Environmental Assessment for the Cove Point Liquefaction Project

May 2014

Dominion Cove Point LNG, LP

Docket No. CP13-113-000

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

Cooperating Agencies:

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

U.S. Army Corps of Engineers

U.S. Coast Guard

U.S. Department of Transportation

U.S. DEPARTMENT OF ENERGY

Office of Fossil Energy
DOE Docket No. FE 11-128-LNG

MARYLAND DEPARTMENT OF NATURAL RESOURCES

Adopted as DOE/EA-1942
November 2014

This environmental assessment was prepared by the staff of the Federal Energy Regulatory Commission to assess the potential environmental impacts of the Cove Point Liquefaction Project (Docket No. CP13-113-000), proposed for construction in Maryland and Virginia. The cooperation and assistance of the U.S. Department of Energy, U.S. Army Corps of Engineers, U.S. Department of Transportation, U.S. Coast Guard, and Maryland Department of Natural Resources was greatly appreciated.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas 2
Dominion Cove Point LNG, LP
Cove Point Liquefaction Project
Docket No. CP13-113-000

TO THE PARTY ADDRESSED:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Cove Point Liquefaction Project (Project) proposed by Dominion Cove Point LNG, LP (DCP) in the above-referenced docket. DCP requests authorization to construct and operate facilities to process and export domestically sourced liquefied natural gas (LNG) at the existing Cove Point LNG Terminal (LNG Terminal) in Calvert County, Maryland. The Project would enable DCP to export approximately 5.75 million metric tons per annum of LNG via LNG marine carriers that would dock at the existing offshore pier. A draft General Conformity Determination has also been prepared by the FERC to assess the potential air quality impacts associated with construction and operation of the proposed Project and is included as appendix B of this EA.

The EA assesses the potential environmental effects of the construction and operation of the Project in accordance with the requirements of the National Environmental Policy Act (NEPA). The draft General Conformity Determination was prepared to implement the conformity provision of the Clean Air Act. The FERC staff concludes that approval of the proposed Project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

The U.S. Department of Energy, U.S. Department of Transportation, U.S. Army Corps of Engineers, U.S. Coast Guard, and Maryland Department of Natural Resources participated as cooperating agencies in the preparation of the EA and draft General Conformity Determination. 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 proposed facilities associated with the LNG Terminal include the following:

- one LNG liquefaction train consisting of gas treatment equipment, natural gas-fired turbine-driven refrigerant compressors, waste heat recovery systems, fire and gas detection and safety systems, and control systems;

- additional power generation including waste heat-driven steam turbine generators and other electrical accessories to supplement the existing on-site power generation;

- minor modifications to the existing pier; and

- the use of two off-site areas to support construction.

The Project would also include the addition of up to 62,500 horsepower of electric-driven compression at DCP's existing Pleasant Valley Compressor Station in Fairfax County, Virginia, and modifications to an existing metering and regulating facility at DCP's Loudoun Compressor Station in Loudoun County, Virginia.

The FERC staff mailed copies of the EA and draft General Conformity Determination 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; libraries in the Project area; and parties to this proceeding. In addition, the EA, including the draft General Conformity Determination, has been placed in the public files of the FERC and is available for public viewing on the FERC's website at www.ferc.gov using the eLibrary link. A limited number of copies of the EA and draft General Conformity Determination are also 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

Any person wishing to comment on the EA and draft General Conformity Determination may do so. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that your comments are properly recorded and considered prior to a Commission decision on the proposal, it is important that the FERC receives your comments in Washington, DC on or before **June 16, 2014.**

For your convenience, there are four methods you can use to submit your comments to the Commission. In all instances please reference the Project docket number (CP13-113-000) with your submission. The Commission encourages electronic filing of comments and has expert staff available to assist you at (202) 502-8258 or efiling@ferc.gov.

(1) You can file your comments electronically by using the eComment feature, which is located on the Commission's website at www.ferc.gov under the link to Documents and Filings. This is an easy method for interested persons to submit brief, text-only comments on a project;

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

(3) You may file a paper copy of your comments at the following address:

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

(4) In lieu of sending written or electronic comments, the Commission invites you to attend a public comment meeting that its staff will conduct in the Project area to receive comments on the EA and draft General Conformity Determination. We encourage interested groups and individuals to attend and present oral comments on the EA and draft General Conformity Determination. A transcript of the meeting will be available for review in eLibrary under the Project docket number. **The meeting is scheduled as follows**:

Date and Time	**Location**
Saturday, May 31, 2014 1:00 – 6:00 p.m.	Patuxent High School 12485 Southern Connector Boulevard Lusby, MD 20657

Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214).[1] Only intervenors have the right to seek rehearing of the Commission's

[1] See the previous discussion on the methods for filing comments.

decision. The Commission grants intervenor status to affected landowners and others with environmental concerns who show good cause by stating that they have a clear and direct interest in this proceeding which no other party can adequately represent. **Simply filing comments will not grant you intervenor status, but you do not need intervenor status to have your comments considered.**

Additional information about the Project is available from the Commission's Office of External Affairs, at **(866) 208-FERC**, or on the FERC website (www.ferc.gov) using the eLibrary link. 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., CP13-113). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

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

Kimberly D. Bose,
Secretary

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TECHNICAL ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
µg/m^3	micrograms per cubic meter
µg/Nm^3	micrograms per normal cubic meter
ACHP	Advisory Council on Historic Preservation
AEGL	Acute Exposure Guideline Level
AGRU	acid gas removal unit
AQCR	Air quality control regions
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BACT	Best Available Control Technology
BCC	Birds of Conservation Concern
bcf	billion cubic feet
BCR	Bird Conservation Regions
BGEPA	Bald and Golden Eagle Protection Act
BLEVE	boiling-liquid-expanding-vapor explosion
BMPs	best management practices
bmsl	below mean sea level
BOG	boil off gas
Btu/ft^2-hr	British thermal units per square foot-hour
CAA	Clean Air Act
Cabot	Cabot Oil & Gas Corporation

CCS	carbon capture and sequestration
CEMS	continuous emissions monitoring system
Certificate	Certificate of Public Convenience and Necessity
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
COMAR	Code of Maryland Regulations
Commission	Federal Energy Regulatory Commission
COOP	U.S. Cooperative Observer Program
CPCN	Maryland Public Service Commission Certificate of Public Convenience and Necessity
CWA	Clean Water Act
dB	decibels
dBA	decibels on the A-weighted scale
DCP	Dominion Cove Point LNG, LP
DOD	U.S. Department of Defense
DOE-FE	U.S. Department of Energy, Office of Fossil Energy
DOT	U.S. Department of Transportation
DTI	Dominion Transmission, Inc.
E&SCPs	Erosion and Sediment Control Plans
EA	environmental assessment
EFH	Essential Fish Habitat
EI	Environmental Inspector
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
ERP	emergency response plan
ESA	Endangered Species Act
ESD	emergency shutdown
FEED	Front-End Engineering Design
FEMA	Federal Emergency Management Agency
Fenced Area	A 131-acre area that includes the land-based components of the LNG Terminal
FERC	Federal Energy Regulatory Commission
FIDS	Forested Interior Dwelling Species
FIRM	Flood Insurance Rate Maps
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLSUs	floating liquefaction and storage units
ft^3	cubic feet
FTA	Free Trade Agreement
FWS	U.S. Fish and Wildlife Service
GCRA	Global Change Research Act of 1990
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
gpd	gallons per day
gpm	gallons per minute
GWP	global warming potential
GZA	GZA GeoEnvironmental Inc.

