously Permitted and Proposed Amendment		
		Permanent	Temporary	Total	Permanent	Temporary	Total	Permanent	Temporary	Total
🟦	Mangrove	1.59	0.42	2.01	5.13	0.21	5.34	6.72	0.63	7.35
🟨	Smooth cordgrass	2.38	0.38	2.76	3.53	-0.1	3.43	5.91	0.28	6.19
🟩	Vegetated flats	1.13	0.49	1.62	-0.13	-0.12	-0.25	1	0.37	1.37
🟥	Non-Vegetated flats	0.23	0.22	0.45	2.64	0.16	2.8	2.87	0.38	3.25
🟩	SAV	5.35	0.69	6.04	3.82	-0.57	3.25	9.17	0.12	9.29
	TOTAL	**10.68**	**2.2**	**12.88**	**14.99**	**-0.42**	**14.57**	**25.67**	**1.78**	**27.45**

▨ TEMPORARY IMPACT AREA – CONSTRUCTION ▨ PERMANENT IMPACT AREA – OPERATIONS

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TEXAS FIRM REGISTRATION NUMBER 754

ACTIVITY: CORPUS CHRISTI LIQUEFACTION – PROPOSED IMPACTS

APPLICANT: CORPUS CHRISTI LIQUEFACTION, LLC AND CHENIERE CORPUS CHRISTI PIPELINE, L.P. DATUM:

DATE: 03/13 REV. DATE: 03/28/2014

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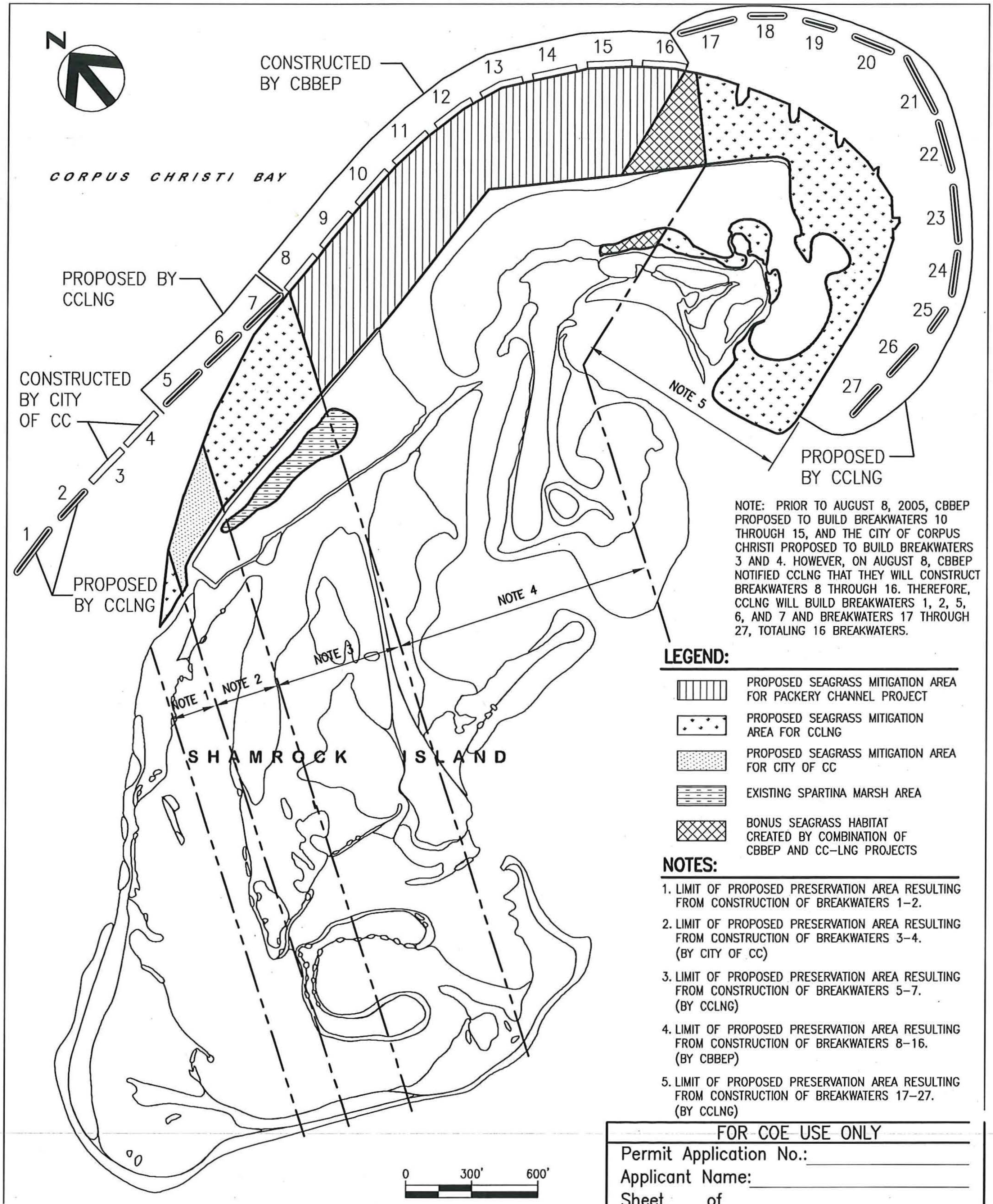

NOTE: PRIOR TO AUGUST 8, 2005, CBBEP PROPOSED TO BUILD BREAKWATERS 10 THROUGH 15, AND THE CITY OF CORPUS CHRISTI PROPOSED TO BUILD BREAKWATERS 3 AND 4. HOWEVER, ON AUGUST 8, CBBEP NOTIFIED CCLNG THAT THEY WILL CONSTRUCT BREAKWATERS 8 THROUGH 16. THEREFORE, CCLNG WILL BUILD BREAKWATERS 1, 2, 5, 6, AND 7 AND BREAKWATERS 17 THROUGH 27, TOTALING 16 BREAKWATERS.

LEGEND:

▥	PROPOSED SEAGRASS MITIGATION AREA FOR PACKERY CHANNEL PROJECT
⁘	PROPOSED SEAGRASS MITIGATION AREA FOR CCLNG
░	PROPOSED SEAGRASS MITIGATION AREA FOR CITY OF CC
☰	EXISTING SPARTINA MARSH AREA
▩	BONUS SEAGRASS HABITAT CREATED BY COMBINATION OF CBBEP AND CC-LNG PROJECTS

NOTES:

1. LIMIT OF PROPOSED PRESERVATION AREA RESULTING FROM CONSTRUCTION OF BREAKWATERS 1-2.
2. LIMIT OF PROPOSED PRESERVATION AREA RESULTING FROM CONSTRUCTION OF BREAKWATERS 3-4. (BY CITY OF CC)
3. LIMIT OF PROPOSED PRESERVATION AREA RESULTING FROM CONSTRUCTION OF BREAKWATERS 5-7. (BY CCLNG)
4. LIMIT OF PROPOSED PRESERVATION AREA RESULTING FROM CONSTRUCTION OF BREAKWATERS 8-16. (BY CBBEP)
5. LIMIT OF PROPOSED PRESERVATION AREA RESULTING FROM CONSTRUCTION OF BREAKWATERS 17-27. (BY CCLNG)

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ACTIVITY: CORPUS CHRISTI LIQUEFACTION – SHAMROCK ISLAND MITIGATION PLAN

APPLICANT: CORPUS CHRISTI LIQUEFACTION

DATUM:

DATE: 03/13

REV. DATE: 03/19/2013

HDR JOB NO: 180841

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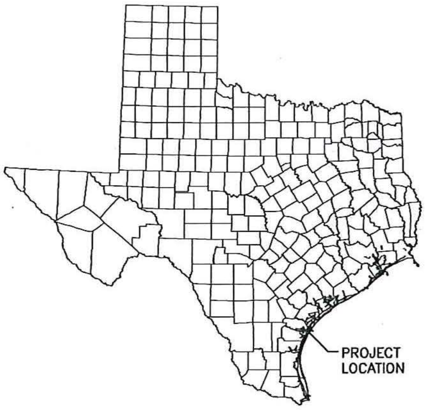
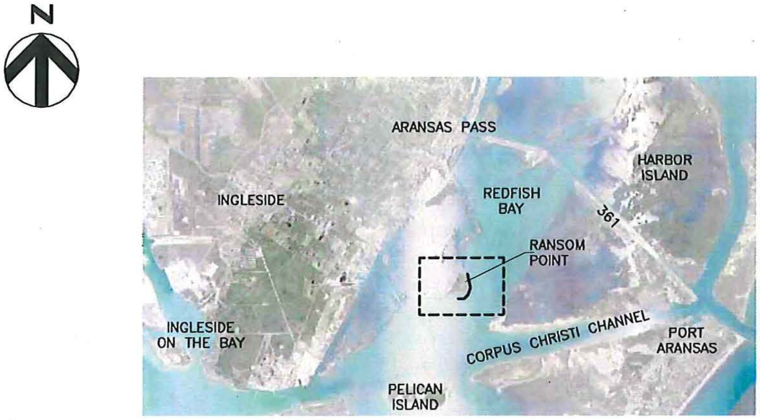
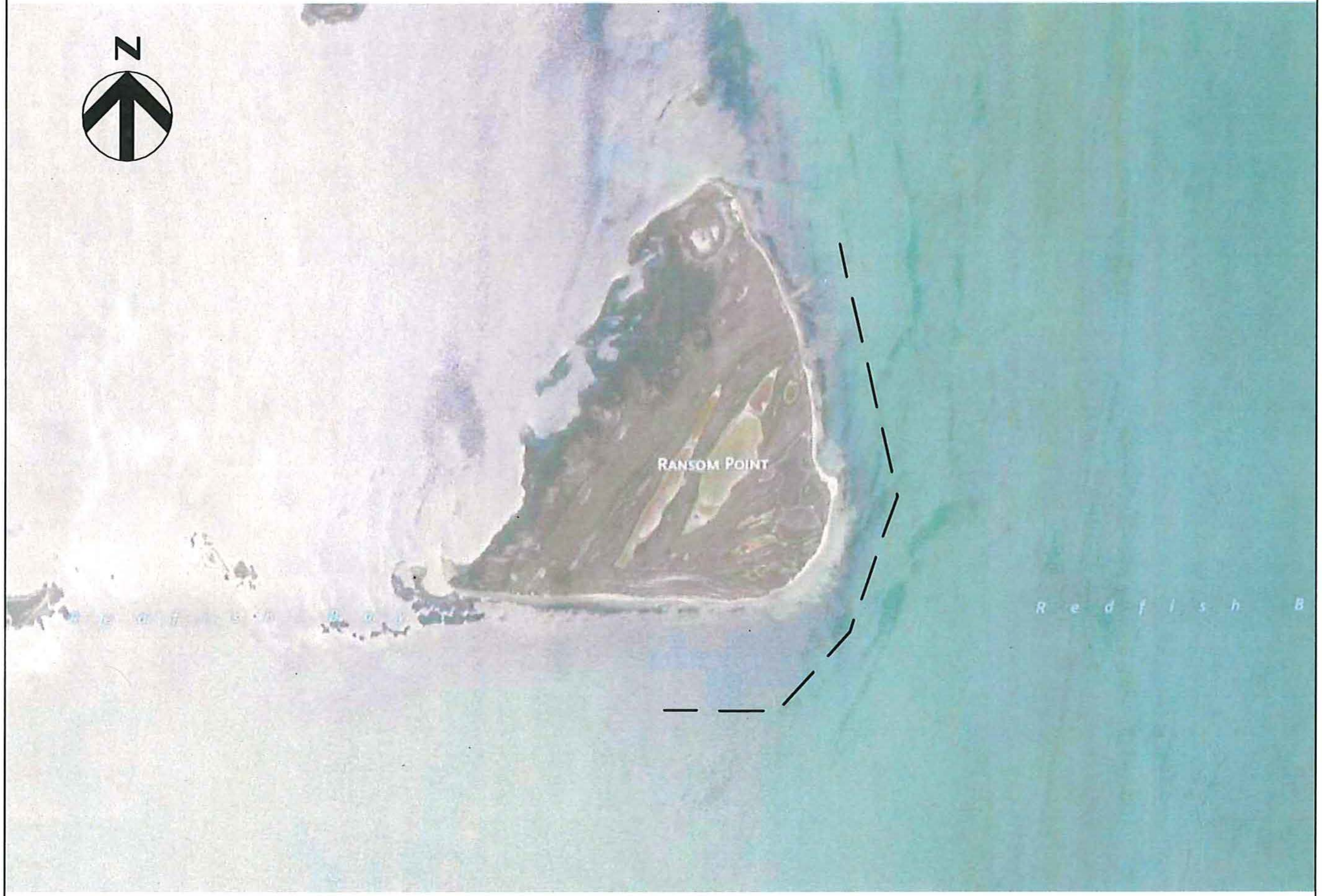


VICINITY MAP
N.T.S.



LOCATION MAP
N.T.S.



RANSOM POINT PROJECT SITE
SCALE: 0 500' 1000'

LEGEND
— — 3500' SEGMENTED BREAKWATER

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ACTIVITY: CORPUS CHRISTI LIQUEFACTION – RANSOM POINT MITIGATION PLAN

APPLICANT: CORPUS CHRISTI LIQUEFACTION DATUM:

DATE: 03/13 REV. DATE: 03/19/2013

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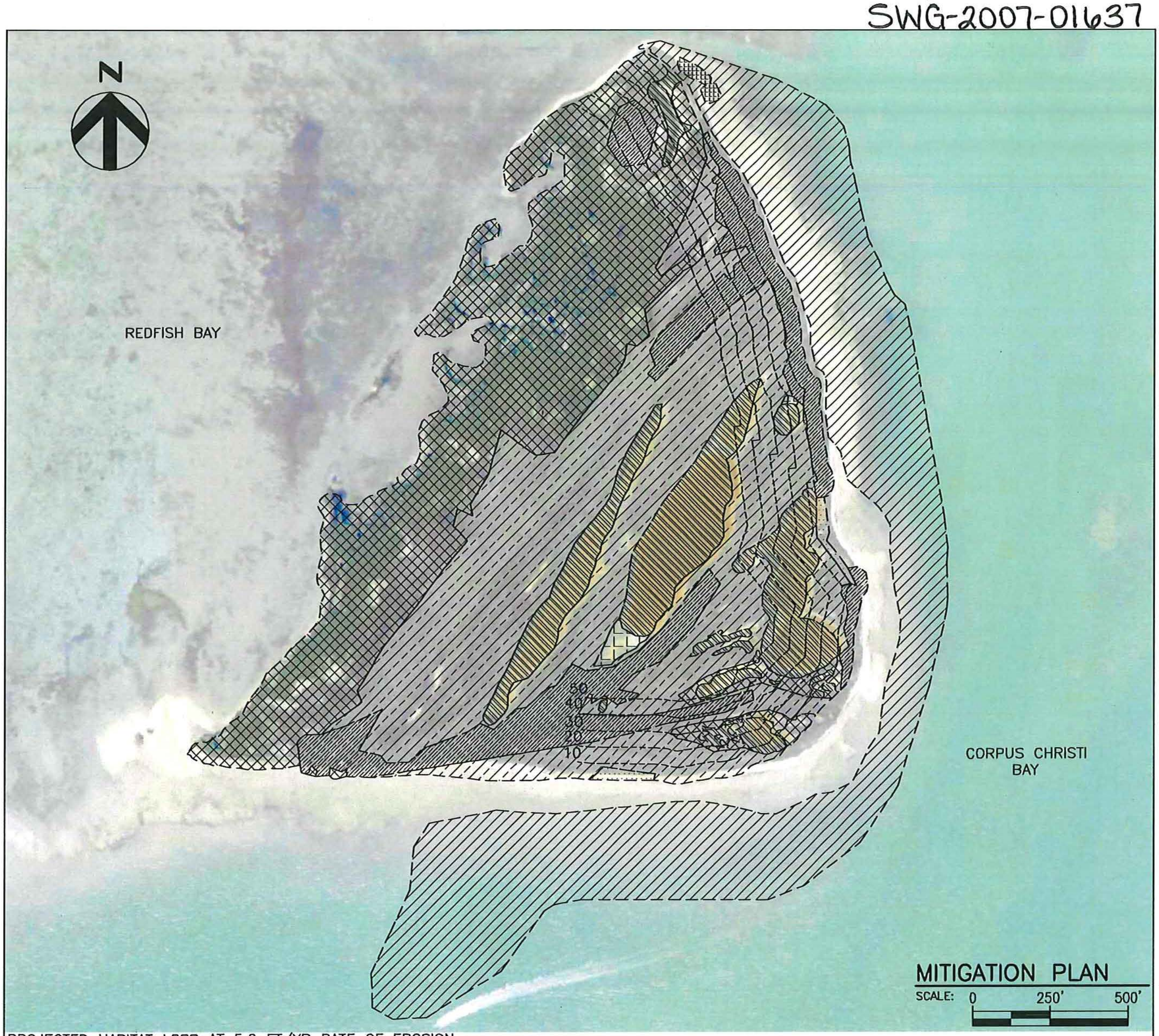

PROJECTED HABITAT LOSS AT 5.2 FT/YR RATE OF EROSION

10 YR – BORRICHIA – 1.00 ACRES
AVICENNIA – 0.59 ACRES
SESUVIUM – 0.32 ACRES
UPLAND – 1.73 ACRES
OPEN WATER – 0.26 ACRES
TOTAL – 3.9 ACRES

20 YR – BORRICHIA – 1.80 ACRES
AVICENNIA – 0.57 ACRES
SPARTINA – 0.02 ACRES
UPLAND – 0.52 ACRES
OPEN WATER – 0.82 ACRES
TOTAL – 3.73 ACRES

30 YR – BORRICHIA – 1.67 ACRES
AVICENNIA – 0.66 ACRES
SPARTINA – 0.01 ACRES
UPLAND – 0.36 ACRES
OPEN WATER – 0.85 ACRES
TOTAL – 3.55 ACRES

40 YR – BORRICHIA – 1.54 ACRES
AVICENNIA – 0.53 ACRES
UPLAND – 0.70
OPEN WATER – 0.62 ACRES
TOTAL – 3.39 ACRES

50 YR – BORRICHIA – 1.47 ACRES
AVICENNIA – 0.61 ACRES
UPLAND – 0.49
OPEN WATER – 0.66 ACRES
TOTAL – 3.23 ACRES

LEGEND

- - - - - - - - - - - 10 YR EROSION (5.2 FT/YEAR)
▨ SEAGRASS (26.57 ACRES)
▨ UPLAND (7.90 ACRES)
░ SESUVIUM (0.32 ACRES)
▦ OYSTER REEF (0.18 ACRES)
▦ S. ALTERNIFLORA (0.28 ACRES)
▩ AVICENNIA (23.13 ACRES)
▨ BORRICHIA (26.20 ACRES)
▧ OPEN WATER (8.14 ACRES)

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*PROJECTED AVERAGE HABITAT LOSS – 3.56 ACRES/10 YEARS

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ACTIVITY: CORPUS CHRISTI LIQUEFACTION – RANSOM POINT MITIGATION PLAN
HABITAT TYPES & PROJECTED LOSS FROM EROSION

APPLICANT: CORPUS CHRISTI LIQUEFACTION

DATUM:

DATE: 03/13

REV. DATE: 03/19/2013

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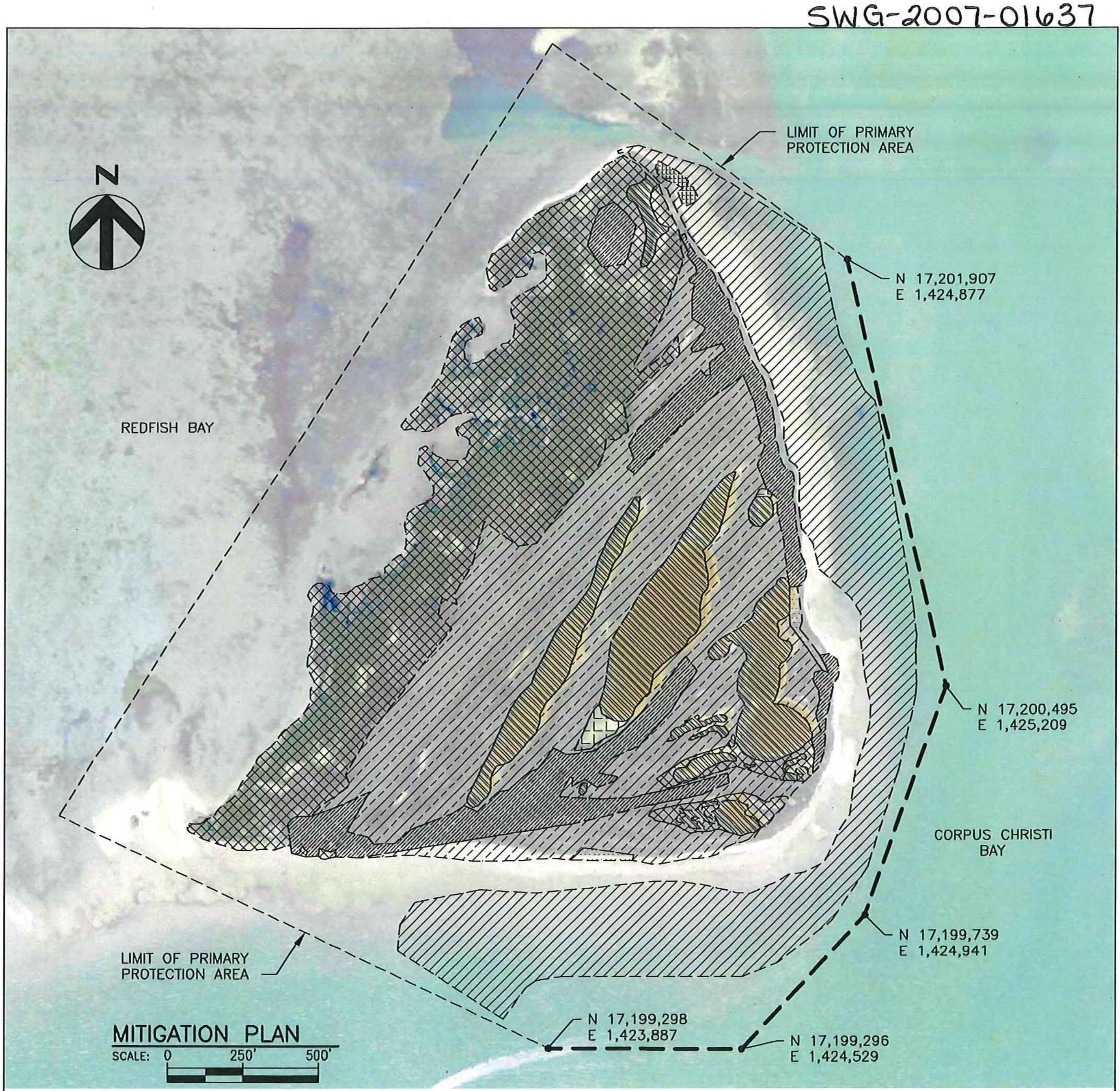

LEGEND

— — — PROPOSED 3500' SEGMENTED BREAKWATER

▨ PROPOSED PROTECTED SEAGRASS (23.26 ACRES)

▨ UPLAND (7.90 ACRES)

▨ SESUVIUM (0.32 ACRES)

▦ OYSTER REEF (0.18 ACRES)

▦ S. ALTERNIFLORA (0.28 ACRES)

▩ AVICENNIA (22.95 ACRES)

▨ BORRICHIA (26.20 ACRES)

▧ OPEN WATER (8.14 ACRES)

NOTES:

1. APPROXIMATELY 48.5 ACRES BETWEEN BREAKWATER AND SHORELINE (DISTANCE VARIES)
2. APPROXIMATELY 2.5 ACRES BETWEEN BREAKWATER AND SEAGRASS BEDS (DISTANCE VARIES)
3. SURFACE AREA OF BAY BOTTOM TO BE COVERED BY PROPOSED ROCK BREAKWATER IS APPROXIMATELY 3.5 ACRES.
4. NORTHINGS & EASTINGS ARE IN NAD83, STATE PLANE, TEXAS SOUTH, US FEET.

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Sheet ____ of ____

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TEXAS FIRM REGISTRATION NUMBER 754

ACTIVITY: CORPUS CHRISTI LIQUEFACTION – PRIMARY PRESERVED HABITATS

APPLICANT: CORPUS CHRISTI LIQUEFACTION, LLC AND CHENIERE CORPUS CHRISTI PIPELINE, L.P. DATUM:

DATE: 03/13 REV. DATE: 03/27/2014

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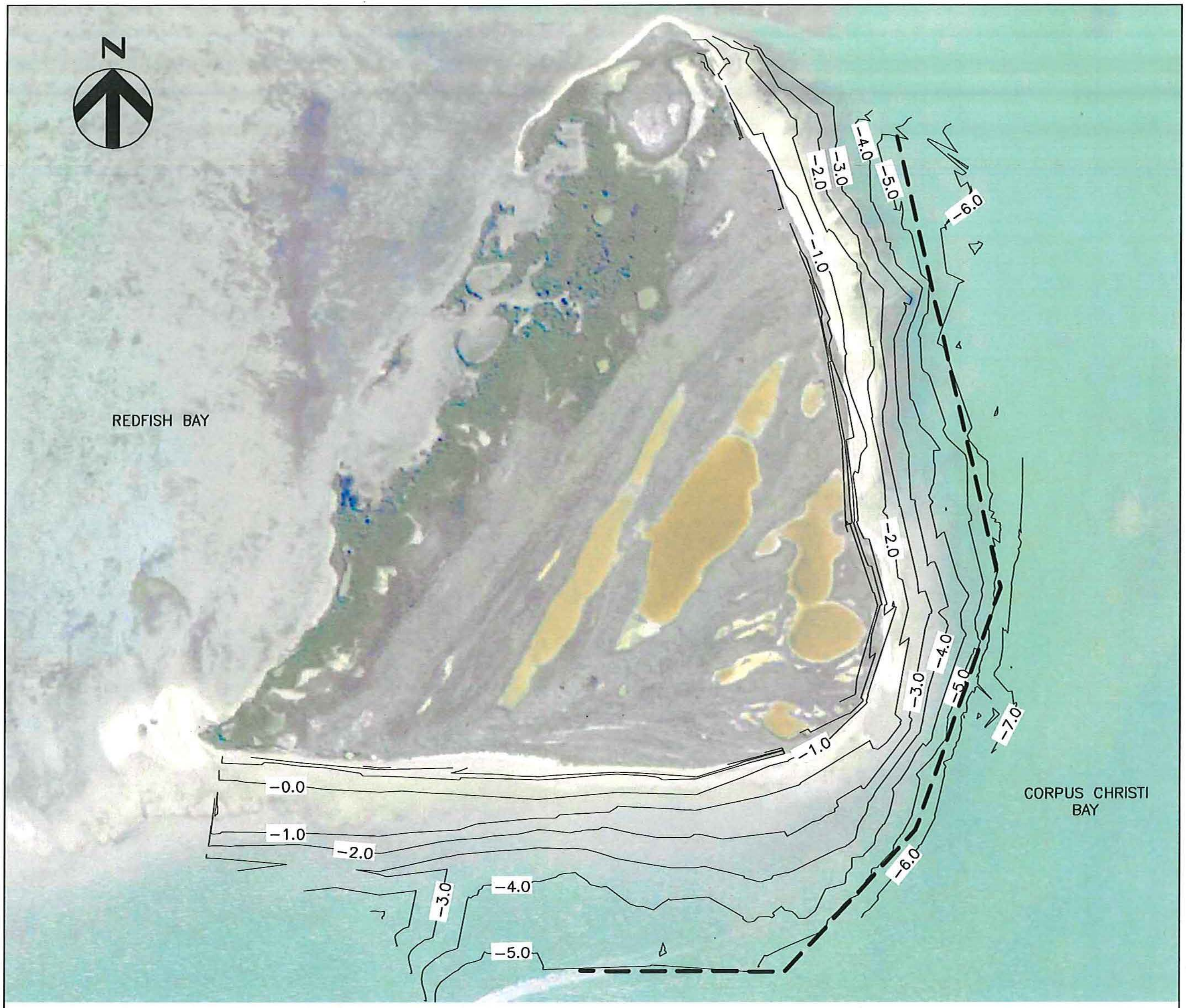

MITIGATION PLAN – BREAKWATER ALIGNMENT

SCALE: 0 250' 500'

LEGEND

▬ ▬ ▬ 3500' SEGMENTED BREAKWATER

—-4.0— CONTOURS

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TEXAS FIRM REGISTRATION NUMBER 754

ACTIVITY: CORPUS CHRISTI LIQUEFACTION – RANSOM POINT MITIGATION PLAN
SEA FLOOR CONTOUR SURVEY

APPLICANT: CORPUS CHRISTI LIQUEFACTION

DATUM:

DATE: 03/13

REV. DATE: 03/19/2013

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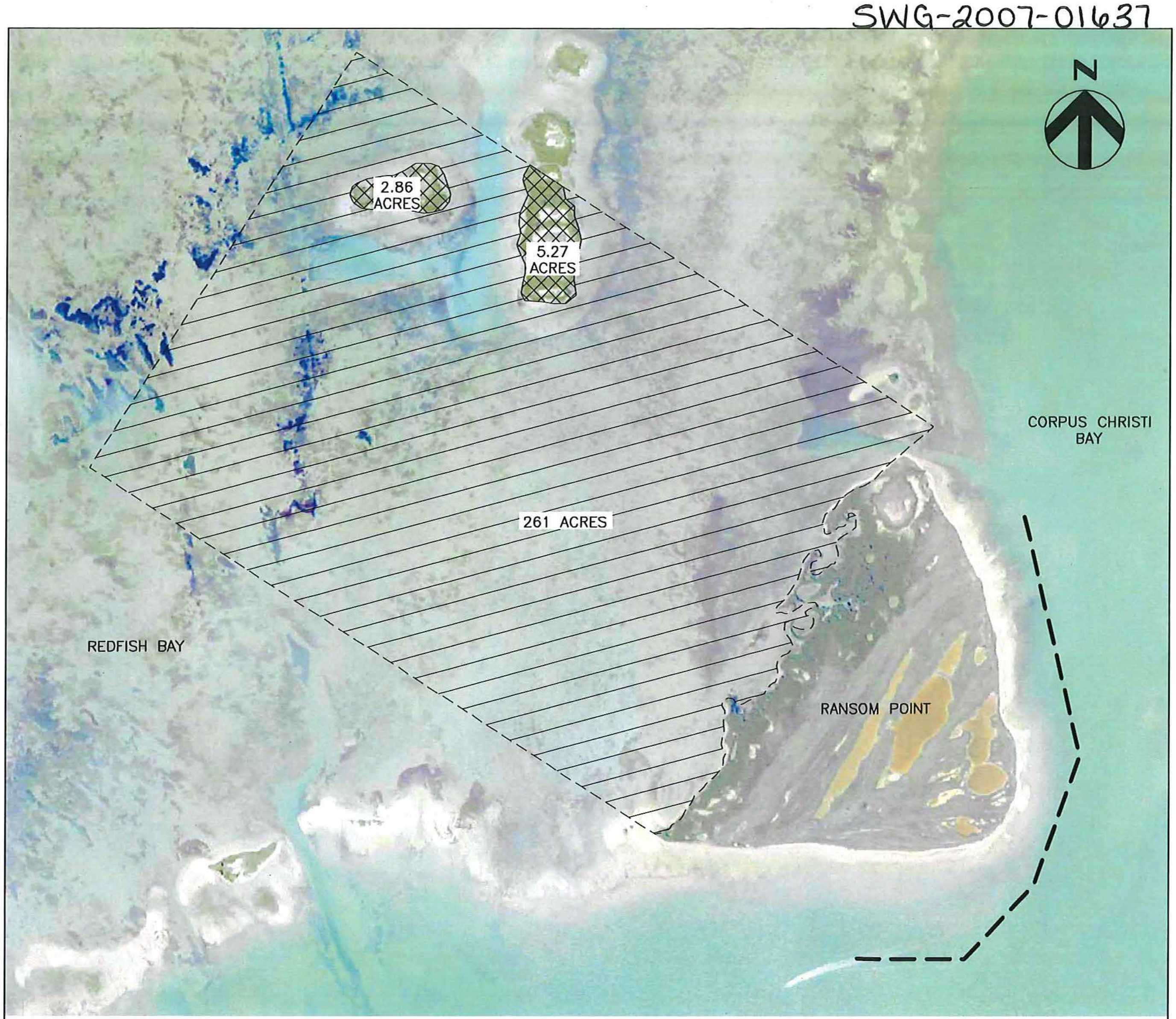

MITIGATION PLAN – SECONDARY PRESERVATION

SCALE: N.T.S.

LEGEND

— — — 3500' SEGMENTED BREAKWATER

- - - - - - SECONDARY PRESERVATION BENEFITS

▨ SEAGRASS (261 ACRES)

▩ AVICENNIA MARSH (8.13 ACRES)

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TEXAS FIRM REGISTRATION NUMBER 754

ACTIVITY: CORPUS CHRISTI LIQUEFACTION – SECONDARY HABITAT BENEFITS FOR RANSOM POINT PRESERVATION

APPLICANT: CORPUS CHRISTI LIQUEFACTION

DATUM:

DATE: 03/13

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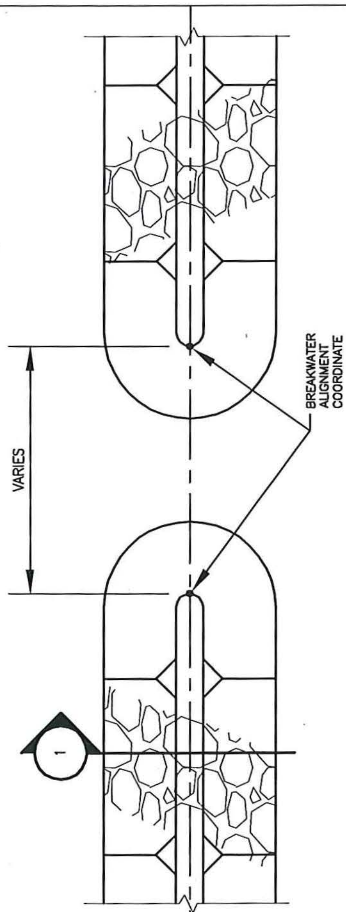
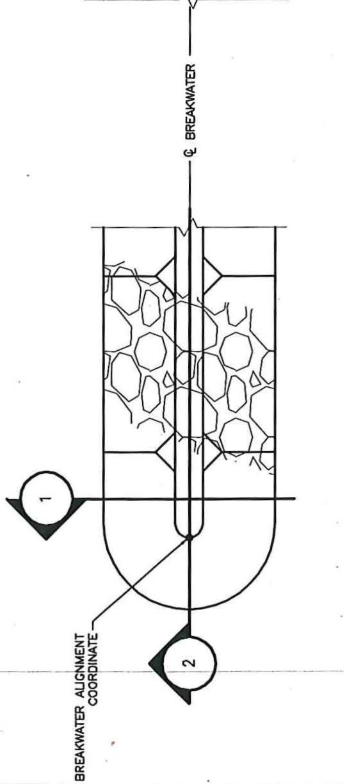
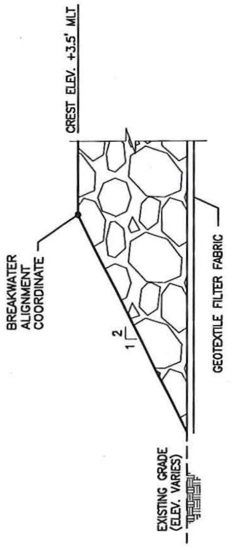


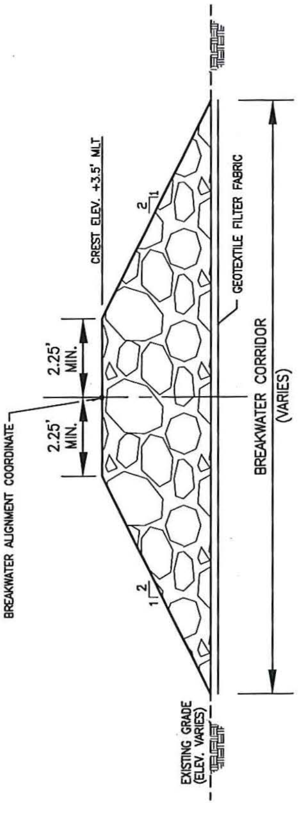
DETAIL – BREAKWATER GAP
SCALE: N.T.S.



DETAIL – BREAKWATER TERMINATION
SCALE: N.T.S.



SECTION ②
SCALE: N.T.S.



SECTION ①
SCALE: N.T.S.

NOTES:

1. EXISTING BOTTOM ELEVATION ALONG BREAKWATER ALIGNMENT VARIES. BREAKWATERS WILL BE CONSTRUCTED ALONG OR SEAWARD OF 5' CONTOUR IN AN ATTEMPT TO AVOID SEAGRASS IMPACTS.

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ACTIVITY: CORPUS CHRISTI LIQUEFACTION – RANSOM POINT MITIGATION PLAN
TYPICAL BREAKWATER DETAILS

APPLICANT: CORPUS CHRISTI LIQUEFACTION
DATUM:

DATE: 03/13
REV. DATE: 03/19/2013

HDR JOB NO: 180841

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Appendix D

TABLES

Table 4.6-4
Birds of Conservation Concern – Gulf Coastal Prairie Region (BCR 37)

Common Name	Scientific Name
Audubon’s shearwater	*Puffinus lherminieri*
Band-rumped storm petral	*Oceanodroma castro*
American bittern	*Botaurus lentiginosus*
Least bittern	*Ixobrychus exilis*
Reddish egret	*Egretta rufescens*
Swallow-tailed kite	*Elanoides forficatus*
Bald eagle	*Haliaeetus leucocephalus*
White-tailed hawk	*Buteo albicaudatus*
Peregrine falcon	*Falco peregrinus*
Yellow rail	*Coturnicops noveboracensis*
Black rail	*Laterallus jamaicensis*
Snowy plover	*Charadrius alexandrinus*
Wilson’s plover	*Charadrius wilsonia*
Mountain plover	*Charadrius montanus*
American oystercatcher	*Haematopus palliatus*
Solitary sandpiper	*Tringa solitaria*
Lesser yellowlegs	*Tringa flavipes*
Upland sandpiper	*Bartramia longicauda*
Whimbrel	*Numenius phaeopus*
Long-billed curlew	*Numenius americanus*
Hudsonian godwit	*Limosa haemastica*
Marbled godwit	*Limosa fedoa*
Red knot	*Calidris canutus*
Buff-breasted sandpiper	*Tryngites subruficollis*
Short-billed dowitcher	*Limnodromus griseus*
Least tern	*Sternula antillarum*
Gull-billed tern	*Gelochelidon nilotica*

Table 4.6-4
Birds of Conservation Concern – Gulf Coastal Prairie Region (BCR 37)

Common Name	Scientific Name
Sandwich tern	*Thalasseus sandvicensis*
Black skimmer	*Rynchops niger*
Short-eared owl	*Asio flammeus*
Loggerhead shrike	*Lanius ludovicianus*
Sedge wren	*Cistothorus platensis*
Sprague’s pipit	*Anthus spragueii*
Prothonotary warbler	*Protonotaria citrea*
Swainson’s warbler	*Limnothlypis swainsonii*
Botteri’s sparrow	*Aimophila botterii*
Grasshopper sparrow	*Ammodramus savannarum*
Henslow’s sparrow	*Ammodramus henslowii*
LeConte’s sparrow	*Ammodramus leconteii*
Nelson’s sharp-tailed sparrow	*Ammodramus nelsoni*
Seaside sparrow	*Ammodramus maritimus*
Painted bunting	*Passerina ciris*
Dickcissel	*Spiza americana*

Table 4.7-1
Federally Threatened and Endangered Species in the Project Area

Species	Scientific Name	Federal Status a/	State Status a/	Project Component	Preferred Habitat	Determination
MAMMALS						
Gulf Coast Jaguarundi	*Herpailurus yagouaroundi*	E	E		The 2012 survey of the Project area found semi-suitable habitat for the jaguarundi. However, San Patricio County is out of this species known range.	*No Effect*
Ocelot	*Leopardus pardalis*	E	E		The 2012 survey of the Project area found semi-suitable habitat for the ocelot, however the habitat is small and isolated. The ocelot is not known to inhabit this part of San Patricio County.	*No Effect*
Blue whale	*Balaenoptera musculus*	E	--	Terminal	Inhabits deep waters of the continental shelf. Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.	*Not Likely to Adversely Affect*
Fin whale	*Balaenoptera physalus*	E	--	Terminal	Inhabits deep waters of the continental shelf. Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.	*Not Likely to Adversely Affect*
Humpback whale	*Megapetra novaeangliae*	E	--	Terminal	Inhabits deep waters of the continental shelf. Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.	*Not Likely to Adversely Affect*
Sei whale	*Balaenoptera borealis*	E	--	Terminal	Inhabits deep waters of the continental shelf. Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.	*Not Likely to Adversely Affect*
Sperm whale	*Physeter macrocephalus*	E	--	Terminal	Inhabits deep waters of the continental shelf. Suitable habitat is not present in the Project area, but is present in the open Gulf of Mexico in the vicinity of transiting LNGCs.	*Not Likely to Adversely Affect*
West Indian manatee	*Trichechus manatus*	E	E	Terminal	Occasional visitor to Texas waters. Inhabits warm, shallow coastal waters, estuaries, bays, rivers, and lakes. Suitable habitat is present within the Project area.	*Not Likely to Adversely Affect*

Table 4.7-1
Federally Threatened and Endangered Species in the Project Area

Species	Scientific Name	Federal Status a/	State Status a/	Project Component	Preferred Habitat	Determination
BIRDS						
Whooping crane	*Grus americana*	E	E	Terminal	Winter habitat in Texas comprises brackish marshes, bays, and flats. Suitable habitat may be present near the Project area.	*Not Likely to Adversely Affect*
Piping plover	*Charadrius melodus*	T	T	Terminal	Beaches, mudflats, and sand flats. Suitable habitat is present in the Project area.	*Not Likely to Adversely Affect*
REPTILES						
Loggerhead sea turtle	*Caretta caretta*	T	T	Terminal	Juveniles are found in Gulf and bay systems. Adults are mostly pelagic. Suitable habitat is present in the Project area.	*Not Likely to Adversely Affect*
Green sea turtle	*Chelonia mydas*	T	T	Terminal	Gulf and bay systems, shallow water seagrass beds, open water. Suitable habitat is present in the Project area.	*Not Likely to Adversely Affect*
Leatherback sea turtle	*Dermochelys coriacea*	E	E	Terminal	Gulf and bay systems. Widest ranging open water reptile. Suitable habitat is present in the Project area.	*Not Likely to Adversely Affect*
Atlantic hawksbill sea turtle	*Eretmochelys imbricata*	E	E	Terminal	Gulf and bay systems, warm, shallow waters especially in rocky marine environments, jetties and coral reefs. Suitable habitat may be present in the Project area.	*Not Likely to Adversely Affect*
Kemp's ridley sea turtle	*Lepidochelys kempii*	E	E	Terminal	Gulf and bay systems. Adults stay within the shallow waters of the Gulf of Mexico. Suitable habitat is present in the Project area.	*Not Likely to Adversely Affect*
PLANTS						
Slender rush pea	*Hoffsmanseggia tenelle*	E	E	Terminal	Project is outside of known range	*No Effect*
South Texas ambrosia	*Ambrosia cheiranthifolia*	E	E	Terminal	Project is outside of known range	*No Effect*

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a/ E=Endangered, T=Threatened

Table 4.7-2
State Threatened and Endangered Species in the Project Area

Species	Scientific Name	State Status a/	Preferred Habitat	Determination
MAMMALS				
Red wolf	*Canus rufus*	E	Brushy or forested areas and coastal prairies. Species has been extirpated in the Project area.	*No impact*
White-nosed coati	*Nasua narica*	T	Woodlands, riparian corridors and canyons. Suitable habitat is not present in the Project area.	*No impact*
Southern yellow bat	*Lasiurus ega*	T	Roosts in trees of far south Texas. Suitable habitat is present in the Project area.	*Impacts would not be significant*
BIRDS				
Eskimo curlew	*Numenius borealis*	E	Grasslands, pastures, plowed fields, marshes, and mudflats. Species has likely been extirpated in the Project area.	*No impact*
Texas Botteri's Sparrow	*Aimophila botterii texana*	T	Grassland and short-grass plains with scattered bushes or shrubs. Suitable habitat is present within the Project area; however, the Project area is outside the species' known range.	*No impact*
Peregrine falcon	*Falco peregrinus*	T	Urban, concentrations along coast and barrier islands. Suitable habitat is present within the Project area; however, the species only occurs within the Project area as an occasional transient.	*No impact*
American peregrine falcon	*Falco peregrinus anatum*	T	Urban, concentrations along coast and barrier islands. Suitable habitat is present within the Project area; however, the species only occurs within the Project area as an occasional transient.	*No impact*
Northern Aplomado falcon	*Falco femoralis septentrionalis*	E	Savanna, open woodland, grass plains, plowed fields, coastal prairies, and marshes. Suitable habitat is present within the Project area; however, the Project area is outside the species' known range.	*No impact*

Table 4.7-2
State Threatened and Endangered Species in the Project Area

Species	Scientific Name	State Status a/	Preferred Habitat	Determination
Sooty tern	*Sterna fuscata*	T	Islands and coastal beaches. Suitable habitat is present in the Project area; however the species is very uncommon in coastal Texas.	*No impact*
White-faced ibis	*Plegadis chihi*	T	Freshwater marshes, swamps, and ponds. Suitable habitat is not present in the Project area.	*No impact*
Reddish egret	*Egretta rufescens*	T	Coastal marshes, shell beaches, sand flats, and mudflats. Suitable habitat is present in the Project area.	*Impacts would not be significant*
White-tailed hawk	*Buteo albicaudatus*	T	Coastal grasslands. Suitable habitat is present in the Project area.	*Impacts would not be significant*
Wood stork	*Mycteria americana*	T	Prairie ponds, flooded pastures, and fields. Suitable habitat is present in the Project area.	*Impacts would not be significant*
REPTILES / AMPHIBIANS				
Sheep frog	*Hypopachus variolosus*	T	Tropical humid forests. Suitable habitat is not present in the Project area.	*No impact*
Black-spotted newt	*Notophthalmus meridionalis*	T	Freshwater ponds, canals, and ditches. Suitable is present within the Project area.	*Impacts would not be significant*
South Texas siren	*Siren* spp.	T	Freshwater ponds, ditches, and swamps. Suitable is present within the Project area.	*Impacts would not be significant*
Texas tortoise	*Gopherus berlandieri*	T	Cactus rich areas of south Texas. Suitable habitat is present in the Project area.	*Impacts would not be significant*
Timber/canebrake rattlesnake	*Crotalus horridus*	T	Hilly woodlands and thickets near freshwater. Suitable habitat is not present in the Project area.	*No impact*
Texas horned lizard	*Phrynosoma cornutum*	T	Loose sand and loamy soils throughout Texas. Suitable habitat is present in the Project area.	*Impacts would not be significant*

Table 4.7-2
State Threatened and Endangered Species in the Project Area

Species	Scientific Name	State Status a/	Preferred Habitat	Determination
Texas scarlet snake	*Cemophora coccinea lineri*	T	Sandy thickets of the Texas Coastal Bend. Suitable habitat is not present in the Project area.	No
Texas indigo snake	*Drymarchon melanurus erebennus*	T	Sparsely vegetated areas of south Texas. Suitable habitat is present in the Project area.	*Impacts would not be significant*
FISH				
Smalltooth sawfish	*Pristis pecinata*	E	Sheltered bays, shallow banks, and in estuaries or river mouths for young and mangrove, reef, seagrass, and coral for adults. Species has likely been extirpated in the Project area.	*No impact*
Opossum pipefish	*Microphis brachyurus*	T	Anadromous and breeds in freshwater. Spends majority of its time in open ocean. Suitable habitat is present in the Project area.	*Impacts would not be significant*
MOLLUSKS				
Golden orb	*Quadrula aurea*	T	Habitat is restricted to lentic and lotic areas of river basins. Suitable habitat is not present in the Project area.	*No impact*

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a/ E=Endangered, T=Threatened

Table 4.13-1
Cumulative Impacts of the Corpus Christi LNG Project and Other Projects in the Project Area

Project	Land Disturbance	Wetlands/ Surface Waterbodies	Water Use / Discharge	T&E Species/ EFH	Coastal Marine Disturbance (Dredging) a/	Marine Transportation	Socioeconomics	Air Quality	Noise	Visual	Geology	Soils
Cheniere Terminal and Pipeline	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
COE La Quinta Channel Extension	Yes	Yes	No	Yes	Yes	Yes	Yes	IU	No	Yes	Yes	Yes
POCCA La Quinta Trade Gateway Terminal	Yes	Yes	IU	IU	Yes	Yes	Yes	IU	No	Yes	Yes	Yes
Revolution Energy Harbor Wind Project	Yes	Yes	IU	IU	No	Yes	IU	No	No	Yes	No	No
Offshore Wind Power Systems of Texas, LLC Foundation Test Site	Yes	Yes	No	IU	Yes	Yes	IU	No	No	Yes	No	No
TPCO America Corporation Minimill	Yes	IU	Yes	IU	No	IU	Yes	Yes	No	Yes	IU	Yes
OIEC Propane Export Facility	Yes	IU	Yes	IU	IU	Yes	Yes	Yes	No	Yes	IU	Yes
Papalote Creek Wind Farm	Yes	No	No	IU	No	No	Yes	No	No	Yes	No	No

Table 4.13-1
Cumulative Impacts of the Corpus Christi LNG Project and Other Projects in the Project Area

Project	Land Disturbance	Wetlands/ Surface Waterbodies	Water Use / Discharge	T&E Species/ EFH	Coastal Marine Disturbance (Dredging) a/	Marine Transportation	Socioeconomics	Air Quality	Noise	Visual	Geology	Soils
OxyChem NGL Fractionation Facility	Yes	IU	Yes	No	IU	Yes	Yes	Yes	Yes	Yes	No	Yes
OxyChem Ethylene Plant	Yes	IU	Yes	IU	IU	Yes	Yes	Yes	Yes	Yes	No	Yes
Voestalpine DRI Plant	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Flint Hills West Refinery Expansion	No	No	IU	No	No	Yes	Yes	Yes	No	Yes	No	Yes
Freeport Liquefaction	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Non-Jurisdictional electrical power lines and substations	Yes	No	No	No	No	No	No	No	No	No	No	Yes
Non-Jurisdictional waterline	Yes	No	No	No	No	No	No	No	No	No	No	Yes
Removal of Non-Jurisdictional Natural Gas Pipelines	Yes	Yes	No	Yes	Yes	No	No	No	No	No	No	No

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a/ IU = Information Unavailable

Appendix E

CHENIERE’S FUGITIVE DUST CONTROL PLAN

Fugitive Dust Control Plan

1 Objective

The objective of this fugitive dust control plan is to identify potential dust emission sources and provide guidance to construction and field personnel on measures to avoid the generation of fugitive dust and control any generated fugitive dust during construction activities associated with the Corpus Christi Liquefaction Project. It will be the responsibility of Project Contractors and the Environmental Inspectors to identify all activities generating fugitive dust, implement feasible dust control measures, and ensure compliance with regulatory requirements.

2 Fugitive Dust Sources

Dust is generated by the mechanical disturbance of granular material exposed to the air. Dust from open sources is termed “fugitive” because it is not discharged to the atmosphere in a confined flow stream. The following activities are identified as having potential for generating fugitive dust.

- Vehicle and motorized equipment movement on paved and unpaved surfaces;
- Vegetation Removal;
- Clearing and Grading;
- Soil Stabilization;
- Bulk/Piles material loading, unloading, hauling, etc.; and
- Abrasive Blasting.

3 Dust Control Measures

3.1 Water Truck

Project Contractors will make all practicable efforts to minimize fugitive dust emissions from construction activities. The Project will have a water tank and will purchase water from the local municipality from which the Project’s 80 barrel water truck on site that will load water to spray areas for dust control.

Areas to be sprayed include most areas within the Project Boundary; for example, but not limited to:

- Designated access roads;
- Construction Dock and staging areas;
- All designated Staging and Laydown areas; and
- All designated parking areas.

The frequency at which the water truck will spray the Project areas will vary based on weather and site conditions. For example, in dry conditions, construction traffic may increase the amount of dust generated on access roads, thus the water truck would be instructed to spray regularly throughout the workday.

In contrast, if there is light traffic, minimal dust generating activities, and/or wet weather, the water truck may not be necessary. It will be at the discretion of the Environmental Inspector and Site Managers to engage water spraying of the site. Corpus Christi will ensure that a water truck be available at all times during construction. Please refer to Section 4 below for Project Authority.

3.2 Other dust control measures within and outside of the soil improvement areas:

3.2.1 Limiting vehicles from tracking "off-road", and keeping traffic to designated roads

Corpus Christi will install proper signage to direct traffic to designated roads. Any traffic that deviates from designated roads will be redirected to the designated road and the activity will be reported to the appropriate supervisor for corrective action.

3.2.2 Enforcing a speed-limit of 15 mph on unsurfaced roads

Corpus Christi will install speed limit signs on all designated access roads. Any observances of excessive speeds will be reported to the appropriate supervisors for corrective action, and removal from the Project if necessary. Speeding on the Project Site will not be tolerated.

3.2.3 Covering open-bodied haul trucks

The Environmental Inspector, Contractor Supervisors and Project Management will regularly be observing activities on-site. If there are observances of excessive dust being generated from open bodied trucks, they will be stopped and asked to reduce speeds or cover the truck beds as necessary.

3.2.4 Enclosing the work area

For discreet activities such as abrasive blasting, the contractors will be instructed to enclose the work area to contain any fugitive dust and emissions as per Corpus Christi's standard operation procedures.

3.2.5 Construction Entrances and Exits

Corpus Christi will use gravel at construction entrance and exit locations on any acess roads that are not paved. Additionally, the Environmental Inspector, Contractor Supervisors and Project Management will regularly monitor the roadways and will ensure paved roads are cleaned should mud or dirt track out.

4 Project Authority

During all phases of Site Preparation and Construction, Corpus Christi will ensure the appropriate authorities are on site at all times.

The following individuals have the equal authority to:

1. determine if/when water needs to be reapplied for dust control:
2. determine if/when a palliative action should be used; and
3. Stop the dust-producing work if the contractor does not comply with the dust control measures.

Title	**Name**	**Cell Phone Number**
Environmental Inspector		
Corpus Christi Construction Director		
Corpus Christi Project Director		
Contractor ES&H Manager		
Corpus Christi HSE Manager		

Appendix F

DISTRIBUTION LIST FOR DRAFT ENVIRONMENTAL IMPACT STATEMENT

Federal Government Agencies

- United States Environmental Protection Agency
    - Lisa Jackson, Administrator
    - Jerome Blackman, Natural Gas STAR
  - Office of Federal Activities
    - Robert Hargrove, NEPA Compliance
    - Susan E. Bromm, Acting Director
  - Office Enforcement and Compliance Assurance
    - Cynthia Giles, Assistant Administrator
  - Region 6
    - Jeff Robinson
    - Al Almendariz, Regional Administrator
    - Alfred Dumaual, GHG Cross - Cutting Issues
    - Barbara Keeler, Coastal Issues
    - Jim Herrington, Wetland Issues
    - Larry Giglio, NPDES Permits
    - Melanie Magee, GHG Air Permits
    - Michael Jansky, NEPA Compliance
    - Patrick Rankin, Legal Cross - Cutting Issues
    - Rhonda Smith, Chief - Office of Planning and Coordination
    - Rob Lawrence, Energy Policy Advisor
    - Tina Arnold, Legal Cross - Cutting Issues
- United States Fish and Wildlife Service
    - Frank Weaver
    - Daniel Ashe, Director
  - Division of Conservation and Classification
    - Nicole Alt, Chief
    - Pat Clements, Federal Project Coordinator
    - Allan Strand, Field Supervisor
  - Corpus Christi Ecological Services Field Office
    - Dawn Whitehead, Deputy Field Office Supervisor
  - Southwest Regional Office
    - Benjamin Tuggle, Regional Director
- United States Department of Energy
  - Office of Environmental Compliance
  - Office of Environmental Management
    - Ed LeDuc, Deputy Assistant General Counsel
  - Office of Intergovernmental Affairs
    - Carol M. Borgstrom, Director
  - Office of Import/Export Activities

    - Bob Corbin, Director
  - Office of Natural Gas Regulatory Activities
    - John Anderson, Manager
    - Lisa Tracy, NEPA Document Manager
  - International Activities Team
    - Sally Kornfeld, Team Leader
- United States Department of Agriculture
    - Jonathan Adelstein, Administrator
- Natural Resources Conservation Service
  - Texas State Office
    - Bob Stobaugh, Public Affairs Specialist
  - National Environmental Coordinator
    - John Matt Harrington
    - Andree Duvarney
  - Forest Service
    - Director of Lands
    - Deputy Chief, National Forest System
    - Ecosystem Management Coordination
    - Joe Carbone, Assistant Director, NEPA
- United States Army Corps of Engineers
    - John Furry, Senior Policy Advisor
    - Meredith Temple, Acting Chief of Engineers
    - Nicholas Laskowski, Permitting Agent
  - Galveston District
    - Supervisor, Corpus Christi Field Office
    - Regulatory Division Chief
    - Richard P. Pannell, District Commander
    - Casey Cutler, Policy Division Chief
- Advisory Council on Historic Preservation
    - Charlene D. Vaughn, Assistant Director for Federal Program
    - John Fowler, Executive Director
- United States Department of Transportation
    - Environmental Policies Team Leader
  - Federal Aviation Administration
    - Michael Huerta, Acting Administrator
  - Research and Special Programs Administration
    - William H. Gute, Eastern Region
    - John Pepper, Southwest Region
  - Pipeline and Hazardous Materials Safety Administration
    - Jeffrey Wiese, Associate Administrator

        Magdy El-Sibaie, Associate Administrator
    Office of Pipeline Safety
        Mike Israni, Program Manager
        Community Assistance/Technical Services
        Tom Fortner, Director
    Research and Special Programs Administration
        Administrator
    Western Region
        Michael J. Khayata, Sr. Compliance Investigator
        Ross Reineke, Comm. Assistance/Tech. Services
    Central Region
        Harold Winnie, Comm. Assistance/Tech. Services
        Joseph Mataich, Comm. Assistance/Tech Services
    Eastern Region
        Alex Dankanich, DPS-14
    Southwest Region
        Charles Helm
    Enforcement/Research and Special Programs
    Office of Drug Abuse, Compliance and Investigations and Compliance
        Stanley T. Kastanas, Director
Office of Deputy Assistant Secretary of the Army
    Environmental Safety and Occupational Health
        Cheryl Antosh, Assistant for Sustainability, Safety and Occupational Health
Bureau of Indian Affairs
    Southern Plains Regional Office
        Dan Deerinwater, Regional Director
    Branch of Fish, Wildlife and Recreation
        Gary Rankel, Director
        Michael Black, Director
Council on Environmental Quality
        Ellen Athas, Senior Counsel
        Horst G. Greczmiel, Director for NEPA Oversight
United States Coast Guard
        Peter Gooding, Commander
        Kathy Moore, Captain
        George Leshner
        LCDR Justin Jacobs
    Office of Operating and Environmental Standards
        Commandant
    Marine Safety Office

        - DeWayne R. Penberthy
        - Brian Salerno, Captain of the Port
    - Port Arthur
        - G.W. Anderson, Captain
        - Michael Hunt
    - Boston
        - LT Antonellis
    - Providence
        - Mary E. Landry, Commanding Officer
    - Texas City
        - Ricardo M. Alonso, Commanding Officer
    - Los Angeles-Long Beach
        - Ryan Manning
    - Portsmouth
        - William Lee, Commander
    - Sector Corpus Christi
        - Erich Stein
        - Erik Heithaus
    - 8th District
        - Roy Nash, Commander
- Center for Disease Control and Prevention
    - Building and Facilities Office
        - George Chandler, Director
- National Marine Fisheries Service
    - Office of Habitat Protection
        - Marine Resource Habitat Specialist
        - Heather Young, Biologist
        - Rusty Swafford, Supervisor Fishery Biologist
    - Southeast Region
        - Dr. Roy Crabtee, Regional Administrator
- Federal Energy Management Agency
    - Region VI
        - Heidi Carlin, Regional Director
- Department of Justice
    - Land and Natural Resources Division
        - Ignacia Moreno, Assistant Attorney General
- Department of the Air Force
    - Basing and Units
        - Jack Bush, Senior Planner/NEPA Program Manager
        - Jeffrey Blevins, Real Property Agency

United States Department of Housing and Urban Development
    Environmental Planning Division
        James M. Potter, Community Planner
Department of State
    Bureau of Oceans and International Environmental and Scientific Affairs
        John Matuszak
United States Department of the Interior
    Bureau of Land Management
        Deputy Assistant Secretary
    Minerals Management Service
        Marci Todd, Division of Decision Support, Planning, and NEPA
    Environmental Policy and Compliance
    Natural Resource Management
        Vijai N. Rai, Team Leader
National Park Service
        Jonathan Jarvis, Director
    Intermountain Region
        John Wessels, Director
    Environmental Planning and Compliance Branch
        Patrick Walsh, Chief
Operations Division (DAIM-ODO)
        Ravin L. Howell, ACSIM, Operations Directorate - Army
Gulf of Mexico Fishery Management Council
        Robert Shipp, Chairman
Office of the Deputy Under Secretary of Defense
    Installations and Environment
        Terry Bowers, Director of Environmental Security
Surface Transportation Board
    Office of Environmental Analysis
        Victoria Rutson, Director
Committee on Energy and Natural Gas
National Oceanic and Atmospheric Administration
        NEPA Coordinator
    Program Planning and Integration
Department of Commerce
    Office of the Secretary
        Senior Policy Advisor
Department of Labor
    Office of Regulatory Economics

Federal Representatives and Senators

Senator John Cornyn
Speaker John Boehner
Energy Policy Advisor Mike Catanzaro
Representative Blake Farenthold
Representative Ruben Hinojosa
Representative Jeff Morehouse
Representative Kay Granger
Representative Henry Cuellar
Representative Lloyd Doggett
Representative Charles Boustany

State Representatives and Senators

Governor Rick Perry
Lieutenant Governor David Dewhurst
Texas Secretary of State
Speaker Joe Straus
Senator Juan Hinojosa
Senator Judith Zaffirini
Representative Jim Keffer
Representative Todd Hunter

Texas State Agencies

- Texas Commission on Environmental Quality
    - Mark Vickery, Executive Director
    - Zak Covar, Executive Director
    - Erik Hendrickson, Team Leader
  - Air Permits Division
    - Mike Wilson, Director
    - Rebecca Partee, Manager
  - Office of Compliance and Enforcement
    - Richard Hyde, Deputy Director
  - Office of Air
    - Steve Hagle, Deputy Director
  - Region 14
    - Susan Clewis, Director
- Railroad Commission of Texas
    - Michael Williams, Commissioner
  - Pipeline Safety Division
    - Polly McDonald, Director
  - Corpus Christi - District 4
    - Fermin Munoz, Jr., Director
  - Oil and Gas Division
    - Gil Bujano, Deputy Director
    - Leslie Savage, Chief Geologist- Oil and Gas Permits
  - Intergovernmental Relations
    - Stacie Fowler, Director
- Texas Department of Transportation
  - Environmental Affairs
    - Mark A. Marek, Interim Director
    - Howard Gillespie, Port Aransas Ferry Operations Manager
- Texas Historical Commission
    - Mark Wolfe, Executive Director
    - Jeff Durst, Project Reviewer (Archaeological)
- Texas General Land Office
    - Jerry Patterson, Texas Land Commissioner
  - Texas Coastal Coordination Council
  - Lower Coast
    - Jesse Solis
  - Federal Consistency Review
    - Kate Zultner
  - Environmental Review
    - Tony Williams
- Public Utilities Commission of Texas
    - Kenneth W. Anderson, Jr., Commissioner
- Texas Parks and Wildlife Department
    - Mary Ellen Vega
    - Leslie Williams, Lower Coast Team Leader
- Texas Bureau of Economic Geology
    - Scott W. Tinker, Director
- Texas Department of Agriculture
    - Todd Staples, Commissioner
- Texas Natural Resource Conservation Service
  - Soils Section
- Texas Association of Regional Councils
- Texas Department of Public Safety
- Texas Department of State Health Services
- Texas Economic Development Council
- Texas Forest Service
- Texas Soil and Water Conservation Board

Local and County Government

- Nueces County
    - Lloyd Neal, County Judge
- San Patricio County
    - Terry Simpson, County Judge
    - Gracie Alaniz-Gonzales, County Clerk
    - Precinct 1
        - Nina Teveno, County Commissioner
    - Precinct 2
        - Fred Nardini, County Commissioner
    - Precinct 4
        - Jim Price, County Commissioner
        - Lucia Rodriguez, Floodplain Program Manager
- Port of Corpus Christi Authority
    - John LaRue, Executive Director
    - Frank Brogan, Deputy Director
    - Greg Brubeck, Director of Engineering Services
    - Judy Hawley, Port Commissioner (San Jacinto County)
    - Mike Carrell, Port Commission Chairman
    - Paul Carangelo, Coastal Environmental Planner
- City of Corpus Christi
    - Angel Escobar, City Manager
    - Joe Adame, Mayor
    - Ron Olson, City Manager
    - Mark Scott, Councilman at Large
    - Gas Department
        - John M. Alexander, Planner/Scheduler
- City of Taft
    - Jerry King, Mayor
    - Bob Gorson, City Manager
- City of Portland
    - David Krebs, Mayor
    - Ron Jorgensen, Mayor Pro Tem
    - John Green, Mayor Pro Tem
    - Randy Wright, Chief of Police and Assistant City Manager
    - Cathy Skurow, City Council
    - Mike Tanner, City Manager
- City of Port Aransas
    - Keith McMullin, Mayor
    - David Parsons, Interim City Manager
- City of Ingleside
    - Pete Perkins, Mayor
    - Jim Gray, City Manager
- City of Ingleside on the Bay
    - Howard Gillespie, Mayor
- City of Sinton
    - Pete Gonzales, Mayor
    - Jackie Knox, City Manager
- City of Gregory
    - Victor Lara, Mayor
    - John Valls, City Consultant
    - Norma Garcia, City Secretary
- Gregory-Portland Independent School District
    - Paul Clore, Superintendent
- City of Aransas Pass
    - Tommy Knight, Mayor

Native American Tribes

- Comecrudo Nation
- Kickapoo Traditional Tribe of Texas
- Kiowa Tribe
- Lipan Apache Band of Texas
- Mescalero Apache Tribe
- People of LaJunta
- Tonkawa Tribe of Oklahoma
- Ysleta de Sur Pueblo

Libraries

Del Mar College Libraries
Texas A&M University, Mary and Jeff Bell Library
Bell/Whittington Public Library
Ed and Hazel Richmond Public Library
Ingleside Public Library
La Retama Central Library
Sinton Public Library
Taft Public Library

Media

The Aransas Pass Progress
Corpus Christi Caller-Times
The Coastal Bend Herald
San Patricio County News
Portland News
Kiii 3 News

Organizations

Soil & Water Conservation Society
        Craig Cox, Executive Director
Coastal Bend Audubon Society
        David Newstead, President
Texas League of Conservation Voters
        David Weinberg, Executive Director
American Fisheries Society
        Gus Rassam, Executive Director
Coastal Bend Bays Foundation
        John Adams, President Board of Directors
        Ismael Nava, Executive Director
Coastal Bend Bays and Estuaries Program
        Ray Allen, Executive Director
        Leo Trevino, Deputy Director
Clean Economy Coalition
        James Klein, Chairperson
Ducks Unlimited, Inc.
    Southern Regional Office
        Ken Babcock, Director of Operations
Sierra Club
    Lone Star Chapter
        Ken Kramer, Chapter Director
Gulf of Mexico Foundation
        Richard Gonzales, Science and Spanish Club
Nature Conservancy
    TX Chapter
        Robert Potts, State Director
National Wildlife Federation
        Susan Kaderka, Director, Gulf States
Wildlife Society
        Terry Blankenship, Texas Chapter President
Texas State Aquarium
        Tom Schmidt, Chief Executive Officer
Texas Bass Chapter Federation
The Wilderness Society
        Resource Economist
Air Alliance Houston
        Adrian Shelley, Executive Director
Ima Hogg Foundation
    University of Texas Real Estate
        Allan Prickett
Pipeline Contractors Association
        J. Patrick Tielborg
Rocky Mountain Pipeline Contractors Association
        J.D. Lormand, Executive Director
Rocky Mountain Pipeline Contractors Association
        Executive Director
Association of Texas Soil and Water Conservation Districts
        Jose Dodier, Jr., President and NACD Board Member
Ingleside Chamber of Commerce

Organizations (continued)

Michael Ladewig, Chairman
Portland Chamber of Commerce
Patti Cass-Strain, President
Sue Zimmermann, Executive Director
Aransas Pass Chamber of Commerce
Rincon Water Supply District
San Patricio Water District

Companies

ConocoPhillips Company
Bruce Connell, Director
Pete Frost
American Gas Association
Dave Parker, President
Exxon Mobil Corporation
Douglas Rasch, Attorney
National Association of Conservation Districts
Eugene Lamb, Director of Programs
BP America, Inc.
Frederick Kolb, Attorney
Total Gas and Power North America
J. Mark Ingram, Chairman and CEO
Jones Day
Jason Leif
Occidental Energy Ventures Corporation
Jeff Hanig, Director
Thomas Feeney, Senior Vice President
Tetra Tech EC, Inc.
John Scott, Project Manager
Crosstex Energy Services, L.P.
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Mark Cook, Attorney
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Max Laun, Vice President and General Counsel
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Scott Turkington, Director
Weaver's Cove Energy, LLC
Ted Gehrig, President
Trunkline LNG Company, LLC
William Grygar, Vice President
Bell Rachel Partnership
Berryman Properties, Ltd.
Bracewell & Patterson, LLP
Gregory Power Partners, LP
Lackey Partnership
Sherwin Alumina Company, L.P.
Corpus Christi Regional Economic Development Corporation
Roland Mower, President and CEO
John Plotnik, Executive Vice President
San Patricio Economic Development Corporation
Josephine Miller, Executive Director
American Electric Power
Vince Deases, Commercial Manager
Bell South Telephone Building

Landowners

Alexandra E. Zafiriou
Magnuson Protection Trust
April F.
Nancy Fleming Shelton Trust
Ben and Nancy F. Shelton
Betty McGregor Pamplin
Betty Ann Pamplin
Betty Jo Pyron

Landowners (continued)

Brad M. Floerke
Mary Madeline O'Connor Family Exempt Trust
    Carter Lynn O’Connor
Charles A. and Linda D. Brown
Cheri P. Collier
Christopher H. Cable
Corinne McKamey
Cornelia Ann Moore Phillis
Danny Windland
Daryl Hass
David Edwards
David and Marion Trees
Diane DeCou
GJW Partnership
    Don Cable
Estate of Donald Frank
    Donald F. Swann
Dora Faye and Otto Schuster
Dorothy Tutt Asbury
Douglas Ray Hart
E.C. Pustejovsky
Welder Heirs
    Earl Shouse
Edwin Danford
Estate of Clestine M. Schubert
Frank and Linda Decker Erhard
Gary Schubert
Gilbert and Elvia Hernandez
Harry B. Fessler
Hart Douglas
James and Lynn Lackey
Jason Floerke
Jean Ivy
Jeff McKamey
Estate of A.H. Moore
    Jerry Lea Moore
    Kathleen Young Moore
Jimmy Mauch
GJW Partnership
    Joe Garrett
Joseph Cable
Joseph D. Cable
Julia and Robert Driscoll
Katherine S. Cable
Estate of Donald Frank
    Kay H. Swann
    Kay P. Hart Swann
Alcoa, Inc.
    Keith Schmidt, Project Manager Remediation
Kenneth G. McKamey, Jr.
Kenny Mutchler
Kim Elaine Hunt
Larry Baker
Leon Boils
Leslie Jo Ann Owen
Lydia Schmalstieg
Bell Family Farms, Ltd.
    M. and J. Bell
Margie Shelborne
Margie M. Shelburne
Martha McKamey Decou
Mary Donna Smothers
Mary Madeline O'Connor Family Exempt Trust
    Mary Madeline O'Connor
Mary Willeen Schmidt
Floerke Family Limited Partnership, L.P.
    Max M. Floerke
Mayo Toyce
Melissa Mires
Mildred M. Robinson
    c/o John Robinson
Neal L. Floerke
Nikolaos T. Zafiriou
Norman Telschik

Landowners (continued)

Estate of G.H. McCann
    Ola McCann
Ora Marie Floerke
P. H. Welder
Pablo Garza
Patrick Raymond
BDJ Properties, LLC
    Phil Berryman
R.H. Welder Heirs, Ltd.
Rachel Randolph
Rafael Q. Garza Estate
    c/o Pablo Garza Sr.
Randy Rachal
Richard Thomas
Robert Weagley Jr. and Rev. Trust
Robert F. Barlow
Roy J. Floerke
Sanford Shelburne
Portilla Ranch Holdings, Ltd.
    Scott Galloway
Estate of A.H. Moore
    Scott Moore
DeCou Family Partnership, Ltd.
    Susan DeCou Lamb
T. Michael O'Conner
Terry Reed Smith
Thomas and Joyce Houser
Tim Pyron
Sherwin Alumina Company
    Tom Ballou Legal and External
    Affairs Coordinator
    Tom Russell, President and CEO
Velma Cantu
Alcoa & Reynolds
    Property Tax Department
CCC Properties, Ltd.
E. H. Partnership, Ltd.
Midway Gin and Grain Co Op
Olle Farm, Ltd.
    c/o Susan M. Anderson
Port of Corpus Christi
San Patricio Municipal Water District
    San Patricio Municipal Water District

Appendix G

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REFERENCES

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Appendix H

LIST OF PREPARERS AND REVIEWERS

LIST OF PREPARES AND REVIEWERS

This EIS was prepared by Perennial Environmental Service, LLC, a third-party contractor, under the direction of the FERC Staff. Representatives from the COE, Coast Guard, DOE, and DOT also contributed to or participated in the preparation of this document and the NEPA review process. The following presents the names of individuals who prepared and/or reviewed this Administrative Draft EIS and their area of areas of responsibility.

TABLE G-1
Prepares/Reviewers for FERC

Name	**Education**	**Responsibility**
Kandilarya Barakat	M.E., Environmental Engineering/Project Management, 2006, University of Maryland, College Park B.S., Chemical Engineering, 2003, University of Maryland, College Park.	Project Manager; Land Use; Socioeconomics; and Cumulative Impacts
John Peconom	B.S., Biology and Management, 2000, University of California, Davis	Deputy Project Manager
James Glaze	B.S., Geology, 1975, California Lutheran University	Geologic Conditions, Resources, and Hazards
John Wisniewski	B.S., Mineral Economics, 1975, The Pennsylvania State University	Alternatives
Joanne Wachholder	M.S., Crop and Soil Sciences/Environmental Toxicology, 1997, Michigan State University B.S., Biology, 1994, University of Wisconsin – Stevens Point	Wildlife and Aquatic Resources; Vegetation; Threatened, Endangered, and Other Special Status Species
Paul Friedman	M.A., 1980, History, University of California, Santa Barbara B.A., 1976, Anthropology and History, University of California, Santa Barbara	Cultural Resources
Magdalene Suter	B.S., Environmental Systems Engineering, 2004, The Pennsylvania State University	Air Quality and Noise; Pipeline Reliability and Safety
Andrew Kohout	M.S., Fire Protection Engineering, 2011, University of Maryland B.S., Fire Protection Engineering, 2006, University of Maryland B.S., Mechanical Engineering, 2006, University of Maryland	LNG Reliability and Safety
Sentho White	M.S., Environmental Engineering, 2001, Johns Hopkins University B.S., Civil Engineering, 2000, Georgia Institute of Technology	LNG Reliability and Safety

TABLE G-2
Prepares/Reviewers for Perennial Environmental Services

Name	Education	Responsibility
Dennis Woods	M.S., Environmental Management, 2006, University of Houston – Clear Lake M.B.A., 2006, University of Houston – Clear Lake B.S., Biology, 1997, University of Texas at Austin	Project Manger. Alternatives; Cumulative Impacts, Conclusions and Recommendations, Executive Summary
Leslie Yoo	M.S., Zoology, 2001, Oklahoma State University B.S., Biology, 1995, Randolph Macon Woman's College	Deputy Project Manager, Project Coordination. Executive Summary; Conclusions and Recommendations;
Jennifer Seinfeld	B.S., Chemical Engineering, 1982, University of Tennessee	Air Quality
Lou Corio	M.S., Meteorology, 1983, University of Maryland B.S., Meteorology, 1980, Rutgers University – Cook College	Air Quality
Tim Simmons	Ph.D., Physics, 2003, University of Mississippi M.S., Physics, 1998, University of Mississippi B.S., Engineering Physics, 1996, University of Tennessee	Noise
Amy Williams	M.S., Wildlife Ecology, 2011, University of Nebraska – Lincoln B.S., Natural Resource Sciences, 2008, Washington State University	Geology and Soils; Aquatic Resources; Vegetation; Threatened, Endangered, and Other Special Status Species; Water resources; Wetlands; and Wildlife
Megan Rathwell	B.S., Environmental Science, 2013, Texas A&M University	Land Use, Recreation, and Visual Resources; Socioeconomics
Abby Peyton	M.A., Archaeology, 2005, Texas State University B.A., Anthropology, 2001, Baylor University	Cultural Resources
Jeremiah Bowling	M.S., Water Resource Management, 2012, Texas A&M University B.S., Spatial Science, 2009, Texas A&M University	GIS; Graphics

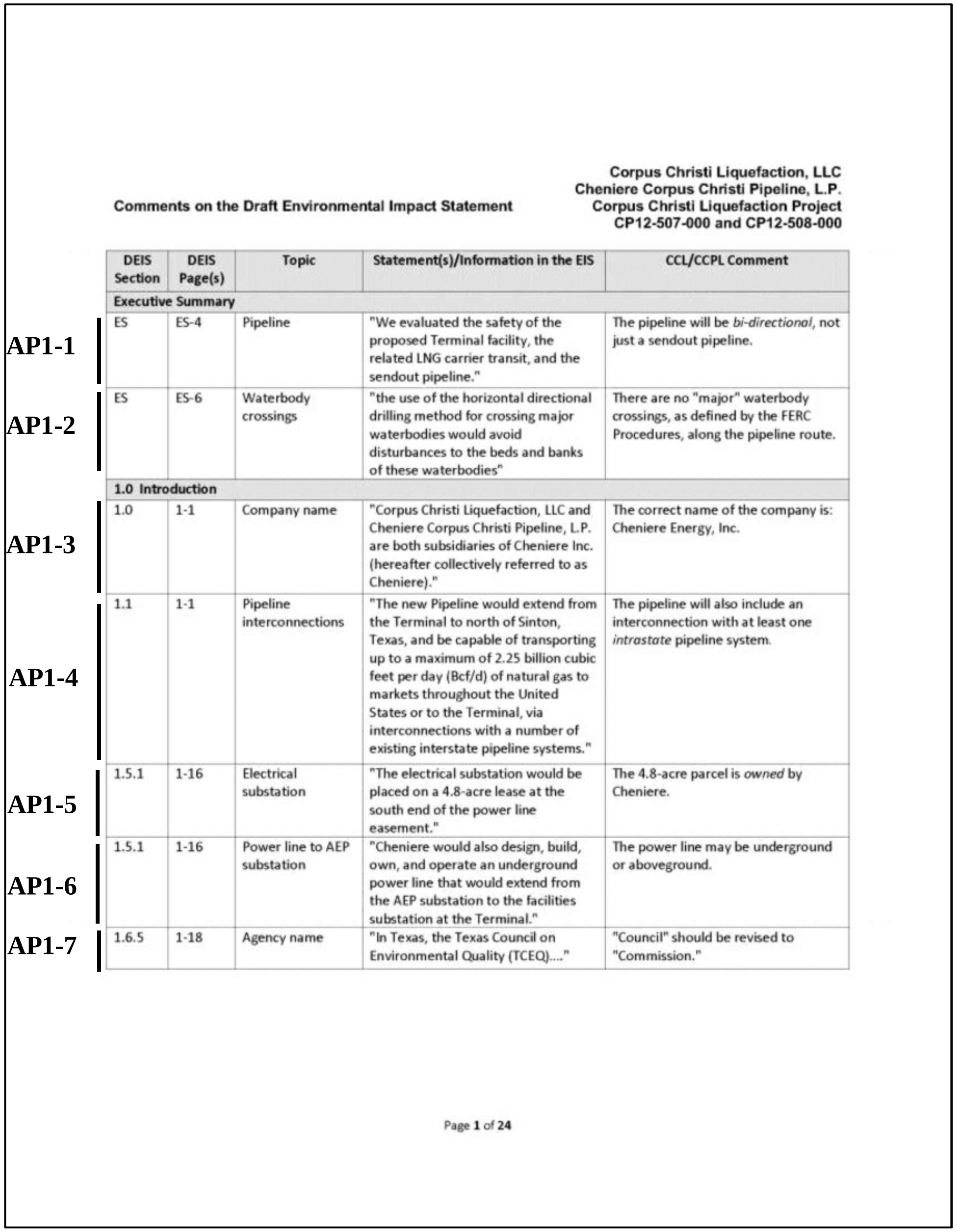
Appendix I

COMMENTS AND RESPONSES

List of Comment Letters

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



Comments on the Draft Environmental Impact Statement

Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Corpus Christi Liquefaction Project
CP12-507-000 and CP12-508-000

	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
	Executive Summary				
AP1-1	ES	ES-4	Pipeline	"We evaluated the safety of the proposed Terminal facility, the related LNG carrier transit, and the sendout pipeline."	The pipeline will be *bi-directional*, not just a sendout pipeline.
AP1-2	ES	ES-6	Waterbody crossings	"the use of the horizontal directional drilling method for crossing major waterbodies would avoid disturbances to the beds and banks of these waterbodies"	There are no "major" waterbody crossings, as defined by the FERC Procedures, along the pipeline route.
	1.0 Introduction				
AP1-3	1.0	1-1	Company name	"Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P. are both subsidiaries of Cheniere Inc. (hereafter collectively referred to as Cheniere)."	The correct name of the company is: Cheniere Energy, Inc.
AP1-4	1.1	1-1	Pipeline interconnections	"The new Pipeline would extend from the Terminal to north of Sinton, Texas, and be capable of transporting up to a maximum of 2.25 billion cubic feet per day (Bcf/d) of natural gas to markets throughout the United States or to the Terminal, via interconnections with a number of existing interstate pipeline systems."	The pipeline will also include an interconnection with at least one *intrastate* pipeline system.
AP1-5	1.5.1	1-16	Electrical substation	"The electrical substation would be placed on a 4.8-acre lease at the south end of the power line easement."	The 4.8-acre parcel is *owned* by Cheniere.
AP1-6	1.5.1	1-16	Power line to AEP substation	"Cheniere would also design, build, own, and operate an underground power line that would extend from the AEP substation to the facilities substation at the Terminal."	The power line may be underground or aboveground.
AP1-7	1.6.5	1-18	Agency name	"In Texas, the Texas Council on Environmental Quality (TCEQ)...."	"Council" should be revised to "Commission."

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AP1-1: The Executive Summary of the final EIS has been updated to replace sendout with bi-directional.

AP1-2: The Executive Summary of the final EIS has been updated to remove the word "major."

AP1-3: Section 1.0 of the final EIS has been revised with the correct name of the company.

AP1-4: This sentence has been revised in section 1.1 of the final EIS to include "intrastate" pipeline systems.

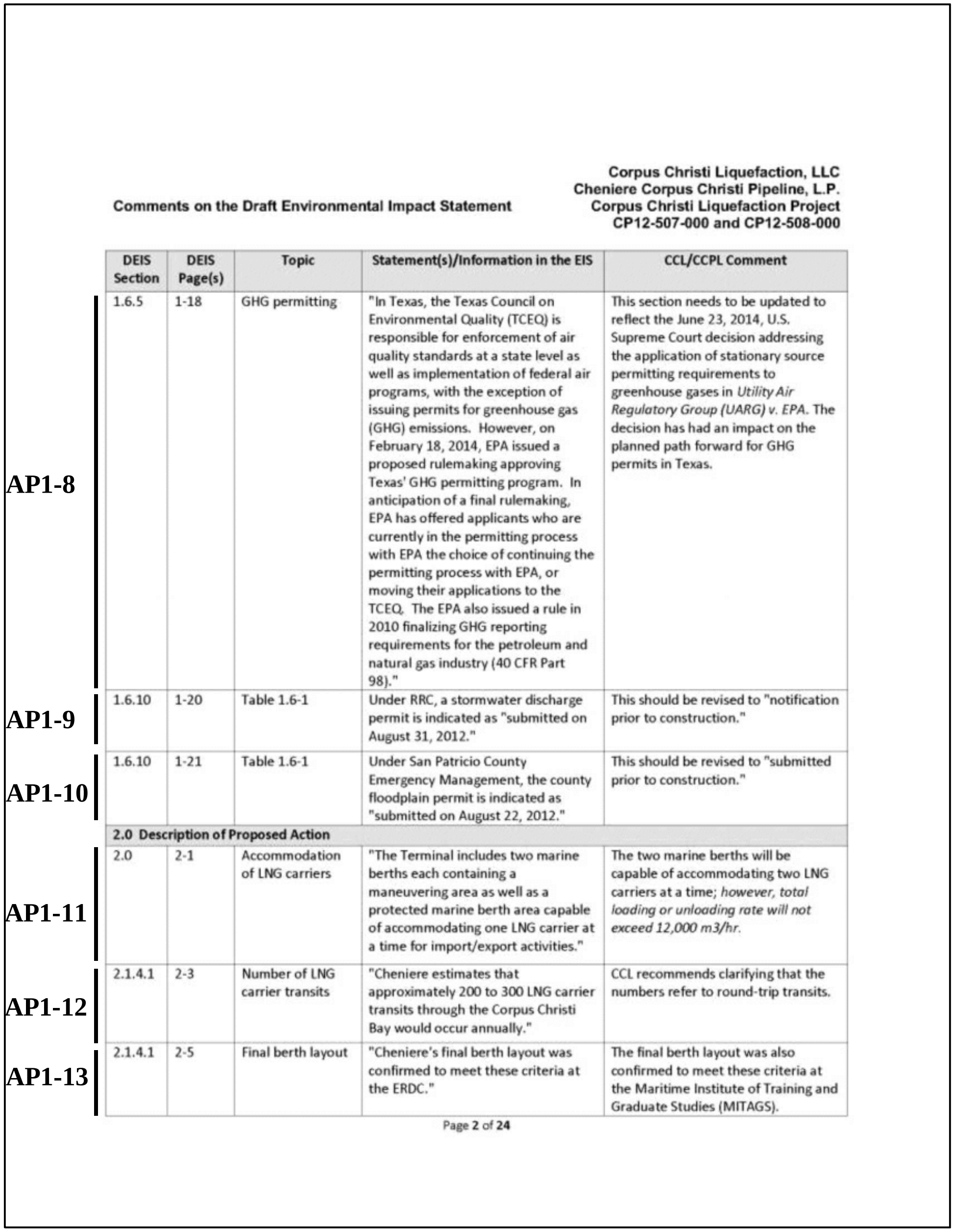
AP1-5: Section 1.5.1 of the final EIS has been revised to state that Cheniere owns the 4.8-acre parcel.

AP1-6: Section 1.5.1 of the EIS has been revised to clarify this information.

AP1-7: Section 1.6.5 of the final EIS has been revised to include the correct agency name.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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AP1-8	1.6.5	1-18	GHG permitting	"In Texas, the Texas Council on Environmental Quality (TCEQ) is responsible for enforcement of air quality standards at a state level as well as implementation of federal air programs, with the exception of issuing permits for greenhouse gas (GHG) emissions. However, on February 18, 2014, EPA issued a proposed rulemaking approving Texas' GHG permitting program. In anticipation of a final rulemaking, EPA has offered applicants who are currently in the permitting process with EPA the choice of continuing the permitting process with EPA, or moving their applications to the TCEQ. The EPA also issued a rule in 2010 finalizing GHG reporting requirements for the petroleum and natural gas industry (40 CFR Part 98)."	This section needs to be updated to reflect the June 23, 2014, U.S. Supreme Court decision addressing the application of stationary source permitting requirements to greenhouse gases in *Utility Air Regulatory Group (UARG) v. EPA*. The decision has had an impact on the planned path forward for GHG permits in Texas.
AP1-9	1.6.10	1-20	Table 1.6-1	Under RRC, a stormwater discharge permit is indicated as "submitted on August 31, 2012."	This should be revised to "notification prior to construction."
AP1-10	1.6.10	1-21	Table 1.6-1	Under San Patricio County Emergency Management, the county floodplain permit is indicated as "submitted on August 22, 2012."	This should be revised to "submitted prior to construction."
	2.0 Description of Proposed Action				
AP1-11	2.0	2-1	Accommodation of LNG carriers	"The Terminal includes two marine berths each containing a maneuvering area as well as a protected marine berth area capable of accommodating one LNG carrier at a time for import/export activities."	The two marine berths will be capable of accommodating two LNG carriers at a time; *however, total loading or unloading rate will not exceed 12,000 m3/hr.*
AP1-12	2.1.4.1	2-3	Number of LNG carrier transits	"Cheniere estimates that approximately 200 to 300 LNG carrier transits through the Corpus Christi Bay would occur annually."	CCL recommends clarifying that the numbers refer to round-trip transits.
AP1-13	2.1.4.1	2-5	Final berth layout	"Cheniere's final berth layout was confirmed to meet these criteria at the ERDC."	The final berth layout was also confirmed to meet these criteria at the Maritime Institute of Training and Graduate Studies (MITAGS).

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AP1-8: Section 1.6.5 has been updated in the final EIS to reflect the June 23, 2014 U.S. Supreme Court decision addressing the application of stationary source permitting requirements to greenhouse gases.

AP1-9: Table 1.6-1 in the final EIS has been updated to reflect this information.

AP1-10: Table 1.6-1 in the final EIS has been updated to reflect this information.

AP1-11: Section 2.0 of the final EIS has been revised to include this statement.

AP1-12: Section 2.1.4.1 of the final EIS has been revised to clarify this information.

AP1-13: Section 2.1.4.1 of the final EIS has been revised to include this information.

APPLICANT COMMENTS

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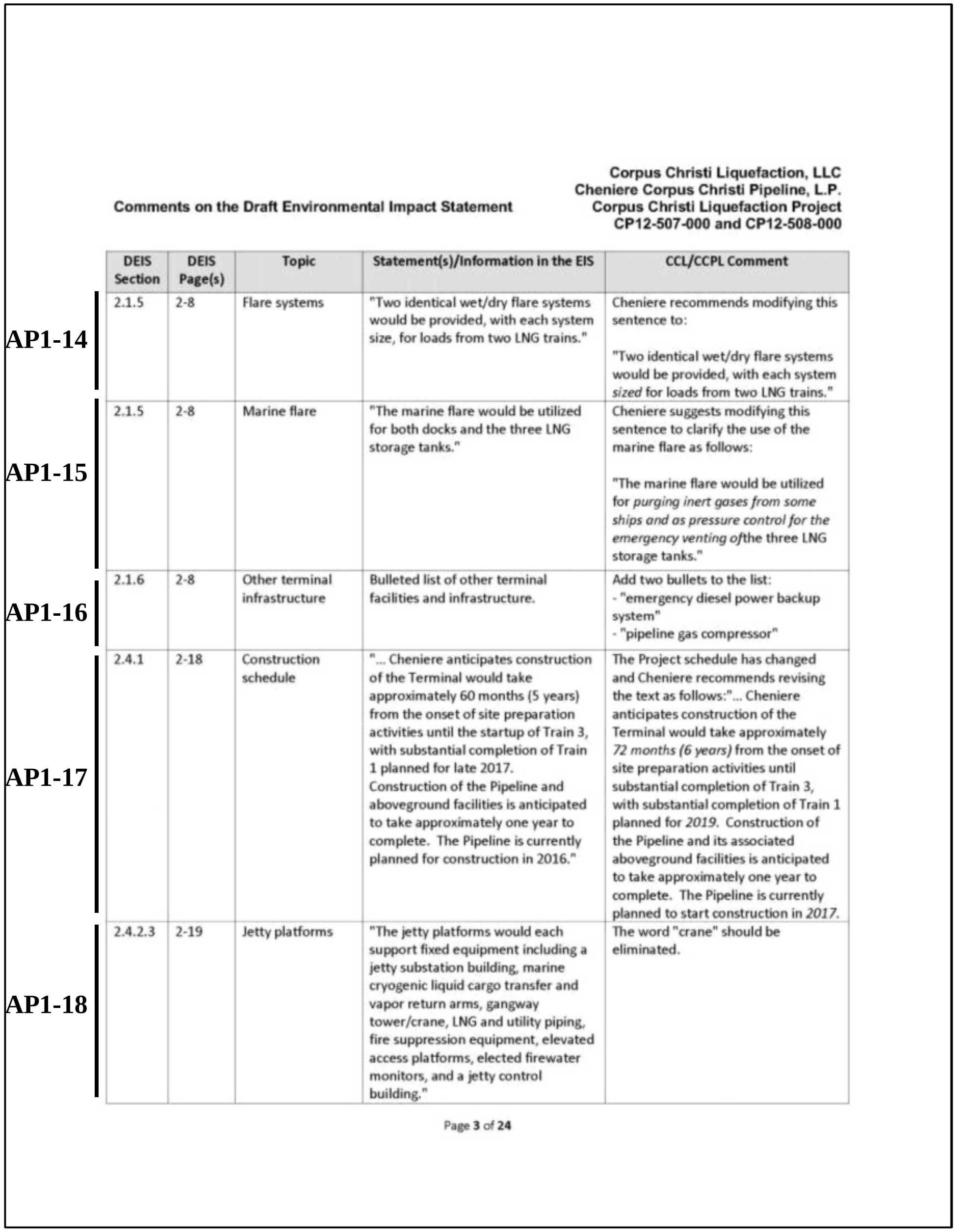

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AP1-14	2.1.5	2-8	Flare systems	"Two identical wet/dry flare systems would be provided, with each system size, for loads from two LNG trains."	Cheniere recommends modifying this sentence to: "Two identical wet/dry flare systems would be provided, with each system *sized* for loads from two LNG trains."
AP1-15	2.1.5	2-8	Marine flare	"The marine flare would be utilized for both docks and the three LNG storage tanks."	Cheniere suggests modifying this sentence to clarify the use of the marine flare as follows: "The marine flare would be utilized for *purging inert gases from some ships and as pressure control for the emergency venting of*the three LNG storage tanks."
AP1-16	2.1.6	2-8	Other terminal infrastructure	Bulleted list of other terminal facilities and infrastructure.	Add two bullets to the list: - "emergency diesel power backup system" - "pipeline gas compressor"
AP1-17	2.4.1	2-18	Construction schedule	"... Cheniere anticipates construction of the Terminal would take approximately 60 months (5 years) from the onset of site preparation activities until the startup of Train 3, with substantial completion of Train 1 planned for late 2017. Construction of the Pipeline and aboveground facilities is anticipated to take approximately one year to complete. The Pipeline is currently planned for construction in 2016."	The Project schedule has changed and Cheniere recommends revising the text as follows:"... Cheniere anticipates construction of the Terminal would take approximately *72 months (6 years)* from the onset of site preparation activities until substantial completion of Train 3, with substantial completion of Train 1 planned for *2019*. Construction of the Pipeline and its associated aboveground facilities is anticipated to take approximately one year to complete. The Pipeline is currently planned to start construction in *2017*.
AP1-18	2.4.2.3	2-19	Jetty platforms	"The jetty platforms would each support fixed equipment including a jetty substation building, marine cryogenic liquid cargo transfer and vapor return arms, gangway tower/crane, LNG and utility piping, fire suppression equipment, elevated access platforms, elected firewater monitors, and a jetty control building."	The word "crane" should be eliminated.

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AP1-14: This sentence has been revised in section 2.1.5 of the final EIS as suggested.

AP1-15: Section 2.1.5 of the final EIS has been revised to include this statement.

AP1-16: The two bullets have been added to section 2.1.6 of the final EIS.

AP1-17: Section 2.4.1 of the final EIS has been revised to reflect these updates to the Project schedule.

AP1-18: The word "crane" has been removed from this sentence in section 2.4.2.3 of the final EIS.

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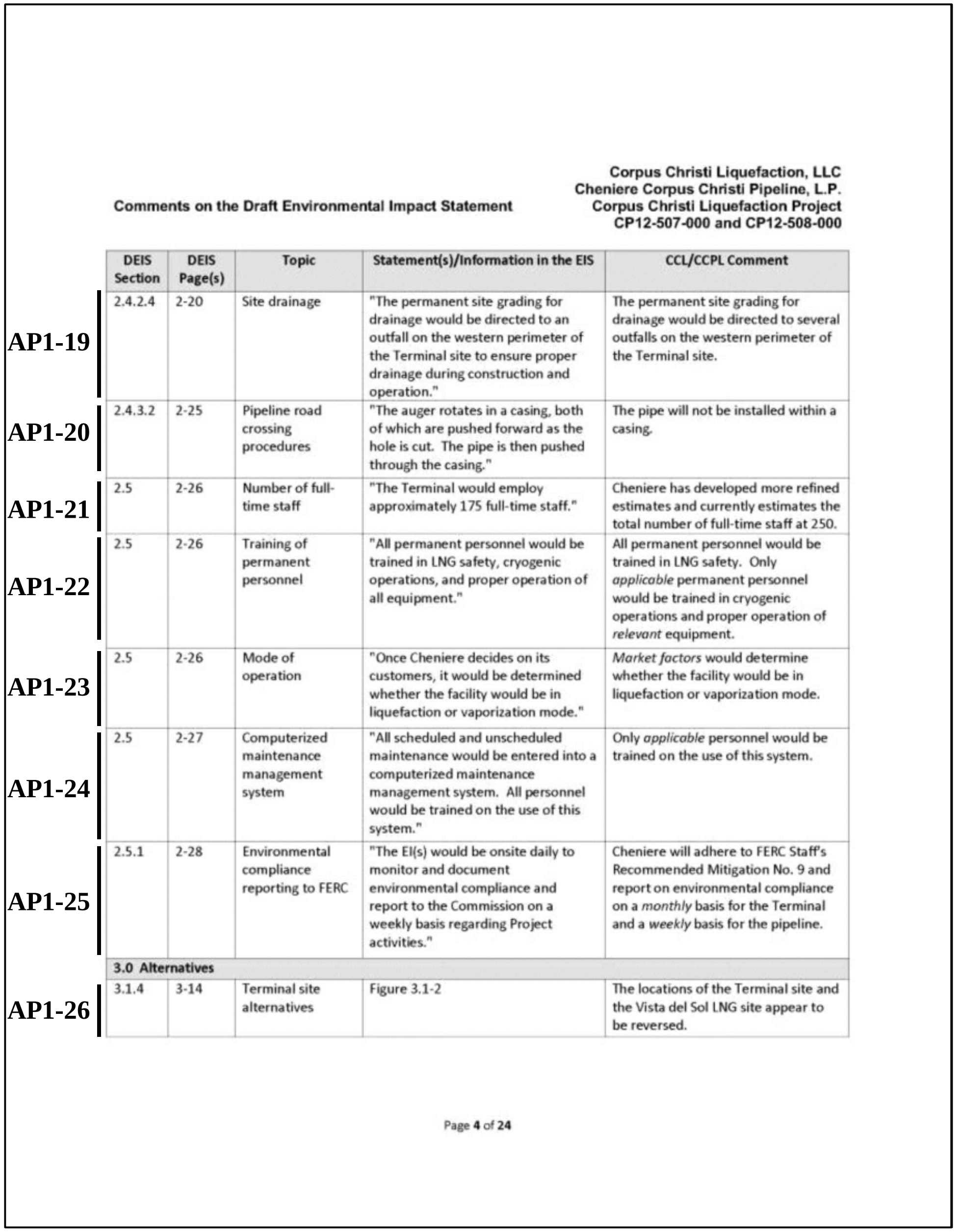

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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-19	2.4.2.4	2-20	Site drainage	"The permanent site grading for drainage would be directed to an outfall on the western perimeter of the Terminal site to ensure proper drainage during construction and operation."	The permanent site grading for drainage would be directed to several outfalls on the western perimeter of the Terminal site.
AP1-20	2.4.3.2	2-25	Pipeline road crossing procedures	"The auger rotates in a casing, both of which are pushed forward as the hole is cut. The pipe is then pushed through the casing."	The pipe will not be installed within a casing.
AP1-21	2.5	2-26	Number of full-time staff	"The Terminal would employ approximately 175 full-time staff."	Cheniere has developed more refined estimates and currently estimates the total number of full-time staff at 250.
AP1-22	2.5	2-26	Training of permanent personnel	"All permanent personnel would be trained in LNG safety, cryogenic operations, and proper operation of all equipment."	All permanent personnel would be trained in LNG safety. Only *applicable* permanent personnel would be trained in cryogenic operations and proper operation of *relevant* equipment.
AP1-23	2.5	2-26	Mode of operation	"Once Cheniere decides on its customers, it would be determined whether the facility would be in liquefaction or vaporization mode."	*Market factors* would determine whether the facility would be in liquefaction or vaporization mode.
AP1-24	2.5	2-27	Computerized maintenance management system	"All scheduled and unscheduled maintenance would be entered into a computerized maintenance management system. All personnel would be trained on the use of this system."	Only *applicable* personnel would be trained on the use of this system.
AP1-25	2.5.1	2-28	Environmental compliance reporting to FERC	"The EI(s) would be onsite daily to monitor and document environmental compliance and report to the Commission on a weekly basis regarding Project activities."	Cheniere will adhere to FERC Staff's Recommended Mitigation No. 9 and report on environmental compliance on a *monthly* basis for the Terminal and a *weekly* basis for the pipeline.
	3.0 Alternatives				
AP1-26	3.1.4	3-14	Terminal site alternatives	Figure 3.1-2	The locations of the Terminal site and the Vista del Sol LNG site appear to be reversed.

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AP1-19: Section 2.4.2.4 of the final EIS has been revised to clarify that multiple outfalls would be utilized.

AP1-20: Section 2.4.3.2 of the final EIS has been revised to clarify this information.

AP1-21: Sections 2.5 and 4.9 of the final EIS have been revised to reflect these updates to the Project workforce.

AP1-22: Section 2.5 of the final EIS has been revised to include these clarifications.

AP1-23: Section 2.5 of the final EIS has been revised to include this clarification.

AP1-24: Section 2.5 of the final EIS has been revised to include this clarification.

AP1-25: Section 2.5.1 of the final EIS has been revised to include this clarification.

AP1-26: Figure 3.1-2 has been revised in the final EIS to depict the correct locations of the Terminal site and the Vista del Sol LNG site.

APPLICANT COMMENTS

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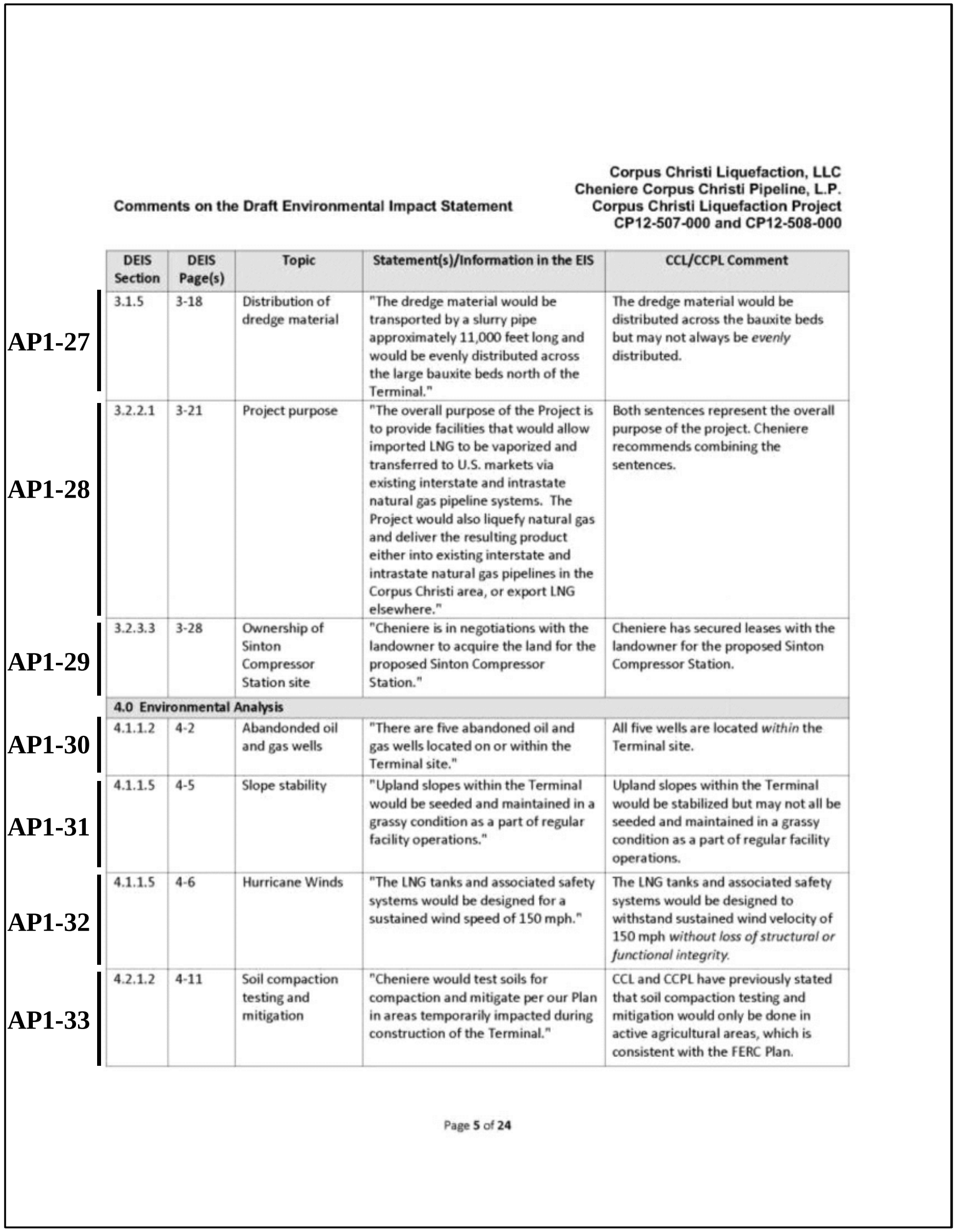

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AP1-27	3.1.5	3-18	Distribution of dredge material	"The dredge material would be transported by a slurry pipe approximately 11,000 feet long and would be evenly distributed across the large bauxite beds north of the Terminal."	The dredge material would be distributed across the bauxite beds but may not always be *evenly* distributed.
AP1-28	3.2.2.1	3-21	Project purpose	"The overall purpose of the Project is to provide facilities that would allow imported LNG to be vaporized and transferred to U.S. markets via existing interstate and intrastate natural gas pipeline systems. The Project would also liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export LNG elsewhere."	Both sentences represent the overall purpose of the project. Cheniere recommends combining the sentences.
AP1-29	3.2.3.3	3-28	Ownership of Sinton Compressor Station site	"Cheniere is in negotiations with the landowner to acquire the land for the proposed Sinton Compressor Station."	Cheniere has secured leases with the landowner for the proposed Sinton Compressor Station.
	4.0 Environmental Analysis				
AP1-30	4.1.1.2	4-2	Abandonded oil and gas wells	"There are five abandoned oil and gas wells located on or within the Terminal site."	All five wells are located *within* the Terminal site.
AP1-31	4.1.1.5	4-5	Slope stability	"Upland slopes within the Terminal would be seeded and maintained in a grassy condition as a part of regular facility operations."	Upland slopes within the Terminal would be stabilized but may not all be seeded and maintained in a grassy condition as a part of regular facility operations.
AP1-32	4.1.1.5	4-6	Hurricane Winds	"The LNG tanks and associated safety systems would be designed for a sustained wind speed of 150 mph."	The LNG tanks and associated safety systems would be designed to withstand sustained wind velocity of 150 mph *without loss of structural or functional integrity.*
AP1-33	4.2.1.2	4-11	Soil compaction testing and mitigation	"Cheniere would test soils for compaction and mitigate per our Plan in areas temporarily impacted during construction of the Terminal."	CCL and CCPL have previously stated that soil compaction testing and mitigation would only be done in active agricultural areas, which is consistent with the FERC Plan.

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AP1-27: The word "evenly" was removed from this sentence in section 3.1.5 of the final EIS.

AP1-28: Section 3.2.2.1 of the final EIS has been revised to clarify the overall purpose of the Project.

AP1-29: Section 3.2.3.3 of the final EIS has been updated to reflect this information.

AP1-30: Section 4.1.1.2 of the final EIS has been revised to include this clarification.

AP1-31: Section 4.1.1.5 of the final EIS has been revised to reflect this information.

AP1-32: Section 4.1.1.5 of the final EIS has been updated to include this statement.

AP1-33: Section 4.2.1.2 of the final EIS has been revised to reflect Cheniere's commitments regarding soil compaction testing and mitigation.

APPLICANT COMMENTS

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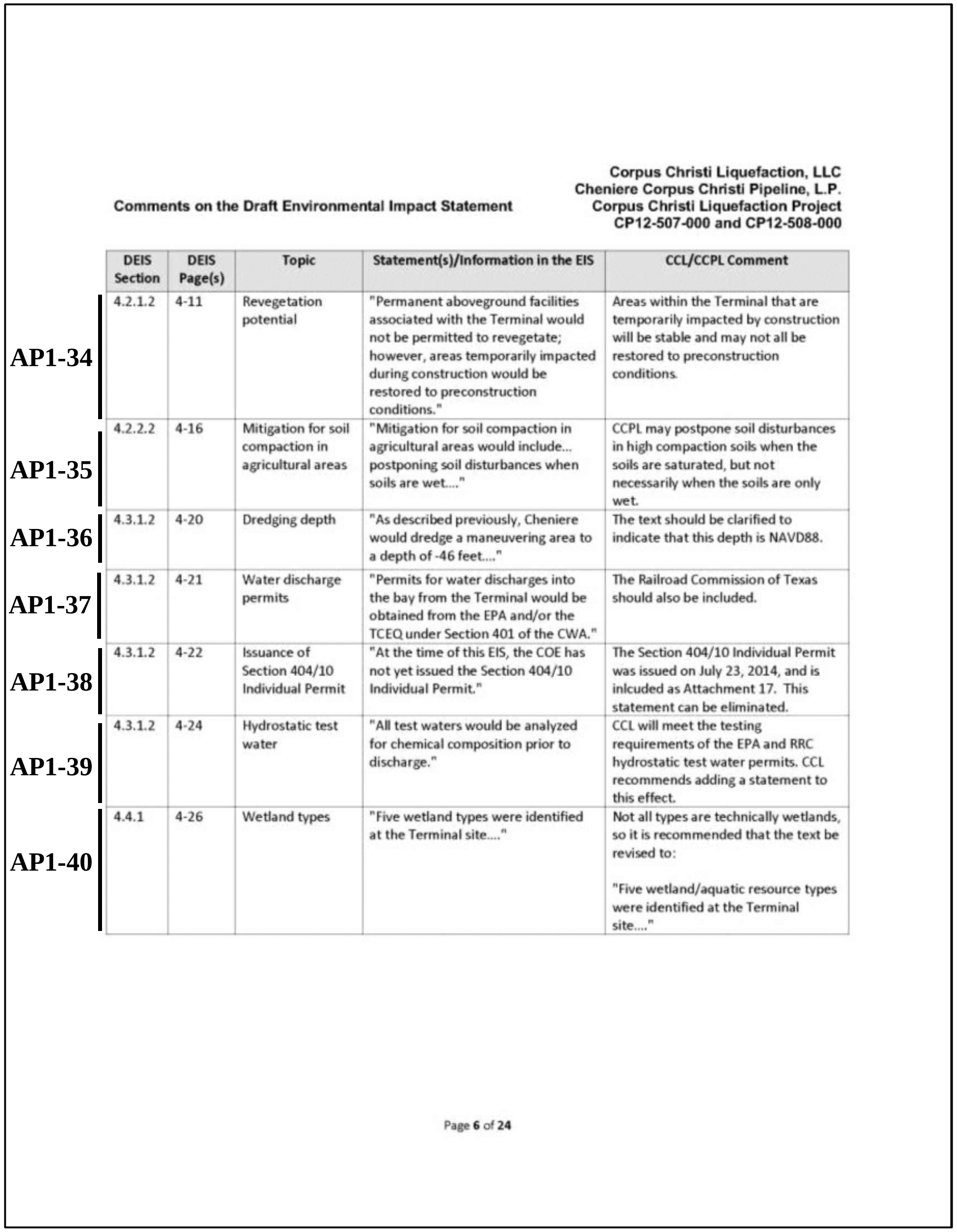

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AP1-34	4.2.1.2	4-11	Revegetation potential	"Permanent aboveground facilities associated with the Terminal would not be permitted to revegetate; however, areas temporarily impacted during construction would be restored to preconstruction conditions."	Areas within the Terminal that are temporarily impacted by construction will be stable and may not all be restored to preconstruction conditions.
AP1-35	4.2.2.2	4-16	Mitigation for soil compaction in agricultural areas	"Mitigation for soil compaction in agricultural areas would include… postponing soil disturbances when soils are wet…."	CCPL may postpone soil disturbances in high compaction soils when the soils are saturated, but not necessarily when the soils are only wet.
AP1-36	4.3.1.2	4-20	Dredging depth	"As described previously, Cheniere would dredge a maneuvering area to a depth of -46 feet…."	The text should be clarified to indicate that this depth is NAVD88.
AP1-37	4.3.1.2	4-21	Water discharge permits	"Permits for water discharges into the bay from the Terminal would be obtained from the EPA and/or the TCEQ under Section 401 of the CWA."	The Railroad Commission of Texas should also be included.
AP1-38	4.3.1.2	4-22	Issuance of Section 404/10 Individual Permit	"At the time of this EIS, the COE has not yet issued the Section 404/10 Individual Permit."	The Section 404/10 Individual Permit was issued on July 23, 2014, and is inlcuded as Attachment 17. This statement can be eliminated.
AP1-39	4.3.1.2	4-24	Hydrostatic test water	"All test waters would be analyzed for chemical composition prior to discharge."	CCL will meet the testing requirements of the EPA and RRC hydrostatic test water permits. CCL recommends adding a statement to this effect.
AP1-40	4.4.1	4-26	Wetland types	"Five wetland types were identified at the Terminal site…."	Not all types are technically wetlands, so it is recommended that the text be revised to: "Five wetland/aquatic resource types were identified at the Terminal site…."

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AP1-34: Section 4.2.1.2 of the final EIS has been revised to clarify this issue.

AP1-35: Section 4.2.2.2 of the final EIS has been updated to include this clarification.

AP1-36: Section 4.3.1.2 of the final EIS has been updated to include this clarification.

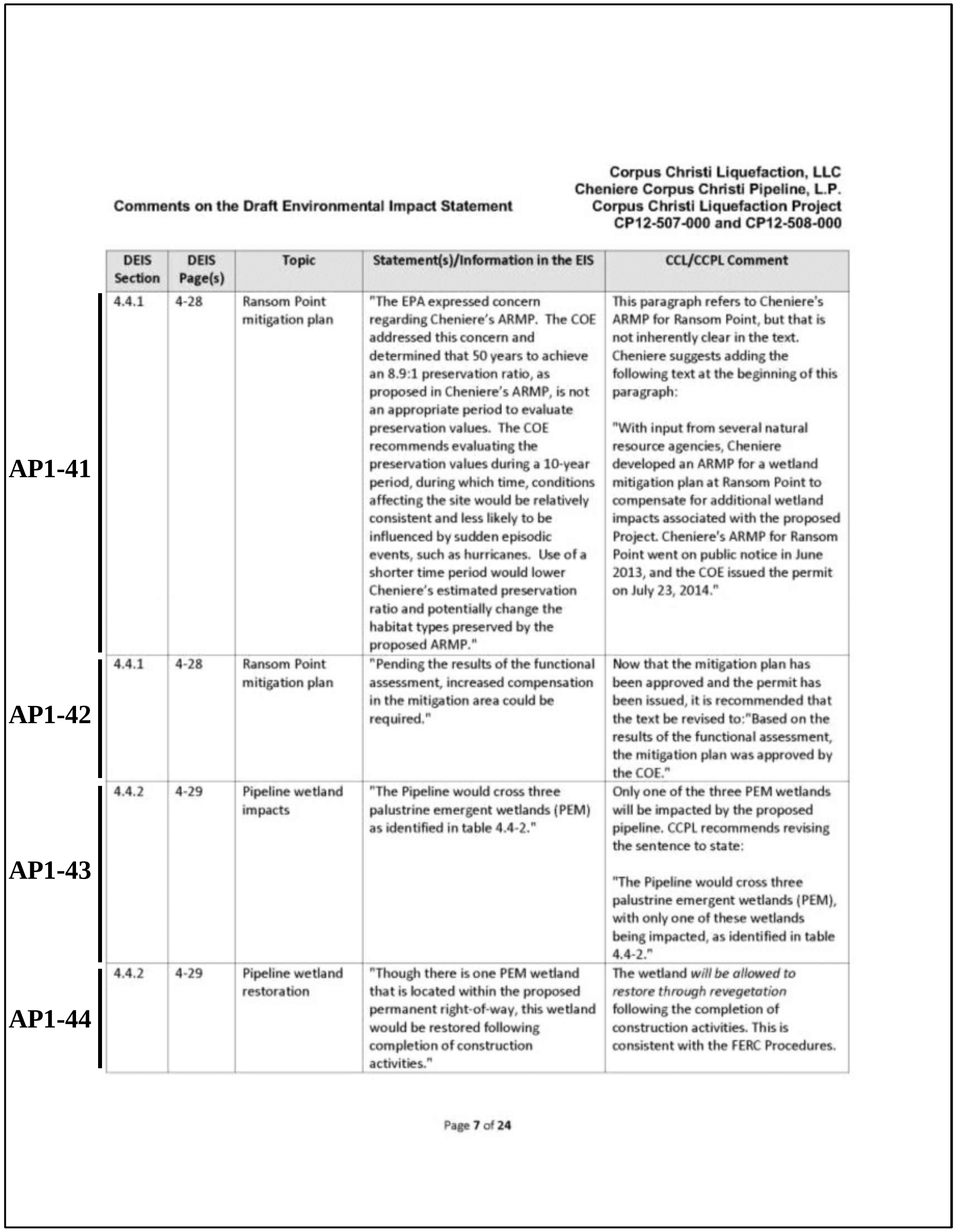
AP1-37: Section 4.3.1.2 of the final EIS has been updated to include the Railroad Commission of Texas.

AP1-38: The final EIS has been updated throughout to reflect issuance of this permit. See section 4.4.1.

AP1-39: A statement has been added to section 4.3.1.2 of the final EIS to clarify this issue.

AP1-40: Section 4.4.1 of the final EIS has been updated to clarify this issue.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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AP1-41	4.4.1	4-28	Ransom Point mitigation plan	"The EPA expressed concern regarding Cheniere's ARMP. The COE addressed this concern and determined that 50 years to achieve an 8.9:1 preservation ratio, as proposed in Cheniere's ARMP, is not an appropriate period to evaluate preservation values. The COE recommends evaluating the preservation values during a 10-year period, during which time, conditions affecting the site would be relatively consistent and less likely to be influenced by sudden episodic events, such as hurricanes. Use of a shorter time period would lower Cheniere's estimated preservation ratio and potentially change the habitat types preserved by the proposed ARMP."	This paragraph refers to Cheniere's ARMP for Ransom Point, but that is not inherently clear in the text. Cheniere suggests adding the following text at the beginning of this paragraph: "With input from several natural resource agencies, Cheniere developed an ARMP for a wetland mitigation plan at Ransom Point to compensate for additional wetland impacts associated with the proposed Project. Cheniere's ARMP for Ransom Point went on public notice in June 2013, and the COE issued the permit on July 23, 2014."
AP1-42	4.4.1	4-28	Ransom Point mitigation plan	"Pending the results of the functional assessment, increased compensation in the mitigation area could be required."	Now that the mitigation plan has been approved and the permit has been issued, it is recommended that the text be revised to:"Based on the results of the functional assessment, the mitigation plan was approved by the COE."
AP1-43	4.4.2	4-29	Pipeline wetland impacts	"The Pipeline would cross three palustrine emergent wetlands (PEM) as identified in table 4.4-2."	Only one of the three PEM wetlands will be impacted by the proposed pipeline. CCPL recommends revising the sentence to state: "The Pipeline would cross three palustrine emergent wetlands (PEM), with only one of these wetlands being impacted, as identified in table 4.4-2."
AP1-44	4.4.2	4-29	Pipeline wetland restoration	"Though there is one PEM wetland that is located within the proposed permanent right-of-way, this wetland would be restored following completion of construction activities."	The wetland *will be allowed to restore through revegetation* following the completion of construction activities. This is consistent with the FERC Procedures.

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AP1-41: Section 4.4.1 has been updated to include a summary of the Aquatic Resources Mitigation Plan (ARMP) as well as issuance of the Section 10/404 permit on July 23, 2014.

AP1-42: See response to AP1-38.

AP1-43: Section 4.4.2 of the final EIS has been revised to clarify this information.

AP1-44: Section 4.4.2 of the final EIS has been revised to clarify that wetland restoration would be in accordance with our Procedures, including that the wetland does not need to be actively revegetated; however, preconstruction contours must be restored following construction.

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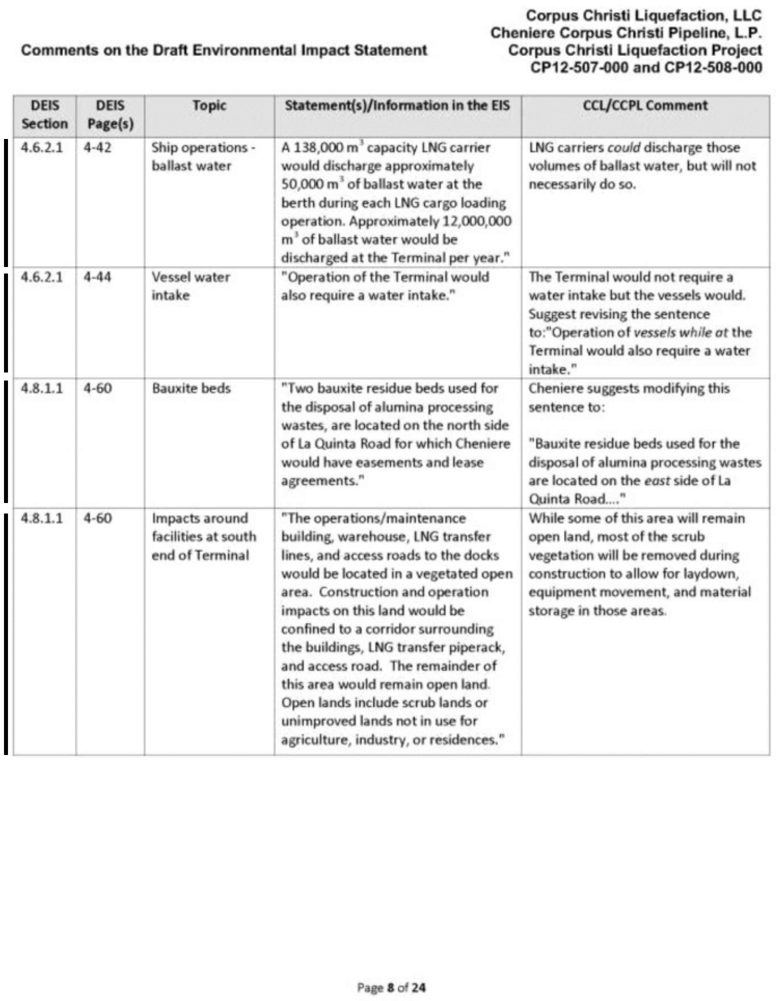

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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
4.6.2.1	4-42	Ship operations - ballast water	A 138,000 m^3 capacity LNG carrier would discharge approximately 50,000 m^3 of ballast water at the berth during each LNG cargo loading operation. Approximately 12,000,000 m^3 of ballast water would be discharged at the Terminal per year."	LNG carriers *could* discharge those volumes of ballast water, but will not necessarily do so.
4.6.2.1	4-44	Vessel water intake	"Operation of the Terminal would also require a water intake."	The Terminal would not require a water intake but the vessels would. Suggest revising the sentence to:"Operation of *vessels while at* the Terminal would also require a water intake."
4.8.1.1	4-60	Bauxite beds	"Two bauxite residue beds used for the disposal of alumina processing wastes, are located on the north side of La Quinta Road for which Cheniere would have easements and lease agreements."	Cheniere suggests modifying this sentence to: "Bauxite residue beds used for the disposal of alumina processing wastes are located on the *east* side of La Quinta Road...."
4.8.1.1	4-60	Impacts around facilities at south end of Terminal	"The operations/maintenance building, warehouse, LNG transfer lines, and access roads to the docks would be located in a vegetated open area. Construction and operation impacts on this land would be confined to a corridor surrounding the buildings, LNG transfer piperack, and access road. The remainder of this area would remain open land. Open lands include scrub lands or unimproved lands not in use for agriculture, industry, or residences."	While some of this area will remain open land, most of the scrub vegetation will be removed during construction to allow for laydown, equipment movement, and material storage in those areas.

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AP1-45

AP1-46

AP1-47

AP1-48

AP1-45: Section 4.6.2.1 of the final EIS has been revised to include this clarification.

AP1-46: Section 4.6.2.1 of the final EIS has been revised to clarify that the Terminal would not require water intake.

AP1-47: Section 4.8.1.1 of the final EIS has been revised to include this clarification.

AP1-48: We clarify that, although the vegetation would be removed during construction, the land use would remain open following construction.

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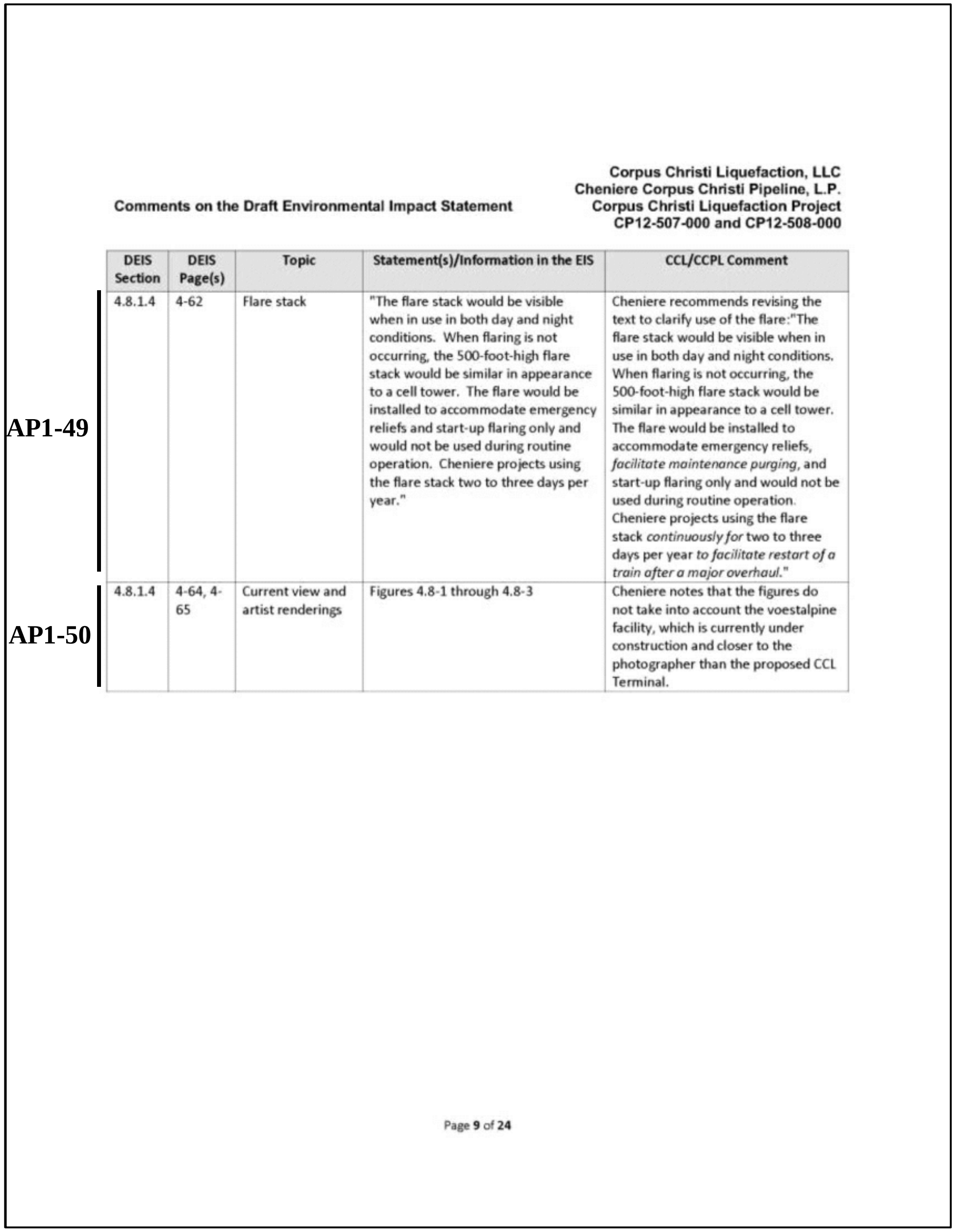

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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
4.8.1.4	4-62	Flare stack	"The flare stack would be visible when in use in both day and night conditions. When flaring is not occurring, the 500-foot-high flare stack would be similar in appearance to a cell tower. The flare would be installed to accommodate emergency reliefs and start-up flaring only and would not be used during routine operation. Cheniere projects using the flare stack two to three days per year."	Cheniere recommends revising the text to clarify use of the flare:"The flare stack would be visible when in use in both day and night conditions. When flaring is not occurring, the 500-foot-high flare stack would be similar in appearance to a cell tower. The flare would be installed to accommodate emergency reliefs, *facilitate maintenance purging*, and start-up flaring only and would not be used during routine operation. Cheniere projects using the flare stack *continuously for* two to three days per year *to facilitate restart of a train after a major overhaul.*"
4.8.1.4	4-64, 4-65	Current view and artist renderings	Figures 4.8-1 through 4.8-3	Cheniere notes that the figures do not take into account the voestalpine facility, which is currently under construction and closer to the photographer than the proposed CCL Terminal.

AP1-49

AP1-50

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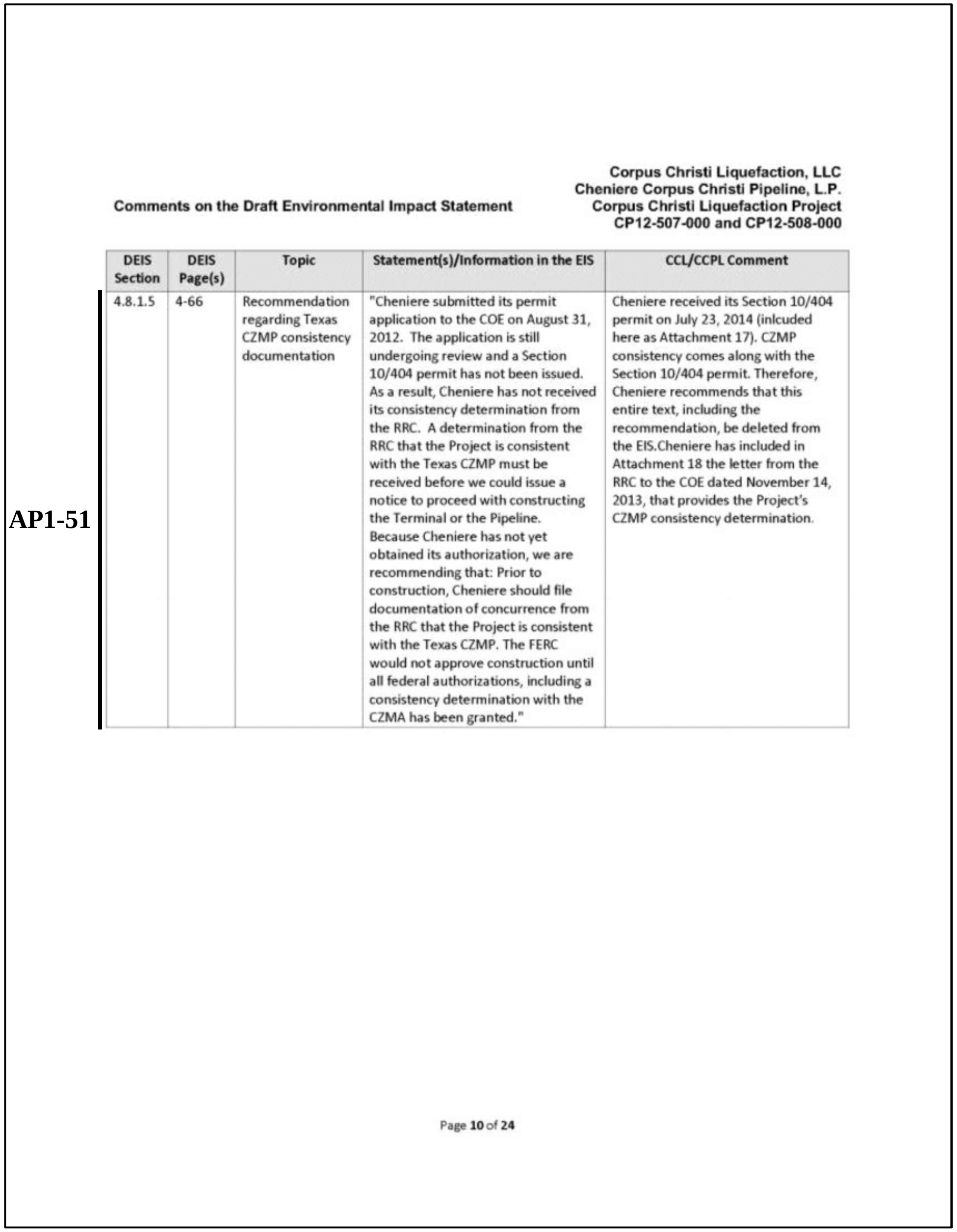
AP1-49: Section 4.8.1.4 of the final EIS has been revised to include these clarifications.

AP1-50: Comment acknowledged.



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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
4.8.1.5	4-66	Recommendation regarding Texas CZMP consistency documentation	"Cheniere submitted its permit application to the COE on August 31, 2012. The application is still undergoing review and a Section 10/404 permit has not been issued. As a result, Cheniere has not received its consistency determination from the RRC. A determination from the RRC that the Project is consistent with the Texas CZMP must be received before we could issue a notice to proceed with constructing the Terminal or the Pipeline. Because Cheniere has not yet obtained its authorization, we are recommending that: Prior to construction, Cheniere should file documentation of concurrence from the RRC that the Project is consistent with the Texas CZMP. The FERC would not approve construction until all federal authorizations, including a consistency determination with the CZMA has been granted."	Cheniere received its Section 10/404 permit on July 23, 2014 (inlcuded here as Attachment 17). CZMP consistency comes along with the Section 10/404 permit. Therefore, Cheniere recommends that this entire text, including the recommendation, be deleted from the EIS.Cheniere has included in Attachment 18 the letter from the RRC to the COE dated November 14, 2013, that provides the Project's CZMP consistency determination.

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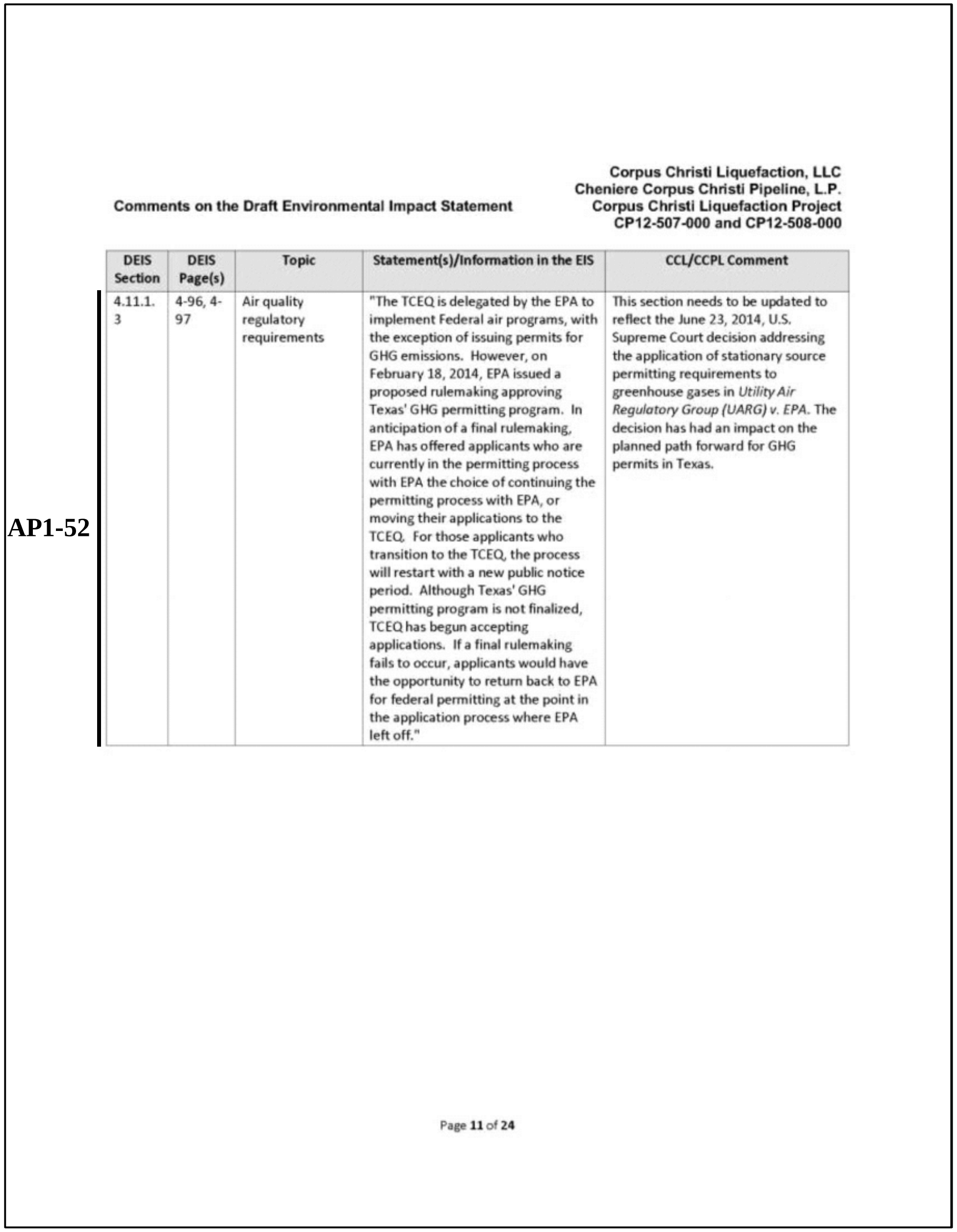
AP1-51

AP1-51: See response to AP1-38. Section 4.8.1.5 of the final EIS has been updated to reflect the Railroad Commission of Texas (RRC) Coastal Zone consistency determination.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
4.11.1.3	4-96, 4-97	Air quality regulatory requirements	"The TCEQ is delegated by the EPA to implement Federal air programs, with the exception of issuing permits for GHG emissions. However, on February 18, 2014, EPA issued a proposed rulemaking approving Texas' GHG permitting program. In anticipation of a final rulemaking, EPA has offered applicants who are currently in the permitting process with EPA the choice of continuing the permitting process with EPA, or moving their applications to the TCEQ. For those applicants who transition to the TCEQ, the process will restart with a new public notice period. Although Texas' GHG permitting program is not finalized, TCEQ has begun accepting applications. If a final rulemaking fails to occur, applicants would have the opportunity to return back to EPA for federal permitting at the point in the application process where EPA left off."	This section needs to be updated to reflect the June 23, 2014, U.S. Supreme Court decision addressing the application of stationary source permitting requirements to greenhouse gases in *Utility Air Regulatory Group (UARG) v. EPA*. The decision has had an impact on the planned path forward for GHG permits in Texas.

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AP1-52

AP1-52: Section 4.11.1.3 has been updated in the final EIS to reflect the current permitting status of each facility, addressing the application of stationary source permitting requirements to greenhouse gases.

APPLICANT COMMENTS

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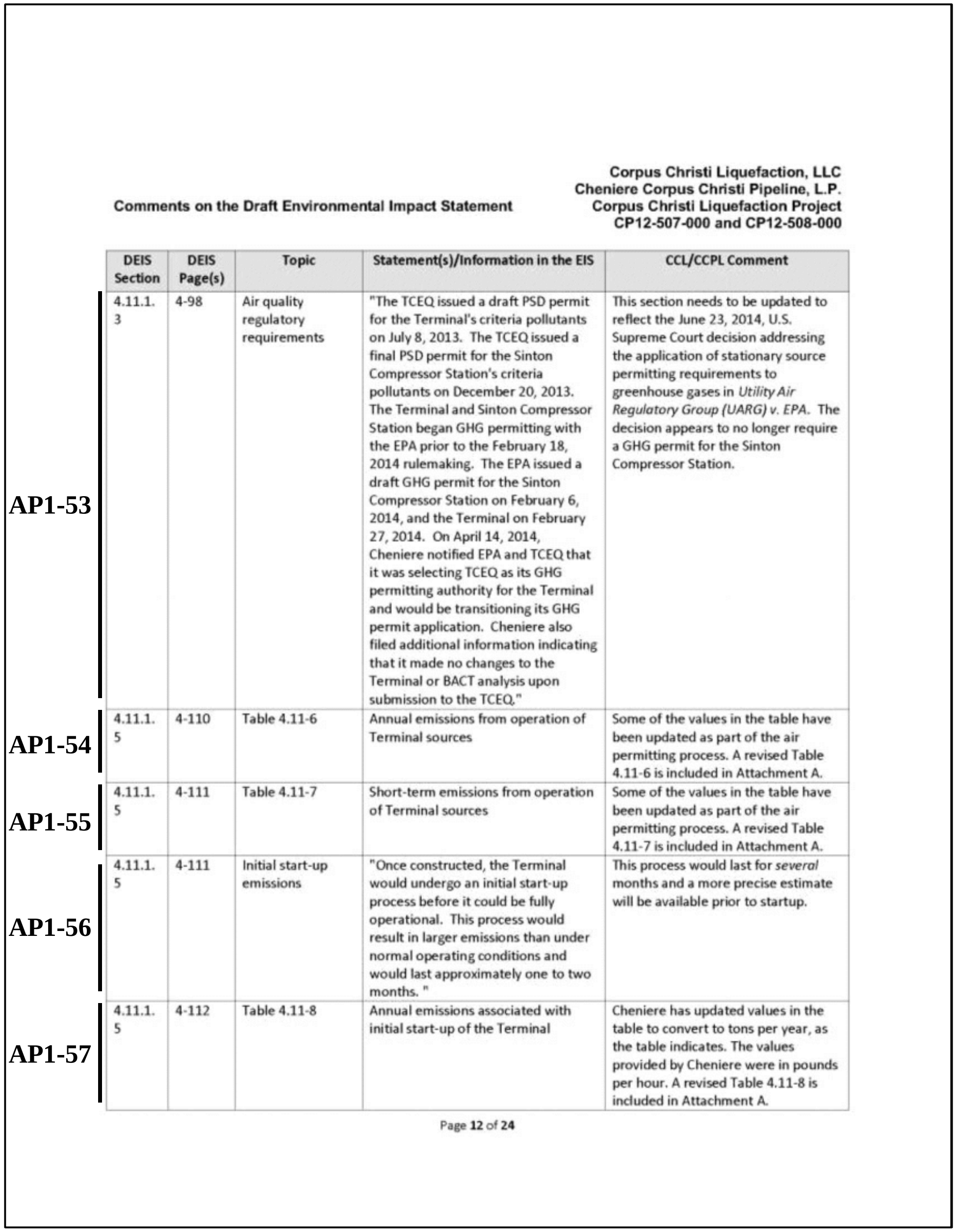

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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-53	4.11.1.3	4-98	Air quality regulatory requirements	"The TCEQ issued a draft PSD permit for the Terminal's criteria pollutants on July 8, 2013. The TCEQ issued a final PSD permit for the Sinton Compressor Station's criteria pollutants on December 20, 2013. The Terminal and Sinton Compressor Station began GHG permitting with the EPA prior to the February 18, 2014 rulemaking. The EPA issued a draft GHG permit for the Sinton Compressor Station on February 6, 2014, and the Terminal on February 27, 2014. On April 14, 2014, Cheniere notified EPA and TCEQ that it was selecting TCEQ as its GHG permitting authority for the Terminal and would be transitioning its GHG permit application. Cheniere also filed additional information indicating that it made no changes to the Terminal or BACT analysis upon submission to the TCEQ."	This section needs to be updated to reflect the June 23, 2014, U.S. Supreme Court decision addressing the application of stationary source permitting requirements to greenhouse gases in *Utility Air Regulatory Group (UARG) v. EPA*. The decision appears to no longer require a GHG permit for the Sinton Compressor Station.
AP1-54	4.11.1.5	4-110	Table 4.11-6	Annual emissions from operation of Terminal sources	Some of the values in the table have been updated as part of the air permitting process. A revised Table 4.11-6 is included in Attachment A.
AP1-55	4.11.1.5	4-111	Table 4.11-7	Short-term emissions from operation of Terminal sources	Some of the values in the table have been updated as part of the air permitting process. A revised Table 4.11-7 is included in Attachment A.
AP1-56	4.11.1.5	4-111	Initial start-up emissions	"Once constructed, the Terminal would undergo an initial start-up process before it could be fully operational. This process would result in larger emissions than under normal operating conditions and would last approximately one to two months. "	This process would last for *several* months and a more precise estimate will be available prior to startup.
AP1-57	4.11.1.5	4-112	Table 4.11-8	Annual emissions associated with initial start-up of the Terminal	Cheniere has updated values in the table to convert to tons per year, as the table indicates. The values provided by Cheniere were in pounds per hour. A revised Table 4.11-8 is included in Attachment A.

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AP1-53: Section 4.11.1.3 has been updated in the final EIS to reflect the current air permitting status. However, we note that the Environmental Protection Agency (EPA) has indicated that because a criteria pollutant Prevention of Significant Deterioration (PSD) permit has already been issued for the Sinton Compressor Station, EPA may need to issue a greenhouse gas (GHG) PSD permit for the Sinton Compressor Station.

AP1-54: We have reviewed the updated emissions and Table 4.11-6 of the final EIS has been revised to include these updated values.

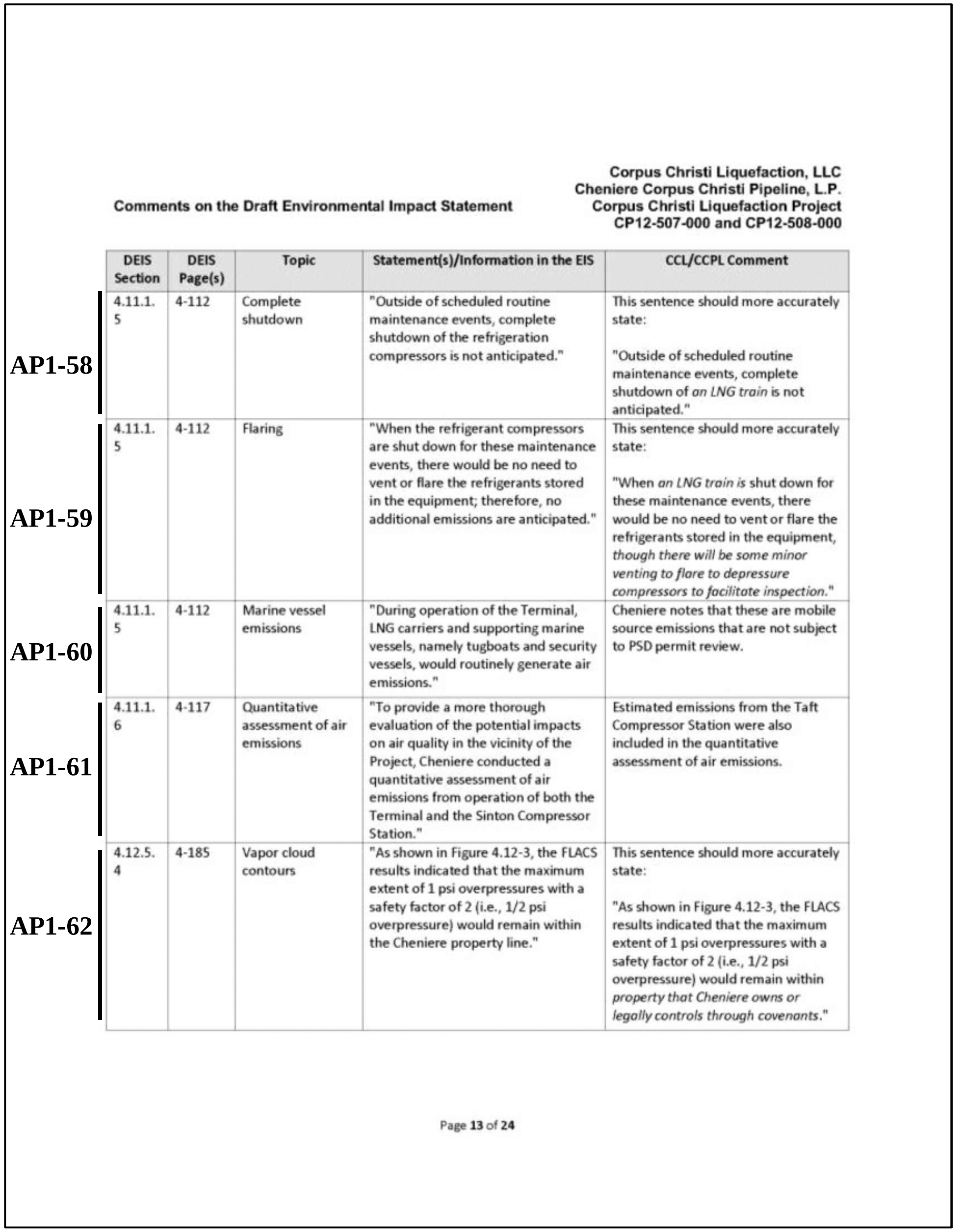
AP1-55: We have reviewed the updated emissions and Table 4.11-7 of the final EIS has been revised to include these updated values.

AP1-56: Section 4.11.1.5 of the final EIS has been revised to include this clarification.

AP1-57: We have reviewed the updated emissions and section 4.11.1.5 of the final EIS has been revised to clarify this information.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-58	4.11.1.5	4-112	Complete shutdown	"Outside of scheduled routine maintenance events, complete shutdown of the refrigeration compressors is not anticipated."	This sentence should more accurately state: "Outside of scheduled routine maintenance events, complete shutdown of *an LNG train* is not anticipated."
AP1-59	4.11.1.5	4-112	Flaring	"When the refrigerant compressors are shut down for these maintenance events, there would be no need to vent or flare the refrigerants stored in the equipment; therefore, no additional emissions are anticipated."	This sentence should more accurately state: "When *an LNG train is* shut down for these maintenance events, there would be no need to vent or flare the refrigerants stored in the equipment, *though there will be some minor venting to flare to depressure compressors to facilitate inspection.*"
AP1-60	4.11.1.5	4-112	Marine vessel emissions	"During operation of the Terminal, LNG carriers and supporting marine vessels, namely tugboats and security vessels, would routinely generate air emissions."	Cheniere notes that these are mobile source emissions that are not subject to PSD permit review.
AP1-61	4.11.1.6	4-117	Quantitative assessment of air emissions	"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 from operation of both the Terminal and the Sinton Compressor Station."	Estimated emissions from the Taft Compressor Station were also included in the quantitative assessment of air emissions.
AP1-62	4.12.5.4	4-185	Vapor cloud contours	"As shown in Figure 4.12-3, the FLACS results indicated that the maximum extent of 1 psi overpressures with a safety factor of 2 (i.e., 1/2 psi overpressure) would remain within the Cheniere property line."	This sentence should more accurately state: "As shown in Figure 4.12-3, the FLACS results indicated that the maximum extent of 1 psi overpressures with a safety factor of 2 (i.e., 1/2 psi overpressure) would remain within *property that Cheniere owns or legally controls through covenants.*"

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AP1-58: Section 4.11.1.5 of the final EIS has been revised to include this clarification.

AP1-59: Section 4.11.1.5 of the final EIS has been revised to include this clarification.

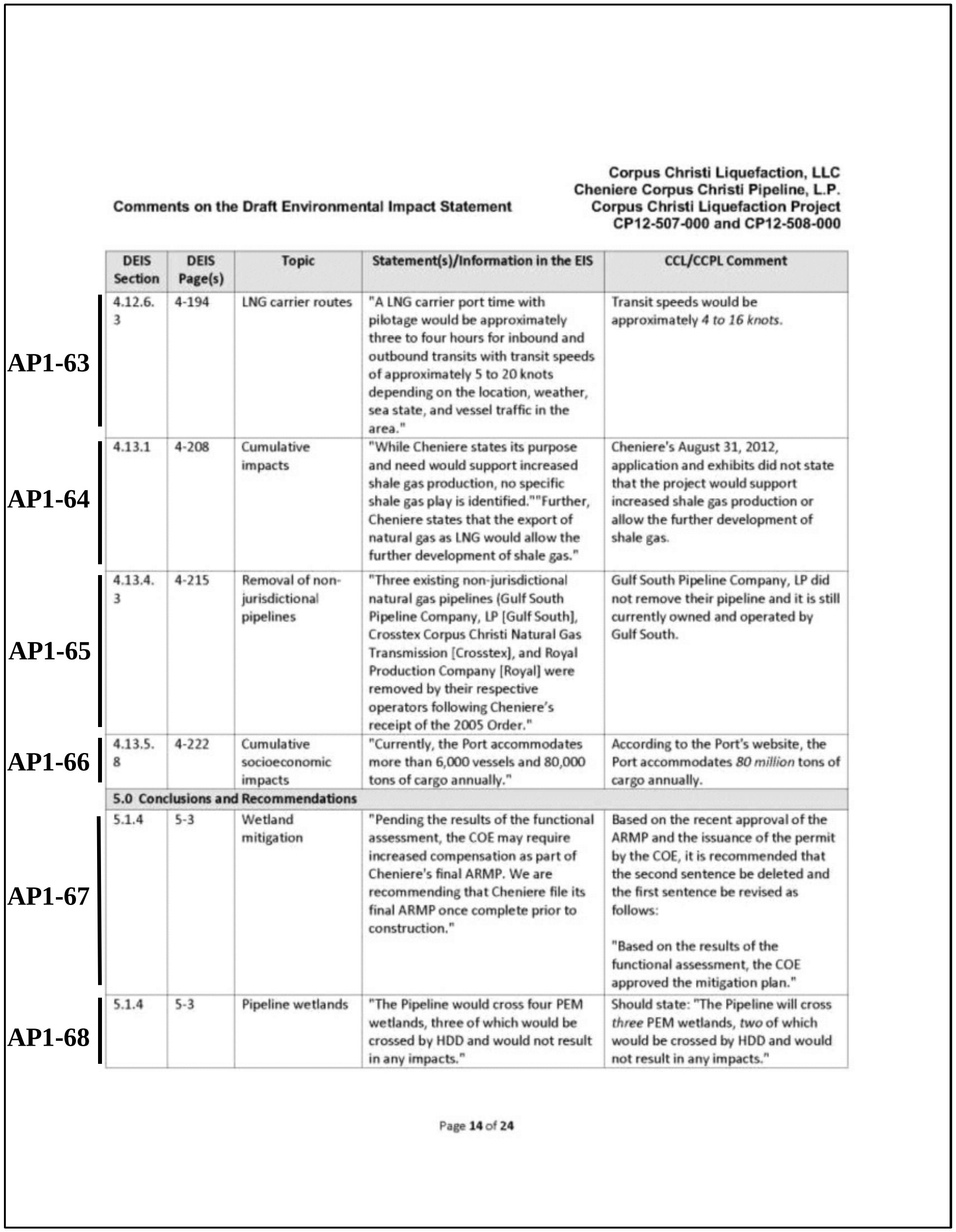
AP1-60: Section 4.11.1.5 of the final EIS addresses all operating emission sources regardless of regulatory permitting applicability, which includes mobile marine sources.

AP1-61: Section 4.11.1.6 of the final EIS has been revised to reflect this clarification.

AP1-62: Section 4.12.5.4 of the final EIS has been revised to include this clarification.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-63	4.12.6.3	4-194	LNG carrier routes	"A LNG carrier port time with pilotage would be approximately three to four hours for inbound and outbound transits with transit speeds of approximately 5 to 20 knots depending on the location, weather, sea state, and vessel traffic in the area."	Transit speeds would be approximately *4 to 16 knots.*
AP1-64	4.13.1	4-208	Cumulative impacts	"While Cheniere states its purpose and need would support increased shale gas production, no specific shale gas play is identified.""Further, Cheniere states that the export of natural gas as LNG would allow the further development of shale gas."	Cheniere's August 31, 2012, application and exhibits did not state that the project would support increased shale gas production or allow the further development of shale gas.
AP1-65	4.13.4.3	4-215	Removal of non-jurisdictional pipelines	"Three existing non-jurisdictional natural gas pipelines (Gulf South Pipeline Company, LP [Gulf South], Crosstex Corpus Christi Natural Gas Transmission [Crosstex], and Royal Production Company [Royal] were removed by their respective operators following Cheniere's receipt of the 2005 Order."	Gulf South Pipeline Company, LP did not remove their pipeline and it is still currently owned and operated by Gulf South.
AP1-66	4.13.5.8	4-222	Cumulative socioeconomic impacts	"Currently, the Port accommodates more than 6,000 vessels and 80,000 tons of cargo annually."	According to the Port's website, the Port accommodates *80 million* tons of cargo annually.
	5.0 Conclusions and Recommendations				
AP1-67	5.1.4	5-3	Wetland mitigation	"Pending the results of the functional assessment, the COE may require increased compensation as part of Cheniere's final ARMP. We are recommending that Cheniere file its final ARMP once complete prior to construction."	Based on the recent approval of the ARMP and the issuance of the permit by the COE, it is recommended that the second sentence be deleted and the first sentence be revised as follows: "Based on the results of the functional assessment, the COE approved the mitigation plan."
AP1-68	5.1.4	5-3	Pipeline wetlands	"The Pipeline would cross four PEM wetlands, three of which would be crossed by HDD and would not result in any impacts."	Should state: "The Pipeline will cross *three* PEM wetlands, *two* of which would be crossed by HDD and would not result in any impacts."

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AP1-63: Section 4.12.6.3 of the final EIS has been revised to include this clarification.

AP1-64: Section 4.13.1 of the final EIS has been revised to reflect this information.

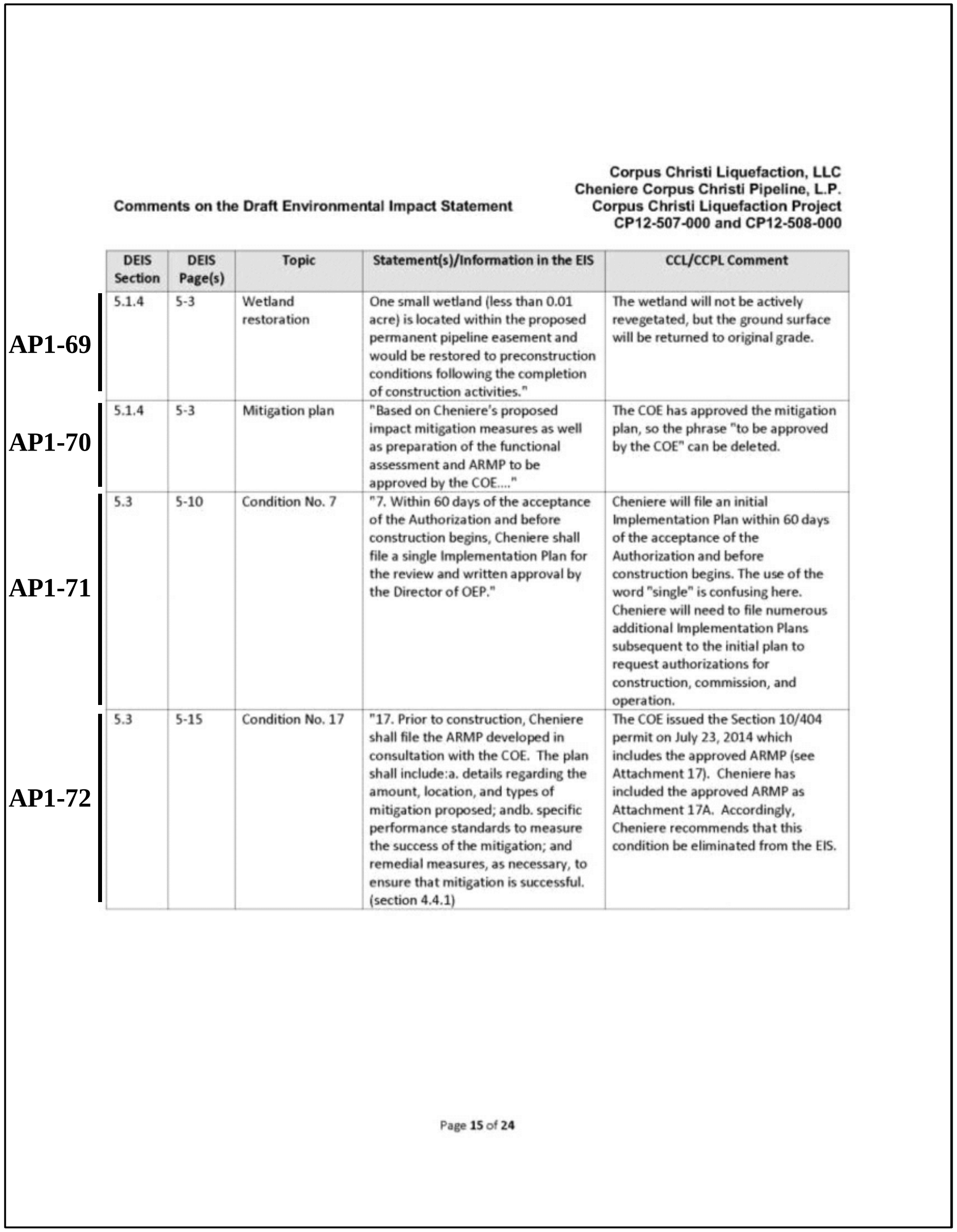
AP1-65: Section 4.13.4.3 of the final EIS has been revised to reflect this information.

AP1-66: Section 4.13.5.8 of the final EIS has been revised to include this information.

AP1-67: See response to AP1-38.

AP1-68: Section 5.1.4 of the final EIS has been revised to include this clarification.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-69	5.1.4	5-3	Wetland restoration	One small wetland (less than 0.01 acre) is located within the proposed permanent pipeline easement and would be restored to preconstruction conditions following the completion of construction activities."	The wetland will not be actively revegetated, but the ground surface will be returned to original grade.
AP1-70	5.1.4	5-3	Mitigation plan	"Based on Cheniere's proposed impact mitigation measures as well as preparation of the functional assessment and ARMP to be approved by the COE...."	The COE has approved the mitigation plan, so the phrase "to be approved by the COE" can be deleted.
AP1-71	5.3	5-10	Condition No. 7	"7. Within 60 days of the acceptance of the Authorization and before construction begins, Cheniere shall file a single Implementation Plan for the review and written approval by the Director of OEP."	Cheniere will file an initial Implementation Plan within 60 days of the acceptance of the Authorization and before construction begins. The use of the word "single" is confusing here. Cheniere will need to file numerous additional Implementation Plans subsequent to the initial plan to request authorizations for construction, commission, and operation.
AP1-72	5.3	5-15	Condition No. 17	"17. Prior to construction, Cheniere shall file the ARMP developed in consultation with the COE. The plan shall include:a. details regarding the amount, location, and types of mitigation proposed; andb. specific performance standards to measure the success of the mitigation; and remedial measures, as necessary, to ensure that mitigation is successful. (section 4.4.1)	The COE issued the Section 10/404 permit on July 23, 2014 which includes the approved ARMP (see Attachment 17). Cheniere has included the approved ARMP as Attachment 17A. Accordingly, Cheniere recommends that this condition be eliminated from the EIS.

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AP1-69: See response to AP1-44.

AP1-70: See response to AP1-38.

AP1-71: We disagree. We recognize that changes may occur to the initial Implementation Plan requiring Cheniere to provide additional information; however, these changes would be considered revisions or supplements rather than separate plans.

AP1-72: This recommendation has been removed from section 4.4.1 and 5.3 of the final EIS.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.

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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-73	5.3	5-15	Condition No. 18	"18. Prior to construction, Cheniere shall file documentation of concurrence from the RRC that the Project is consistent with the Texas CZMP. (section 4.8.1.5)"	Cheniere received its Section 10/404 permit on July 23, 2014. CZMP consistency comes along with the Section 10/404 permit. Therefore, Cheniere recommends that this entire text, including the recommendation, be deleted from the EIS. Cheniere has included in Attachment 18 a letter from the RRC to the COE from November 2013 that provides the CZMP consistency determination.
AP1-74	5.3	5-15	Condition No. 19	"19. Cheniere shall not begin construction or use of any staging, storage, and temporary work areas, and new or to-be-improved roads, until: a. Cheniere files with the Secretary: 1. any additional inventory reports, including documentation of survey of the proposed pipeline route between approximate MP 0.0 and 0.5…."	Cultural resources clearance has been obtained from the SHPO for the entirety of the pipeline route. Attachment 19 contains the relevant clearance for the beginning of the pipeline route. Therefore, CCPL requests that this portion of this condition be eliminated from the EIS.
AP1-75	5.3	5-16	Condition No. 20	"20. Prior to construction, Cheniere shall file a revised FDCP with the Secretary for review and written approval from the Director of OEP. The revised FDCP shall include the following:a. the use of gravel at construction entrance and exit locations; andb. measures to clean paved roads upon mud or dirt track out. (section 4.11.1.4)"	Cheniere has revised the FDCP to include the two requested items. The revised FDCP is included in Attachment 20. Therefore, Cheniere recommends that this condition be eliminated from the EIS.
AP1-76	5.3	5-16	Condition No. 23	"23. Prior to the end of the draft environmental impact statement comment period, Cheniere shall file with the Secretary for review and written approval by the Director of OEP, clarification if a 10-foot vapor fence would be provided to mitigate vapor dispersion from releases when the ambient air vaporizers are operational. (section 4.12.5)"	Cheniere confirms that it will provide a 10-foot vapor fence to mitigate vapor dispersion from releases when the ambient air vaporizers are operational. Therefore, Cheniere recommends that this condition be eliminated from the EIS.

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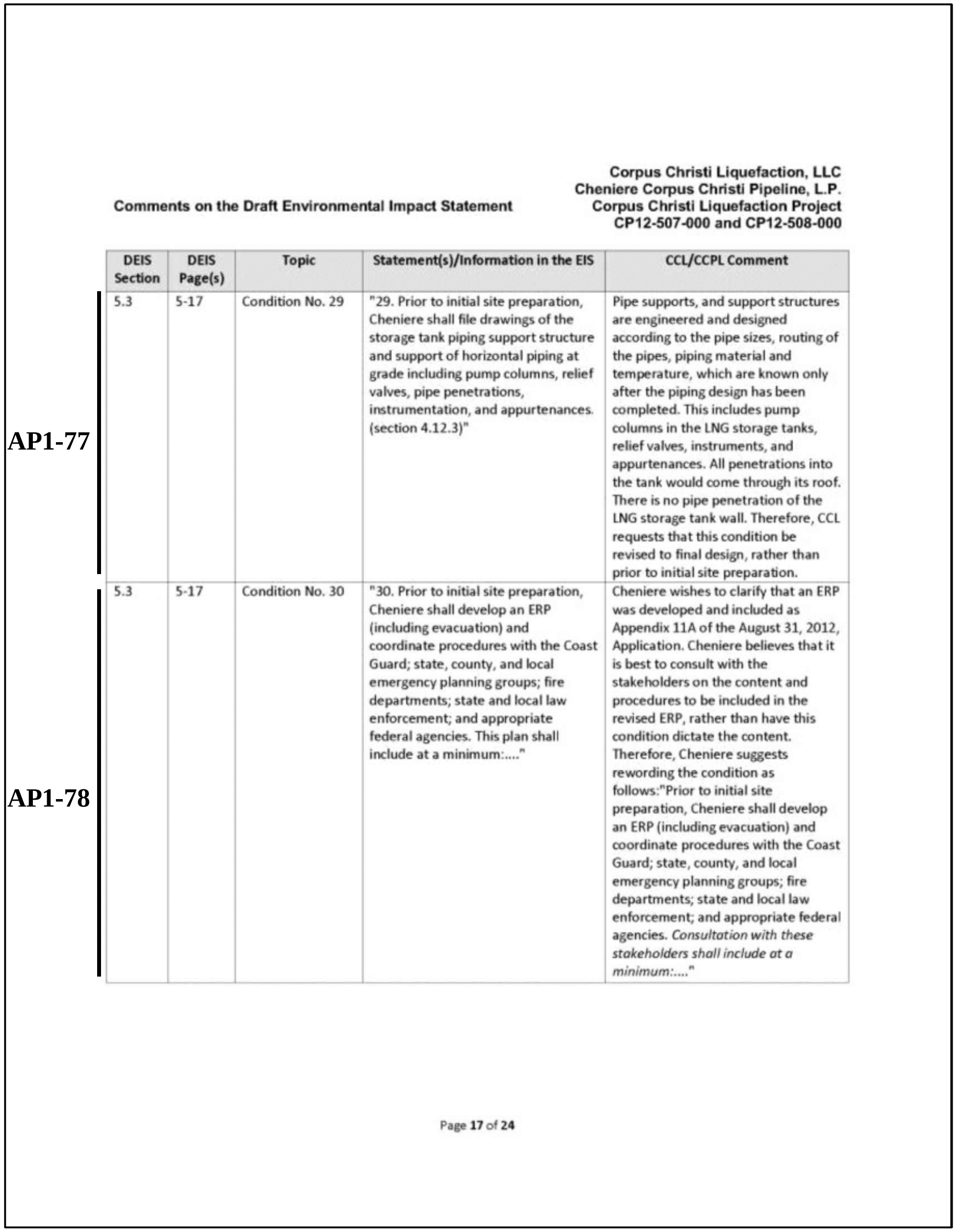
AP1-73: See response to AP1-51.

AP1-74: Section 4.10 of the final EIS has been revised to reflect receipt of SHPO clearance. This recommendation has been removed from sections 4.10 and 5.3 of the final EIS.

AP1-75: We disagree. Section 4.11.1.4 has been updated to include the revised FDCP. However, the revised FDCP fails to address how Cheniere would implement the use of gravel at construction entrance and exit locations and does not outline the measures to be used to clean paved roads upon mud or dirt track-out. Therefore, the recommendation remains in the final EIS.

AP1-76: This recommendation has been removed from sections 4.12.5.4 and 5.3 of the final EIS.



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AP1-77

AP1-78

DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
5.3	5-17	Condition No. 29	"29. Prior to initial site preparation, Cheniere 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 4.12.3)"	Pipe supports, and support structures are engineered and designed according to the pipe sizes, routing of the pipes, piping material and temperature, which are known only after the piping design has been completed. This includes pump columns in the LNG storage tanks, relief valves, instruments, and appurtenances. All penetrations into the tank would come through its roof. There is no pipe penetration of the LNG storage tank wall. Therefore, CCL requests that this condition be revised to final design, rather than prior to initial site preparation.
5.3	5-17	Condition No. 30	"30. Prior to initial site preparation, Cheniere shall develop an ERP (including evacuation) 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:...."	Cheniere wishes to clarify that an ERP was developed and included as Appendix 11A of the August 31, 2012, Application. Cheniere believes that it is best to consult with the stakeholders on the content and procedures to be included in the revised ERP, rather than have this condition dictate the content. Therefore, Cheniere suggests rewording the condition as follows:"Prior to initial site preparation, Cheniere shall develop an ERP (including evacuation) 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. *Consultation with these stakeholders shall include at a minimum:....*"

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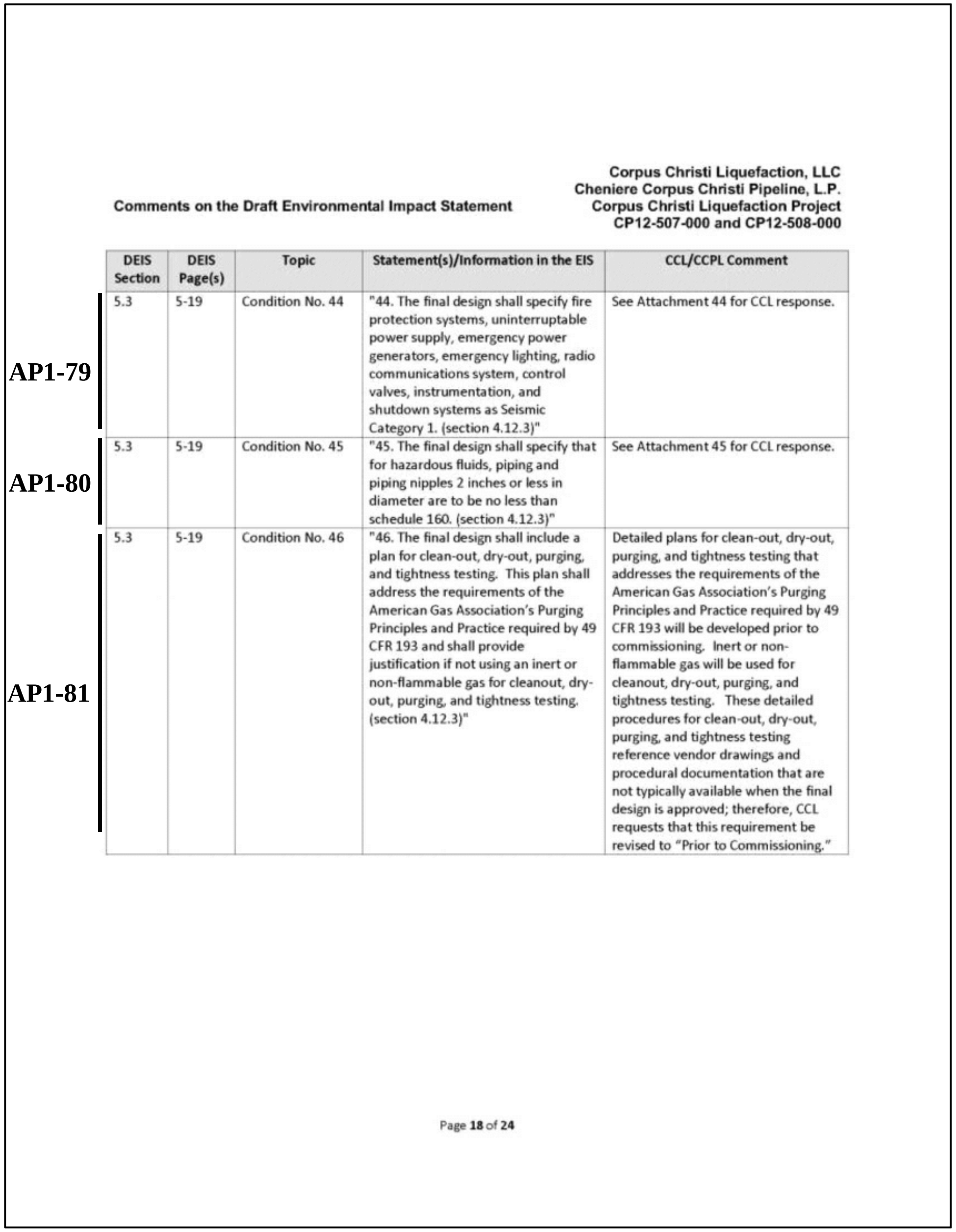
AP1-77: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-78: The ERP should include the items listed a through e in the recommendation.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
5.3	5-19	Condition No. 44	"44. The final design shall specify fire protection systems, uninterruptable power supply, emergency power generators, emergency lighting, radio communications system, control valves, instrumentation, and shutdown systems as Seismic Category 1. (section 4.12.3)"	See Attachment 44 for CCL response.
5.3	5-19	Condition No. 45	"45. The final design shall specify that for hazardous fluids, piping and piping nipples 2 inches or less in diameter are to be no less than schedule 160. (section 4.12.3)"	See Attachment 45 for CCL response.
5.3	5-19	Condition No. 46	"46. The final design shall include 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 required by 49 CFR 193 and shall provide justification if not using an inert or non-flammable gas for cleanout, dry-out, purging, and tightness testing. (section 4.12.3)"	Detailed plans for clean-out, dry-out, purging, and tightness testing that addresses the requirements of the American Gas Association's Purging Principles and Practice required by 49 CFR 193 will be developed prior to commissioning. Inert or non-flammable gas will be used for cleanout, dry-out, purging, and tightness testing. These detailed procedures for clean-out, dry-out, purging, and tightness testing reference vendor drawings and procedural documentation that are not typically available when the final design is approved; therefore, CCL requests that this requirement be revised to "Prior to Commissioning."

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AP1-79

AP1-80

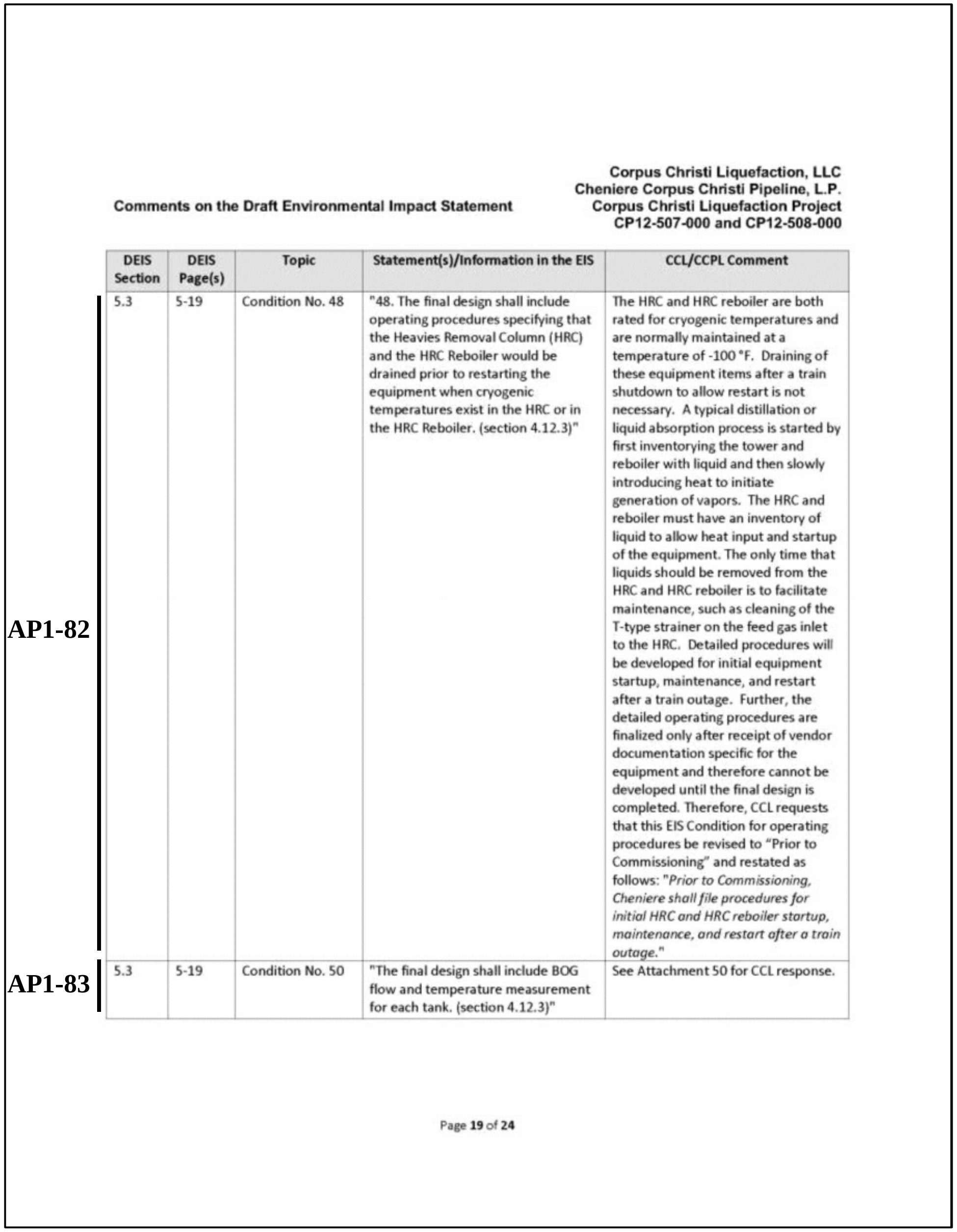
AP1-81

AP1-79: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-80: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-81: Some of these activities, such as clean out and dry out, may precede commissioning and therefore the plans should be developed and established for review before these activities are carried out.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
5.3	5-19	Condition No. 48	"48. The final design shall include operating procedures specifying that the Heavies Removal Column (HRC) and the HRC Reboiler would be drained prior to restarting the equipment when cryogenic temperatures exist in the HRC or in the HRC Reboiler. (section 4.12.3)"	The HRC and HRC reboiler are both rated for cryogenic temperatures and are normally maintained at a temperature of -100 °F. Draining of these equipment items after a train shutdown to allow restart is not necessary. A typical distillation or liquid absorption process is started by first inventorying the tower and reboiler with liquid and then slowly introducing heat to initiate generation of vapors. The HRC and reboiler must have an inventory of liquid to allow heat input and startup of the equipment. The only time that liquids should be removed from the HRC and HRC reboiler is to facilitate maintenance, such as cleaning of the T-type strainer on the feed gas inlet to the HRC. Detailed procedures will be developed for initial equipment startup, maintenance, and restart after a train outage. Further, the detailed operating procedures are finalized only after receipt of vendor documentation specific for the equipment and therefore cannot be developed until the final design is completed. Therefore, CCL requests that this EIS Condition for operating procedures be revised to "Prior to Commissioning" and restated as follows: "*Prior to Commissioning, Cheniere shall file procedures for initial HRC and HRC reboiler startup, maintenance, and restart after a train outage.*"
5.3	5-19	Condition No. 50	"The final design shall include BOG flow and temperature measurement for each tank. (section 4.12.3)"	See Attachment 50 for CCL response.

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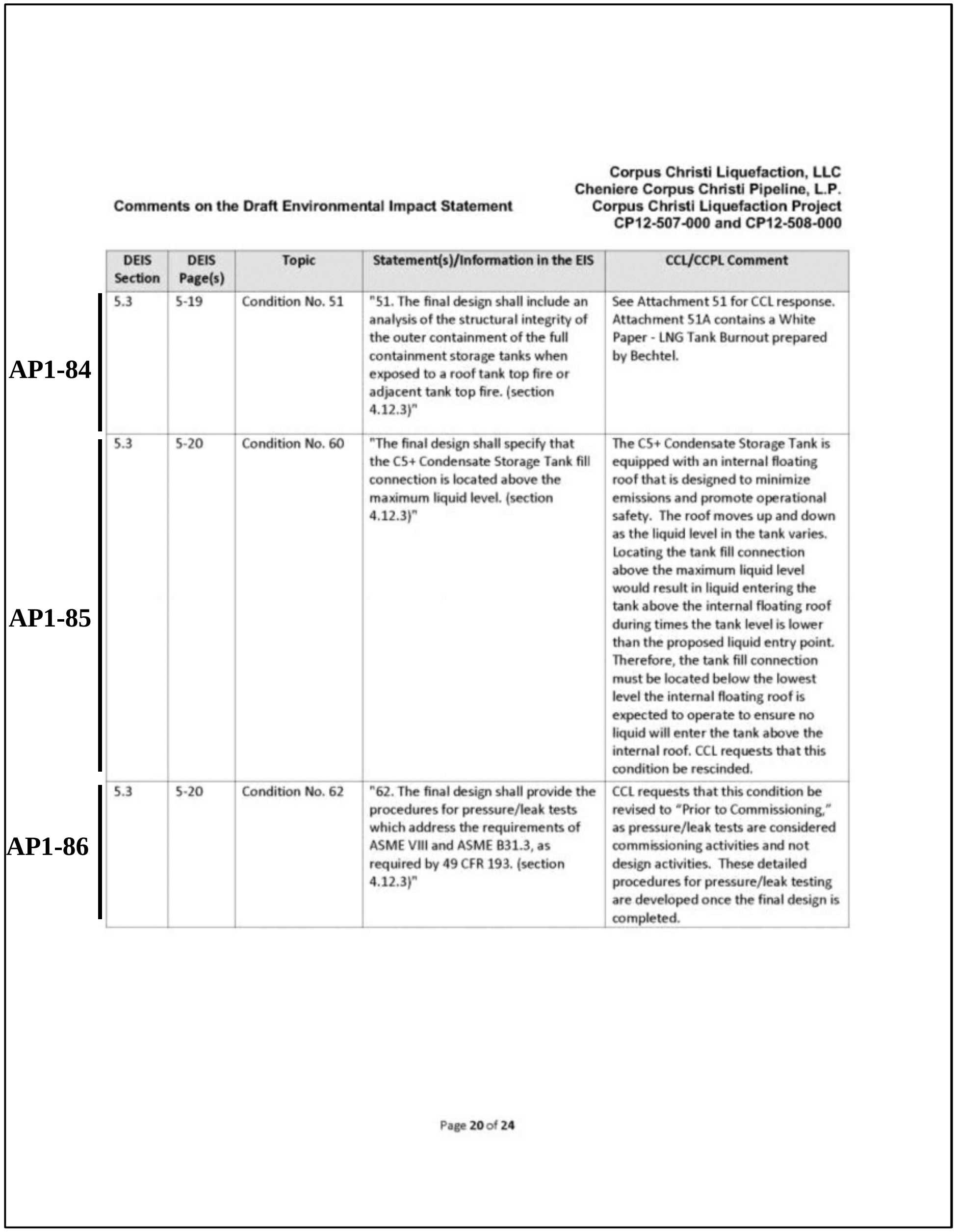
AP1-82

AP1-83

AP1-82: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-83: The boil-off gas (BOG) flow from each tank provides additional information that may not be ascertained by measuring the total flow from the BOG compressors.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



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	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-84	5.3	5-19	Condition No. 51	"51. The final design shall include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire. (section 4.12.3)"	See Attachment 51 for CCL response. Attachment 51A contains a White Paper - LNG Tank Burnout prepared by Bechtel.
AP1-85	5.3	5-20	Condition No. 60	"The final design shall specify that the C5+ Condensate Storage Tank fill connection is located above the maximum liquid level. (section 4.12.3)"	The C5+ Condensate Storage Tank is equipped with an internal floating roof that is designed to minimize emissions and promote operational safety. The roof moves up and down as the liquid level in the tank varies. Locating the tank fill connection above the maximum liquid level would result in liquid entering the tank above the internal floating roof during times the tank level is lower than the proposed liquid entry point. Therefore, the tank fill connection must be located below the lowest level the internal floating roof is expected to operate to ensure no liquid will enter the tank above the internal roof. CCL requests that this condition be rescinded.
AP1-86	5.3	5-20	Condition No. 62	"62. The final design shall provide the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3, as required by 49 CFR 193. (section 4.12.3)"	CCL requests that this condition be revised to "Prior to Commissioning," as pressure/leak tests are considered commissioning activities and not design activities. These detailed procedures for pressure/leak testing are developed once the final design is completed.