H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid mist
HAPs	hazardous air pollutants
HAZOP	Hazards and Operability Study
hp	horsepower
HRSG	heat recovery steam generators
HRU	hydrocarbon removal unit
HUC	Hydrologic Unit Code
HVAC	heating, ventilation, and air conditioning
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LAER	Lowest Achievable Emission Rate
lb/MMBtu	pounds per million British thermal units
LDAR	leak detection and repair
L_{dn}	day-night sound level
L_{eq}	equivalent sound level
LFL	lower flammability limit
LNG	liquefied natural gas
LNG Terminal	Cove Point LNG Terminal
LOR	Letter of Recommendation
M&R	Metering and Regulating
m/s	meters per second
MACT	Maximum Achievable Control Technology
MAOP	maximum allowable operating pressure
MBTA	Migratory Bird Treaty Act
MCHE	main cryogenic heat exchanger
MDE	Maryland Department of the Environment
MDNR	Maryland Department of Natural Resources
mgd	million gallons per day
MMBtu/hr	million British thermal units per hour
MOU	Memorandum of Understanding
mph	miles per hour
MR	mixed refrigerant
MRL	mixed refrigerant liquid
MSHA	Maryland State Highway Administration
MST	Major Source Threshold
MTPA	metric tons per annum
MW	megawatt
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESHAP	National Emission Standard for Hazardous Air Pollutants for Source Categories
NFPA	National Fire Protection Association
ng/J	nanograms per Joule
NGA	Natural Gas Act
NGL	natural gas liquid
NGOs	non-governmental organizations

NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NNSR	Nonattainment New Source Review
NO_2	nitrogen dioxide
NOI	Notice of Intent
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSA	noise sensitive area
NSPS	New Source Performance Standards
OEP	Office of Energy Projects
OPS	Office of Pipeline Safety
OSHA	Occupational Safety and Health Administration
OTR	Ozone Transport Region
P&IDs	piping and instrumentation diagrams
Pb	lead
PCBs	polychlorinated biphenyls
PHA	Process Hazards Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
Plan	*Upland Erosion Control, Revegetation, and Maintenance Plan*
PM_{10}	particulate matter less than 10 microns
$PM_{2.5}$	particulate matter less than 2.5 microns
ppb	parts per billion
ppm	parts per million
ppm-v	parts per million by volume
PPRP	Power Plant Research Division
ppt	parts per thousand
Procedures	*Wetland and Waterbody Construction and Mitigation Procedures*
Project	Cove Point Liquefaction Project
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PSM	Process Safety Management of Highly Hazardous Chemicals; Explosive and Blasting Agents
PVMRM	plume volume molar ration method
Q/d	ratio of visibility-affecting emissions to distance
QRA	quantitative risk assessment
Reviewing State Agencies	Maryland Departments of the Environment; Natural Resources; Transportation; Planning; Business and Economic Development; and Agriculture; and the Maryland Energy Administration
RICE	reciprocating internal combustion engines
RMP	risk management plan
Secretary	Secretary of the Commission
SEP	surface emissive power
SER	Significant Emission Rate
SHPO	State Historic Preservation Office
SIP	State Implementation Plan
SMECO	Southern Maryland Electric Cooperative

SMPs	Stormwater Management Plans
SO_2	sulfur dioxide
T-BACT	Best Available Control Technology for Toxics
TAPs	toxic air pollutants
TCEQ	Texas Commission of Environmental Quality
tpy	tons per year
UFL	upper flammability limit
USC	United States Code
USCG	U.S. Coast Guard
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
VDACS	Virginia Department of Agriculture and Consumer Services
VDCR	Virginia Department of Conservation and Recreation
VDEQ	Virginia Department of Environmental Quality
VDGIF	Virginia Department of Game and Inland Fisheries
VOCs	volatile organic compounds
WSA	Waterway Suitability Assessment

1.0 PROPOSED ACTION

1.1 INTRODUCTION

The staff of the Federal Energy Regulatory Commission (Commission or FERC) has prepared this environmental assessment (EA) to assess the potential environmental impact of facilities proposed by Dominion Cove Point LNG, LP (DCP) to process and export domestically sourced liquefied natural gas (LNG). We[1] prepared this EA in compliance with the requirements of the National Environmental Policy Act (NEPA) (Title 40 of the Code of Federal Regulations [CFR], Parts 1500-1508), and the Commission's implementing regulations under 18 CFR 380. The U.S. Department of Energy, Office of Fossil Energy (DOE-FE); U.S. Department of Transportation (DOT); U.S. Army Corps of Engineers (COE); U.S. Coast Guard (USCG); and Maryland Department of Natural Resources (MDNR) participated as cooperating agencies in preparing this EA (see section 1.5).

On April 1, 2013, DCP filed an application in Docket No. CP13-113-000 under section 3(a) of the Natural Gas Act (NGA) and the procedures of Part 153 of the Commission's regulations seeking authority to site, construct, modify, and operate facilities to be used for the liquefaction of natural gas for export at DCP's existing Cove Point LNG Terminal (LNG Terminal) in Calvert County, Maryland. The section 3(a) facilities are referred to as the Liquefaction Facilities. In addition, DCP's application requested authorization under section 7(c) of the NGA and Part 157 of the Commission's regulations to construct, install, own, operate, and maintain facilities at DCP's existing Pleasant Valley Compressor Station in Fairfax County, Virginia and existing Loudoun Compressor Station in Loudoun County, Virginia, for the transportation of natural gas associated with DCP's proposal. The facilities proposed under sections 3(a) and 7(c) of the NGA are collectively referred to as the Cove Point Liquefaction Project (Project) and are described in section 1.2. Prior to filing its application, DCP participated in the Commission's pre-filing process under Docket No. PF12-16-000.

On September 1, 2011, DCP filed an *Application for Long-Term Authorization to Export LNG to Free Trade Agreement Countries* with the DOE-FE (FE Docket No. 11-115-LNG). In its application, DCP requested approval to export up to approximately 1.0 billion cubic feet (bcf) of natural gas per day, or about 7.8 million metric tons per annum (MTPA) of LNG, to any country that has or in the future develops the ability to import LNG via ocean-going carrier and with which the United States has, or in the future enters into, a Free Trade Agreement (FTA). On October 7, 2011, DOE-FE issued Order No. 3019 authorizing DCP to export LNG to FTA nations in accordance with section 3(c) of the NGA as amended by section 201 of the Energy Policy Act of 1992.

On October 3, 2011, DCP filed an *Application for Long-Term Authorization to Export LNG to Non-Free Trade Agreement Countries* with the DOE-FE (FE Docket No. 11-128-LNG). In its application, DCP requested approval to export up to approximately 7.82 million MTPA of LNG to any country with which the United States does not have a FTA and with which trade is not prohibited by U.S. law or policy. Subsequent to the two above-referenced applications with the DOE-FE and as indicated in FERC Docket No. CP13-113-000, DCP modified the Project and is seeking authorization to export 5.75 million MTPA of LNG to FTA and non-FTA nations. On September 11, 2013, DOE-FE issued Order No. 3331 conditionally authorizing DCP to export LNG to non-FTA nations in accordance with section 3(a) of the NGA as amended by section 201 of the Energy Policy Act of 1992.

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

Previous Cove Point LNG Terminal Authorizations

The Federal Power Commission (now the FERC) originally authorized Cove Point LNG, LP to construct and operate the LNG Terminal and Cove Point Pipeline on June 6, 1972, in Docket No. CP71-68-000. The LNG Terminal was designed to receive imported LNG from ocean-going carriers, temporarily store LNG in insulated tanks, and vaporize the LNG for delivery to U.S. markets. The LNG Terminal includes a pier located 1.1 miles offshore in the Chesapeake Bay, as well as a concrete-lined tunnel beneath the floor of the Chesapeake Bay that provides personnel access, LNG piping, and other support systems to the offshore pier. In 1980, LNG imports ceased, and between 1980 and 1994 the original facilities were unused except for a small amount of interruptible transportation service on the Cove Point Pipeline.

In 1994, the FERC authorized Cove Point LNG, LP to reactivate the on-shore storage and vaporization facilities and to construct a liquefaction unit to liquefy domestic natural gas in order to provide LNG peaking and storage services (Docket No. CP94-59-000). The environmental review for the project was included in an EA issued in August 1994. The offshore pier at the LNG Terminal was not reactivated in 1994.

In 2001, the FERC authorized Cove Point LNG, LP to construct new facilities and reactivate and operate existing facilities, including the offshore pier, in order to recommence LNG import and terminal services (Docket No. CP01-76-000). The new facilities included a fifth LNG storage tank, increasing the LNG Terminal's storage capacity to 7.8 bcf. The environmental review for the facilities was included in an EA for the project issued in July 2001. DCP acquired the LNG Terminal and Cove Point Pipeline in 2002 and has operated the facilities to date.

In 2006, the FERC approved DCP's Cove Point Expansion Project, which included the construction of two new LNG storage tanks and additional vaporization facilities that increased the storage capacity to 14.6 bcf and peak send-out capacity to approximately 1.8 bcf per day. The Cove Point Expansion Project also included expansion of the Cove Point Pipeline by DCP, and construction of new downstream pipeline and storage facilities by Dominion Transmission, Inc. (DTI). Environmental review of the Cove Point Expansion Project was included in an environmental impact statement (EIS) issued under Docket Nos. CP05-130-000, CP05-131-000, and CP05-132-000 in April 2006.

In 2009, the FERC authorized the Pier Reinforcement Project to modify the existing offshore pier at the LNG Terminal to accommodate larger vessels (Docket No. CP09-60-000). The environmental review for this project was included in an EA issued in May 2009.

1.2 PROPOSED FACILITIES

The Project would generally include the construction and operation of:

- new Liquefaction Facilities at the LNG Terminal in Calvert County, Maryland;
- installation of additional compression at the existing Pleasant Valley Compressor Station, miscellaneous piping and measurement upgrades at the Pleasant Valley Metering and Regulating (M&R) Facility, and installation/replacement of the Pleasant Valley Suction/ Discharge Pipelines in Fairfax County, Virginia;
- miscellaneous piping and measurement upgrades at the Loudoun M&R Facility at the existing Loudoun Compressor Station in Loudoun County, Virginia; and

- the temporary use of sites in Maryland and Virginia to support construction of the facilities.

If approved by the Commission, DCP proposes to begin construction of the Liquefaction Facilities in the summer of 2014, and would place the facilities in service in June 2017. Construction of the Virginia facilities would begin in the first quarter of 2016 and the facilities would be placed in service in March 2017. The locations of the proposed facilities are depicted on figure 1.2-1.

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 used for importation or exportation, the FERC shall authorize the proposal unless it finds that the proposed facilities will not be consistent with the public interest.

Under section 7 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 of Public Convenience and Necessity (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 a proposed project.

1.2.1 Liquefaction Facilities

Figure 1.2.1-1 depicts the location of the LNG Terminal and offsite support areas. The land-based components of the LNG Terminal are situated within a 131-acre area, referred to as the Fenced Area, which is located within an approximately 1,017-acre parcel owned by DCP. As indicated on figure 1.2.1-2, portions of the land owned by DCP are covered under conservation easements with the Cove Point Beach Association (20 acres), Calvert County (91 acres), the Maryland Environmental Trust and The Nature Conservancy (588 acres), and the Sierra Club and the Maryland Conservation Council (318 acres, which includes the 131-acre Fenced Area). DCP's property is generally bounded by the Chesapeake Bay to the east, residential development to the south and west, and Calvert Cliffs State Park to the north.

The Liquefaction Facilities would occupy 59.5 acres within the Fenced Area and would tie into the existing facilities and share common equipment and infrastructure such as the LNG storage tanks, pumps, piping, and offshore pier to support both the import and export of LNG (figure 1.2.1-3). The primary Liquefaction Facilities would consist of the components described below.

Pre-treatment Facilities

Natural gas for liquefaction would be received via the Cove Point Pipeline, which terminates on the west side of the LNG Terminal. The feed gas would be pretreated prior to liquefaction in order to remove impurities that have no heating value, have corrosive potential, or would solidify during the liquefaction process. Mercury would be removed from the feed gas in order to protect the aluminum heat exchangers in the liquefaction equipment. After mercury removal, the feed gas would flow to an acid gas removal unit (AGRU) to remove all of the carbon dioxide (CO_2) and the majority of sulfur compounds from the gas. Upon acid gas removal, water would be removed from the feed gas through a series of molecular sieve dryers. After dehydration, the feed gas would flow through a heavy hydrocarbon removal unit (HRU) where heavier hydrocarbons would be condensed and removed. The resulting stabilized condensate would be routed to two storage tanks. A truck loading station with loading pumps would be installed to facilitate periodic truck load-out of the condensate.

0 5 10 Miles

N S E W

Figure 1.2-1

Cove Point Liquefaction Project

Project Overview Map

Existing Compressor Station

Existing LNG Terminal

Source: Z:\Clients\A_D\Dominion\Cove_Point\ArcGIS\2013\07\Application\Dominion_Cove_Point_Figure_1_2-1.mxd

Date: (7/25/2013)

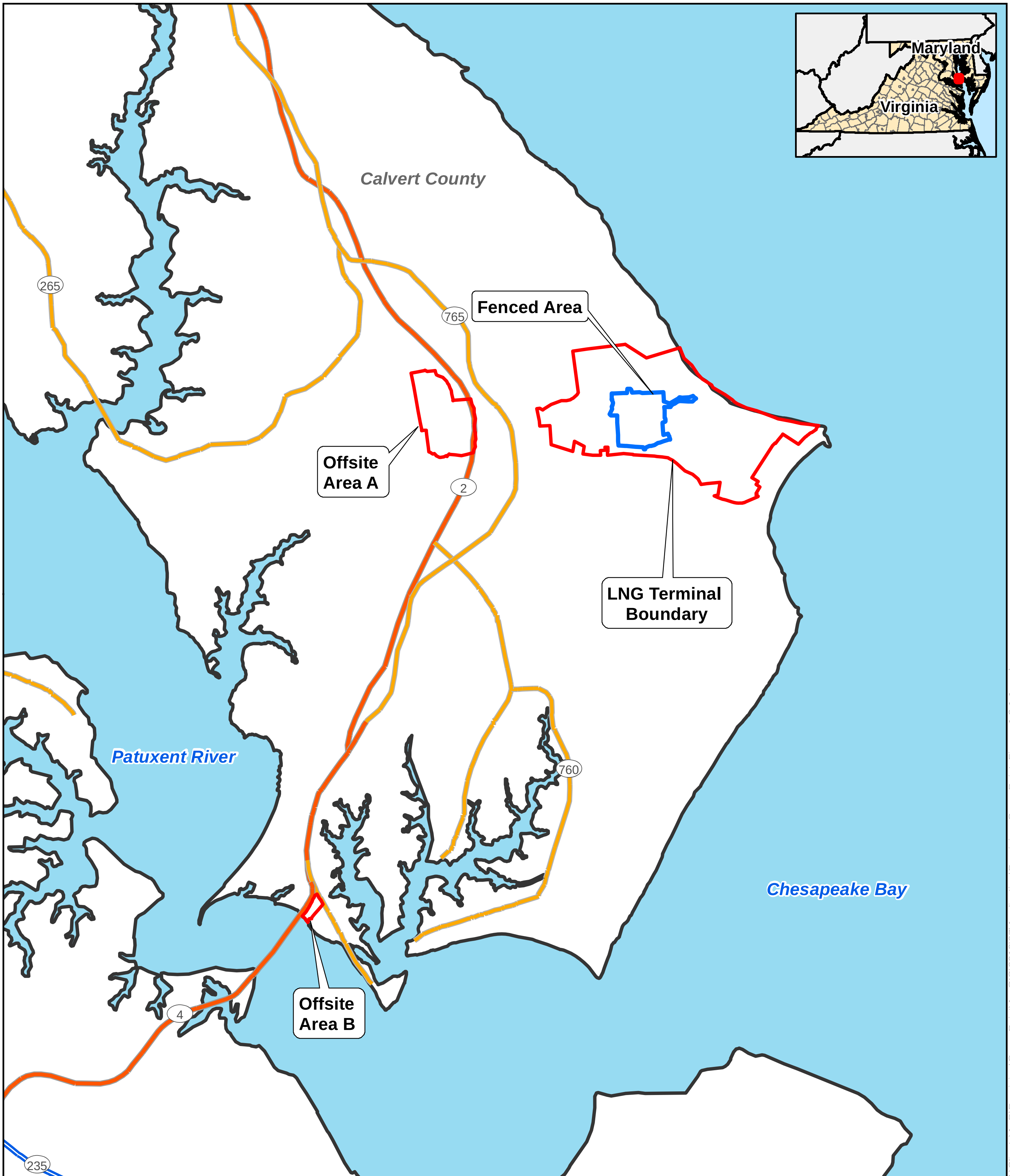

Figure 1.2.1-1
Cove Point Liquefaction Project
LNG Terminal and Offsite Support Areas