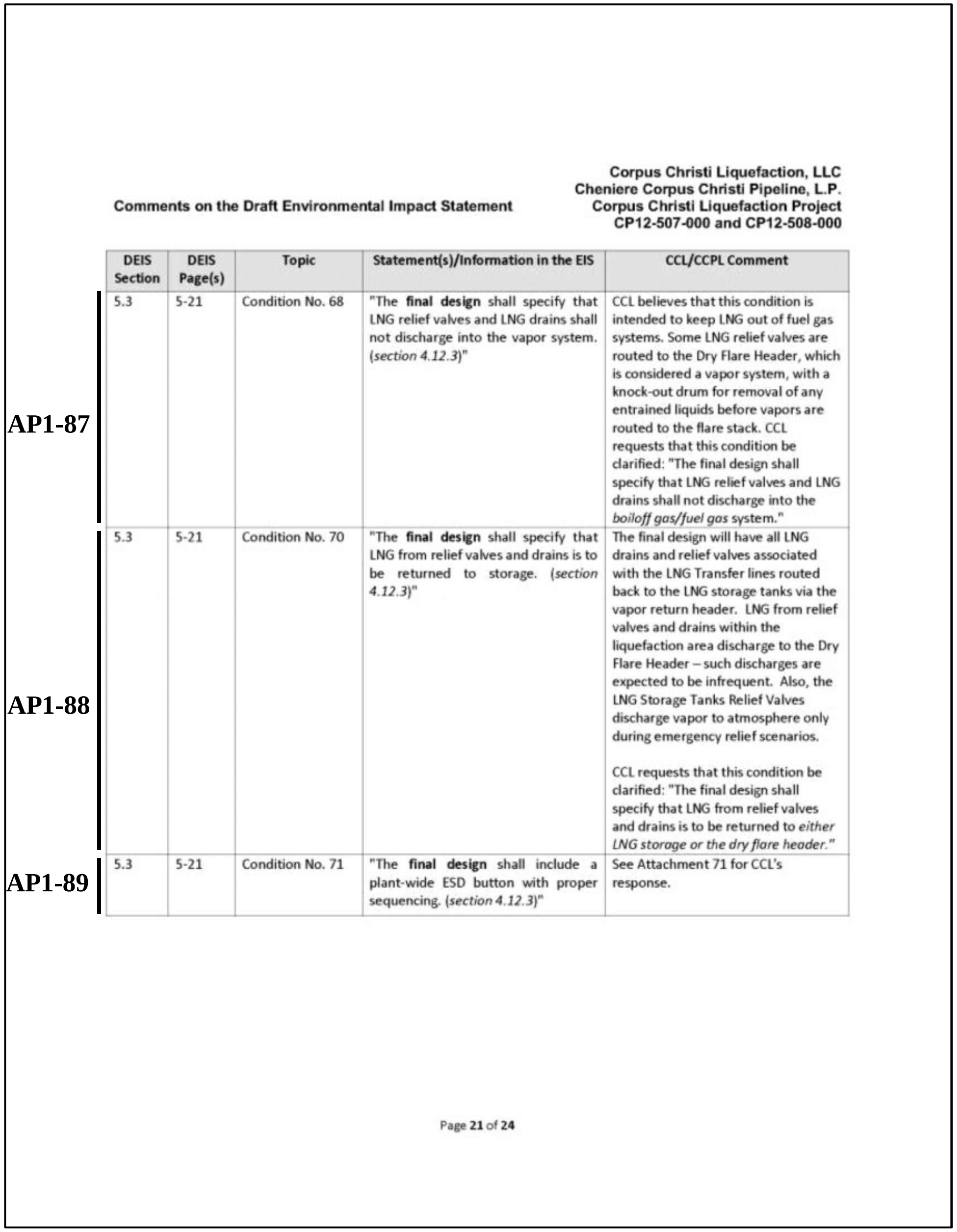
Page 20 of 24

AP1-84: The siting of the storage tanks and facility are based up on a tank top fire and therefore the ability of the storage tank to be able to withstand this event is critical for the siting of the facility.

AP1-85: This recommendation has been removed from sections 4.12.3 and 5.3 of the final EIS.

AP1-86: We recognize these activities require the final design to be completed before they can be developed. However, the timing of the recommendation reflect that some of these activities may precede commissioning and therefore the plans should be developed and established for review before these activities are carried out.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



Comments on the Draft Environmental Impact Statement

Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Corpus Christi Liquefaction Project
CP12-507-000 and CP12-508-000

	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-87	5.3	5-21	Condition No. 68	"The **final design** shall specify that LNG relief valves and LNG drains shall not discharge into the vapor system. (*section 4.12.3*)"	CCL believes that this condition is intended to keep LNG out of fuel gas systems. Some LNG relief valves are routed to the Dry Flare Header, which is considered a vapor system, with a knock-out drum for removal of any entrained liquids before vapors are routed to the flare stack. CCL requests that this condition be clarified: "The final design shall specify that LNG relief valves and LNG drains shall not discharge into the *boiloff gas/fuel gas* system."
AP1-88	5.3	5-21	Condition No. 70	"The **final design** shall specify that LNG from relief valves and drains is to be returned to storage. (*section 4.12.3*)"	The final design will have all LNG drains and relief valves associated with the LNG Transfer lines routed back to the LNG storage tanks via the vapor return header. LNG from relief valves and drains within the liquefaction area discharge to the Dry Flare Header – such discharges are expected to be infrequent. Also, the LNG Storage Tanks Relief Valves discharge vapor to atmosphere only during emergency relief scenarios. CCL requests that this condition be clarified: "The final design shall specify that LNG from relief valves and drains is to be returned to *either LNG storage or the dry flare header.*"
AP1-89	5.3	5-21	Condition No. 71	"The **final design** shall include a plant-wide ESD button with proper sequencing. (*section 4.12.3*)"	See Attachment 71 for CCL's response.

Page **21** of **24**

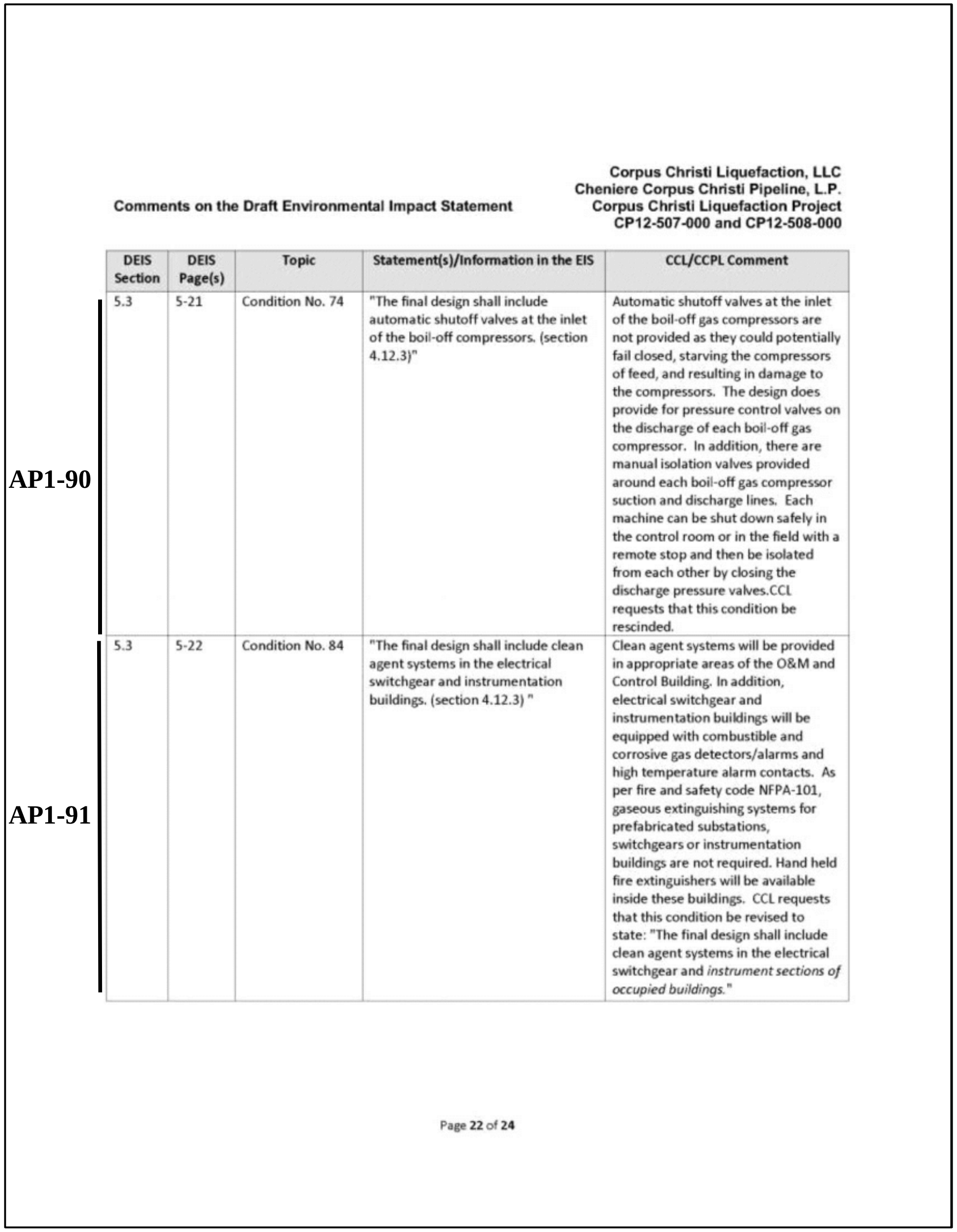
AP1-87: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-88: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1-89: Having a single plant-wide shutdown in addition to the other shutdown buttons reduces the risk of operator error from inadvertently missing one of the several emergency shutdown buttons he/she would otherwise have to press to ensure a complete shutdown. Having the single plant-wide button does not preclude an operator from shutting down portions of the plant and there are other means (e.g. double action systems) to help prevent inadvertent operation of a plant-wide shutdown.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



Comments on the Draft Environmental Impact Statement

Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Corpus Christi Liquefaction Project
CP12-507-000 and CP12-508-000

DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
5.3	5-21	Condition No. 74	"The final design shall include automatic shutoff valves at the inlet of the boil-off compressors. (section 4.12.3)"	Automatic shutoff valves at the inlet of the boil-off gas compressors are not provided as they could potentially fail closed, starving the compressors of feed, and resulting in damage to the compressors. The design does provide for pressure control valves on the discharge of each boil-off gas compressor. In addition, there are manual isolation valves provided around each boil-off gas compressor suction and discharge lines. Each machine can be shut down safely in the control room or in the field with a remote stop and then be isolated from each other by closing the discharge pressure valves.CCL requests that this condition be rescinded.
5.3	5-22	Condition No. 84	"The final design shall include clean agent systems in the electrical switchgear and instrumentation buildings. (section 4.12.3) "	Clean agent systems will be provided in appropriate areas of the O&M and Control Building. In addition, electrical switchgear and instrumentation buildings will be equipped with combustible and corrosive gas detectors/alarms and high temperature alarm contacts. As per fire and safety code NFPA-101, gaseous extinguishing systems for prefabricated substations, switchgears or instrumentation buildings are not required. Hand held fire extinguishers will be available inside these buildings. CCL requests that this condition be revised to state: "The final design shall include clean agent systems in the electrical switchgear and *instrument sections of occupied buildings.*"

AP1-90

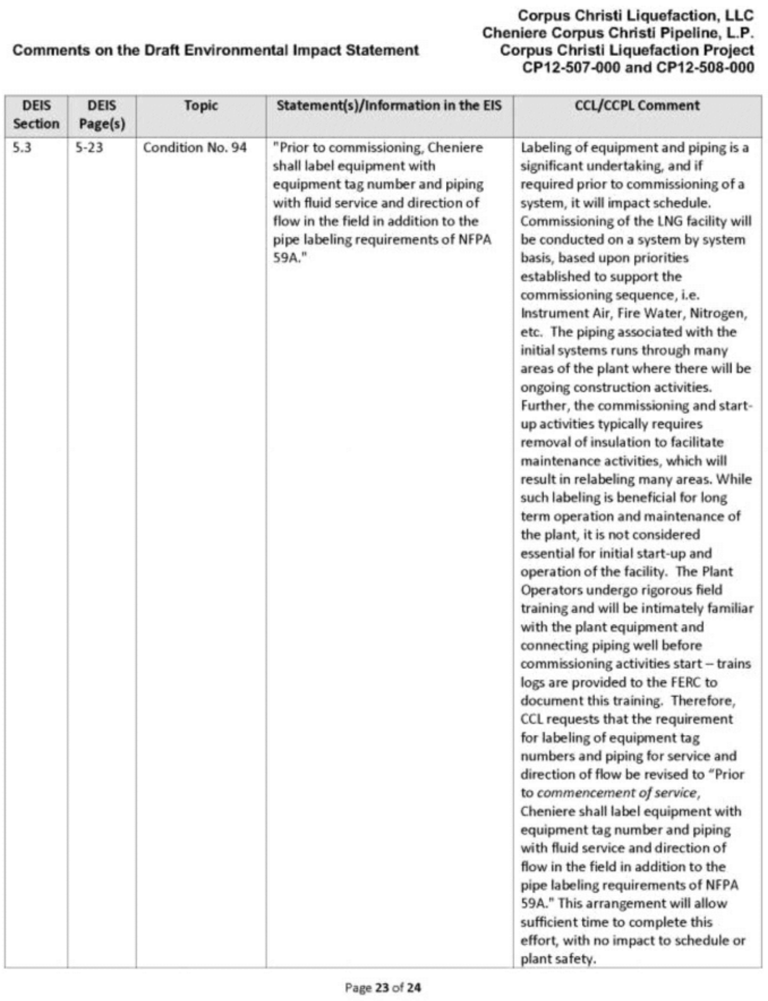
AP1-91

AP1-90: We have removed the recommendation in sections 4.12.3 and 5.3 of the final EIS.

AP1-91: We disagree that limiting the clean agent systems to only electrical switchgear and instrument sections of occupied buildings is appropriate.

APPLICANT COMMENTS

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



Comments on the Draft Environmental Impact Statement

Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Corpus Christi Liquefaction Project
CP12-507-000 and CP12-508-000

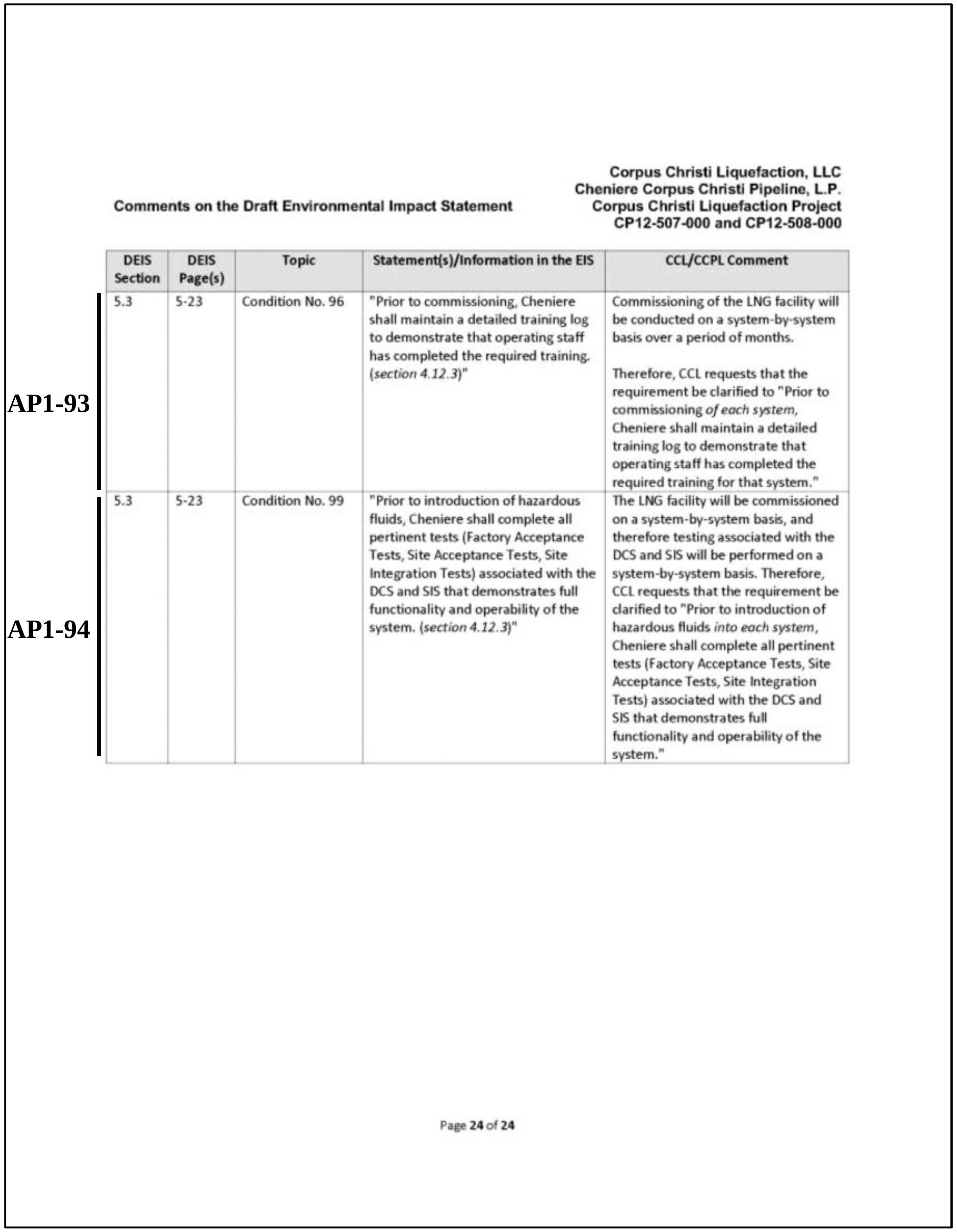
DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
5.3	5-23	Condition No. 94	"Prior to commissioning, Cheniere shall label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A."	Labeling of equipment and piping is a significant undertaking, and if required prior to commissioning of a system, it will impact schedule. Commissioning of the LNG facility will be conducted on a system by system basis, based upon priorities established to support the commissioning sequence, i.e. Instrument Air, Fire Water, Nitrogen, etc. The piping associated with the initial systems runs through many areas of the plant where there will be ongoing construction activities. Further, the commissioning and start-up activities typically requires removal of insulation to facilitate maintenance activities, which will result in relabeling many areas. While such labeling is beneficial for long term operation and maintenance of the plant, it is not considered essential for initial start-up and operation of the facility. The Plant Operators undergo rigorous field training and will be intimately familiar with the plant equipment and connecting piping well before commissioning activities start – trains logs are provided to the FERC to document this training. Therefore, CCL requests that the requirement for labeling of equipment tag numbers and piping for service and direction of flow be revised to "Prior to *commencement of service*, Cheniere shall label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A." This arrangement will allow sufficient time to complete this effort, with no impact to schedule or plant safety.

Page 23 of 24

AP1-92

AP1-92: This recommendation has been revised in sections 4.12.3 and 5.3 of the final EIS.

AP1 – Corpus Christi Liquefaction, LLC/Cheniere Corpus Christi Pipeline, L.P.



Comments on the Draft Environmental Impact Statement

Corpus Christi Liquefaction, LLC
Cheniere Corpus Christi Pipeline, L.P.
Corpus Christi Liquefaction Project
CP12-507-000 and CP12-508-000

	DEIS Section	DEIS Page(s)	Topic	Statement(s)/Information in the EIS	CCL/CCPL Comment
AP1-93	5.3	5-23	Condition No. 96	"Prior to commissioning, Cheniere shall maintain a detailed training log to demonstrate that operating staff has completed the required training. (*section 4.12.3*)"	Commissioning of the LNG facility will be conducted on a system-by-system basis over a period of months. Therefore, CCL requests that the requirement be clarified to "Prior to commissioning *of each system*, Cheniere shall maintain a detailed training log to demonstrate that operating staff has completed the required training for that system."
AP1-94	5.3	5-23	Condition No. 99	"Prior to introduction of hazardous fluids, Cheniere shall complete 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 4.12.3*)"	The LNG facility will be commissioned on a system-by-system basis, and therefore testing associated with the DCS and SIS will be performed on a system-by-system basis. Therefore, CCL requests that the requirement be clarified to "Prior to introduction of hazardous fluids *into each system*, Cheniere shall complete 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."

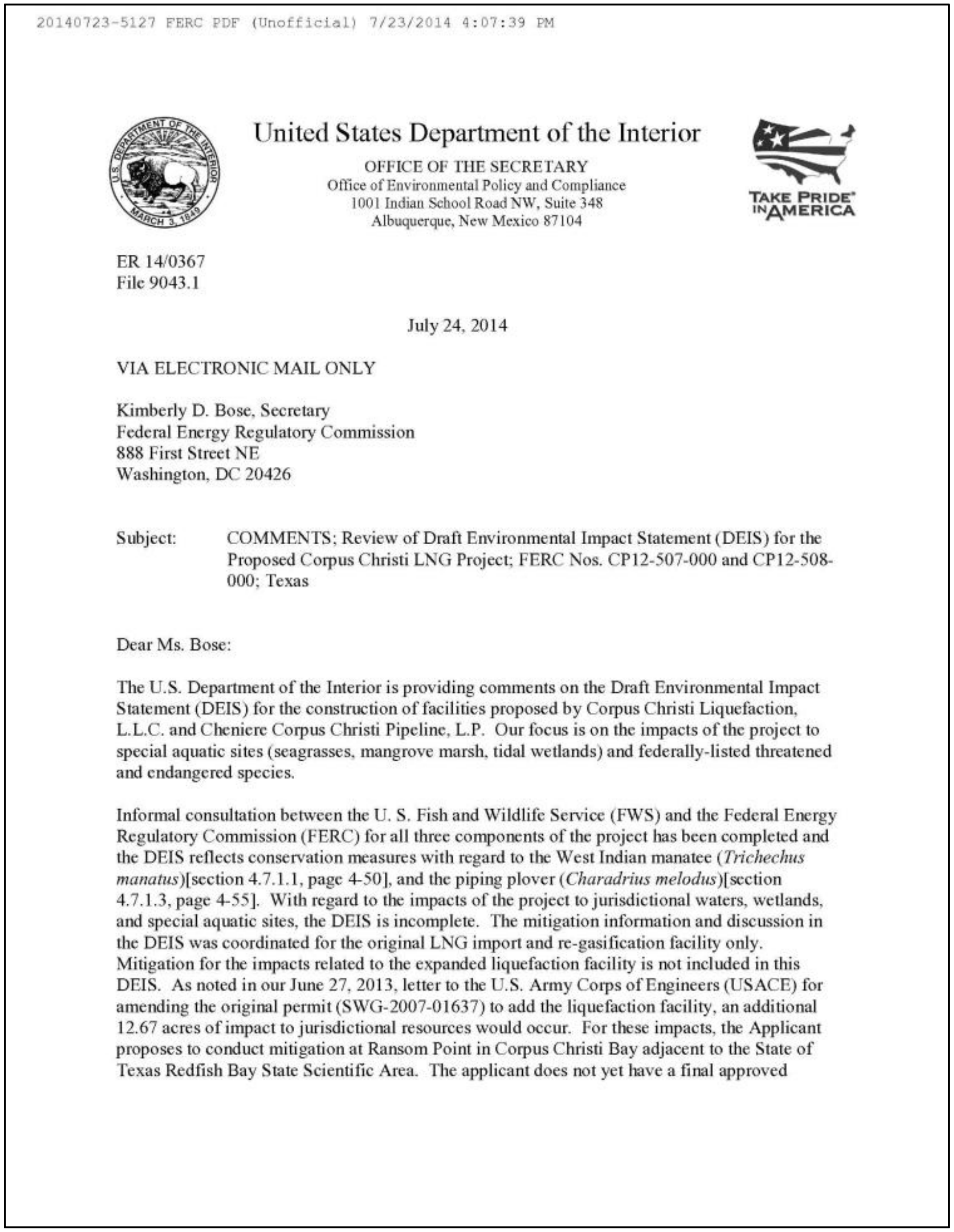
Page **24** of **24**

AP1-93: Each recommendation may be approved on a system-by-system basis subject to the approval of the Director of Office of Energy Projects or delegated staff. The current language does not restrict that policy.

AP1-94: Individual FAT/SAT/SITs may not function seamlessly when integrated together and can cause complete failure of the control system and human machine interface.

FEDERAL GOVERNMENT COMMENTS

FG1 – United States Department of the Interior



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United States Department of the Interior
OFFICE OF THE SECRETARY
Office of Environmental Policy and Compliance
1001 Indian School Road NW, Suite 348
Albuquerque, New Mexico 87104

TAKE PRIDE IN AMERICA

ER 14/0367
File 9043.1

July 24, 2014

VIA ELECTRONIC MAIL ONLY

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Subject: COMMENTS; Review of Draft Environmental Impact Statement (DEIS) for the Proposed Corpus Christi LNG Project; FERC Nos. CP12-507-000 and CP12-508-000; Texas

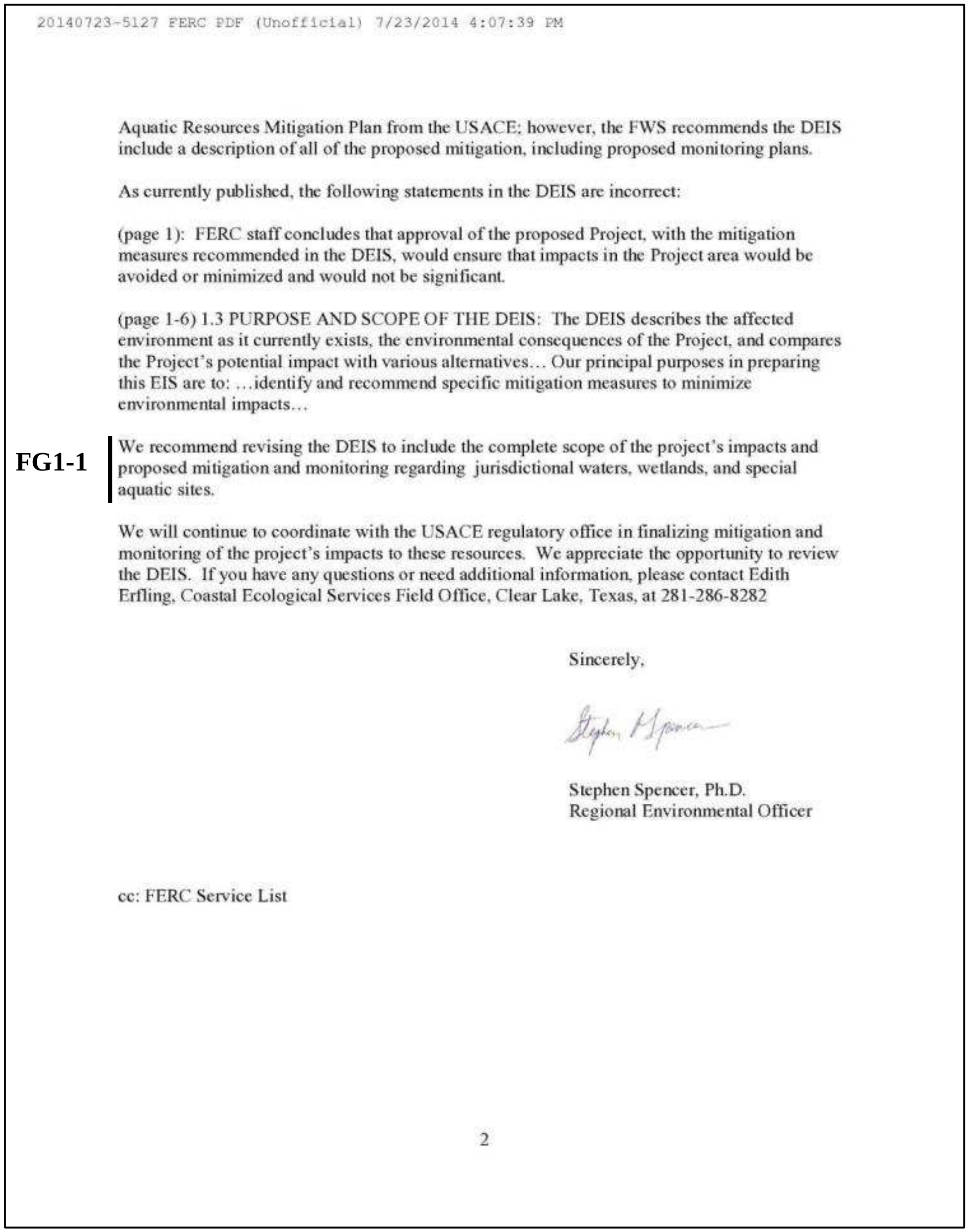
Dear Ms. Bose:

The U.S. Department of the Interior is providing comments on the Draft Environmental Impact Statement (DEIS) for the construction of facilities proposed by Corpus Christi Liquefaction, L.L.C. and Cheniere Corpus Christi Pipeline, L.P. Our focus is on the impacts of the project to special aquatic sites (seagrasses, mangrove marsh, tidal wetlands) and federally-listed threatened and endangered species.

Informal consultation between the U. S. Fish and Wildlife Service (FWS) and the Federal Energy Regulatory Commission (FERC) for all three components of the project has been completed and the DEIS reflects conservation measures with regard to the West Indian manatee (*Trichechus manatus*)[section 4.7.1.1, page 4-50], and the piping plover (*Charadrius melodus*)[section 4.7.1.3, page 4-55]. With regard to the impacts of the project to jurisdictional waters, wetlands, and special aquatic sites, the DEIS is incomplete. The mitigation information and discussion in the DEIS was coordinated for the original LNG import and re-gasification facility only. Mitigation for the impacts related to the expanded liquefaction facility is not included in this DEIS. As noted in our June 27, 2013, letter to the U.S. Army Corps of Engineers (USACE) for amending the original permit (SWG-2007-01637) to add the liquefaction facility, an additional 12.67 acres of impact to jurisdictional resources would occur. For these impacts, the Applicant proposes to conduct mitigation at Ransom Point in Corpus Christi Bay adjacent to the State of Texas Redfish Bay State Scientific Area. The applicant does not yet have a final approved

FEDERAL GOVERNMENT COMMENTS

FG1 – United States Department of the Interior



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Aquatic Resources Mitigation Plan from the USACE; however, the FWS recommends the DEIS include a description of all of the proposed mitigation, including proposed monitoring plans.

As currently published, the following statements in the DEIS are incorrect:

(page 1): FERC staff concludes that approval of the proposed Project, with the mitigation measures recommended in the DEIS, would ensure that impacts in the Project area would be avoided or minimized and would not be significant.

(page 1-6) 1.3 PURPOSE AND SCOPE OF THE DEIS: The DEIS describes the affected environment as it currently exists, the environmental consequences of the Project, and compares the Project's potential impact with various alternatives… Our principal purposes in preparing this EIS are to: …identify and recommend specific mitigation measures to minimize environmental impacts…

FG1-1 We recommend revising the DEIS to include the complete scope of the project's impacts and proposed mitigation and monitoring regarding jurisdictional waters, wetlands, and special aquatic sites.

We will continue to coordinate with the USACE regulatory office in finalizing mitigation and monitoring of the project's impacts to these resources. We appreciate the opportunity to review the DEIS. If you have any questions or need additional information, please contact Edith Erfling, Coastal Ecological Services Field Office, Clear Lake, Texas, at 281-286-8282

Sincerely,

Stephen Spencer

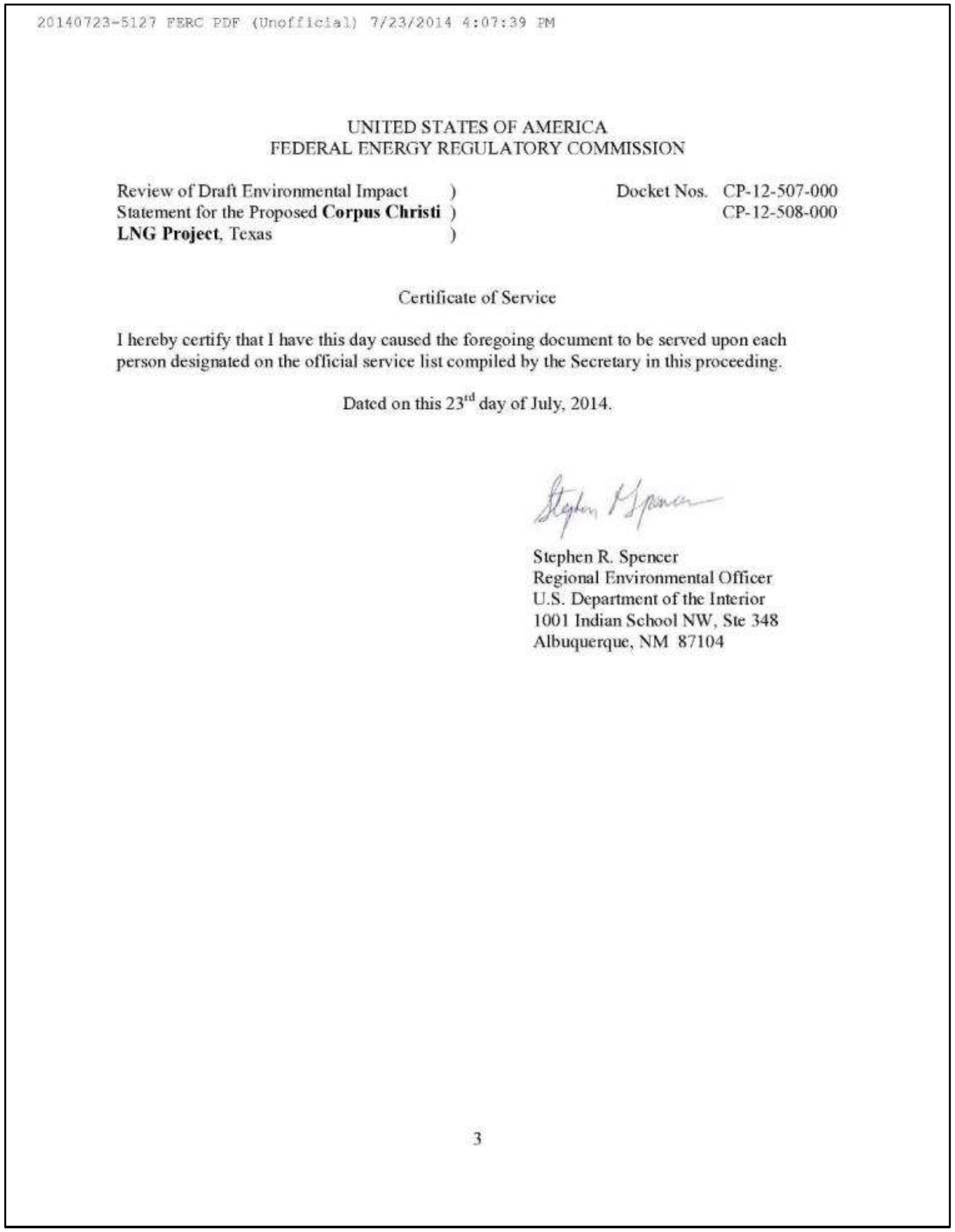
Stephen Spencer, Ph.D.
Regional Environmental Officer

cc: FERC Service List

2

FG1-1: Section 4.4.1 of the final EIS has been revised to include proposed mitigation and monitoring regarding jurisdictional waters, wetlands, and special aquatic sites.

FG1 – United States Department of the Interior



UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Review of Draft Environmental Impact)
Statement for the Proposed **Corpus Christi**)
LNG Project, Texas)

Docket Nos. CP-12-507-000
CP-12-508-000

Certificate of Service

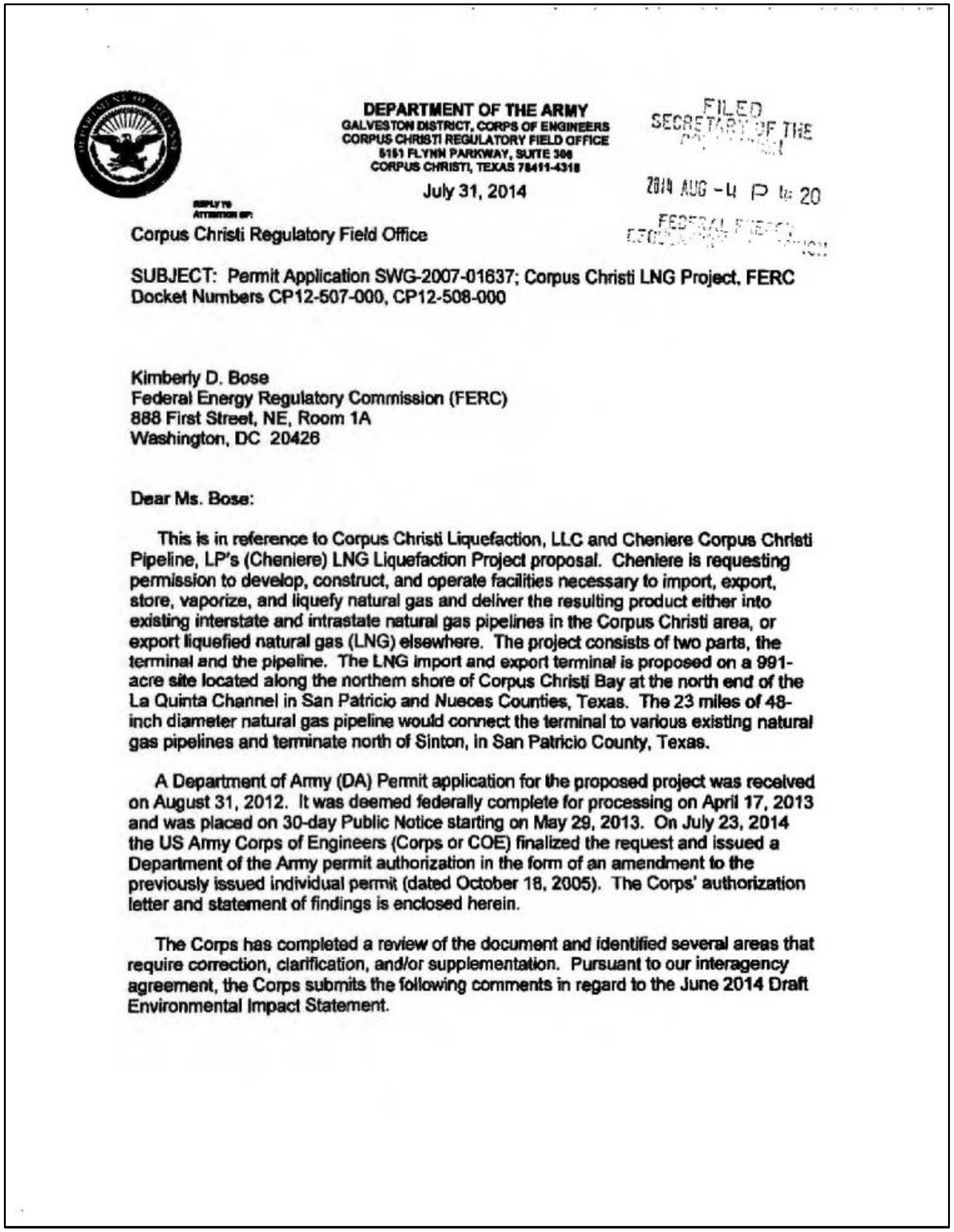
I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 23rd day of July, 2014.

Stephen R Spencer

Stephen R. Spencer
Regional Environmental Officer
U.S. Department of the Interior
1001 Indian School NW, Ste 348
Albuquerque, NM 87104

FG2 – United States Army Corps of Engineers



DEPARTMENT OF THE ARMY
GALVESTON DISTRICT, CORPS OF ENGINEERS
CORPUS CHRISTI REGULATORY FIELD OFFICE
5151 FLYNN PARKWAY, SUITE 306
CORPUS CHRISTI, TEXAS 78411-4318

July 31, 2014

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FEDERAL ENERGY
REGULATORY COMMISSION

REPLY TO
ATTENTION OF:
Corpus Christi Regulatory Field Office

SUBJECT: Permit Application SWG-2007-01637; Corpus Christi LNG Project, FERC Docket Numbers CP12-507-000, CP12-508-000

Kimberly D. Bose
Federal Energy Regulatory Commission (FERC)
888 First Street, NE, Room 1A
Washington, DC 20426

Dear Ms. Bose:

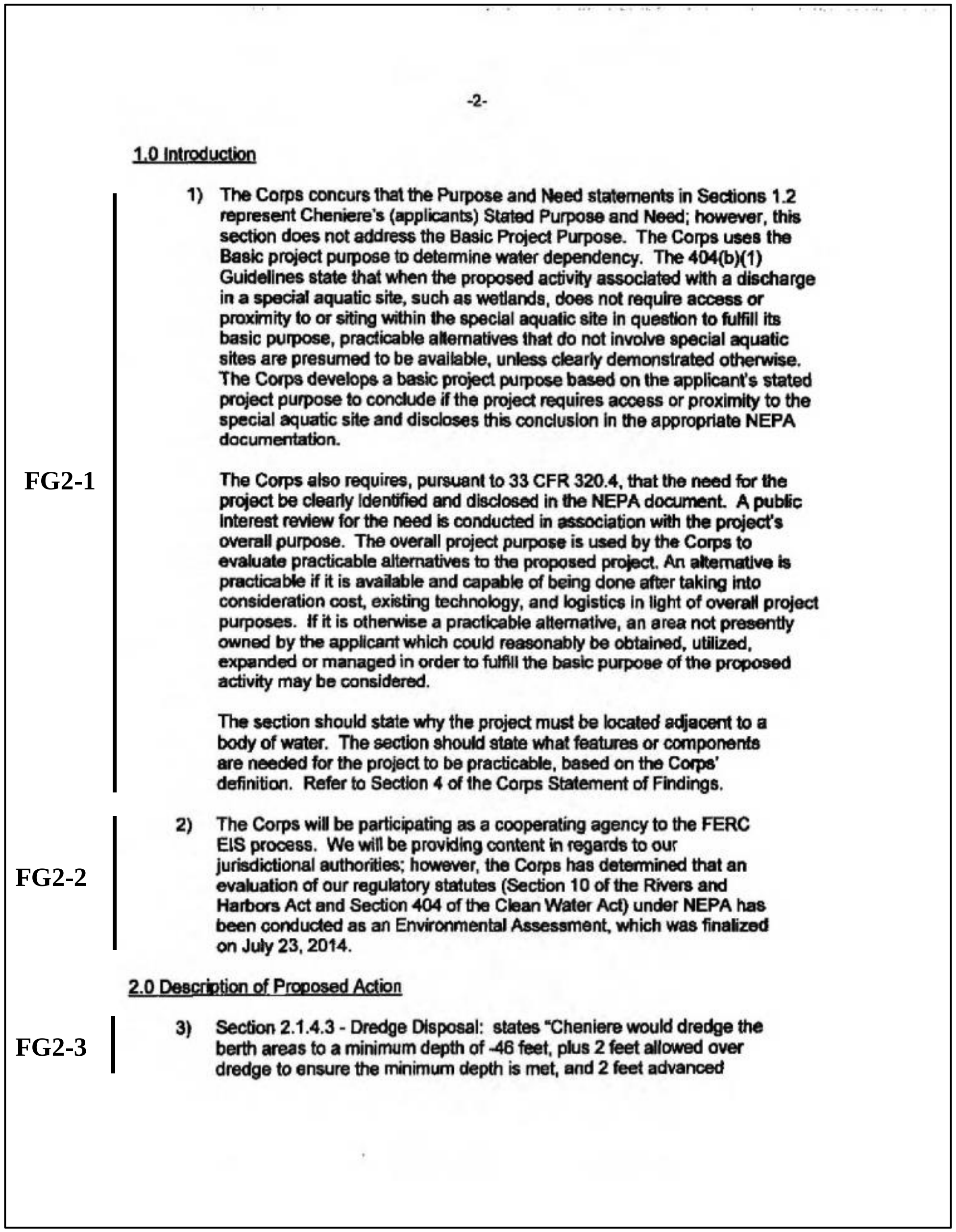
This is in reference to Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP's (Cheniere) LNG Liquefaction Project proposal. Cheniere is requesting permission to develop, construct, and operate facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export liquefied natural gas (LNG) elsewhere. The project consists of two parts, the terminal and the pipeline. The LNG import and export terminal is proposed on a 991-acre site located along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio and Nueces Counties, Texas. The 23 miles of 48-inch diameter natural gas pipeline would connect the terminal to various existing natural gas pipelines and terminate north of Sinton, in San Patricio County, Texas.

A Department of Army (DA) Permit application for the proposed project was received on August 31, 2012. It was deemed federally complete for processing on April 17, 2013 and was placed on 30-day Public Notice starting on May 29, 2013. On July 23, 2014 the US Army Corps of Engineers (Corps or COE) finalized the request and issued a Department of the Army permit authorization in the form of an amendment to the previously issued individual permit (dated October 18, 2005). The Corps' authorization letter and statement of findings is enclosed herein.

The Corps has completed a review of the document and identified several areas that require correction, clarification, and/or supplementation. Pursuant to our interagency agreement, the Corps submits the following comments in regard to the June 2014 Draft Environmental Impact Statement.

FEDERAL GOVERNMENT COMMENTS

FG2 - United States Army Corps of Engineers



-2-

1.0 Introduction

FG2-1

1) The Corps concurs that the Purpose and Need statements in Sections 1.2 represent Cheniere's (applicants) Stated Purpose and Need; however, this section does not address the Basic Project Purpose. The Corps uses the Basic project purpose to determine water dependency. The 404(b)(1) Guidelines state that when the proposed activity associated with a discharge in a special aquatic site, such as wetlands, does not require access or proximity to or siting within the special aquatic site in question to fulfill its basic purpose, practicable alternatives that do not involve special aquatic sites are presumed to be available, unless clearly demonstrated otherwise. The Corps develops a basic project purpose based on the applicant's stated project purpose to conclude if the project requires access or proximity to the special aquatic site and discloses this conclusion in the appropriate NEPA documentation.

The Corps also requires, pursuant to 33 CFR 320.4, that the need for the project be clearly identified and disclosed in the NEPA document. A public interest review for the need is conducted in association with the project's overall purpose. The overall project purpose is used by the Corps to evaluate practicable alternatives to the proposed project. An alternative is practicable if it is available and capable of being done after taking into consideration cost, existing technology, and logistics in light of overall project purposes. If it is otherwise a practicable alternative, an area not presently owned by the applicant which could reasonably be obtained, utilized, expanded or managed in order to fulfill the basic purpose of the proposed activity may be considered.

The section should state why the project must be located adjacent to a body of water. The section should state what features or components are needed for the project to be practicable, based on the Corps' definition. Refer to Section 4 of the Corps Statement of Findings.

FG2-2

2) The Corps will be participating as a cooperating agency to the FERC EIS process. We will be providing content in regards to our jurisdictional authorities; however, the Corps has determined that an evaluation of our regulatory statutes (Section 10 of the Rivers and Harbors Act and Section 404 of the Clean Water Act) under NEPA has been conducted as an Environmental Assessment, which was finalized on July 23, 2014.

2.0 Description of Proposed Action

FG2-3

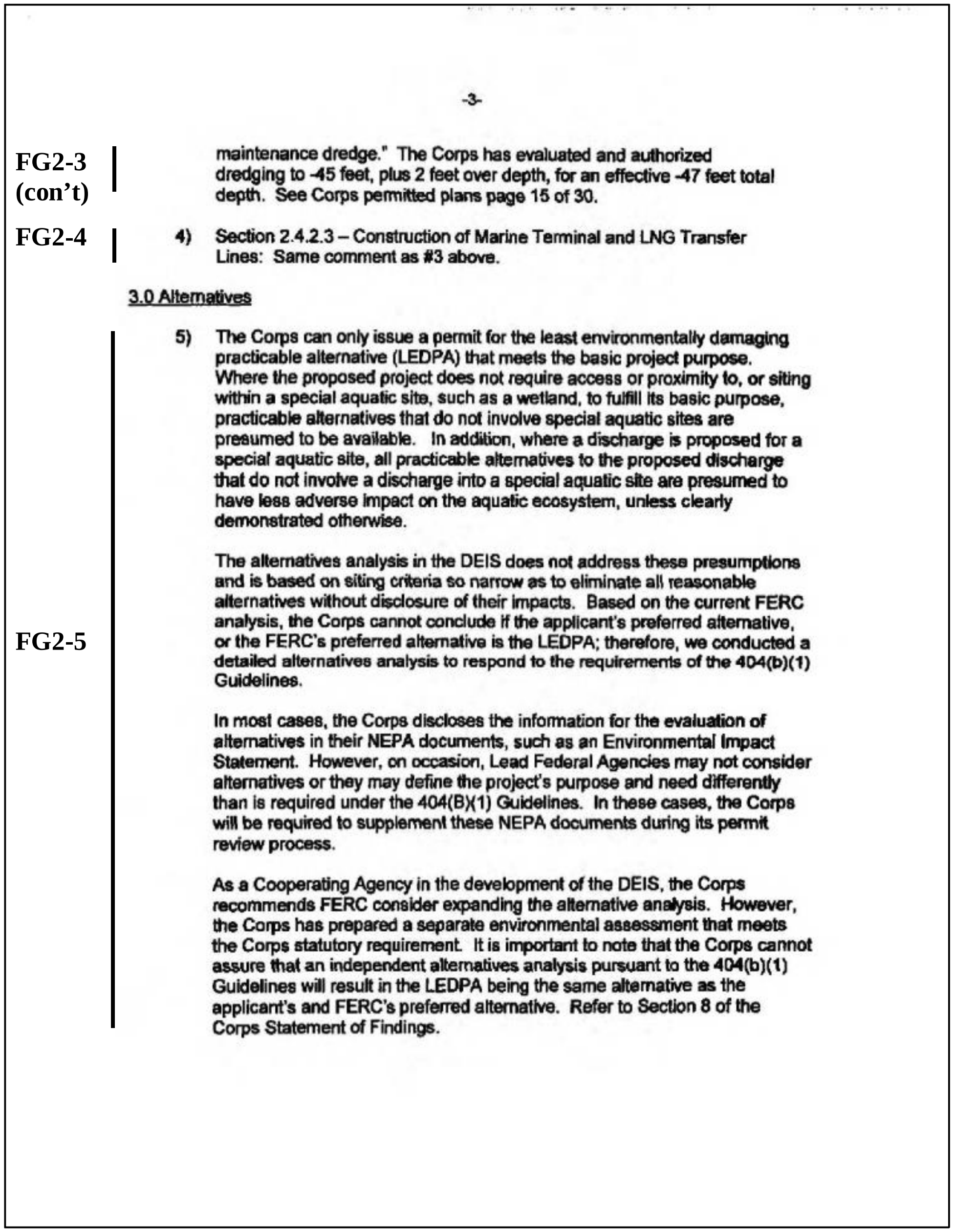
3) Section 2.1.4.3 - Dredge Disposal: states "Cheniere would dredge the berth areas to a minimum depth of -46 feet, plus 2 feet allowed over dredge to ensure the minimum depth is met, and 2 feet advanced

FG2-1: Section 1.2 of the final EIS has been revised to include information regarding why the Project must be located adjacent to a body of water.

FG2-2: Section 1.3.2 of the final EIS has been revised to clarify the U.S. Army Corps of Engineer's (COE) role as a cooperating agency and its evaluation of its regulatory statues under NEPA.

FG2-3: On September 9, 2014, Cheniere requested an amendment from the COE to allow for dredging to -46 feet NAVD88 plus 2 feet overdredge and 2 feet advanced maintenance dredging, as stated in sections 2.1.4.3, 2.4.2.3, and 4.3.1.2. The COE has informed FERC that it is evaluating this action and will keep FERC apprised of developments. Section 4.3.1.2 of the final EIS has been revised to address this issue.

FG2 – United States Army Corps of Engineers



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FG2-3 (con't)

maintenance dredge." The Corps has evaluated and authorized dredging to -45 feet, plus 2 feet over depth, for an effective -47 feet total depth. See Corps permitted plans page 15 of 30.

FG2-4

4) Section 2.4.2.3 – Construction of Marine Terminal and LNG Transfer Lines: Same comment as #3 above.

3.0 Alternatives

FG2-5

5) The Corps can only issue a permit for the least environmentally damaging practicable alternative (LEDPA) that meets the basic project purpose. Where the proposed project does not require access or proximity to, or siting within a special aquatic site, such as a wetland, to fulfill its basic purpose, practicable alternatives that do not involve special aquatic sites are presumed to be available. In addition, where a discharge is proposed for a special aquatic site, all practicable alternatives to the proposed discharge that do not involve a discharge into a special aquatic site are presumed to have less adverse impact on the aquatic ecosystem, unless clearly demonstrated otherwise.

The alternatives analysis in the DEIS does not address these presumptions and is based on siting criteria so narrow as to eliminate all reasonable alternatives without disclosure of their impacts. Based on the current FERC analysis, the Corps cannot conclude if the applicant's preferred alternative, or the FERC's preferred alternative is the LEDPA; therefore, we conducted a detailed alternatives analysis to respond to the requirements of the 404(b)(1) Guidelines.

In most cases, the Corps discloses the information for the evaluation of alternatives in their NEPA documents, such as an Environmental Impact Statement. However, on occasion, Lead Federal Agencies may not consider alternatives or they may define the project's purpose and need differently than is required under the 404(B)(1) Guidelines. In these cases, the Corps will be required to supplement these NEPA documents during its permit review process.

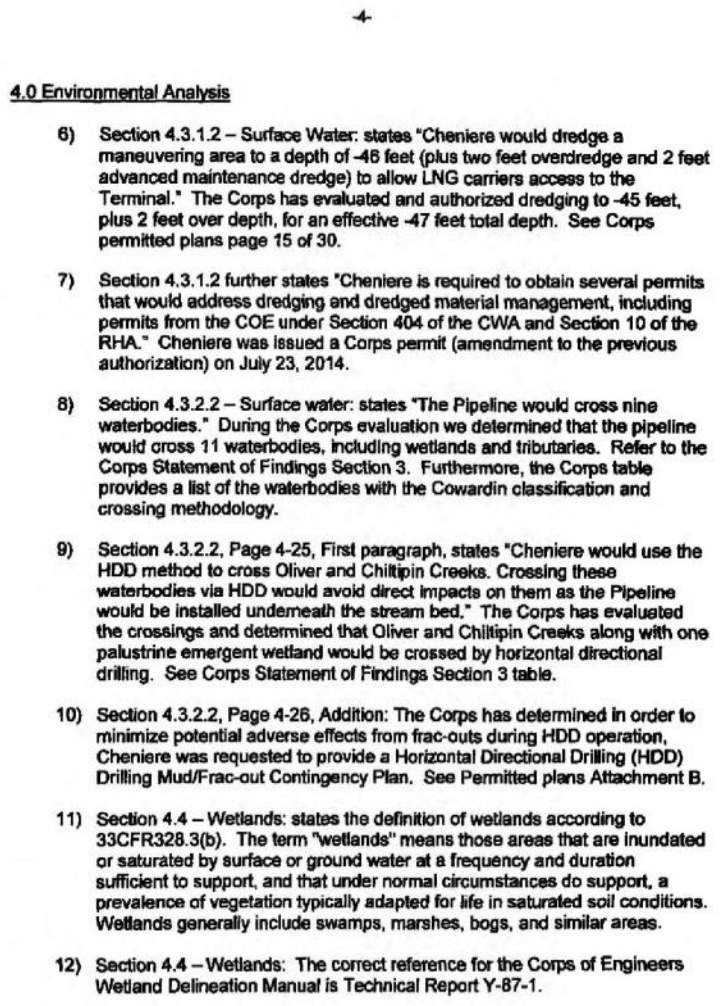
As a Cooperating Agency in the development of the DEIS, the Corps recommends FERC consider expanding the alternative analysis. However, the Corps has prepared a separate environmental assessment that meets the Corps statutory requirement. It is important to note that the Corps cannot assure that an independent alternatives analysis pursuant to the 404(b)(1) Guidelines will result in the LEDPA being the same alternative as the applicant's and FERC's preferred alternative. Refer to Section 8 of the Corps Statement of Findings.

FG2-4: See response to FG2-3.

FG2-5: In response to FG2-1, section 1.2 of the final EIS was revised to include information regarding why the Project must be located adjacent to a body of water. Section 3.1.4 of the final EIS has been revised to include a discussion of the dismissal of evaluating alternative sites located outside of special aquatic sites.

FEDERAL GOVERNMENT COMMENTS

FG2 - United States Army Corps of Engineers



-4-

4.0 Environmental Analysis

FG2-6

6) Section 4.3.1.2 – Surface Water: states "Cheniere would dredge a maneuvering area to a depth of -46 feet (plus two feet overdredge and 2 feet advanced maintenance dredge) to allow LNG carriers access to the Terminal." The Corps has evaluated and authorized dredging to -45 feet, plus 2 feet over depth, for an effective -47 feet total depth. See Corps permitted plans page 15 of 30.

FG2-7

7) Section 4.3.1.2 further states "Cheniere is required to obtain several permits that would address dredging and dredged material management, including permits from the COE under Section 404 of the CWA and Section 10 of the RHA." Cheniere was issued a Corps permit (amendment to the previous authorization) on July 23, 2014.

FG2-8

8) Section 4.3.2.2 – Surface water: states "The Pipeline would cross nine waterbodies." During the Corps evaluation we determined that the pipeline would cross 11 waterbodies, including wetlands and tributaries. Refer to the Corps Statement of Findings Section 3. Furthermore, the Corps table provides a list of the waterbodies with the Cowardin classification and crossing methodology.

FG2-9

9) Section 4.3.2.2, Page 4-25, First paragraph, states "Cheniere would use the HDD method to cross Oliver and Chiltipin Creeks. Crossing these waterbodies via HDD would avoid direct impacts on them as the Pipeline would be installed underneath the stream bed." The Corps has evaluated the crossings and determined that Oliver and Chiltipin Creeks along with one palustrine emergent wetland would be crossed by horizontal directional drilling. See Corps Statement of Findings Section 3 table.

FG2-10

10) Section 4.3.2.2, Page 4-26, Addition: The Corps has determined in order to minimize potential adverse effects from frac-outs during HDD operation, Cheniere was requested to provide a Horizontal Directional Drilling (HDD) Drilling Mud/Frac-out Contingency Plan. See Permitted plans Attachment B.

FG2-11

11) Section 4.4 – Wetlands: states the definition of wetlands according to 33CFR328.3(b). The term "wetlands" means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

FG2-12

12) Section 4.4 – Wetlands: The correct reference for the Corps of Engineers Wetland Delineation Manual is Technical Report Y-87-1.

FG2-6: See response to FG2-3.

FG2-7: The final EIS has been updated throughout to reflect issuance of this permit.

FG2-8: Cheniere clarified these discrepancies in its Response to Comments Received on the DEIS on August 22, 2014. According to Cheniere, a total of 10 waterbodies and 3 wetlands would be crossed by the Pipeline. Cheniere stated that the COE did not account for the waterbody at MP 0.5 which would be crossed via bore, rather than avoided as indicated in the COE Statement of Findings. The draft EIS reported the crossing method of this waterbody as open cut; however, the final EIS has been updated to reflect the change in crossing method to bore. Additionally, a drainage ditch at MP 18.6 was inadvertently omitted. Table 4.4-2 of the final EIS has been revised to include the drainage ditch at MP 18.6. Cheniere also clarified that the COE incorrectly identified the wetland at MP 21-1 as avoided, though it would be crossed via bore.

FG2-9: See response to FG2-8.

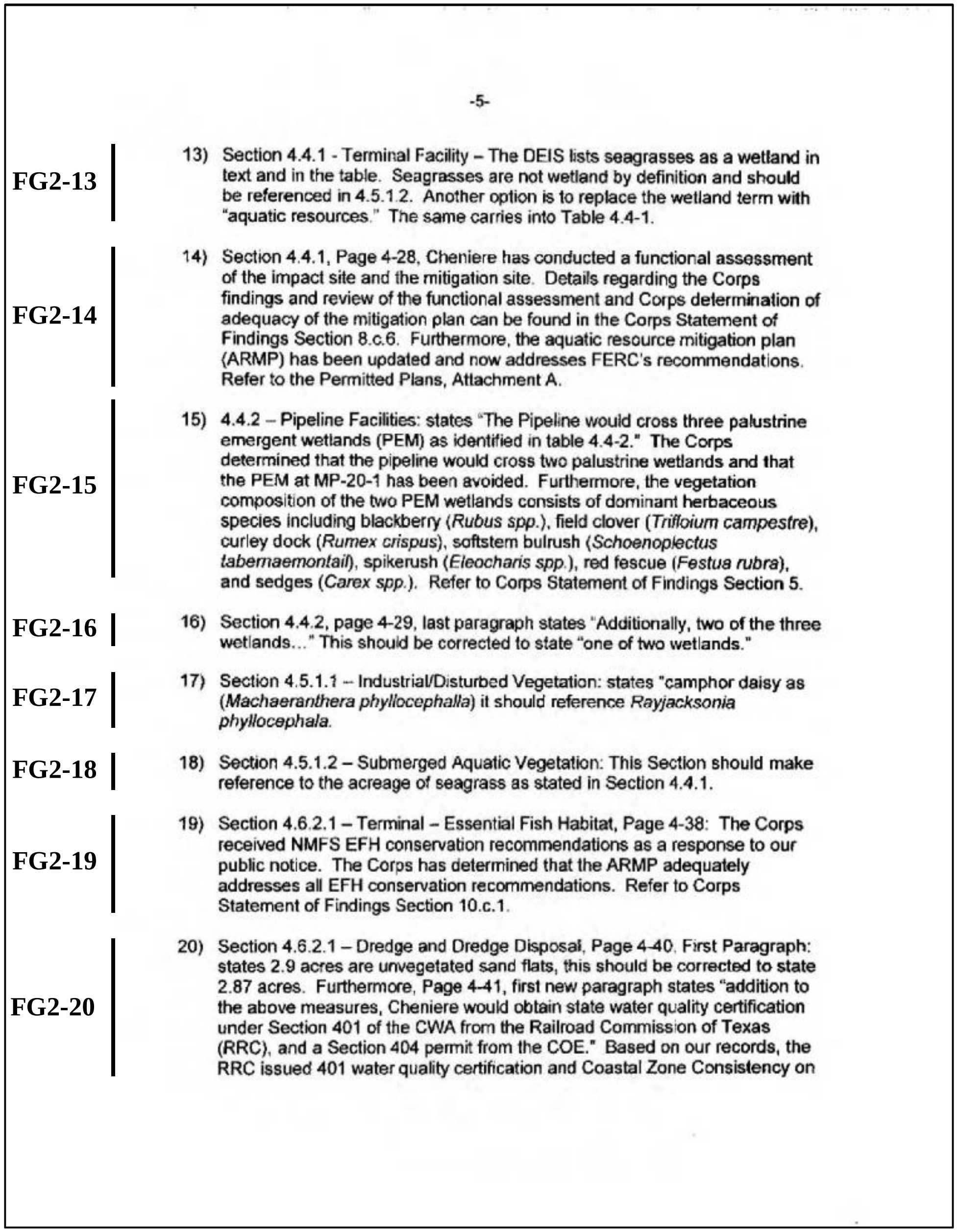
FG2-10: Section 4.3.2.2 of the final EIS has been updated to include this information.

FG2-11: Section 4.4 of the final EIS has been revised to clarify this information.

FG2-12: The reference to the Corps of Engineers Wetland Delineation Manual has been corrected in section 4.4 of the final EIS.

FEDERAL GOVERNMENT COMMENTS

FG2 - United States Army Corps of Engineers



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FG2-13

13) Section 4.4.1 - Terminal Facility – The DEIS lists seagrasses as a wetland in text and in the table. Seagrasses are not wetland by definition and should be referenced in 4.5.1.2. Another option is to replace the wetland term with "aquatic resources." The same carries into Table 4.4-1.

FG2-14

14) Section 4.4.1, Page 4-28, Cheniere has conducted a functional assessment of the impact site and the mitigation site. Details regarding the Corps findings and review of the functional assessment and Corps determination of adequacy of the mitigation plan can be found in the Corps Statement of Findings Section 8.c.6. Furthermore, the aquatic resource mitigation plan (ARMP) has been updated and now addresses FERC's recommendations. Refer to the Permitted Plans, Attachment A.

FG2-15

15) 4.4.2 – Pipeline Facilities: states "The Pipeline would cross three palustrine emergent wetlands (PEM) as identified in table 4.4-2." The Corps determined that the pipeline would cross two palustrine wetlands and that the PEM at MP-20-1 has been avoided. Furthermore, the vegetation composition of the two PEM wetlands consists of dominant herbaceous species including blackberry (*Rubus spp.*), field clover (*Trifloium campestre*), curley dock (*Rumex crispus*), softstem bulrush (*Schoenoplectus tabernaemontail*), spikerush (*Eleocharis spp.*), red fescue (*Festua rubra*), and sedges (*Carex spp.*). Refer to Corps Statement of Findings Section 5.

FG2-16

16) Section 4.4.2, page 4-29, last paragraph states "Additionally, two of the three wetlands..." This should be corrected to state "one of two wetlands."

FG2-17

17) Section 4.5.1.1 – Industrial/Disturbed Vegetation: states "camphor daisy as (*Machaeranthera phyllocephalla*) it should reference *Rayjacksonia phyllocephala*.

FG2-18

18) Section 4.5.1.2 – Submerged Aquatic Vegetation: This Section should make reference to the acreage of seagrass as stated in Section 4.4.1.

FG2-19

19) Section 4.6.2.1 – Terminal – Essential Fish Habitat, Page 4-38: The Corps received NMFS EFH conservation recommendations as a response to our public notice. The Corps has determined that the ARMP adequately addresses all EFH conservation recommendations. Refer to Corps Statement of Findings Section 10.c.1.

FG2-20

20) Section 4.6.2.1 – Dredge and Dredge Disposal, Page 4-40, First Paragraph: states 2.9 acres are unvegetated sand flats, this should be corrected to state 2.87 acres. Furthermore, Page 4-41, first new paragraph states "addition to the above measures, Cheniere would obtain state water quality certification under Section 401 of the CWA from the Railroad Commission of Texas (RRC), and a Section 404 permit from the COE." Based on our records, the RRC issued 401 water quality certification and Coastal Zone Consistency on

FG2-13: Section 4.4.1 of the final EIS has been revised to clarify that seagrasses are special aquatic sites.

FG2-14: Section 4.4.1 of the final EIS has been updated to reflect approval of Cheniere's ARMP.

FG2-15: Cheniere clarified in its Response to Comments Received on the DEIS on August 22, 2014, that the wetland at MP 20-1 would not be avoided, and would be crossed via the bore of U.S. Highway 77. The species identified in section 4.4.2 of the final EIS have been revised to more clearly represent dominant species within the wetland that would be impacted by the Pipeline.

FG2-16: See responses to FG2-8 and FG2-15.

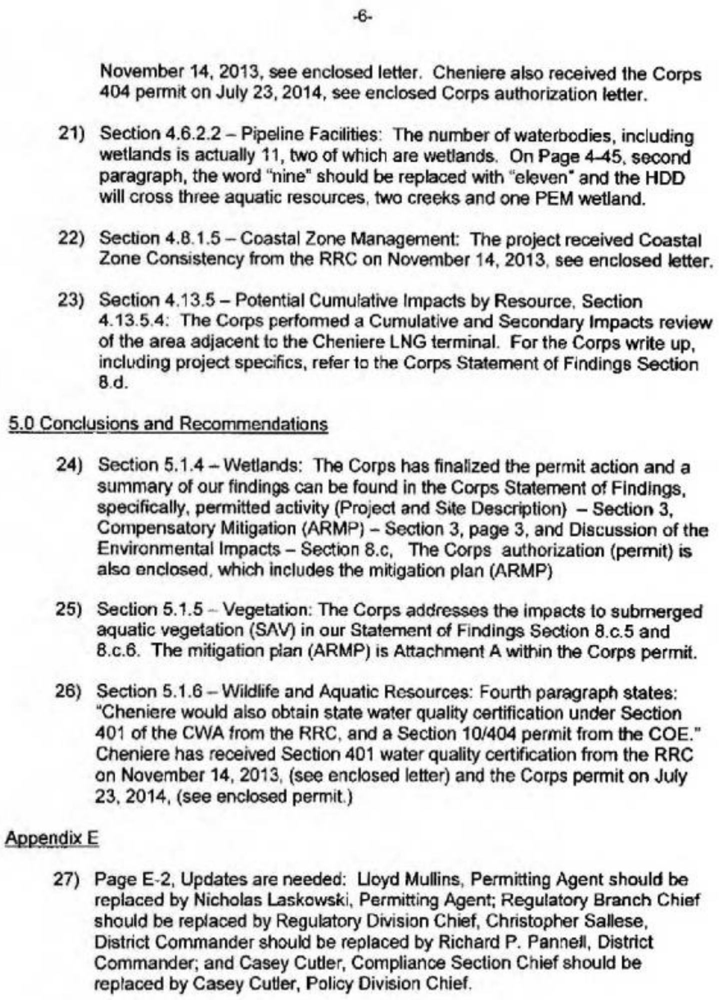
FG2-17: The scientific name has been revised in section 4.5.1.1 of the final EIS.

FG2-18: Section 4.5.1.2 has been revised to include the acreage of seagrass impacts as stated in section 4.4.1.

FG2-19: As stated in section 4.6.2.1 of the final EIS, we have also determined that impacts on fisheries, including EFH, during construction and operation of the Terminal have been sufficiently minimized.

FG2-20: Section 4.6.2.1 of the final EIS has been updated to state that 2.87 acres of unvegetated sand flats would be impacted. In addition, the final EIS has been updated throughout to reflect issuance of both the state water quality certification from the RRC and the Section 10/404 permit from the COE.

FG2 - United States Army Corps of Engineers



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FG2-20 (con't)

November 14, 2013, see enclosed letter. Cheniere also received the Corps 404 permit on July 23, 2014, see enclosed Corps authorization letter.

FG2-21

21) Section 4.6.2.2 – Pipeline Facilities: The number of waterbodies, including wetlands is actually 11, two of which are wetlands. On Page 4-45, second paragraph, the word "nine" should be replaced with "eleven" and the HDD will cross three aquatic resources, two creeks and one PEM wetland.

FG2-22

22) Section 4.8.1.5 – Coastal Zone Management: The project received Coastal Zone Consistency from the RRC on November 14, 2013, see enclosed letter.

FG2-23

23) Section 4.13.5 – Potential Cumulative Impacts by Resource, Section 4.13.5.4: The Corps performed a Cumulative and Secondary Impacts review of the area adjacent to the Cheniere LNG terminal. For the Corps write up, including project specifics, refer to the Corps Statement of Findings Section 8.d.

5.0 Conclusions and Recommendations

FG2-24

24) Section 5.1.4 – Wetlands: The Corps has finalized the permit action and a summary of our findings can be found in the Corps Statement of Findings, specifically, permitted activity (Project and Site Description) – Section 3, Compensatory Mitigation (ARMP) – Section 3, page 3, and Discussion of the Environmental Impacts – Section 8.c, The Corps authorization (permit) is also enclosed, which includes the mitigation plan (ARMP)

FG2-25

25) Section 5.1.5 – Vegetation: The Corps addresses the impacts to submerged aquatic vegetation (SAV) in our Statement of Findings Section 8.c.5 and 8.c.6. The mitigation plan (ARMP) is Attachment A within the Corps permit.

FG2-26

26) Section 5.1.6 – Wildlife and Aquatic Resources: Fourth paragraph states: "Cheniere would also obtain state water quality certification under Section 401 of the CWA from the RRC, and a Section 10/404 permit from the COE." Cheniere has received Section 401 water quality certification from the RRC on November 14, 2013, (see enclosed letter) and the Corps permit on July 23, 2014, (see enclosed permit.)

Appendix E

FG2-27

27) Page E-2, Updates are needed: Lloyd Mullins, Permitting Agent should be replaced by Nicholas Laskowski, Permitting Agent; Regulatory Branch Chief should be replaced by Regulatory Division Chief, Christopher Sallese, District Commander should be replaced by Richard P. Pannell, District Commander; and Casey Cutler, Compliance Section Chief should be replaced by Casey Cutler, Policy Division Chief.

FG2-21: See responses to FG2-8 and FG2-15.

FG2-22: Section 4.8.1.5 of the final EIS has been updated to reflect receipt of the Coastal Zone Consistency determination.

FG2-23: Section 4.13.5.4 of the final EIS has been updated to address additional information provided in the COE Statement of Findings.

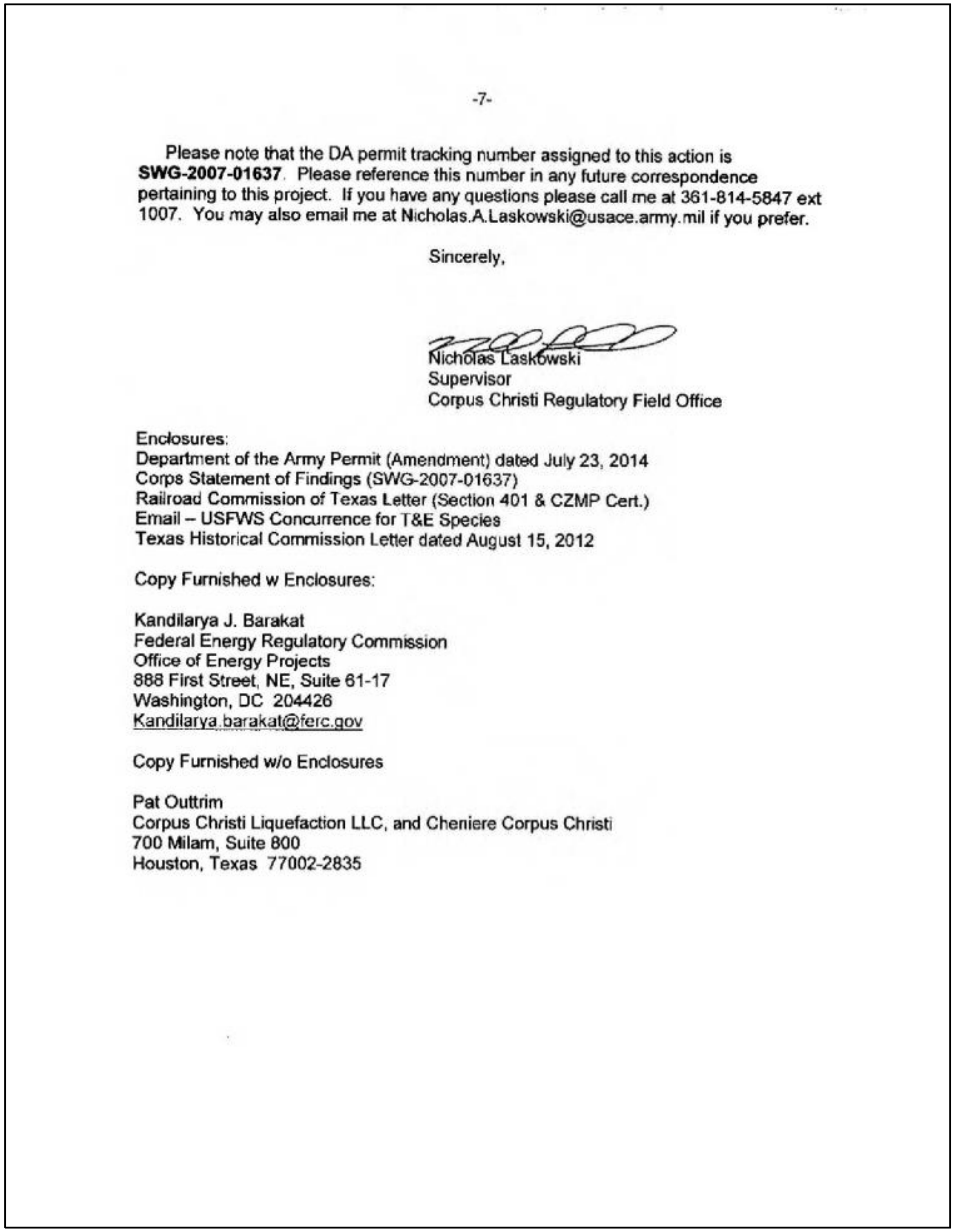
FG2-24: See responses to FG2-7 and FG2-14.

FG2-25: See response to FG2-14.

FG2-26: See responses to FG2-7 and FG2-20.

FG2-27: Appendix E of the final EIS has been revised to reflect these updates.

FG2 - United States Army Corps of Engineers



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Please note that the DA permit tracking number assigned to this action is **SWG-2007-01637**. Please reference this number in any future correspondence pertaining to this project. If you have any questions please call me at 361-814-5847 ext 1007. You may also email me at Nicholas.A.Laskowski@usace.army.mil if you prefer.

Sincerely,

Nicholas Laskowski
Supervisor
Corpus Christi Regulatory Field Office

Enclosures:
Department of the Army Permit (Amendment) dated July 23, 2014
Corps Statement of Findings (SWG-2007-01637)
Railroad Commission of Texas Letter (Section 401 & CZMP Cert.)
Email – USFWS Concurrence for T&E Species
Texas Historical Commission Letter dated August 15, 2012

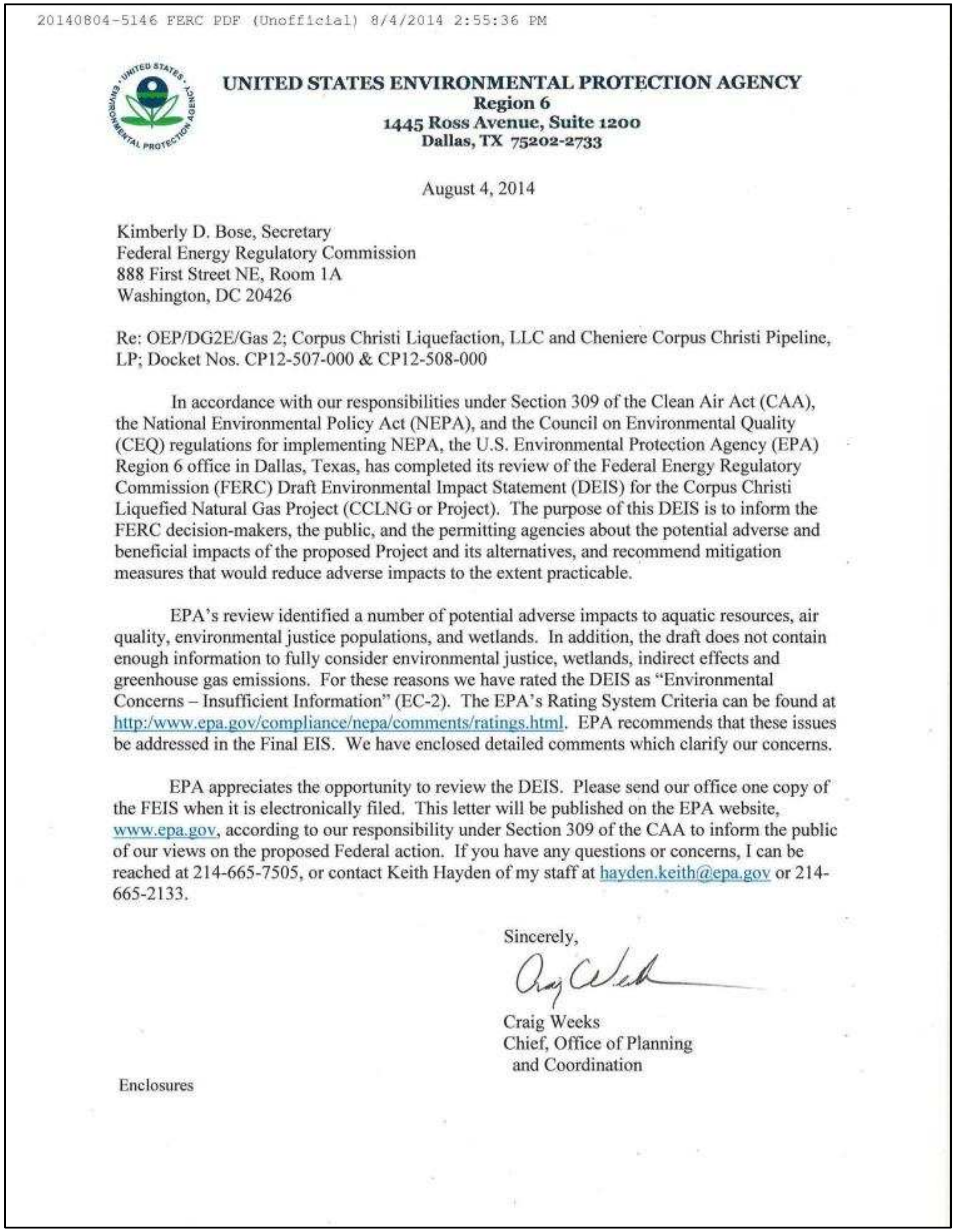
Copy Furnished w Enclosures:

Kandilarya J. Barakat
Federal Energy Regulatory Commission
Office of Energy Projects
888 First Street, NE, Suite 61-17
Washington, DC 204426
Kandilarya.barakat@ferc.gov

Copy Furnished w/o Enclosures

Pat Outtrim
Corpus Christi Liquefaction LLC, and Cheniere Corpus Christi
700 Milam, Suite 800
Houston, Texas 77002-2835

FG3 – United States Environmental Protection Agency



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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

August 4, 2014

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Re: OEP/DG2E/Gas 2; Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP; Docket Nos. CP12-507-000 & CP12-508-000

In accordance with our responsibilities under Section 309 of the Clean Air Act (CAA), the National Environmental Policy Act (NEPA), and the Council on Environmental Quality (CEQ) regulations for implementing NEPA, the U.S. Environmental Protection Agency (EPA) Region 6 office in Dallas, Texas, has completed its review of the Federal Energy Regulatory Commission (FERC) Draft Environmental Impact Statement (DEIS) for the Corpus Christi Liquefied Natural Gas Project (CCLNG or Project). The purpose of this DEIS is to inform the FERC decision-makers, the public, and the permitting agencies about the potential adverse and beneficial impacts of the proposed Project and its alternatives, and recommend mitigation measures that would reduce adverse impacts to the extent practicable.

EPA's review identified a number of potential adverse impacts to aquatic resources, air quality, environmental justice populations, and wetlands. In addition, the draft does not contain enough information to fully consider environmental justice, wetlands, indirect effects and greenhouse gas emissions. For these reasons we have rated the DEIS as "Environmental Concerns – Insufficient Information" (EC-2). The EPA's Rating System Criteria can be found at http:/www.epa.gov/compliance/nepa/comments/ratings.html. EPA recommends that these issues be addressed in the Final EIS. We have enclosed detailed comments which clarify our concerns.

EPA appreciates the opportunity to review the DEIS. Please send our office one copy of the FEIS when it is electronically filed. This letter will be published on the EPA website, www.epa.gov, according to our responsibility under Section 309 of the CAA to inform the public of our views on the proposed Federal action. If you have any questions or concerns, I can be reached at 214-665-7505, or contact Keith Hayden of my staff at hayden.keith@epa.gov or 214-665-2133.

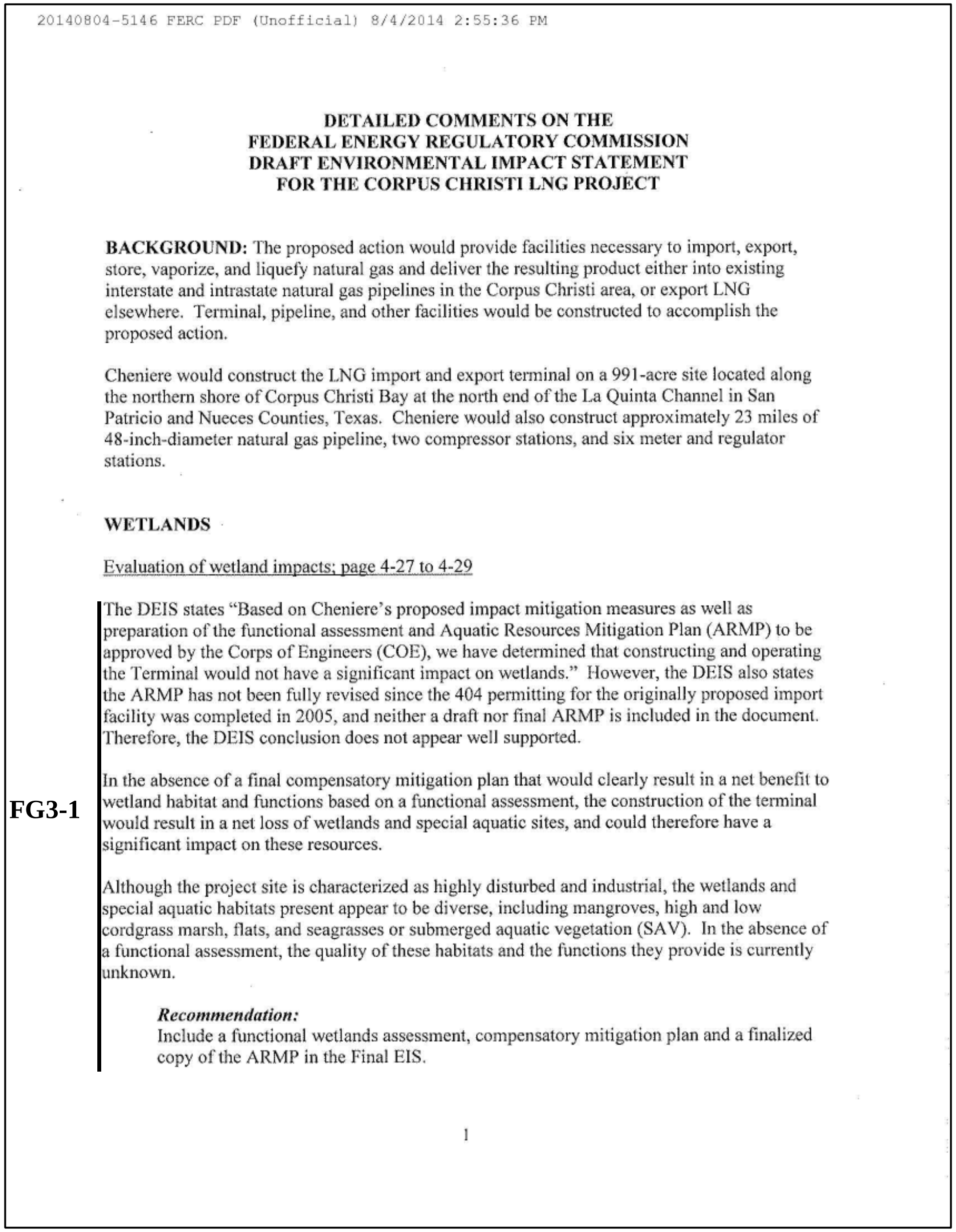
Sincerely,

Craig Weeks

Craig Weeks
Chief, Office of Planning
and Coordination

Enclosures

FG3 - United States Environmental Protection Agency



DETAILED COMMENTS ON THE FEDERAL ENERGY REGULATORY COMMISSION DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR THE CORPUS CHRISTI LNG PROJECT

BACKGROUND: The proposed action would provide facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export LNG elsewhere. Terminal, pipeline, and other facilities would be constructed to accomplish the proposed action.

Cheniere would construct the LNG import and export terminal on a 991-acre site located along the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in San Patricio and Nueces Counties, Texas. Cheniere would also construct approximately 23 miles of 48-inch-diameter natural gas pipeline, two compressor stations, and six meter and regulator stations.

WETLANDS

Evaluation of wetland impacts; page 4-27 to 4-29

FG3-1

The DEIS states "Based on Cheniere's proposed impact mitigation measures as well as preparation of the functional assessment and Aquatic Resources Mitigation Plan (ARMP) to be approved by the Corps of Engineers (COE), we have determined that constructing and operating the Terminal would not have a significant impact on wetlands." However, the DEIS also states the ARMP has not been fully revised since the 404 permitting for the originally proposed import facility was completed in 2005, and neither a draft nor final ARMP is included in the document. Therefore, the DEIS conclusion does not appear well supported.

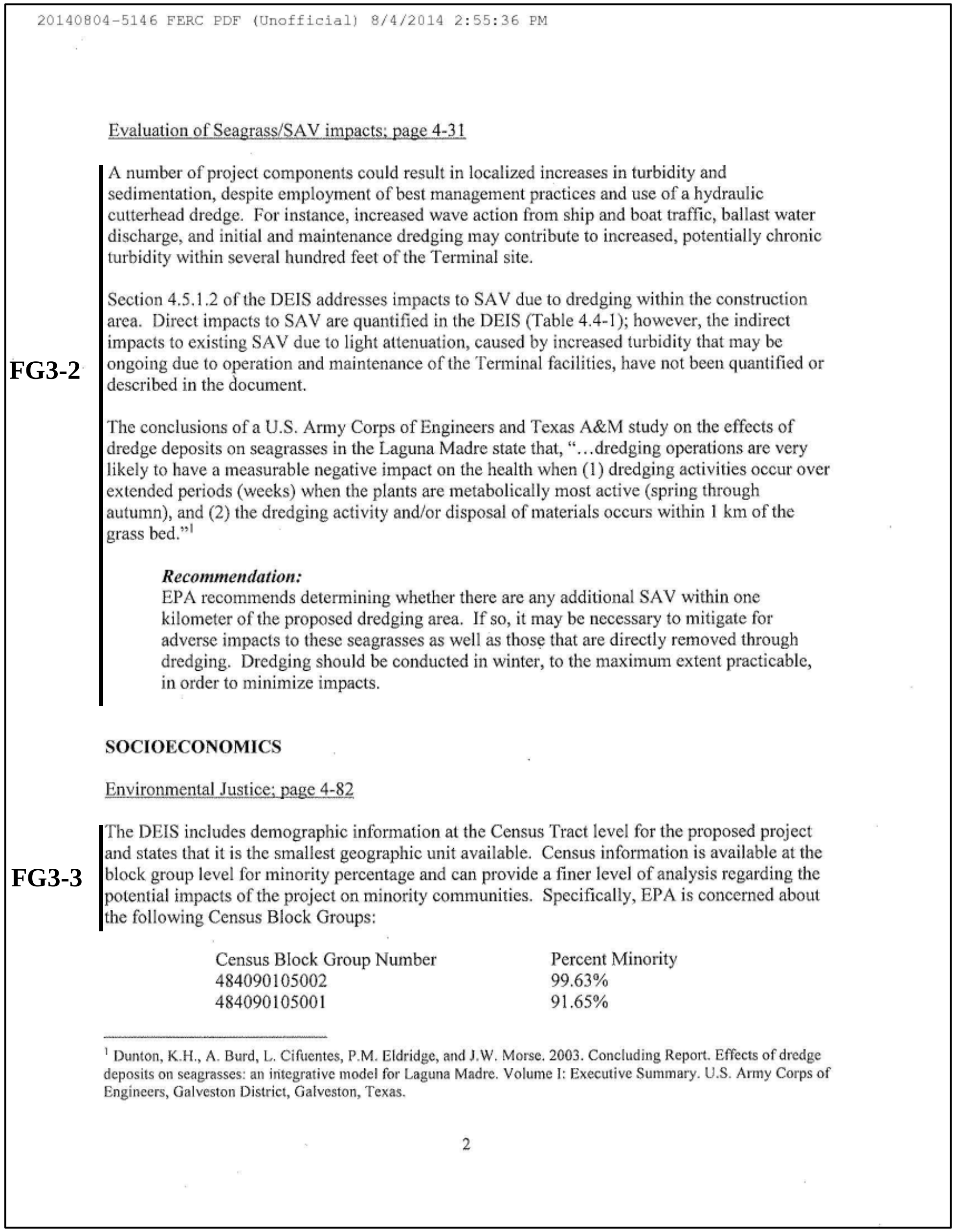
In the absence of a final compensatory mitigation plan that would clearly result in a net benefit to wetland habitat and functions based on a functional assessment, the construction of the terminal would result in a net loss of wetlands and special aquatic sites, and could therefore have a significant impact on these resources.

Although the project site is characterized as highly disturbed and industrial, the wetlands and special aquatic habitats present appear to be diverse, including mangroves, high and low cordgrass marsh, flats, and seagrasses or submerged aquatic vegetation (SAV). In the absence of a functional assessment, the quality of these habitats and the functions they provide is currently unknown.

> ***Recommendation:***
> Include a functional wetlands assessment, compensatory mitigation plan and a finalized copy of the ARMP in the Final EIS.

FG3-1: Section 4.4.1 and appendix C of the final EIS has been revised to reflect COE approval of the ARMP through issuance of its Section 404/10 Permit.

FG3 - United States Environmental Protection Agency



Evaluation of Seagrass/SAV impacts; page 4-31

A number of project components could result in localized increases in turbidity and sedimentation, despite employment of best management practices and use of a hydraulic cutterhead dredge. For instance, increased wave action from ship and boat traffic, ballast water discharge, and initial and maintenance dredging may contribute to increased, potentially chronic turbidity within several hundred feet of the Terminal site.

FG3-2 Section 4.5.1.2 of the DEIS addresses impacts to SAV due to dredging within the construction area. Direct impacts to SAV are quantified in the DEIS (Table 4.4-1); however, the indirect impacts to existing SAV due to light attenuation, caused by increased turbidity that may be ongoing due to operation and maintenance of the Terminal facilities, have not been quantified or described in the document.

The conclusions of a U.S. Army Corps of Engineers and Texas A&M study on the effects of dredge deposits on seagrasses in the Laguna Madre state that, "…dredging operations are very likely to have a measurable negative impact on the health when (1) dredging activities occur over extended periods (weeks) when the plants are metabolically most active (spring through autumn), and (2) the dredging activity and/or disposal of materials occurs within 1 km of the grass bed."[1]

> ***Recommendation:***
> EPA recommends determining whether there are any additional SAV within one kilometer of the proposed dredging area. If so, it may be necessary to mitigate for adverse impacts to these seagrasses as well as those that are directly removed through dredging. Dredging should be conducted in winter, to the maximum extent practicable, in order to minimize impacts.

SOCIOECONOMICS

Environmental Justice; page 4-82

FG3-3 The DEIS includes demographic information at the Census Tract level for the proposed project and states that it is the smallest geographic unit available. Census information is available at the block group level for minority percentage and can provide a finer level of analysis regarding the potential impacts of the project on minority communities. Specifically, EPA is concerned about the following Census Block Groups:

Census Block Group Number	Percent Minority
484090105002	99.63%
484090105001	91.65%

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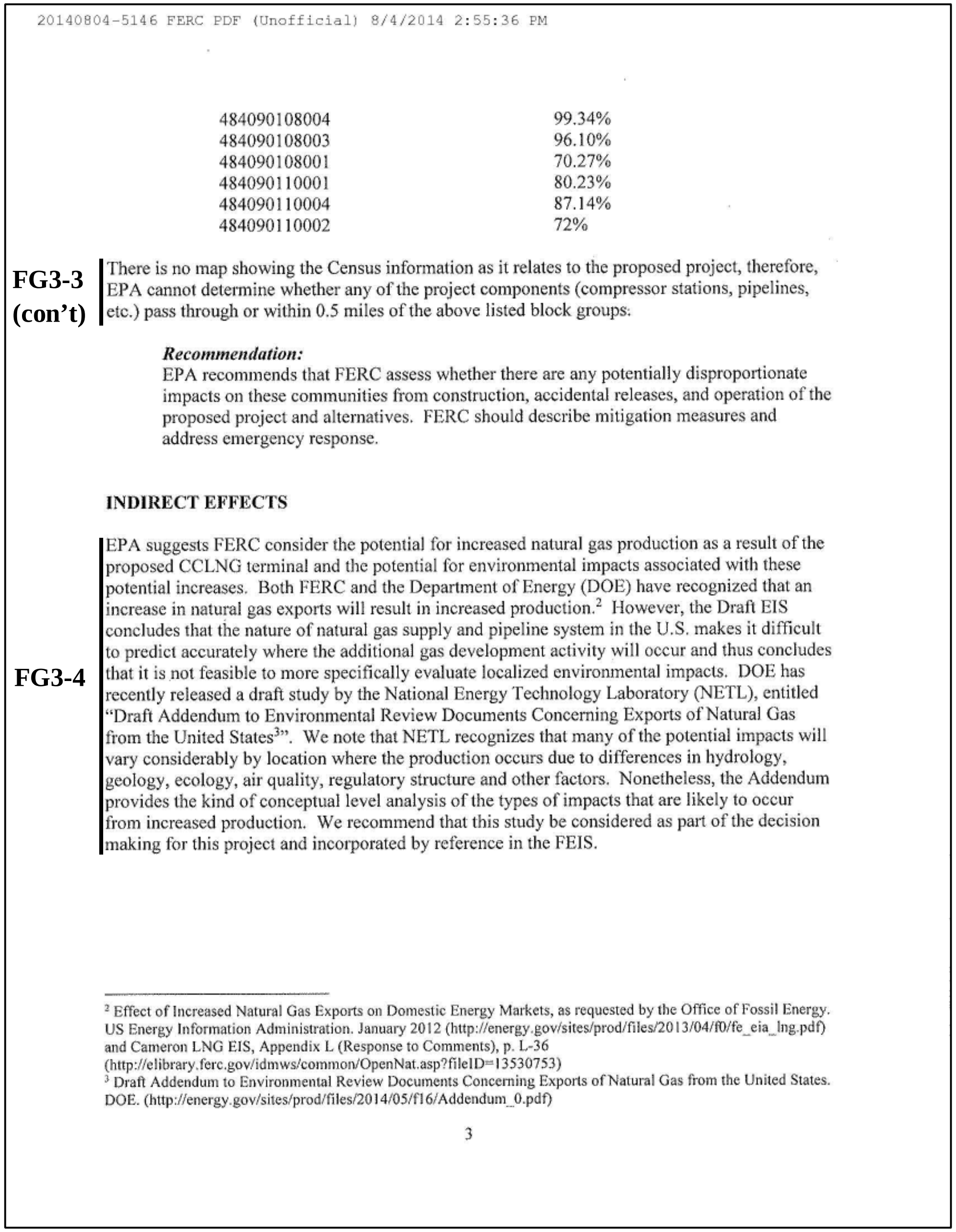
[1] Dunton, K.H., A. Burd, L. Cifuentes, P.M. Eldridge, and J.W. Morse. 2003. Concluding Report. Effects of dredge deposits on seagrasses: an integrative model for Laguna Madre. Volume I: Executive Summary. U.S. Army Corps of Engineers, Galveston District, Galveston, Texas.

FG3-2: The FERC defers to the COE, a cooperating agency in the Cheniere Liquefaction Project review, in regards to wetland impacts and mitigation. As such, this has been adequately addressed through the Section 404 permitting process.

FG3-3: Section 4.9.9 of the final EIS addresses our assessment of low income and minority populations in the Project area and concludes that there are no disproportionate impacts on these communities. The locations of the census tracts crossed by the Project and evaluated in the final EIS, are publicly available through the U.S. Census Bureau. The final EIS addresses emergency response procedures in sections 4.12.7 and 5.3.

FEDERAL GOVERNMENT COMMENTS

FG3 - United States Environmental Protection Agency



484090108004	99.34%
484090108003	96.10%
484090108001	70.27%
484090110001	80.23%
484090110004	87.14%
484090110002	72%

FG3-3 (con't) There is no map showing the Census information as it relates to the proposed project, therefore, EPA cannot determine whether any of the project components (compressor stations, pipelines, etc.) pass through or within 0.5 miles of the above listed block groups.

Recommendation:
EPA recommends that FERC assess whether there are any potentially disproportionate impacts on these communities from construction, accidental releases, and operation of the proposed project and alternatives. FERC should describe mitigation measures and address emergency response.

INDIRECT EFFECTS

FG3-4 EPA suggests FERC consider the potential for increased natural gas production as a result of the proposed CCLNG terminal and the potential for environmental impacts associated with these potential increases. Both FERC and the Department of Energy (DOE) have recognized that an increase in natural gas exports will result in increased production.[2] However, the Draft EIS concludes that the nature of natural gas supply and pipeline system in the U.S. makes it difficult to predict accurately where the additional gas development activity will occur and thus concludes that it is not feasible to more specifically evaluate localized environmental impacts. DOE has recently released a draft study by the National Energy Technology Laboratory (NETL), entitled "Draft Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States[3]". We note that NETL recognizes that many of the potential impacts will vary considerably by location where the production occurs due to differences in hydrology, geology, ecology, air quality, regulatory structure and other factors. Nonetheless, the Addendum provides the kind of conceptual level analysis of the types of impacts that are likely to occur from increased production. We recommend that this study be considered as part of the decision making for this project and incorporated by reference in the FEIS.

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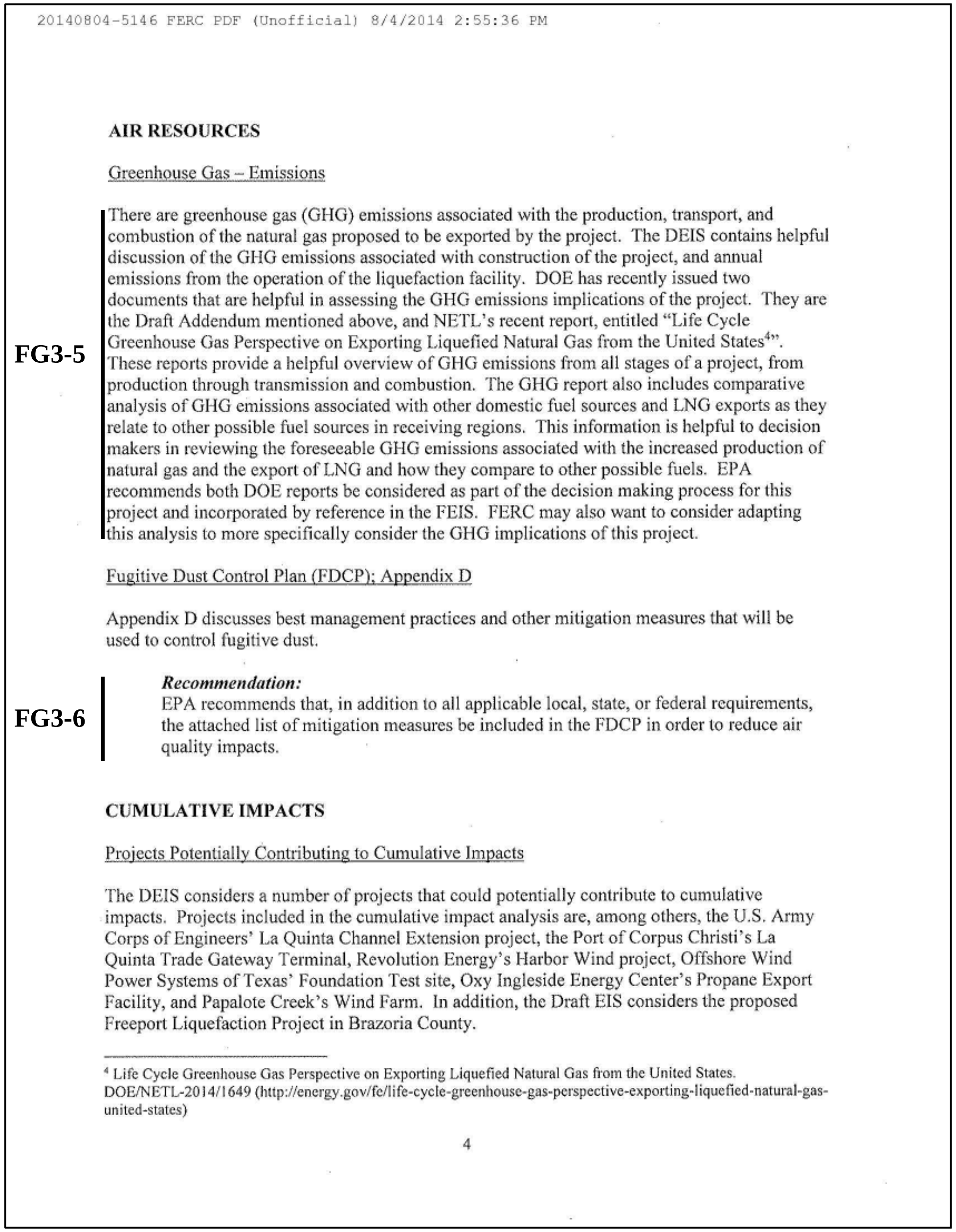
[2] Effect of Increased Natural Gas Exports on Domestic Energy Markets, as requested by the Office of Fossil Energy. US Energy Information Administration. January 2012 (http://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf) and Cameron LNG EIS, Appendix L (Response to Comments), p. L-36 (http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13530753)

[3] Draft Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States. DOE. (http://energy.gov/sites/prod/files/2014/05/f16/Addendum_0.pdf)

FG3-4: We disagree. While the DOE Draft Addendum provides certain general estimates about the environmental impacts associated with natural gas production, those impacts have no particular relationship to Cheniere's proposed project. In its notice of the Draft Addendum, DOE stated that the discussion of natural gas production activities went beyond what NEPA requires. "While DOE has made broad projections about the types of resources from which additional production may come, DOE cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced. Therefore, DOE cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature." Section 4.13 of the final EIS has been revised to address this issue. Also see section 4.13.5.11.

FEDERAL GOVERNMENT COMMENTS

FG3 - United States Environmental Protection Agency



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AIR RESOURCES

Greenhouse Gas – Emissions

FG3-5 There are greenhouse gas (GHG) emissions associated with the production, transport, and combustion of the natural gas proposed to be exported by the project. The DEIS contains helpful discussion of the GHG emissions associated with construction of the project, and annual emissions from the operation of the liquefaction facility. DOE has recently issued two documents that are helpful in assessing the GHG emissions implications of the project. They are the Draft Addendum mentioned above, and NETL's recent report, entitled "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States[4]". These reports provide a helpful overview of GHG emissions from all stages of a project, from production through transmission and combustion. The GHG report also includes comparative analysis of GHG emissions associated with other domestic fuel sources and LNG exports as they relate to other possible fuel sources in receiving regions. This information is helpful to decision makers in reviewing the foreseeable GHG emissions associated with the increased production of natural gas and the export of LNG and how they compare to other possible fuels. EPA recommends both DOE reports be considered as part of the decision making process for this project and incorporated by reference in the FEIS. FERC may also want to consider adapting this analysis to more specifically consider the GHG implications of this project.

Fugitive Dust Control Plan (FDCP); Appendix D

Appendix D discusses best management practices and other mitigation measures that will be used to control fugitive dust.

FG3-6 ***Recommendation:***
EPA recommends that, in addition to all applicable local, state, or federal requirements, the attached list of mitigation measures be included in the FDCP in order to reduce air quality impacts.

CUMULATIVE IMPACTS

Projects Potentially Contributing to Cumulative Impacts

The DEIS considers a number of projects that could potentially contribute to cumulative impacts. Projects included in the cumulative impact analysis are, among others, the U.S. Army Corps of Engineers' La Quinta Channel Extension project, the Port of Corpus Christi's La Quinta Trade Gateway Terminal, Revolution Energy's Harbor Wind project, Offshore Wind Power Systems of Texas' Foundation Test site, Oxy Ingleside Energy Center's Propane Export Facility, and Papalote Creek's Wind Farm. In addition, the Draft EIS considers the proposed Freeport Liquefaction Project in Brazoria County.

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[4] Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States. DOE/NETL-2014/1649 (http://energy.gov/fe/life-cycle-greenhouse-gas-perspective-exporting-liquefied-natural-gas-united-states)

FG3-5: See response to FG3-4.

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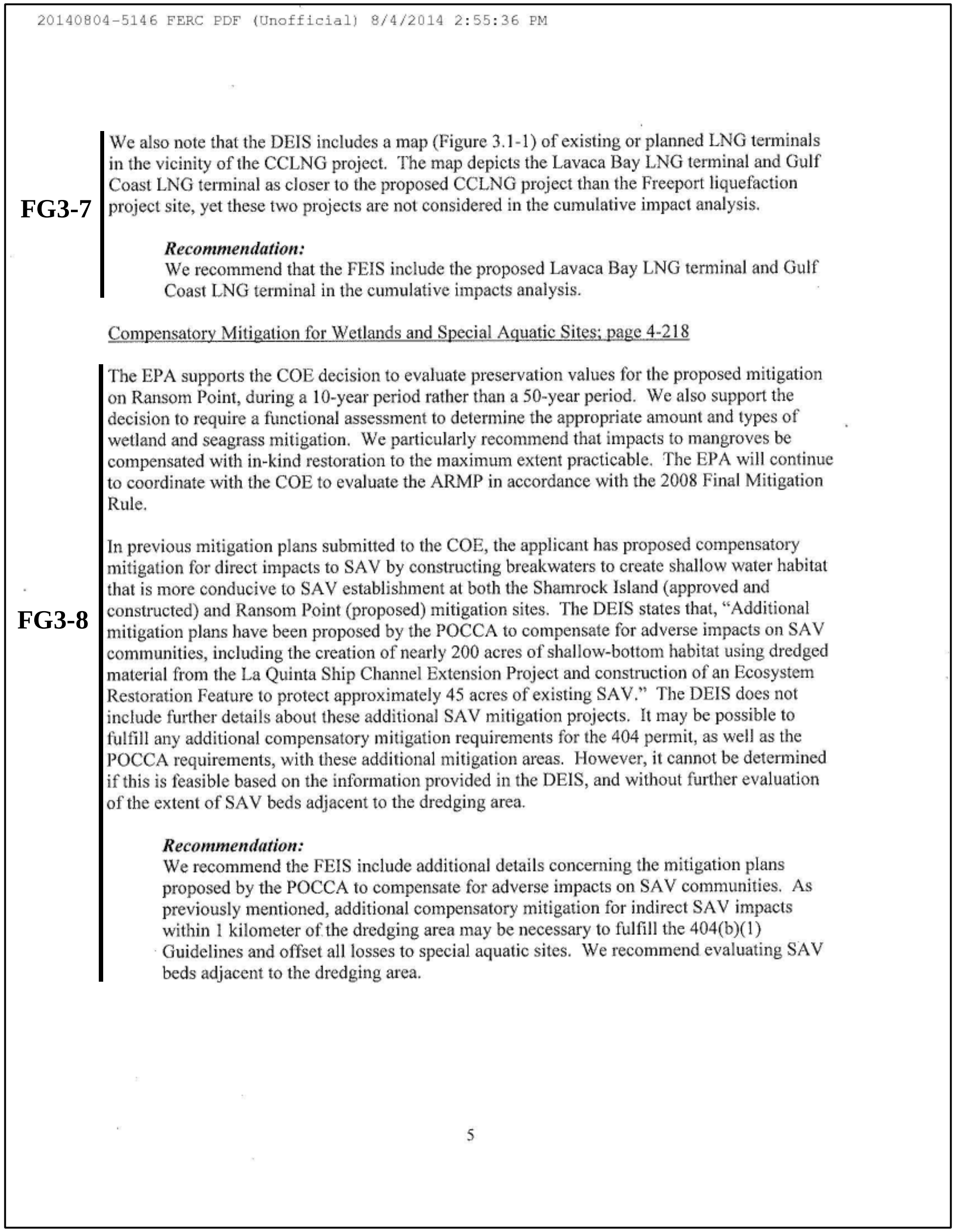
FG3-6: The FDCP already incorporates some of the measures EPA identifies (e.g., vehicle speed limit, water stabilization). FERC has recommended that Cheniere revise its FDCP to incorporate additional measures and specificity to address potential mud and dirt track-out.

FG3 - United States Environmental Protection Agency



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FG3-7

We also note that the DEIS includes a map (Figure 3.1-1) of existing or planned LNG terminals in the vicinity of the CCLNG project. The map depicts the Lavaca Bay LNG terminal and Gulf Coast LNG terminal as closer to the proposed CCLNG project than the Freeport liquefaction project site, yet these two projects are not considered in the cumulative impact analysis.

> ***Recommendation:***
> We recommend that the FEIS include the proposed Lavaca Bay LNG terminal and Gulf Coast LNG terminal in the cumulative impacts analysis.

Compensatory Mitigation for Wetlands and Special Aquatic Sites; page 4-218

FG3-8

The EPA supports the COE decision to evaluate preservation values for the proposed mitigation on Ransom Point, during a 10-year period rather than a 50-year period. We also support the decision to require a functional assessment to determine the appropriate amount and types of wetland and seagrass mitigation. We particularly recommend that impacts to mangroves be compensated with in-kind restoration to the maximum extent practicable. The EPA will continue to coordinate with the COE to evaluate the ARMP in accordance with the 2008 Final Mitigation Rule.

In previous mitigation plans submitted to the COE, the applicant has proposed compensatory mitigation for direct impacts to SAV by constructing breakwaters to create shallow water habitat that is more conducive to SAV establishment at both the Shamrock Island (approved and constructed) and Ransom Point (proposed) mitigation sites. The DEIS states that, "Additional mitigation plans have been proposed by the POCCA to compensate for adverse impacts on SAV communities, including the creation of nearly 200 acres of shallow-bottom habitat using dredged material from the La Quinta Ship Channel Extension Project and construction of an Ecosystem Restoration Feature to protect approximately 45 acres of existing SAV." The DEIS does not include further details about these additional SAV mitigation projects. It may be possible to fulfill any additional compensatory mitigation requirements for the 404 permit, as well as the POCCA requirements, with these additional mitigation areas. However, it cannot be determined if this is feasible based on the information provided in the DEIS, and without further evaluation of the extent of SAV beds adjacent to the dredging area.

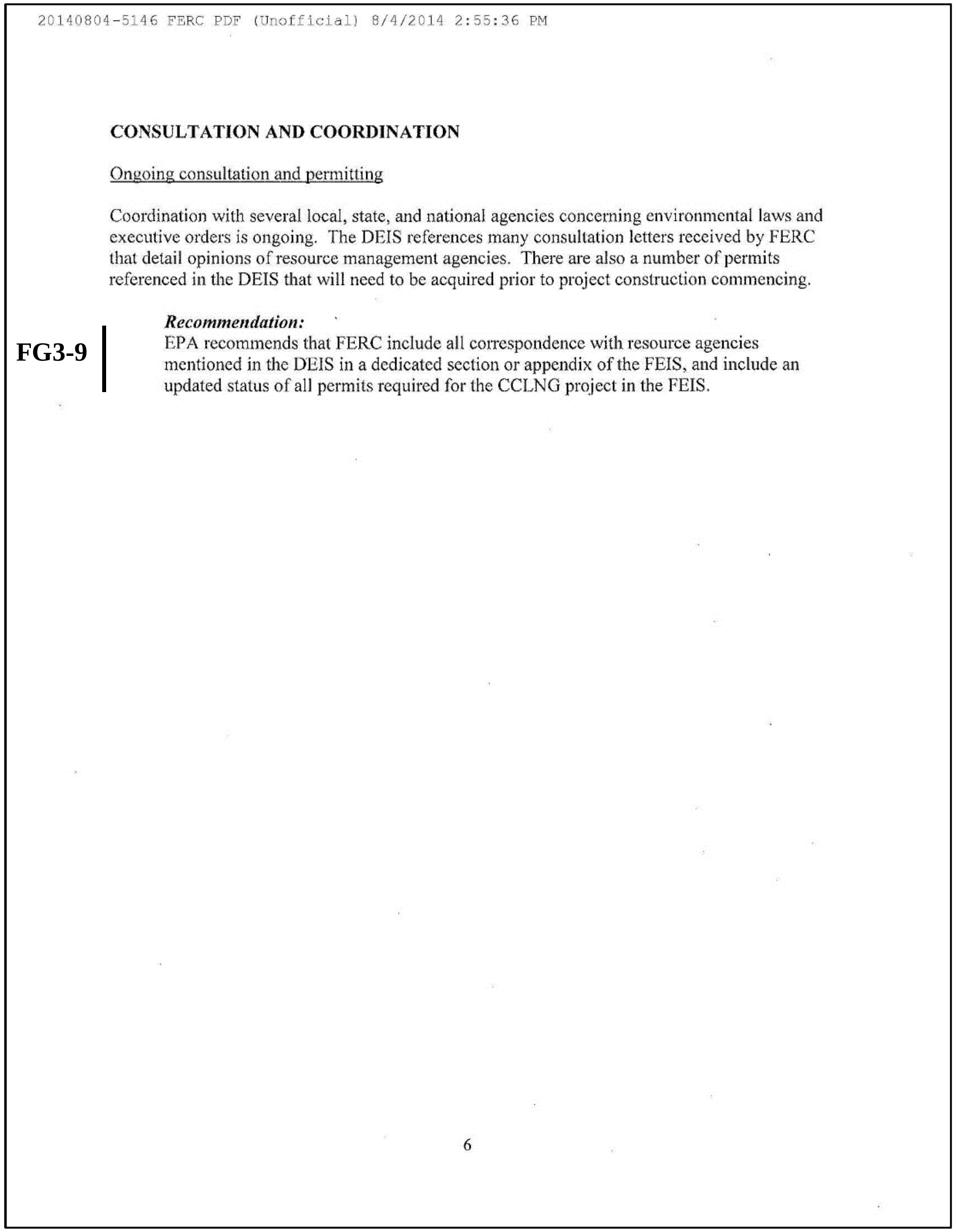
> ***Recommendation:***
> We recommend the FEIS include additional details concerning the mitigation plans proposed by the POCCA to compensate for adverse impacts on SAV communities. As previously mentioned, additional compensatory mitigation for indirect SAV impacts within 1 kilometer of the dredging area may be necessary to fulfill the 404(b)(1) Guidelines and offset all losses to special aquatic sites. We recommend evaluating SAV beds adjacent to the dredging area.

5

FG3-7: Section 4.13.2 of the final EIS has been revised to include the proposed Lavaca Bay LNG Project and the planned Gulf Coast Liquefaction Project in the cumulative impacts analysis.

FG3-8: The FERC defers to the U.S. Army Corps of Engineers, a cooperating agency in the Cheniere Liquefaction Project review, in regards to wetland impacts and mitigation. As such, this has been adequately addressed through the Section 404 permitting process.

FG3 - United States Environmental Protection Agency – Page 7



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CONSULTATION AND COORDINATION

Ongoing consultation and permitting

Coordination with several local, state, and national agencies concerning environmental laws and executive orders is ongoing. The DEIS references many consultation letters received by FERC that detail opinions of resource management agencies. There are also a number of permits referenced in the DEIS that will need to be acquired prior to project construction commencing.

FG3-9

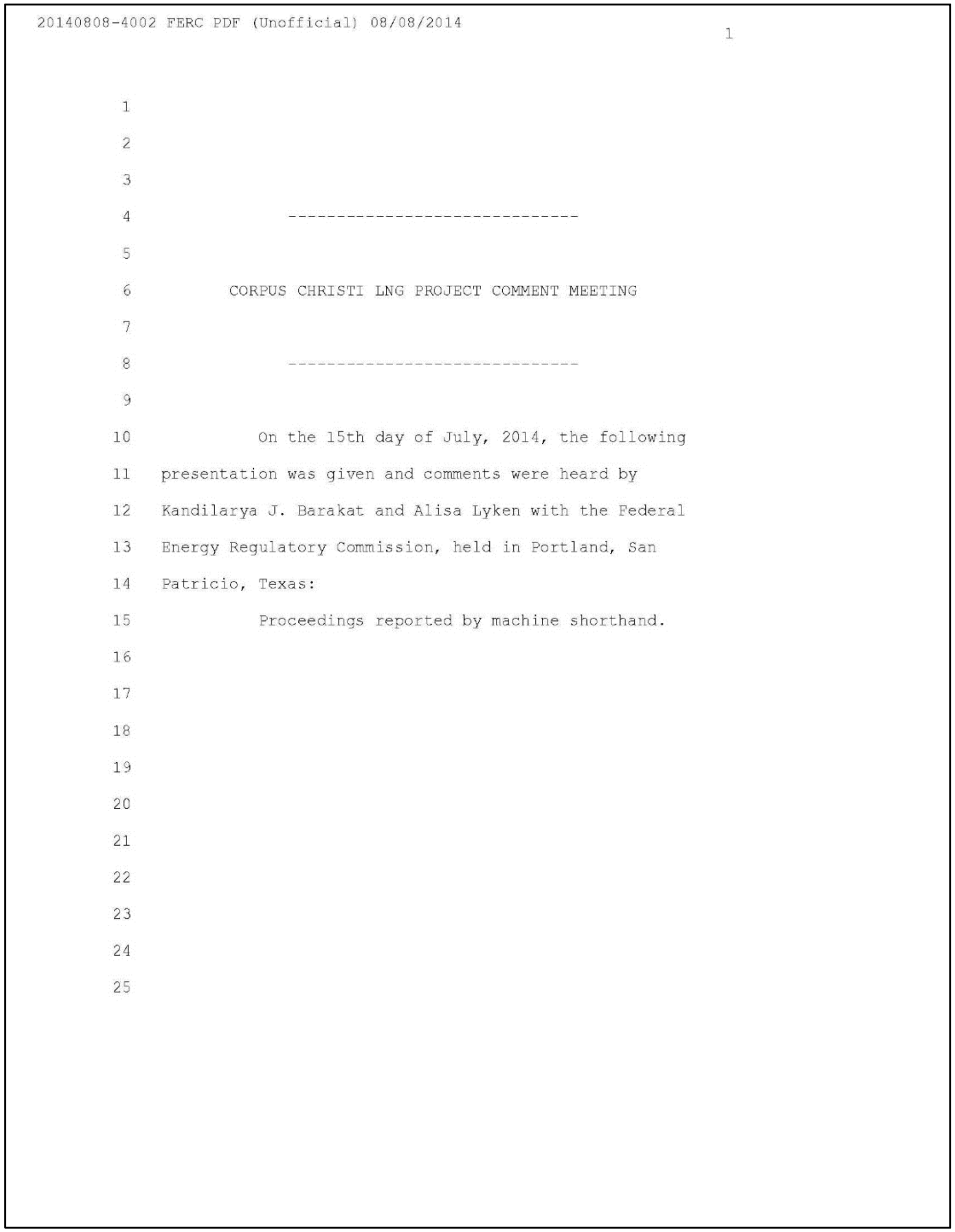
Recommendation:
EPA recommends that FERC include all correspondence with resource agencies mentioned in the DEIS in a dedicated section or appendix of the FEIS, and include an updated status of all permits required for the CCLNG project in the FEIS.

6

FG3-9: All correspondence with resource agencies mentioned in the DEIS is publicly available on the FERC website under Docket Nos. CP12-507-000 and CP12-508-000. The status of permits in Table 1.6-1 has been updated in the final EIS.

PUBLIC MEETING TRANSCRIPT COMMENTS

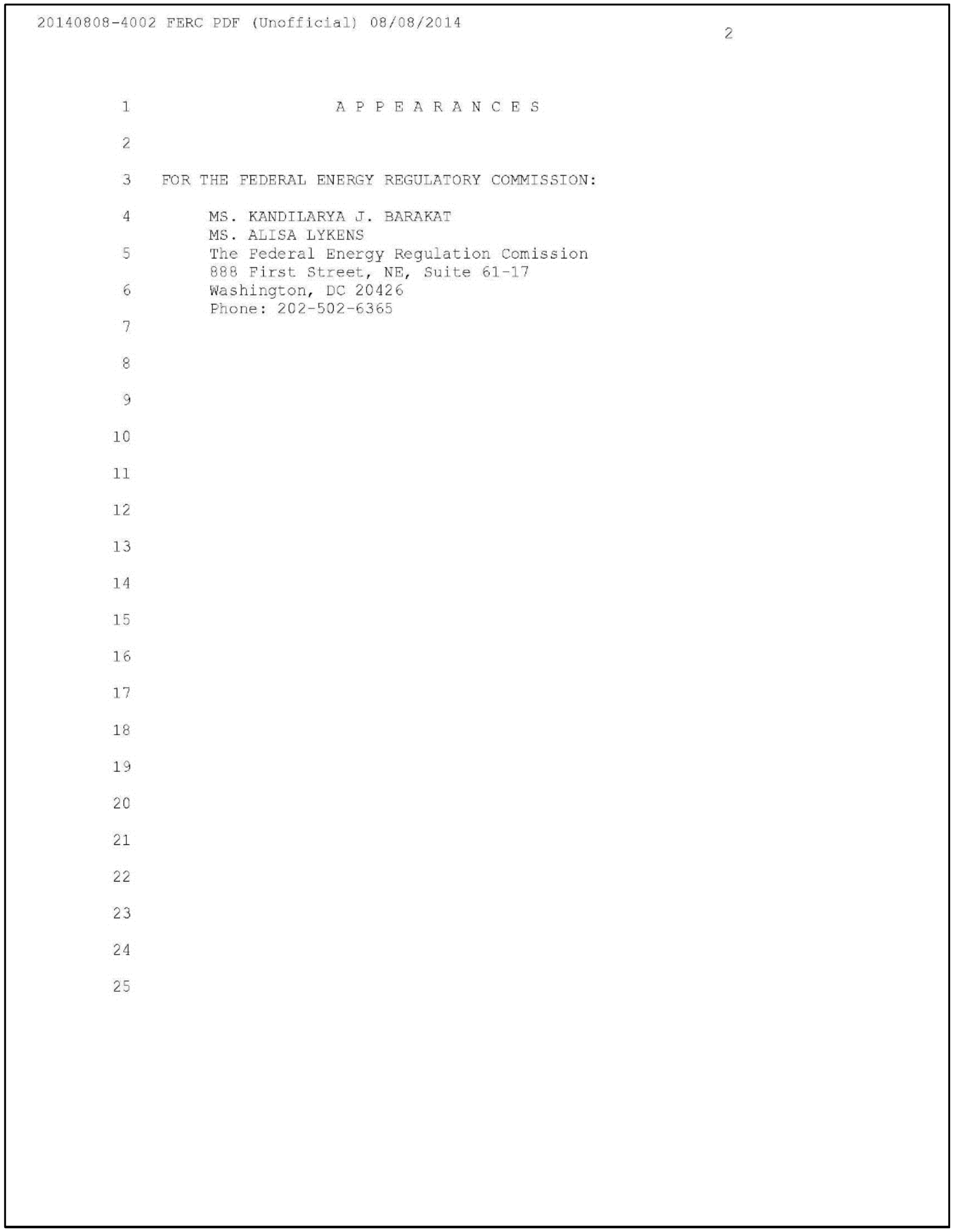
PM1 – Corpus Christi LNG Transcript from Public Meeting



CORPUS CHRISTI LNG PROJECT COMMENT MEETING

On the 15th day of July, 2014, the following presentation was given and comments were heard by Kandilarya J. Barakat and Alisa Lyken with the Federal Energy Regulatory Commission, held in Portland, San Patricio, Texas:

Proceedings reported by machine shorthand.



APPEARANCES

FOR THE FEDERAL ENERGY REGULATORY COMMISSION:

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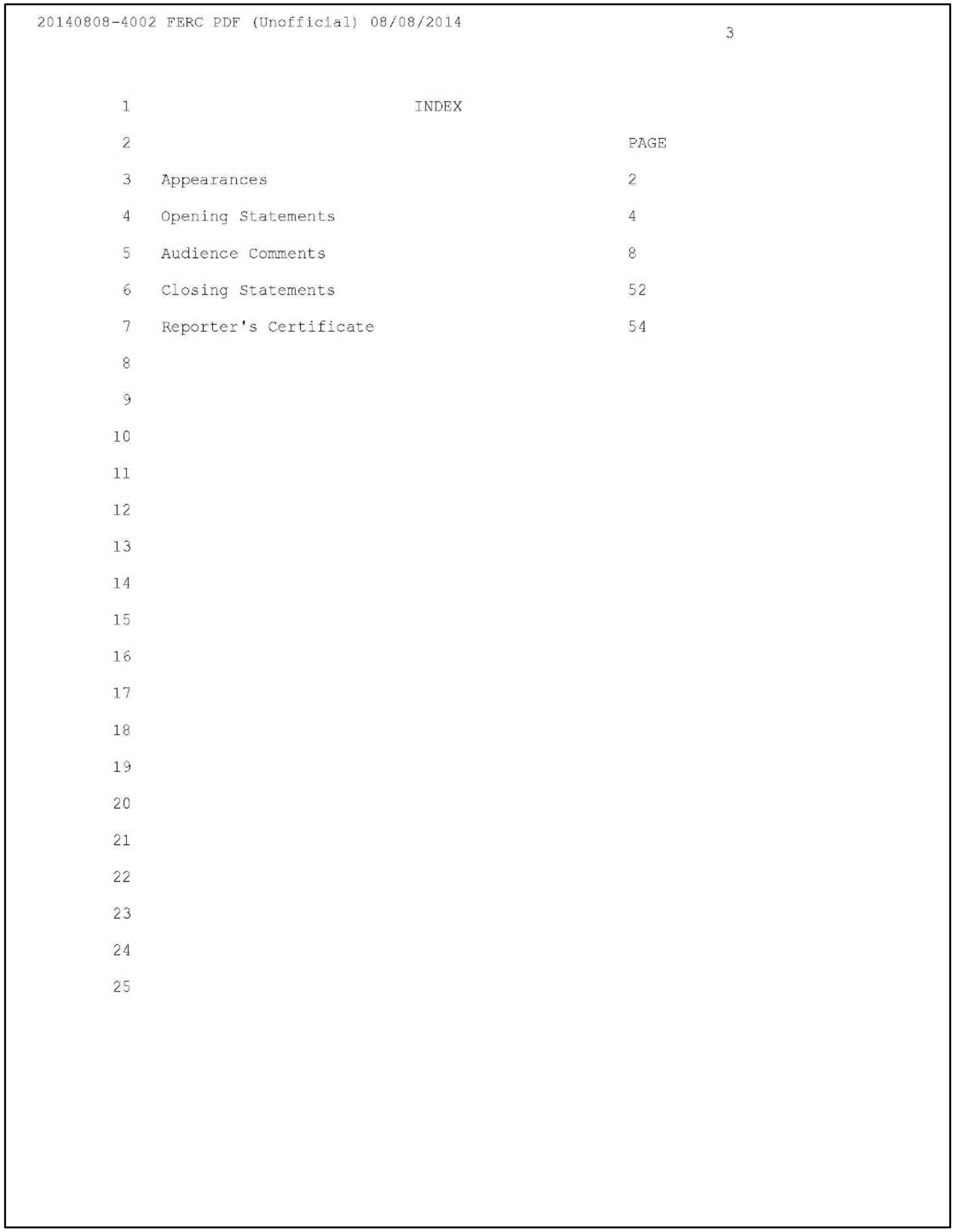

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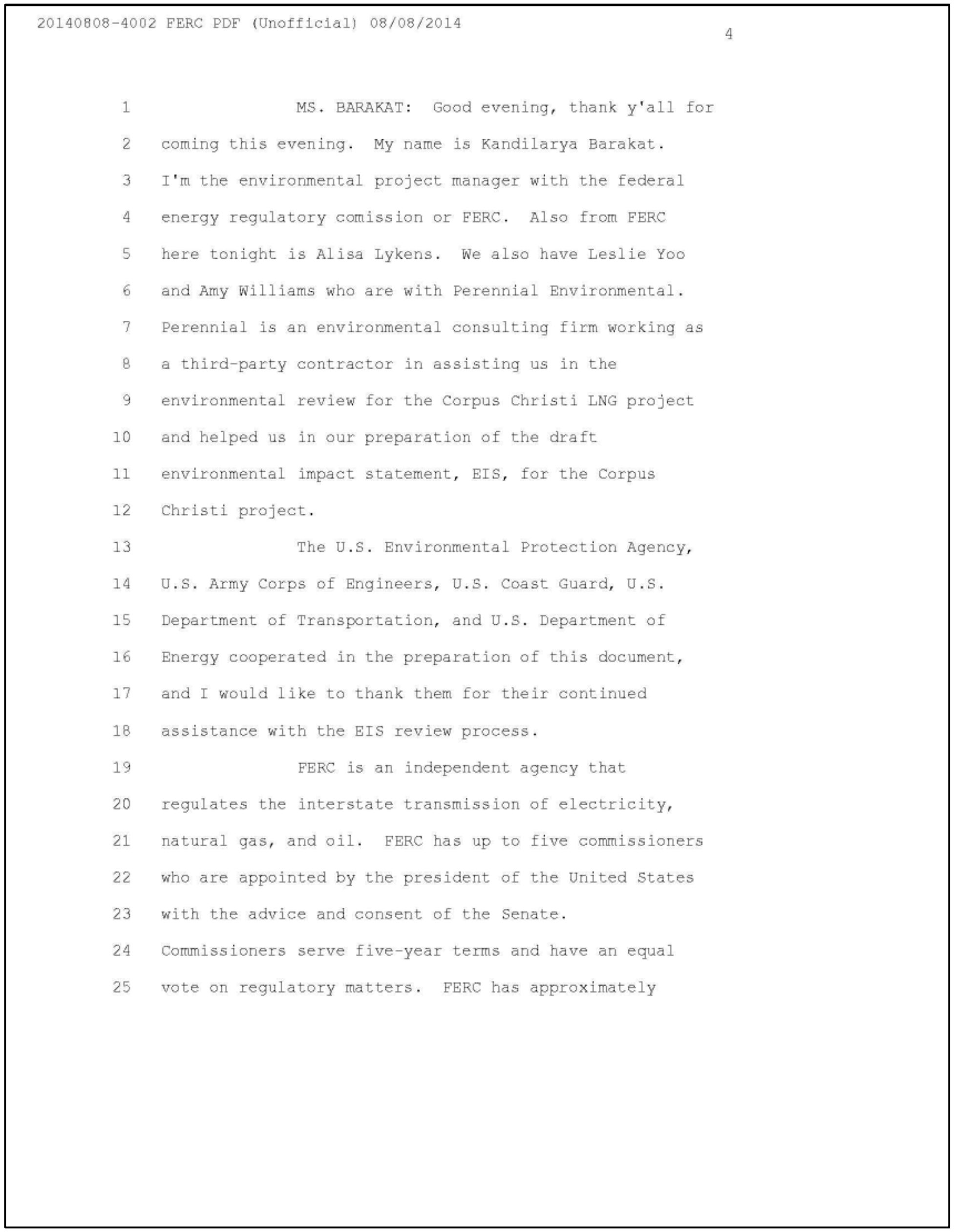

MS. BARAKAT: Good evening, thank y'all for coming this evening. My name is Kandilarya Barakat. I'm the environmental project manager with the federal energy regulatory comission or FERC. Also from FERC here tonight is Alisa Lykens. We also have Leslie Yoo and Amy Williams who are with Perennial Environmental. Perennial is an environmental consulting firm working as a third-party contractor in assisting us in the environmental review for the Corpus Christi LNG project and helped us in our preparation of the draft environmental impact statement, EIS, for the Corpus Christi project.

The U.S. Environmental Protection Agency, U.S. Army Corps of Engineers, U.S. Coast Guard, U.S. Department of Transportation, and U.S. Department of Energy cooperated in the preparation of this document, and I would like to thank them for their continued assistance with the EIS review process.

FERC is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC has up to five commissioners who are appointed by the president of the United States with the advice and consent of the Senate. Commissioners serve five-year terms and have an equal vote on regulatory matters. FERC has approximately

1,200 staff employees. FERC is the lead federal agency responsible for National Environmental Policy Act of 1969 (NEPA) review for the Corpus Christi LNG project and the lead agency for the preparation of this draft EIS. NEPA requires FERC to analyze the environmental impacts, consider alternatives, and provide mitigation measures on proposed projects.

On June 13th, 2014, we issued draft EIS for the Corpus Christi LNG project and the document was mailed to those individuals on environmental mailing lists, government agencies, local libraries, and newspapers. If you did not receive a copy of the draft EIS, then you are not on our environmental mailing list. Please provide us with your address at the table in front of the room after the meeting.

This is a project being proposed by Corpus Christi Liquefaction, LLC and Corpus -- City of Corpus Christi Pipeline, LP, collectively referred to as Cheniere, not by the FERC. Cheniere filed applications under Sections 7 and 3 of the Natural Gas Act to construct facilities including three liquefaction trains, three LNG storage tanks, marine terminal facilities, 23 miles of 48-inch diameter natural gas pipeline, and two compressor stations in San Patricio and Nueces Counties, Texas.

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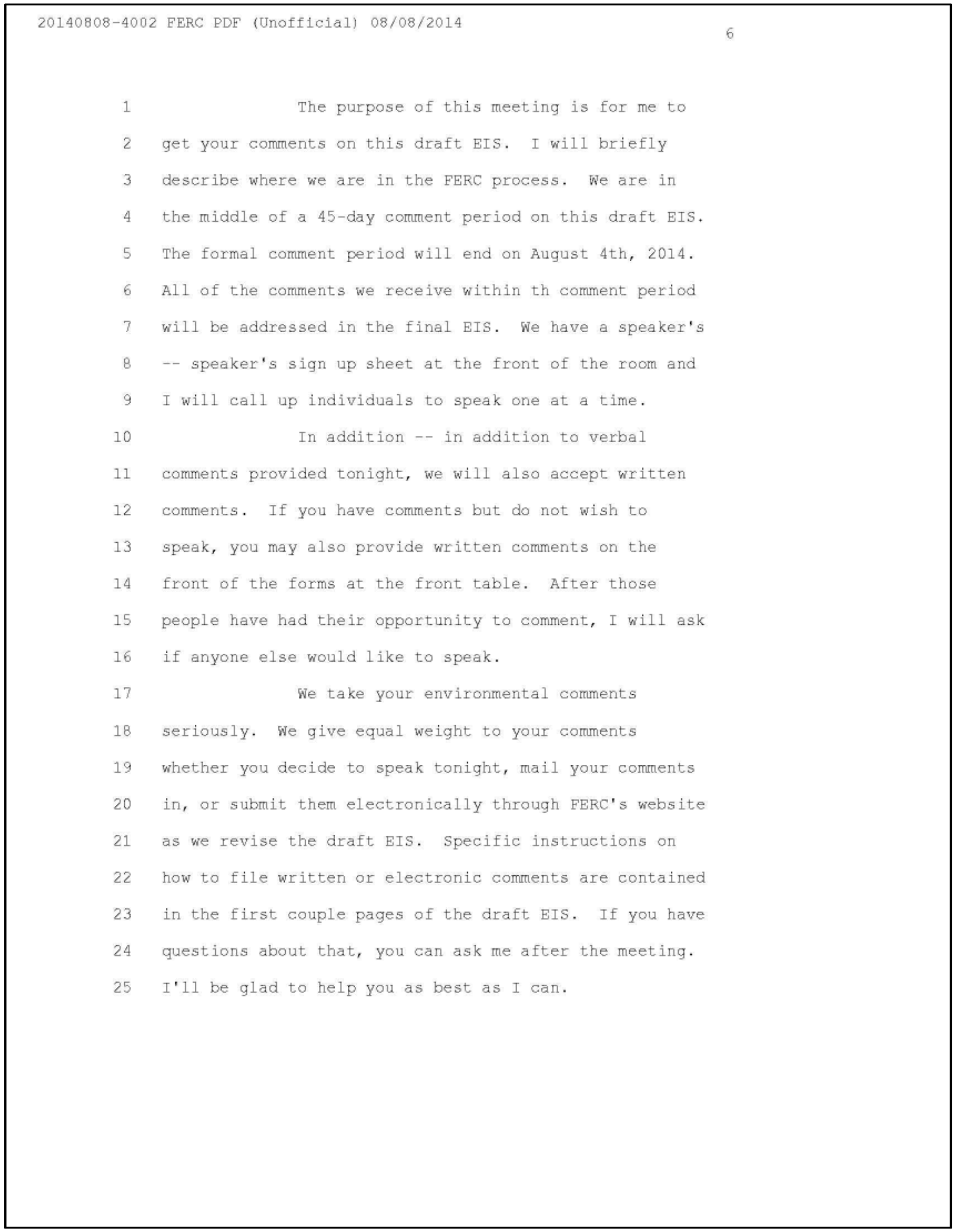

The purpose of this meeting is for me to get your comments on this draft EIS. I will briefly describe where we are in the FERC process. We are in the middle of a 45-day comment period on this draft EIS. The formal comment period will end on August 4th, 2014. All of the comments we receive within th comment period will be addressed in the final EIS. We have a speaker's -- speaker's sign up sheet at the front of the room and I will call up individuals to speak one at a time.

In addition -- in addition to verbal comments provided tonight, we will also accept written comments. If you have comments but do not wish to speak, you may also provide written comments on the front of the forms at the front table. After those people have had their opportunity to comment, I will ask if anyone else would like to speak.

We take your environmental comments seriously. We give equal weight to your comments whether you decide to speak tonight, mail your comments in, or submit them electronically through FERC's website as we revise the draft EIS. Specific instructions on how to file written or electronic comments are contained in the first couple pages of the draft EIS. If you have questions about that, you can ask me after the meeting. I'll be glad to help you as best as I can.

The more specific comments we receive from you, the better we can address your concerns. General comments such as I don't like the project are not as helpful as specific comments. Our job here the next couple of months is to revise environmental analysis based on the type of comments that we receive.

If you received a copy of the draft EIS, you will automatically receive a copy of the final. You do not need to sign up again on another mailing list. Once we finish the final EIS and mail it out, we will forward that on to the four presidentially-appointed commissioners at the FERC. The commissioners will consider our environmental analysis along with non-environmental issues such as engineering markets and rates in order to determine whether to authorize the project. Thus, the EIS itself is one tool in the process. It's not a decision-making document.

Like I said, this is your opportunity to make your comments on the draft EIS. If you have specific questions regarding a negotiation or an easement situation on your property, there are representatives from Cheniere here tonight and they can discuss these issues with you after the meeting. With that, we have how many people signed up? We have about 28 people signed up to speak. And after they have their

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opportunity, I will ask if there are any additional comments regarding the draft EIS.

As you notice, the meeting is being transcribed by a court reporting service to make sure that all the information gathered here tonight is on the public record. To ensure your comments are addressed in the final EIS, please come to the podium, speak into the microphone, and state and spell your name that way your comments will be accurate for the record.

Let's see, the first person signed up is -- and I'm going to ask the first three -- I'm going to say the first three names so they can line up so we're not holding. And then since we have a lot of commentators, I'm going to limit it to five minutes. So please stay to the point so we can get everybody's comments on the record. The first person is Mark Johnson and then we have Julie Gehrig and Freddy Garcia. If I can have those line up, please?

PM1-1

MR. MARK JOHNSON: My name is Mark Johnson. I'm with the World Affairs Counsel. I am speaking just on behalf of myself. I'm really excited about this project the pipeline terminal. I think it's good for the community. I think it's good for the state. I think it's good for the world.

MS. BARAKAT: Thank you, Mark.

PM1-1: Comment acknowledged.

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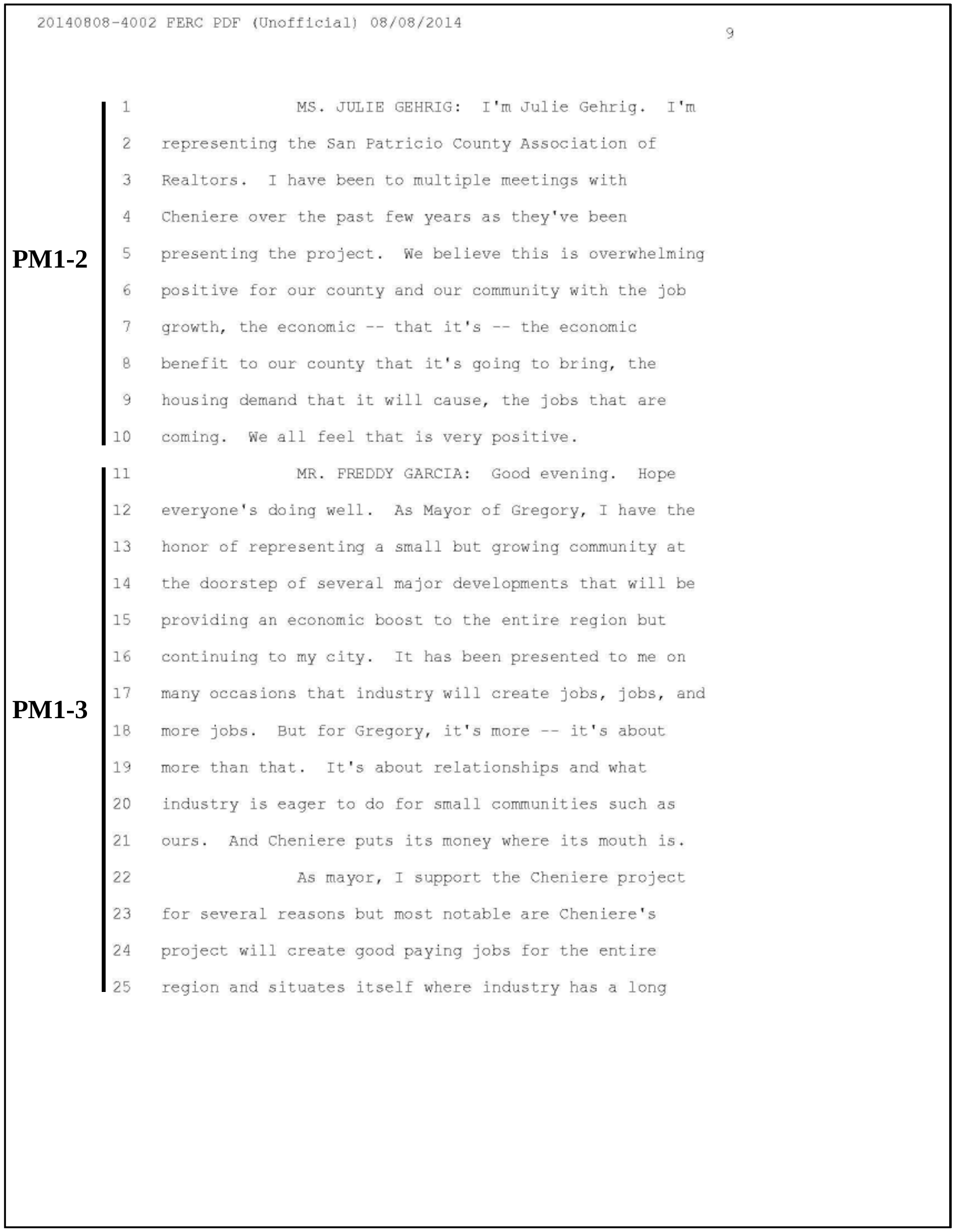

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PM1-2

MS. JULIE GEHRIG: I'm Julie Gehrig. I'm representing the San Patricio County Association of Realtors. I have been to multiple meetings with Cheniere over the past few years as they've been presenting the project. We believe this is overwhelming positive for our county and our community with the job growth, the economic -- that it's -- the economic benefit to our county that it's going to bring, the housing demand that it will cause, the jobs that are coming. We all feel that is very positive.

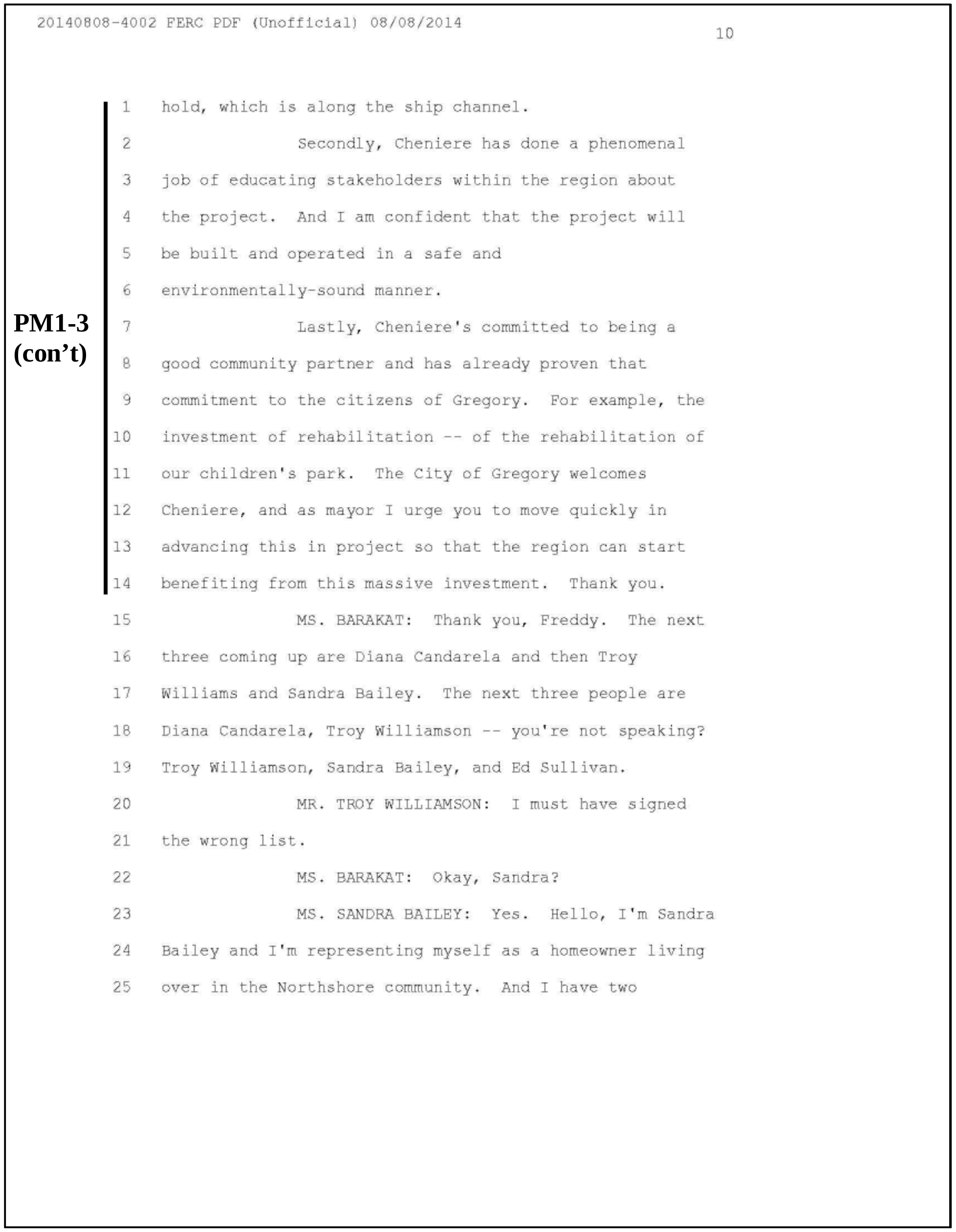
PM1-3

MR. FREDDY GARCIA: Good evening. Hope everyone's doing well. As Mayor of Gregory, I have the honor of representing a small but growing community at the doorstep of several major developments that will be providing an economic boost to the entire region but continuing to my city. It has been presented to me on many occasions that industry will create jobs, jobs, and more jobs. But for Gregory, it's more -- it's about more than that. It's about relationships and what industry is eager to do for small communities such as ours. And Cheniere puts its money where its mouth is.

As mayor, I support the Cheniere project for several reasons but most notable are Cheniere's project will create good paying jobs for the entire region and situates itself where industry has a long

PM1-2: Comment acknowledged.

PM1-3: Comment acknowledged.



PM1-3 (con't)

hold, which is along the ship channel.

Secondly, Cheniere has done a phenomenal job of educating stakeholders within the region about the project. And I am confident that the project will be built and operated in a safe and environmentally-sound manner.

Lastly, Cheniere's committed to being a good community partner and has already proven that commitment to the citizens of Gregory. For example, the investment of rehabilitation -- of the rehabilitation of our children's park. The City of Gregory welcomes Cheniere, and as mayor I urge you to move quickly in advancing this in project so that the region can start benefiting from this massive investment. Thank you.

MS. BARAKAT: Thank you, Freddy. The next three coming up are Diana Candarela and then Troy Williams and Sandra Bailey. The next three people are Diana Candarela, Troy Williamson -- you're not speaking? Troy Williamson, Sandra Bailey, and Ed Sullivan.

MR. TROY WILLIAMSON: I must have signed the wrong list.

MS. BARAKAT: Okay, Sandra?

MS. SANDRA BAILEY: Yes. Hello, I'm Sandra Bailey and I'm representing myself as a homeowner living over in the Northshore community. And I have two

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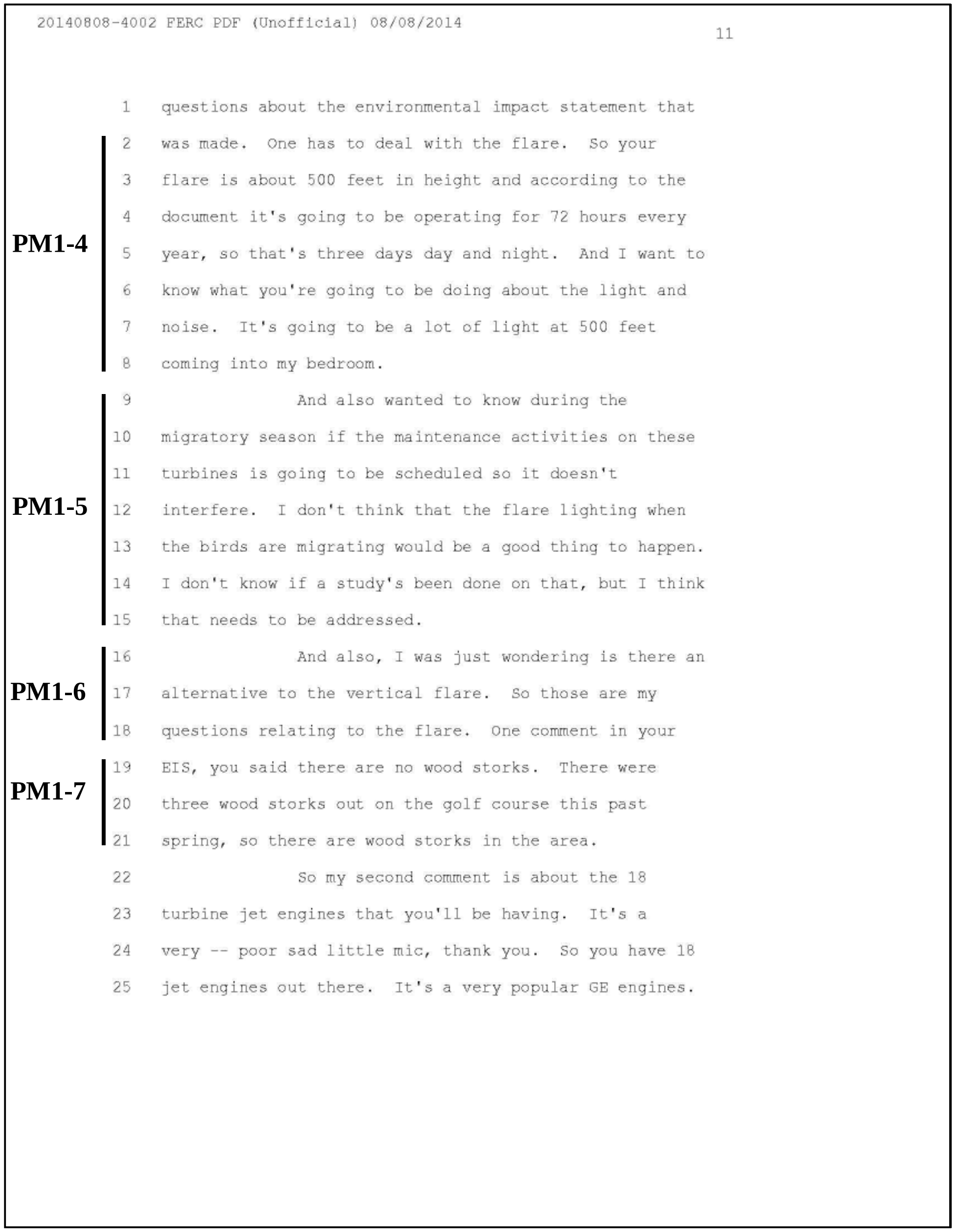

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PM1-4

questions about the environmental impact statement that was made. One has to deal with the flare. So your flare is about 500 feet in height and according to the document it's going to be operating for 72 hours every year, so that's three days day and night. And I want to know what you're going to be doing about the light and noise. It's going to be a lot of light at 500 feet coming into my bedroom.

PM1-5

And also wanted to know during the migratory season if the maintenance activities on these turbines is going to be scheduled so it doesn't interfere. I don't think that the flare lighting when the birds are migrating would be a good thing to happen. I don't know if a study's been done on that, but I think that needs to be addressed.

PM1-6

PM1-7

And also, I was just wondering is there an alternative to the vertical flare. So those are my questions relating to the flare. One comment in your EIS, you said there are no wood storks. There were three wood storks out on the golf course this past spring, so there are wood storks in the area.

So my second comment is about the 18 turbine jet engines that you'll be having. It's a very -- poor sad little mic, thank you. So you have 18 jet engines out there. It's a very popular GE engines.

PM1-4: Visual impacts associated with the flares are discussed in sections 3.1.6 and 4.8.1.4.

PM1-5: As stated in section 4.6.3.1 of the final EIS, Cheniere has consulted with the U.S. Fish and Wildlife Service (USFWS) regarding potential impacts on migratory birds including measures that could be utilized to minimize or avoid impacts. Based on implementation of these measures that were recommended by USFWS, we have determined that the Project would not significantly impact migratory birds.

PM1-6: The final EIS has been revised to address alternatives to elevated flares. See section 3.1.6.

PM1-7: As stated in section 4.7.2.2 of the final EIS, wood storks could occur in the Project vicinity, but were not observed during field surveys conducted in 2011 and 2012.

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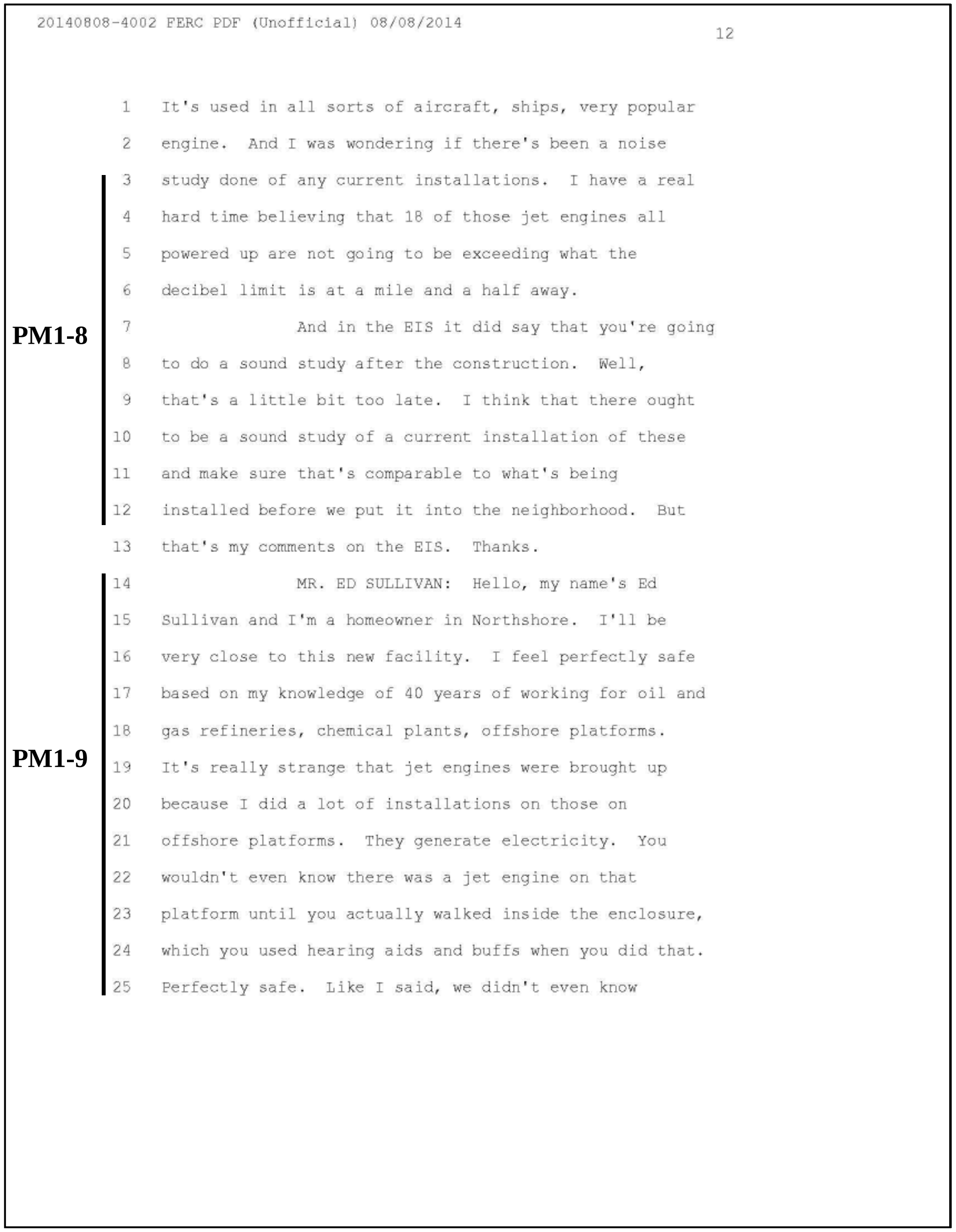

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It's used in all sorts of aircraft, ships, very popular engine. And I was wondering if there's been a noise

PM1-8

study done of any current installations. I have a real hard time believing that 18 of those jet engines all powered up are not going to be exceeding what the decibel limit is at a mile and a half away.

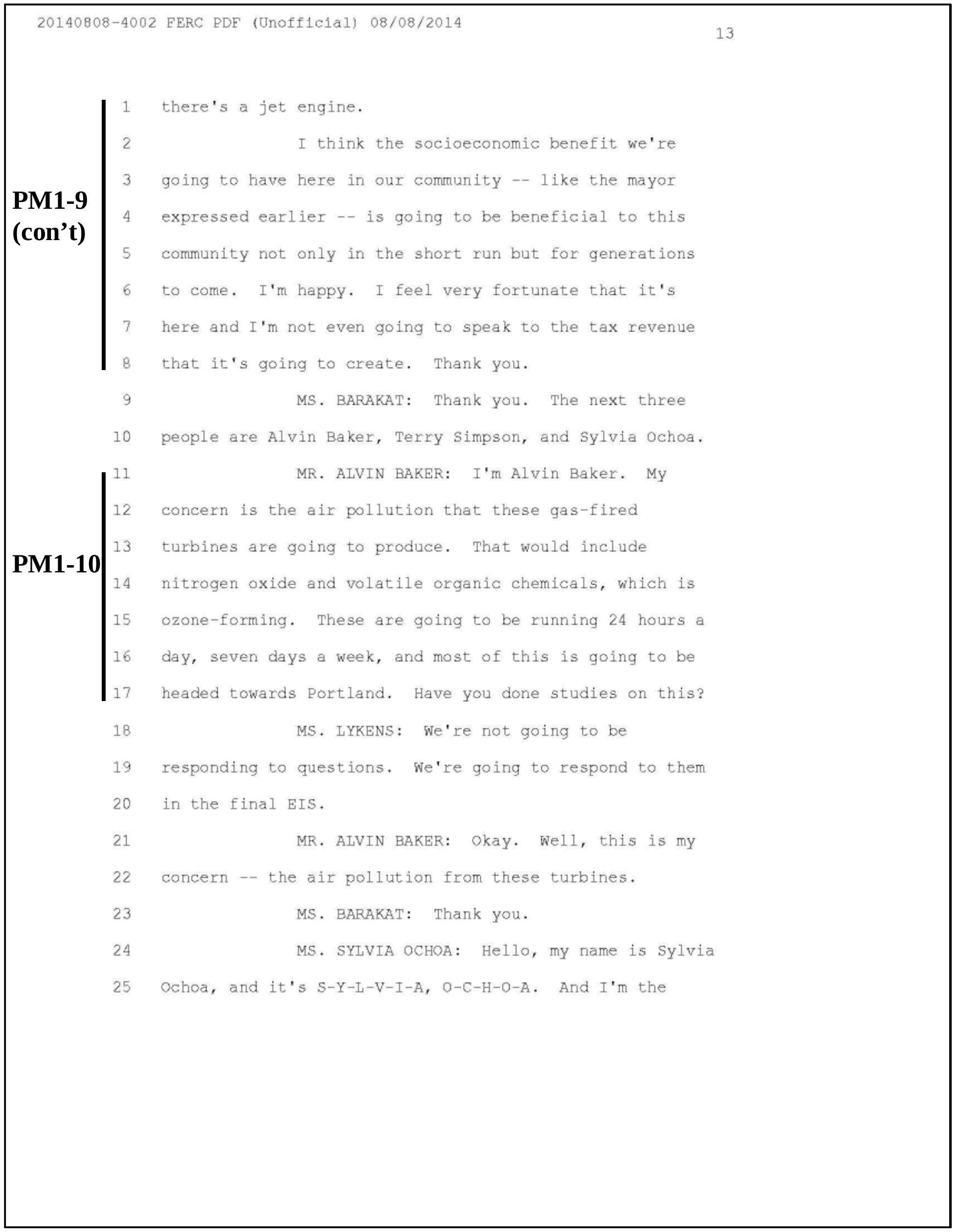
And in the EIS it did say that you're going to do a sound study after the construction. Well, that's a little bit too late. I think that there ought to be a sound study of a current installation of these and make sure that's comparable to what's being installed before we put it into the neighborhood. But that's my comments on the EIS. Thanks.

PM1-9

MR. ED SULLIVAN: Hello, my name's Ed Sullivan and I'm a homeowner in Northshore. I'll be very close to this new facility. I feel perfectly safe based on my knowledge of 40 years of working for oil and gas refineries, chemical plants, offshore platforms. It's really strange that jet engines were brought up because I did a lot of installations on those on offshore platforms. They generate electricity. You wouldn't even know there was a jet engine on that platform until you actually walked inside the enclosure, which you used hearing aids and buffs when you did that. Perfectly safe. Like I said, we didn't even know

PM1-8: Section 4.11.2.3 of the FEIS presents the results of the predictive noise study that was conducted for the Terminal. Sound level emissions of the gas turbine driven refrigerant compressors were included in the analysis, which included computer noise modeling. Table 4.11-26 shows the results of the predicted noise study for the Terminal at the nearest NSAs. Existing noise levels were determined as presented in Section 4.11.2.2. We also recommend that Cheniere file a noise survey with the Secretary no later than 60 days after placing each liquefaction train and the entire Terminal in service, which would verify the results of the predictive noise study and ensure compliance with the FERC sound criterion.

PM1-9: Comment acknowledged.



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PM1-9 (con't)

there's a jet engine.

I think the socioeconomic benefit we're going to have here in our community -- like the mayor expressed earlier -- is going to be beneficial to this community not only in the short run but for generations to come. I'm happy. I feel very fortunate that it's here and I'm not even going to speak to the tax revenue that it's going to create. Thank you.

MS. BARAKAT: Thank you. The next three people are Alvin Baker, Terry Simpson, and Sylvia Ochoa.

PM1-10

MR. ALVIN BAKER: I'm Alvin Baker. My concern is the air pollution that these gas-fired turbines are going to produce. That would include nitrogen oxide and volatile organic chemicals, which is ozone-forming. These are going to be running 24 hours a day, seven days a week, and most of this is going to be headed towards Portland. Have you done studies on this?

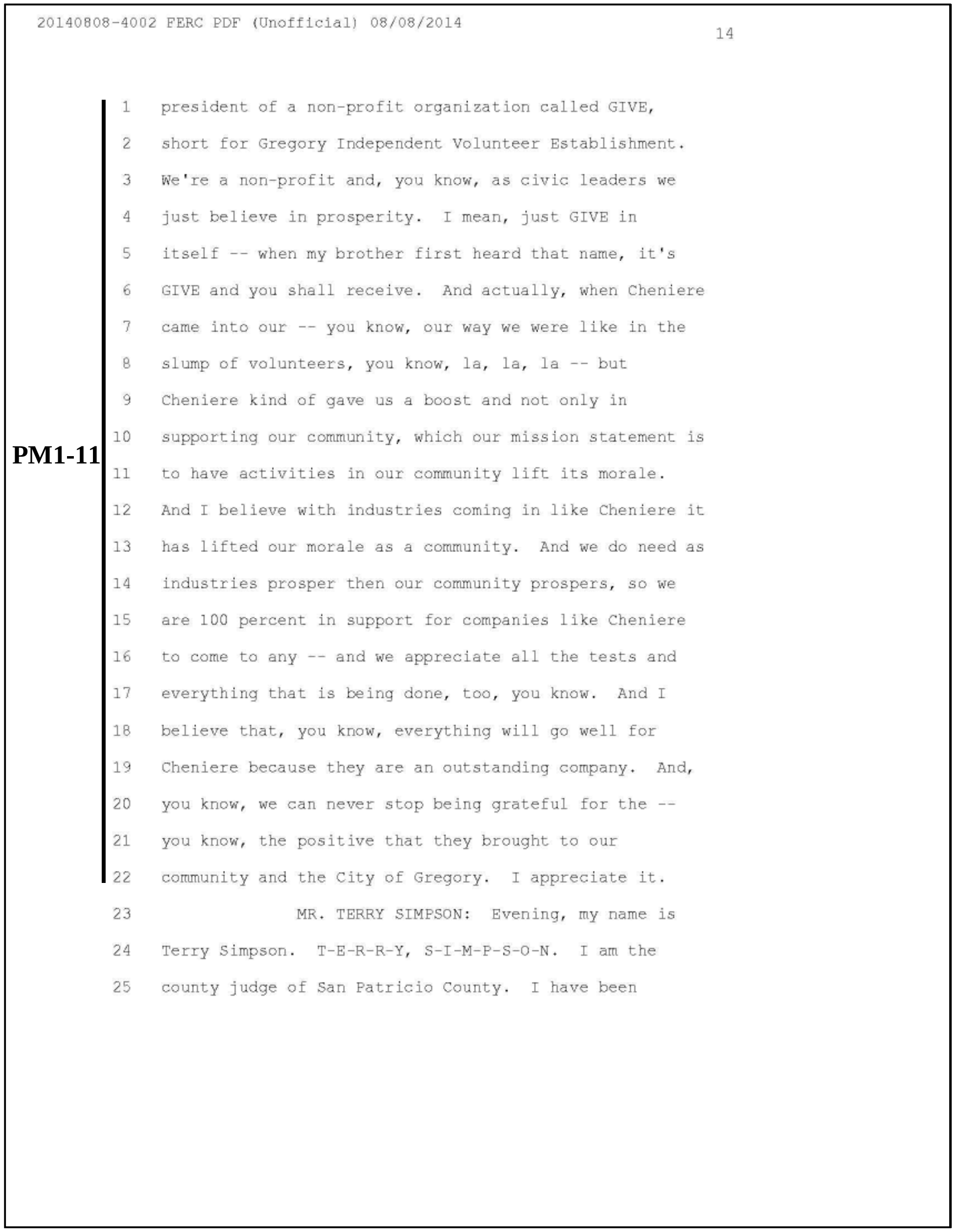
MS. LYKENS: We're not going to be responding to questions. We're going to respond to them in the final EIS.

MR. ALVIN BAKER: Okay. Well, this is my concern -- the air pollution from these turbines.

MS. BARAKAT: Thank you.

MS. SYLVIA OCHOA: Hello, my name is Sylvia Ochoa, and it's S-Y-L-V-I-A, O-C-H-O-A. And I'm the

PM1-10: The potential impact on regional ozone levels due to the estimated emissions of ozone precursors – nitrogen oxides and volatile organic compounds – from the turbines as well as the other Project sources of these pollutants was assessed by Cheniere, in accordance with EPA recommendations, and discussed in the final EIS within section 4.11.1.6 (see Analysis 3 – Ozone Modeling). The results of this analysis demonstrated that the Project emissions would not significantly change ozone levels in the region, including San Patricio and Nueces Counties.



PM1-11

president of a non-profit organization called GIVE, short for Gregory Independent Volunteer Establishment. We're a non-profit and, you know, as civic leaders we just believe in prosperity. I mean, just GIVE in itself -- when my brother first heard that name, it's GIVE and you shall receive. And actually, when Cheniere came into our -- you know, our way we were like in the slump of volunteers, you know, la, la, la -- but Cheniere kind of gave us a boost and not only in supporting our community, which our mission statement is to have activities in our community lift its morale. And I believe with industries coming in like Cheniere it has lifted our morale as a community. And we do need as industries prosper then our community prospers, so we are 100 percent in support for companies like Cheniere to come to any -- and we appreciate all the tests and everything that is being done, too, you know. And I believe that, you know, everything will go well for Cheniere because they are an outstanding company. And, you know, we can never stop being grateful for the -- you know, the positive that they brought to our community and the City of Gregory. I appreciate it.

MR. TERRY SIMPSON: Evening, my name is Terry Simpson. T-E-R-R-Y, S-I-M-P-S-O-N. I am the county judge of San Patricio County. I have been

PM1-11: Comment acknowledged.

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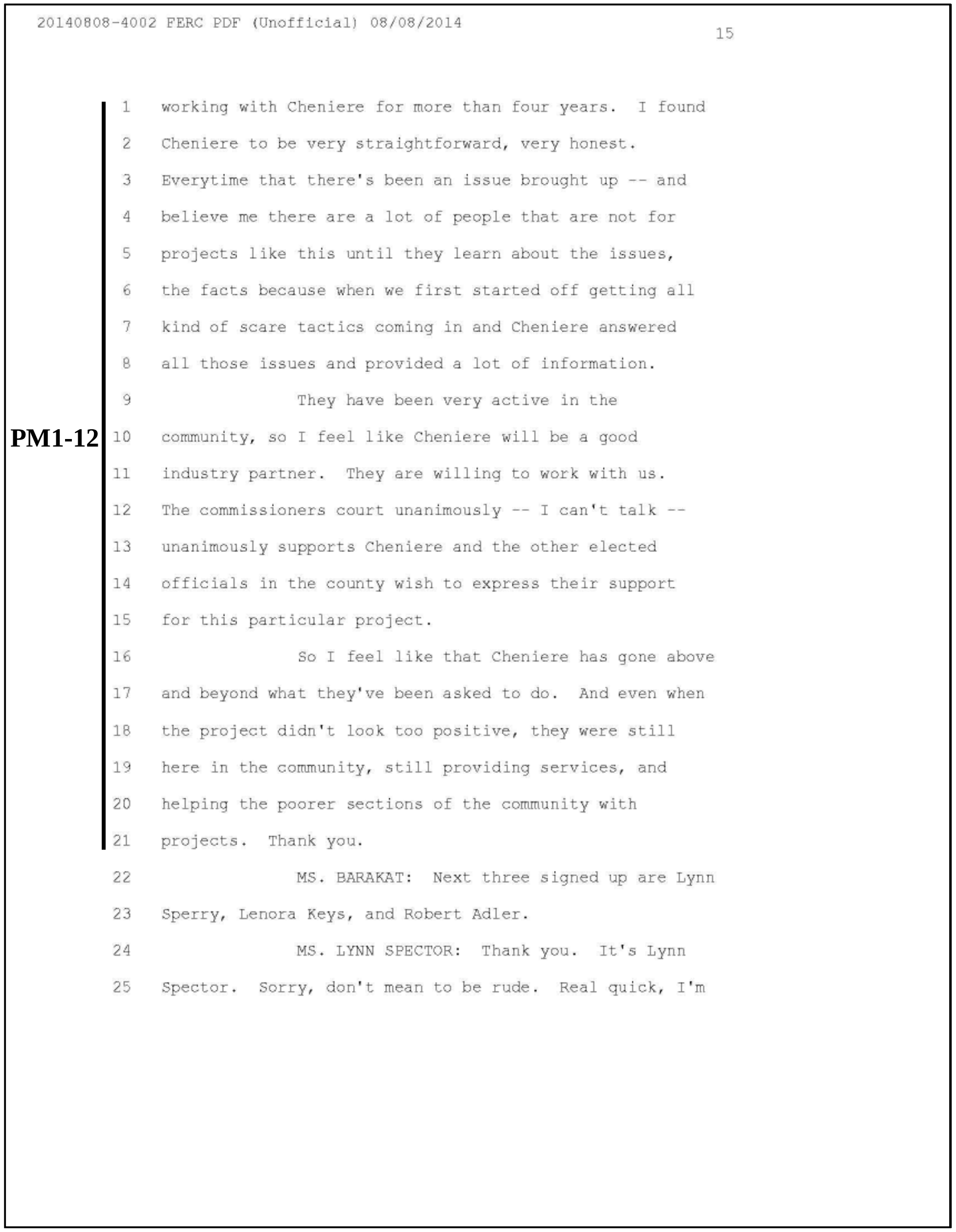

PM1-12

working with Cheniere for more than four years. I found Cheniere to be very straightforward, very honest. Everytime that there's been an issue brought up -- and believe me there are a lot of people that are not for projects like this until they learn about the issues, the facts because when we first started off getting all kind of scare tactics coming in and Cheniere answered all those issues and provided a lot of information.

They have been very active in the community, so I feel like Cheniere will be a good industry partner. They are willing to work with us. The commissioners court unanimously -- I can't talk -- unanimously supports Cheniere and the other elected officials in the county wish to express their support for this particular project.

So I feel like that Cheniere has gone above and beyond what they've been asked to do. And even when the project didn't look too positive, they were still here in the community, still providing services, and helping the poorer sections of the community with projects. Thank you.

MS. BARAKAT: Next three signed up are Lynn Sperry, Lenora Keys, and Robert Adler.

MS. LYNN SPECTOR: Thank you. It's Lynn Spector. Sorry, don't mean to be rude. Real quick, I'm

PM1-12: Comment acknowledged.

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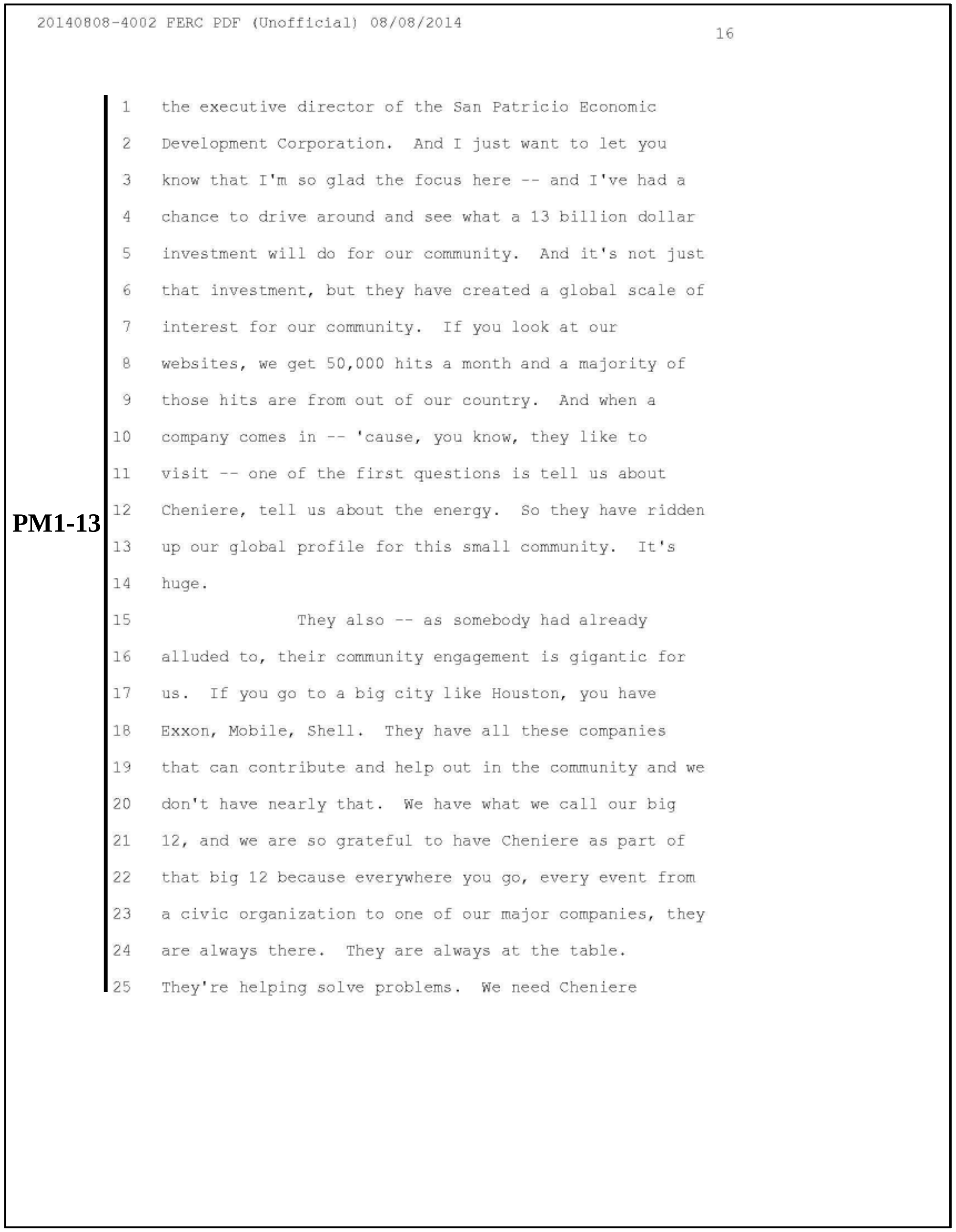

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PM1-13

the executive director of the San Patricio Economic Development Corporation. And I just want to let you know that I'm so glad the focus here -- and I've had a chance to drive around and see what a 13 billion dollar investment will do for our community. And it's not just that investment, but they have created a global scale of interest for our community. If you look at our websites, we get 50,000 hits a month and a majority of those hits are from out of our country. And when a company comes in -- 'cause, you know, they like to visit -- one of the first questions is tell us about Cheniere, tell us about the energy. So they have ridden up our global profile for this small community. It's huge.

They also -- as somebody had already alluded to, their community engagement is gigantic for us. If you go to a big city like Houston, you have Exxon, Mobile, Shell. They have all these companies that can contribute and help out in the community and we don't have nearly that. We have what we call our big 12, and we are so grateful to have Cheniere as part of that big 12 because everywhere you go, every event from a civic organization to one of our major companies, they are always there. They are always at the table. They're helping solve problems. We need Cheniere

PM1-13: Comment acknowledged.

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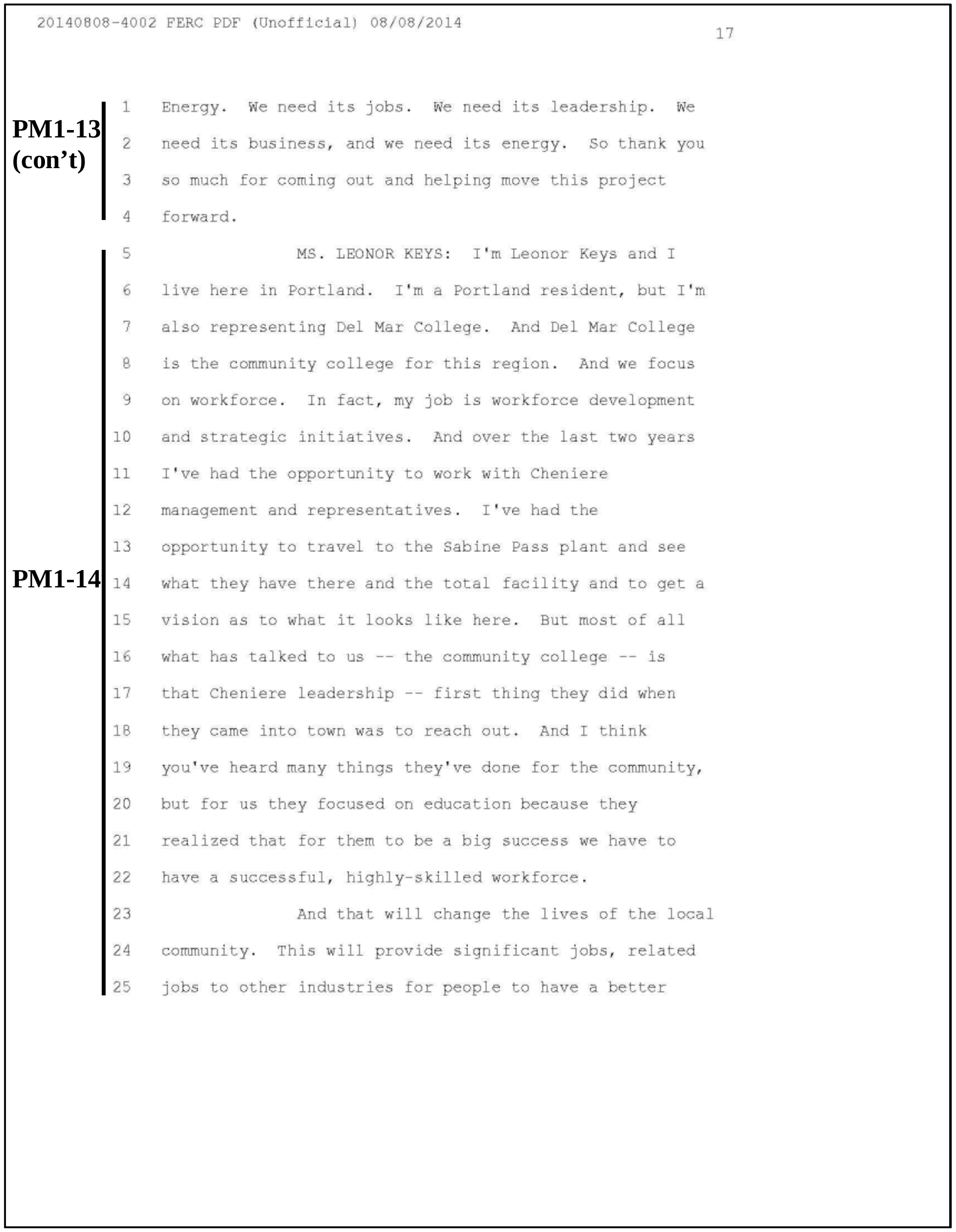

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PM1-13 (con't)

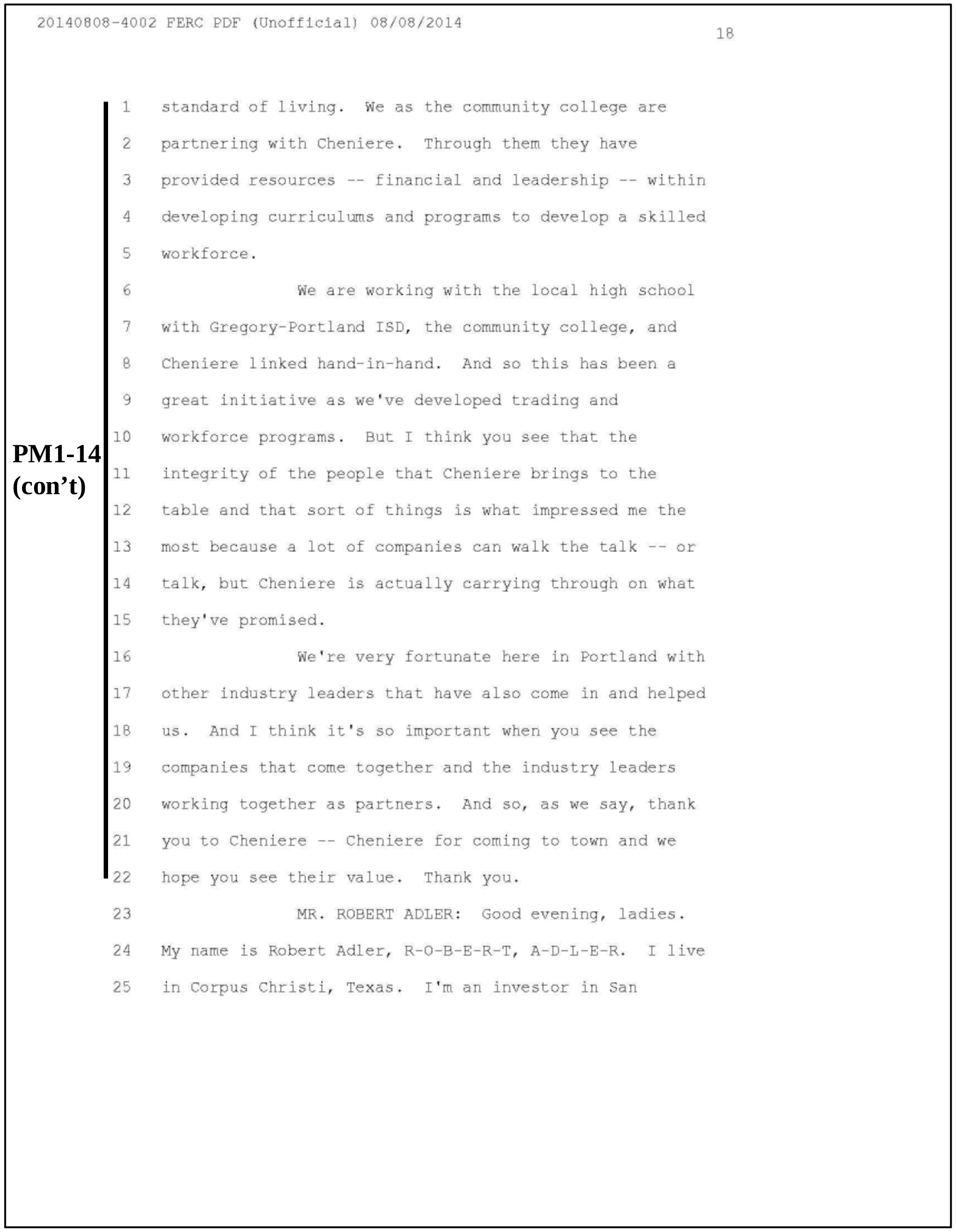
Energy. We need its jobs. We need its leadership. We need its business, and we need its energy. So thank you so much for coming out and helping move this project forward.