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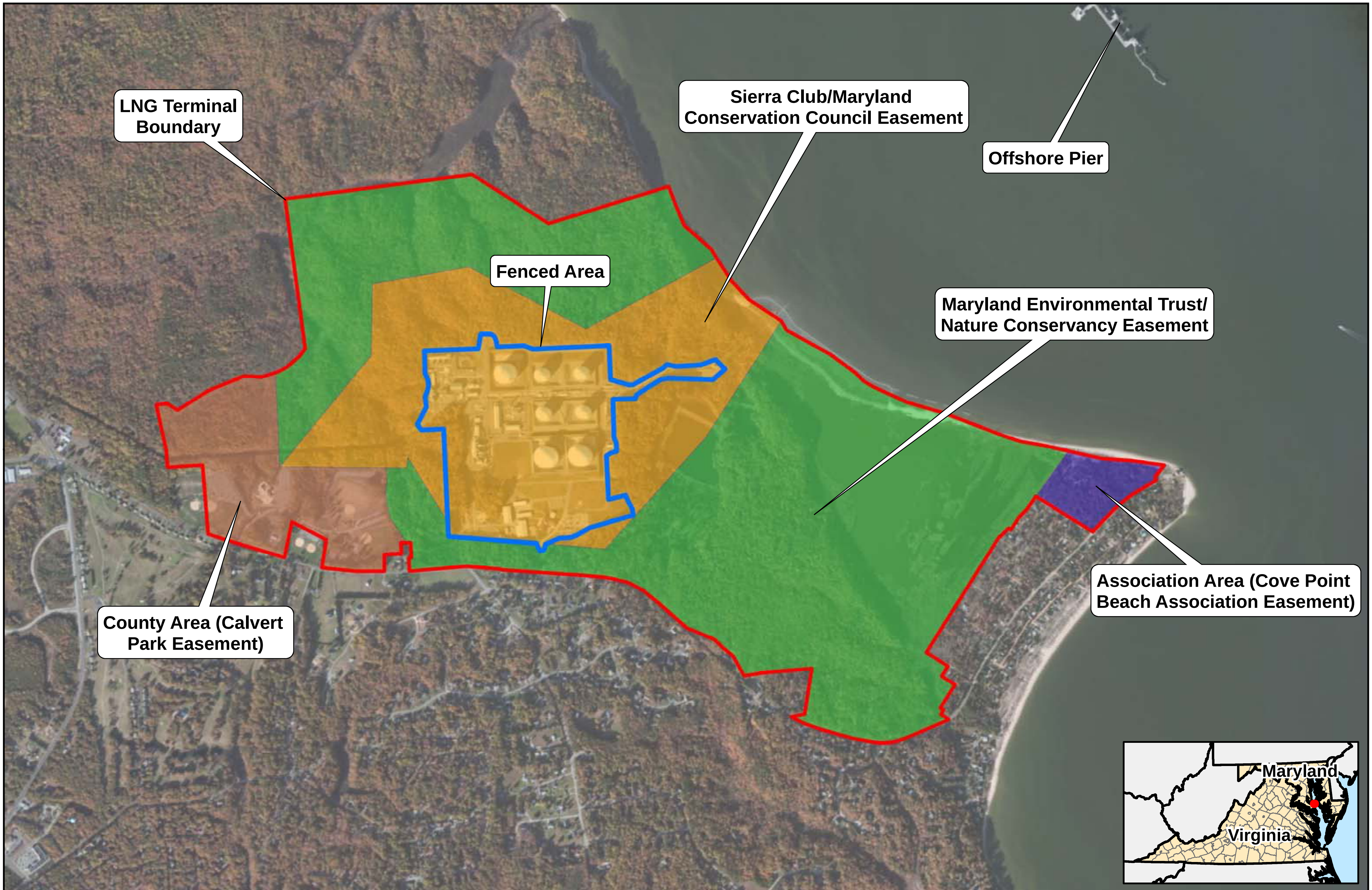
Date: (8/8/2013)



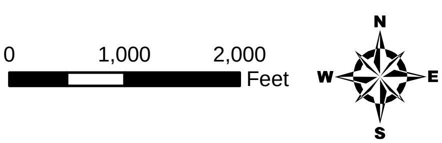


Figure 1.2.1-2
Cove Point Liquefaction Project
LNG Terminal Detail

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Date: (2/12/2014)