PM1-14

MS. LEONOR KEYS: I'm Leonor Keys and I live here in Portland. I'm a Portland resident, but I'm also representing Del Mar College. And Del Mar College is the community college for this region. And we focus on workforce. In fact, my job is workforce development and strategic initiatives. And over the last two years I've had the opportunity to work with Cheniere management and representatives. I've had the opportunity to travel to the Sabine Pass plant and see what they have there and the total facility and to get a vision as to what it looks like here. But most of all what has talked to us -- the community college -- is that Cheniere leadership -- first thing they did when they came into town was to reach out. And I think you've heard many things they've done for the community, but for us they focused on education because they realized that for them to be a big success we have to have a successful, highly-skilled workforce.

And that will change the lives of the local community. This will provide significant jobs, related jobs to other industries for people to have a better

PM1-14: Comment acknowledged.



PM1-14 (con't)

standard of living. We as the community college are partnering with Cheniere. Through them they have provided resources -- financial and leadership -- within developing curriculums and programs to develop a skilled workforce.

We are working with the local high school with Gregory-Portland ISD, the community college, and Cheniere linked hand-in-hand. And so this has been a great initiative as we've developed trading and workforce programs. But I think you see that the integrity of the people that Cheniere brings to the table and that sort of things is what impressed me the most because a lot of companies can walk the talk -- or talk, but Cheniere is actually carrying through on what they've promised.

We're very fortunate here in Portland with other industry leaders that have also come in and helped us. And I think it's so important when you see the companies that come together and the industry leaders working together as partners. And so, as we say, thank you to Cheniere -- Cheniere for coming to town and we hope you see their value. Thank you.

MR. ROBERT ADLER: Good evening, ladies. My name is Robert Adler, R-O-B-E-R-T, A-D-L-E-R. I live in Corpus Christi, Texas. I'm an investor in San

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PM1-15

Patricio County. Weekends are sometimes slow around our house. Not often, but when we have a couple of empty hours, we head to our favorite drive around Corpus Christi Bay to look at all the huge, beautiful sights that we can see from our house to the other side of the bay. We've watched the gigantic rigs being built from beginning to end -- Popeye and Bullwinkle. We watch ships coming in to our port and we feel so lucky to live by the sea and have the opportunity to see what's coming and going all around our area. The growth and construction makes us proud to live in Corpus Christi.

Former county judge and at that time head of the Economic Development Counsel, Josephine Miller, took Chris and I on a preliminary tour of the proposed Cheniere facility several years ago. The anticipated construction of the Cheniere plant, we know what prize we received when we got word that Cheniere was moving to the Coastal Bend. We need jobs in our area and Cheniere promised to bring us 3,500 construction jobs and 350 permanent jobs when completed. Those jobs along with the increased investments Cheniere is making will amount to about 13 billion -- that's a B -- and provide us with the largest industrial projects in the history of the State of Texas.

The economic impact of the Coastal Bend

PM1-15: Comment acknowledged.

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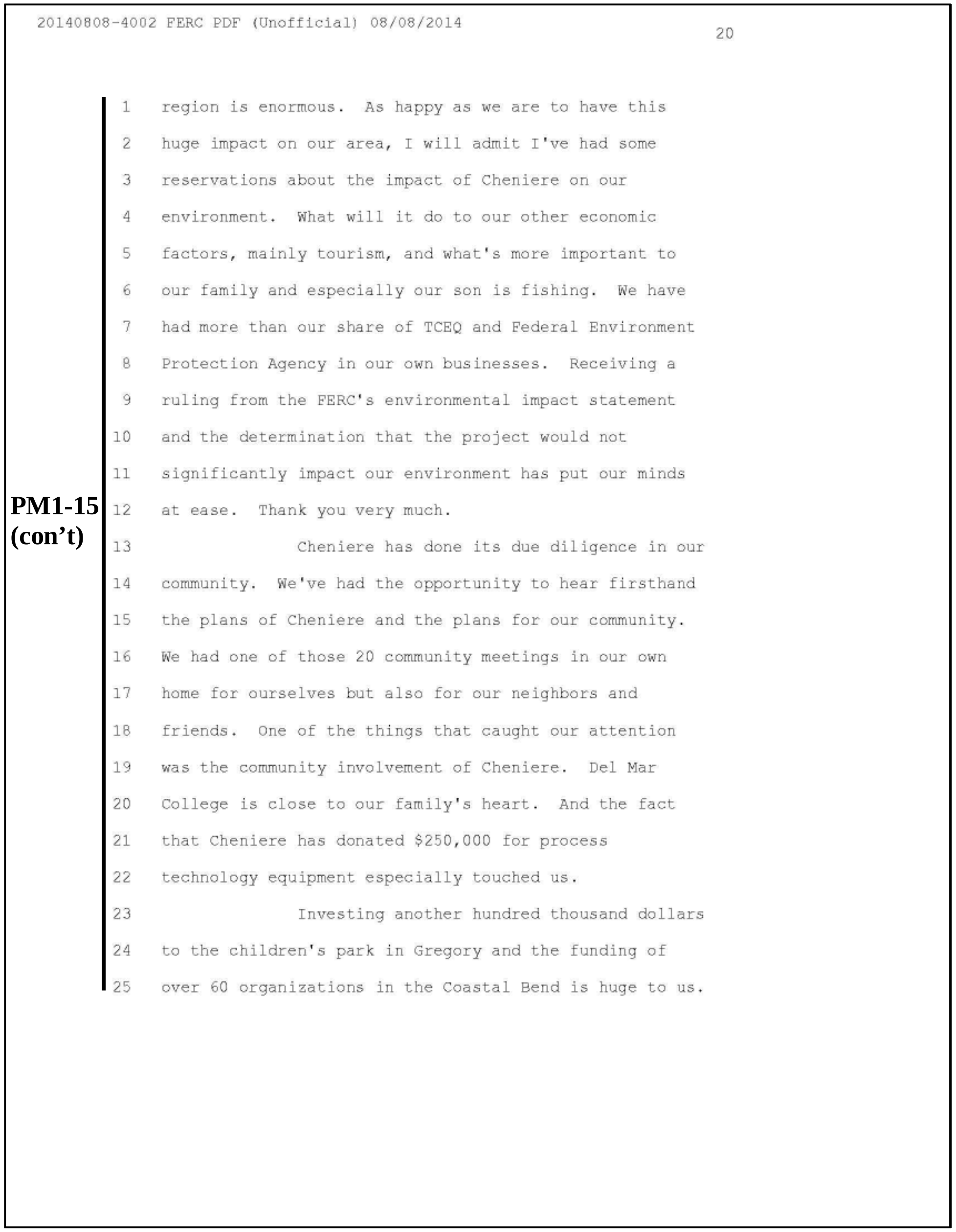

PM1-15 (con't)

region is enormous. As happy as we are to have this huge impact on our area, I will admit I've had some reservations about the impact of Cheniere on our environment. What will it do to our other economic factors, mainly tourism, and what's more important to our family and especially our son is fishing. We have had more than our share of TCEQ and Federal Environment Protection Agency in our own businesses. Receiving a ruling from the FERC's environmental impact statement and the determination that the project would not significantly impact our environment has put our minds at ease. Thank you very much.

Cheniere has done its due diligence in our community. We've had the opportunity to hear firsthand the plans of Cheniere and the plans for our community. We had one of those 20 community meetings in our own home for ourselves but also for our neighbors and friends. One of the things that caught our attention was the community involvement of Cheniere. Del Mar College is close to our family's heart. And the fact that Cheniere has donated $250,000 for process technology equipment especially touched us.

Investing another hundred thousand dollars to the children's park in Gregory and the funding of over 60 organizations in the Coastal Bend is huge to us.

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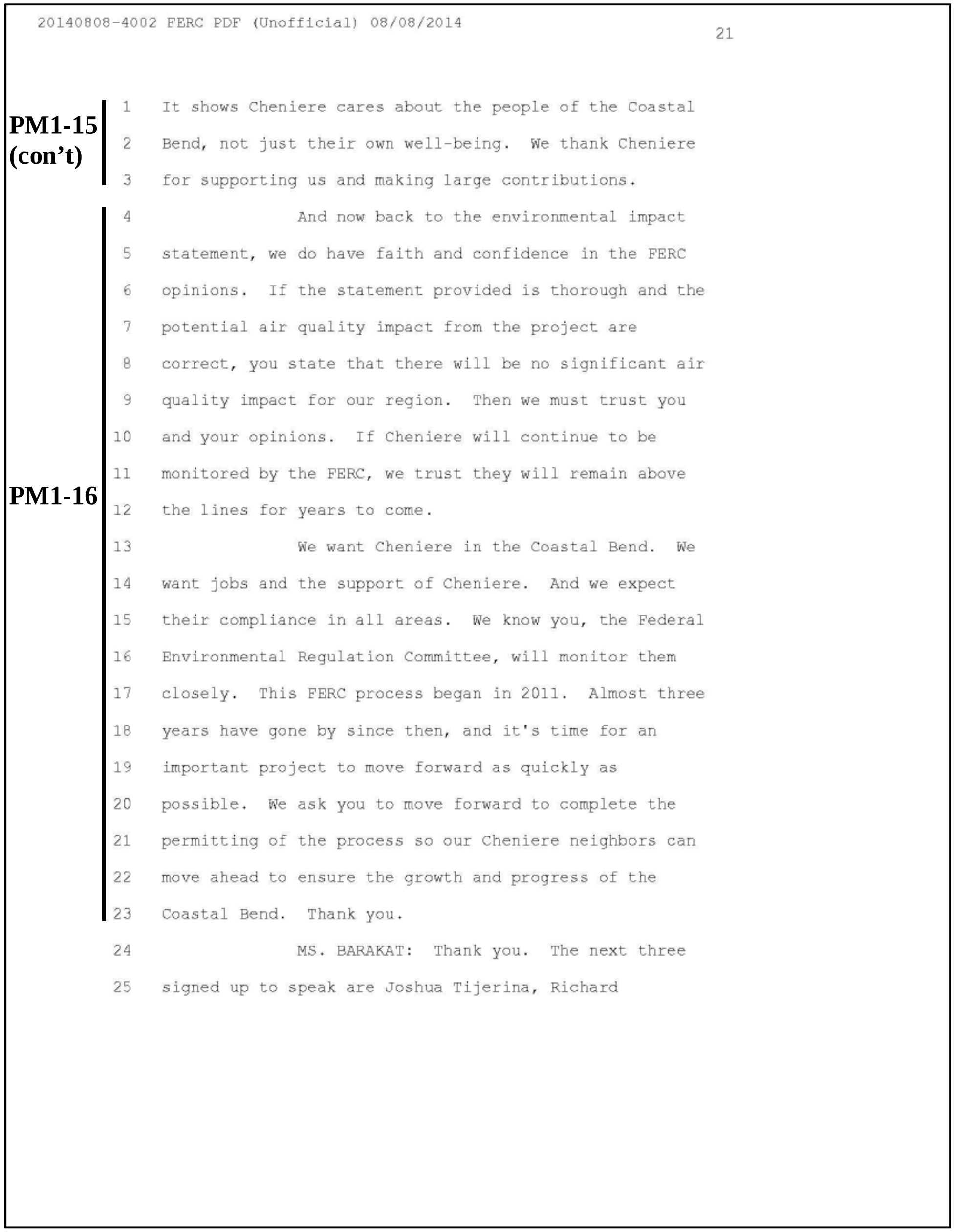

PM1-15 (con't)

It shows Cheniere cares about the people of the Coastal Bend, not just their own well-being. We thank Cheniere for supporting us and making large contributions.

PM1-16

And now back to the environmental impact statement, we do have faith and confidence in the FERC opinions. If the statement provided is thorough and the potential air quality impact from the project are correct, you state that there will be no significant air quality impact for our region. Then we must trust you and your opinions. If Cheniere will continue to be monitored by the FERC, we trust they will remain above the lines for years to come.

We want Cheniere in the Coastal Bend. We want jobs and the support of Cheniere. And we expect their compliance in all areas. We know you, the Federal Environmental Regulation Committee, will monitor them closely. This FERC process began in 2011. Almost three years have gone by since then, and it's time for an important project to move forward as quickly as possible. We ask you to move forward to complete the permitting of the process so our Cheniere neighbors can move ahead to ensure the growth and progress of the Coastal Bend. Thank you.

MS. BARAKAT: Thank you. The next three signed up to speak are Joshua Tijerina, Richard

PM1-16: See sections 4.11.1 and 5.1.11 of the final EIS.

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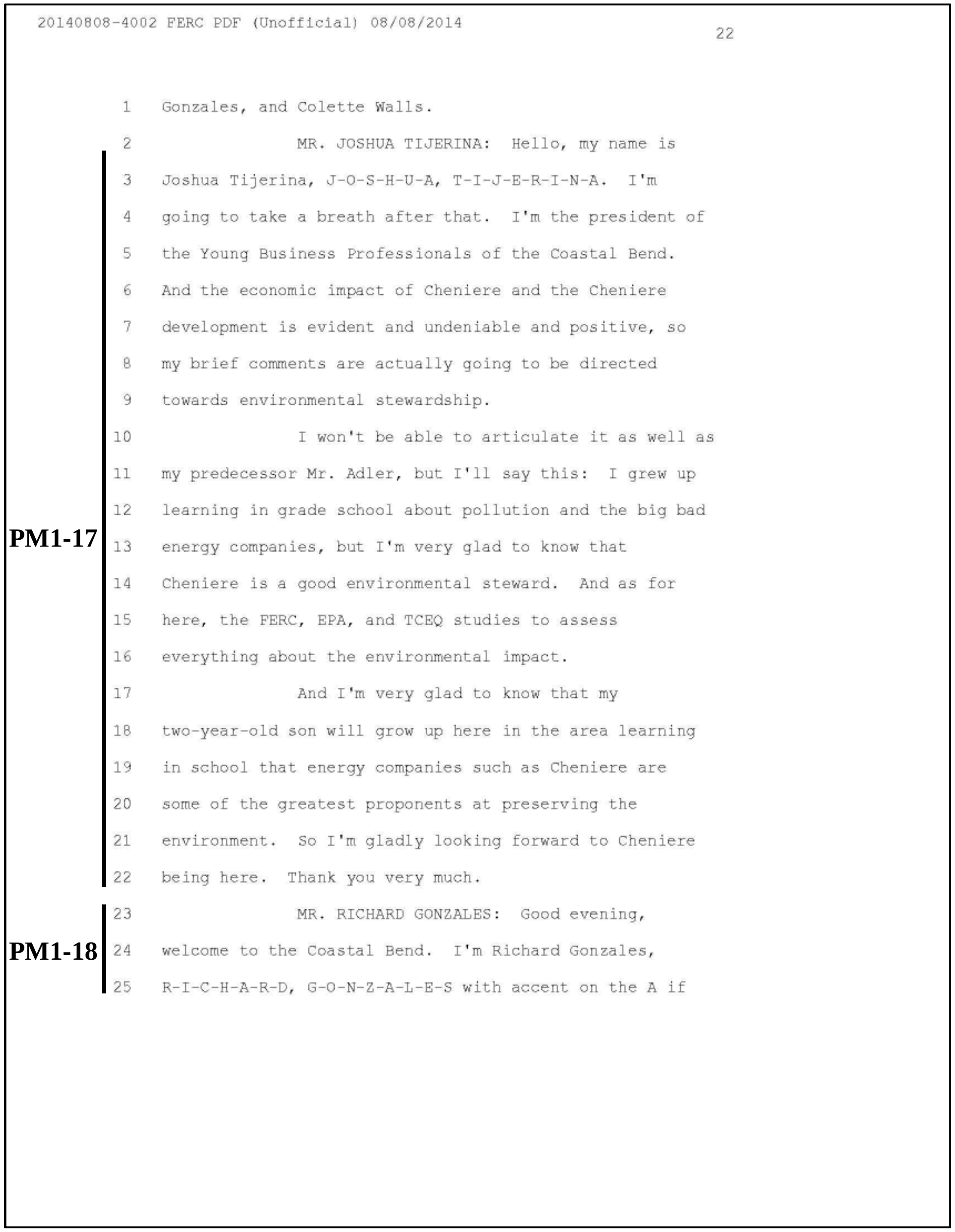

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Gonzales, and Colette Walls.

PM1-17

MR. JOSHUA TIJERINA: Hello, my name is Joshua Tijerina, J-O-S-H-U-A, T-I-J-E-R-I-N-A. I'm going to take a breath after that. I'm the president of the Young Business Professionals of the Coastal Bend. And the economic impact of Cheniere and the Cheniere development is evident and undeniable and positive, so my brief comments are actually going to be directed towards environmental stewardship.

I won't be able to articulate it as well as my predecessor Mr. Adler, but I'll say this: I grew up learning in grade school about pollution and the big bad energy companies, but I'm very glad to know that Cheniere is a good environmental steward. And as for here, the FERC, EPA, and TCEQ studies to assess everything about the environmental impact.

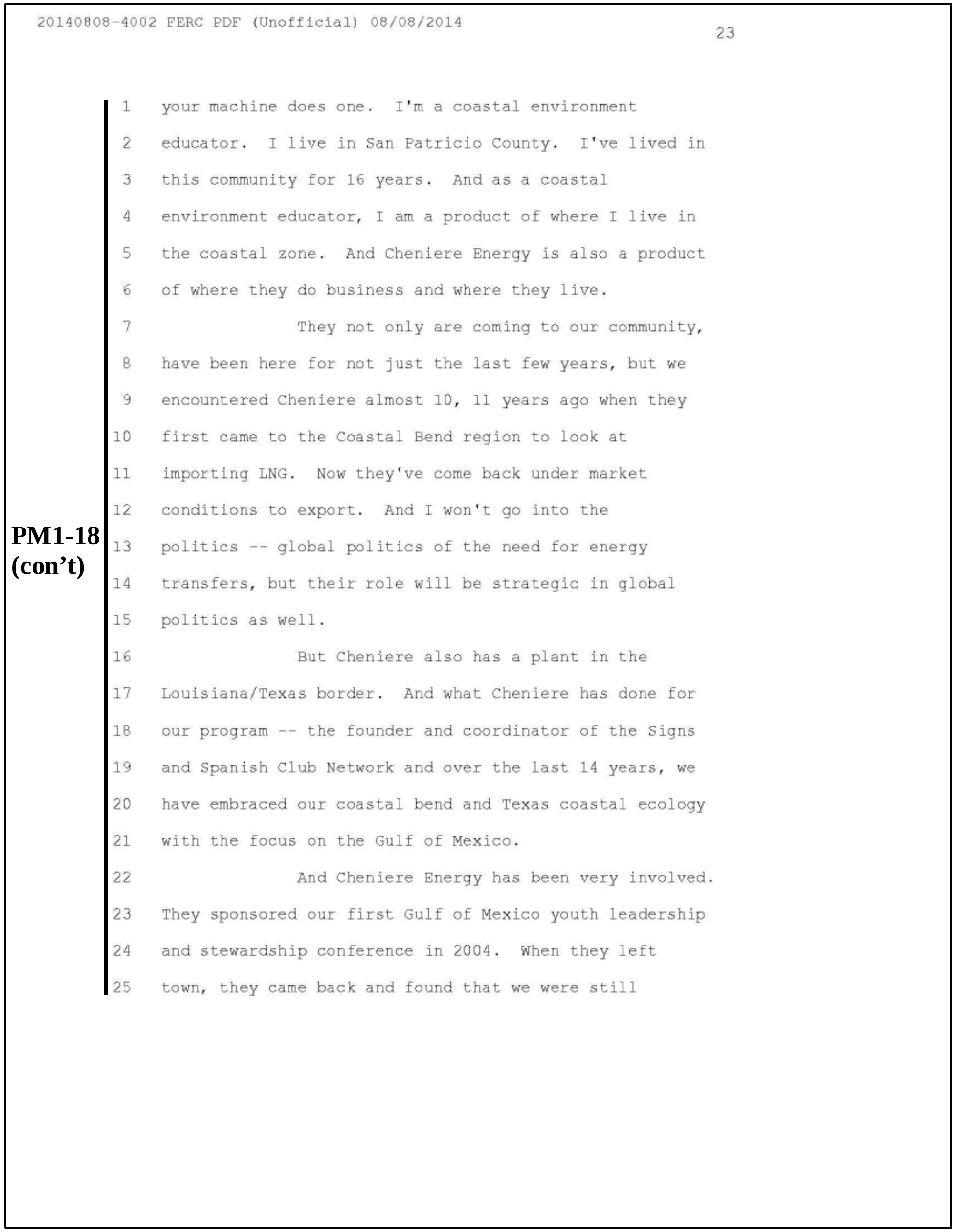
And I'm very glad to know that my two-year-old son will grow up here in the area learning in school that energy companies such as Cheniere are some of the greatest proponents at preserving the environment. So I'm gladly looking forward to Cheniere being here. Thank you very much.

PM1-18

MR. RICHARD GONZALES: Good evening, welcome to the Coastal Bend. I'm Richard Gonzales, R-I-C-H-A-R-D, G-O-N-Z-A-L-E-S with accent on the A if

PM1-17: Comment acknowledged.

PM1-18: Comment acknowledged.



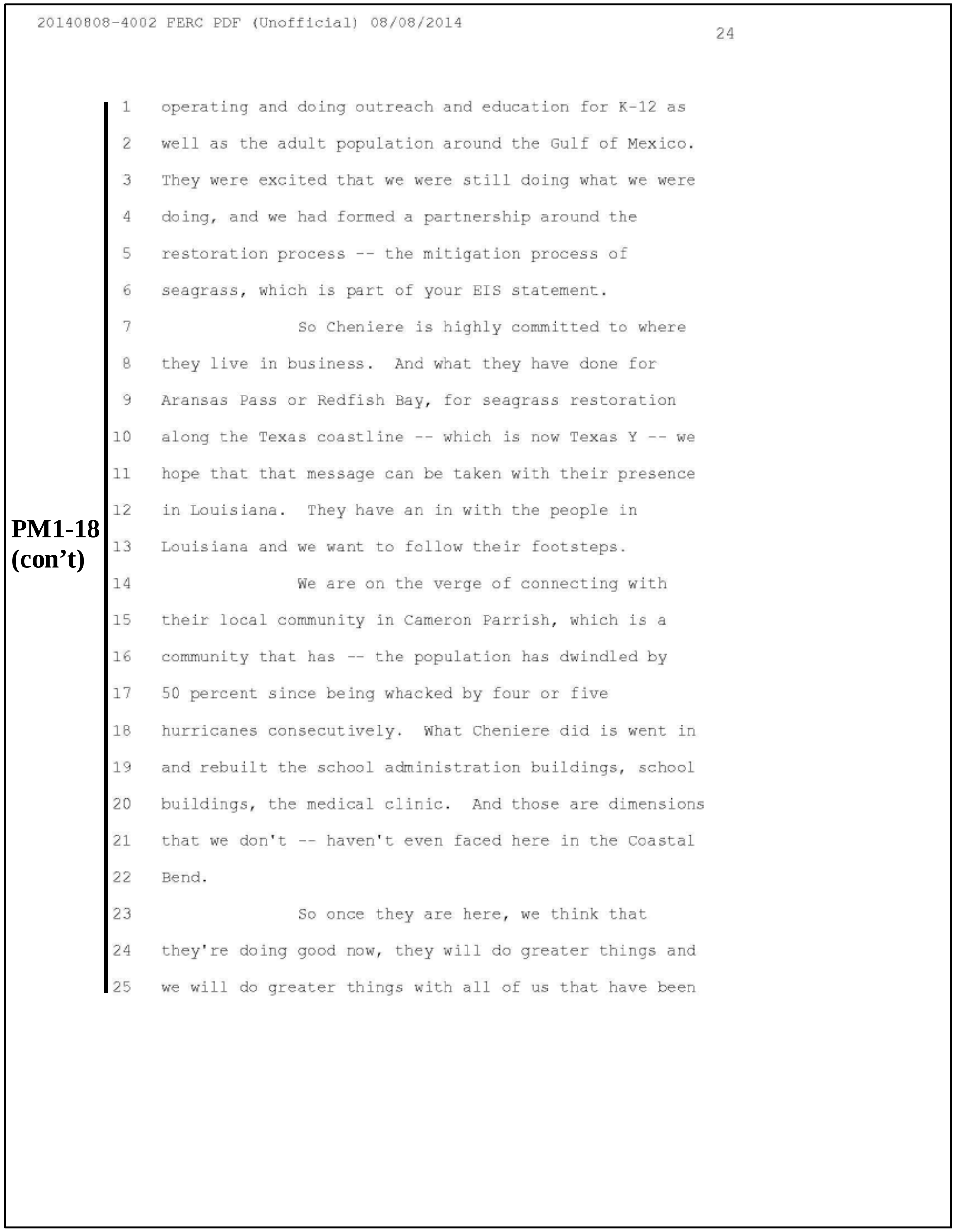
PM1-18 (con't)

your machine does one. I'm a coastal environment educator. I live in San Patricio County. I've lived in this community for 16 years. And as a coastal environment educator, I am a product of where I live in the coastal zone. And Cheniere Energy is also a product of where they do business and where they live.

They not only are coming to our community, have been here for not just the last few years, but we encountered Cheniere almost 10, 11 years ago when they first came to the Coastal Bend region to look at importing LNG. Now they've come back under market conditions to export. And I won't go into the politics -- global politics of the need for energy transfers, but their role will be strategic in global politics as well.

But Cheniere also has a plant in the Louisiana/Texas border. And what Cheniere has done for our program -- the founder and coordinator of the Signs and Spanish Club Network and over the last 14 years, we have embraced our coastal bend and Texas coastal ecology with the focus on the Gulf of Mexico.

And Cheniere Energy has been very involved. They sponsored our first Gulf of Mexico youth leadership and stewardship conference in 2004. When they left town, they came back and found that we were still



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PM1-18 (con't)

operating and doing outreach and education for K-12 as well as the adult population around the Gulf of Mexico. They were excited that we were still doing what we were doing, and we had formed a partnership around the restoration process -- the mitigation process of seagrass, which is part of your EIS statement.

So Cheniere is highly committed to where they live in business. And what they have done for Aransas Pass or Redfish Bay, for seagrass restoration along the Texas coastline -- which is now Texas Y -- we hope that that message can be taken with their presence in Louisiana. They have an in with the people in Louisiana and we want to follow their footsteps.

We are on the verge of connecting with their local community in Cameron Parrish, which is a community that has -- the population has dwindled by 50 percent since being whacked by four or five hurricanes consecutively. What Cheniere did is went in and rebuilt the school administration buildings, school buildings, the medical clinic. And those are dimensions that we don't -- haven't even faced here in the Coastal Bend.

So once they are here, we think that they're doing good now, they will do greater things and we will do greater things with all of us that have been

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PM1-18 (con't)

partnered with them in the last few years in the Coastal Bend. So I hope that we'll begin the permanent process so they can move on and we can all move on in making this a better Gulf of Mexico community. Thank you.

PM1-19

MS. COLETTE WALLS: Good evening. My name is Colette Walls, C-O-L-E-T-T-E, W-A-L-L-S, and I'm the president and CEO of the Portland chamber of commerce. It's my pleasure to speak to you this evening on behalf of the 300-plus members of the Portland chamber of commerce. The Portland business community is very supportive of the Cheniere LNG facility. Our communities have been planning for this project for some years now and have been working diligently to be prepared for the economic impact this facility will provide.

It is an exciting time for our community. Cheniere alone will provide 3,500 construction jobs and 350 permanent jobs. This will be a 13 billion dollar investment for Cheniere. This will also be a 13 billion dollar investment for the future of our children. These are great numbers and very exciting.

However, these numbers do not reflect the true economic impact Cheniere's facility will have on our business community in Portland. The sky is the limit for our chamber business members. With the

PM1-19: Comment acknowledged.

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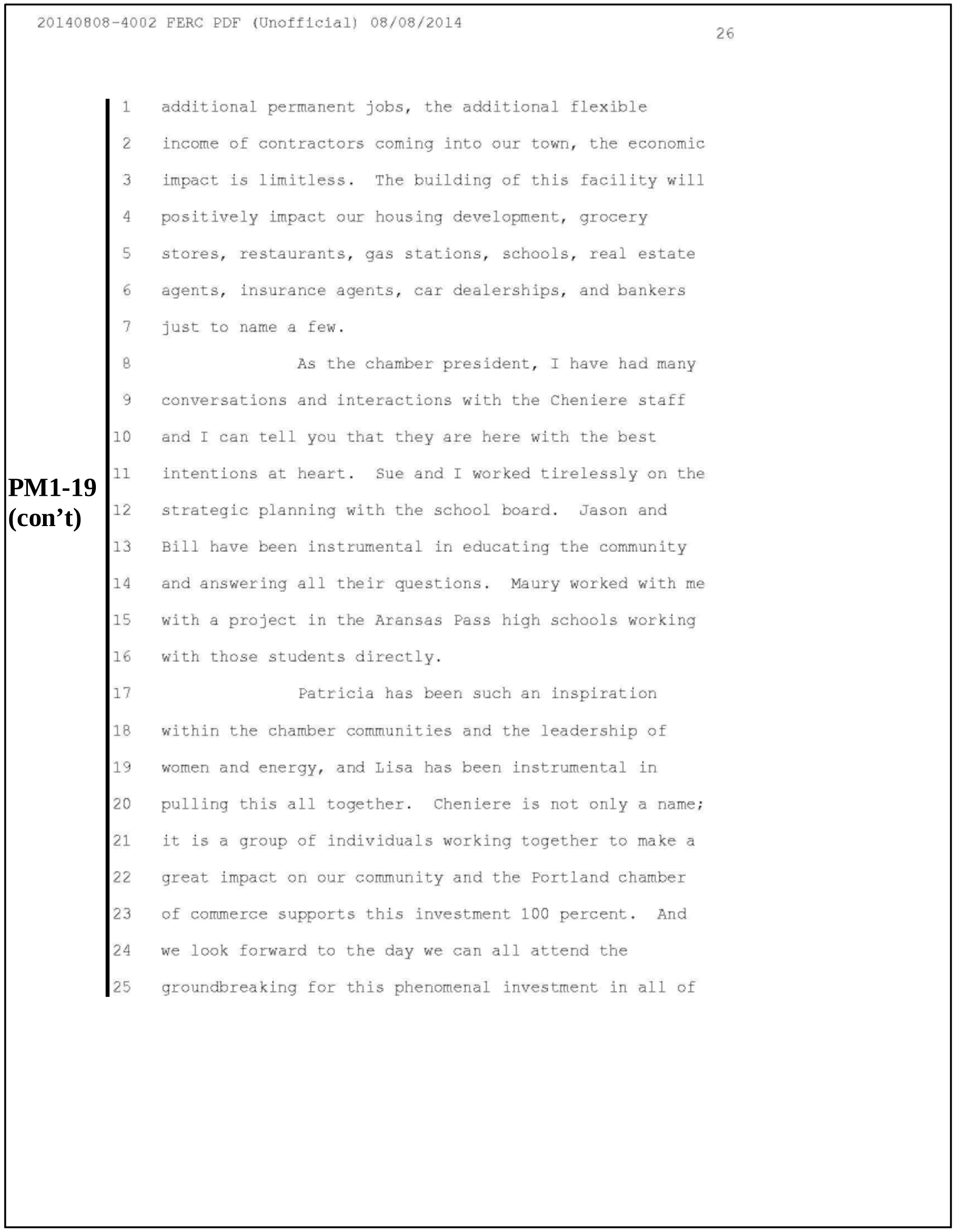

PM1-19 (con't)

additional permanent jobs, the additional flexible income of contractors coming into our town, the economic impact is limitless. The building of this facility will positively impact our housing development, grocery stores, restaurants, gas stations, schools, real estate agents, insurance agents, car dealerships, and bankers just to name a few.

As the chamber president, I have had many conversations and interactions with the Cheniere staff and I can tell you that they are here with the best intentions at heart. Sue and I worked tirelessly on the strategic planning with the school board. Jason and Bill have been instrumental in educating the community and answering all their questions. Maury worked with me with a project in the Aransas Pass high schools working with those students directly.

Patricia has been such an inspiration within the chamber communities and the leadership of women and energy, and Lisa has been instrumental in pulling this all together. Cheniere is not only a name; it is a group of individuals working together to make a great impact on our community and the Portland chamber of commerce supports this investment 100 percent. And we look forward to the day we can all attend the groundbreaking for this phenomenal investment in all of

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our futures. Thank you.

MS. BARAKAT: The next three signed up are George (sic) Neblett, Ann V-A-U-G-H-A-N is the last name, and Tom Shamia. I'm sorry, I'm butchering people's last names.

PM1-20

MS. GEORGIA NEBLETT: My name is Georgia Neblett, G-E-O-R-G-I-A, N-E-B-L-E-T-T, and I'm speaking on behalf of myself. I have a long history with Cheniere. I was mayor at the time they were expecting to import the natural gas. Cheniere as you have heard have been wonderful community supporters. They've really become actively involved. To say more about that would be reiteration, but they've also demonstrated their environmental stewardship not with words but with dollars. Whether it is protecting an eroded shoreline or protecting a bird sanctuary, they have put their money where their heart is and that is in environmental stewardship. So I believe that the environmental issues involved in this will be well taken care of and will be supported by their community and corporate intentions to have fine stewardship of the environment. Thank you.

MS. ANN VAUGHAN: Ann Vaughan, A-N-N, V-A-U-G-H-A-N, and I'm the president and CEO of the Port Aransas chamber of commerce. And that's where Georgia's from. I don't know if she said she's from Port Aransas.

PM1-20: Comment acknowledged.

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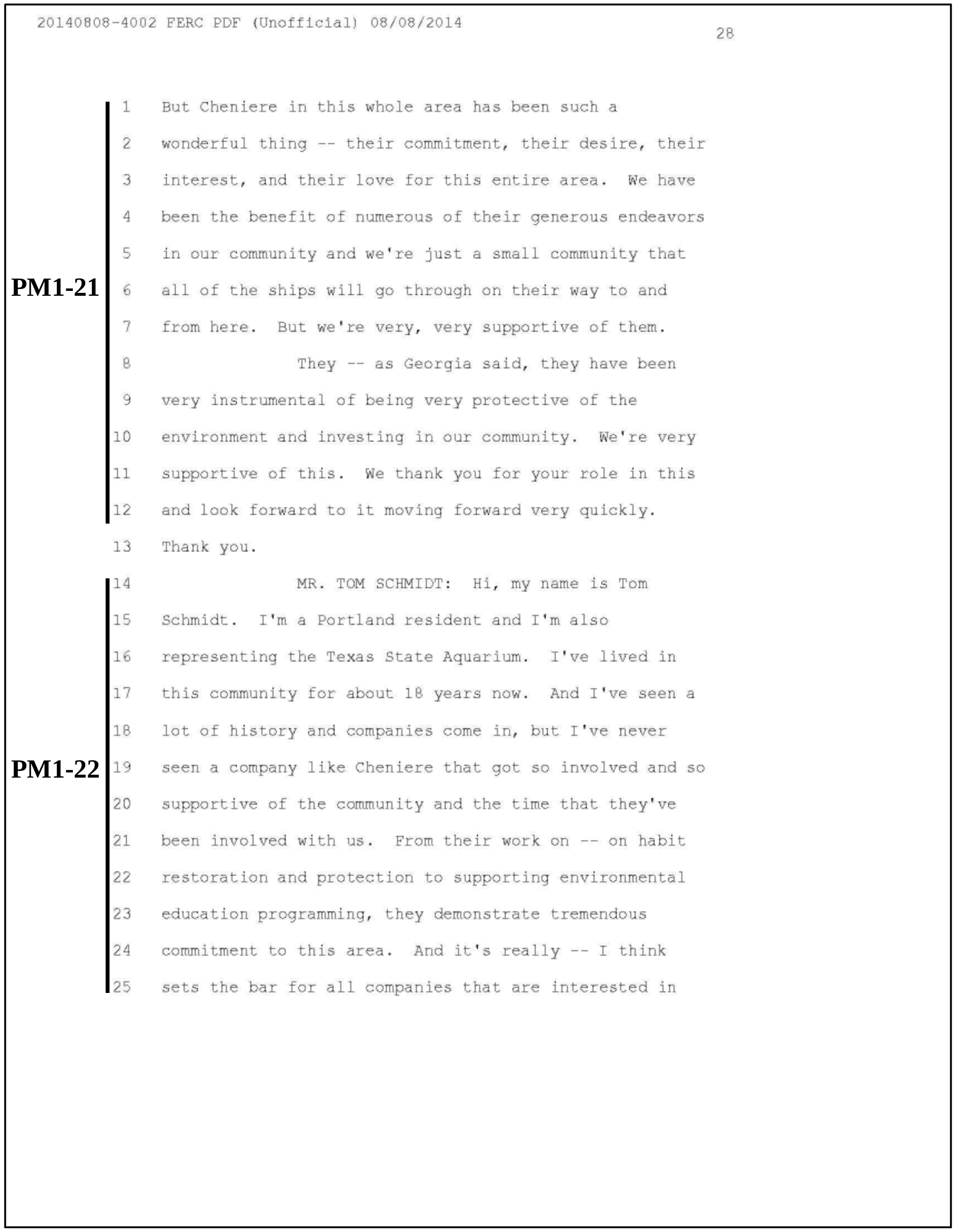


PM1-21

But Cheniere in this whole area has been such a wonderful thing -- their commitment, their desire, their interest, and their love for this entire area. We have been the benefit of numerous of their generous endeavors in our community and we're just a small community that all of the ships will go through on their way to and from here. But we're very, very supportive of them.

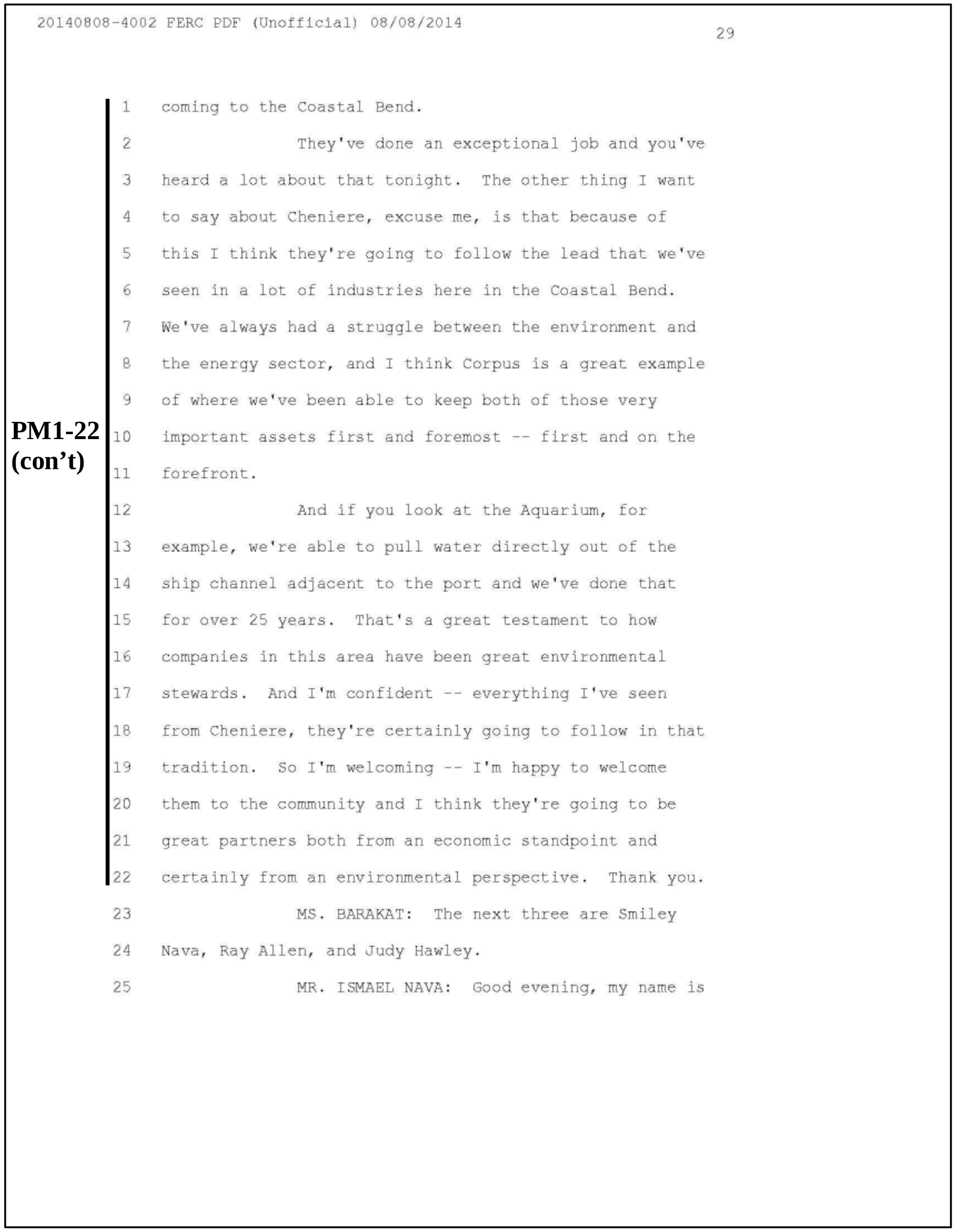
They -- as Georgia said, they have been very instrumental of being very protective of the environment and investing in our community. We're very supportive of this. We thank you for your role in this and look forward to it moving forward very quickly. Thank you.

PM1-22

MR. TOM SCHMIDT: Hi, my name is Tom Schmidt. I'm a Portland resident and I'm also representing the Texas State Aquarium. I've lived in this community for about 18 years now. And I've seen a lot of history and companies come in, but I've never seen a company like Cheniere that got so involved and so supportive of the community and the time that they've been involved with us. From their work on -- on habit restoration and protection to supporting environmental education programming, they demonstrate tremendous commitment to this area. And it's really -- I think sets the bar for all companies that are interested in

PM1-21: Comment acknowledged.

PM1-22: Comment acknowledged.



PM1-22 (con't)

coming to the Coastal Bend.

They've done an exceptional job and you've heard a lot about that tonight. The other thing I want to say about Cheniere, excuse me, is that because of this I think they're going to follow the lead that we've seen in a lot of industries here in the Coastal Bend. We've always had a struggle between the environment and the energy sector, and I think Corpus is a great example of where we've been able to keep both of those very important assets first and foremost -- first and on the forefront.

And if you look at the Aquarium, for example, we're able to pull water directly out of the ship channel adjacent to the port and we've done that for over 25 years. That's a great testament to how companies in this area have been great environmental stewards. And I'm confident -- everything I've seen from Cheniere, they're certainly going to follow in that tradition. So I'm welcoming -- I'm happy to welcome them to the community and I think they're going to be great partners both from an economic standpoint and certainly from an environmental perspective. Thank you.

MS. BARAKAT: The next three are Smiley Nava, Ray Allen, and Judy Hawley.

MR. ISMAEL NAVA: Good evening, my name is

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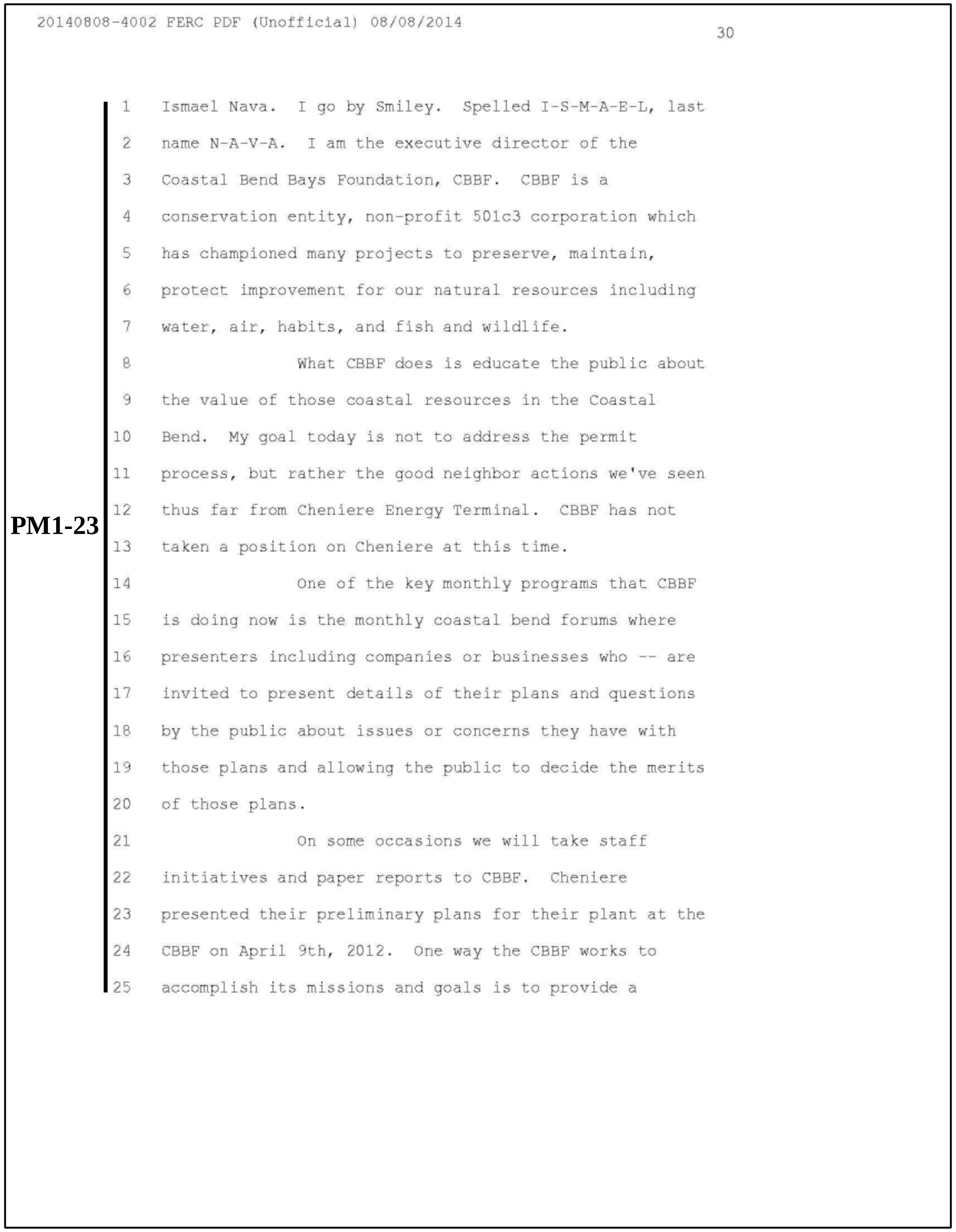

PM1-23

Ismael Nava. I go by Smiley. Spelled I-S-M-A-E-L, last name N-A-V-A. I am the executive director of the Coastal Bend Bays Foundation, CBBF. CBBF is a conservation entity, non-profit 501c3 corporation which has championed many projects to preserve, maintain, protect improvement for our natural resources including water, air, habits, and fish and wildlife.

What CBBF does is educate the public about the value of those coastal resources in the Coastal Bend. My goal today is not to address the permit process, but rather the good neighbor actions we've seen thus far from Cheniere Energy Terminal. CBBF has not taken a position on Cheniere at this time.

One of the key monthly programs that CBBF is doing now is the monthly coastal bend forums where presenters including companies or businesses who -- are invited to present details of their plans and questions by the public about issues or concerns they have with those plans and allowing the public to decide the merits of those plans.

On some occasions we will take staff initiatives and paper reports to CBBF. Cheniere presented their preliminary plans for their plant at the CBBF on April 9th, 2012. One way the CBBF works to accomplish its missions and goals is to provide a

PM1-23: Comment acknowledged.

PM1-23 (con't)

partnership with businesses who have a desire to invest in their local environment, to provide opportunities that instill stewardship and a sense of ownership of our natural resources.

CBBF is committed to providing ways to develop stewardship by planning outdoor volunteer events. Examples include projects to restore destabilized wetlands in Nueces Bay and shoreline cleanups, such as the Nueces Causeway and Packery Channel Preserve on Mustang Island. And CBBF is involved in these cleanups.

You may ask where does Cheniere fit into the CBBF planning and its goals. Well, CBBF depends on those sponsors from all public sectors such as state, federal, local government organizations for funding. It also depends on local businesses such as the oil and gas industries, local companies, and other non-profit businesses for support.

Cheniere is one of those organizations which in the last two-plus years has stepped up to give back to the community and to the CBBF in planning some specific programs and events. The environmental community in the Coastal Bend, Cheniere's contributed to multiple organizations and community natural resource efforts and events. For its effort, Cheniere was

PM1-23 (con't)

nominated by and selected by an independent committee to receive the Coastal Bend Bays Foundation's 2013 conservation and environmental stewardship award for industry.

They're instrumental in protecting bays and estuaries, Coastal Bend bays, and has enhanced drilling areas on the causeway using bay drilling. Cheniere also sponsored an education and outreach field trip for more than 200 students to teach them about the importance of preserving natural habitat, plants, and animals. And that was Richard Gonzales' program, by the way.

Cheniere has also been involved in multiple habitat protection projects such as protecting critical wetlands and other sensitive areas. So based on this, CBBF has established a working relationship with Cheniere and keep good relationships like Bill English and Sue Zimmerman to name a few.

It is CBBF's resolve to stand by and engage with partners such as Cheniere no matter the outcome of the permitting process, the idea that open communication and conservation of the Coastal Bend wetlands and natural resources as we look into the future of opportunities which may come our way. We're very thankful for that. Thank you again for this opportunity to address FERC.

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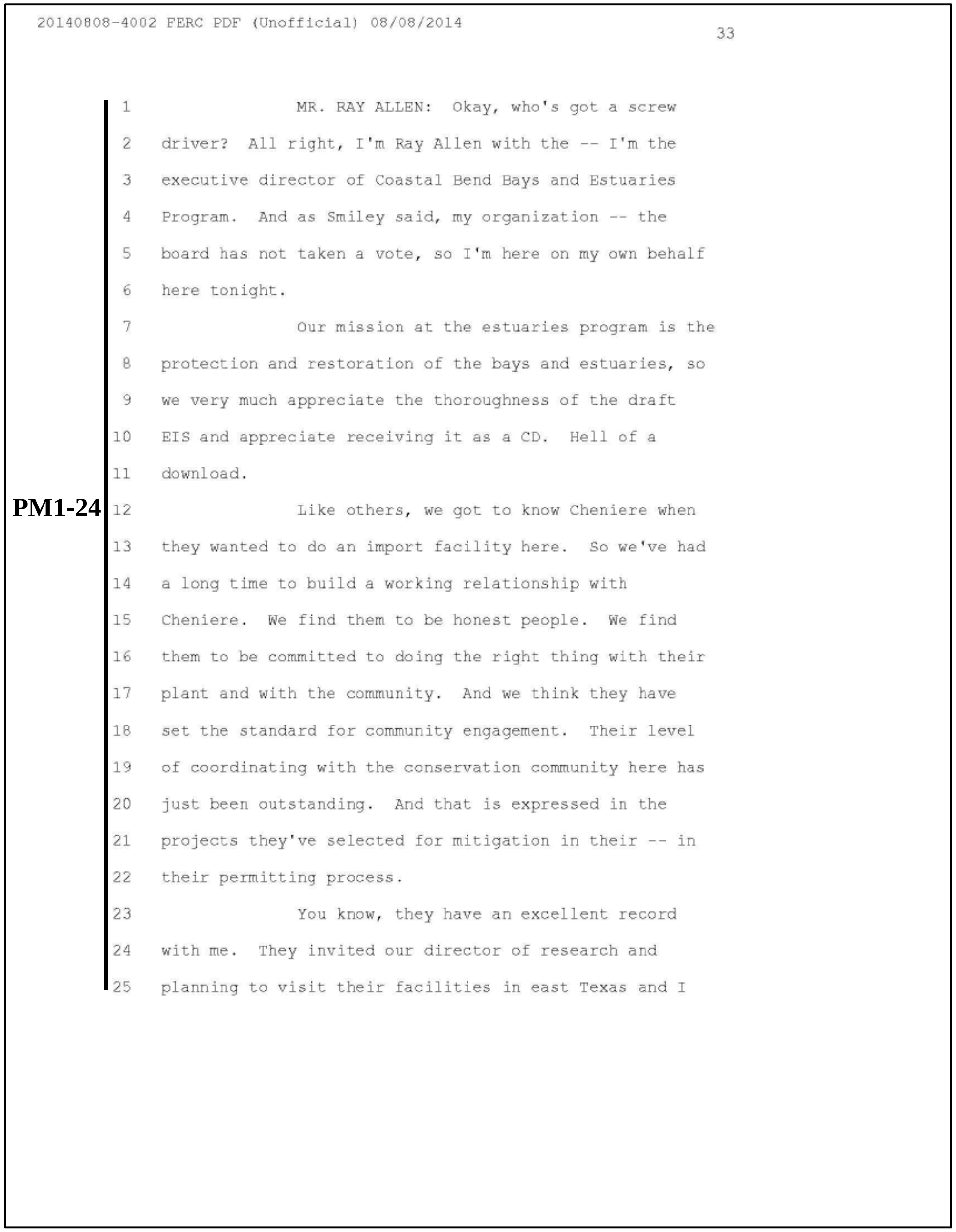

MR. RAY ALLEN: Okay, who's got a screw driver? All right, I'm Ray Allen with the -- I'm the executive director of Coastal Bend Bays and Estuaries Program. And as Smiley said, my organization -- the board has not taken a vote, so I'm here on my own behalf here tonight.

Our mission at the estuaries program is the protection and restoration of the bays and estuaries, so we very much appreciate the thoroughness of the draft EIS and appreciate receiving it as a CD. Hell of a download.

PM1-24

Like others, we got to know Cheniere when they wanted to do an import facility here. So we've had a long time to build a working relationship with Cheniere. We find them to be honest people. We find them to be committed to doing the right thing with their plant and with the community. And we think they have set the standard for community engagement. Their level of coordinating with the conservation community here has just been outstanding. And that is expressed in the projects they've selected for mitigation in their -- in their permitting process.

You know, they have an excellent record with me. They invited our director of research and planning to visit their facilities in east Texas and I

PM1-24: Comment acknowledged.

PM1-24 (con't)

was quite impressed with the way they maintained the facility and how they interacted with the community. We like that.

You know, when it comes to selecting a site for a facility like this, it's all about location. From our perspective, we're more concerned about the bays and estuaries. We very much prefer to see industry come in and locate on existing navigation channels. They don't have to have -- surely have to do a little bit of dredging for their dock facilities, but they're locating on an existing major channel. It minimizes the impact. It really does allow for them to come in and have a very small impact on the bay resource.

There was a mention earlier about air and water discharge permits, air permits. You know, we have a high degree of confidence in the TCEQ and the EPA that -- and Cheniere also that they'll be making efforts to comply with their discharge permits and we appreciate that.

The proposed mitigation plan and the Associated Core of Engineers permit is something we are aware of that there's still some comments out there on the amendment to the permit from some of the resource agencies. They tend to be clarifying comments and some minor wording issues. In all, it's not very often you

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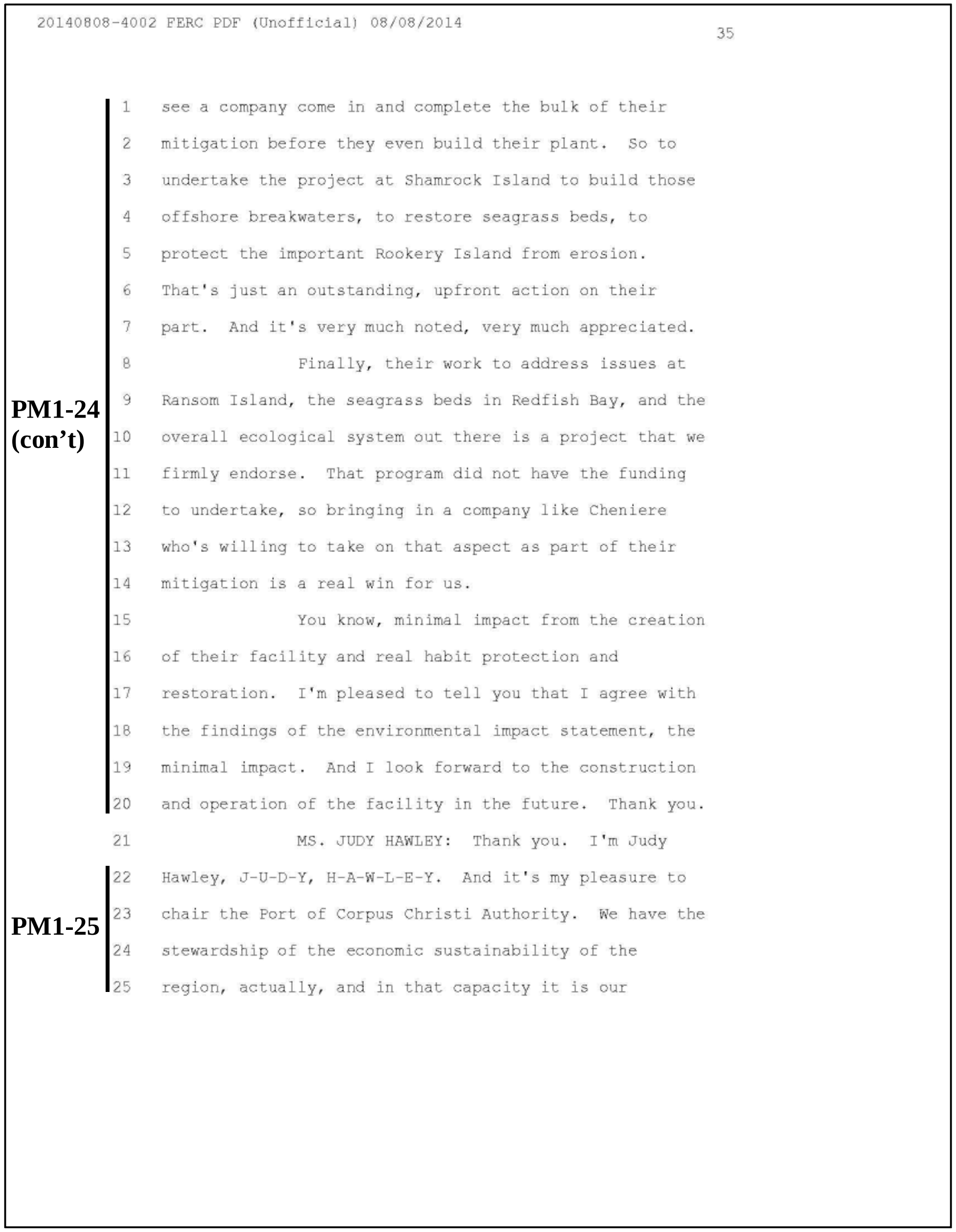

PM1-24 (con't)

see a company come in and complete the bulk of their mitigation before they even build their plant. So to undertake the project at Shamrock Island to build those offshore breakwaters, to restore seagrass beds, to protect the important Rookery Island from erosion. That's just an outstanding, upfront action on their part. And it's very much noted, very much appreciated.

Finally, their work to address issues at Ransom Island, the seagrass beds in Redfish Bay, and the overall ecological system out there is a project that we firmly endorse. That program did not have the funding to undertake, so bringing in a company like Cheniere who's willing to take on that aspect as part of their mitigation is a real win for us.

You know, minimal impact from the creation of their facility and real habit protection and restoration. I'm pleased to tell you that I agree with the findings of the environmental impact statement, the minimal impact. And I look forward to the construction and operation of the facility in the future. Thank you.

MS. JUDY HAWLEY: Thank you. I'm Judy

PM1-25

Hawley, J-U-D-Y, H-A-W-L-E-Y. And it's my pleasure to chair the Port of Corpus Christi Authority. We have the stewardship of the economic sustainability of the region, actually, and in that capacity it is our

PM1-25: Comment acknowledged.

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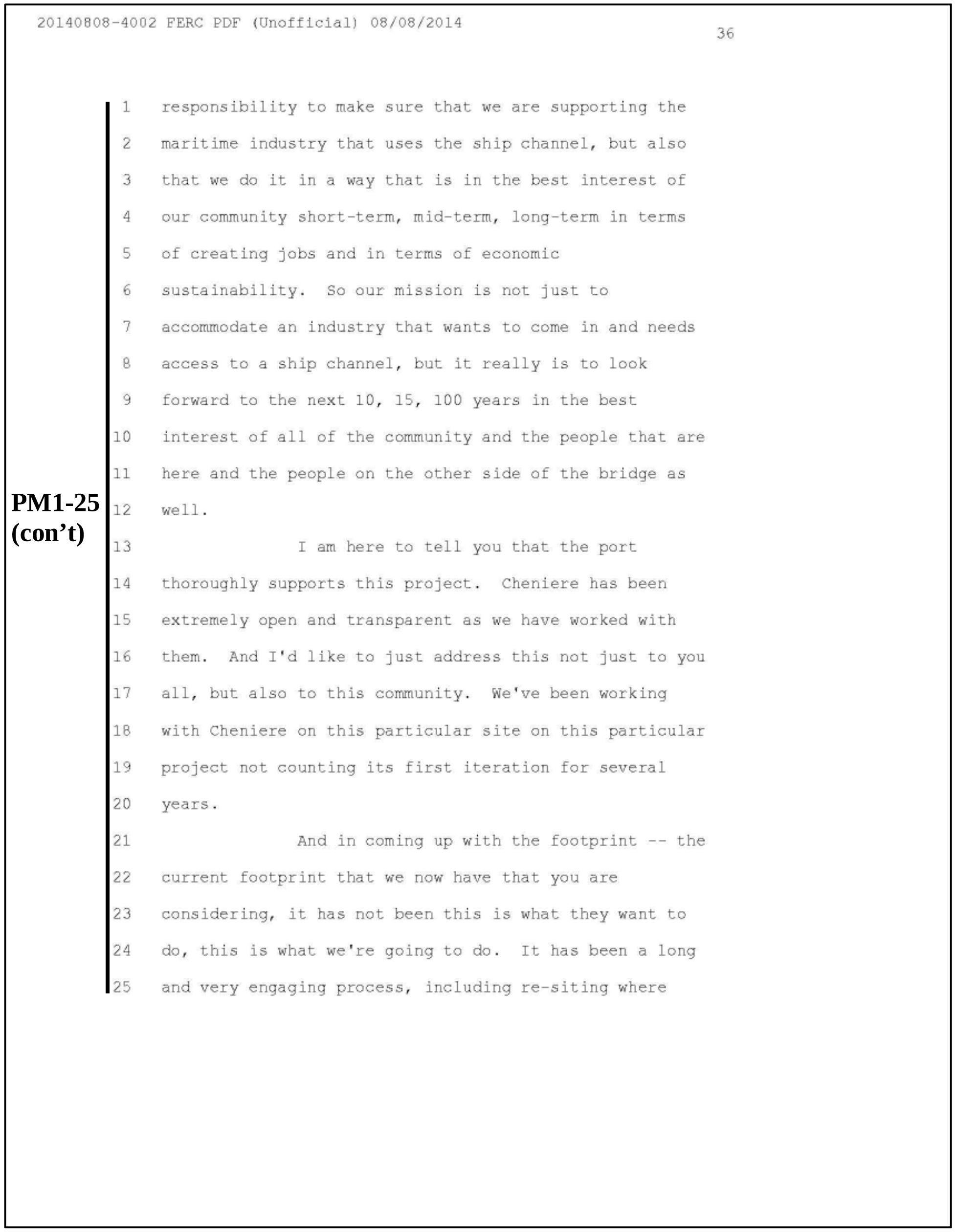
PM1-25 (con't)



responsibility to make sure that we are supporting the maritime industry that uses the ship channel, but also that we do it in a way that is in the best interest of our community short-term, mid-term, long-term in terms of creating jobs and in terms of economic sustainability. So our mission is not just to accommodate an industry that wants to come in and needs access to a ship channel, but it really is to look forward to the next 10, 15, 100 years in the best interest of all of the community and the people that are here and the people on the other side of the bridge as well.

I am here to tell you that the port thoroughly supports this project. Cheniere has been extremely open and transparent as we have worked with them. And I'd like to just address this not just to you all, but also to this community. We've been working with Cheniere on this particular site on this particular project not counting its first iteration for several years.

And in coming up with the footprint -- the current footprint that we now have that you are considering, it has not been this is what they want to do, this is what we're going to do. It has been a long and very engaging process, including re-siting where

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their facility is going to be on that piece of property. How do we make the piers that they need to be as -- to interfere in the least possible way with the ship traffic that's going to be coming on? How do we help them be better neighbors to the other industries that are already there? How do we pull all those pieces together in the most harmonious, most efficient, safest, most environmentally-sound way for the industries that are there and for the communities that surround them?

And we've gone through many iterations of what that footprint might look like. Cheniere and the port have worked together with the pilots for Cheniere, of the Coast Guard, certainly with their communities on all of these issues for a number of years and with their neighbors.

I have four points. My first point is we have vetted the Cheniere process, their footprint, their processes, their environmental impact, many different ways from engineering to environmental to the community impact through the port.

Second point is that I, too, was privileged to go up and see the Sabine Pass operations. It's easy to come into a community, throw a little money around, and say we're good stewards. We went up there to see the Sabine Pass operation and and I can tell you safety

PM1-25 (con't)

was phenomenal, environmental considerations were amazing. They had four tug boats there that you could eat off the floor. Cleanest, most efficient operations you've ever seen in terms of taking care of what goes into the water, taking care of the impact on their side.

Thirdly, I'd like to say they've been a model of transparency of forthrightness of the community. You would not have this many people standing up to say we have a question and an answer. They've answered it many, many, times. They've been in many small forums and many large forums. And that builds confidence from the people in this room, from the people at the port, and from the people in my neighborhood. I live in Portland as well.

And my final point is a little broader in reach. I had an opportunity to testify in front of Congress a couple of months ago. And the issue was about the export of natural gas and its impact on not only South Texas but on the United States. And one of the pieces that became very, very clear as I visited with Congress and with most of the members of that committee was that this balance of trade issue is extremely important. And having the ability to export LNG in the United States and certainly here in South Texas is going to go a long way to helping the current

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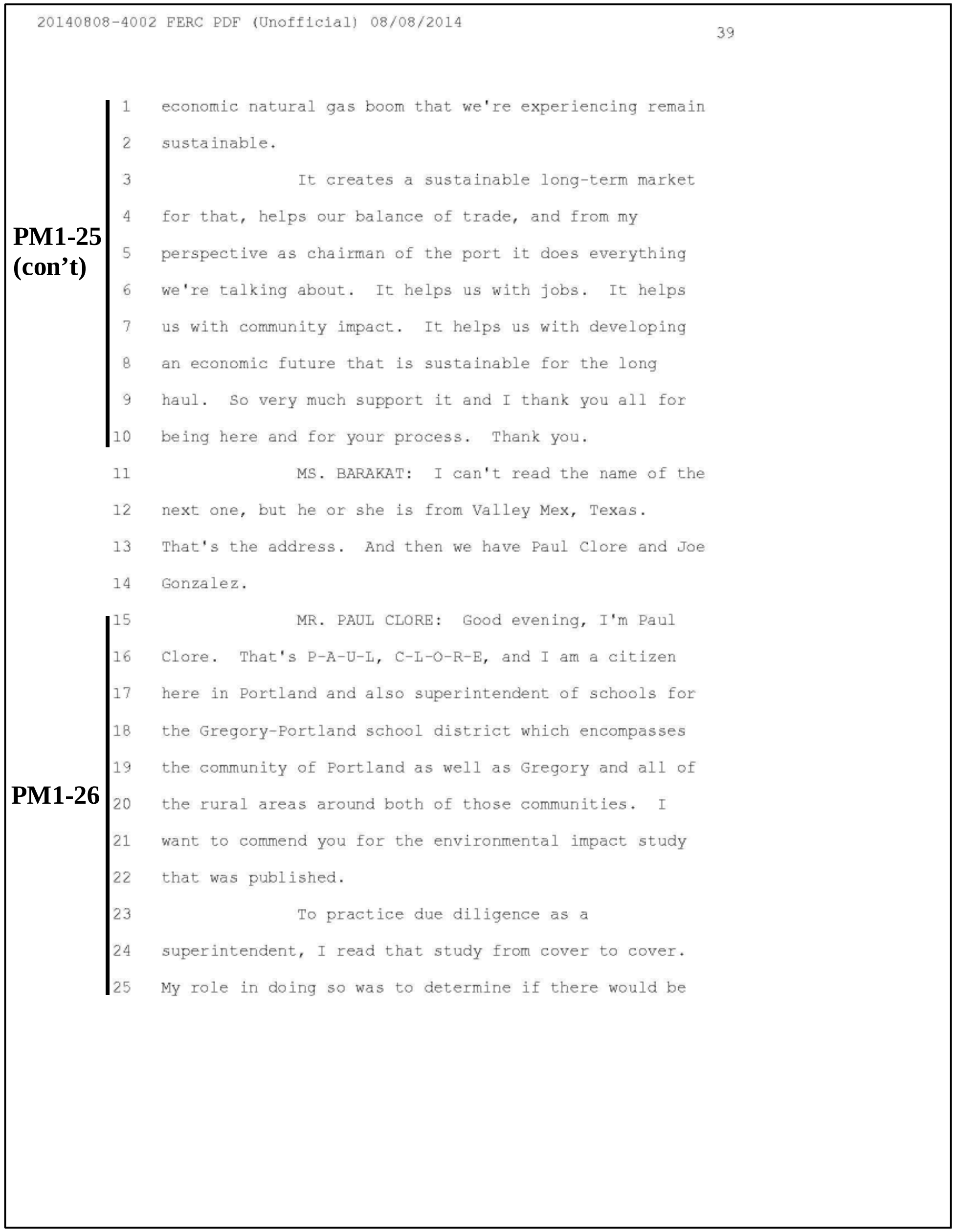

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PM1-25 (con't)

economic natural gas boom that we're experiencing remain sustainable.

It creates a sustainable long-term market for that, helps our balance of trade, and from my perspective as chairman of the port it does everything we're talking about. It helps us with jobs. It helps us with community impact. It helps us with developing an economic future that is sustainable for the long haul. So very much support it and I thank you all for being here and for your process. Thank you.

MS. BARAKAT: I can't read the name of the next one, but he or she is from Valley Mex, Texas. That's the address. And then we have Paul Clore and Joe Gonzalez.

PM1-26

MR. PAUL CLORE: Good evening, I'm Paul Clore. That's P-A-U-L, C-L-O-R-E, and I am a citizen here in Portland and also superintendent of schools for the Gregory-Portland school district which encompasses the community of Portland as well as Gregory and all of the rural areas around both of those communities. I want to commend you for the environmental impact study that was published.

To practice due diligence as a superintendent, I read that study from cover to cover. My role in doing so was to determine if there would be

PM1-26: Comment acknowledged.

PM1-26 (con't)

any impact from Cheniere on our school district -- we have seven campuses -- whether it be noise pollution, air quality issues, or anything else. I can tell you without reservation that I had no concerns about any of what was contained within your report as it would impact our school district.

I can also tell you that having been superintendent of schools here for 13 years I have worked in partnership with Cheniere and their representatives for about ten of those 13 years, so I have quite a bit of experience working with them on different applications that they have brought forward.

I want to tell you that they do put their money where their heart is. This time they came to us and asked if we would consider developing an introduction to process technology course that we could begin teaching at high school this coming August. They offered to sit down and co-write the curriculum for that course with us and with Del Mar College. All of us did that collaboratively, and I'm happy to tell you that we will start teaching that course this coming -- again, this August of the coming school year. And we intend to expand those courses to meet student needs and to help provide workforce for business and industry including Cheniere as we go forward in time.

PM1-26 (con't)

Let me tell you how seriously they took that role. Not only did they commit their executive leadership time to help us write the course, but they then turned around and offered to support purchase of the instructional program and software material up to $50,000 which has been done now. And that is what we will use as part of the information to teach the course.

In addition to that, they did take me along with the other people you have heard from this evening to Sabine Pass so that I as a superintendent of schools could see what the plant that they are building here would look like and so they could answer any questions that I might have.

And in addition to that, they have encouraged us to develop a student leadership program in which students in Gregory-Portland High School can identify projects here in the local community that students would like to work on in order to maintain the improvements within the community. And Cheniere is offering to underwrite that program on an annual basis moving forward.

Anytime anything comes up, if we have a question or a concern, we go to them without hesitation with confidence that they will step forward and address whatever needs and concerns there are. Based on my

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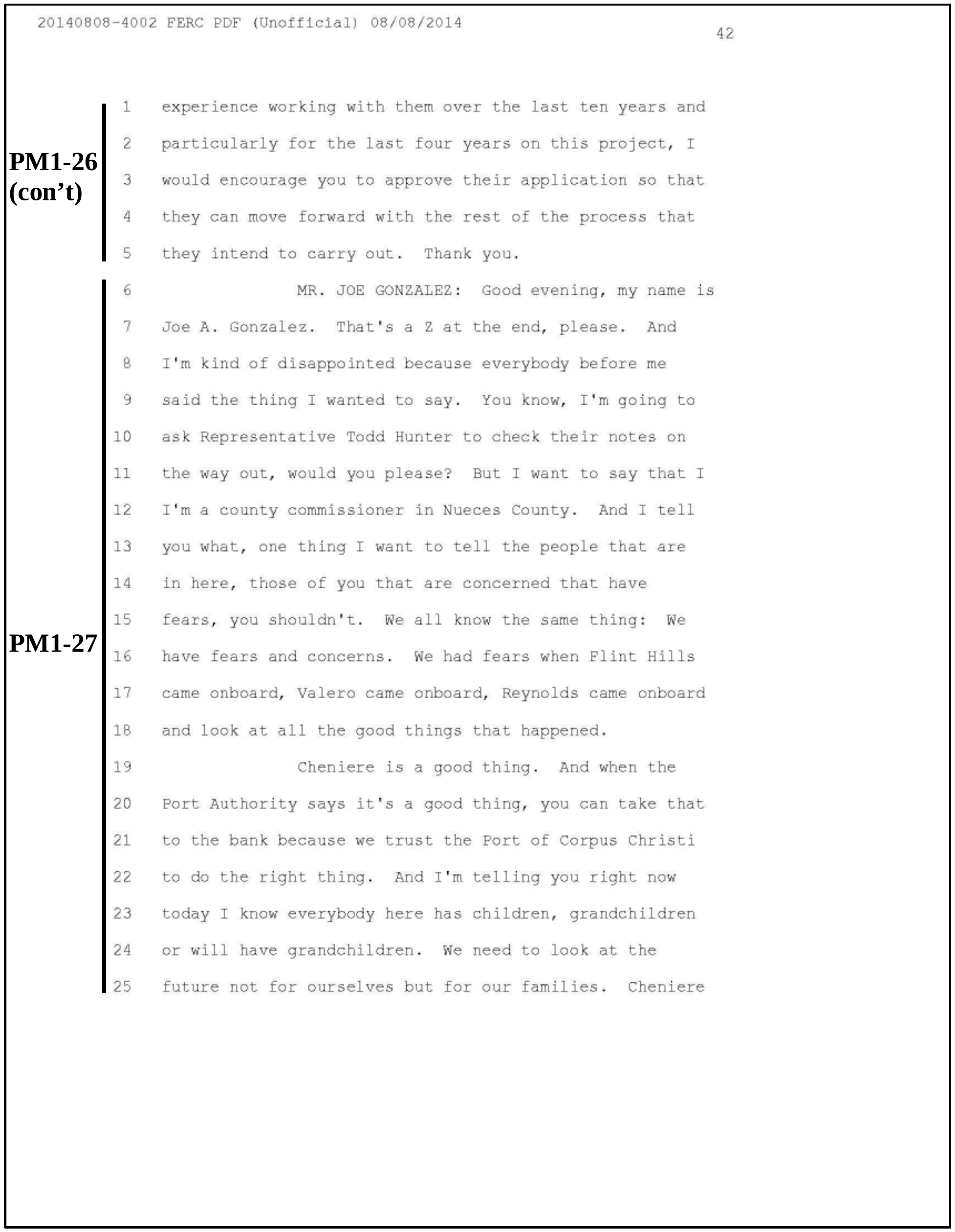

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PM1-26 (con't)

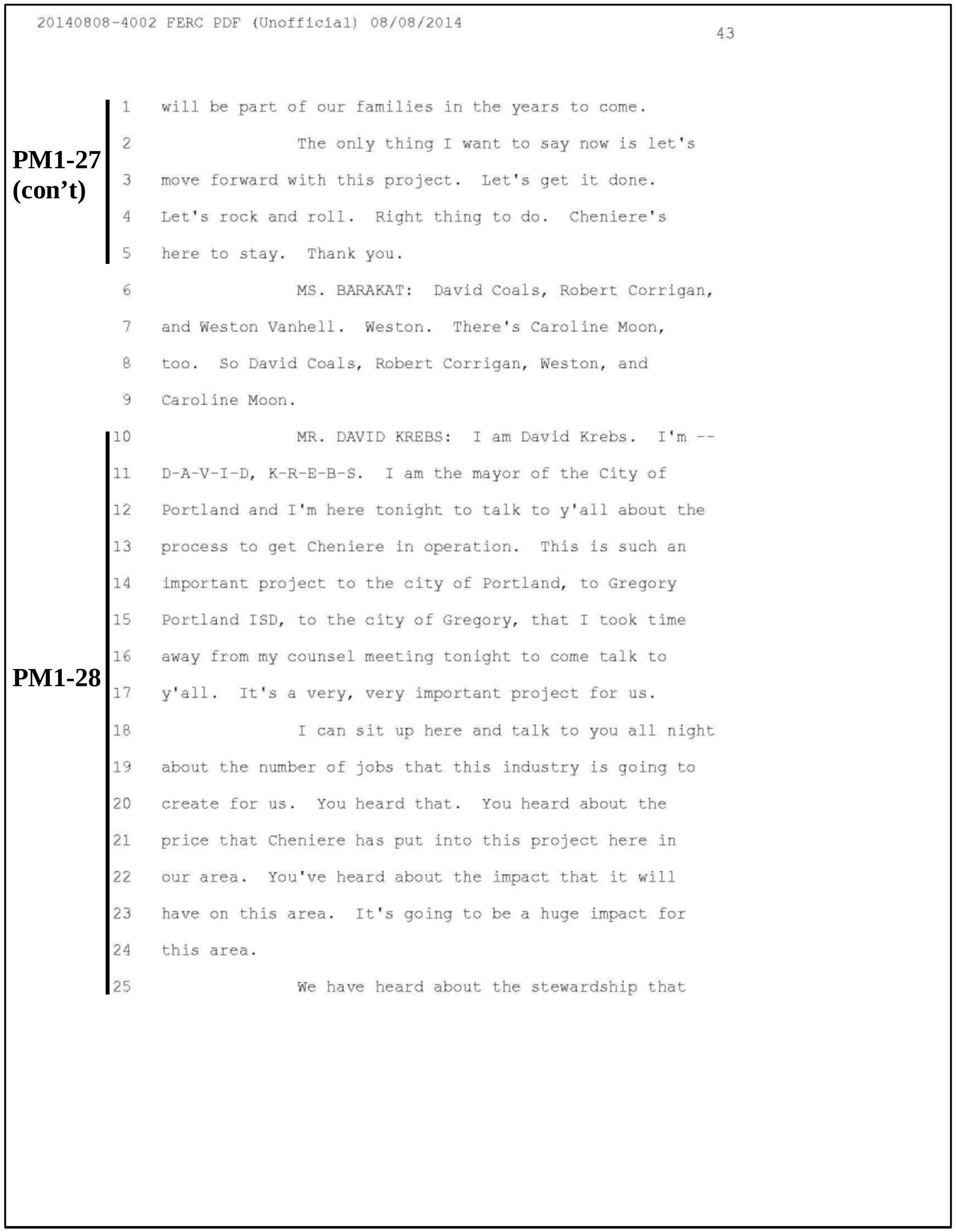
experience working with them over the last ten years and particularly for the last four years on this project, I would encourage you to approve their application so that they can move forward with the rest of the process that they intend to carry out. Thank you.

PM1-27

MR. JOE GONZALEZ: Good evening, my name is Joe A. Gonzalez. That's a Z at the end, please. And I'm kind of disappointed because everybody before me said the thing I wanted to say. You know, I'm going to ask Representative Todd Hunter to check their notes on the way out, would you please? But I want to say that I I'm a county commissioner in Nueces County. And I tell you what, one thing I want to tell the people that are in here, those of you that are concerned that have fears, you shouldn't. We all know the same thing: We have fears and concerns. We had fears when Flint Hills came onboard, Valero came onboard, Reynolds came onboard and look at all the good things that happened.

Cheniere is a good thing. And when the Port Authority says it's a good thing, you can take that to the bank because we trust the Port of Corpus Christi to do the right thing. And I'm telling you right now today I know everybody here has children, grandchildren or will have grandchildren. We need to look at the future not for ourselves but for our families. Cheniere

PM1-27: Comment acknowledged.



PM1-27 (con't)

will be part of our families in the years to come.

The only thing I want to say now is let's move forward with this project. Let's get it done. Let's rock and roll. Right thing to do. Cheniere's here to stay. Thank you.

MS. BARAKAT: David Coals, Robert Corrigan, and Weston Vanhell. Weston. There's Caroline Moon, too. So David Coals, Robert Corrigan, Weston, and Caroline Moon.

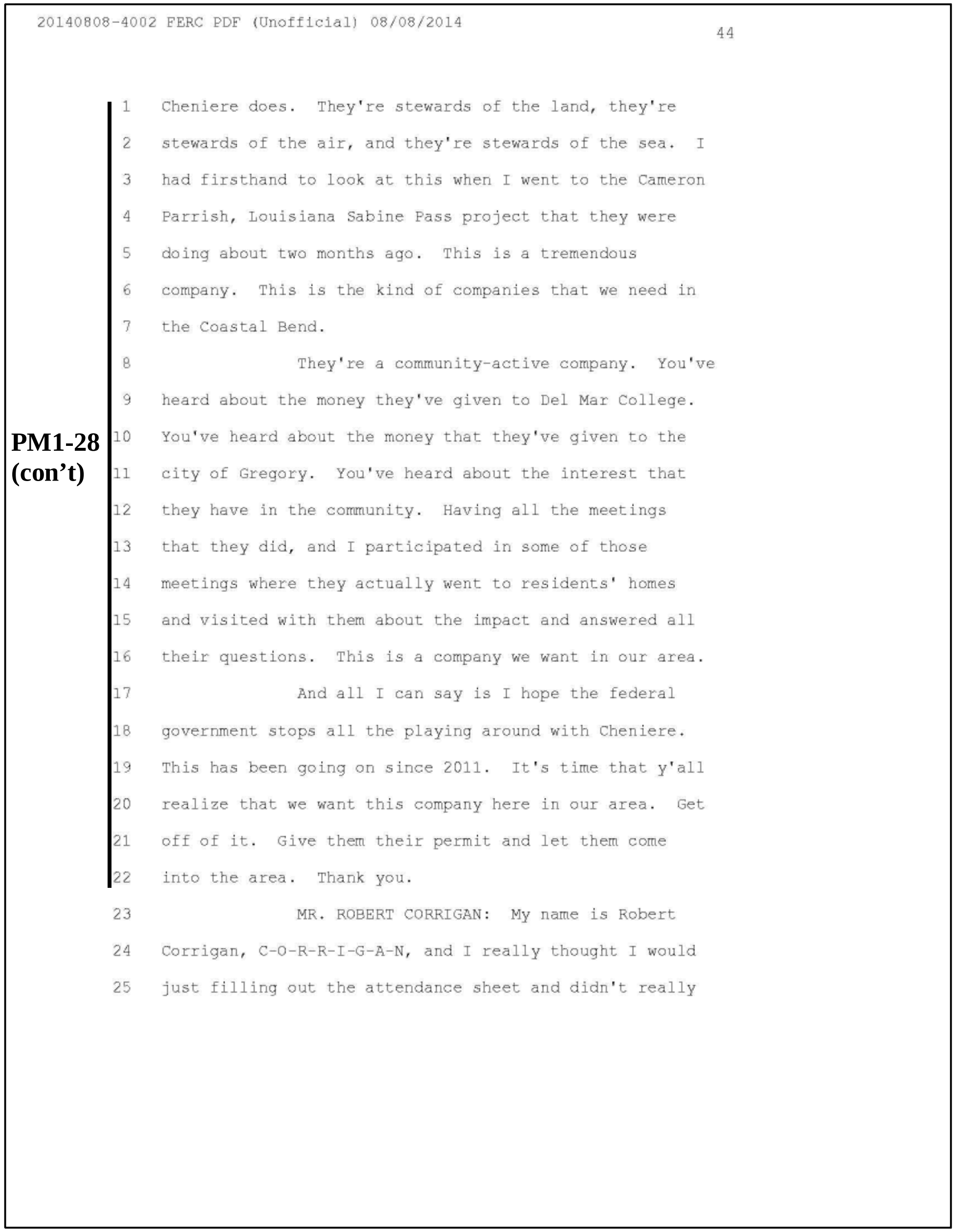
PM1-28

MR. DAVID KREBS: I am David Krebs. I'm -- D-A-V-I-D, K-R-E-B-S. I am the mayor of the City of Portland and I'm here tonight to talk to y'all about the process to get Cheniere in operation. This is such an important project to the city of Portland, to Gregory Portland ISD, to the city of Gregory, that I took time away from my counsel meeting tonight to come talk to y'all. It's a very, very important project for us.

I can sit up here and talk to you all night about the number of jobs that this industry is going to create for us. You heard that. You heard about the price that Cheniere has put into this project here in our area. You've heard about the impact that it will have on this area. It's going to be a huge impact for this area.

We have heard about the stewardship that

PM1-28: Comment acknowledged.



PM1-28 (con't)

Cheniere does. They're stewards of the land, they're stewards of the air, and they're stewards of the sea. I had firsthand to look at this when I went to the Cameron Parrish, Louisiana Sabine Pass project that they were doing about two months ago. This is a tremendous company. This is the kind of companies that we need in the Coastal Bend.

They're a community-active company. You've heard about the money they've given to Del Mar College. You've heard about the money that they've given to the city of Gregory. You've heard about the interest that they have in the community. Having all the meetings that they did, and I participated in some of those meetings where they actually went to residents' homes and visited with them about the impact and answered all their questions. This is a company we want in our area.

And all I can say is I hope the federal government stops all the playing around with Cheniere. This has been going on since 2011. It's time that y'all realize that we want this company here in our area. Get off of it. Give them their permit and let them come into the area. Thank you.

MR. ROBERT CORRIGAN: My name is Robert Corrigan, C-O-R-R-I-G-A-N, and I really thought I would just filling out the attendance sheet and didn't really

PM1 – Corpus Christi LNG Transcript from Public Meeting

PM1-29

intend to get up and talk. I have been involved with the environmental community as a volunteer I guess since 1971 and extensively here. I'm on the -- had been on the board for the bays and estuaries program for 11 or 12 years. The DUCCA, Coastal Bend Bays Foundation, a member of that. I'm just going to make a real short comment.

I probably know over 50, maybe 60 percent of the people that stood up here today. And I know they have the fire and the gut about the environment. I've seen this -- these permittings go before and some of them haven't been a very pretty sight. But in this situation I haven't heard one person who is concerned about the resource come out with any objections.

And that means a tremendous amount to make sure that -- I know all the things Cheniere's done is wonderful, but most important to me is the fact that the people that I know that are the stewards of the resource are saying let's let this happen.

And I hope that -- and thank you all from the EPA for being here, and I hope you all expedite getting this permitting done and let this great company come to Corpus Christi. Thank you.

MR. CELESTINO ZAMARANO: Hello, my name is Celestino Zamarano. That's C-E-L-E-S-T-I-N-O, last name

PM1-29: Comment acknowledged.

PUBLIC MEETING TRANSCRIPT COMMENTS

PM1 – Corpus Christi LNG Transcript from Public Meeting

PM1-30

Zamarano, Z-A-M-A-R-A-N-O. And I am the mayor pro tem for the City of Gregory, and I'm here to speak on behalf of Cheniere that we are totally supportive of Cheniere for what they are doing and for what they have done.

I myself, I'm retired, but I have 37 years experience in industry. I know exactly -- I know what they do. My last job dealt with multiple generations. I dealt with the jet engines that everybody was talking about. I am familiar with the sound enclosures. I am familiar with how much noise they make, but everything is controllable. They have sound enclosures. You don't hear a thing.

So environmentally sound-wise and the other issues that are of concern are really controllable. And they are an industry that have been dealing with this for years, and Cheniere is no different. They know what what they're doing and they know that they have to comply because they have to keep the community informed and they have to keep the community in their best interest. So with that in mind, I am supporting Cheniere for what they're doing.

Two years ago I spoke with a gentleman Bill English and Mr. French. And whether they realize it or not, the city of Gregory has serious issues infracture-wise, but I think Cheniere presents like an

PM1-30: Comment acknowledged.

PM1-30 (con't)

end of the tunnel for the city of Gregory. Even though we're not directly benefiting from the -- from the settle sites or anything of that nature, we will be benefiting in the sense that their -- their jet engines produce a lot of heat and they need water to minimize the -- the temperature. And that water is very good at pulling water and will be discharged into a -- a pond or -- which we call Green Lake. And that will provide enough water for the Northshore so they can irrigate their golf course. It will be more water than what they need. This is clean, ample water.

The city of Gregory intends to benefit because there's a strong possibility that if they have enough water, then there's no need for a dam that is there holding the water back, thus creating a flood problem for the city of Gregory. Once this is done, once Cheniere gets in line, this -- there's a strong possibility that this dam can be lowered and the city of Gregory will benefit directly by solving the drainage problem.

One of the most important things for a community is what's called infracture. And we all think about infracture being water, sewer, and streets, but without drainage you cannot have either one. Drainage is the most important piece of infracture. Cheniere had

PM1-30 (con't)

already started their process two or three years ago so we could have this drainage problem solved, but now Cheniere presents hope for the city of Gregory from the standpoint that environmentally they're sound. Economically, it's not -- you cannot debate the issue. It's sound. They're bringing in a lot of progress to the -- to the area, but most of all what touches the city of Gregory the most is if we could see a light at the end of the tunnel by -- by having this drainage problem solved.

It will benefit the city more than anything else, and this is why Cheniere is here and they have shown a positive -- they have shown positive actions by providing monies for the city of Gregory to bring the -- the attitude of city of Gregory into being positive. And they're contributing to show their -- their interest and their sincerity to the city of Gregory.

So therefore, it's not because of what their say they are doing, it's because of what lies in the future because of their presence. And the most important thing for us is to solve the greatest issue. They're not aware of this, but it's just a result of their -- of -- of them being here.

So I strongly support this project and I strongly recommend that all of you give serious

PUBLIC MEETING TRANSCRIPT COMMENTS

PM1 – Corpus Christi LNG Transcript from Public Meeting

PM1-30 (con't)

consideration to the success of Cheniere being here because everybody -- everyone in this area will be benefiting from their existence. Thank you.

PM1-31

MS. CAROLYN MOON: I'm Carolyn Moon, C-A-R-O-L-Y-N, Moon like up in the sky. And I'm with the Clean and Healthy Economy Coalition. And we are a group comprised of people who are highly skeptical of industry, especially the oil and gas industry. We are scientists, we are speakers, we are teachers, all kinds of people have gotten together to keep an eye on what industries are doing.

And Mr. English came to visit with us. I believe it was even back when they were still going to import. And he told us all about it and it looked really nice and he went on his way and we went oh yeah, right. And we started studying on their permits and all of these things that they said they were going to do. And anytime we had any tiny concern, they already fixed it. And we tried. We tried really hard, but we do not find anything to object to. So welcome, Cheniere.