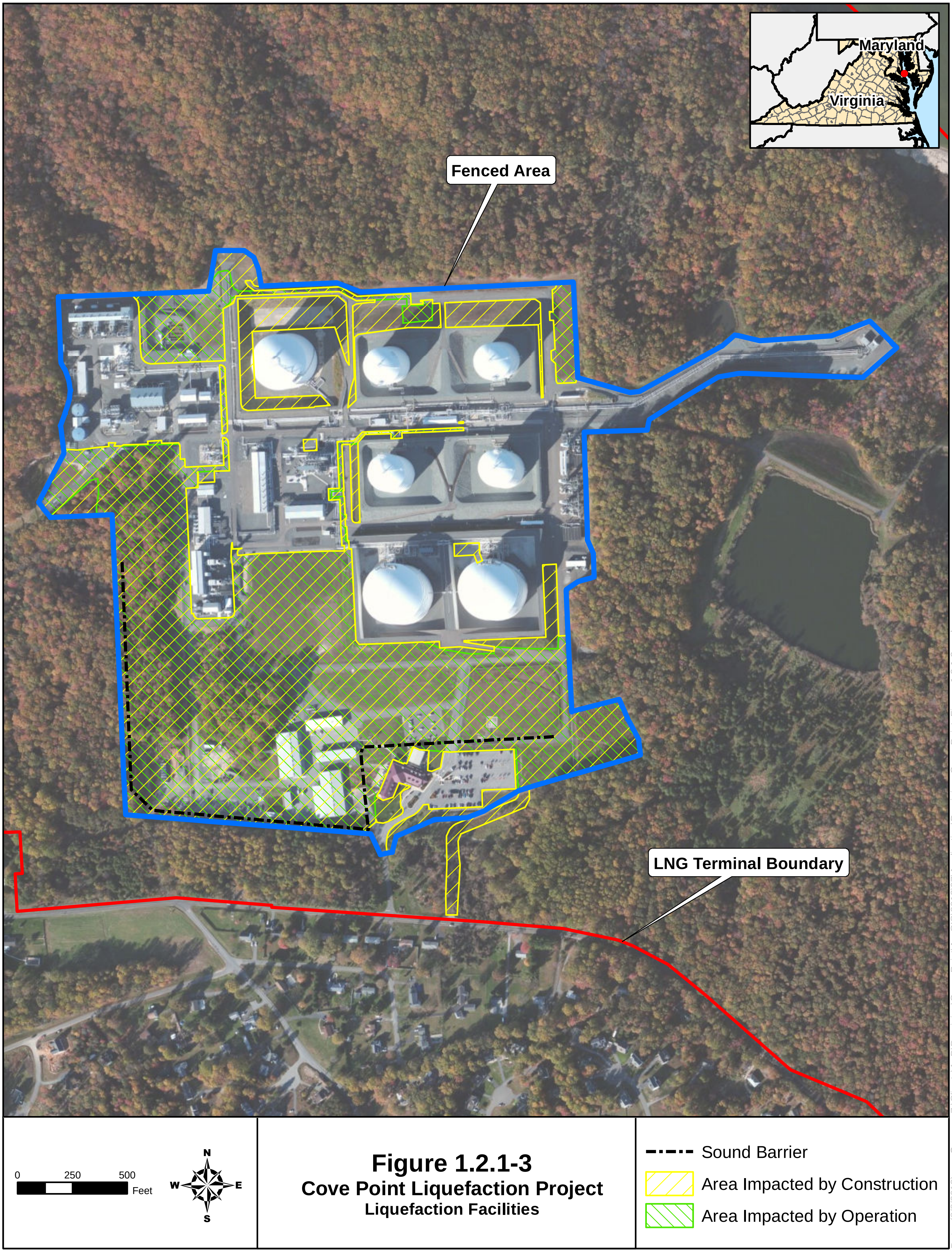

Figure 1.2.1-3
Cove Point Liquefaction Project
Liquefaction Facilities

Liquefaction Equipment

The dry gas from the HRU would flow to the refrigeration system where it would be chilled to approximately -245 degrees Fahrenheit (°F) through a combination of heat exchangers and pressure reduction processes. DCP selected the Air Products (APCI) C3/split mixed refrigerant (MR) process as the liquefaction technology. This technology consists of a propane pre-cooled system, MR system, and a proprietary main cryogenic heat exchanger (MCHE). During operation, make-up refrigerants would come from three sources: nitrogen would be obtained from the existing nitrogen system; methane would be supplied from downstream of the HRU; and ethane and propane would be trucked in and stored in vessels. The propane and MR compressors would be driven by two new General Electric Frame 7EA gas turbines.

After liquefaction, the LNG would be sent to a stripper for nitrogen removal. After nitrogen removal, the final LNG product would be pumped to the LNG storage tanks and then to the offshore pier for loading onto ships for export. The nitrogen rich stream would be used as fuel gas for the gas turbines.

LNG Unloading/Loading Facilities

The existing LNG unloading facilities would be modified to provide bi-directional loading and unloading of LNG to and from ships. Modifications would occur onshore within the Fenced Area, within the concrete-lined tunnel from the LNG Terminal to the offshore pier, and on the offshore pier. The Project would not require the construction of new LNG storage tanks, additional LNG loading/unloading piers, or dredging, and DCP stated that none of the Project-related activities at the LNG Terminal or existing offshore pier would involve in-water work.

For export LNG loading operations, DCP would install additional pumps onshore to provide an average ship loading rate of 10,200 cubic meters per hour, and new blowers would be installed on the offshore pier to return vapors (i.e., natural gas) displaced by the loading process into the onshore LNG storage tanks. DCP would also remove two unloading suction drums on the offshore pier to make room for the new blowers. For import LNG unloading operations, LNG carriers would use their own onboard pumps to unload LNG into the onshore LNG storage tanks.

DCP would also modify the LNG transfer piping in the tunnel to allow for bi-directional flow of LNG. This piping modification would require replacement of the tunnel's existing expansion joints. All activities associated with the transfer piping modifications would take place within the existing tunnel and no environmental impacts are likely to occur.

Utilities and Other Facilities

As previously indicated and as described below, the Project would utilize existing and new utilities and other facilities to support LNG import and export operations. The Project would also include the removal of some existing structures within the Fenced Area to accommodate new Project facilities.

<u>Electric Power Generation and Steam Systems</u>

Electric power for the LNG Terminal is currently generated on-site, with only a limited connection to the outside power distribution grid for backup power. All of the electric power necessary to operate the Liquefaction Facilities would be provided by two new 65 megawatt (MW) steam turbine power generators located within the Fenced Area. The steam needed to drive the generators would be obtained from heat recovery steam generators (HRSG) installed in the refrigerant compressor gas turbine exhaust duct and two auxiliary boilers. In addition to driving the electric generators, steam would also serve low, medium, and high pressure steam systems. Heat would be removed from a portion of the steam system and used for process heating.

The existing on-site electric power system would provide supplemental and back-up power to the Project.

Water

Water necessary for Project construction and operation would be obtained from existing water wells at the LNG Terminal. As indicated in table 1.10-1 and as discussed in section 2.2.1, DCP has applied to the Maryland Public Service Commission (PSC) for a Certificate of Public Convenience and Necessity (CPCN). The CPCN application includes a request to modify the LNG Terminal's existing water appropriations permit to allow for the additional groundwater use required for the Project. The Maryland Department of the Environment (MDE) has reviewed the request and has conditionally recommended granting authorization for up to an average daily withdrawal of 233,000 gallons, and 275,000 gallons per day (gpd) during the month of maximum use. Alternative water sources are discussed in section 3.5.

Plant and Instrument Air Systems

The Project would include a new instrument air and plant air system independent of the existing LNG Terminal air systems. A second, new air system would be installed to provide redundancy.

Nitrogen

The Liquefaction Facilities would consume nitrogen for refrigerant make-up, refrigerant compressor seal, and other utility demands. Nitrogen would be obtained via connection to the existing LNG Terminal nitrogen supply.

Fuel Gas

Flash gas from the nitrogen stripper would be compressed and combined with boil off gas (BOG) from the existing LNG storage tanks and used as the primary fuel for the low pressure fuel systems (e.g., auxiliary boilers, thermal oxidizer, and flares). The remaining low pressure fuel gas would be compressed for use in the high pressure fuel system (i.e., turbines). Natural gas from the Cove Point Pipeline would supplement fuel to the gas turbines.

Flare System

Ground flares would be installed as the emission control technology for volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). Due to site restrictions and flaring requirements, one ground flare pad would be installed in the northern area of the LNG Terminal and a second ground flare pad would be installed in the southern area of the LNG Terminal. A heat shield would be installed around each ground flare pad.

Fire Protection Systems

The existing LNG Terminal maintains extensive fire protection facilities. These systems would be expanded to serve the Project facilities and would include vapor and fire detection sensors and fire mitigation measures including water spray equipment. The fire protection systems associated with the Project are detailed in section 2.8.4.

Spill Containment Systems

The existing LNG Terminal includes an engineered system to contain potential spills of LNG. The Liquefaction Facilities would be installed within similar engineered systems to contain potential spills of LNG and refrigerants. The spill containment systems associated with the Project are detailed in section 2.8.6.

Sound Barrier

DCP would install an approximately 3,500-foot-long wall along the south and west sides of the Fenced Area to mitigate for sound generated by the Project. The wall would be 60 feet high, constructed of sound absorbing panels, and painted to blend into the surrounding landscape. Due to the surrounding forested area, the sound barrier would only be visible to the public at the entrance to the LNG Terminal. Additional discussion of the sound barrier and potential visibility from Cove Point Road in the vicinity of the LNG Terminal entrance is provided in section 2.4.5.

Structure Removal

DCP would remove an existing warehouse, maintenance shop, and radio tower within the Fenced Area to accommodate Project construction and new facilities. A new warehouse, maintenance shop, and radio tower would be constructed within the Fenced Area as described in section 1.3.2.

1.2.2 Virginia Facilities

Additional compression on the Cove Point Pipeline would be required to deliver the inlet gas to the LNG Terminal. The current maximum allowable operating pressure (MAOP) of the Cove Point Pipeline is 1,250 pounds per square inch gauge (psig). DCP would operate the Cove Point Pipeline within the current MAOP. To support the transfer of natural gas to the LNG Terminal, DCP would install the following new or modified facilities at the Pleasant Valley Compressor Station in Fairfax County, Virginia and at the Loudoun M&R Facility in Loudoun County, Virginia (figures 1.2.2-1 and 1.2.2-2, respectively).

Pleasant Valley Compressor Station

- Installation of four new electric-driven compressor units totaling up to 62,500 horsepower (hp), increasing the total compression at the station up to 68,500 hp;
- Installation of equipment and facilities, including a new compressor building and extension of the existing compressor building, gas coolers, filter/separators, valves, piping, headers, electrical facilities, and a natural gas-fired boiler;
- Installation of an approximately 800-foot-long, 20-foot-high sound barrier wall along the eastern side of the compressor station site; and
- Installation of a 36-inch-diameter suction pipeline within the compressor station site, extending from the new compressors to a new tap on DCP's 36-inch-diameter TL-522 pipeline.

Pleasant Valley Suction/Discharge Pipelines and M&R Facility

- Installation of a new 36-inch-diameter suction pipeline extending approximately 1,200 feet from the Pleasant Valley Compressor Station to the Pleasant Valley M&R Facility;
- Replacement of an existing 16-inch-diameter discharge pipeline with a new 36-inch-diameter discharge pipeline extending approximately 1,200 feet from the Pleasant Valley Compressor Station to the Pleasant Valley M&R Facility; and

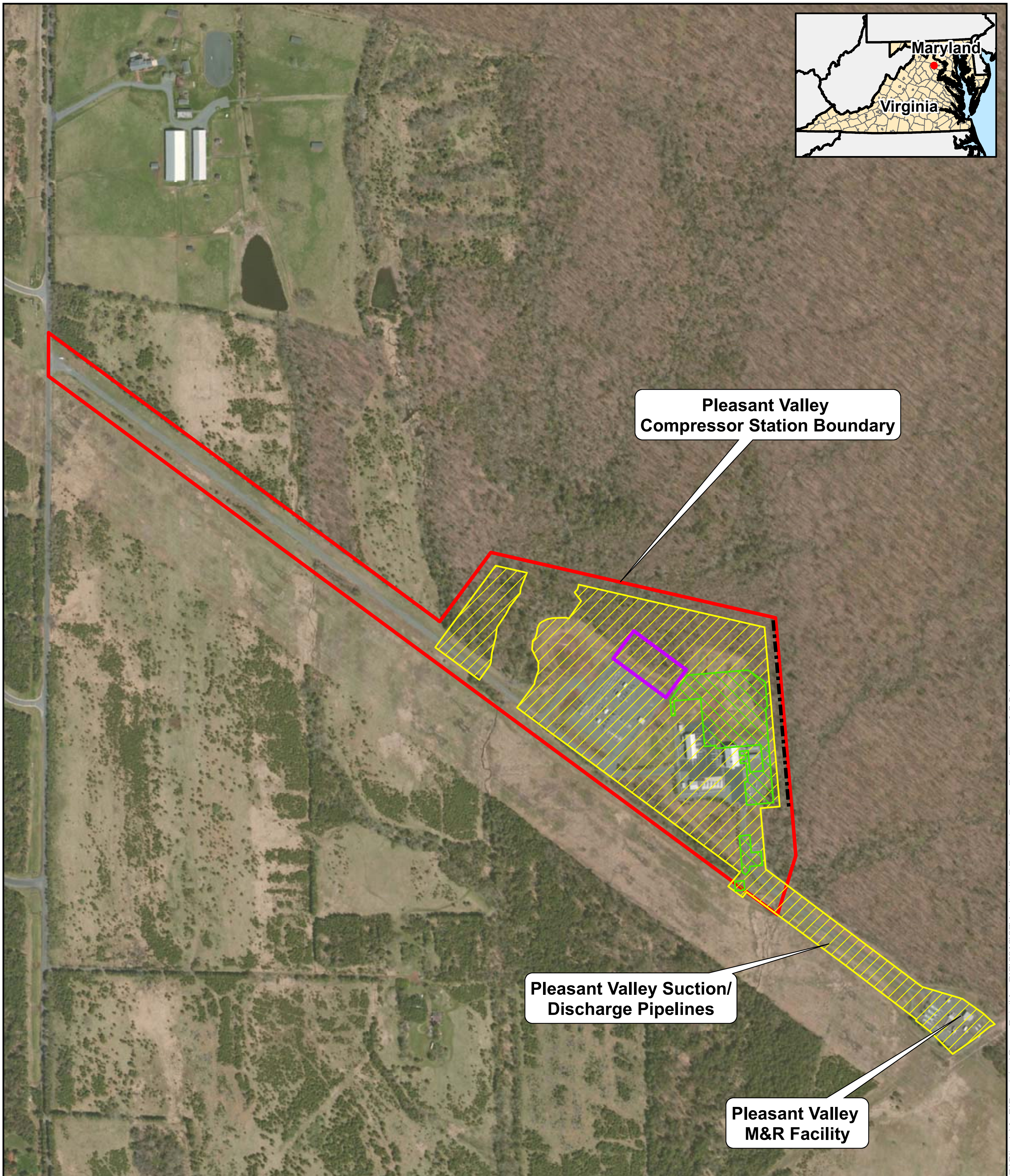

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Figure 1.2.2-1
Cove Point Liquefaction Project
Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility

Sound Barrier
Area Impacted by Construction
Area Impacted by Operation
NOVEC Substation Expansion (Nonjurisdictional)

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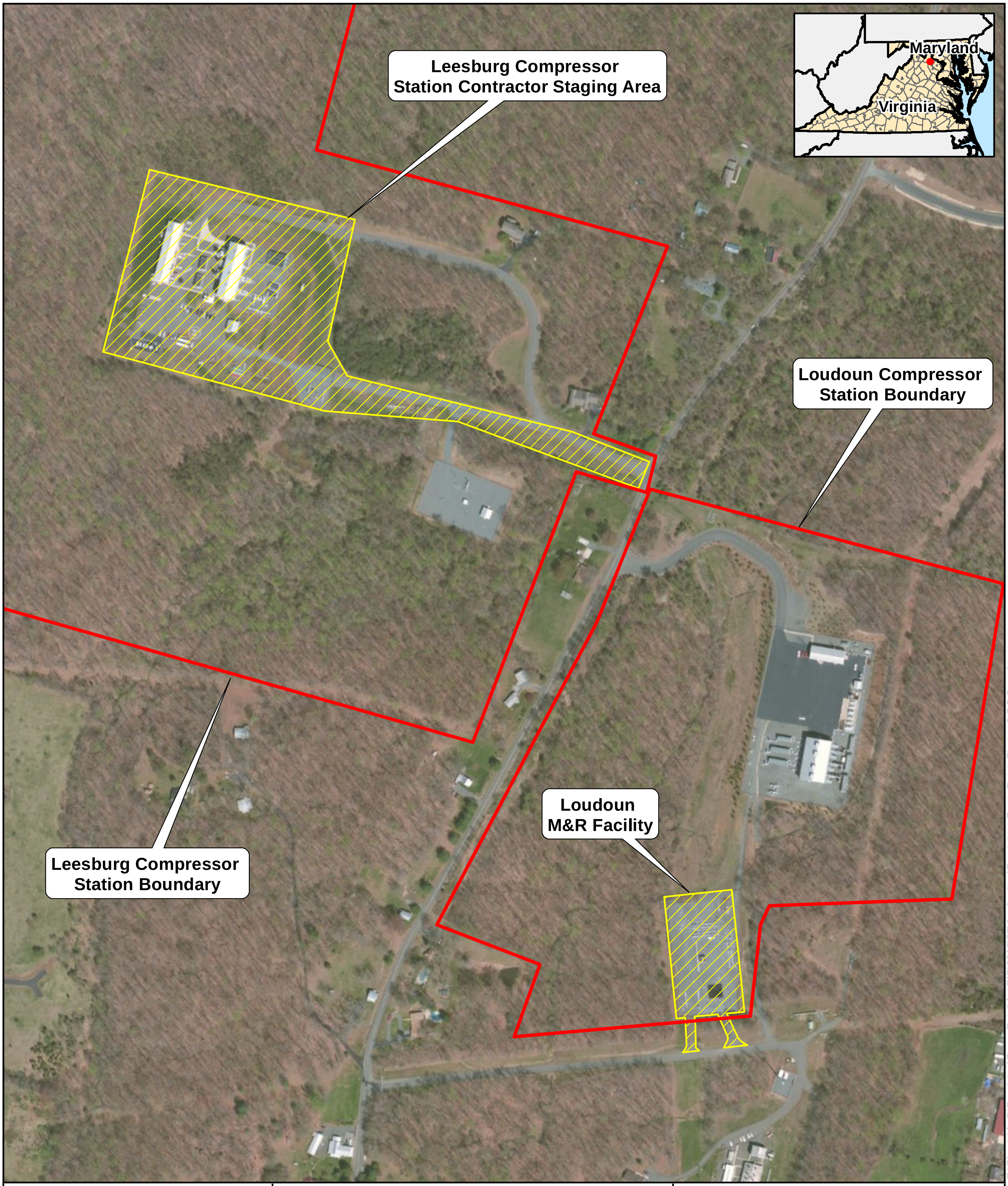