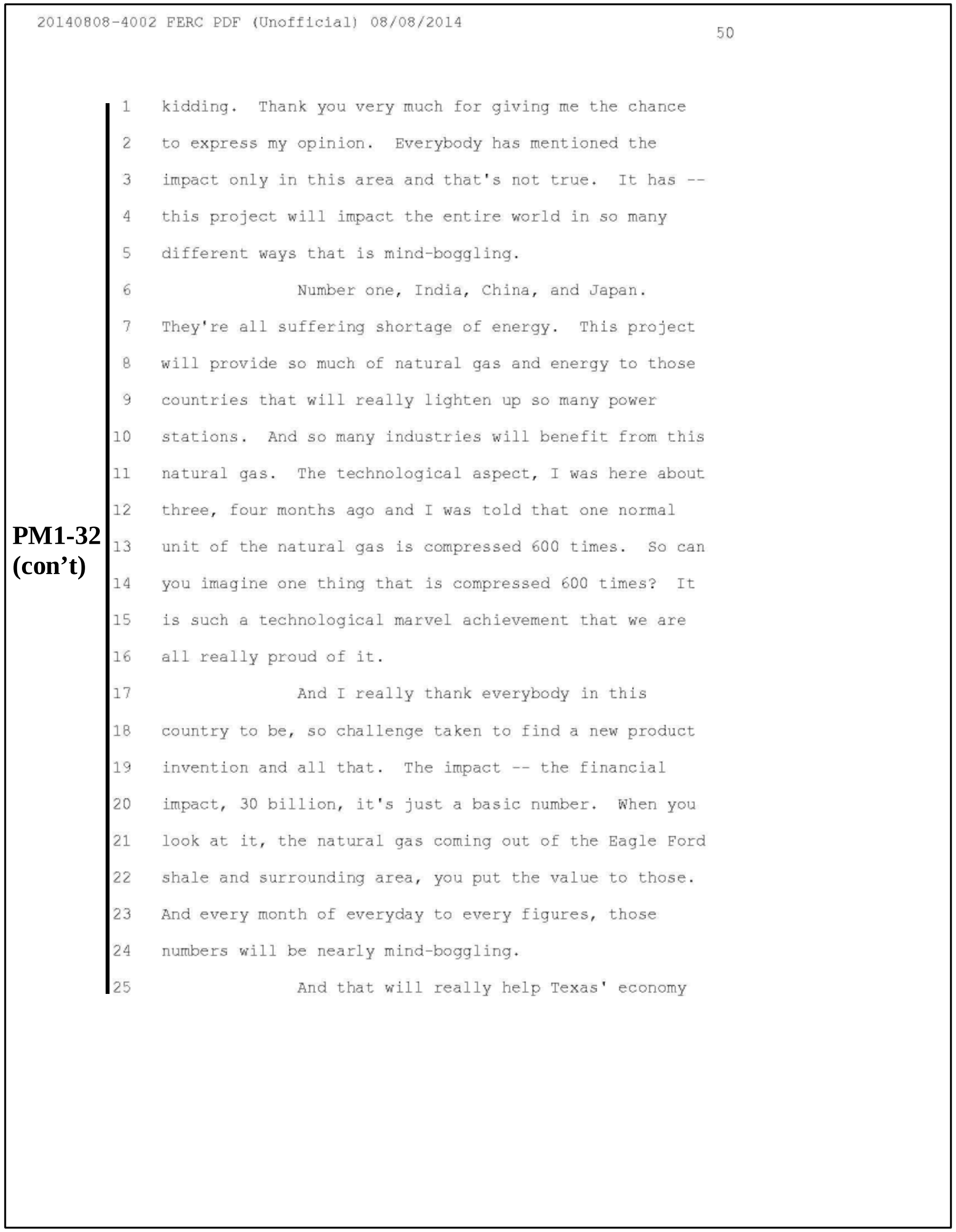
MS. BARAKAT: Is there anyone else that would like to comment?

PM1-32

MR. VINOD SHAH: My name is Vinod Shah, V-I-N-O-D, Shah, S-H-A-H. Colette, you mentioned so many industries, but you forgot my industry. I'm just

PM1-31: Comment acknowledged.

PM1-32: Comment acknowledged.



PM1-32 (con't)

kidding. Thank you very much for giving me the chance to express my opinion. Everybody has mentioned the impact only in this area and that's not true. It has -- this project will impact the entire world in so many different ways that is mind-boggling.

Number one, India, China, and Japan. They're all suffering shortage of energy. This project will provide so much of natural gas and energy to those countries that will really lighten up so many power stations. And so many industries will benefit from this natural gas. The technological aspect, I was here about three, four months ago and I was told that one normal unit of the natural gas is compressed 600 times. So can you imagine one thing that is compressed 600 times? It is such a technological marvel achievement that we are all really proud of it.

And I really thank everybody in this country to be, so challenge taken to find a new product invention and all that. The impact -- the financial impact, 30 billion, it's just a basic number. When you look at it, the natural gas coming out of the Eagle Ford shale and surrounding area, you put the value to those. And every month of everyday to every figures, those numbers will be nearly mind-boggling.

And that will really help Texas' economy

PM1-32 (con't)

when everybody else and other states -- you hear -- talk to your friends and they all talk about struggle and struggle and struggle. And here we struggle. Our struggle is different to find people who are ready to work, who are ready to make a commitment. But we will find -- we'll find a solution. Always look for the solution, don't worry about the trouble. That's my personal philosophy and I have enjoyed, you know, that.

There are people who want to complain. That's always the life, but my question to them is always look at the merits and demerits. If there is some demerits small but 95 percent benefits, we should go for it. And that's how people should evaluate anything that they come across anything in their life.

Always there is a -- there is a sacrifice in a life. I remember there was a project in India and there was a height issue. And there were some negative elements and they said they were going to go some 350 meters high. And if they go to 400 meter high, you know, there are more in India that could get waters, but along with that there are some families or some villages that would be affected that would be flooded. And they didn't have enough space and money and everything, so it was a win-win situation.

With the new government, it was a piece of

PM1-32 (con't)

cake. Everything happened so fast within one day that was there just like Cheniere here. Everybody is supporting it, so I am really happy, excited, and looking forward to the Cheniere project. And from the bottom of my heart, I'm praying federal government to give the permit. Thank you.

MS. BARAKAT: Anyone else would like to comment? If not, I'm going to go ahead and close the formal part of the meeting. Anyone wishes to keep up with the official activity associated with Corpus Christi LNG project can use the FERC website at www.FERC.gov. Within our website there is an e-library link where you can enter the docket numbers for the project CP12-507 and CP12-508.

You can use e-library to gain access to everything on the public record concerning the project including all of the public filings by Cheniere agencies and other landowners. Like I said earlier, the representative from Cheniere will stay in the room for a little while to answer any of your questions. If you would like immediate copies of the transcription, please see the court reporter.

On behalf of the Federal Energy Regulatory Commission, the Environmental Protection Agency, U.S. Army Corps of Engineers, U.S. Coast Guard, U.S.

PUBLIC MEETING TRANSCRIPT COMMENTS

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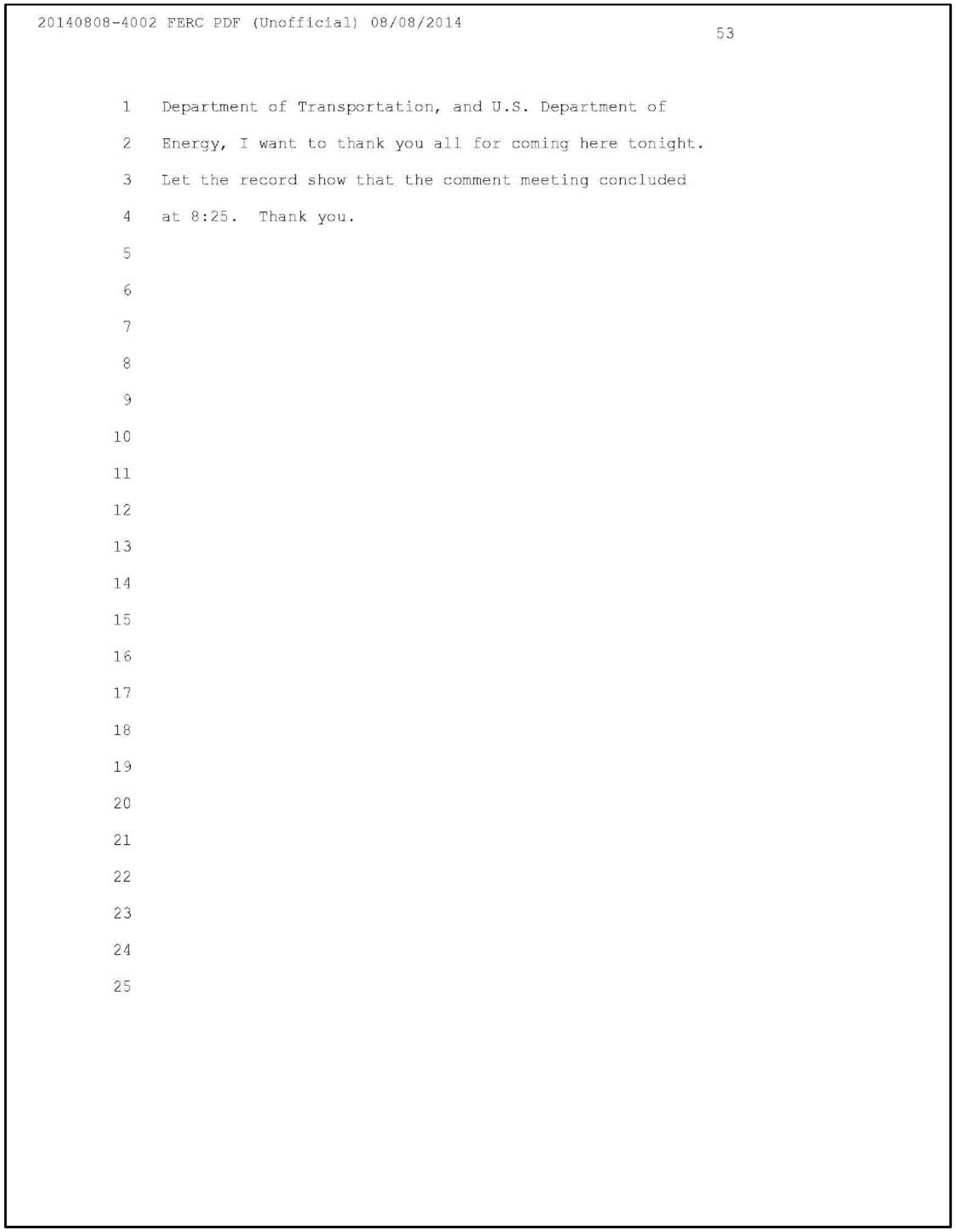
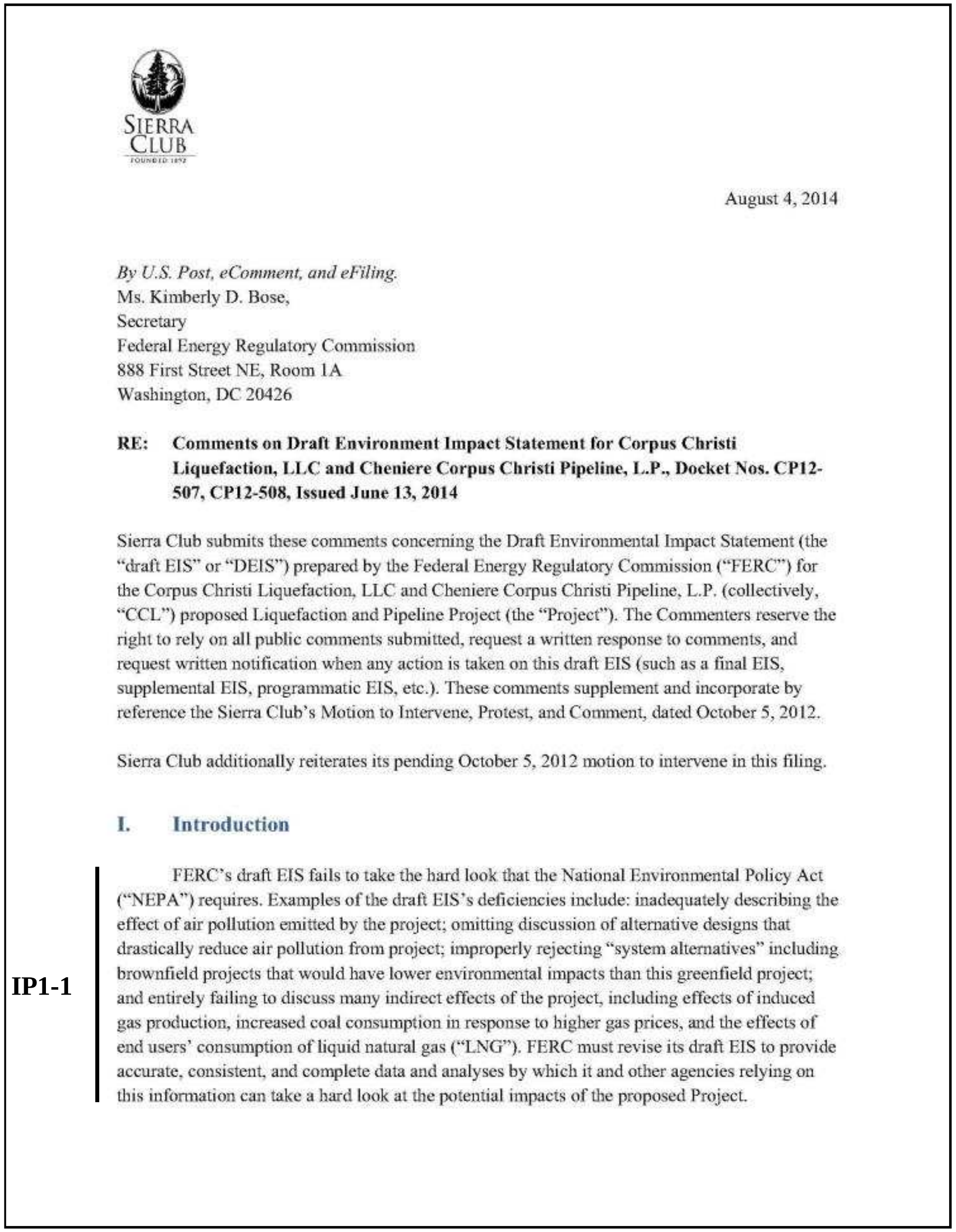


Department of Transportation, and U.S. Department of Energy, I want to thank you all for coming here tonight. Let the record show that the comment meeting concluded at 8:25. Thank you.

INTERESTED PARTY COMMENTS

IP1 – Sierra Club



SIERRA CLUB
FOUNDED 1892

August 4, 2014

By U.S. Post, eComment, and eFiling.
Ms. Kimberly D. Bose,
Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

RE: Comments on Draft Environment Impact Statement for Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P., Docket Nos. CP12-507, CP12-508, Issued June 13, 2014

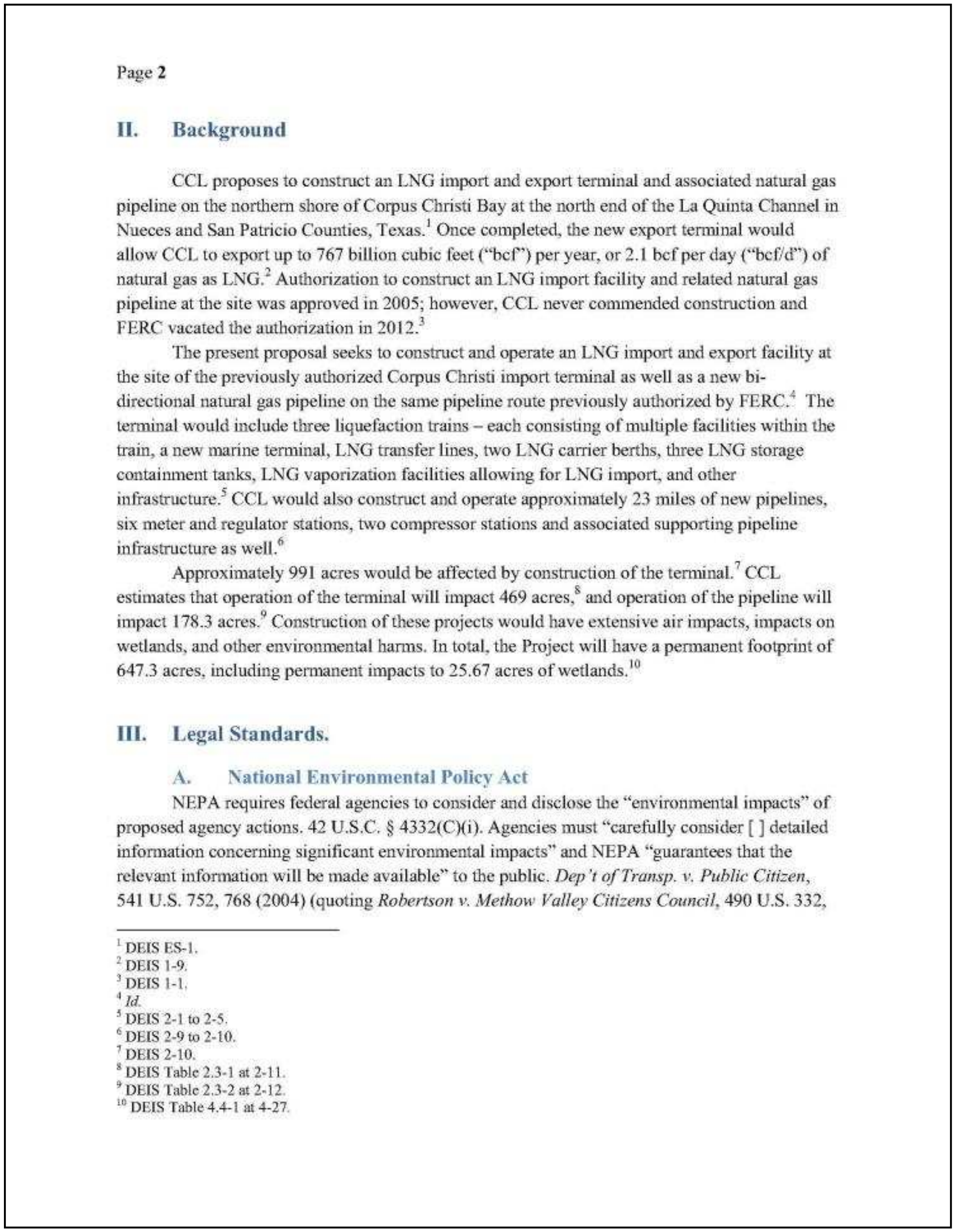
Sierra Club submits these comments concerning the Draft Environmental Impact Statement (the "draft EIS" or "DEIS") prepared by the Federal Energy Regulatory Commission ("FERC") for the Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P. (collectively, "CCL") proposed Liquefaction and Pipeline Project (the "Project"). The Commenters reserve the right to rely on all public comments submitted, request a written response to comments, and request written notification when any action is taken on this draft EIS (such as a final EIS, supplemental EIS, programmatic EIS, etc.). These comments supplement and incorporate by reference the Sierra Club's Motion to Intervene, Protest, and Comment, dated October 5, 2012.

Sierra Club additionally reiterates its pending October 5, 2012 motion to intervene in this filing.

I. Introduction

IP1-1 FERC's draft EIS fails to take the hard look that the National Environmental Policy Act ("NEPA") requires. Examples of the draft EIS's deficiencies include: inadequately describing the effect of air pollution emitted by the project; omitting discussion of alternative designs that drastically reduce air pollution from project; improperly rejecting "system alternatives" including brownfield projects that would have lower environmental impacts than this greenfield project; and entirely failing to discuss many indirect effects of the project, including effects of induced gas production, increased coal consumption in response to higher gas prices, and the effects of end users' consumption of liquid natural gas ("LNG"). FERC must revise its draft EIS to provide accurate, consistent, and complete data and analyses by which it and other agencies relying on this information can take a hard look at the potential impacts of the proposed Project.

IP1-1: Our responses to the issues are provided below with the more specific comments.



II. Background

CCL proposes to construct an LNG import and export terminal and associated natural gas pipeline on the northern shore of Corpus Christi Bay at the north end of the La Quinta Channel in Nueces and San Patricio Counties, Texas.[1] Once completed, the new export terminal would allow CCL to export up to 767 billion cubic feet ("bcf") per year, or 2.1 bcf per day ("bcf/d") of natural gas as LNG.[2] Authorization to construct an LNG import facility and related natural gas pipeline at the site was approved in 2005; however, CCL never commended construction and FERC vacated the authorization in 2012.[3]

The present proposal seeks to construct and operate an LNG import and export facility at the site of the previously authorized Corpus Christi import terminal as well as a new bi-directional natural gas pipeline on the same pipeline route previously authorized by FERC.[4] The terminal would include three liquefaction trains – each consisting of multiple facilities within the train, a new marine terminal, LNG transfer lines, two LNG carrier berths, three LNG storage containment tanks, LNG vaporization facilities allowing for LNG import, and other infrastructure.[5] CCL would also construct and operate approximately 23 miles of new pipelines, six meter and regulator stations, two compressor stations and associated supporting pipeline infrastructure as well.[6]

Approximately 991 acres would be affected by construction of the terminal.[7] CCL estimates that operation of the terminal will impact 469 acres,[8] and operation of the pipeline will impact 178.3 acres.[9] Construction of these projects would have extensive air impacts, impacts on wetlands, and other environmental harms. In total, the Project will have a permanent footprint of 647.3 acres, including permanent impacts to 25.67 acres of wetlands.[10]

III. Legal Standards.

A. National Environmental Policy Act

NEPA requires federal agencies to consider and disclose the "environmental impacts" of proposed agency actions. 42 U.S.C. § 4332(C)(i). Agencies must "carefully consider [ ] detailed information concerning significant environmental impacts" and NEPA "guarantees that the relevant information will be made available" to the public. *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 768 (2004) (quoting *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332,

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[1] DEIS ES-1.

[2] DEIS 1-9.

[3] DEIS 1-1.

[4] *Id.*

[5] DEIS 2-1 to 2-5.

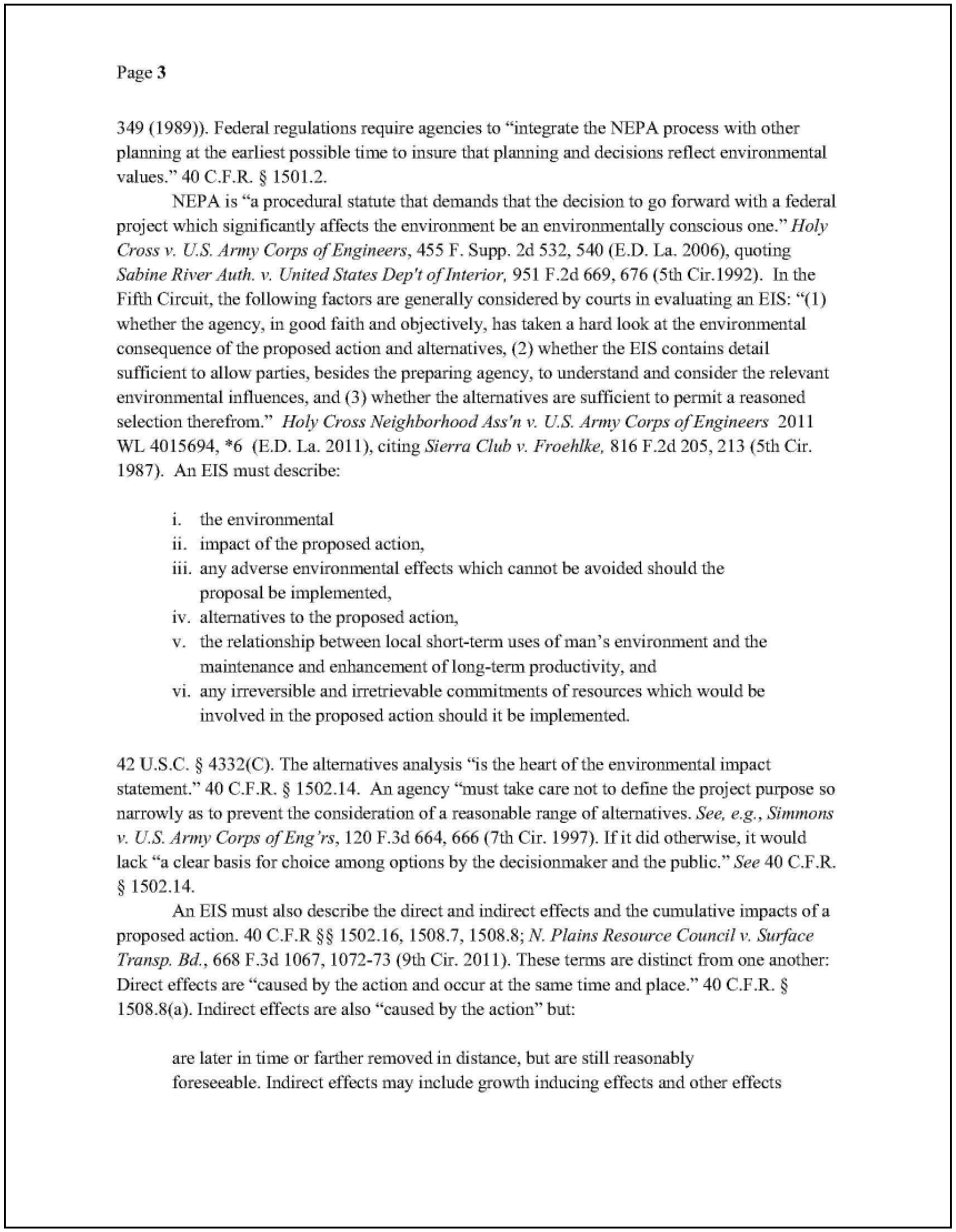
[6] DEIS 2-9 to 2-10.

[7] DEIS 2-10.

[8] DEIS Table 2.3-1 at 2-11.

[9] DEIS Table 2.3-2 at 2-12.

[10] DEIS Table 4.4-1 at 4-27.



349 (1989)). Federal regulations require agencies to "integrate the NEPA process with other planning at the earliest possible time to insure that planning and decisions reflect environmental values." 40 C.F.R. § 1501.2.

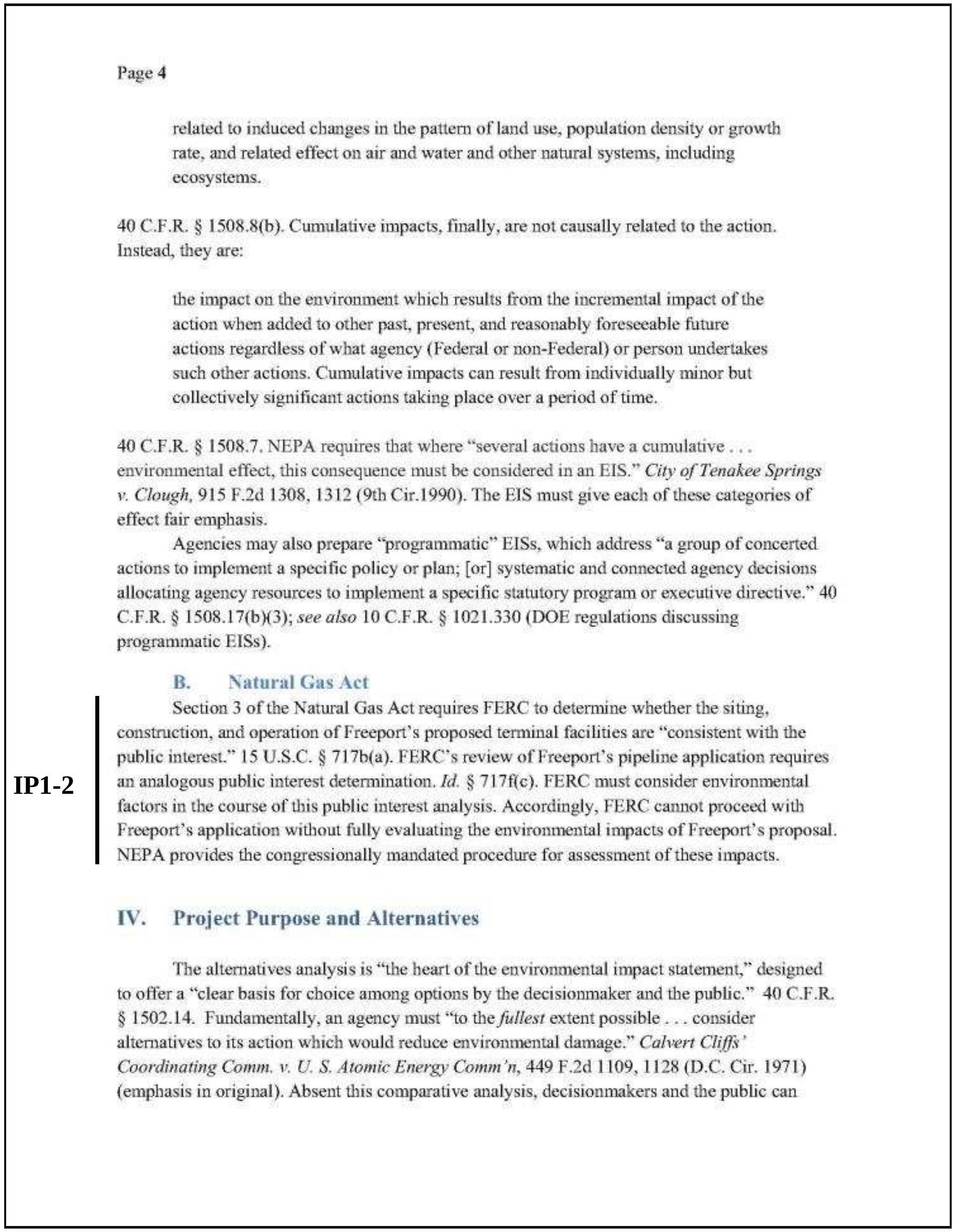
NEPA is "a procedural statute that demands that the decision to go forward with a federal project which significantly affects the environment be an environmentally conscious one." *Holy Cross v. U.S. Army Corps of Engineers*, 455 F. Supp. 2d 532, 540 (E.D. La. 2006), quoting *Sabine River Auth. v. United States Dep't of Interior,* 951 F.2d 669, 676 (5th Cir.1992). In the Fifth Circuit, the following factors are generally considered by courts in evaluating an EIS: "(1) whether the agency, in good faith and objectively, has taken a hard look at the environmental consequence of the proposed action and alternatives, (2) whether the EIS contains detail sufficient to allow parties, besides the preparing agency, to understand and consider the relevant environmental influences, and (3) whether the alternatives are sufficient to permit a reasoned selection therefrom." *Holy Cross Neighborhood Ass'n v. U.S. Army Corps of Engineers* 2011 WL 4015694, *6 (E.D. La. 2011), citing *Sierra Club v. Froehlke,* 816 F.2d 205, 213 (5th Cir. 1987). An EIS must describe:

i. the environmental
ii. impact of the proposed action,
iii. any adverse environmental effects which cannot be avoided should the proposal be implemented,
iv. alternatives to the proposed action,
v. the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
vi. any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

42 U.S.C. § 4332(C). The alternatives analysis "is the heart of the environmental impact statement." 40 C.F.R. § 1502.14. An agency "must take care not to define the project purpose so narrowly as to prevent the consideration of a reasonable range of alternatives. *See, e.g., Simmons v. U.S. Army Corps of Eng'rs*, 120 F.3d 664, 666 (7th Cir. 1997). If it did otherwise, it would lack "a clear basis for choice among options by the decisionmaker and the public." *See* 40 C.F.R. § 1502.14.

An EIS must also describe the direct and indirect effects and the cumulative impacts of a proposed action. 40 C.F.R §§ 1502.16, 1508.7, 1508.8; *N. Plains Resource Council v. Surface Transp. Bd.*, 668 F.3d 1067, 1072-73 (9th Cir. 2011). These terms are distinct from one another: Direct effects are "caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a). Indirect effects are also "caused by the action" but:

> are later in time or farther removed in distance, but are still reasonably foreseeable. Indirect effects may include growth inducing effects and other effects



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> related to induced changes in the pattern of land use, population density or growth rate, and related effect on air and water and other natural systems, including ecosystems.

40 C.F.R. § 1508.8(b). Cumulative impacts, finally, are not causally related to the action. Instead, they are:

> the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

40 C.F.R. § 1508.7. NEPA requires that where "several actions have a cumulative . . . environmental effect, this consequence must be considered in an EIS." *City of Tenakee Springs v. Clough,* 915 F.2d 1308, 1312 (9th Cir.1990). The EIS must give each of these categories of effect fair emphasis.

Agencies may also prepare "programmatic" EISs, which address "a group of concerted actions to implement a specific policy or plan; [or] systematic and connected agency decisions allocating agency resources to implement a specific statutory program or executive directive." 40 C.F.R. § 1508.17(b)(3); *see also* 10 C.F.R. § 1021.330 (DOE regulations discussing programmatic EISs).

B. Natural Gas Act

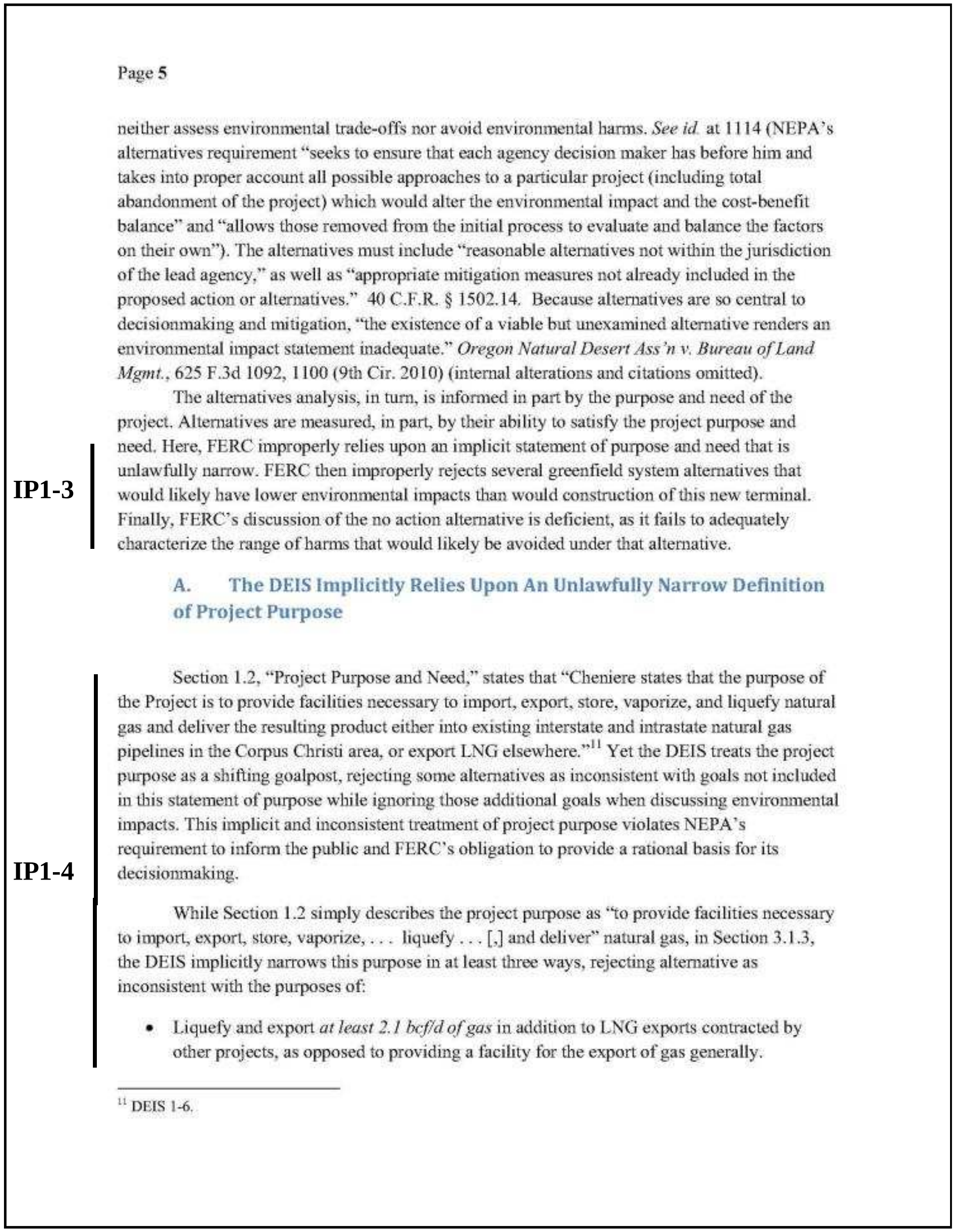
IP1-2

Section 3 of the Natural Gas Act requires FERC to determine whether the siting, construction, and operation of Freeport's proposed terminal facilities are "consistent with the public interest." 15 U.S.C. § 717b(a). FERC's review of Freeport's pipeline application requires an analogous public interest determination. *Id.* § 717f(c). FERC must consider environmental factors in the course of this public interest analysis. Accordingly, FERC cannot proceed with Freeport's application without fully evaluating the environmental impacts of Freeport's proposal. NEPA provides the congressionally mandated procedure for assessment of these impacts.

IV. Project Purpose and Alternatives

The alternatives analysis is "the heart of the environmental impact statement," designed to offer a "clear basis for choice among options by the decisionmaker and the public." 40 C.F.R. § 1502.14. Fundamentally, an agency must "to the *fullest* extent possible . . . consider alternatives to its action which would reduce environmental damage." *Calvert Cliffs' Coordinating Comm. v. U. S. Atomic Energy Comm'n*, 449 F.2d 1109, 1128 (D.C. Cir. 1971) (emphasis in original). Absent this comparative analysis, decisionmakers and the public can

IP1-2: Comment acknowledged. The environmental review and EIS evaluated the potential environmental impacts of the proposed Project. As noted below, portions of the EIS have been revised to present information made public after the draft EIS was issued.



Page 5

neither assess environmental trade-offs nor avoid environmental harms. *See id.* at 1114 (NEPA's alternatives requirement "seeks to ensure that each agency decision maker has before him and takes into proper account all possible approaches to a particular project (including total abandonment of the project) which would alter the environmental impact and the cost-benefit balance" and "allows those removed from the initial process to evaluate and balance the factors on their own"). The alternatives must include "reasonable alternatives not within the jurisdiction of the lead agency," as well as "appropriate mitigation measures not already included in the proposed action or alternatives." 40 C.F.R. § 1502.14. Because alternatives are so central to decisionmaking and mitigation, "the existence of a viable but unexamined alternative renders an environmental impact statement inadequate." *Oregon Natural Desert Ass'n v. Bureau of Land Mgmt.*, 625 F.3d 1092, 1100 (9th Cir. 2010) (internal alterations and citations omitted).

IP1-3

The alternatives analysis, in turn, is informed in part by the purpose and need of the project. Alternatives are measured, in part, by their ability to satisfy the project purpose and need. Here, FERC improperly relies upon an implicit statement of purpose and need that is unlawfully narrow. FERC then improperly rejects several greenfield system alternatives that would likely have lower environmental impacts than would construction of this new terminal. Finally, FERC's discussion of the no action alternative is deficient, as it fails to adequately characterize the range of harms that would likely be avoided under that alternative.

A. The DEIS Implicitly Relies Upon An Unlawfully Narrow Definition of Project Purpose

IP1-4

Section 1.2, "Project Purpose and Need," states that "Cheniere states that the purpose of the Project is to provide facilities necessary to import, export, store, vaporize, and liquefy natural gas and deliver the resulting product either into existing interstate and intrastate natural gas pipelines in the Corpus Christi area, or export LNG elsewhere."[11] Yet the DEIS treats the project purpose as a shifting goalpost, rejecting some alternatives as inconsistent with goals not included in this statement of purpose while ignoring those additional goals when discussing environmental impacts. This implicit and inconsistent treatment of project purpose violates NEPA's requirement to inform the public and FERC's obligation to provide a rational basis for its decisionmaking.

While Section 1.2 simply describes the project purpose as "to provide facilities necessary to import, export, store, vaporize, . . . liquefy . . . [,] and deliver" natural gas, in Section 3.1.3, the DEIS implicitly narrows this purpose in at least three ways, rejecting alternative as inconsistent with the purposes of:

- Liquefy and export *at least 2.1 bcf/d of gas* in addition to LNG exports contracted by other projects, as opposed to providing a facility for the export of gas generally.

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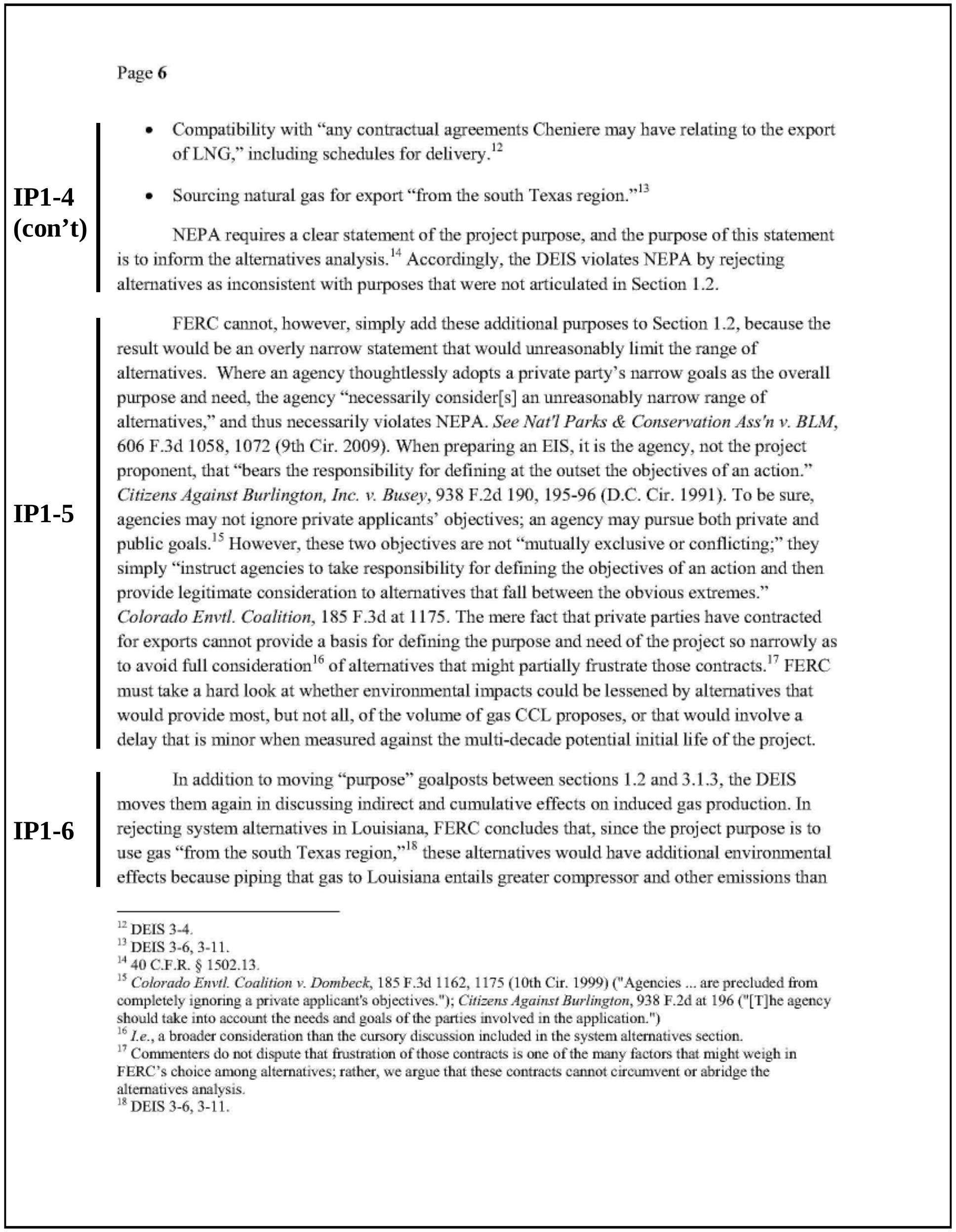
[11] DEIS 1-6.

IP1-3: Our responses to the issues are provided below with the more specific comments.

IP1-4: The Department of Energy (DOE) provided approval for the export of LNG at Cheniere's facility. The EIS specifically evaluates the siting and operation of the proposed Project. The Project purpose stated in section 1.2 of the final EIS was summarized to better serve the reader; however, the final EIS provides an accurate description of Cheniere's stated purpose and need for the proposed Project and evaluates potential alternatives to meeting that purpose and need.

IP1 – Sierra Club



IP1-4 (con't)

- Compatibility with "any contractual agreements Cheniere may have relating to the export of LNG," including schedules for delivery.[12]
- Sourcing natural gas for export "from the south Texas region."[13]

NEPA requires a clear statement of the project purpose, and the purpose of this statement is to inform the alternatives analysis.[14] Accordingly, the DEIS violates NEPA by rejecting alternatives as inconsistent with purposes that were not articulated in Section 1.2.

IP1-5

FERC cannot, however, simply add these additional purposes to Section 1.2, because the result would be an overly narrow statement that would unreasonably limit the range of alternatives. Where an agency thoughtlessly adopts a private party's narrow goals as the overall purpose and need, the agency "necessarily consider[s] an unreasonably narrow range of alternatives," and thus necessarily violates NEPA. *See Nat'l Parks & Conservation Ass'n v. BLM*, 606 F.3d 1058, 1072 (9th Cir. 2009). When preparing an EIS, it is the agency, not the project proponent, that "bears the responsibility for defining at the outset the objectives of an action." *Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 195-96 (D.C. Cir. 1991). To be sure, agencies may not ignore private applicants' objectives; an agency may pursue both private and public goals.[15] However, these two objectives are not "mutually exclusive or conflicting;" they simply "instruct agencies to take responsibility for defining the objectives of an action and then provide legitimate consideration to alternatives that fall between the obvious extremes." *Colorado Envtl. Coalition*, 185 F.3d at 1175. The mere fact that private parties have contracted for exports cannot provide a basis for defining the purpose and need of the project so narrowly as to avoid full consideration[16] of alternatives that might partially frustrate those contracts.[17] FERC must take a hard look at whether environmental impacts could be lessened by alternatives that would provide most, but not all, of the volume of gas CCL proposes, or that would involve a delay that is minor when measured against the multi-decade potential initial life of the project.

IP1-6

In addition to moving "purpose" goalposts between sections 1.2 and 3.1.3, the DEIS moves them again in discussing indirect and cumulative effects on induced gas production. In rejecting system alternatives in Louisiana, FERC concludes that, since the project purpose is to use gas "from the south Texas region,"[18] these alternatives would have additional environmental effects because piping that gas to Louisiana entails greater compressor and other emissions than

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[12] DEIS 3-4.

[13] DEIS 3-6, 3-11.

[14] 40 C.F.R. § 1502.13.

[15] *Colorado Envtl. Coalition v. Dombeck*, 185 F.3d 1162, 1175 (10th Cir. 1999) ("Agencies ... are precluded from completely ignoring a private applicant's objectives."); *Citizens Against Burlington*, 938 F.2d at 196 ("[T]he agency should take into account the needs and goals of the parties involved in the application.")

[16] *I.e.*, a broader consideration than the cursory discussion included in the system alternatives section.

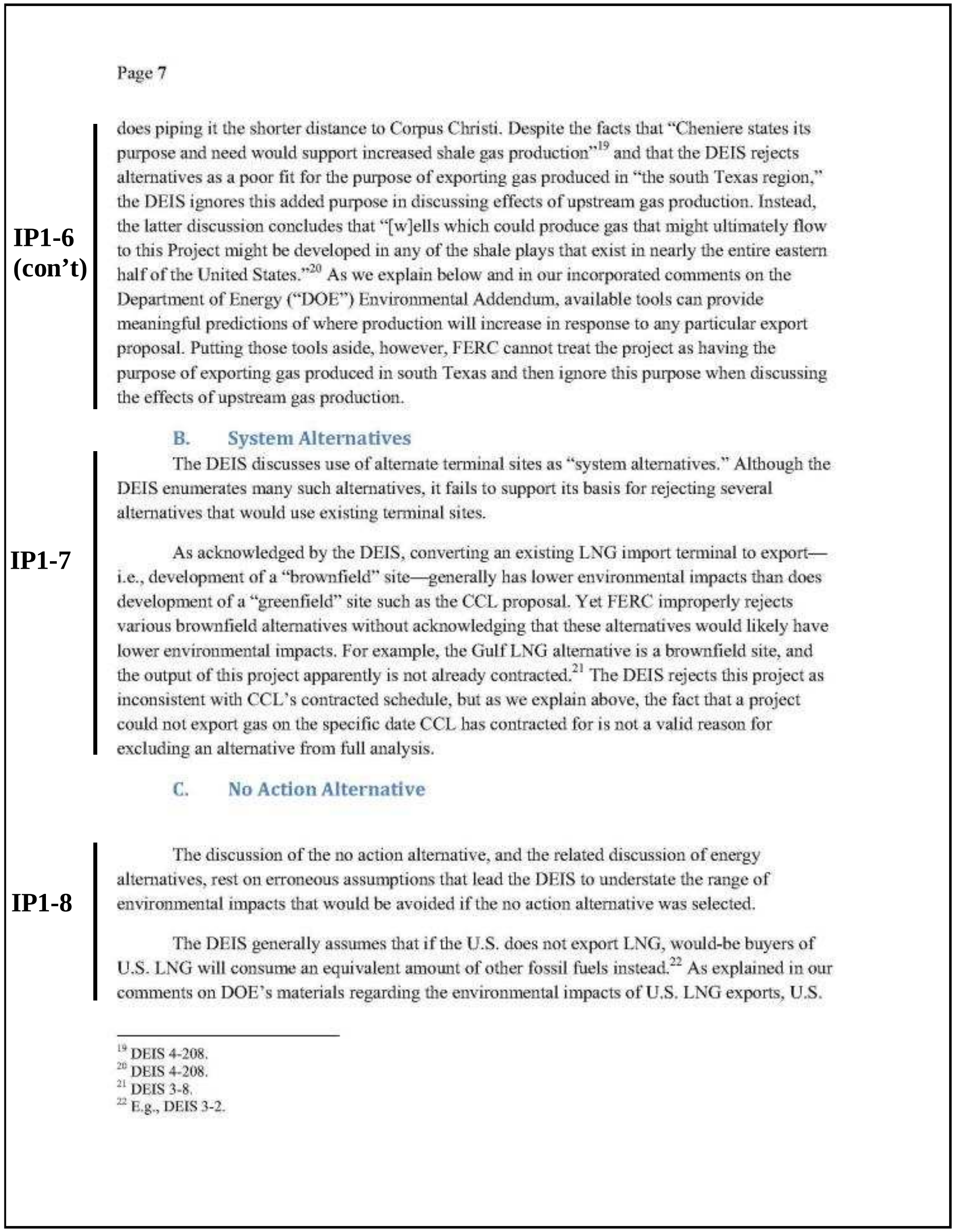
[17] Commenters do not dispute that frustration of those contracts is one of the many factors that might weigh in FERC's choice among alternatives; rather, we argue that these contracts cannot circumvent or abridge the alternatives analysis.

[18] DEIS 3-6, 3-11.

IP1-5: The EIS is not intended to be a determination of Project need. It is the duty and authority of the FERC's Commissioners to determine if the Project is in the public's convenience and necessity during its evaluation and review prior to authorization. The FERC is not a proponent of the proposed Project, and therefore does not define the Project's purpose and need. The purpose is defined by Cheniere in its applications to the FERC, and we use that stated purpose in the EIS for the Project. The purpose and need statement in the EIS serves as a disclosure of Cheniere's stated purpose to which the FERC is responding and provides the basis for developing a reasonable range of alternatives. FERC staff neither endorses nor opposes Cheniere's assertions of need. Need is not an environmental issue to be addressed at length in the EIS to justify the Project. Applicants propose projects and present their objectives, and the FERC reviews those proposals, including producing an environmental document to satisfy NEPA. The CEQ regulations for implementing NEPA (at 40 CFR 1502.13) only require that the EIS "briefly specify the underlying purpose and need to which the agency is responding…" The Commission will more fully consider the need for the Project when making its decision on whether or not to authorize the Project. Section 3 of the final EIS contains a thorough analysis of alternatives to the Cheniere Liquefaction Project, including the No-Action alternative.

IP1-6: The FERC does not regulate "upstream gas production." The effects of upstream gas production are addressed in section 4.13.1 of the final EIS.

IP1 – Sierra Club



IP1-6 (con't)

does piping it the shorter distance to Corpus Christi. Despite the facts that "Cheniere states its purpose and need would support increased shale gas production"[19] and that the DEIS rejects alternatives as a poor fit for the purpose of exporting gas produced in "the south Texas region," the DEIS ignores this added purpose in discussing effects of upstream gas production. Instead, the latter discussion concludes that "[w]ells which could produce gas that might ultimately flow to this Project might be developed in any of the shale plays that exist in nearly the entire eastern half of the United States."[20] As we explain below and in our incorporated comments on the Department of Energy ("DOE") Environmental Addendum, available tools can provide meaningful predictions of where production will increase in response to any particular export proposal. Putting those tools aside, however, FERC cannot treat the project as having the purpose of exporting gas produced in south Texas and then ignore this purpose when discussing the effects of upstream gas production.

B. System Alternatives

IP1-7

The DEIS discusses use of alternate terminal sites as "system alternatives." Although the DEIS enumerates many such alternatives, it fails to support its basis for rejecting several alternatives that would use existing terminal sites.

As acknowledged by the DEIS, converting an existing LNG import terminal to export—i.e., development of a "brownfield" site—generally has lower environmental impacts than does development of a "greenfield" site such as the CCL proposal. Yet FERC improperly rejects various brownfield alternatives without acknowledging that these alternatives would likely have lower environmental impacts. For example, the Gulf LNG alternative is a brownfield site, and the output of this project apparently is not already contracted.[21] The DEIS rejects this project as inconsistent with CCL's contracted schedule, but as we explain above, the fact that a project could not export gas on the specific date CCL has contracted for is not a valid reason for excluding an alternative from full analysis.

C. No Action Alternative

IP1-8

The discussion of the no action alternative, and the related discussion of energy alternatives, rest on erroneous assumptions that lead the DEIS to understate the range of environmental impacts that would be avoided if the no action alternative was selected.

The DEIS generally assumes that if the U.S. does not export LNG, would-be buyers of U.S. LNG will consume an equivalent amount of other fossil fuels instead.[22] As explained in our comments on DOE's materials regarding the environmental impacts of U.S. LNG exports, U.S.

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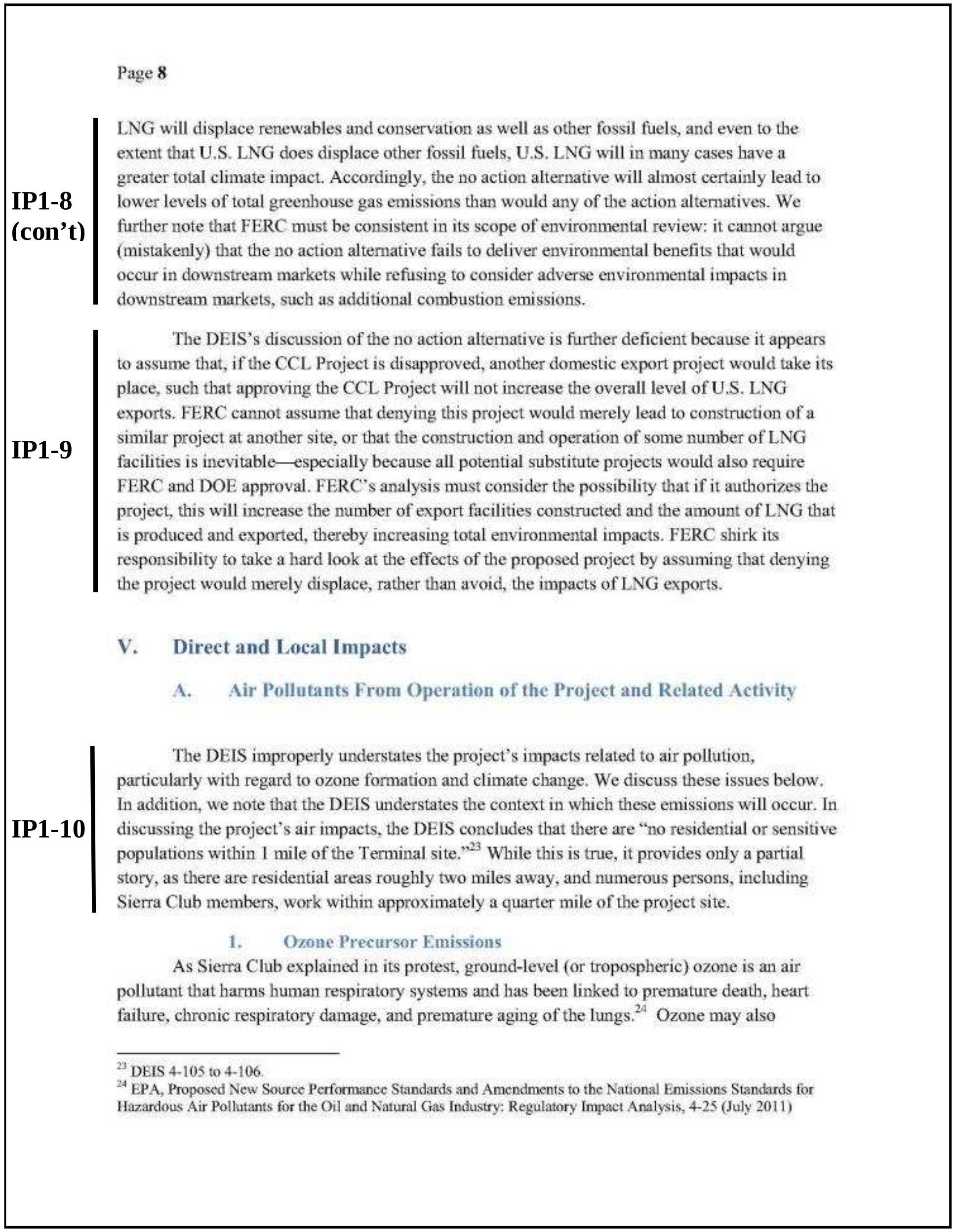
[19] DEIS 4-208.
[20] DEIS 4-208.
[21] DEIS 3-8.
[22] E.g., DEIS 3-2.

IP1-7: The alternatives analysis is consistent with CEQ regulations, particularly 40 CFR 1502.14, which in addition to requiring detailed analysis of alternatives in comparative form, states that "and for alternatives which were eliminated from detailed study, briefly discuss the reasons for their having been eliminated." For each alternative eliminated, the EIS states why the alternative was eliminated, and therefore, we do not need a detailed analysis of those alternatives for comparison. The timeline for each alternative is still a component of the Project and the evaluation of alternatives. The lack of providing a significant environmental advantage is the main reason for each alternative's elimination. The system alternatives addressed in section 3.1 of the final EIS were not eliminated solely on the basis of the timing of in-service dates, although many of the projects were in such an early stage of development that if approved, they would not be completed within years of the anticipated in-service date of the proposed Project. As noted in section 3.1, the majority of projects eliminated did not offer a significant environmental advantage over the proposed Project.

IP1-8: "Downstream market uses" and any potential impacts are not within the Commission's jurisdiction. Because end users have not been and cannot be identified at this time, it is not possible to consider impacts of end use. Further, the impacts of end use in foreign, likely non-adjacent, countries is beyond the scope of a project proposed within the United States and evaluated under NEPA and CEQ regulations.

IP1 – Sierra Club



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IP1-8 (con't)

LNG will displace renewables and conservation as well as other fossil fuels, and even to the extent that U.S. LNG does displace other fossil fuels, U.S. LNG will in many cases have a greater total climate impact. Accordingly, the no action alternative will almost certainly lead to lower levels of total greenhouse gas emissions than would any of the action alternatives. We further note that FERC must be consistent in its scope of environmental review: it cannot argue (mistakenly) that the no action alternative fails to deliver environmental benefits that would occur in downstream markets while refusing to consider adverse environmental impacts in downstream markets, such as additional combustion emissions.

IP1-9

The DEIS's discussion of the no action alternative is further deficient because it appears to assume that, if the CCL Project is disapproved, another domestic export project would take its place, such that approving the CCL Project will not increase the overall level of U.S. LNG exports. FERC cannot assume that denying this project would merely lead to construction of a similar project at another site, or that the construction and operation of some number of LNG facilities is inevitable—especially because all potential substitute projects would also require FERC and DOE approval. FERC's analysis must consider the possibility that if it authorizes the project, this will increase the number of export facilities constructed and the amount of LNG that is produced and exported, thereby increasing total environmental impacts. FERC shirk its responsibility to take a hard look at the effects of the proposed project by assuming that denying the project would merely displace, rather than avoid, the impacts of LNG exports.

V. Direct and Local Impacts

A. Air Pollutants From Operation of the Project and Related Activity

IP1-10

The DEIS improperly understates the project's impacts related to air pollution, particularly with regard to ozone formation and climate change. We discuss these issues below. In addition, we note that the DEIS understates the context in which these emissions will occur. In discussing the project's air impacts, the DEIS concludes that there are "no residential or sensitive populations within 1 mile of the Terminal site."[23] While this is true, it provides only a partial story, as there are residential areas roughly two miles away, and numerous persons, including Sierra Club members, work within approximately a quarter mile of the project site.

1. Ozone Precursor Emissions

As Sierra Club explained in its protest, ground-level (or tropospheric) ozone is an air pollutant that harms human respiratory systems and has been linked to premature death, heart failure, chronic respiratory damage, and premature aging of the lungs.[24] Ozone may also

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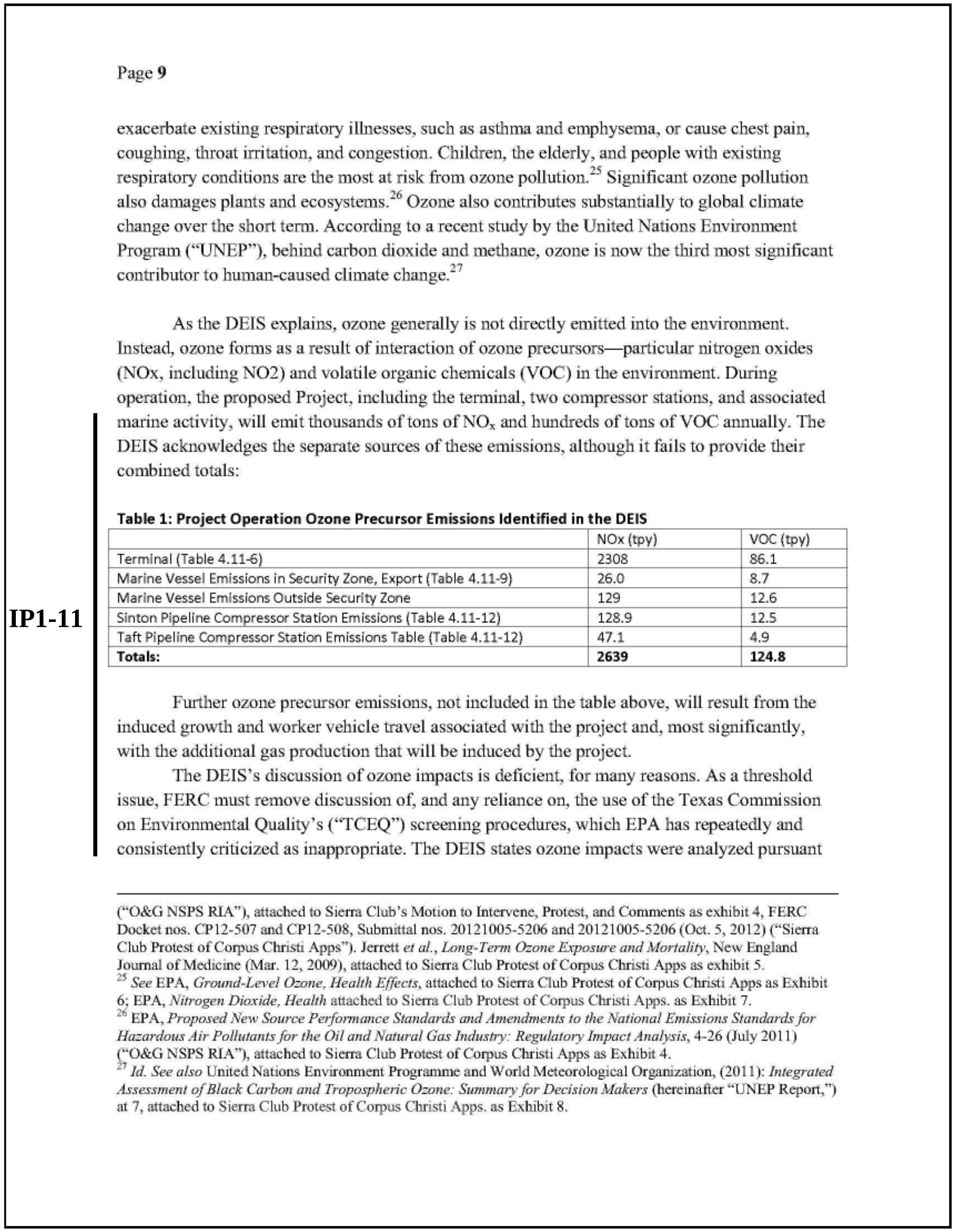
[23] DEIS 4-105 to 4-106.

[24] EPA, Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry: Regulatory Impact Analysis, 4-25 (July 2011)

IP1-8 (con't): NEPA requires the Commission to disclose the potential impacts resulting from its action to authorize the construction and operation of an LNG terminal.

IP1-9: In order to address alternatives, we must make the assumption that the purpose and need of the project (and competing projects) is valid. However, the market will ultimately decide which and how many LNG export facilities will be built and operated. Our assessment of the No-Action alternative states that "other LNG import/export projects *could* also be developed…" [emphasis ours] and clearly states that with the No-Action Alternative, "…the potential adverse and beneficial environmental impacts identified in section 4.0 of this EIS would not occur."

IP1-10: Our responses to the issues are provided below with the more specific comments.



IP1-11

exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation, and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[25] Significant ozone pollution also damages plants and ecosystems.[26] Ozone also contributes substantially to global climate change over the short term. According to a recent study by the United Nations Environment Program ("UNEP"), behind carbon dioxide and methane, ozone is now the third most significant contributor to human-caused climate change.[27]

As the DEIS explains, ozone generally is not directly emitted into the environment. Instead, ozone forms as a result of interaction of ozone precursors—particular nitrogen oxides (NOx, including NO2) and volatile organic chemicals (VOC) in the environment. During operation, the proposed Project, including the terminal, two compressor stations, and associated marine activity, will emit thousands of tons of NO_x and hundreds of tons of VOC annually. The DEIS acknowledges the separate sources of these emissions, although it fails to provide their combined totals:

Table 1: Project Operation Ozone Precursor Emissions Identified in the DEIS

	NOx (tpy)	VOC (tpy)
Terminal (Table 4.11-6)	2308	86.1
Marine Vessel Emissions in Security Zone, Export (Table 4.11-9)	26.0	8.7
Marine Vessel Emissions Outside Security Zone	129	12.6
Sinton Pipeline Compressor Station Emissions (Table 4.11-12)	128.9	12.5
Taft Pipeline Compressor Station Emissions Table (Table 4.11-12)	47.1	4.9
Totals:	**2639**	**124.8**

Further ozone precursor emissions, not included in the table above, will result from the induced growth and worker vehicle travel associated with the project and, most significantly, with the additional gas production that will be induced by the project.

The DEIS's discussion of ozone impacts is deficient, for many reasons. As a threshold issue, FERC must remove discussion of, and any reliance on, the use of the Texas Commission on Environmental Quality's ("TCEQ") screening procedures, which EPA has repeatedly and consistently criticized as inappropriate. The DEIS states ozone impacts were analyzed pursuant

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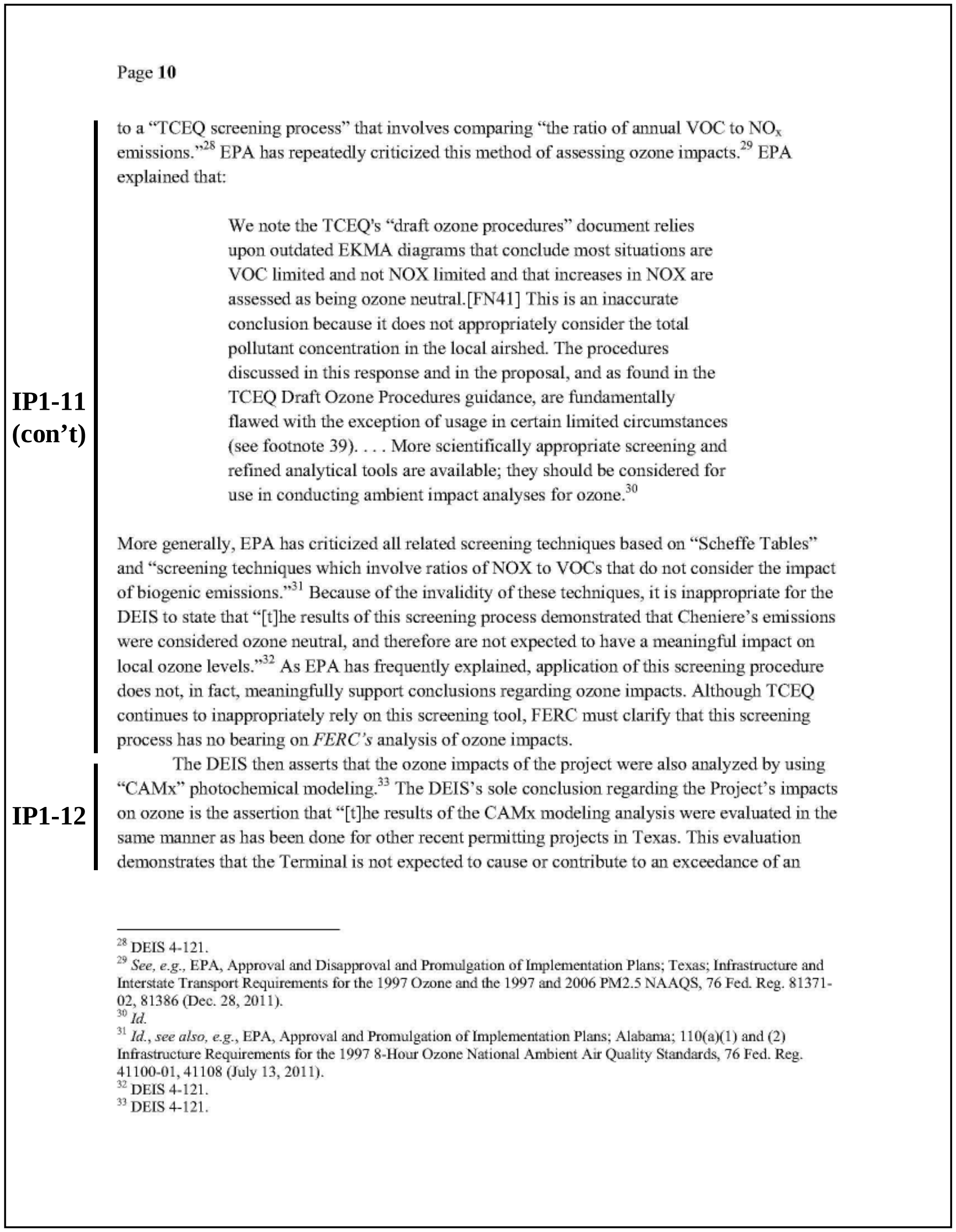
("O&G NSPS RIA"), attached to Sierra Club's Motion to Intervene, Protest, and Comments as exhibit 4, FERC Docket nos. CP12-507 and CP12-508, Submittal nos. 20121005-5206 and 20121005-5206 (Oct. 5, 2012) ("Sierra Club Protest of Corpus Christi Apps"). Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), attached to Sierra Club Protest of Corpus Christi Apps as exhibit 5.

[25] *See* EPA, *Ground-Level Ozone, Health Effects*, attached to Sierra Club Protest of Corpus Christi Apps as Exhibit 6; EPA, *Nitrogen Dioxide, Health* attached to Sierra Club Protest of Corpus Christi Apps. as Exhibit 7.

[26] EPA, *Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry: Regulatory Impact Analysis*, 4-26 (July 2011) ("O&G NSPS RIA"), attached to Sierra Club Protest of Corpus Christi Apps as Exhibit 4.

[27] *Id. See also* United Nations Environment Programme and World Meteorological Organization, (2011): *Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers* (hereinafter "UNEP Report,") at 7, attached to Sierra Club Protest of Corpus Christi Apps. as Exhibit 8.

IP1-11: The final EIS appropriately identifies the emissions of each separate facility or category of emissions, which are either separated geographically or by type of emissions (e.g., mobile vs. stationary). Although the emissions were presented separately, the final EIS presents modeled impacts from emissions that included marine sources and the Terminal combined. As stated in the draft EIS, the Texas Commission on Environmental Quality (TCEQ) and FERC did not rely on the results of the TCEQ's screening analysis alone in concluding that the Project would not have an adverse impact on ozone levels in the region. (We note that the TCEQ is currently in the process of revising its methodology for conducting an ambient ozone impacts analysis, as described in the Commission's Air Quality Modeling Guidelines, APDG 6232, June 2014.) After discussions with EPA and the TCEQ, Cheniere conducted a refined modeling analysis using the CAMx model, the results of which are discussed in section 4.11.1.5 of the final EIS.



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IP1-11 (con't)

to a "TCEQ screening process" that involves comparing "the ratio of annual VOC to NO_x emissions."[28] EPA has repeatedly criticized this method of assessing ozone impacts.[29] EPA explained that:

> We note the TCEQ's "draft ozone procedures" document relies upon outdated EKMA diagrams that conclude most situations are VOC limited and not NOX limited and that increases in NOX are assessed as being ozone neutral.[FN41] This is an inaccurate conclusion because it does not appropriately consider the total pollutant concentration in the local airshed. The procedures discussed in this response and in the proposal, and as found in the TCEQ Draft Ozone Procedures guidance, are fundamentally flawed with the exception of usage in certain limited circumstances (see footnote 39). . . . More scientifically appropriate screening and refined analytical tools are available; they should be considered for use in conducting ambient impact analyses for ozone.[30]

More generally, EPA has criticized all related screening techniques based on "Scheffe Tables" and "screening techniques which involve ratios of NOX to VOCs that do not consider the impact of biogenic emissions."[31] Because of the invalidity of these techniques, it is inappropriate for the DEIS to state that "[t]he results of this screening process demonstrated that Cheniere's emissions were considered ozone neutral, and therefore are not expected to have a meaningful impact on local ozone levels."[32] As EPA has frequently explained, application of this screening procedure does not, in fact, meaningfully support conclusions regarding ozone impacts. Although TCEQ continues to inappropriately rely on this screening tool, FERC must clarify that this screening process has no bearing on *FERC's* analysis of ozone impacts.

IP1-12

The DEIS then asserts that the ozone impacts of the project were also analyzed by using "CAMx" photochemical modeling.[33] The DEIS's sole conclusion regarding the Project's impacts on ozone is the assertion that "[t]he results of the CAMx modeling analysis were evaluated in the same manner as has been done for other recent permitting projects in Texas. This evaluation demonstrates that the Terminal is not expected to cause or contribute to an exceedance of an

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[28] DEIS 4-121.

[29] *See, e.g.*, EPA, Approval and Disapproval and Promulgation of Implementation Plans; Texas; Infrastructure and Interstate Transport Requirements for the 1997 Ozone and the 1997 and 2006 PM2.5 NAAQS, 76 Fed. Reg. 81371-02, 81386 (Dec. 28, 2011).

[30] *Id.*

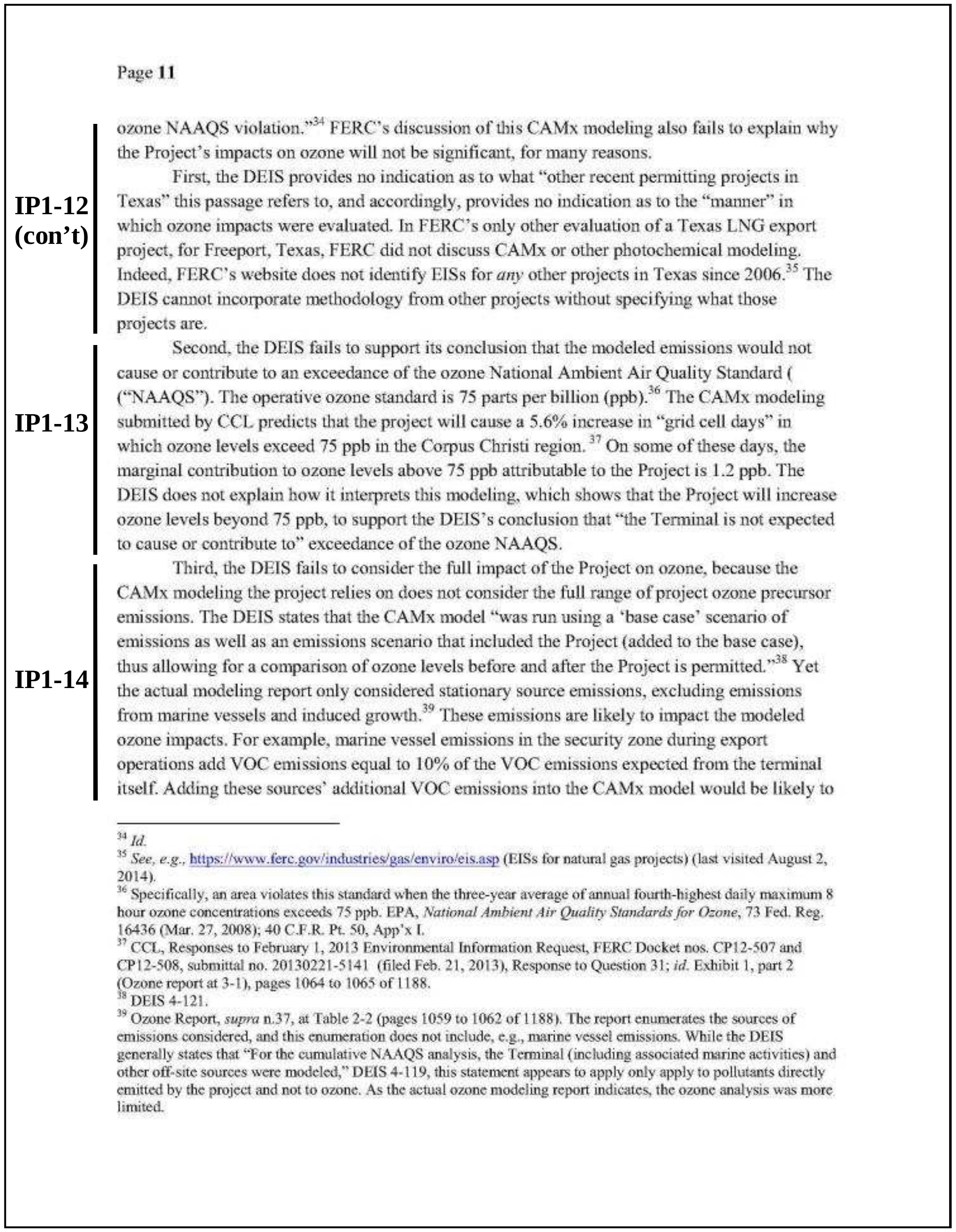
[31] *Id.*, *see also, e.g.*, EPA, Approval and Promulgation of Implementation Plans; Alabama; 110(a)(1) and (2) Infrastructure Requirements for the 1997 8-Hour Ozone National Ambient Air Quality Standards, 76 Fed. Reg. 41100-01, 41108 (July 13, 2011).

[32] DEIS 4-121.

[33] DEIS 4-121.

IP1-12: The modeling approach used by Cheniere reflects a modeling protocol used in the ozone impact analysis for the permitting of the Nucor Steel Plant in Louisiana, incorporating updates to the protocol suggested by EPA Region 6 for the more recent Sabine Pass Liquefaction Project, also in Louisiana. The final EIS has been revised to correct this information.

IP1 – Sierra Club



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IP1-12 (con't)

ozone NAAQS violation."[34] FERC's discussion of this CAMx modeling also fails to explain why the Project's impacts on ozone will not be significant, for many reasons.

First, the DEIS provides no indication as to what "other recent permitting projects in Texas" this passage refers to, and accordingly, provides no indication as to the "manner" in which ozone impacts were evaluated. In FERC's only other evaluation of a Texas LNG export project, for Freeport, Texas, FERC did not discuss CAMx or other photochemical modeling. Indeed, FERC's website does not identify EISs for *any* other projects in Texas since 2006.[35] The DEIS cannot incorporate methodology from other projects without specifying what those projects are.

IP1-13

Second, the DEIS fails to support its conclusion that the modeled emissions would not cause or contribute to an exceedance of the ozone National Ambient Air Quality Standard (("NAAQS"). The operative ozone standard is 75 parts per billion (ppb).[36] The CAMx modeling submitted by CCL predicts that the project will cause a 5.6% increase in "grid cell days" in which ozone levels exceed 75 ppb in the Corpus Christi region. [37] On some of these days, the marginal contribution to ozone levels above 75 ppb attributable to the Project is 1.2 ppb. The DEIS does not explain how it interprets this modeling, which shows that the Project will increase ozone levels beyond 75 ppb, to support the DEIS's conclusion that "the Terminal is not expected to cause or contribute to" exceedance of the ozone NAAQS.

IP1-14

Third, the DEIS fails to consider the full impact of the Project on ozone, because the CAMx modeling the project relies on does not consider the full range of project ozone precursor emissions. The DEIS states that the CAMx model "was run using a 'base case' scenario of emissions as well as an emissions scenario that included the Project (added to the base case), thus allowing for a comparison of ozone levels before and after the Project is permitted."[38] Yet the actual modeling report only considered stationary source emissions, excluding emissions from marine vessels and induced growth.[39] These emissions are likely to impact the modeled ozone impacts. For example, marine vessel emissions in the security zone during export operations add VOC emissions equal to 10% of the VOC emissions expected from the terminal itself. Adding these sources' additional VOC emissions into the CAMx model would be likely to

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[34] *Id.*

[35] *See, e.g.*, https://www.ferc.gov/industries/gas/enviro/eis.asp (EISs for natural gas projects) (last visited August 2, 2014).

[36] Specifically, an area violates this standard when the three-year average of annual fourth-highest daily maximum 8 hour ozone concentrations exceeds 75 ppb. EPA, *National Ambient Air Quality Standards for Ozone*, 73 Fed. Reg. 16436 (Mar. 27, 2008); 40 C.F.R. Pt. 50, App'x I.

[37] CCL, Responses to February 1, 2013 Environmental Information Request, FERC Docket nos. CP12-507 and CP12-508, submittal no. 20130221-5141 (filed Feb. 21, 2013), Response to Question 31; *id.* Exhibit 1, part 2 (Ozone report at 3-1), pages 1064 to 1065 of 1188.

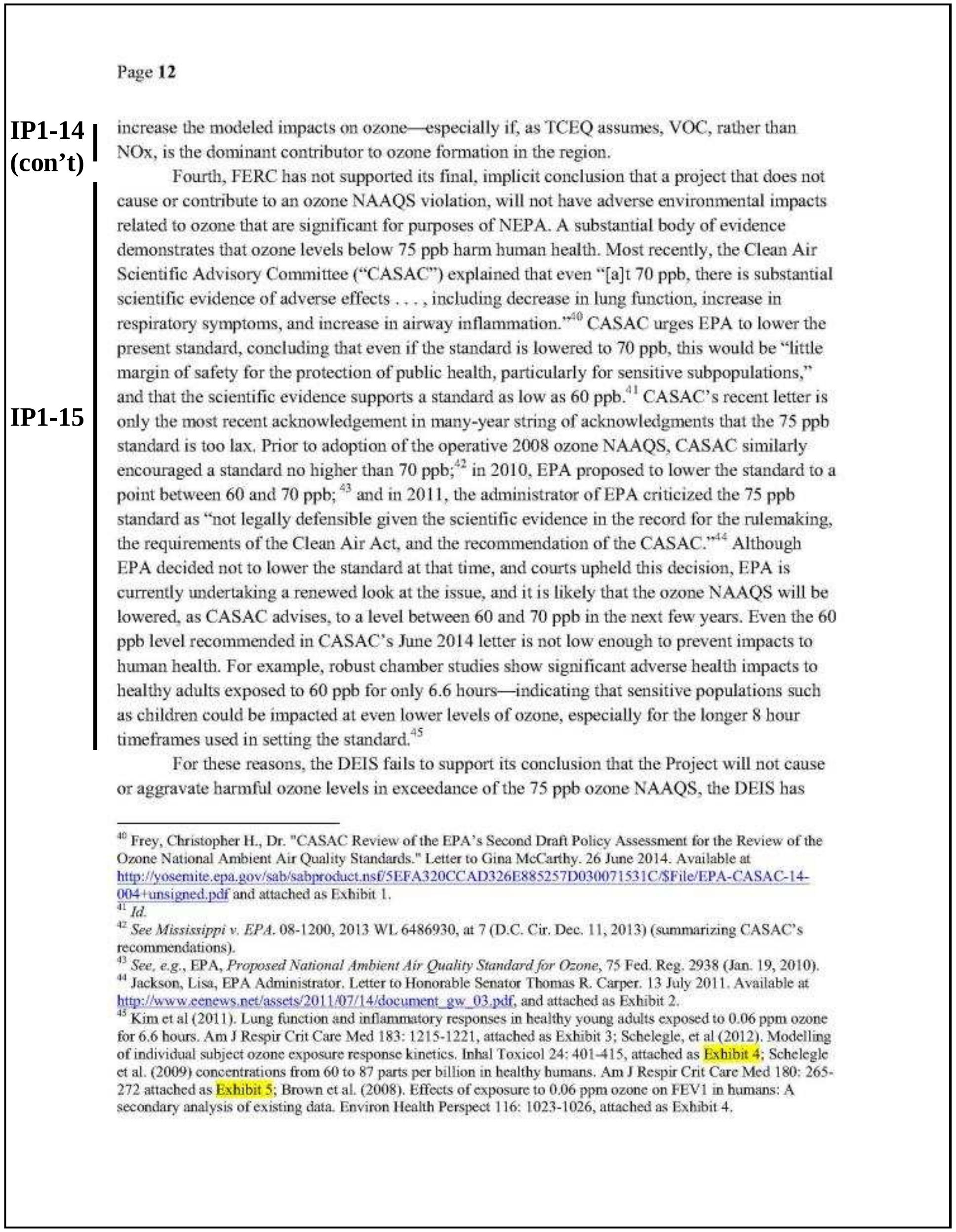
[38] DEIS 4-121.

[39] Ozone Report, *supra* n.37, at Table 2-2 (pages 1059 to 1062 of 1188). The report enumerates the sources of emissions considered, and this enumeration does not include, e.g., marine vessel emissions. While the DEIS generally states that "For the cumulative NAAQS analysis, the Terminal (including associated marine activities) and other off-site sources were modeled," DEIS 4-119, this statement appears to apply only apply to pollutants directly emitted by the project and not to ozone. As the actual ozone modeling report indicates, the ozone analysis was more limited.

IP1-13: Section 4.11.1.6 of the final EIS has been revised to better explain the ozone modeling results.

IP1-14: We disagree. The final EIS incorporates the results of the ozone impact modeling analysis, conducted as part of the Clean Air Act PSD permitting process for the TCEQ. Marine vessel emissions within the security zone would result in a 1.4 percent increase in total ozone precursor emissions for the Project. Section 4.11.1.6 of the final EIS has been revised to include this additional information.

IP1 – Sierra Club



IP1-14 (con't)

increase the modeled impacts on ozone—especially if, as TCEQ assumes, VOC, rather than NOx, is the dominant contributor to ozone formation in the region.

IP1-15

Fourth, FERC has not supported its final, implicit conclusion that a project that does not cause or contribute to an ozone NAAQS violation, will not have adverse environmental impacts related to ozone that are significant for purposes of NEPA. A substantial body of evidence demonstrates that ozone levels below 75 ppb harm human health. Most recently, the Clean Air Scientific Advisory Committee ("CASAC") explained that even "[a]t 70 ppb, there is substantial scientific evidence of adverse effects . . . , including decrease in lung function, increase in respiratory symptoms, and increase in airway inflammation."[40] CASAC urges EPA to lower the present standard, concluding that even if the standard is lowered to 70 ppb, this would be "little margin of safety for the protection of public health, particularly for sensitive subpopulations," and that the scientific evidence supports a standard as low as 60 ppb.[41] CASAC's recent letter is only the most recent acknowledgement in many-year string of acknowledgments that the 75 ppb standard is too lax. Prior to adoption of the operative 2008 ozone NAAQS, CASAC similarly encouraged a standard no higher than 70 ppb;[42] in 2010, EPA proposed to lower the standard to a point between 60 and 70 ppb; [43] and in 2011, the administrator of EPA criticized the 75 ppb standard as "not legally defensible given the scientific evidence in the record for the rulemaking, the requirements of the Clean Air Act, and the recommendation of the CASAC."[44] Although EPA decided not to lower the standard at that time, and courts upheld this decision, EPA is currently undertaking a renewed look at the issue, and it is likely that the ozone NAAQS will be lowered, as CASAC advises, to a level between 60 and 70 ppb in the next few years. Even the 60 ppb level recommended in CASAC's June 2014 letter is not low enough to prevent impacts to human health. For example, robust chamber studies show significant adverse health impacts to healthy adults exposed to 60 ppb for only 6.6 hours—indicating that sensitive populations such as children could be impacted at even lower levels of ozone, especially for the longer 8 hour timeframes used in setting the standard.[45]

For these reasons, the DEIS fails to support its conclusion that the Project will not cause or aggravate harmful ozone levels in exceedance of the 75 ppb ozone NAAQS, the DEIS has

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[40] Frey, Christopher H., Dr. "CASAC Review of the EPA's Second Draft Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards." Letter to Gina McCarthy. 26 June 2014. Available at http://yosemite.epa.gov/sab/sabproduct.nsf/5EFA320CCAD326E885257D030071531C/$File/EPA-CASAC-14-004+unsigned.pdf and attached as Exhibit 1.

[41] *Id.*

[42] *See Mississippi v. EPA*. 08-1200, 2013 WL 6486930, at 7 (D.C. Cir. Dec. 11, 2013) (summarizing CASAC's recommendations).

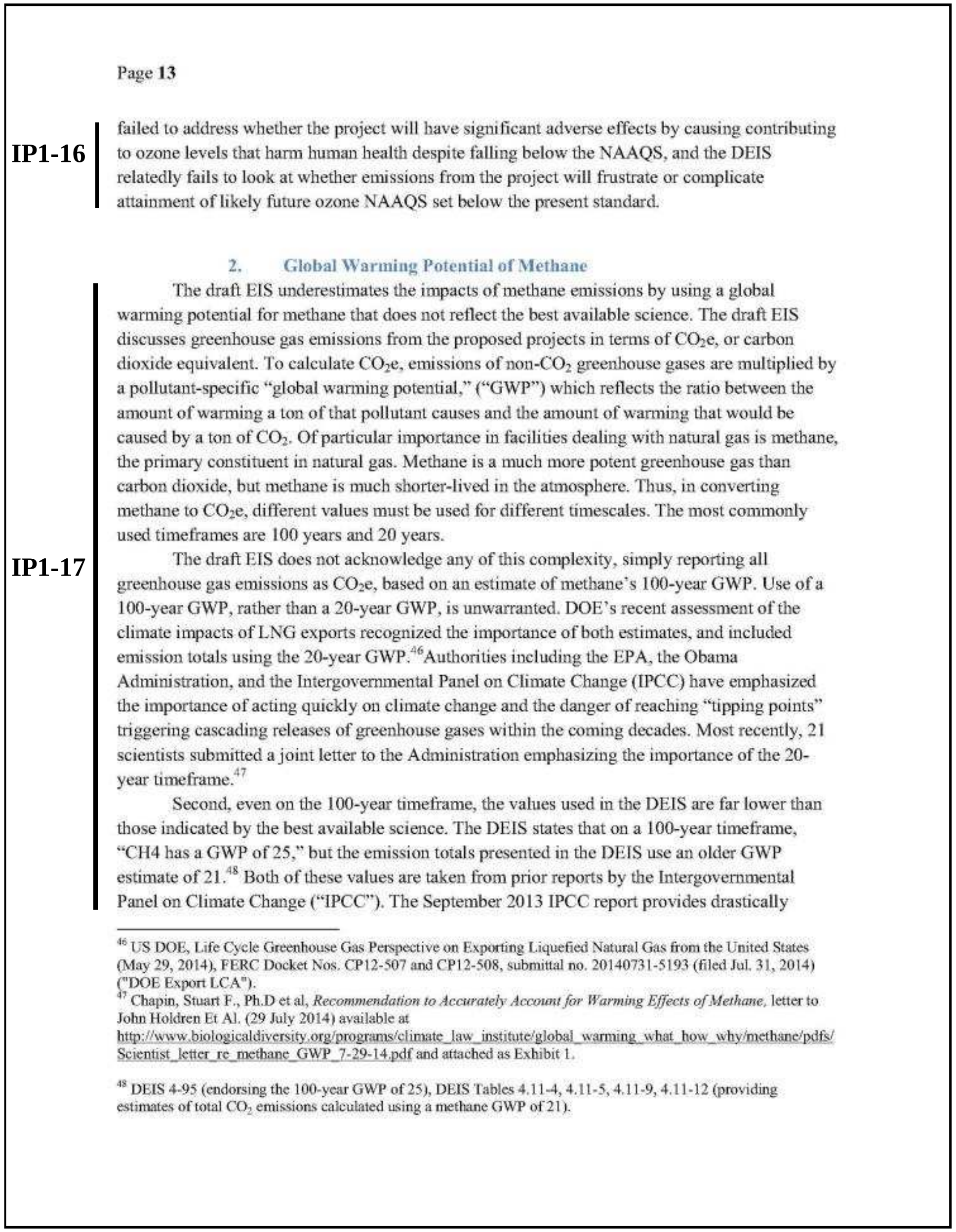
[43] *See, e.g.*, EPA, *Proposed National Ambient Air Quality Standard for Ozone*, 75 Fed. Reg. 2938 (Jan. 19, 2010).

[44] Jackson, Lisa, EPA Administrator. Letter to Honorable Senator Thomas R. Carper. 13 July 2011. Available at http://www.eenews.net/assets/2011/07/14/document_gw_03.pdf, and attached as Exhibit 2.

[45] Kim et al (2011). Lung function and inflammatory responses in healthy young adults exposed to 0.06 ppm ozone for 6.6 hours. Am J Respir Crit Care Med 183: 1215-1221, attached as Exhibit 3; Schelegle, et al (2012). Modelling of individual subject ozone exposure response kinetics. Inhal Toxicol 24: 401-415, attached as Exhibit 4; Schelegle et al. (2009) concentrations from 60 to 87 parts per billion in healthy humans. Am J Respir Crit Care Med 180: 265-272 attached as Exhibit 5; Brown et al. (2008). Effects of exposure to 0.06 ppm ozone on FEV1 in humans: A secondary analysis of existing data. Environ Health Perspect 116: 1023-1026, attached as Exhibit 4.