Figure 1.2.2-2
Cove Point Liquefaction Project
Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area

Area Impacted by Construction

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- Installation of miscellaneous piping and measurement upgrades, including additional meter runs, piping, fittings, and valves at the Pleasant Valley M&R Facility.

As detailed in sections 1.9 and 2.4, construction and operation of the above facilities would occur within the boundaries of the existing Pleasant Valley Compressor Station, Pleasant Valley M&R Facility, or existing pipeline right-of-way between the facilities (figure 1.2.2-1).

Loudoun M&R Facility

DCP would install miscellaneous piping and measurement upgrades, including additional meter runs and/or piping, fittings, and valves at the existing Loudoun M&R Facility located within the boundaries of the Loudoun Compressor Station (figure 1.2.2-2). No additional compression would be installed at the Loudoun Compressor Station.

1.2.3 Offsite Areas

DCP proposes to temporarily use two areas in Calvert County, Maryland to support construction of the Liquefaction Facilities (figure 1.2.1-1). DCP would also use a portion of the existing DTI Leesburg Compressor Station property in Loudoun County, Virginia to support construction of the Virginia facilities.

Offsite Area A

Offsite Area A (figure 1.2.3-1) consists of 179.4 acres of largely wooded, undeveloped land located on the west side of Maryland Route 2/4 approximately 1.5 miles west of the LNG Terminal. DCP has an option to purchase 100 acres of the property from a private party, and is negotiating to lease the remaining 79.4 acres from Calvert County. DCP would clear and utilize 94.9 acres (53 percent) of the property, which DCP states is the area needed to support construction of the Liquefaction Facilities. Offsite Area A would accommodate parking for approximately 1,700 worker vehicles, sheltered warehouse space, outdoor storage racks, outdoor laydown areas, temporary buildings, and office trailers. DCP stated that it would donate the 100-acre privately held portion of Offsite Area A to Calvert County upon completion of the Liquefaction Facilities. Calvert County has not yet determined the final deposition of the property; however, the county has stated that the property would be replanted following construction, and would not be intensely or commercially developed.

Offsite Area A is crossed by overhead electric transmission facilities owned and operated by the Southern Maryland Electric Cooperative (SMECO). DCP is working with SMECO to develop a plan for the joint use of the electric transmission right-of-way during construction of the Liquefaction Facilities.

Offsite Area B

Offsite Area B (figure 1.2.3-2) consists of an 11.0-acre vacant parcel situated on the Patuxent River approximately 4.5 miles south of the LNG Terminal and off of Maryland Route 2/4. Offsite Area B is privately owned, and DCP has obtained an option to lease the property during construction of the Liquefaction Facilities.

DCP would use Offsite Area B to receive large equipment and materials delivered by barge. DCP would utilize approximately 5.8 acres of the site; the remaining 5.2 acres of the site would be undisturbed. DCP would modify the site to include a temporary road and laydown area and would construct a temporary pier in the Patuxent River for mooring barges and offloading equipment and materials.

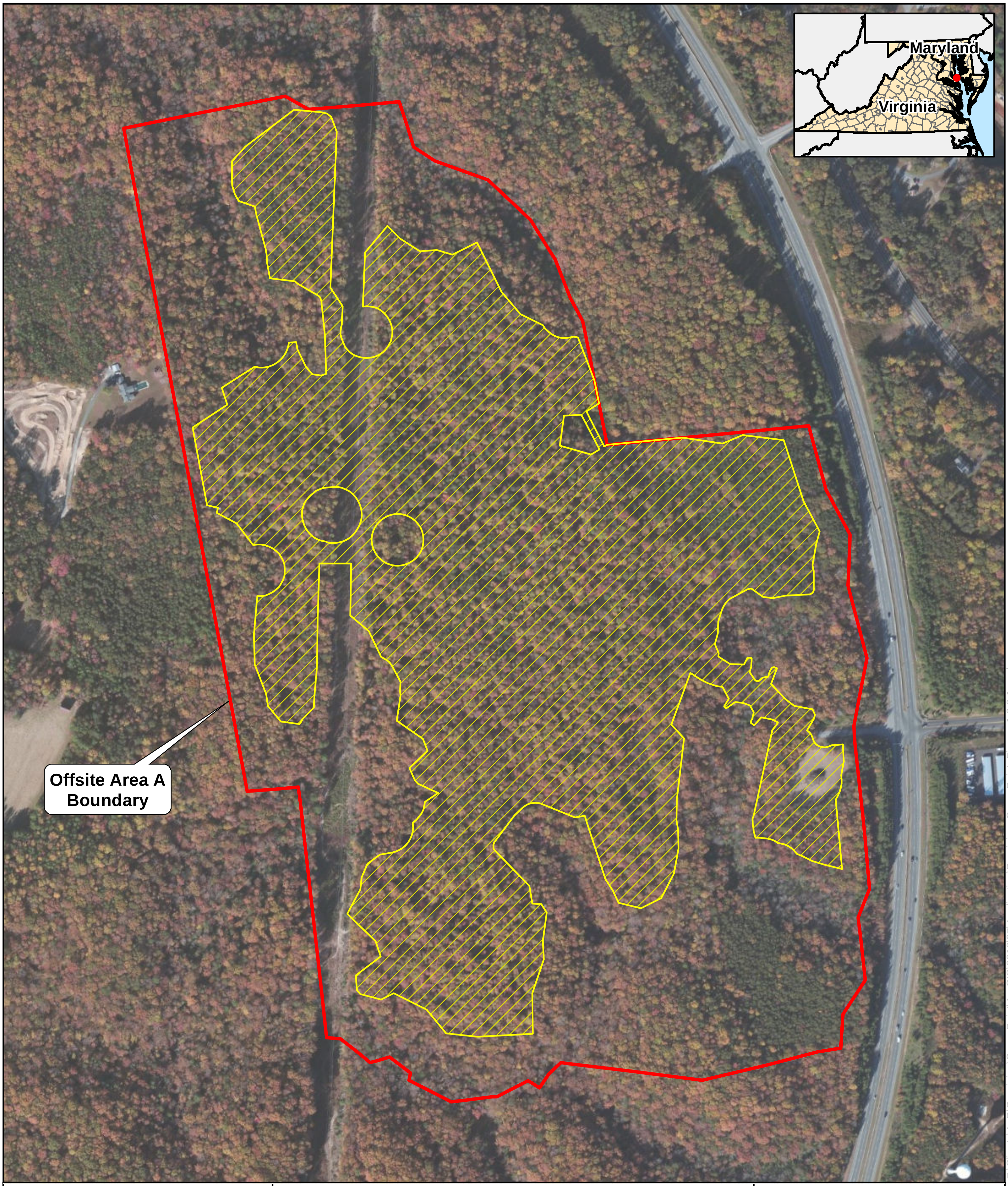

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Figure 1.2.3-1
Cove Point Liquefaction Project
Offsite Area A

Area Impacted by Construction

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Figure 1.2.3-2
Cove Point Liquefaction Project
Offsite Area B

Area Impacted by Construction

Leesburg Compressor Station Contractor Staging Area

DCP would temporarily use approximately 2.4 acres of developed land and 6.0 acres of mowed and maintained land at DTI's Leesburg Compressor Station for material laydown, vehicle parking, and equipment staging support construction of the Virginia facilities (figure 1.2.2-2). The Leesburg Compressor Station is located immediately across Watson Road from the Loudoun Compressor Station.