IP1-15: We disagree. Sierra Club points to ranges of ozone standards that have not been adopted by EPA and speculatively predicts a future EPA proposed ozone standard. The EIS appropriately uses the current EPA established ozone standard, which is supported by EPA to be protective of human health and welfare. If EPA updates its standard in the future in a final rulemaking, we will evaluate projects in comparison with those established standards.

IP1 – Sierra Club



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IP1-16 failed to address whether the project will have significant adverse effects by causing contributing to ozone levels that harm human health despite falling below the NAAQS, and the DEIS relatedly fails to look at whether emissions from the project will frustrate or complicate attainment of likely future ozone NAAQS set below the present standard.

2. Global Warming Potential of Methane

IP1-17 The draft EIS underestimates the impacts of methane emissions by using a global warming potential for methane that does not reflect the best available science. The draft EIS discusses greenhouse gas emissions from the proposed projects in terms of CO_2e, or carbon dioxide equivalent. To calculate CO_2e, emissions of non-CO_2 greenhouse gases are multiplied by a pollutant-specific "global warming potential," ("GWP") which reflects the ratio between the amount of warming a ton of that pollutant causes and the amount of warming that would be caused by a ton of CO_2. Of particular importance in facilities dealing with natural gas is methane, the primary constituent in natural gas. Methane is a much more potent greenhouse gas than carbon dioxide, but methane is much shorter-lived in the atmosphere. Thus, in converting methane to CO_2e, different values must be used for different timescales. The most commonly used timeframes are 100 years and 20 years.

The draft EIS does not acknowledge any of this complexity, simply reporting all greenhouse gas emissions as CO_2e, based on an estimate of methane's 100-year GWP. Use of a 100-year GWP, rather than a 20-year GWP, is unwarranted. DOE's recent assessment of the climate impacts of LNG exports recognized the importance of both estimates, and included emission totals using the 20-year GWP.[46] Authorities including the EPA, the Obama Administration, and the Intergovernmental Panel on Climate Change (IPCC) have emphasized the importance of acting quickly on climate change and the danger of reaching "tipping points" triggering cascading releases of greenhouse gases within the coming decades. Most recently, 21 scientists submitted a joint letter to the Administration emphasizing the importance of the 20-year timeframe.[47]

Second, even on the 100-year timeframe, the values used in the DEIS are far lower than those indicated by the best available science. The DEIS states that on a 100-year timeframe, "CH4 has a GWP of 25," but the emission totals presented in the DEIS use an older GWP estimate of 21.[48] Both of these values are taken from prior reports by the Intergovernmental Panel on Climate Change ("IPCC"). The September 2013 IPCC report provides drastically

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[46] US DOE, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States (May 29, 2014), FERC Docket Nos. CP12-507 and CP12-508, submittal no. 20140731-5193 (filed Jul. 31, 2014) ("DOE Export LCA").

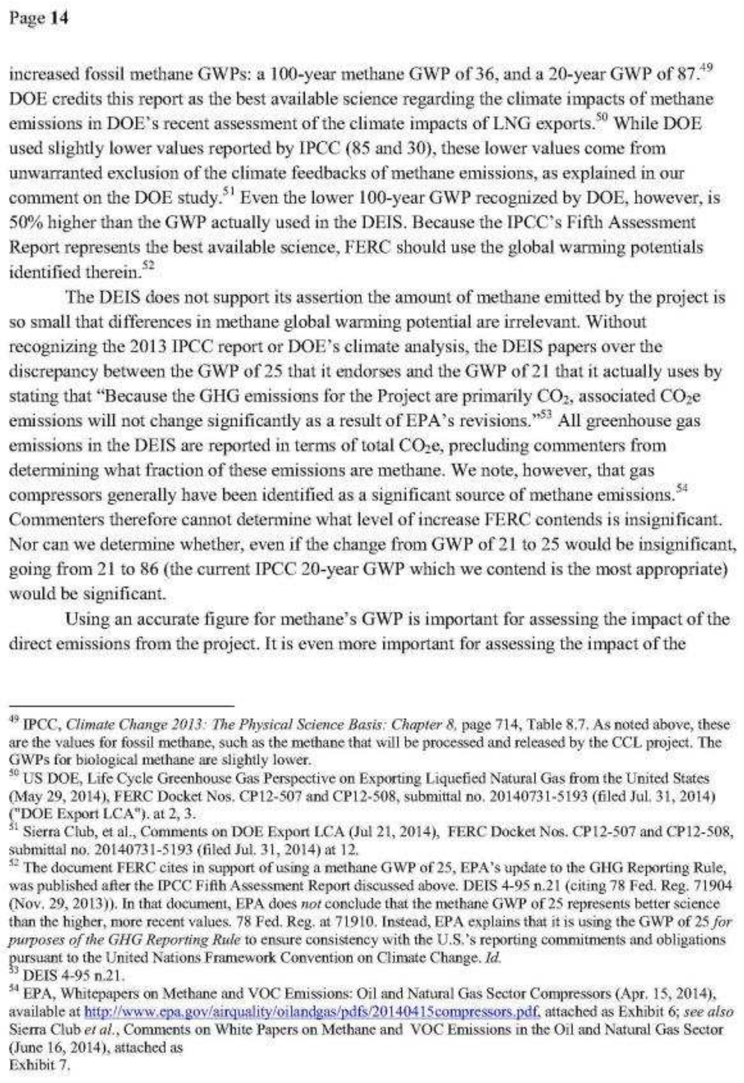
[47] Chapin, Stuart F., Ph.D et al, *Recommendation to Accurately Account for Warming Effects of Methane*, letter to John Holdren Et Al. (29 July 2014) available at http://www.biologicaldiversity.org/programs/climate_law_institute/global_warming_what_how_why/methane/pdfs/Scientist_letter_re_methane_GWP_7-29-14.pdf and attached as Exhibit 1.

[48] DEIS 4-95 (endorsing the 100-year GWP of 25), DEIS Tables 4.11-4, 4.11-5, 4.11-9, 4.11-12 (providing estimates of total CO_2 emissions calculated using a methane GWP of 21).

IP1-16: See responses IP1-12 through IP1-15

IP1-17: We disagree. The Council on Environmental Quality's February 18, 2010 *Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions* proposes that GHG emissions should be quantified in NEPA documents using the methodology established under the Mandatory Reporting Rule for GHGs. When the draft EIS was issued, the EPA accepted GWP value for methane was 25 over a 100-year period. FERC appropriately selected this value because this is the value EPA established on November 29, 2013 for reporting of GHG emissions. EPA supported the 100-year time period over the 20-year period in its summary of comments and responses in the final rulemaking, 2013 Revisions to the Greenhouse Gas Reporting Rule and Final Confidentiality Determinations for New or Substantially Revised Data Elements, establishing the methane GWP at 25 (78 Fed. Reg. 71,904). Similarly, in this final rulemaking, EPA supported the adoption of the published IPCC's Fourth Assessment Report GWP values over the Fifth Assessment Report values. EPA acknowledged the Fifth Assessment Report could lead to more accurate assessments of climate impacts in the future; however, when balanced with the benefit of retaining consistency across national and international programs, the potential gain in accuracy does not justify the loss of consistency in reporting and likely would cause stakeholder confusion among the various GWPs used in different programs. EPA identified that it may consider adoption of the Fifth Assessment Report GWPs in the future, at which time we will ensure that FERC staff request the use of any revised EPA GWP values in future NEPA evaluations.

Also, the magnitude of GHG emissions from the Project are overwhelmingly a function of fossil fuel combustion. For example, for on-shore sources at the LNG Terminal (which is the largest source category of CO_2e for the project), total CO_2 emissions associated with fuel combustion account for about 99 percent of the total projected CO_2e emissions. Therefore, changing the GWP for methane from 21 to 25 would result in an insignificant change in the CO_2e emissions. Tables 4.11-6, 4.11-8, 4.11-9, 4.11-10, and 4.11-12 of the final EIS have been revised to include information on the percentage of the total CO_2e emissions comprised of total CO_2 emissions.



IP1-17 (con't)

increased fossil methane GWPs: a 100-year methane GWP of 36, and a 20-year GWP of 87.[49] DOE credits this report as the best available science regarding the climate impacts of methane emissions in DOE's recent assessment of the climate impacts of LNG exports.[50] While DOE used slightly lower values reported by IPCC (85 and 30), these lower values come from unwarranted exclusion of the climate feedbacks of methane emissions, as explained in our comment on the DOE study.[51] Even the lower 100-year GWP recognized by DOE, however, is 50% higher than the GWP actually used in the DEIS. Because the IPCC's Fifth Assessment Report represents the best available science, FERC should use the global warming potentials identified therein.[52]

The DEIS does not support its assertion the amount of methane emitted by the project is so small that differences in methane global warming potential are irrelevant. Without recognizing the 2013 IPCC report or DOE's climate analysis, the DEIS papers over the discrepancy between the GWP of 25 that it endorses and the GWP of 21 that it actually uses by stating that "Because the GHG emissions for the Project are primarily CO_2, associated CO_2e emissions will not change significantly as a result of EPA's revisions."[53] All greenhouse gas emissions in the DEIS are reported in terms of total CO_2e, precluding commenters from determining what fraction of these emissions are methane. We note, however, that gas compressors generally have been identified as a significant source of methane emissions.[54] Commenters therefore cannot determine what level of increase FERC contends is insignificant. Nor can we determine whether, even if the change from GWP of 21 to 25 would be insignificant, going from 21 to 86 (the current IPCC 20-year GWP which we contend is the most appropriate) would be significant.

Using an accurate figure for methane's GWP is important for assessing the impact of the direct emissions from the project. It is even more important for assessing the impact of the

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[49] IPCC, *Climate Change 2013: The Physical Science Basis: Chapter 8,* page 714, Table 8.7. As noted above, these are the values for fossil methane, such as the methane that will be processed and released by the CCL project. The GWPs for biological methane are slightly lower.

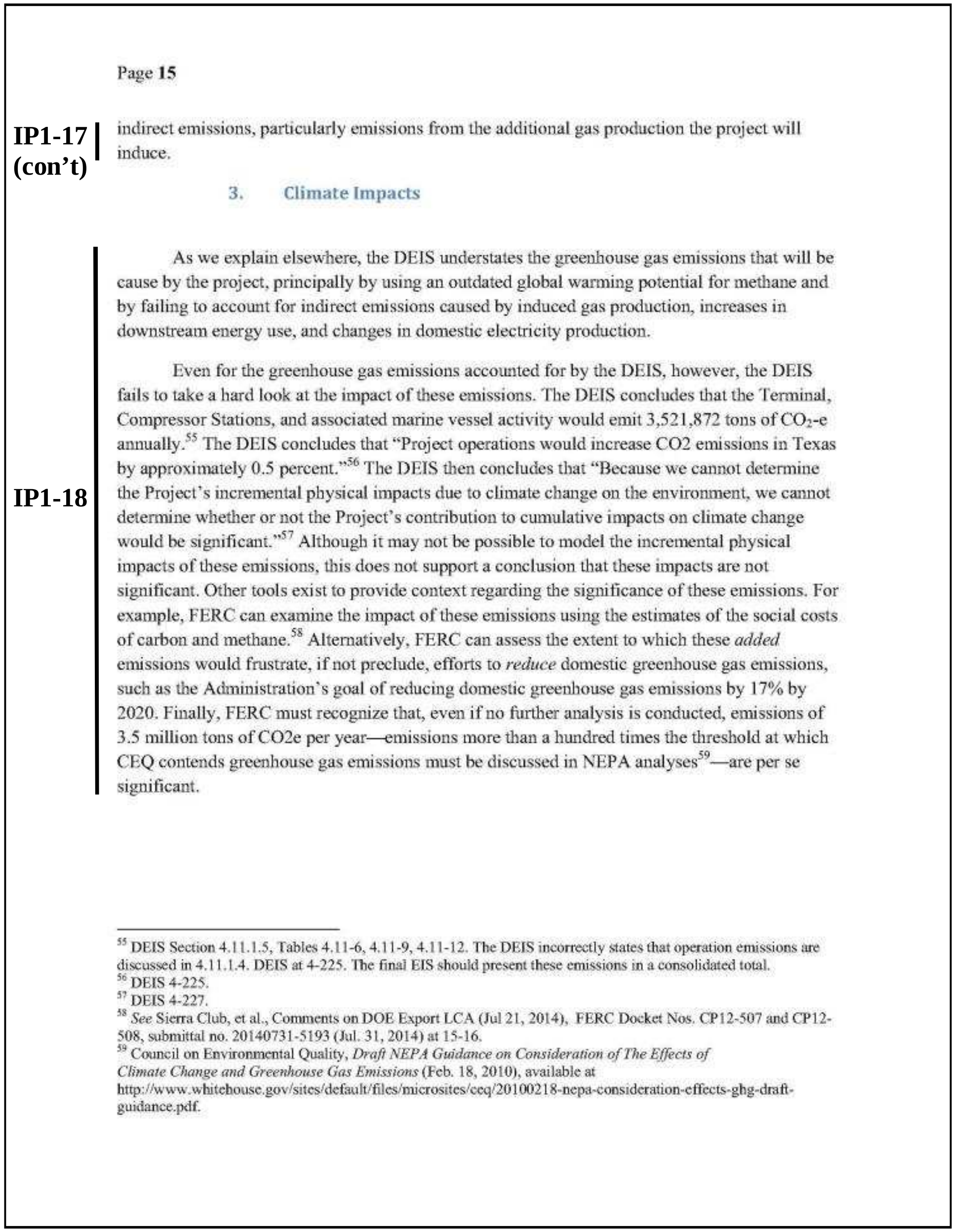
[50] US DOE, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States (May 29, 2014), FERC Docket Nos. CP12-507 and CP12-508, submittal no. 20140731-5193 (filed Jul. 31, 2014) ("DOE Export LCA"). at 2, 3.

[51] Sierra Club, et al., Comments on DOE Export LCA (Jul 21, 2014), FERC Docket Nos. CP12-507 and CP12-508, submittal no. 20140731-5193 (filed Jul. 31, 2014) at 12.

[52] The document FERC cites in support of using a methane GWP of 25, EPA's update to the GHG Reporting Rule, was published after the IPCC Fifth Assessment Report discussed above. DEIS 4-95 n.21 (citing 78 Fed. Reg. 71904 (Nov. 29, 2013)). In that document, EPA does *not* conclude that the methane GWP of 25 represents better science than the higher, more recent values. 78 Fed. Reg. at 71910. Instead, EPA explains that it is using the GWP of 25 *for purposes of the GHG Reporting Rule* to ensure consistency with the U.S.'s reporting commitments and obligations pursuant to the United Nations Framework Convention on Climate Change. *Id.*

[53] DEIS 4-95 n.21.

[54] EPA, Whitepapers on Methane and VOC Emissions: Oil and Natural Gas Sector Compressors (Apr. 15, 2014), available at http://www.epa.gov/airquality/oilandgas/pdfs/20140415compressors.pdf, attached as Exhibit 6; *see also* Sierra Club *et al.*, Comments on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector (June 16, 2014), attached as
Exhibit 7.



Page **15**

IP1-17 (con't) indirect emissions, particularly emissions from the additional gas production the project will induce.

3. Climate Impacts

IP1-18 As we explain elsewhere, the DEIS understates the greenhouse gas emissions that will be cause by the project, principally by using an outdated global warming potential for methane and by failing to account for indirect emissions caused by induced gas production, increases in downstream energy use, and changes in domestic electricity production.

Even for the greenhouse gas emissions accounted for by the DEIS, however, the DEIS fails to take a hard look at the impact of these emissions. The DEIS concludes that the Terminal, Compressor Stations, and associated marine vessel activity would emit 3,521,872 tons of CO_2-e annually.[55] The DEIS concludes that "Project operations would increase CO2 emissions in Texas by approximately 0.5 percent."[56] The DEIS then concludes that "Because we cannot determine the Project's incremental physical impacts due to climate change on the environment, we cannot determine whether or not the Project's contribution to cumulative impacts on climate change would be significant."[57] Although it may not be possible to model the incremental physical impacts of these emissions, this does not support a conclusion that these impacts are not significant. Other tools exist to provide context regarding the significance of these emissions. For example, FERC can examine the impact of these emissions using the estimates of the social costs of carbon and methane.[58] Alternatively, FERC can assess the extent to which these *added* emissions would frustrate, if not preclude, efforts to *reduce* domestic greenhouse gas emissions, such as the Administration's goal of reducing domestic greenhouse gas emissions by 17% by 2020. Finally, FERC must recognize that, even if no further analysis is conducted, emissions of 3.5 million tons of CO2e per year—emissions more than a hundred times the threshold at which CEQ contends greenhouse gas emissions must be discussed in NEPA analyses[59]—are per se significant.

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[55] DEIS Section 4.11.1.5, Tables 4.11-6, 4.11-9, 4.11-12. The DEIS incorrectly states that operation emissions are discussed in 4.11.1.4. DEIS at 4-225. The final EIS should present these emissions in a consolidated total.

[56] DEIS 4-225.

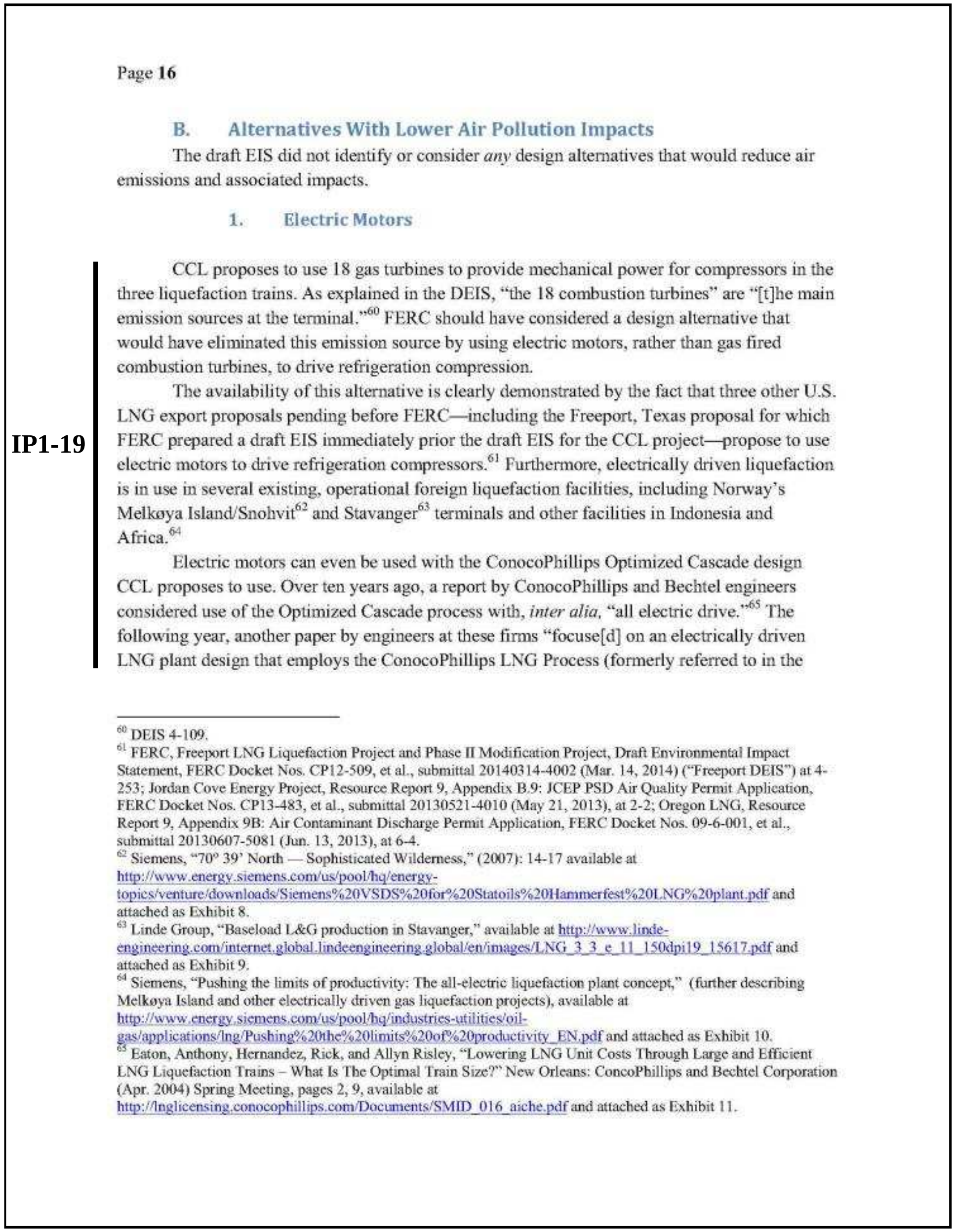
[57] DEIS 4-227.

[58] *See* Sierra Club, et al., Comments on DOE Export LCA (Jul 21, 2014), FERC Docket Nos. CP12-507 and CP12-508, submittal no. 20140731-5193 (Jul. 31, 2014) at 15-16.

[59] Council on Environmental Quality, *Draft NEPA Guidance on Consideration of The Effects of Climate Change and Greenhouse Gas Emissions* (Feb. 18, 2010), available at http://www.whitehouse.gov/sites/default/files/microsites/ceq/20100218-nepa-consideration-effects-ghg-draft-guidance.pdf.

IP1-18: We disagree. The CEQ's February 18, 2010 *Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions* specifies that the threshold identified in the document is merely a "useful indicator", not a threshold of significance for agencies, to use in determining when to evaluate and disclose GHG emissions in NEPA documents. Further CEQ's guidance states that "agencies should recognize the scientific limits of their ability to accurately predict climate change effects, especially of a short-term nature, and not devote effort to analyzing wholly speculative effects". Section 4.11 appropriately calculates the emissions of constructing and operating the Project. Section 4.13.5.11 identifies the impacts climate change has in the southeast region, the potential for climate change to impact the project facilities, and the mitigation measures Cheniere would implement on its proposed facilities to reduce GHG emissions.

IP1 – Sierra Club



B. Alternatives With Lower Air Pollution Impacts

The draft EIS did not identify or consider *any* design alternatives that would reduce air emissions and associated impacts.

1. Electric Motors

IP1-19

CCL proposes to use 18 gas turbines to provide mechanical power for compressors in the three liquefaction trains. As explained in the DEIS, "the 18 combustion turbines" are "[t]he main emission sources at the terminal."[60] FERC should have considered a design alternative that would have eliminated this emission source by using electric motors, rather than gas fired combustion turbines, to drive refrigeration compression.

The availability of this alternative is clearly demonstrated by the fact that three other U.S. LNG export proposals pending before FERC—including the Freeport, Texas proposal for which FERC prepared a draft EIS immediately prior the draft EIS for the CCL project—propose to use electric motors to drive refrigeration compressors.[61] Furthermore, electrically driven liquefaction is in use in several existing, operational foreign liquefaction facilities, including Norway's Melkøya Island/Snohvit[62] and Stavanger[63] terminals and other facilities in Indonesia and Africa.[64]

Electric motors can even be used with the ConocoPhillips Optimized Cascade design CCL proposes to use. Over ten years ago, a report by ConocoPhillips and Bechtel engineers considered use of the Optimized Cascade process with, *inter alia*, "all electric drive."[65] The following year, another paper by engineers at these firms "focuse[d] on an electrically driven LNG plant design that employs the ConocoPhillips LNG Process (formerly referred to in the

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[60] DEIS 4-109.

[61] FERC, Freeport LNG Liquefaction Project and Phase II Modification Project, Draft Environmental Impact Statement, FERC Docket Nos. CP12-509, et al., submittal 20140314-4002 (Mar. 14, 2014) ("Freeport DEIS") at 4-253; Jordan Cove Energy Project, Resource Report 9, Appendix B.9: JCEP PSD Air Quality Permit Application, FERC Docket Nos. CP13-483, et al., submittal 20130521-4010 (May 21, 2013), at 2-2; Oregon LNG, Resource Report 9, Appendix 9B: Air Contaminant Discharge Permit Application, FERC Docket Nos. 09-6-001, et al., submittal 20130607-5081 (Jun. 13, 2013), at 6-4.

[62] Siemens, "70° 39' North — Sophisticated Wilderness," (2007): 14-17 available at http://www.energy.siemens.com/us/pool/hq/energy-topics/venture/downloads/Siemens%20VSDS%20for%20Statoils%20Hammerfest%20LNG%20plant.pdf and attached as Exhibit 8.

[63] Linde Group, "Baseload L&G production in Stavanger," available at http://www.linde-engineering.com/internet.global.lindeengineering.global/en/images/LNG_3_3_e_11_150dpi19_15617.pdf and attached as Exhibit 9.

[64] Siemens, "Pushing the limits of productivity: The all-electric liquefaction plant concept," (further describing Melkøya Island and other electrically driven gas liquefaction projects), available at http://www.energy.siemens.com/us/pool/hq/industries-utilities/oil-gas/applications/lng/Pushing%20the%20limits%20of%20productivity_EN.pdf and attached as Exhibit 10.

[65] Eaton, Anthony, Hernandez, Rick, and Allyn Risley, "Lowering LNG Unit Costs Through Large and Efficient LNG Liquefaction Trains – What Is The Optimal Train Size?" New Orleans: ConcoPhillips and Bechtel Corporation (Apr. 2004) Spring Meeting, pages 2, 9, available at http://lnglicensing.conocophillips.com/Documents/SMID_016_aiche.pdf and attached as Exhibit 11.

IP1-19: The final EIS has been revised to address an alternative design that uses electric motors. See section 3.1.7.

IP1-19 (con't)

trade as the Phillips Optimized Cascade LNG Process)."[66] This paper concluded that "An electric motor driven LNG plant is theoretically a viable solution with today's technology" and that electric compression "is technically feasible."[67] More recently, these firms have identified development of "electric drive and power supply options" as an achievement of their continued efforts to develop the Optimized Cascade process.[68] And as noted above, since publication of this research, electric motor driven plants have in fact been developed and put into practice.

Replacing the 18 gas turbines at the terminal site with electric motors would eliminate the primary source of direct air emissions from project operations. Of course, indirect air emissions would result from generation of the electricity consumed by these electric motors. We assume that an alternative design using electric-driven compression would have lower environmental impacts than the proposed design, with its 18 gas turbines. FERC can and must do more than simply assume that this is the case, however: FERC must take a hard look at the impacts of this alternative.[69] Fortunately, available tools make it possible to assess likely emissions associated with increased demand for electricity. Reflecting the integrated nature of the electricity grid, EPA has created the Emissions & Generation Resource Integrated Database (eGRID),[70] which can be used to estimate air pollution impacts associated with adding marginal units of electricity demand at the level of subregions, states, or by utility.[71] The eGRID database uses detailed information on historical emissions from electric generating units throughout the United States and associated transmission constraints to define emission rates for each subregion. The database conveniently provides emission rates in units of lb/MWh for the three main greenhouse gases (CO_2, CH_4, and N_2O) as well as for the 2 primary air pollutants associated with power production (SO_2 and NO_x, with NO_x given in annual NO_x rates and ozone season NO_x rates).

Electric motors likely provide an emission benefit under present conditions, but a further benefit of electric motors is that they will allow the Project's impacts to decrease over time, as

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[66] Martinez, Bobby et al. *All Electric Motor Drives for LNG Plants*, ConcoPhillips, (2005), page 4, available at http://lnglicensing.conocophillips.com/Documents/SMID_016_GastechElectricMotorPaper.pdf and attached as Exhibit 12.

[67] *Id.* at 15.

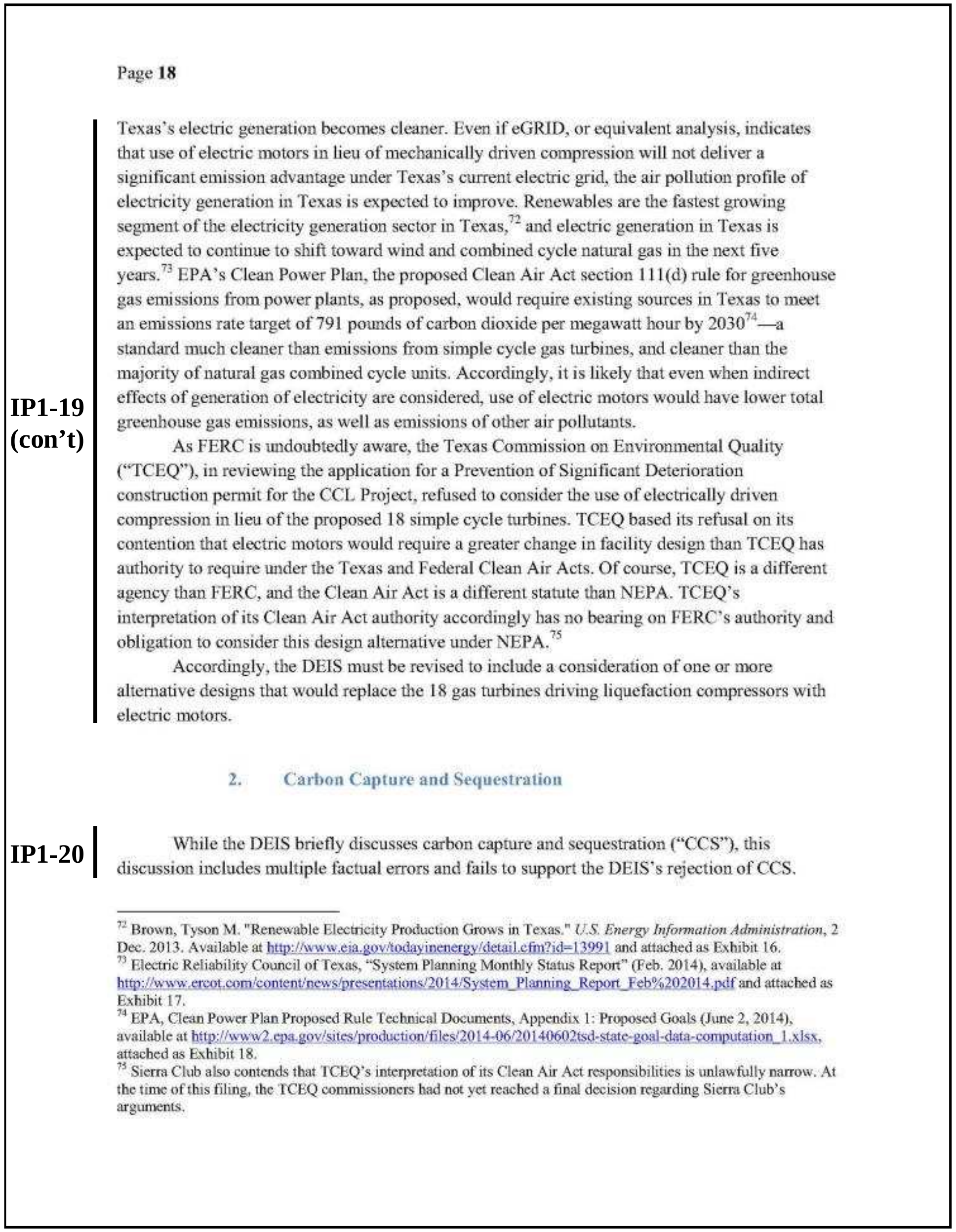
[68] ConocoPhillips, "Optimized Cascade Process" (2009), available at https://web.archive.org/web/20140325040918/http://lnglicensing.conocophillips.com/EN/Documents/ConocoPhillipsLNG_Brochure.pdf and attached as Exhibit 13.

[69] FERC's recent draft EIS for the separate Cameron LNG project illustrates the need to consider the indirect environmental effects associated with purchasing electricity from the grid. There, FERC determined that using a gas fired turbine for a pipeline compressor station was environmentally preferable to using an electric motor, because the electricity supplying an electric motor would come from a coal-fired power plant, providing worse lifecycle impacts than the impacts of gas combustion. FERC, Draft Environment Impact Statement for the Cameron Liquefaction Project, FERC Docket Nos. CP13-25 and CP13-27, submittal 20140110-4001 (Jan. 10, 2014) ("Cameron LNG Draft EIS") at 3-26. Although Sierra Club contends that FERC's conclusion that power would come solely from this coal-fired powerplant is mistaken, the Cameron analysis nonetheless underscores the importance of considering indirect impacts.

[70] *See* http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. Information for 2010, for example, is provided at http://www.epa.gov/cleanenergy/documents/egridzips/eGRID_9th_edition_V1-0_year_2010.zip and attached here as Exhibit 14.

[71] EPA, *How to use eGRID for Carbon Footprinting Electricity Purchases in Greenhouse Gas Emission Inventories* (July 2012), *available at* http://www.epa.gov/ttnchie1/conference/ei20/session3/adiem.pdf and attached as Exhibit 15.

IP1 – Sierra Club



IP1-19 (con't)

Texas's electric generation becomes cleaner. Even if eGRID, or equivalent analysis, indicates that use of electric motors in lieu of mechanically driven compression will not deliver a significant emission advantage under Texas's current electric grid, the air pollution profile of electricity generation in Texas is expected to improve. Renewables are the fastest growing segment of the electricity generation sector in Texas,[72] and electric generation in Texas is expected to continue to shift toward wind and combined cycle natural gas in the next five years.[73] EPA's Clean Power Plan, the proposed Clean Air Act section 111(d) rule for greenhouse gas emissions from power plants, as proposed, would require existing sources in Texas to meet an emissions rate target of 791 pounds of carbon dioxide per megawatt hour by 2030[74]—a standard much cleaner than emissions from simple cycle gas turbines, and cleaner than the majority of natural gas combined cycle units. Accordingly, it is likely that even when indirect effects of generation of electricity are considered, use of electric motors would have lower total greenhouse gas emissions, as well as emissions of other air pollutants.

As FERC is undoubtedly aware, the Texas Commission on Environmental Quality ("TCEQ"), in reviewing the application for a Prevention of Significant Deterioration construction permit for the CCL Project, refused to consider the use of electrically driven compression in lieu of the proposed 18 simple cycle turbines. TCEQ based its refusal on its contention that electric motors would require a greater change in facility design than TCEQ has authority to require under the Texas and Federal Clean Air Acts. Of course, TCEQ is a different agency than FERC, and the Clean Air Act is a different statute than NEPA. TCEQ's interpretation of its Clean Air Act authority accordingly has no bearing on FERC's authority and obligation to consider this design alternative under NEPA.[75]

Accordingly, the DEIS must be revised to include a consideration of one or more alternative designs that would replace the 18 gas turbines driving liquefaction compressors with electric motors.

2. Carbon Capture and Sequestration

IP1-20

While the DEIS briefly discusses carbon capture and sequestration ("CCS"), this discussion includes multiple factual errors and fails to support the DEIS's rejection of CCS.

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[72] Brown, Tyson M. "Renewable Electricity Production Grows in Texas." *U.S. Energy Information Administration*, 2 Dec. 2013. Available at http://www.eia.gov/todayinenergy/detail.cfm?id=13991 and attached as Exhibit 16.

[73] Electric Reliability Council of Texas, "System Planning Monthly Status Report" (Feb. 2014), available at http://www.ercot.com/content/news/presentations/2014/System_Planning_Report_Feb%202014.pdf and attached as Exhibit 17.

[74] EPA, Clean Power Plan Proposed Rule Technical Documents, Appendix 1: Proposed Goals (June 2, 2014), available at http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-state-goal-data-computation_1.xlsx, attached as Exhibit 18.

[75] Sierra Club also contends that TCEQ's interpretation of its Clean Air Act responsibilities is unlawfully narrow. At the time of this filing, the TCEQ commissioners had not yet reached a final decision regarding Sierra Club's arguments.

IP1-20: Section 4.13.5.11 of the final EIS has been updated to address this comment.

IP1-20 (con't)

CCS is a process that uses a chemical or physical solvent to remove CO_2, the dominant GHG, from a CO_2-containing stream (such as flue gas or pipeline-quality natural gas) using absorption, with subsequent stripping of the absorbed CO_2 to produce a concentrated CO_2 stream. CO_2 is an acidic gas, and the CCL project uses the common practice of referring to this the CO_2-containing stream as acid gas. Depending upon the acid gas removal technology applied, the CO_2 may need to be dried, then compressed to a dense phase state for pipeline transport to an appropriate storage location, most likely underground in a geological storage reservoir such as a deep saline aquifer or an oil reservoir or coal seam.

The DEIS broadly and inappropriately rejects CCS by stating "Cheniere noted that any CCS system would cause significant adverse energy and environmental impacts due to the additional water and energy needs for system operation, with the associated generation of additional GHGs and other criteria pollutants from natural gas firing in combustion units."[76] The DEIS does not contain any information regarding the magnitude of these impacts. As such, there is no basis for concluding that these impacts outweigh, or even meaningfully offset, the impacts of full or partial CCS. This cursory assertion that CCS would have some environmental costs as well as benefits is not an adequate basis for rejecting CCS. FERC must either take a harder look at these costs or clarify that its rejection of CCS is not based on the existence of these costs.

The DEIS also improperly rejects applying CCS to the acid gas emissions from the thermal oxidizers. The "acid gas" referred to in this context is a stream of highly pure CO_2—estimated at 93% purity. As FERC has acknowledged elsewhere,[77] the difficulty associated with CCS is inversely correlated with the purity of the CO2 stream. Here, CCL already proposes to install a CO2 removal and concentration system. "Before liquefaction, Cheniere would pre-treat the feed gas for removal of mercury, H2S, and CO2."[78] CO2 will be removed using an amine treatment system similar to those used in CCS installations. As a result of this already-proposed pretreatment process, CO_2 "would be accumulated to concentrations exceeding 93% vol during regeneration of the amine."[79] This stream can potentially be sequestered in a geologic formation with no further treatment or used for enhanced oil recovery or other end uses.

The DEIS's discussion of CCS does not acknowledge the fact that the CCL project design already incorporates a highly pure CO2 stream. Instead, it focuses on the more difficult problem of capturing carbon from turbine combustion emissions. Indeed, the DEIS inappropriately narrowly defines CCS as "involv[ing] deploying a method to capture carbon *from the exhaust stream of the combustion units* and then finding a method for permanent storage (injecting the recovered CO2 underground through various means, including enhanced oil recovery, saline aquifers, and un-mineable coal seams)."[80] The DEIS's sole discussion of

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[76] DEIS 4-226.
[77] Cameron LNG Draft EIS, supra n.69, 4-220.
[78] DEIS 4-143.
[79] DEIS 4-143.
[80] DEIS 4-226 (emphasis added).

IP1-20 (con't)

applying CCS to the CO2 removed from pipeline gas during pretreatment is the fleeting statement that: "In the GHG BACT analysis, Cheniere stated that there is no commercially available carbon capture system of the scale that would be required to control the CO2 emissions from compressor turbines, thermal oxidizers, and flares, such as those typically located at an LNG terminal or compressor station."[81] This is not the hard look NEPA requires. Indeed, in the proceeding on Freeport LNG's PSD permit for GHGs, EPA determined that CCS was technically feasible for emissions from gas pretreatment, and Freeport and Freeport agreed that CO_2 from gas pretreatment could be captured and sequestered for less than $15 per ton, and EPA agreed.[82] Sierra Club's analysis concluded that with better facility design, such as a selective acid gas removal technology that uses a physical solvent, instead of the amine units Freeport LNG proposed, Freeport could capture this CO_2 so cheaply that it could make a net profit off of its sale.[83] Examples of these technologies are Selexol[84] or Rectisol[85] units, which could selectively remove both CO_2 and sulfur compounds to levels suitable for enhanced oil recovery or other sequestration. The resulting CO_2 stream would have a low water content and a lower sulfur content and could go directly to a compression and smaller drying plant and then to a pipeline. This technology is already in commercial use. More than two decades ago (1992), 12 Selexol plants had already been installed to remove CO2 from natural gas.[86] Other similar, recently built and proposed projects also use Selexol. The giant Sandridge natural gas plant in West Texas, for example, is currently recovering 5 tonne/yr of CO2 for EOR using the Selexol process. A second train, with a capacity of 3.4 tonne/yr of CO2 was completed in late 2012.[87] Accordingly, FERC cannot credit CCL's statement that there is no commercially available carbon capture system available to any of the emission streams associated with this project.

Similarly, FERC cannot credit CCL's statement that CCS generally is not economically feasible. As we have shown, CCS can be cheaply applied to pipeline gas pretreatment emissions. FERC cannot reject CCS on the basis of a general assertion of costs without taking a hard look at this particular option (CCS applied solely to amine treatment emissions) and explaining what those costs will be and why FERC determines that they are so extreme as to remove an alternative from the scope of NEPA analysis.

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[81] DEIS 4-226.

[82] EPA Region 6, *Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Freeport LNG Development, L.P., Freeport LNG Liquefaction Project* , PSD-TX-1302-GHG, at 12, 29-30 (Dec. 2, 2013), *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/freeport_lng_sob120213.pdf and attached as Exhibit 19. EPA also concluded that applying CCS to combustion emissions from gas turbines was technically feasible.

[83] Sierra Club, Comments on Freeport LNG Liquefaction Project –Permit No. PSD-TX-1302-GHG (Jan. 6, 2014), at 3, 14-17. Attached as Exhibit 20.

[84] UOP, *UOP Selexol Technology for Acid Gas Removal* (2009), available at: http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1 and attached as Exhibit 21.

[85] Arthur L. Kohl and Richard B. Nielsen, Gas Purification, 5th Edition, Gulf Publishing Company, Chapter 14: Physical Solvent for Acid Gas Removal, 1997.

[86] *Id.* at 1203.

[87] *See* Global CCS Institute, Century Plant, http://www.globalccsinstitute.com/project/century-plant, attached as Exhibit 22.

IP1-20 (con't)

More broadly, the DEIS improperly bases its discussion of CCS entirely on materials CCL submitted to TCEQ as part of the GHG PSD permit application.[88] As FERC is well aware, the analysis required by NEPA is different than the analysis required by the Clean Air Act. In particular, NEPA requires careful consideration of a broader range of alternatives than TCEQ requires under the Clean Air Act, including consideration of alternative facility designs that would be more amenable to CCS than the design proposed by CCL. For example, if FERC determines that the CCL design is less amenable than the Freeport design to capture of CO2 removed from pipeline gas as part of pretreatment (emissions CCL refers to as "acid gas" or "thermal oxidizer" emissions), FERC must consider an alternative under which CCL uses an alternative design that is amenable to CCS, such as the Freeport design.

The DEIS's final, and equally cursory and unsupported, statement regarding CCS is that "Cheniere stated that no long-term CO2 storage facilities are located near the Project, as the region does not have geological formations that support sequestration."[89] FERC must take its own look at the availability of sequestration options. This examination must not be limited to geological sequestration options in the area—it must also consider the option of transporting captured CO2 via pipeline to other regions, or the possibility of industrial uses of CO2. In considering pipeline transport, including potential construction of additional pipelines, FERC must consider the possibility of building a pipeline that would be shared with other facilities, such as the other proposed South Texas LNG export projects that will also fall under FERC's jurisdiction.

VI. Indirect Effects of Induced Gas Production, Gas Price Increases, and End Use of LNG.

Gas exported as LNG must come from somewhere. The only options are an increase in domestic supply to match this new demand or a decrease in other domestic consumption to free up gas that would otherwise be used elsewhere. As explained in the Energy Information Administration's January 2012 LNG Export Study and in numerous subsequent analyses, the US will likely see a combination of both.[90] The predominant effect will be an increase in supply as gas producers increase output in response to new demand. The extra demand will also cause increases in domestic gas prices, which will cause some domestic consumers (primarily in the electricity generating sector) to reduce their consumption (according to EIA, primarily but not

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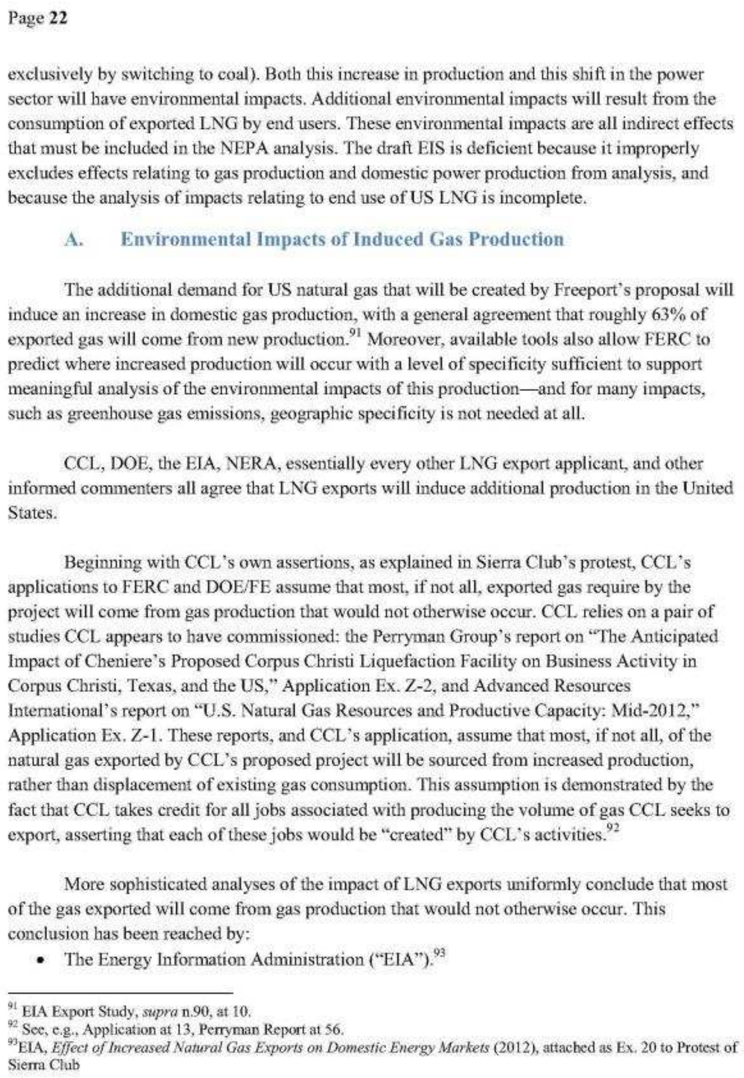
[88] DEIS 4-226.

[89] DEIS 4-226.

[90] DOE/FE has commissioned a two part study of the economic impacts of LNG exports. Energy Information Administration, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, (2012) ("EIA Export Study"), attached as Exhibit 20 to Sierra Club Protest of Corpus Christi Apps; NERA Study, supra n.1. Sierra Club and others submitted extensive comments on these studies. Sierra Club Initial NERA Comment, attached as Exhibit 23; Synapse Analysis of NERA Study, attached as Exhibit 24; Sierra Club Reply NERA Comment, attached as Exhibit 25.

IP1 – Sierra Club



exclusively by switching to coal). Both this increase in production and this shift in the power sector will have environmental impacts. Additional environmental impacts will result from the consumption of exported LNG by end users. These environmental impacts are all indirect effects that must be included in the NEPA analysis. The draft EIS is deficient because it improperly excludes effects relating to gas production and domestic power production from analysis, and because the analysis of impacts relating to end use of US LNG is incomplete.

IP1-21

A. Environmental Impacts of Induced Gas Production

The additional demand for US natural gas that will be created by Freeport's proposal will induce an increase in domestic gas production, with a general agreement that roughly 63% of exported gas will come from new production.[91] Moreover, available tools also allow FERC to predict where increased production will occur with a level of specificity sufficient to support meaningful analysis of the environmental impacts of this production—and for many impacts, such as greenhouse gas emissions, geographic specificity is not needed at all.

CCL, DOE, the EIA, NERA, essentially every other LNG export applicant, and other informed commenters all agree that LNG exports will induce additional production in the United States.

IP1-22

Beginning with CCL's own assertions, as explained in Sierra Club's protest, CCL's applications to FERC and DOE/FE assume that most, if not all, exported gas require by the project will come from gas production that would not otherwise occur. CCL relies on a pair of studies CCL appears to have commissioned: the Perryman Group's report on "The Anticipated Impact of Cheniere's Proposed Corpus Christi Liquefaction Facility on Business Activity in Corpus Christi, Texas, and the US," Application Ex. Z-2, and Advanced Resources International's report on "U.S. Natural Gas Resources and Productive Capacity: Mid-2012," Application Ex. Z-1. These reports, and CCL's application, assume that most, if not all, of the natural gas exported by CCL's proposed project will be sourced from increased production, rather than displacement of existing gas consumption. This assumption is demonstrated by the fact that CCL takes credit for all jobs associated with producing the volume of gas CCL seeks to export, asserting that each of these jobs would be "created" by CCL's activities.[92]

More sophisticated analyses of the impact of LNG exports uniformly conclude that most of the gas exported will come from gas production that would not otherwise occur. This conclusion has been reached by:

- The Energy Information Administration ("EIA").[93]

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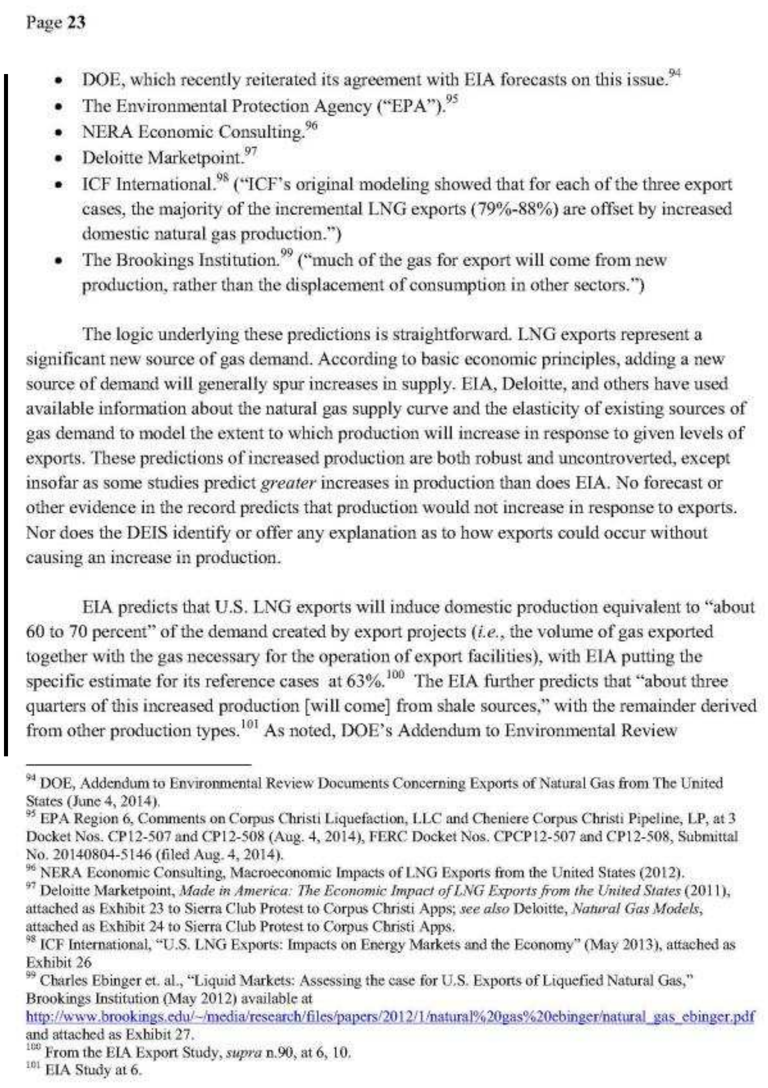
[91] EIA Export Study, *supra* n.90, at 10.
[92] See, e.g., Application at 13, Perryman Report at 56.
[93] EIA, *Effect of Increased Natural Gas Exports on Domestic Energy Markets* (2012), attached as Ex. 20 to Protest of Sierra Club

IP1-21: See response to IP1-8.

IP1-22: Section 4.13 of the final EIS has been revised to address this issue.

IP1-22 (con't)



- DOE, which recently reiterated its agreement with EIA forecasts on this issue.[94]
- The Environmental Protection Agency ("EPA").[95]
- NERA Economic Consulting.[96]
- Deloitte Marketpoint.[97]
- ICF International.[98] ("ICF's original modeling showed that for each of the three export cases, the majority of the incremental LNG exports (79%-88%) are offset by increased domestic natural gas production.")
- The Brookings Institution.[99] ("much of the gas for export will come from new production, rather than the displacement of consumption in other sectors.")

The logic underlying these predictions is straightforward. LNG exports represent a significant new source of gas demand. According to basic economic principles, adding a new source of demand will generally spur increases in supply. EIA, Deloitte, and others have used available information about the natural gas supply curve and the elasticity of existing sources of gas demand to model the extent to which production will increase in response to given levels of exports. These predictions of increased production are both robust and uncontroverted, except insofar as some studies predict *greater* increases in production than does EIA. No forecast or other evidence in the record predicts that production would not increase in response to exports. Nor does the DEIS identify or offer any explanation as to how exports could occur without causing an increase in production.

EIA predicts that U.S. LNG exports will induce domestic production equivalent to "about 60 to 70 percent" of the demand created by export projects (*i.e.*, the volume of gas exported together with the gas necessary for the operation of export facilities), with EIA putting the specific estimate for its reference cases at 63%.[100] The EIA further predicts that "about three quarters of this increased production [will come] from shale sources," with the remainder derived from other production types.[101] As noted, DOE's Addendum to Environmental Review

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[94] DOE, Addendum to Environmental Review Documents Concerning Exports of Natural Gas from The United States (June 4, 2014).

[95] EPA Region 6, Comments on Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP, at 3 Docket Nos. CP12-507 and CP12-508 (Aug. 4, 2014), FERC Docket Nos. CPCP12-507 and CP12-508, Submittal No. 20140804-5146 (filed Aug. 4, 2014).

[96] NERA Economic Consulting, Macroeconomic Impacts of LNG Exports from the United States (2012).

[97] Deloitte Marketpoint, *Made in America: The Economic Impact of LNG Exports from the United States* (2011), attached as Exhibit 23 to Sierra Club Protest to Corpus Christi Apps; *see also* Deloitte, *Natural Gas Models*, attached as Exhibit 24 to Sierra Club Protest to Corpus Christi Apps.

[98] ICF International, "U.S. LNG Exports: Impacts on Energy Markets and the Economy" (May 2013), attached as Exhibit 26

[99] Charles Ebinger et. al., "Liquid Markets: Assessing the case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (May 2012) available at http://www.brookings.edu/~/media/research/files/papers/2012/1/natural%20gas%20ebinger/natural_gas_ebinger.pdf and attached as Exhibit 27.

[100] From the EIA Export Study, *supra* n.90, at 6, 10.

[101] EIA Study at 6.

IP1-22 (con't)

Documents Concerning Exports of Natural Gas from The United States recently reiterated DOE's endorsement of these predictions. CCL proposes to export 2.1 bcf/d of natural gas, or 766.5 bcf/year. Operation of the proposed liquefaction equipment will require roughly an additional 77 bcf/year of gas.[102] Thus, the Project would create roughly 843.5 bcf/year of additional gas demand, and under EIA's reference case, this will lead to roughly 531 bcf/year of gas production that would not otherwise occur.

The majority of this additional production is likely to occur in Texas and surrounding states. The DEIS repeatedly notes that "the natural gas feedstock for the Project would be sourced from the south Texas region,"[103] and identifies use of gas from Gulf sources as part of the purpose and need for the project.[104] The DEIS rejects several "system alternatives" involving use of other terminals in Louisiana on the ground that these alternatives are too far removed from the gas intended to supply the project, such that pipeline transportation of this gas to these alternative locations would entail additional environmental impacts.[105] We acknowledge that production supplying the project and production induced by the project are two distinct concepts, and the two will not perfectly overlap. Some of the induced production may occur outside the South Texas region, with the CCL project consuming nearby gas that would otherwise be sent to other states. Nonetheless, the two are likely to be highly correlated. In the absence of more sophisticated models of where additional production will occur, the former would provide a reasonably geographic proxy for the later.

More sophisticated models are, however, available. As Sierra Club explained in comments on the DOE Addendum and in our prior protest in this docket, EIA's National Energy Modeling System[106] and Deloitte Marketpoint's world gas model are sophisticated tools that can predict where this additional production is most likely to occur.[107] Another report, by ICF, has already published forecasts of state-specific increases in gas production in response to exports.[108] The ICF State Level Impact study uses a detailed model of new production in response to exports. That report's map of predicted production increases in response to the particular LNG export scenario used by the authors is provided below.[109] This same tool could likely be used to predict where production would increase in response to CCL's particular project. Alternatively, the general export scenario already conducted by this study provides a basis for evaluating the cumulative impacts of proposed export projects.

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[102] This estimate is taken derived from EIA's assumption that the liquefaction process consumes gas equivalent to roughly 9 or 10 percent of volume of gas being liquefied. A more precise estimate of liquefaction gas needs for the CCL project could be derived from the particular equipment CCL proposes to install.

[103] DEIS 3-6, 3-11.

[104] DEIS 3-4.

[105] DEIS 3-6, 3-11.

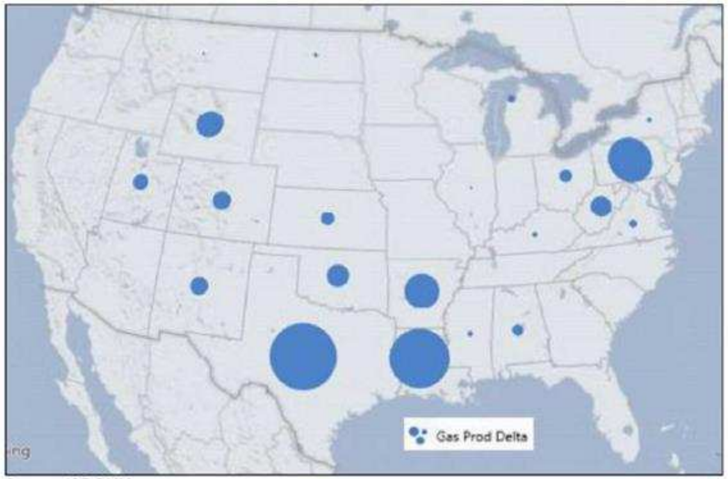
[106] *See* Sierra Club, et al., Comments on DOE Environmental Addendum, page 6, and exhibits 1 – 3 thereto.

[107] *Id.* at 7 and exhibit 4 thereto.

[108] ICF State Level Impact Study, *supra* n.98

[109] *Id.* at 15.

Exhibit 3-4: Map of Relative Natural Gas Production Changes by State in 2025



Source: ICF GMM

Note: The map above shows the relative natural gas production changes in the ICF Base Case in 2025 (relative to the Zero LNG Exports Case).

IP1-22 (con't)

We offer no opinion at this time about the strengths or weaknesses of these private models relative to EIA's. We simply note that multiple tools exist which allow predictions of how and where production will respond to exports

This additional natural gas production—from both conventional and unconventional sources—will have significant environmental impacts. These impacts are generally discussed in DOE's addendum to environmental review and related documents, and in the comments Sierra Club submitted thereon. While those documents consider LNG exports generally, here, in the context of an individual export application, further analysis can and must be undertaken.

For example, production induced by the CCL project will cause significant air pollution. DOE provides a summary of this pollution, but understates the likely volume of emissions, because DOE relies on "bottom-up" estimates of emissions that are significantly lower than estimates based on atmospheric measurements of methane and other pollutants.[110] Since the DOE environmental materials were released, yet another peer reviewed study using atmospheric measurements to estimate natural gas production emissions has been published, providing still

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[110] Sierra Club, et al., Comments on DOE Export LCA, at 7.

IP1-22 (con't)

further evidence that the actual methane leak rate from U.S. gas production is significantly higher than DOE and EPA have acknowledged. This paper, by researchers at Carnegie Mellon and the National Ocean and Atmospheric Administration, concludes that the most likely methane leak rate is between 2 and 4 percent.[111]

As we explain above, the CCL project will likely induce 531 bcf/year of production that would not otherwise occur. Estimates of the gas production leak rate allow us to estimate the air emissions impacts of 531 bcf/year of production. These leak rates, and EPA conversion factors between the typical volumes of methane, VOC, and HAP in natural gas,[112] make it possible to estimate the potential impact of increasing gas production in the way that LNG export would require. We note that these conversion factors are derived from national inventories, and it may be possible to provide estimates particular to the Texas and Gulf Coast regions where production induced by CCL is most likely to occur, but these estimates provide a useful starting point for analysis.

The table below uses these conversion factors to calculate the emissions associated with producing 531 bcf/year of new gas demand, the likely inducement specifically attributable to the present CCL Project. While we contend that the leak rate is most likely to be in the neighborhood of 3%, we calculate for emissions a 1% leak rate (included as a conservative case), DOE's estimated leak of 1.4%,[113] the 2.4% rate used in EPA's previous inventory, the 3% leak rate reflected by general atmospheric studies, and the higher leak rates the NOAA studies suggest in studies of particular plays. We provide results for methane, VOC, and HAP.[114]

Table 2: Annual Emissions Associated with Production of 531 bcf of Natural Gas

Leak Rate	Methane (tons)	VOC (tons)	HAP (tons)
1%	110,448	16,114	1,171
1.40%	154,627	22,560	1,639
2.40%	265,075	38,674	2,810
3.00%	331,344	48,343	3,512
4.00%	441,792	64,457	4,683

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[111] Stefan Scheietzke *et al.*, "Natural gas fugitive emissions rates constrained by global atmospheric methane and ethane" *Environmental Science & Technology*, (June 19, 2014), DOI: 10.1021/es501204c, attached as Exhibit 28 (see pages 22 to 23 of "Just Accepted" manuscript)

[112] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules, at 2-4 (July 2011) ("2011 TSD"), attached to the SC Protest of Corpus Christi Apps as Exhibit 26, at Table 4.2. EPA calculated average composition factors for gas from well completions. These estimates, which are based on a range of national data are robust, but necessarily imprecise for particular fields and points along the line from wellhead to LNG terminal. Nonetheless, they provide a beginning point for quantitative work. EPA's conversions are: 0.0208 tons of methane per mcf of gas; 0.1459 lb VOC per lb methane; and 0.0106 lb HAP per lb methane.

[113] DOE estimates the leak rate of 1.3% for conventional production and 1.4% for shale gas. Because EIA predicts that overwhelming majority of new production induced by exports will be from shale, the rounded weighted average leak rate is 1.4%.

[114] These figures were calculated by multiplying the relevant EPA conversion factors to generate tonnages of the relevant pollutants. These results are approximations: Although we reported the arithmetic results of this calculation, of course only the first few significant figures of each value should be the focus.

9%	994,032	145,029	10,537

IP1-22 (con't)

Thus, the production induced by CCL's proposal, alone, would be responsible for hundreds of thousands of tons of air pollution annually. Notably, the threshold for major source permitting under the Clean Air Act is generally just tens of tons of pollution; for greenhouse gases, it is generally 75,000 tons of carbon dioxide equivalent. CCL would thus greatly increase air pollution in the regions from which it draws its gas, imperiling public health and the global climate.

These emissions will have a significant adverse impact on the climate and on regional air quality. As explained above, the nearest shale play, which is likely to be the primary location of additional production induced by the project, is Texas's Eagle Ford Shale play. The Alamo Area Council of Governments recently completed a study of the effects of ozone precursor emissions from oil and gas production in the Eagle Ford shale on ozone levels in the San Antonio-New Braunfels Metropolitan Statistical Area.[115] This study considered the impacts of low, medium, and high development would have on regional ozone levels in 2018, and predicted that moving from a low to high scenario would increase 8-hour ozone design values at selected monitors by 0.5 to 0.7 ppb, and that in light of emissions from oil and gas production, "If the EPA lowers the 8-hour ozone standard, it will be difficult for the San Antonio-New Braunfels MSA to meet that lower attainment threshold."[116] Notably, the difference between this study's low and high scenarios, with regard to VOC emissions, is equivalent to the VOC emissions that would likely result from new production induced by the CCL project. The study predicted 144.2 tons per day of Eagle Ford VOC emissions in a low development scenario and 276.9 tons per day in a high scenario—a difference of 132.7 tons per day of VOC.[117] As explained above, under EIA's estimate of 63% of new production and the atmospheric studies' estimate of a 3% leak rate, new production induced by CCL can be estimated to emit 132.4 tons per day of VOC. While it is unlikely that a full 100% of the production induced by CCL will be in the Eagle Ford Shale, emissions from oil and gas production are similarly contributing to ozone problems throughout the region.[118] These studies demonstrate the significant impact that CCL's project itself will have

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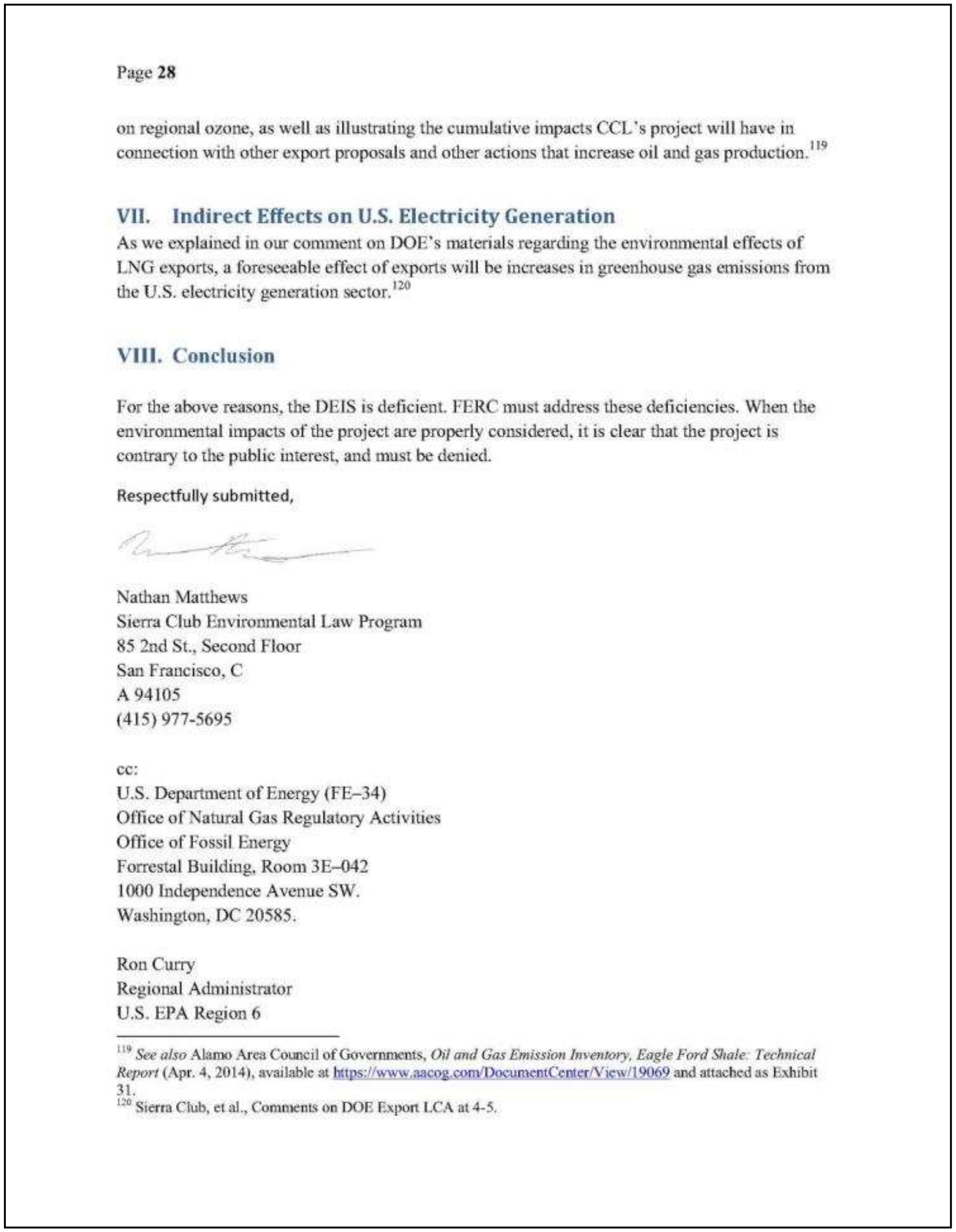
[115] Alamo Area Council of Governments, *Development of the Extended June 2006 Photochemical Modeling Episode: Technical Report* (October 2013), available at https://www.aacog.com/DocumentCenter/View/19262 and attached as Exhibit 29.

[116] *Id.* at v.

[117] *Id.* at 4-54 (Figure 4-9).

[118] *See, e.g.*, Ahmadi, Mahdi and Kuruvilla John, *An evaluation of the spatio-temporal characteristics of meteorologically-adjusted ozone trends in North Texas*, Air Quality Technical Meeting NCTCOG: Arlington, TX (Apr. 17, 2014) (modeling recent history Barnett Shale gas well contribution to ozone levels in the Dallas/Fort Worth area), *available at* http://www.nctcog.org/trans/committees/aqtc/041714/Item.4.pdf and attached as Exhibit 30.



on regional ozone, as well as illustrating the cumulative impacts CCL's project will have in connection with other export proposals and other actions that increase oil and gas production.[119]

VII. Indirect Effects on U.S. Electricity Generation

As we explained in our comment on DOE's materials regarding the environmental effects of LNG exports, a foreseeable effect of exports will be increases in greenhouse gas emissions from the U.S. electricity generation sector.[120]

VIII. Conclusion

For the above reasons, the DEIS is deficient. FERC must address these deficiencies. When the environmental impacts of the project are properly considered, it is clear that the project is contrary to the public interest, and must be denied.

Respectfully submitted,

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cc:
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Washington, DC 20585.

Ron Curry
Regional Administrator
U.S. EPA Region 6

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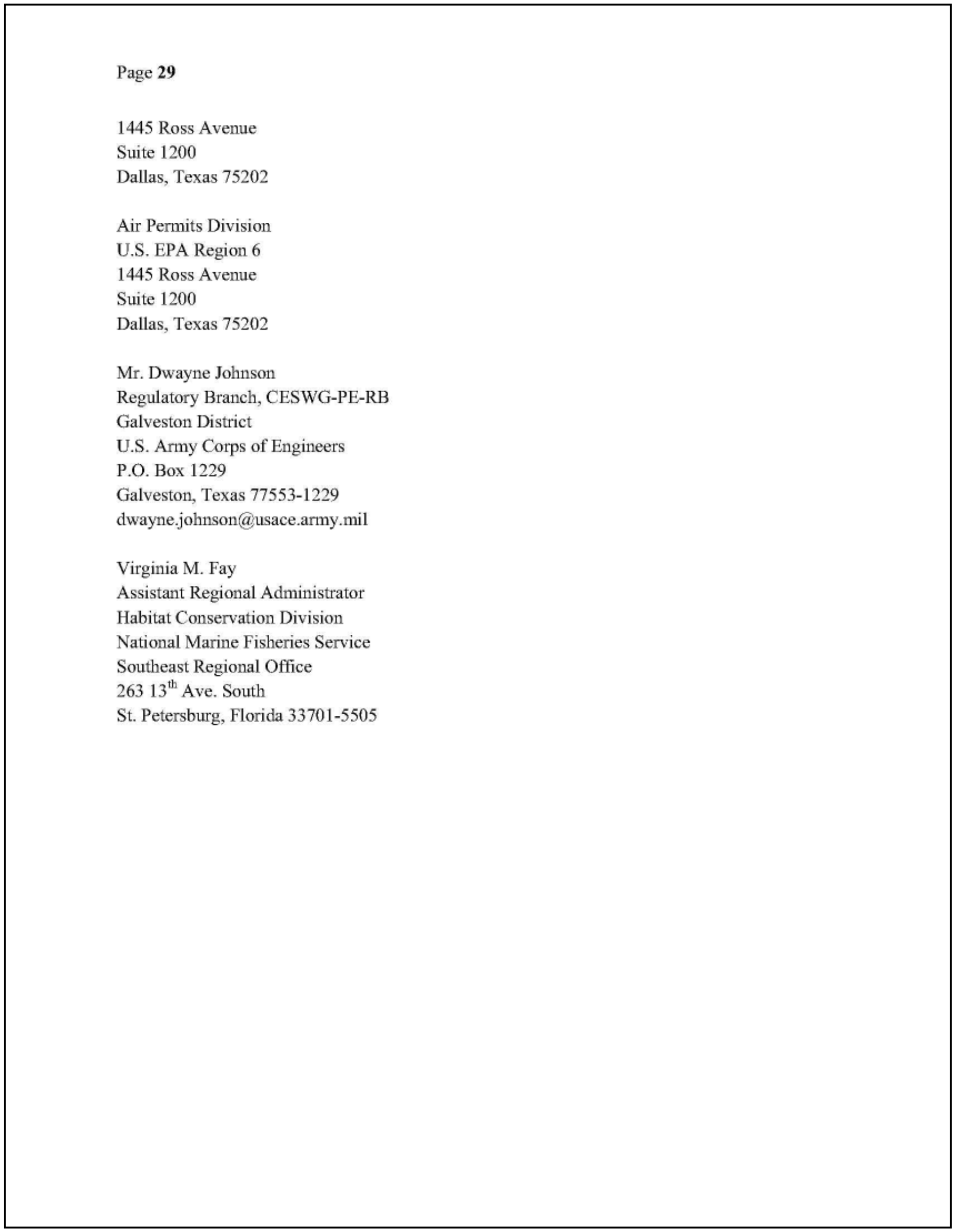
[119] *See also* Alamo Area Council of Governments, *Oil and Gas Emission Inventory, Eagle Ford Shale: Technical Report* (Apr. 4, 2014), available at https://www.aacog.com/DocumentCenter/View/19069 and attached as Exhibit 31.

[120] Sierra Club, et al., Comments on DOE Export LCA at 4-5.



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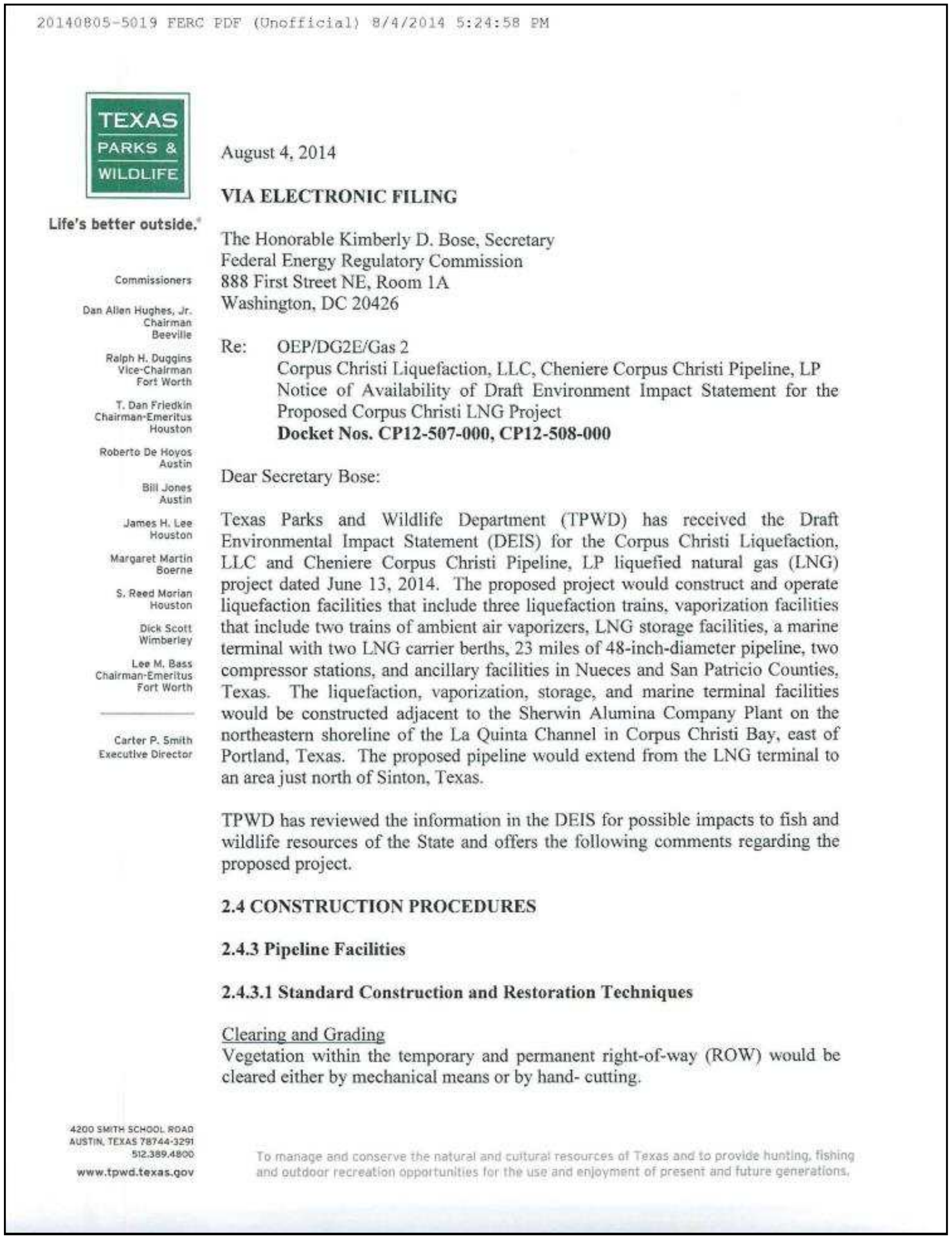
STATE GOVERNMENT COMMENTS

SG1 – Texas Parks & Wildlife



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Executive Director

August 4, 2014

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Re: OEP/DG2E/Gas 2
Corpus Christi Liquefaction, LLC, Cheniere Corpus Christi Pipeline, LP
Notice of Availability of Draft Environment Impact Statement for the Proposed Corpus Christi LNG Project
Docket Nos. CP12-507-000, CP12-508-000

Dear Secretary Bose:

Texas Parks and Wildlife Department (TPWD) has received the Draft Environmental Impact Statement (DEIS) for the Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, LP liquefied natural gas (LNG) project dated June 13, 2014. The proposed project would construct and operate liquefaction facilities that include three liquefaction trains, vaporization facilities that include two trains of ambient air vaporizers, LNG storage facilities, a marine terminal with two LNG carrier berths, 23 miles of 48-inch-diameter pipeline, two compressor stations, and ancillary facilities in Nueces and San Patricio Counties, Texas. The liquefaction, vaporization, storage, and marine terminal facilities would be constructed adjacent to the Sherwin Alumina Company Plant on the northeastern shoreline of the La Quinta Channel in Corpus Christi Bay, east of Portland, Texas. The proposed pipeline would extend from the LNG terminal to an area just north of Sinton, Texas.

TPWD has reviewed the information in the DEIS for possible impacts to fish and wildlife resources of the State and offers the following comments regarding the proposed project.

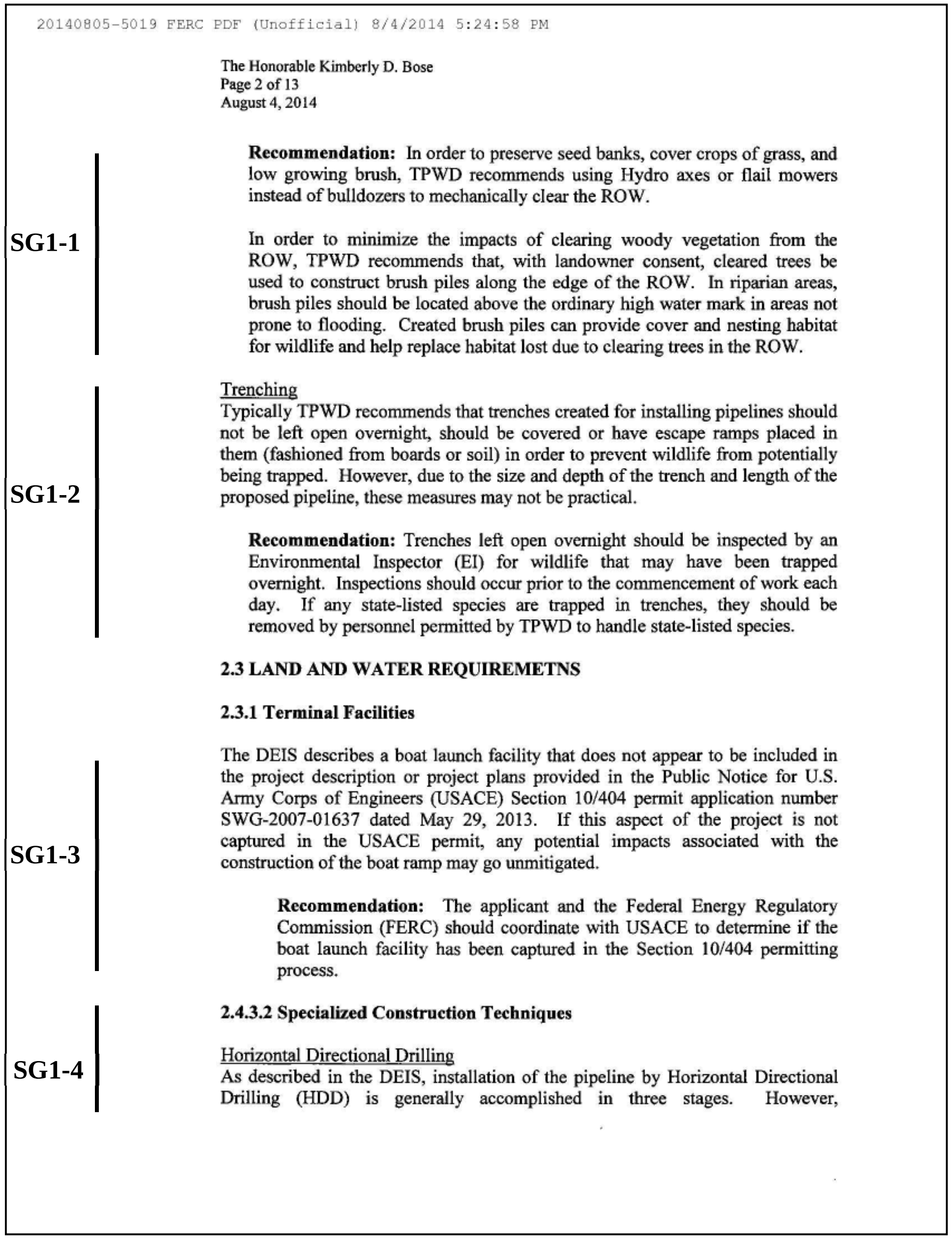
2.4 CONSTRUCTION PROCEDURES

2.4.3 Pipeline Facilities

2.4.3.1 Standard Construction and Restoration Techniques

Clearing and Grading
Vegetation within the temporary and permanent right-of-way (ROW) would be cleared either by mechanical means or by hand- cutting.

SG1 – Texas Parks & Wildlife



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The Honorable Kimberly D. Bose
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SG1-1

Recommendation: In order to preserve seed banks, cover crops of grass, and low growing brush, TPWD recommends using Hydro axes or flail mowers instead of bulldozers to mechanically clear the ROW.

In order to minimize the impacts of clearing woody vegetation from the ROW, TPWD recommends that, with landowner consent, cleared trees be used to construct brush piles along the edge of the ROW. In riparian areas, brush piles should be located above the ordinary high water mark in areas not prone to flooding. Created brush piles can provide cover and nesting habitat for wildlife and help replace habitat lost due to clearing trees in the ROW.

SG1-2

Trenching

Typically TPWD recommends that trenches created for installing pipelines should not be left open overnight, should be covered or have escape ramps placed in them (fashioned from boards or soil) in order to prevent wildlife from potentially being trapped. However, due to the size and depth of the trench and length of the proposed pipeline, these measures may not be practical.

Recommendation: Trenches left open overnight should be inspected by an Environmental Inspector (EI) for wildlife that may have been trapped overnight. Inspections should occur prior to the commencement of work each day. If any state-listed species are trapped in trenches, they should be removed by personnel permitted by TPWD to handle state-listed species.

2.3 LAND AND WATER REQUIREMETNS

2.3.1 Terminal Facilities

SG1-3

The DEIS describes a boat launch facility that does not appear to be included in the project description or project plans provided in the Public Notice for U.S. Army Corps of Engineers (USACE) Section 10/404 permit application number SWG-2007-01637 dated May 29, 2013. If this aspect of the project is not captured in the USACE permit, any potential impacts associated with the construction of the boat ramp may go unmitigated.

Recommendation: The applicant and the Federal Energy Regulatory Commission (FERC) should coordinate with USACE to determine if the boat launch facility has been captured in the Section 10/404 permitting process.

SG1-4

2.4.3.2 Specialized Construction Techniques

Horizontal Directional Drilling

As described in the DEIS, installation of the pipeline by Horizontal Directional Drilling (HDD) is generally accomplished in three stages. However,

SG1-1: As stated in the final EIS we have determined that Cheniere's proposed construction measures are acceptable and consistent with our Plan and Procedures. If requested by a landowner, brush piles can be established along the edge of the ROW through land use agreements and site-specific plans. Section 2.4.3.1 of the final EIS has been revised to address this comment.

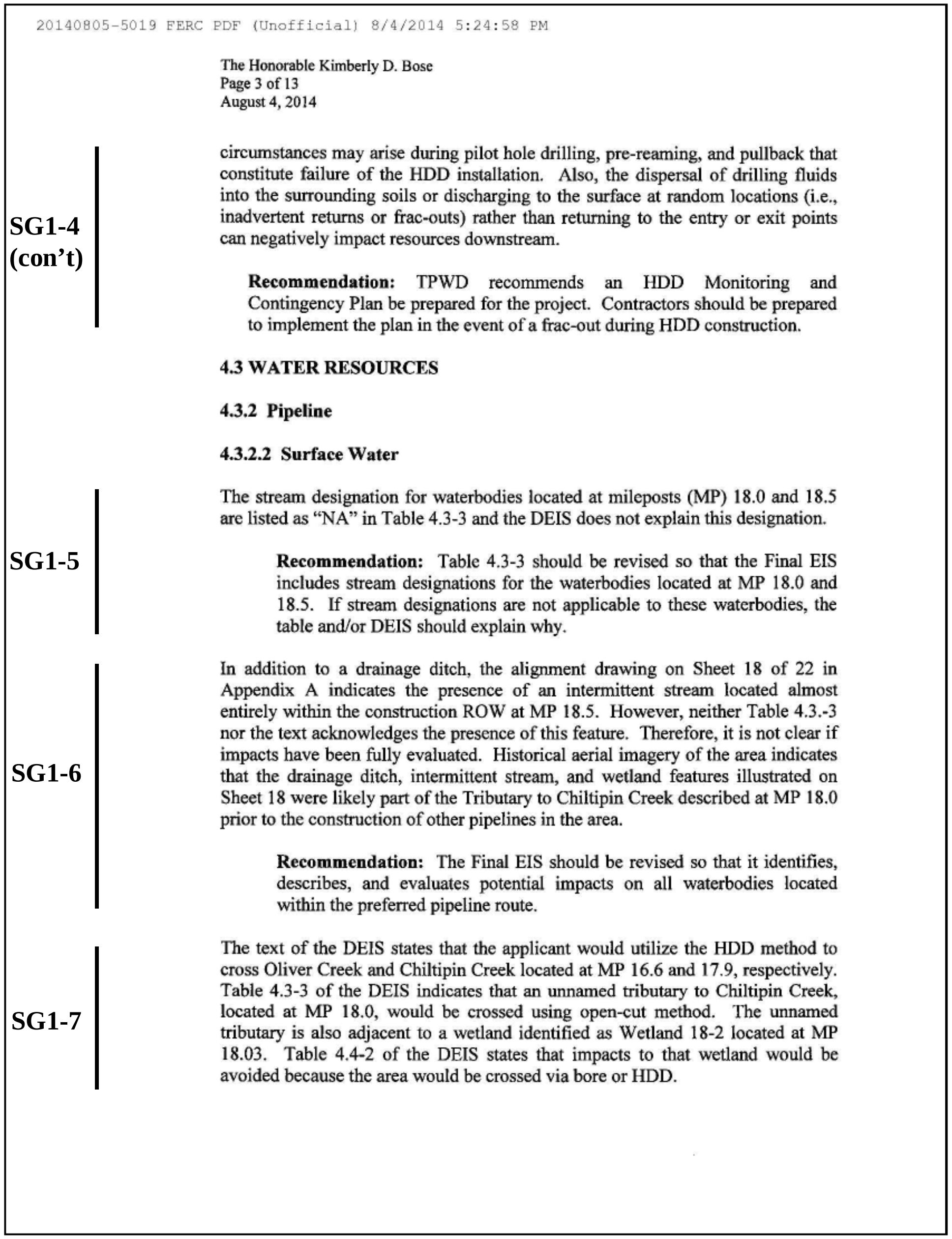
SG1-2: Cheniere indicated in its Response to Comments Received on the DEIS on August 22, 2014 that construction personnel would inspect trenches left open overnight for trapped wildlife. If wildlife is found in the trenches, the environmental inspector would be notified. If the trapped species is state-listed it would be removed by personnel permitted by TPWD to handle state-listed species. Section 4.6.1.2 of the final EIS has been revised to include this measure.

SG1-3: Comment acknowledged. Cheniere indicated in its Response to Comments Received on the DEIS submitted to FERC on August 22, 2014 that the boat launch facility has been removed from the Terminal design, though a construction dock would be utilized to bring equipment to the site via water transport, which was captured in the USACE Section 10/404 permitting process. See section 2.3.1 of the final EIS.

SG1-4: Cheniere prepared an HDD Monitoring and Contingency Plan as part of the USACE Section 10/404 permitting process. We find this plan to be acceptable. See additional discussion in section 4.3.2.2 of the final EIS.

STATE GOVERNMENT COMMENTS

SG1 – Texas Parks & Wildlife



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The Honorable Kimberly D. Bose
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August 4, 2014

SG1-4 (con't)

circumstances may arise during pilot hole drilling, pre-reaming, and pullback that constitute failure of the HDD installation. Also, the dispersal of drilling fluids into the surrounding soils or discharging to the surface at random locations (i.e., inadvertent returns or frac-outs) rather than returning to the entry or exit points can negatively impact resources downstream.

> **Recommendation:** TPWD recommends an HDD Monitoring and Contingency Plan be prepared for the project. Contractors should be prepared to implement the plan in the event of a frac-out during HDD construction.

4.3 WATER RESOURCES

4.3.2 Pipeline

4.3.2.2 Surface Water

SG1-5

The stream designation for waterbodies located at mileposts (MP) 18.0 and 18.5 are listed as "NA" in Table 4.3-3 and the DEIS does not explain this designation.

> **Recommendation:** Table 4.3-3 should be revised so that the Final EIS includes stream designations for the waterbodies located at MP 18.0 and 18.5. If stream designations are not applicable to these waterbodies, the table and/or DEIS should explain why.

SG1-6

In addition to a drainage ditch, the alignment drawing on Sheet 18 of 22 in Appendix A indicates the presence of an intermittent stream located almost entirely within the construction ROW at MP 18.5. However, neither Table 4.3.-3 nor the text acknowledges the presence of this feature. Therefore, it is not clear if impacts have been fully evaluated. Historical aerial imagery of the area indicates that the drainage ditch, intermittent stream, and wetland features illustrated on Sheet 18 were likely part of the Tributary to Chiltipin Creek described at MP 18.0 prior to the construction of other pipelines in the area.

> **Recommendation:** The Final EIS should be revised so that it identifies, describes, and evaluates potential impacts on all waterbodies located within the preferred pipeline route.

SG1-7

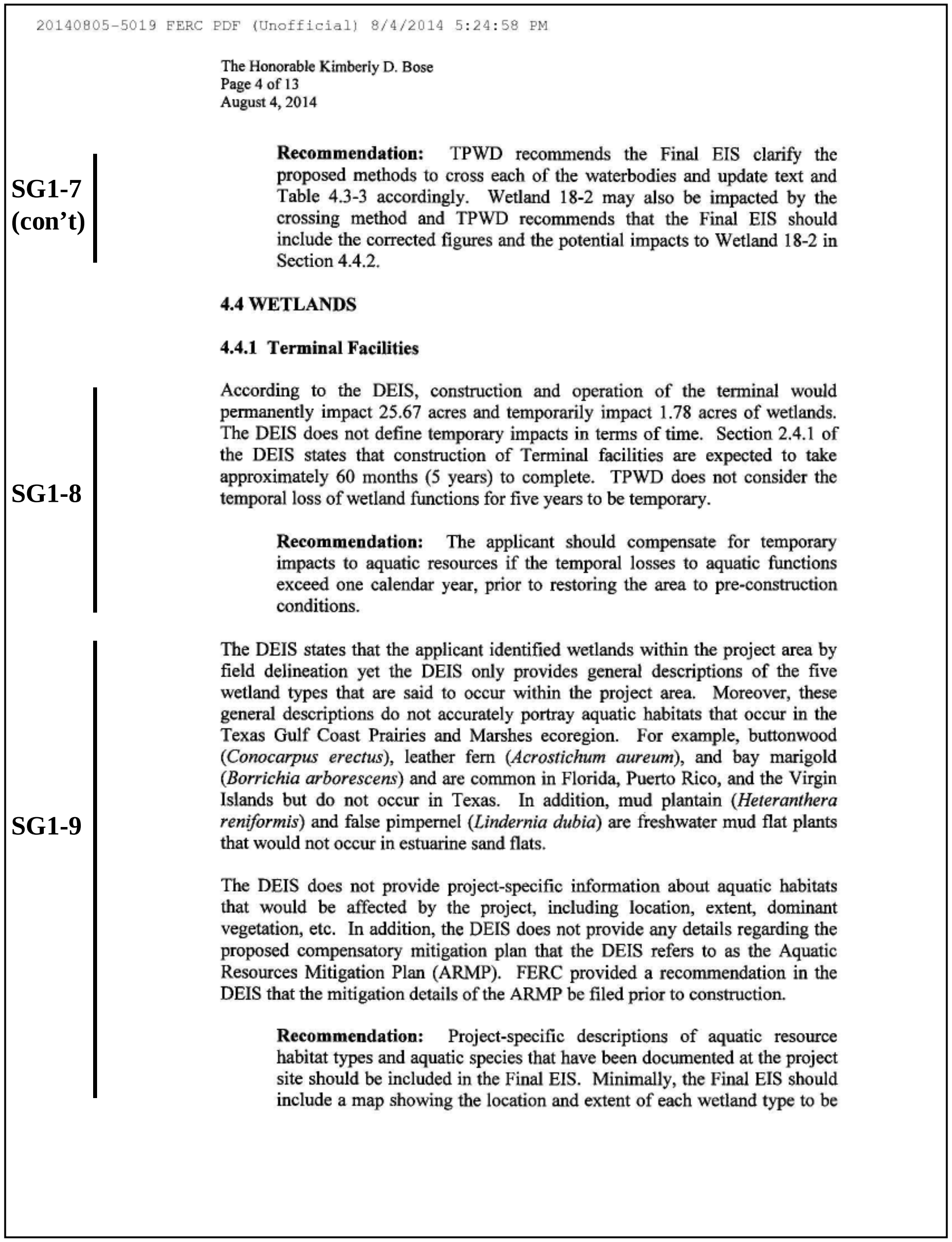
The text of the DEIS states that the applicant would utilize the HDD method to cross Oliver Creek and Chiltipin Creek located at MP 16.6 and 17.9, respectively. Table 4.3-3 of the DEIS indicates that an unnamed tributary to Chiltipin Creek, located at MP 18.0, would be crossed using open-cut method. The unnamed tributary is also adjacent to a wetland identified as Wetland 18-2 located at MP 18.03. Table 4.4-2 of the DEIS states that impacts to that wetland would be avoided because the area would be crossed via bore or HDD.

SG1-5: Table 4.3-3 in the final EIS has been revised to include designations for streams located at MP 18.0 and 18.5.

SG1-6: Cheniere clarified in its Response to Comments Received on the DEIS submitted to FERC on August 22, 2014 that the drainage ditch identified at MP 18.5 in table 4.3-3 is the intermittent stream noted by TPWD. The "bar ditch" noted on the alignment sheet is an upland drainage feature and was not classified by Cheniere as a waterbody, and the COE agreed with this determination. Section 4.3.2.2 of the final EIS has been updated to clarify this issue.

SG1-7: Table 4.3-3 in the final EIS has been updated to clarify the proposed methods to cross each of waterbody. As indicated in section 4.3.2.2 of the final EIS, wetland 18-2 would be crossed via horizontal directional drill; therefore, it would not be impacted.

SG1 – Texas Parks & Wildlife



SG1-7 (con't)

> **Recommendation:** TPWD recommends the Final EIS clarify the proposed methods to cross each of the waterbodies and update text and Table 4.3-3 accordingly. Wetland 18-2 may also be impacted by the crossing method and TPWD recommends that the Final EIS should include the corrected figures and the potential impacts to Wetland 18-2 in Section 4.4.2.

4.4 WETLANDS

4.4.1 Terminal Facilities

SG1-8

According to the DEIS, construction and operation of the terminal would permanently impact 25.67 acres and temporarily impact 1.78 acres of wetlands. The DEIS does not define temporary impacts in terms of time. Section 2.4.1 of the DEIS states that construction of Terminal facilities are expected to take approximately 60 months (5 years) to complete. TPWD does not consider the temporal loss of wetland functions for five years to be temporary.

> **Recommendation:** The applicant should compensate for temporary impacts to aquatic resources if the temporal losses to aquatic functions exceed one calendar year, prior to restoring the area to pre-construction conditions.

SG1-9

The DEIS states that the applicant identified wetlands within the project area by field delineation yet the DEIS only provides general descriptions of the five wetland types that are said to occur within the project area. Moreover, these general descriptions do not accurately portray aquatic habitats that occur in the Texas Gulf Coast Prairies and Marshes ecoregion. For example, buttonwood (*Conocarpus erectus*), leather fern (*Acrostichum aureum*), and bay marigold (*Borrichia arborescens*) and are common in Florida, Puerto Rico, and the Virgin Islands but do not occur in Texas. In addition, mud plantain (*Heteranthera reniformis*) and false pimpernel (*Lindernia dubia*) are freshwater mud flat plants that would not occur in estuarine sand flats.

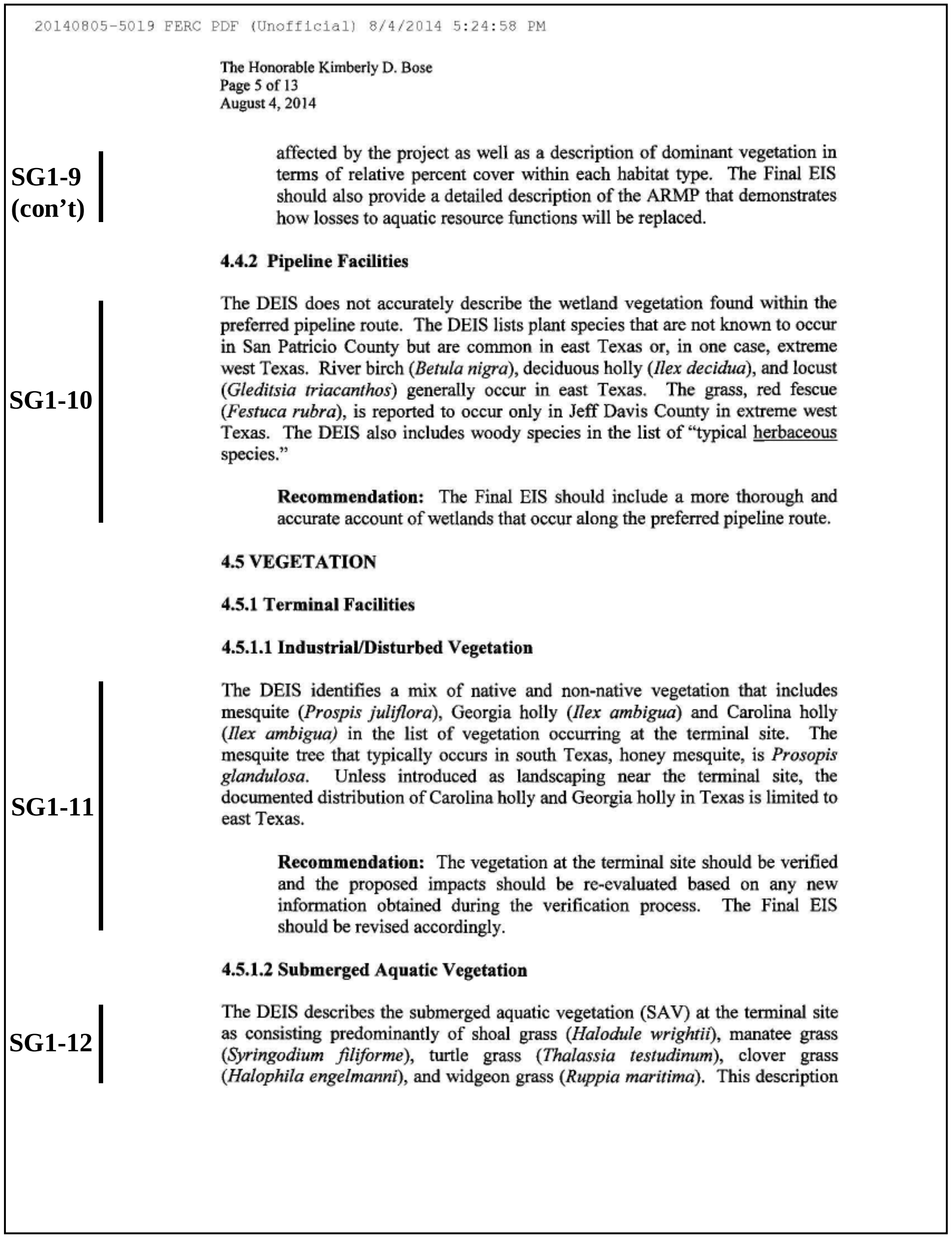
The DEIS does not provide project-specific information about aquatic habitats that would be affected by the project, including location, extent, dominant vegetation, etc. In addition, the DEIS does not provide any details regarding the proposed compensatory mitigation plan that the DEIS refers to as the Aquatic Resources Mitigation Plan (ARMP). FERC provided a recommendation in the DEIS that the mitigation details of the ARMP be filed prior to construction.

> **Recommendation:** Project-specific descriptions of aquatic resource habitat types and aquatic species that have been documented at the project site should be included in the Final EIS. Minimally, the Final EIS should include a map showing the location and extent of each wetland type to be

SG1-8: The FERC defers to the COE, a cooperating agency in the Cheniere Liquefaction Project review, in regards to wetland impacts and mitigation. As such, this has been adequately addressed through the Section 404 permitting process.

SG1-9: Section 4.4.1 and appendix C of the final EIS have been revised to reflect COE approval of the ARMP through issuance of its Section 404/10 Permit.

SG1 – Texas Parks & Wildlife



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SG1-9 (con't)

affected by the project as well as a description of dominant vegetation in terms of relative percent cover within each habitat type. The Final EIS should also provide a detailed description of the ARMP that demonstrates how losses to aquatic resource functions will be replaced.

4.4.2 Pipeline Facilities

SG1-10

The DEIS does not accurately describe the wetland vegetation found within the preferred pipeline route. The DEIS lists plant species that are not known to occur in San Patricio County but are common in east Texas or, in one case, extreme west Texas. River birch (*Betula nigra*), deciduous holly (*Ilex decidua*), and locust (*Gleditsia triacanthos*) generally occur in east Texas. The grass, red fescue (*Festuca rubra*), is reported to occur only in Jeff Davis County in extreme west Texas. The DEIS also includes woody species in the list of "typical herbaceous species."

> **Recommendation:** The Final EIS should include a more thorough and accurate account of wetlands that occur along the preferred pipeline route.

4.5 VEGETATION

4.5.1 Terminal Facilities

4.5.1.1 Industrial/Disturbed Vegetation

SG1-11

The DEIS identifies a mix of native and non-native vegetation that includes mesquite (*Prospis juliflora*), Georgia holly (*Ilex ambigua*) and Carolina holly (*Ilex ambigua)* in the list of vegetation occurring at the terminal site. The mesquite tree that typically occurs in south Texas, honey mesquite, is *Prosopis glandulosa*. Unless introduced as landscaping near the terminal site, the documented distribution of Carolina holly and Georgia holly in Texas is limited to east Texas.

> **Recommendation:** The vegetation at the terminal site should be verified and the proposed impacts should be re-evaluated based on any new information obtained during the verification process. The Final EIS should be revised accordingly.

4.5.1.2 Submerged Aquatic Vegetation

SG1-12

The DEIS describes the submerged aquatic vegetation (SAV) at the terminal site as consisting predominantly of shoal grass (*Halodule wrightii*), manatee grass (*Syringodium filiforme*), turtle grass (*Thalassia testudinum*), clover grass (*Halophila engelmanni*), and widgeon grass (*Ruppia maritima*). This description

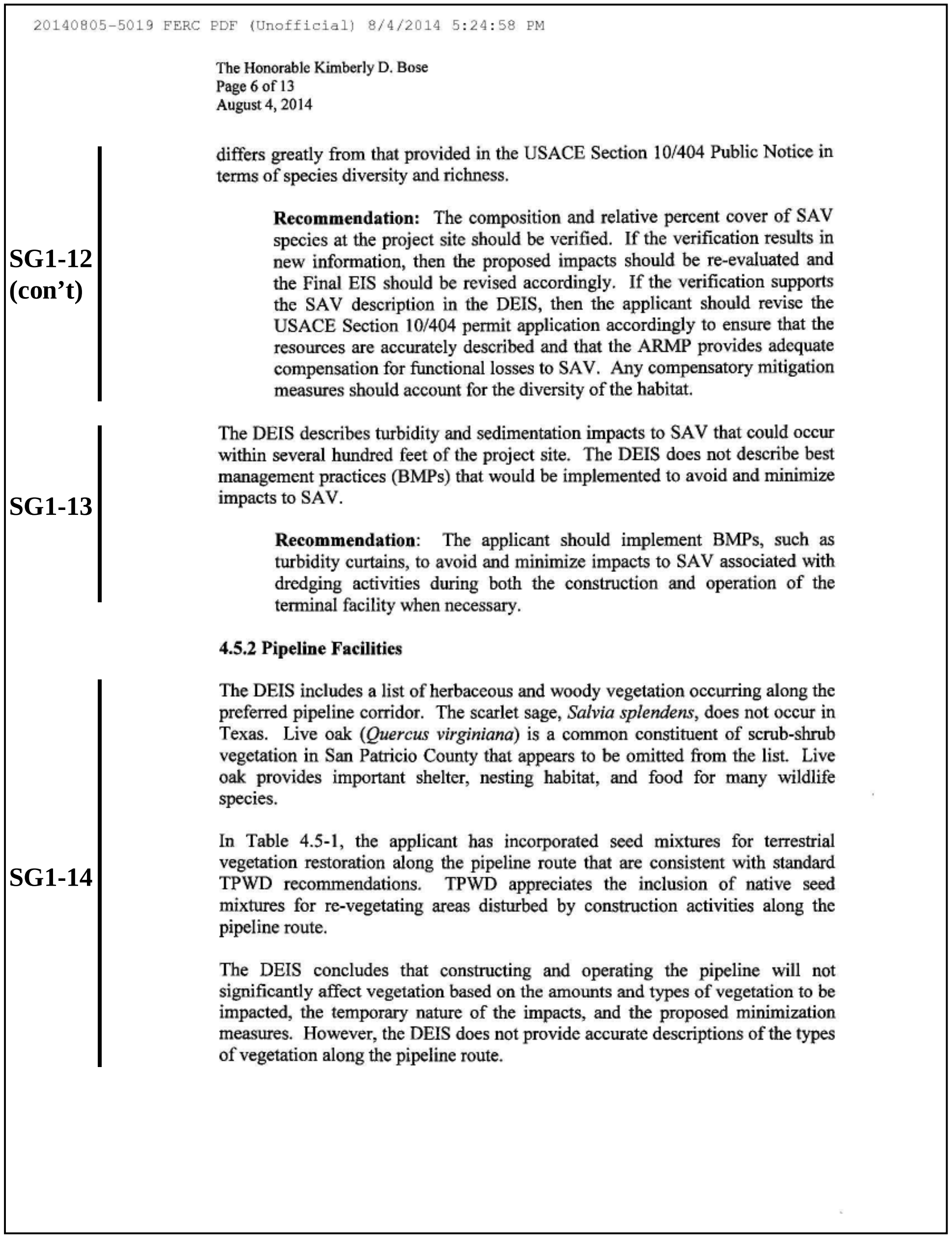
SG1-10: The species listed in section 4.4.2 of the final EIS are those identified on the wetland delineation data sheets filed by Cheniere with its FERC Application.

SG1-11: Vegetation listed at the Terminal site in section 4.5.1.1 of the final EIS are those identified on the 2004 wetland delineation data sheets filed by Cheniere with the previous FERC filing in 2005 (Docket No. CP04-37-000). Wetland data from the 2004 delineation supplemented the 2011/2012 delineation. However, one species was corrected based on the 2004 delineation data sheets, Carolina holly (*Ilex ambigua*) should have been listed as yaupon (*Ilex vomitoria*).

SG1-12: Cheniere indicated that it resurveyed SAV at the Project site and that the COE. The FERC defers to the COE, a cooperating agency in the Cheniere Liquefaction Project review, in regards to its Section 10/404 permit mitigation requirements wetland impacts and mitigation. Section 4.5.1 of the final EIS has been revised to include this information.

STATE GOVERNMENT COMMENTS

SG1 – Texas Parks & Wildlife



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SG1-12 (con't)

differs greatly from that provided in the USACE Section 10/404 Public Notice in terms of species diversity and richness.

> **Recommendation:** The composition and relative percent cover of SAV species at the project site should be verified. If the verification results in new information, then the proposed impacts should be re-evaluated and the Final EIS should be revised accordingly. If the verification supports the SAV description in the DEIS, then the applicant should revise the USACE Section 10/404 permit application accordingly to ensure that the resources are accurately described and that the ARMP provides adequate compensation for functional losses to SAV. Any compensatory mitigation measures should account for the diversity of the habitat.

SG1-13

The DEIS describes turbidity and sedimentation impacts to SAV that could occur within several hundred feet of the project site. The DEIS does not describe best management practices (BMPs) that would be implemented to avoid and minimize impacts to SAV.

> **Recommendation**: The applicant should implement BMPs, such as turbidity curtains, to avoid and minimize impacts to SAV associated with dredging activities during both the construction and operation of the terminal facility when necessary.

4.5.2 Pipeline Facilities

SG1-14

The DEIS includes a list of herbaceous and woody vegetation occurring along the preferred pipeline corridor. The scarlet sage, *Salvia splendens*, does not occur in Texas. Live oak (*Quercus virginiana*) is a common constituent of scrub-shrub vegetation in San Patricio County that appears to be omitted from the list. Live oak provides important shelter, nesting habitat, and food for many wildlife species.

In Table 4.5-1, the applicant has incorporated seed mixtures for terrestrial vegetation restoration along the pipeline route that are consistent with standard TPWD recommendations. TPWD appreciates the inclusion of native seed mixtures for re-vegetating areas disturbed by construction activities along the pipeline route.

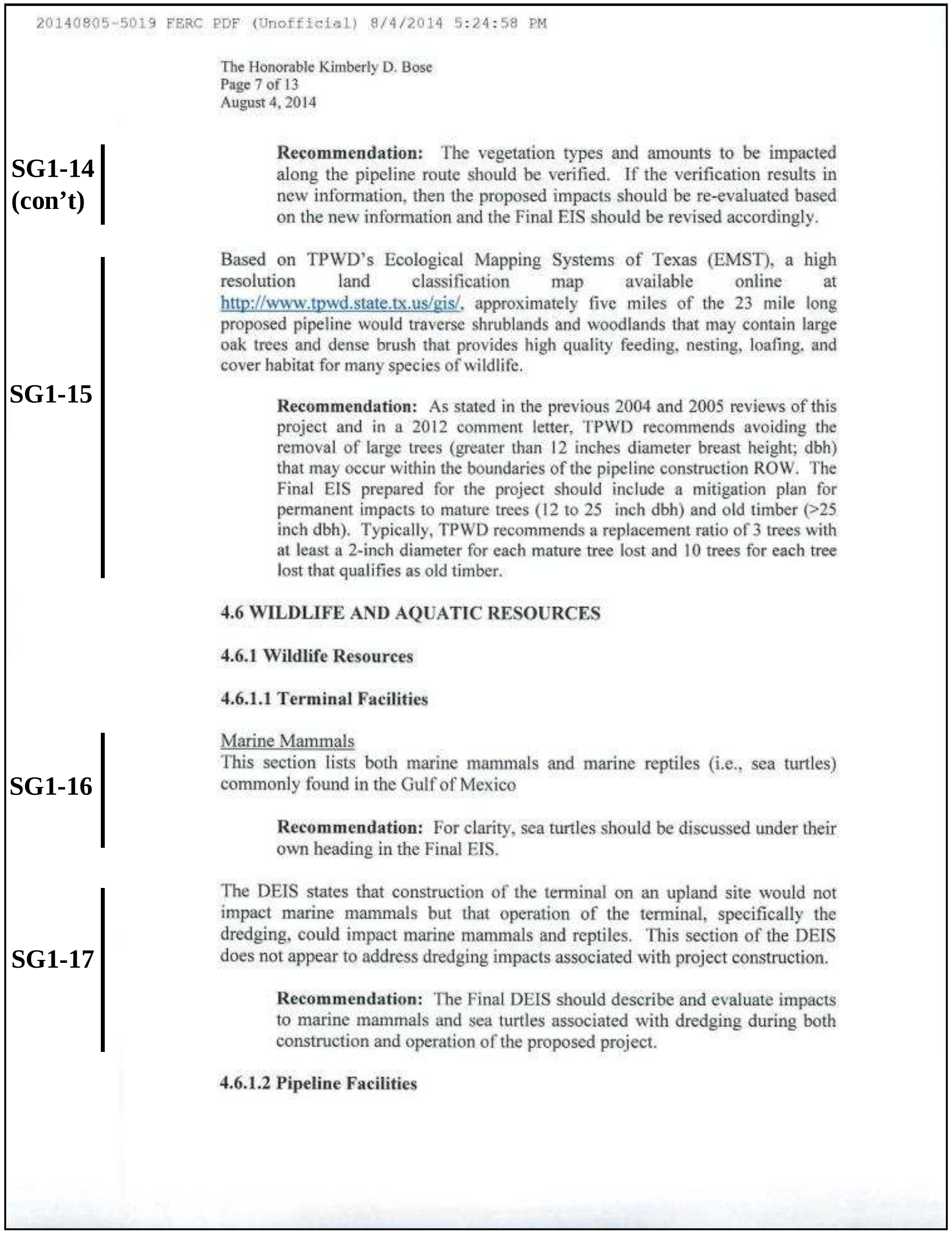
The DEIS concludes that constructing and operating the pipeline will not significantly affect vegetation based on the amounts and types of vegetation to be impacted, the temporary nature of the impacts, and the proposed minimization measures. However, the DEIS does not provide accurate descriptions of the types of vegetation along the pipeline route.

SG1-13: Impacts on SAV have been adequately addressed through the Section 404 permitting process.

SG1-14: The species listed in section 4.5.2 are those identified by Cheniere in its FERC Application. The literature reference for the species has been updated in section 4.5.2 of the final EIS.

STATE GOVERNMENT COMMENTS

SG1 – Texas Parks & Wildlife



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SG1-14 (con't)

Recommendation: The vegetation types and amounts to be impacted along the pipeline route should be verified. If the verification results in new information, then the proposed impacts should be re-evaluated based on the new information and the Final EIS should be revised accordingly.

SG1-15

Based on TPWD's Ecological Mapping Systems of Texas (EMST), a high resolution land classification map available online at http://www.tpwd.state.tx.us/gis/, approximately five miles of the 23 mile long proposed pipeline would traverse shrublands and woodlands that may contain large oak trees and dense brush that provides high quality feeding, nesting, loafing, and cover habitat for many species of wildlife.

Recommendation: As stated in the previous 2004 and 2005 reviews of this project and in a 2012 comment letter, TPWD recommends avoiding the removal of large trees (greater than 12 inches diameter breast height; dbh) that may occur within the boundaries of the pipeline construction ROW. The Final EIS prepared for the project should include a mitigation plan for permanent impacts to mature trees (12 to 25 inch dbh) and old timber (>25 inch dbh). Typically, TPWD recommends a replacement ratio of 3 trees with at least a 2-inch diameter for each mature tree lost and 10 trees for each tree lost that qualifies as old timber.

4.6 WILDLIFE AND AQUATIC RESOURCES

4.6.1 Wildlife Resources

4.6.1.1 Terminal Facilities

SG1-16

Marine Mammals
This section lists both marine mammals and marine reptiles (i.e., sea turtles) commonly found in the Gulf of Mexico

Recommendation: For clarity, sea turtles should be discussed under their own heading in the Final EIS.

SG1-17

The DEIS states that construction of the terminal on an upland site would not impact marine mammals but that operation of the terminal, specifically the dredging, could impact marine mammals and reptiles. This section of the DEIS does not appear to address dredging impacts associated with project construction.

Recommendation: The Final DEIS should describe and evaluate impacts to marine mammals and sea turtles associated with dredging during both construction and operation of the proposed project.

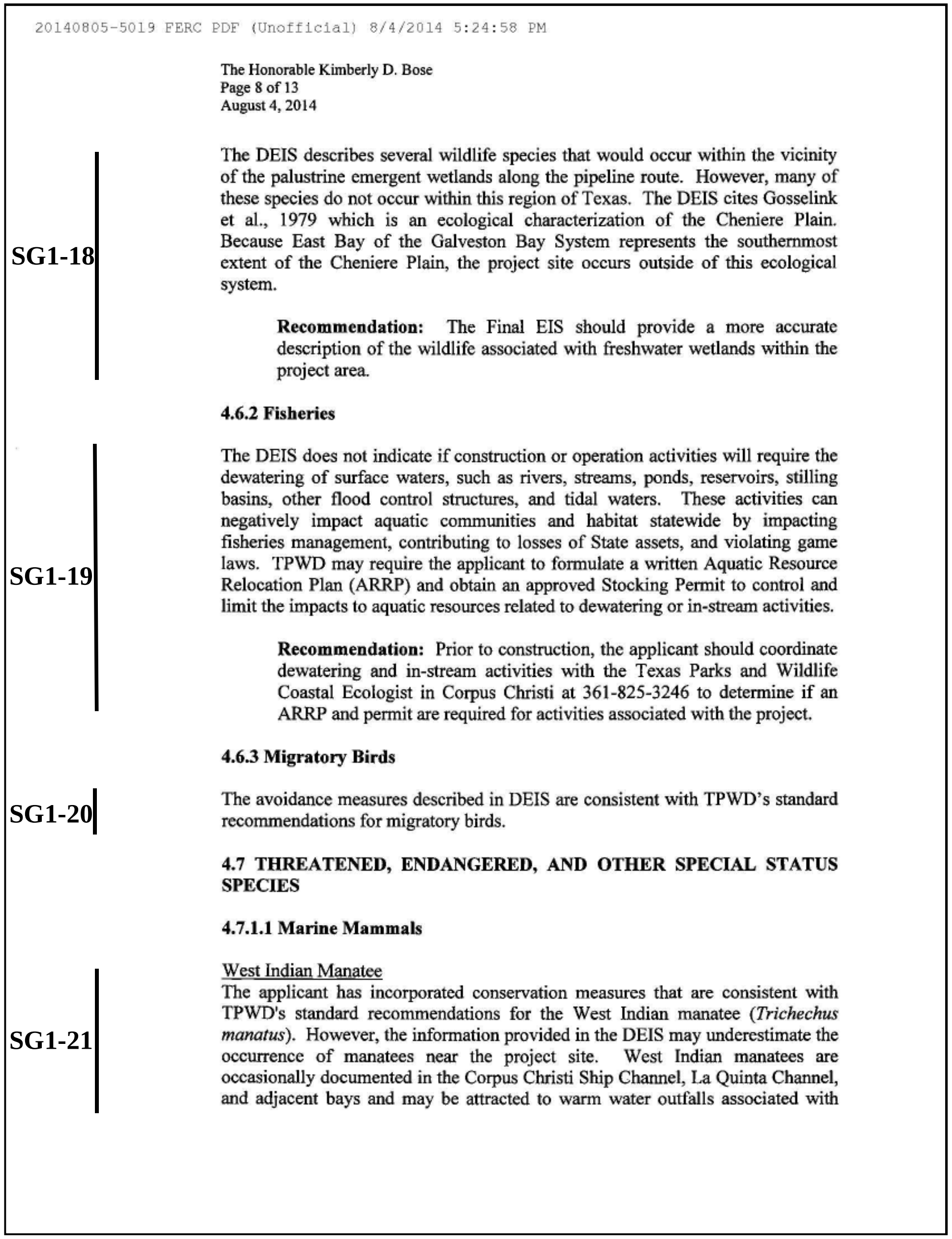
4.6.1.2 Pipeline Facilities

SG1-15: As discussed in sections 2.3.2 and 4.5.2 of the final EIS, the majority of the Project is located within agricultural or open areas and is collocated with other utility corridors. Therefore, any impacts on large diameter trees within the Project area, should they occur, would be minor.

SG1-16: Section 4.6.1.1 of the final EIS has been revised to include this clarification.

SG1-17: As stated in the final EIS, Cheniere received concurrence with its determination that the Project would be not likely to adversely affect marine mammals and reptiles from both the USFWS and the National Marine Fisheries Service (NMFS). Whales are not likely to occur in the shallow waters at the Terminal and would thus not be impacted by dredging. Measures Cheniere would implement to avoid or minimize impacts on West Indian manatee during both construction and operation, as recommended by the USFWS, are described in section 4.7.1.1. Impacts from dredging activities on sea turtles are discussed in section 4.7.1.2.

SG1 – Texas Parks & Wildlife



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SG1-18 The DEIS describes several wildlife species that would occur within the vicinity of the palustrine emergent wetlands along the pipeline route. However, many of these species do not occur within this region of Texas. The DEIS cites Gosselink et al., 1979 which is an ecological characterization of the Cheniere Plain. Because East Bay of the Galveston Bay System represents the southernmost extent of the Cheniere Plain, the project site occurs outside of this ecological system.

> **Recommendation:** The Final EIS should provide a more accurate description of the wildlife associated with freshwater wetlands within the project area.

4.6.2 Fisheries

SG1-19 The DEIS does not indicate if construction or operation activities will require the dewatering of surface waters, such as rivers, streams, ponds, reservoirs, stilling basins, other flood control structures, and tidal waters. These activities can negatively impact aquatic communities and habitat statewide by impacting fisheries management, contributing to losses of State assets, and violating game laws. TPWD may require the applicant to formulate a written Aquatic Resource Relocation Plan (ARRP) and obtain an approved Stocking Permit to control and limit the impacts to aquatic resources related to dewatering or in-stream activities.

> **Recommendation:** Prior to construction, the applicant should coordinate dewatering and in-stream activities with the Texas Parks and Wildlife Coastal Ecologist in Corpus Christi at 361-825-3246 to determine if an ARRP and permit are required for activities associated with the project.

4.6.3 Migratory Birds

SG1-20 The avoidance measures described in DEIS are consistent with TPWD's standard recommendations for migratory birds.

4.7 THREATENED, ENDANGERED, AND OTHER SPECIAL STATUS SPECIES

4.7.1.1 Marine Mammals

SG1-21 West Indian Manatee
The applicant has incorporated conservation measures that are consistent with TPWD's standard recommendations for the West Indian manatee (*Trichechus manatus*). However, the information provided in the DEIS may underestimate the occurrence of manatees near the project site. West Indian manatees are occasionally documented in the Corpus Christi Ship Channel, La Quinta Channel, and adjacent bays and may be attracted to warm water outfalls associated with

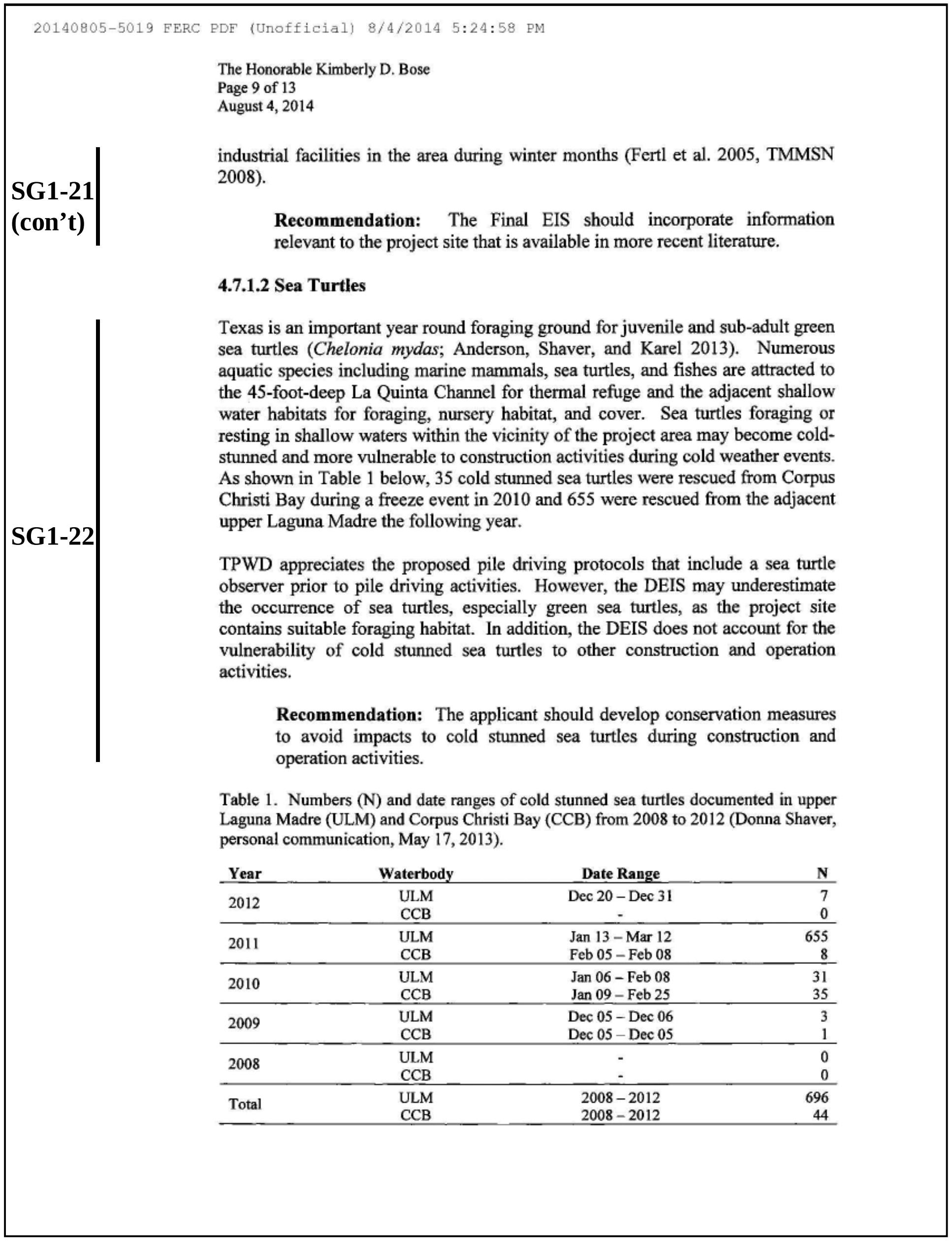
SG1-18: Section 4.6.1.2 of the final EIS has been revised to include a more accurate description of wildlife associated with freshwater wetlands in the Project area.

SG1-19: Cheniere indicated in its Response to Comments Received on the DEIS on August 22, 2014 that no dewatering of surface waters is anticipated for the Project. If dewatering of surface waters is necessary, Cheniere would coordinate with TPWD to determine if an Aquatic Resource Relocation Plan is required. Section 4.6.2 has been revised to include this information.

SG1-20: Comment acknowledged

SG1-21: Section 4.7.1.1 of the final EIS has been revised to reference more recent literature.

SG1 – Texas Parks & Wildlife



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SG1-21 (con't)

industrial facilities in the area during winter months (Fertl et al. 2005, TMMSN 2008).

> **Recommendation:** The Final EIS should incorporate information relevant to the project site that is available in more recent literature.

4.7.1.2 Sea Turtles

SG1-22

Texas is an important year round foraging ground for juvenile and sub-adult green sea turtles (*Chelonia mydas*; Anderson, Shaver, and Karel 2013). Numerous aquatic species including marine mammals, sea turtles, and fishes are attracted to the 45-foot-deep La Quinta Channel for thermal refuge and the adjacent shallow water habitats for foraging, nursery habitat, and cover. Sea turtles foraging or resting in shallow waters within the vicinity of the project area may become cold-stunned and more vulnerable to construction activities during cold weather events. As shown in Table 1 below, 35 cold stunned sea turtles were rescued from Corpus Christi Bay during a freeze event in 2010 and 655 were rescued from the adjacent upper Laguna Madre the following year.

TPWD appreciates the proposed pile driving protocols that include a sea turtle observer prior to pile driving activities. However, the DEIS may underestimate the occurrence of sea turtles, especially green sea turtles, as the project site contains suitable foraging habitat. In addition, the DEIS does not account for the vulnerability of cold stunned sea turtles to other construction and operation activities.

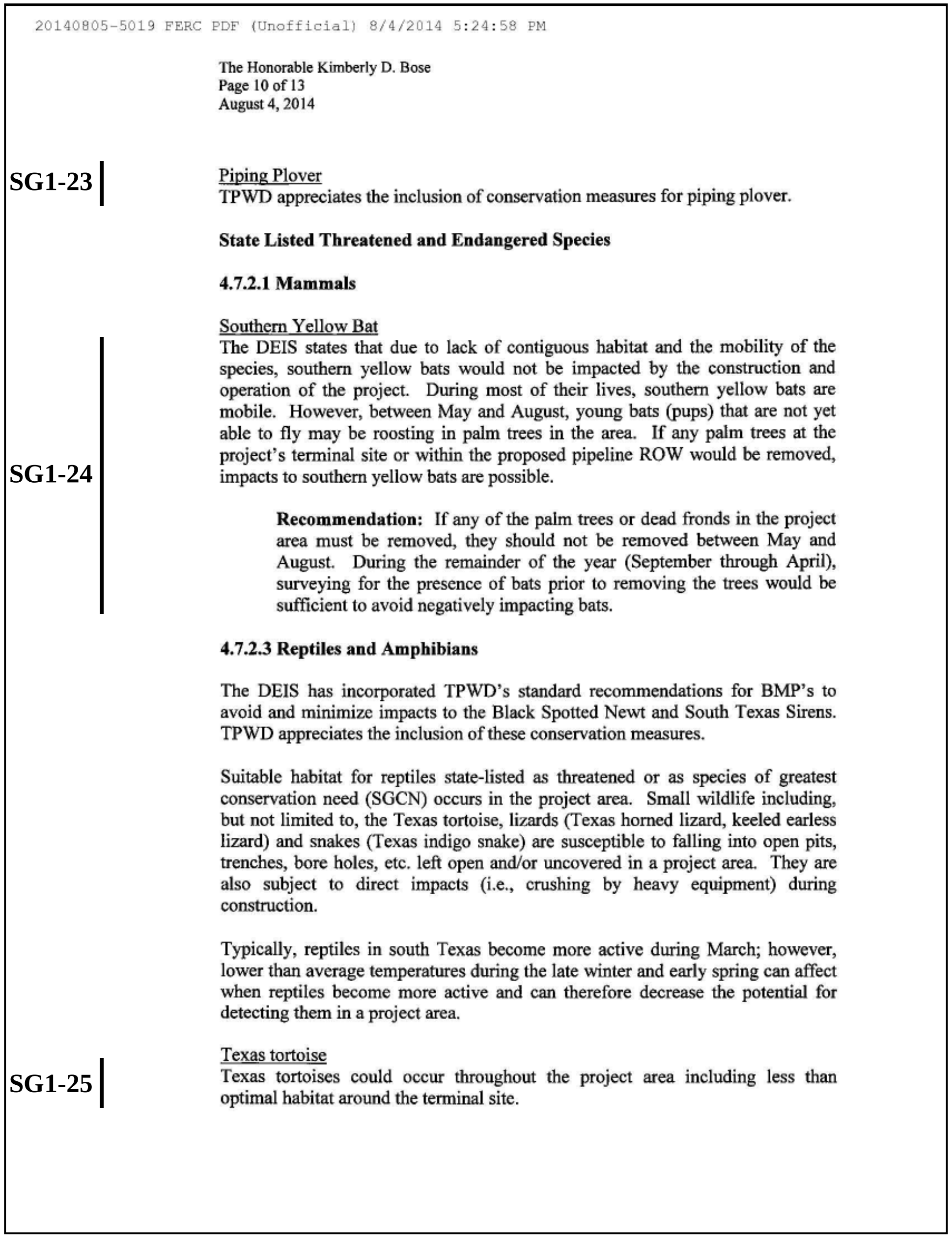
> **Recommendation:** The applicant should develop conservation measures to avoid impacts to cold stunned sea turtles during construction and operation activities.

Table 1. Numbers (N) and date ranges of cold stunned sea turtles documented in upper Laguna Madre (ULM) and Corpus Christi Bay (CCB) from 2008 to 2012 (Donna Shaver, personal communication, May 17, 2013).

Year	Waterbody	Date Range	N
2012	ULM	Dec 20 – Dec 31	7
	CCB	-	0
2011	ULM	Jan 13 – Mar 12	655
	CCB	Feb 05 – Feb 08	8
2010	ULM	Jan 06 – Feb 08	31
	CCB	Jan 09 – Feb 25	35
2009	ULM	Dec 05 – Dec 06	3
	CCB	Dec 05 – Dec 05	1
2008	ULM	-	0
	CCB	-	0
Total	ULM	2008 – 2012	696
	CCB	2008 – 2012	44

SG1-22: We have determined that the final EIS adequately addresses measures that would be implemented to minimize impacts on sea turtles during all Project phases. Additionally, Cheniere has received concurrence from the USFWS and NMFS regarding impacts on sea turtles. See section 4.7.1.2.

SG1 – Texas Parks & Wildlife



SG1-23 Piping Plover
TPWD appreciates the inclusion of conservation measures for piping plover.

State Listed Threatened and Endangered Species

4.7.2.1 Mammals

SG1-24 Southern Yellow Bat
The DEIS states that due to lack of contiguous habitat and the mobility of the species, southern yellow bats would not be impacted by the construction and operation of the project. During most of their lives, southern yellow bats are mobile. However, between May and August, young bats (pups) that are not yet able to fly may be roosting in palm trees in the area. If any palm trees at the project's terminal site or within the proposed pipeline ROW would be removed, impacts to southern yellow bats are possible.

> **Recommendation:** If any of the palm trees or dead fronds in the project area must be removed, they should not be removed between May and August. During the remainder of the year (September through April), surveying for the presence of bats prior to removing the trees would be sufficient to avoid negatively impacting bats.

4.7.2.3 Reptiles and Amphibians

The DEIS has incorporated TPWD's standard recommendations for BMP's to avoid and minimize impacts to the Black Spotted Newt and South Texas Sirens. TPWD appreciates the inclusion of these conservation measures.

Suitable habitat for reptiles state-listed as threatened or as species of greatest conservation need (SGCN) occurs in the project area. Small wildlife including, but not limited to, the Texas tortoise, lizards (Texas horned lizard, keeled earless lizard) and snakes (Texas indigo snake) are susceptible to falling into open pits, trenches, bore holes, etc. left open and/or uncovered in a project area. They are also subject to direct impacts (i.e., crushing by heavy equipment) during construction.

Typically, reptiles in south Texas become more active during March; however, lower than average temperatures during the late winter and early spring can affect when reptiles become more active and can therefore decrease the potential for detecting them in a project area.

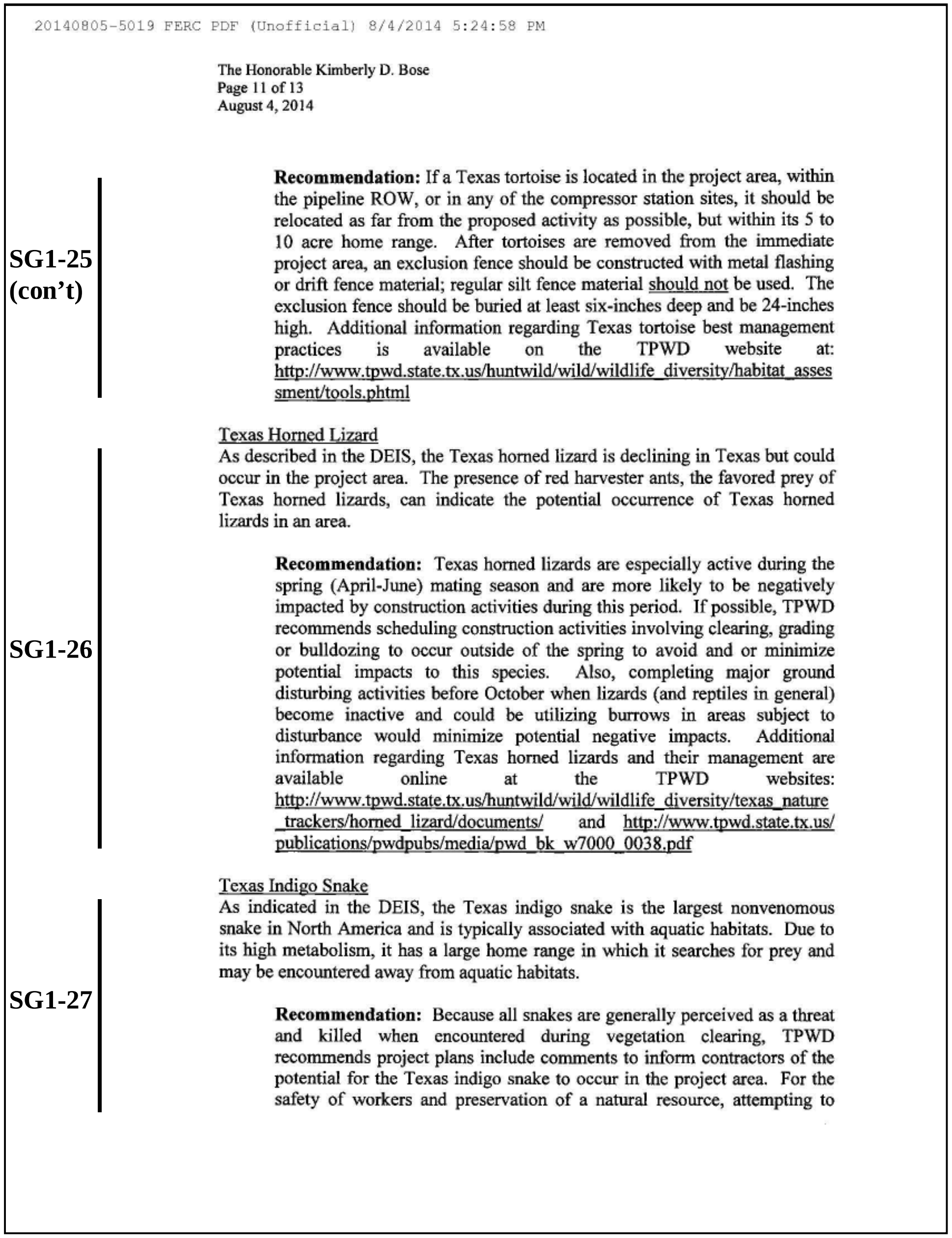
SG1-25 Texas tortoise
Texas tortoises could occur throughout the project area including less than optimal habitat around the terminal site.

SG1-23: Comment acknowledged.

SG1-24: Section 4.7.2.1 of the final EIS has been revised to address this issue.

SG1-25: Section 4.7.2 of the final EIS has been revised to address this issue.

SG1 – Texas Parks & Wildlife



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SG1-25 (con't)

> **Recommendation:** If a Texas tortoise is located in the project area, within the pipeline ROW, or in any of the compressor station sites, it should be relocated as far from the proposed activity as possible, but within its 5 to 10 acre home range. After tortoises are removed from the immediate project area, an exclusion fence should be constructed with metal flashing or drift fence material; regular silt fence material should not be used. The exclusion fence should be buried at least six-inches deep and be 24-inches high. Additional information regarding Texas tortoise best management practices is available on the TPWD website at: http://www.tpwd.state.tx.us/huntwild/wild/wildlife_diversity/habitat_assessment/tools.phtml

Texas Horned Lizard

SG1-26

As described in the DEIS, the Texas horned lizard is declining in Texas but could occur in the project area. The presence of red harvester ants, the favored prey of Texas horned lizards, can indicate the potential occurrence of Texas horned lizards in an area.

> **Recommendation:** Texas horned lizards are especially active during the spring (April-June) mating season and are more likely to be negatively impacted by construction activities during this period. If possible, TPWD recommends scheduling construction activities involving clearing, grading or bulldozing to occur outside of the spring to avoid and or minimize potential impacts to this species. Also, completing major ground disturbing activities before October when lizards (and reptiles in general) become inactive and could be utilizing burrows in areas subject to disturbance would minimize potential negative impacts. Additional information regarding Texas horned lizards and their management are available online at the TPWD websites: http://www.tpwd.state.tx.us/huntwild/wild/wildlife_diversity/texas_nature_trackers/horned_lizard/documents/ and http://www.tpwd.state.tx.us/publications/pwdpubs/media/pwd_bk_w7000_0038.pdf

Texas Indigo Snake

SG1-27

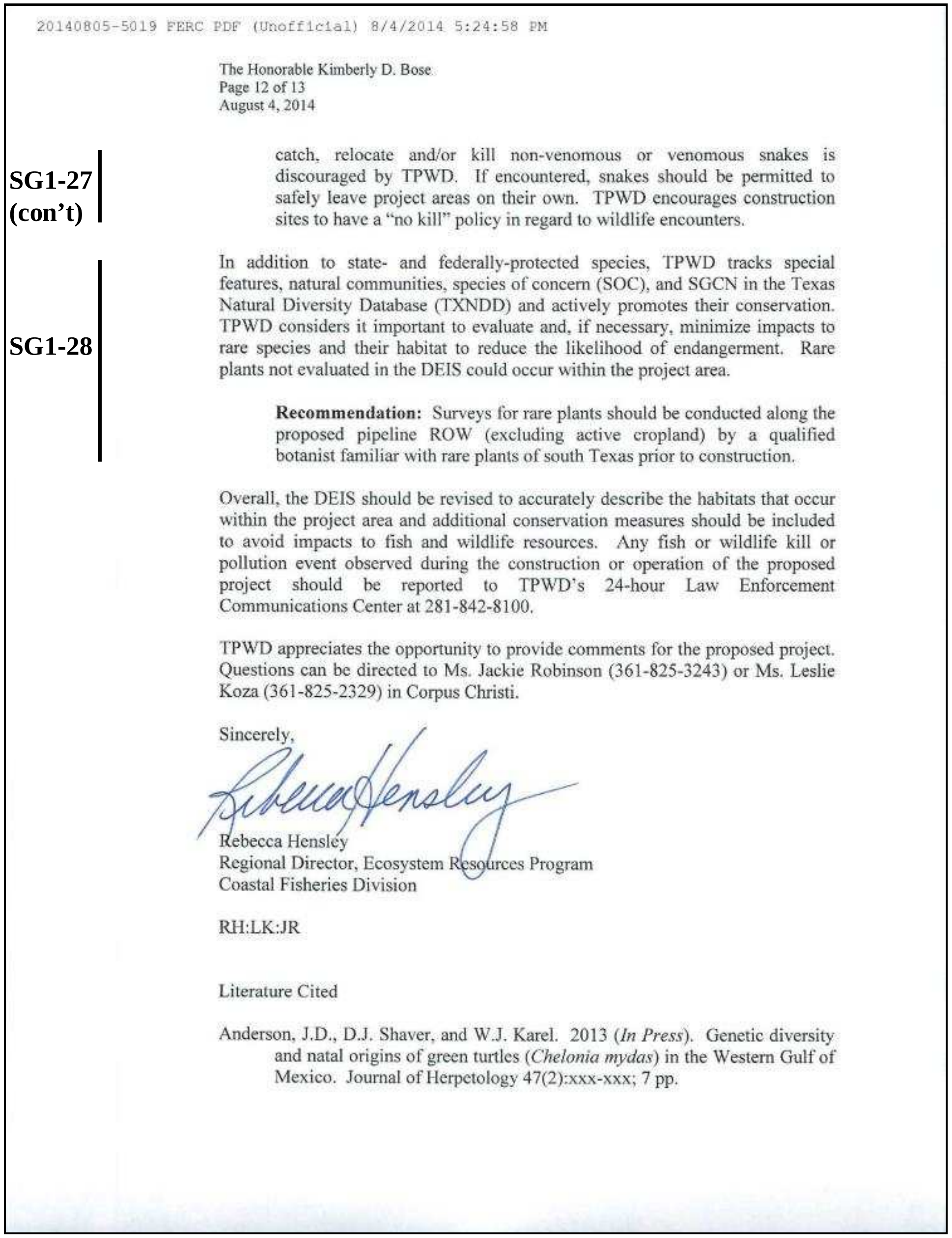
As indicated in the DEIS, the Texas indigo snake is the largest nonvenomous snake in North America and is typically associated with aquatic habitats. Due to its high metabolism, it has a large home range in which it searches for prey and may be encountered away from aquatic habitats.

> **Recommendation:** Because all snakes are generally perceived as a threat and killed when encountered during vegetation clearing, TPWD recommends project plans include comments to inform contractors of the potential for the Texas indigo snake to occur in the project area. For the safety of workers and preservation of a natural resource, attempting to

SG1-26: Section 4.7.2 of the final EIS has been revised to address this issue.

SG1-27: Section 4.7.2 of the final EIS has been revised to address this issue.

SG1 – Texas Parks & Wildlife



SG1-27 (con't)

> catch, relocate and/or kill non-venomous or venomous snakes is discouraged by TPWD. If encountered, snakes should be permitted to safely leave project areas on their own. TPWD encourages construction sites to have a "no kill" policy in regard to wildlife encounters.

SG1-28

In addition to state- and federally-protected species, TPWD tracks special features, natural communities, species of concern (SOC), and SGCN in the Texas Natural Diversity Database (TXNDD) and actively promotes their conservation. TPWD considers it important to evaluate and, if necessary, minimize impacts to rare species and their habitat to reduce the likelihood of endangerment. Rare plants not evaluated in the DEIS could occur within the project area.

> **Recommendation:** Surveys for rare plants should be conducted along the proposed pipeline ROW (excluding active cropland) by a qualified botanist familiar with rare plants of south Texas prior to construction.

Overall, the DEIS should be revised to accurately describe the habitats that occur within the project area and additional conservation measures should be included to avoid impacts to fish and wildlife resources. Any fish or wildlife kill or pollution event observed during the construction or operation of the proposed project should be reported to TPWD's 24-hour Law Enforcement Communications Center at 281-842-8100.

TPWD appreciates the opportunity to provide comments for the proposed project. Questions can be directed to Ms. Jackie Robinson (361-825-3243) or Ms. Leslie Koza (361-825-2329) in Corpus Christi.

Sincerely,

Rebecca Hensley

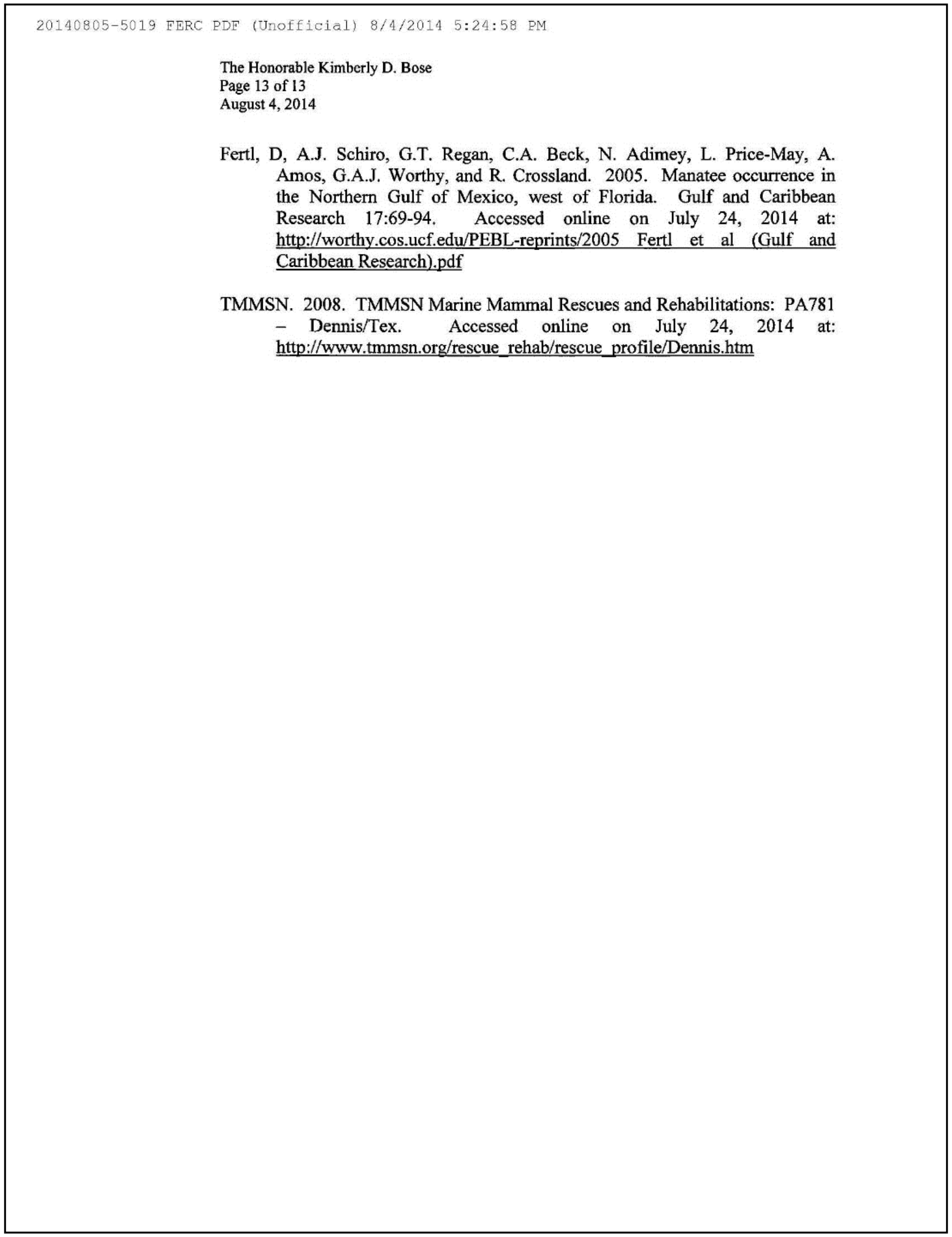
Rebecca Hensley
Regional Director, Ecosystem Resources Program
Coastal Fisheries Division

RH:LK:JR

Literature Cited

Anderson, J.D., D.J. Shaver, and W.J. Karel. 2013 (*In Press*). Genetic diversity and natal origins of green turtles (*Chelonia mydas*) in the Western Gulf of Mexico. Journal of Herpetology 47(2):xxx-xxx; 7 pp.

SG1-28: No federal or state protected plant species were identified within the Project area.

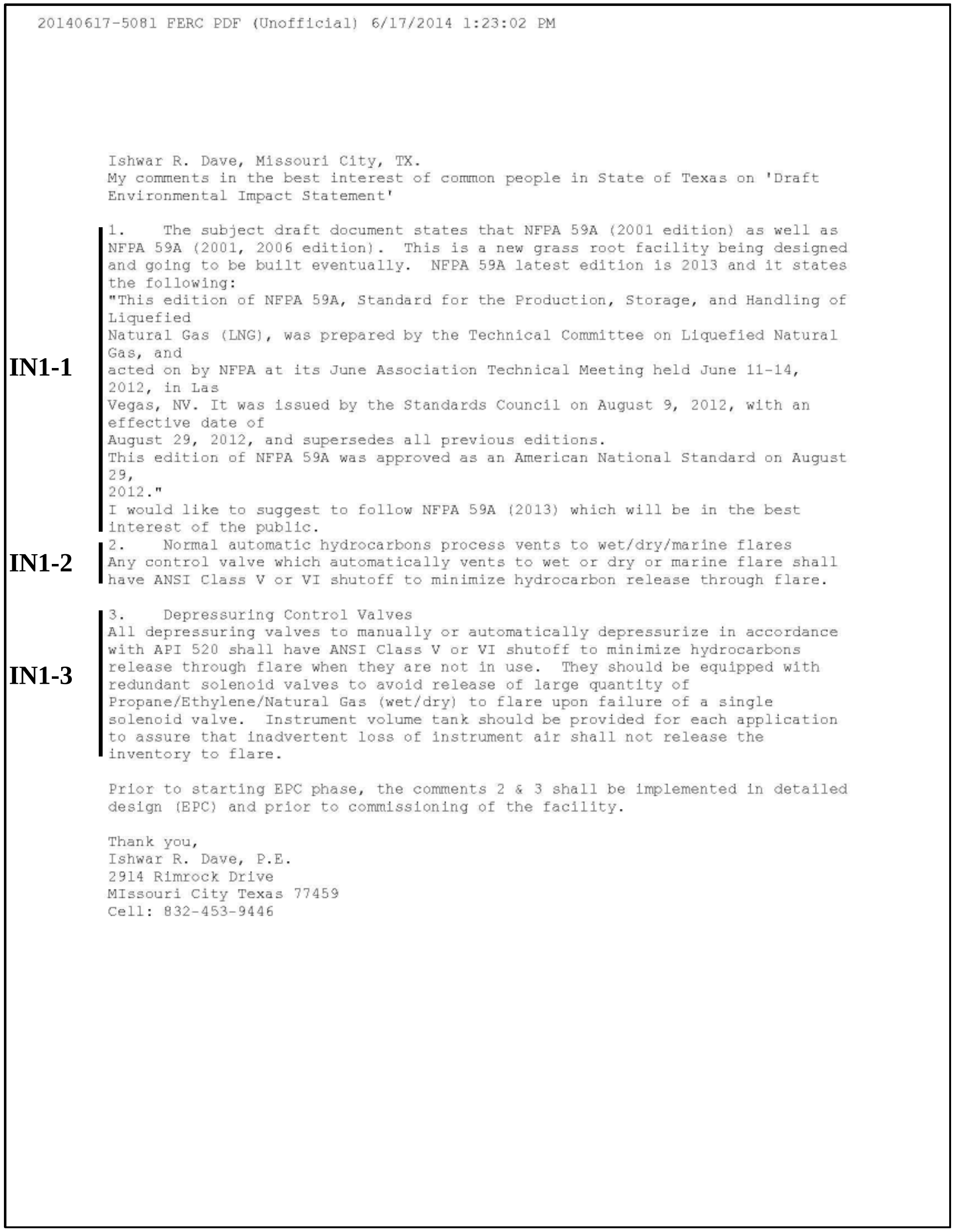


Fertl, D, A.J. Schiro, G.T. Regan, C.A. Beck, N. Adimey, L. Price-May, A. Amos, G.A.J. Worthy, and R. Crossland. 2005. Manatee occurrence in the Northern Gulf of Mexico, west of Florida. Gulf and Caribbean Research 17:69-94. Accessed online on July 24, 2014 at: http://worthy.cos.ucf.edu/PEBL-reprints/2005 Fertl et al (Gulf and Caribbean Research).pdf

TMMSN. 2008. TMMSN Marine Mammal Rescues and Rehabilitations: PA781 – Dennis/Tex. Accessed online on July 24, 2014 at: http://www.tmmsn.org/rescue_rehab/rescue_profile/Dennis.htm

INDIVIDUAL COMMENTS

IN1 – Ishwar R. Dave



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Ishwar R. Dave, Missouri City, TX.
My comments in the best interest of common people in State of Texas on 'Draft Environmental Impact Statement'

IN1-1

1. The subject draft document states that NFPA 59A (2001 edition) as well as NFPA 59A (2001, 2006 edition). This is a new grass root facility being designed and going to be built eventually. NFPA 59A latest edition is 2013 and it states the following:
"This edition of NFPA 59A, Standard for the Production, Storage, and Handling of Liquefied
Natural Gas (LNG), was prepared by the Technical Committee on Liquefied Natural Gas, and
acted on by NFPA at its June Association Technical Meeting held June 11-14, 2012, in Las
Vegas, NV. It was issued by the Standards Council on August 9, 2012, with an effective date of
August 29, 2012, and supersedes all previous editions.
This edition of NFPA 59A was approved as an American National Standard on August 29,
2012."
I would like to suggest to follow NFPA 59A (2013) which will be in the best interest of the public.

IN1-2

2. Normal automatic hydrocarbons process vents to wet/dry/marine flares
Any control valve which automatically vents to wet or dry or marine flare shall have ANSI Class V or VI shutoff to minimize hydrocarbon release through flare.

IN1-3

3. Depressuring Control Valves
All depressuring valves to manually or automatically depressurize in accordance with API 520 shall have ANSI Class V or VI shutoff to minimize hydrocarbons release through flare when they are not in use. They should be equipped with redundant solenoid valves to avoid release of large quantity of Propane/Ethylene/Natural Gas (wet/dry) to flare upon failure of a single solenoid valve. Instrument volume tank should be provided for each application to assure that inadvertent loss of instrument air shall not release the inventory to flare.

Prior to starting EPC phase, the comments 2 & 3 shall be implemented in detailed design (EPC) and prior to commissioning of the facility.

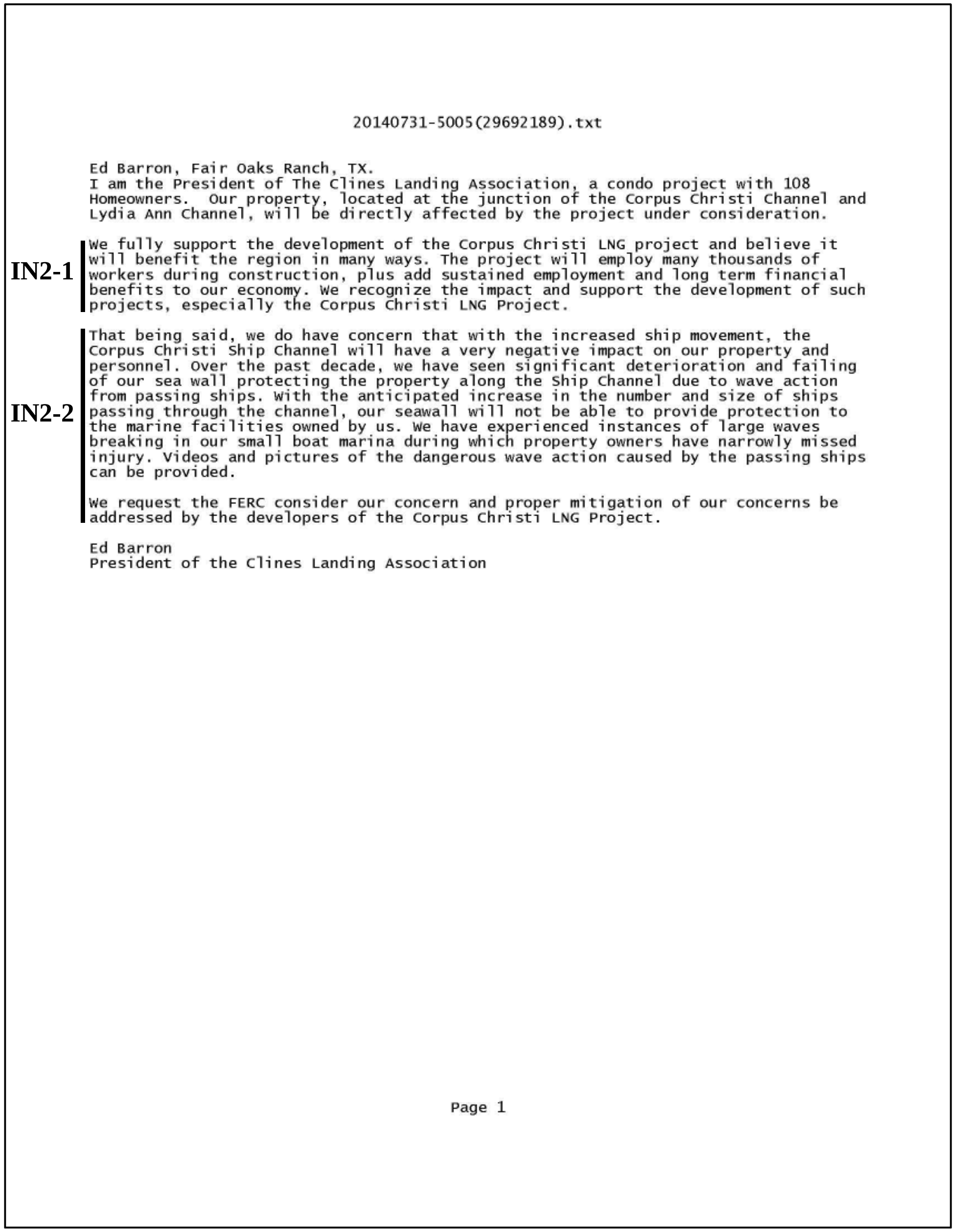
Thank you,
Ishwar R. Dave, P.E.
2914 Rimrock Drive
MIssouri City Texas 77459
Cell: 832-453-9446

IN1-1: As stated in section 4.12, Cheniere's facility must comply with the Federal Safety Standards for Liquefied Natural Gas Facilities in 49 C.F.R. Part 193 promulgated by the Department of Transportation (DOT). The DOT regulations incorporate by reference portions of the 2001 and 2006 edition of NFPA 59A. The 2013 edition of NFPA 59A is not currently part of the federal regulations covering LNG. In order to make it so, the DOT would need to initiate a rulemaking and provide for adequate public notification and comment prior to adopting the 2013 edition into 49 C.F.R. Part 193.

IN1-2: As stated in section 4.12.3, Cheniere proposes to design safety relief systems in accordance with American Petroleum Institute (API) 520, *Sizing, Selection, and Installation of Pressure Relieving Devices*, API 521, *Pressure Relieving and Depressuring Systems*, and API 527, *Seat Tightness of Pressure Relief Valves*, and other recommended and generally accepted good engineering practices. Cheniere also proposes to use American National Standard Institute/Flow Control Institute (ANSI/FCI) 70-2, *Seat Leakage*. The maximum leakage rates prescribed by API 527 would not pose a safety hazard. The flares have been sized in accordance with API 521, which includes an analysis of loss of instrument air and power as well as other scenarios that far exceed the leakage flow rates. As part of this process, the radiant heat was evaluated from the largest flaring scenario, which would not impact the safety of the public. In addition, flare emissions have been evaluated and are discussed in section 4.11.

IN1-3: The activation of a depressurizing valve would not pose a public safety hazard due to the flare design. The instrument air package would be provided with redundant equipment to increase reliability and reduce the likelihood of loss of instrument air. Please see response to IN1-2 for discussion of proposed flare design, radiant heat, and emissions.

IN2 – Ed Barren



20140731-5005(29692189).txt

Ed Barron, Fair Oaks Ranch, TX.
I am the President of The Clines Landing Association, a condo project with 108 Homeowners. Our property, located at the junction of the Corpus Christi Channel and Lydia Ann Channel, will be directly affected by the project under consideration.

IN2-1 We fully support the development of the Corpus Christi LNG project and believe it will benefit the region in many ways. The project will employ many thousands of workers during construction, plus add sustained employment and long term financial benefits to our economy. We recognize the impact and support the development of such projects, especially the Corpus Christi LNG Project.

IN2-2 That being said, we do have concern that with the increased ship movement, the Corpus Christi Ship Channel will have a very negative impact on our property and personnel. Over the past decade, we have seen significant deterioration and failing of our sea wall protecting the property along the Ship Channel due to wave action from passing ships. With the anticipated increase in the number and size of ships passing through the channel, our seawall will not be able to provide protection to the marine facilities owned by us. We have experienced instances of large waves breaking in our small boat marina during which property owners have narrowly missed injury. Videos and pictures of the dangerous wave action caused by the passing ships can be provided.

We request the FERC consider our concern and proper mitigation of our concerns be addressed by the developers of the Corpus Christi LNG Project.

Ed Barron
President of the Clines Landing Association

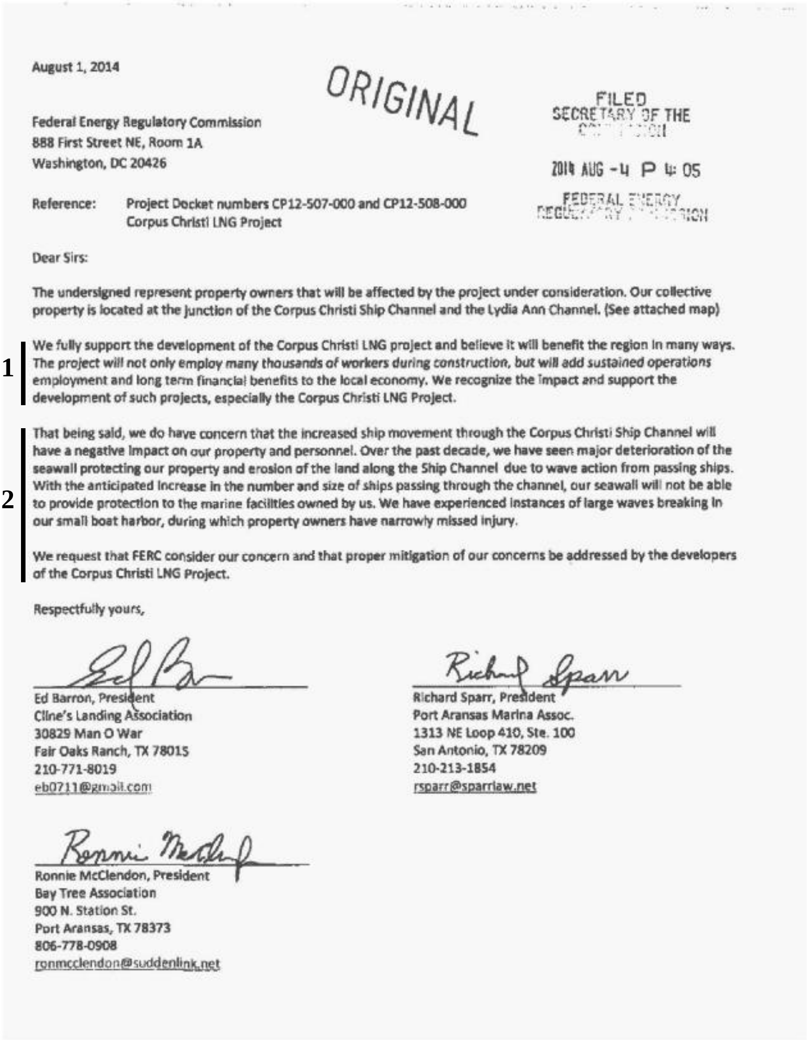
Page 1

IN2-1: Comment acknowledged.

IN2-2: Section 4.9.10.1 of the final EIS has been revised to address this comment.

INDIVIDUAL COMMENTS

IN3 – Ed Barren, Richard Sparr, and Ronnie McClendon



August 1, 2014

ORIGINAL

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COMMISSION

2014 AUG -4 P 4:05

FEDERAL ENERGY
REGULATORY COMMISSION

Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Reference: Project Docket numbers CP12-507-000 and CP12-508-000
Corpus Christi LNG Project

Dear Sirs:

The undersigned represent property owners that will be affected by the project under consideration. Our collective property is located at the junction of the Corpus Christi Ship Channel and the Lydia Ann Channel. (See attached map)

IN3-1 We fully support the development of the Corpus Christi LNG project and believe it will benefit the region in many ways. The project will not only employ many thousands of workers during construction, but will add sustained operations employment and long term financial benefits to the local economy. We recognize the impact and support the development of such projects, especially the Corpus Christi LNG Project.

IN3-2 That being said, we do have concern that the increased ship movement through the Corpus Christi Ship Channel will have a negative impact on our property and personnel. Over the past decade, we have seen major deterioration of the seawall protecting our property and erosion of the land along the Ship Channel due to wave action from passing ships. With the anticipated increase in the number and size of ships passing through the channel, our seawall will not be able to provide protection to the marine facilities owned by us. We have experienced instances of large waves breaking in our small boat harbor, during which property owners have narrowly missed injury.

We request that FERC consider our concern and that proper mitigation of our concerns be addressed by the developers of the Corpus Christi LNG Project.

Respectfully yours,

Ed Barron, President
Cline's Landing Association
30829 Man O War
Fair Oaks Ranch, TX 78015
210-771-8019
eb0711@gmail.com

Richard Sparr
Richard Sparr, President
Port Aransas Marina Assoc.
1313 NE Loop 410, Ste. 100
San Antonio, TX 78209
210-213-1854
rsparr@sparrlaw.net

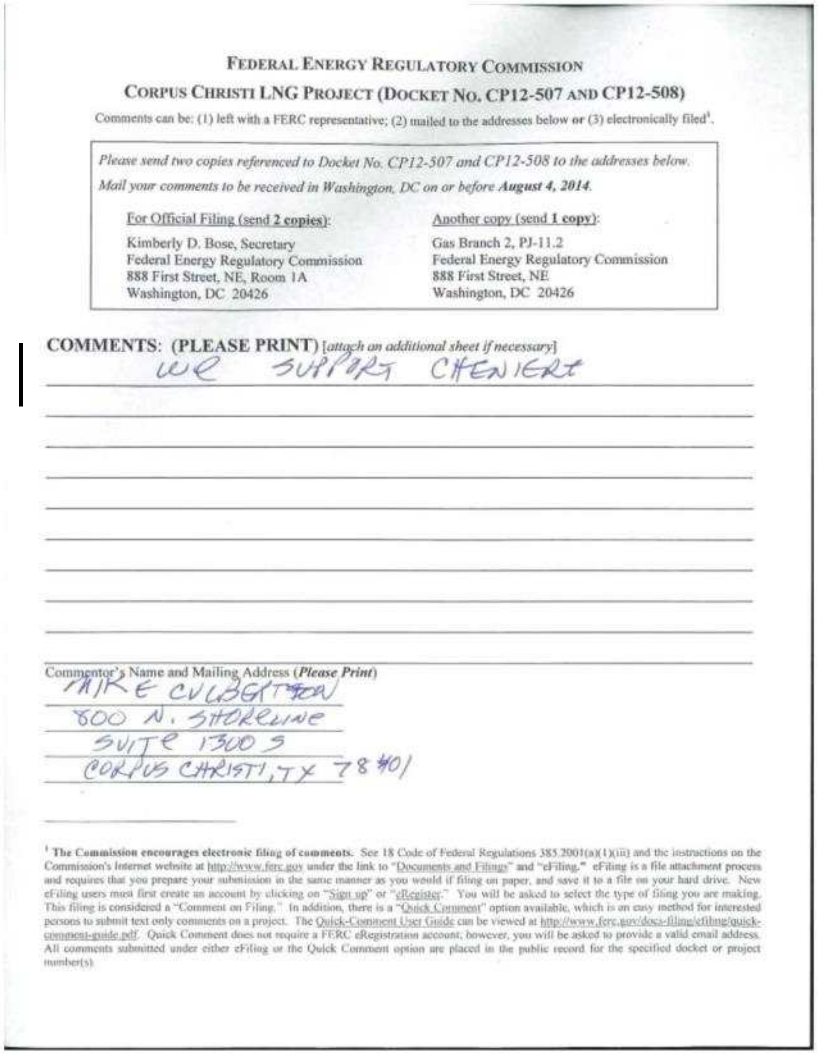
Ronnie McClendon
Ronnie McClendon, President
Bay Tree Association
900 N. Station St.
Port Aransas, TX 78373
806-778-0908
ronmcclendon@suddenlink.net

IN3-1: Comment acknowledged.

IN3-2: See response IN2-2.

INDIVIDUAL COMMENTS

IN4 – Mike Culberton



FEDERAL ENERGY REGULATORY COMMISSION

CORPUS CHRISTI LNG PROJECT (DOCKET NO. CP12-507 AND CP12-508)

Comments can be: (1) left with a FERC representative; (2) mailed to the addresses below **or** (3) electronically filed[1].

Please send two copies referenced to Docket No. CP12-507 and CP12-508 to the addresses below.

Mail your comments to be received in Washington, DC on or before ***August 4, 2014****.*

For Official Filing (send **2 copies**):	Another copy (send **1 copy**):
Kimberly D. Bose, Secretary Federal Energy Regulatory Commission 888 First Street, NE, Room 1A Washington, DC 20426	Gas Branch 2, PJ-11.2 Federal Energy Regulatory Commission 888 First Street, NE Washington, DC 20426

IN4-1

COMMENTS: (PLEASE PRINT) *[attach an additional sheet if necessary]*

WE SUPPORT CHENIERE

Commentor's Name and Mailing Address (***Please Print***)

MIKE CULBERTSON
800 N. SHORELINE
SUITE 1300 S
CORPUS CHRISTI, TX 78401

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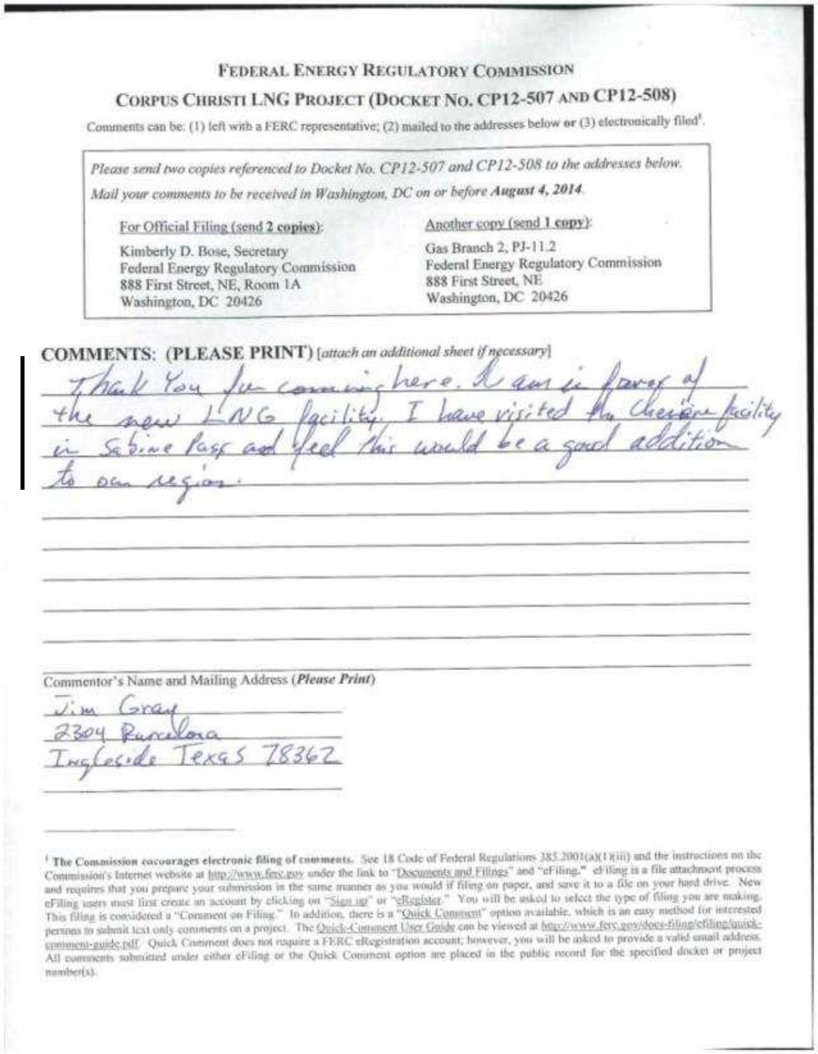
[1] **The Commission encourages electronic filing of comments.** See 18 Code of Federal Regulations 385.2001(a)(1)(iii) and the instructions on the Commission's Internet website at http://www.ferc.gov under the link to "Documents and Filings" and "eFiling." eFiling is a file attachment process and requires that you prepare your submission in the same manner as you would if filing on paper, and save it to a file on your hard drive. New eFiling users must first create an account by clicking on "Sign up" or "eRegister." You will be asked to select the type of filing you are making. This filing is considered a "Comment on Filing." In addition, there is a "Quick Comment" option available, which is an easy method for interested persons to submit text only comments on a project. The Quick-Comment User Guide can be viewed at http://www.ferc.gov/docs-filing/efiling/quick-comment-guide.pdf. Quick Comment does not require a FERC eRegistration account; however, you will be asked to provide a valid email address. All comments submitted under either eFiling or the Quick Comment option are placed in the public record for the specified docket or project number(s).

IN4-1: Comment acknowledged.

INDIVIDUAL COMMENTS

IN5 – Jim Gray



FEDERAL ENERGY REGULATORY COMMISSION

CORPUS CHRISTI LNG PROJECT (DOCKET NO. CP12-507 AND CP12-508)

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COMMENTS: (PLEASE PRINT) [*attach an additional sheet if necessary*]

IN3-1

Thank You for comming here. I am in favor of the new LNG facility. I have visited the Cheniere facility in Sabine Pass and feel this would be a good addition to our region.

Commentor's Name and Mailing Address (***Please Print***)

Jim Gray
2304 Barcelona
Ingleside Texas 78362

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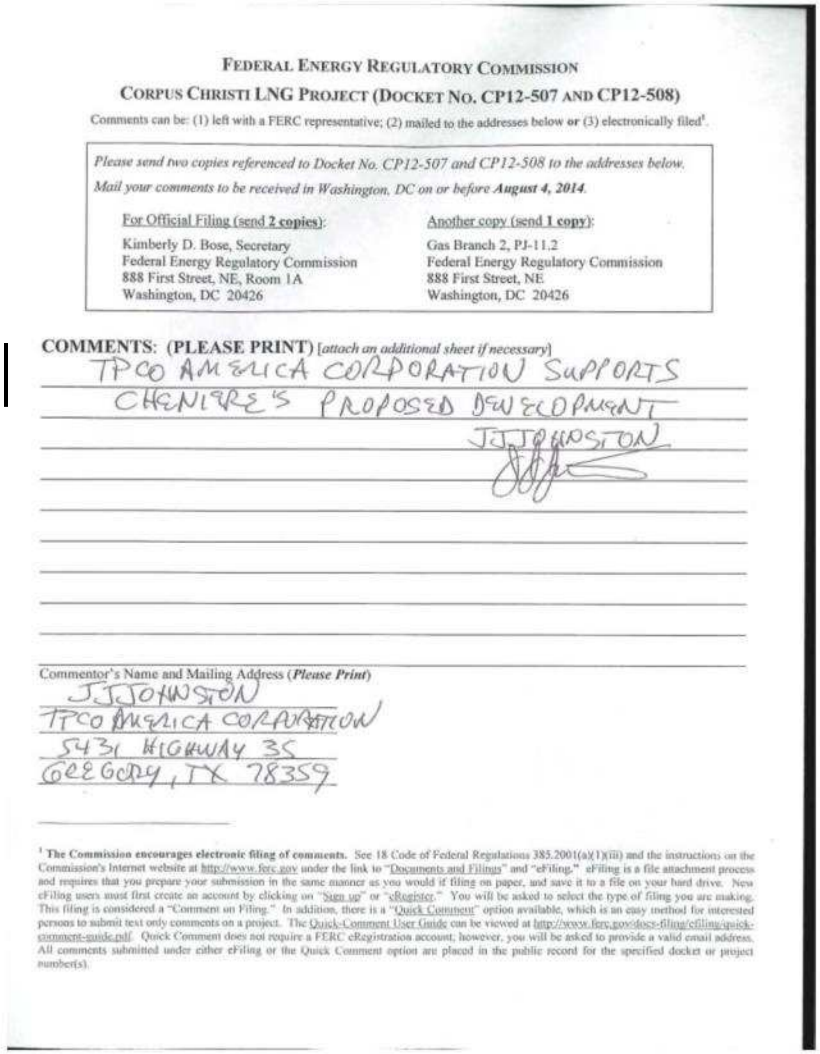
IN5-1: Comment acknowledged.

INDIVIDUAL COMMENTS

IN6 – JJ Johnson

IN6-1



FEDERAL ENERGY REGULATORY COMMISSION

CORPUS CHRISTI LNG PROJECT (DOCKET NO. CP12-507 AND CP12-508)

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COMMENTS: (PLEASE PRINT) [*attach an additional sheet if necessary*]

TPCO AMERICA CORPORATION SUPPORTS
CHENIERE'S PROPOSED DEVELOPMENT
JJ JOHNSTON

Commentor's Name and Mailing Address (***Please Print***)

J.J. JOHNSTON
TPCO AMERICA CORPORATION
5431 HIGHWAY 35
GREGORY, TX 78359

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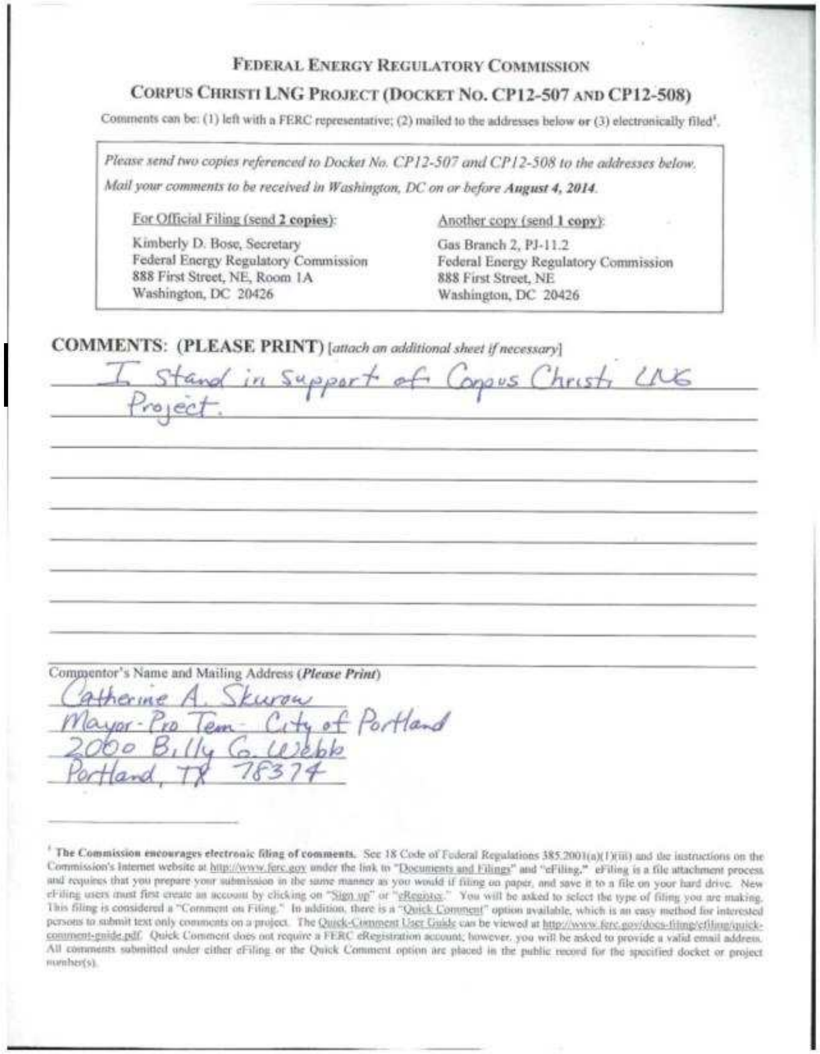
IN6-1: Comment acknowledged.

INDIVIDUAL COMMENTS

IN7 – Catherine A. Skurow



FEDERAL ENERGY REGULATORY COMMISSION

CORPUS CHRISTI LNG PROJECT (DOCKET NO. CP12-507 AND CP12-508)

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IN7-1

COMMENTS: (PLEASE PRINT) [*attach an additional sheet if necessary*]

I stand in support of Corpus Christi LNG Project.

Commentor's Name and Mailing Address (***Please Print***)

Catherine A. Skurow
Mayor-Pro Tem - City of Portland
2000 Billy G. Webb
Portland, TX 78374

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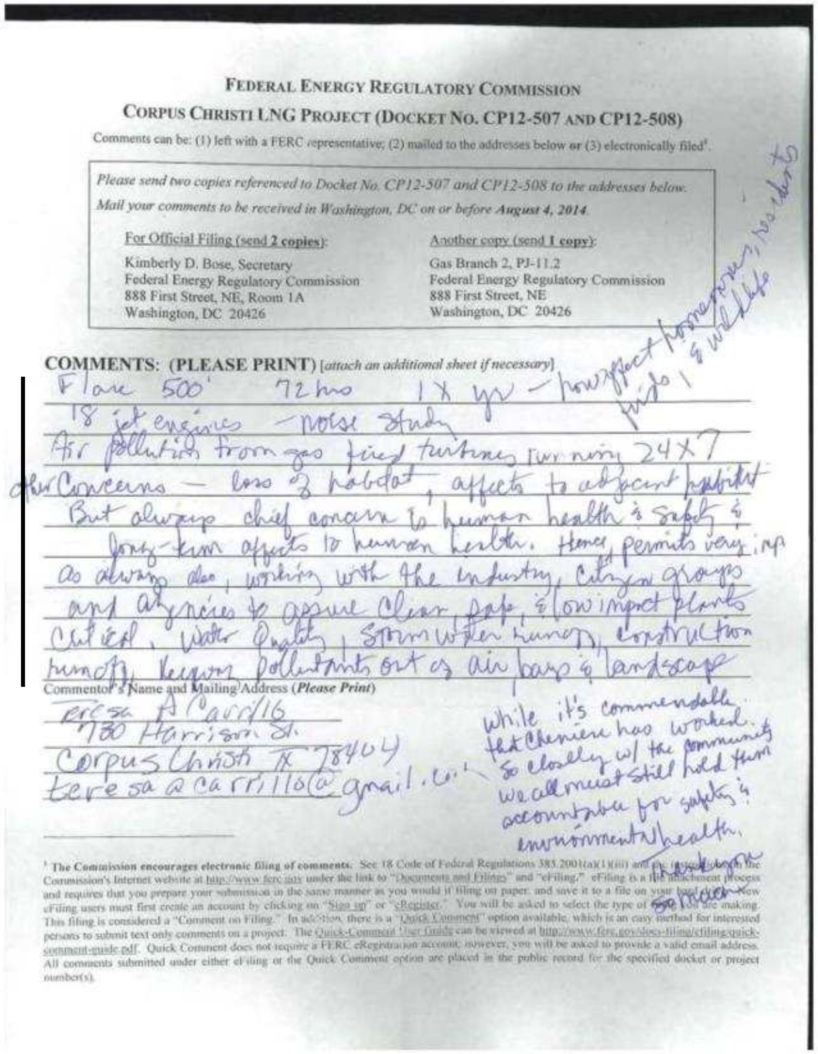
IN7-1: Comment acknowledged.

IN8 – Teresa A. Carrillo



FEDERAL ENERGY REGULATORY COMMISSION

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COMMENTS: (PLEASE PRINT) *[attach an additional sheet if necessary]*

Flare 500' 72 hrs 1 X yr – how affect homeowners, residents fields & wildlife
18 jet engines – noise study
Air pollution from gas fired turbines running 24 X 7
other Concerns – loss of habitat, affects to adjacent habitat
But always chief concern to human health & safety &
long-term affects to human health. Hence, permits very imp
as always also, working with the industry, citizen groups
and agencies to assure clean, safe, & low impact plants
critical, water quality, storm water runoff, construction
runoff, keeping pollutants out of air, bays & landscape

IN8-1

Commentor's Name and Mailing Address (*Please Print*)

Teresa A Carrillo
730 Harrison St.
Corpus Christi TX 78404
teresaacarrillo@gmail.com

While it's commendable that Cheniere has worked so closely w/ the community we all must still hold them accountable for safety & environmental health.
thank you so much

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IN8-1: Impacts on residents from the flare are discussed in section 4.8.1.4 of the final EIS. Impacts on wildlife and habitats are discussed in sections 4.6 and 4.7. Information related to the noise studies conducted for the Project is provided in section 4.11.2 of the final EIS. Section 4.11.1 of the final EIS discusses air quality impacts and relevant permits. Human health and safety is discussed in section 4.12 of the final EIS. Impacts on water quality, including stormwater run-off is addressed in section 4.3 of the final EIS.