1.2.4 Access Roads

DCP would utilize existing roads to access the construction workspaces and would construct temporary roads within Offsite Areas A and B. For construction of the Liquefaction Facilities, DCP would reestablish a gravel road on the LNG Terminal property that was constructed and used in Docket No. CP05-130 et.al. Reuse of this road would require vegetation clearing, grading, and gravel placement. DCP would remove the temporary roads within Offsite Areas A and B and restore the area upon completion of construction of the Liquefaction Facilities.

1.3 NONJURISDICTIONAL FACILITIES AND ACTIVITIES

Occasionally, proposed projects have associated facilities that do not come under the jurisdiction of the FERC. These "nonjurisdictional" facilities may be integral to the need for the project (e.g., a new or expanded power plant at the end of a pipeline that is not under the jurisdiction of the FERC) or they may be merely associated as a minor, non-integral component of the jurisdictional facilities that would be constructed and operated as part of the project. The nonjurisdictional facilities and other related activities for the Project are described below and cumulative impacts associated with the facilities are addressed in section 2.9.

1.3.1 Nonjurisdictional Facilities

Road Improvements

DCP completed a traffic impact analysis to address public concerns regarding increased traffic during construction of the Project and to satisfy Maryland State Highway Administration (MSHA)[2] and Calvert County Department of Public Works requirements for vehicular traffic on public roadways. In its traffic impact analysis, DCP recommended adding a signal at the intersection of Maryland Route 2/4 and Maryland Route 497 and constructing a 200-foot-long right turn lane with a 150-foot-long taper along eastbound Maryland Route 497 at Cove Point Road. The MSHA and Calvert County approved the recommendations in the analysis. The purpose of these road improvements would be to accommodate construction and operation traffic and deliveries of large pieces of equipment. The improvements would be constructed by DCP but owned and operated by the State of Maryland. Permits and approvals required for the road improvements consist of an Access Permit from the MSHA, a Calvert County Grading Permit, and a Notice of Intent (NOI) from the MDE. DCP has received the required permits and began construction of the road improvements in April 2014.

The transport of large equipment from Offsite Area B to the LNG Terminal would also require potential modifications to utilities and obstructions along the transfer route. Utility modifications may include relocation of poles, guy wires and cables, and power and telecommunications wiring, as well as relocation of planned municipal improvements (e.g., road, water, sewer) along Cove Point Road. Utilities could be relocated to new poles and/or beneath existing roadways in order to obtain clearance for

[2] The MSHA is a part of the Maryland Department of Transportation, which is one of the Reviewing State Agencies for the CPCN.

transported loads. Modifications to traffic signals, signage, and road crossings may also be required. DCP would coordinate with the MSHA and Calvert County regarding potential modifications prior to the start of construction.

Calvert County Sewer Extension

DCP plans to extend the existing Calvert County septic sewer system approximately 2 miles to the LNG Terminal entrance. The new sewer line would be designed and installed by contractors under contract to DCP, and all work would be performed under the guidance of the Calvert County Department of Public Works, which would own and operate the sewer system. This sewer system would be designed to serve the DCP Terminal operations; it would not be designed to serve the construction workforce. During construction, the additional workforce would be provided with portable toilet facilities.

The new sewer line would be collocated with existing rights-of-way for the majority of its length and would impact approximately 1.7 acres of land during construction. Permits and approvals for the sewer line extension consist of a Utility Permit from the MSHA, a Sewer Construction Permit and NOI from MDE, approval from MDE to change the sewer category (to be obtained by Calvert County), and a Grading Permit and Utility Cut Permit from Calvert County. Except as noted, DCP or its construction contractors would obtain all necessary permits. DCP submitted permit applications to the state and county agencies; to date, DCP has received the Utility Permit from the MSHA. The sewer extension would be completed in 2014.

Calvert County Sewer Service Internal to the LNG Terminal

The existing sewage facilities on the offshore pier require periodic pumping to a barge, and air separation units at the LNG Terminal collect a condensate that requires treatment prior to discharge to an outfall. To eliminate these actions, DCP plans to construct a new sewer system at the LNG Terminal and connect the system to the Calvert County sewer extension described above. Permits and approvals for the onsite sewer system have been submitted to Calvert County and MDE, and consist of a Grading Permit and System Access Permit from the County, and an NOI from MDE. The onsite sewer system would be designed, installed, and operated by DCP.

Electric Substation Expansion

The existing electrical substation at the Pleasant Valley Compressor Station would be expanded to support the additional compressor units proposed by DCP. The expansion would permanently impact 0.9 acre within the fence line of the compressor station and would be constructed, owned, and operated by the Northern Virginia Electric Cooperative. Permits and approvals necessary for the substation expansion consist of an Electrical Permit, Grading Permit, and Plan Approval from Fairfax County.

Truck Loading/Unloading

The truck loading/unloading facility would serve to unload make-up refrigerants trucked to the LNG Terminal during operation and load condensate product into tanker trucks for delivery into the market place. Construction and operation of the truck loading/unloading facility at the LNG Terminal is jurisdictional and is analyzed throughout this EA. However, the loaded tanker trucks would be non-jurisdictional once they leave the LNG Terminal. These trucks would be subject to regulation by the Federal Motor Carrier Safety Administration and the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA). DCP estimates that, on average, two trucks per day would be required to transport refrigerant and condensate products.

1.3.2 Other Related Activities

DCP would conduct the following related activities in accordance with all applicable permits and approvals would be obtained prior to conducting the work:

- An existing 19,500 square-foot warehouse and 1-acre storage yard in the Calvert County Industrial Park in Prince Frederick, Maryland would be used to temporarily store stock from an existing warehouse in the Fenced Area that would be removed as part of the Project. DCP has completed installation of a fence and security measures, and has begun relocation of materials from the LNG Terminal to the temporary facility.

- An approximately 9,600 square-foot building would be built within the northeast corner of the Fenced Area for use as a temporary maintenance shop during construction of the Liquefaction Facilities, and as a warehouse following construction. DCP would also construct a new radio tower next to the new building. Permits for the warehouse have been submitted to Calvert County, and to federal, state, and county agencies for the radio tower; however, construction has not yet begun on either facility.

- A new, permanent maintenance shop would be constructed near the current administration building within the Fenced Area. Permits for the warehouse have been submitted to Calvert County; however, construction has not yet begun on the maintenance shop.

- Temporary security fencing is currently being installed within the Fenced Area to separate work zones and secure areas during construction of the Liquefaction Facilities. Upon completion of construction, the temporary fencing would be removed, portions of the existing security fence would be relocated, and new, permanent security fencing would be installed within the Fenced Area.

No Commission authority is needed for these activities. DCP would complete the activities at its own risk and expense.

1.4 PROJECT PURPOSE AND NEED

DCP's stated purpose of the Project is to liquefy for export domestically produced natural gas. DCP asserts that the LNG Terminal is ideally located to provide access to abundant and diverse domestic supply sources through the Cove Point Pipeline, which connects to the interstate natural gas transmission systems of Transcontinental Gas Pipeline Company, Columbia Gas Transmission, and DTI. According to DCP, these interconnects would allow feed gas for the Project to be sourced from a wide variety of regions in the U.S. depending on market forces and circumstances at any given time. DCP has fully contracted the proposed bi-directional service at the LNG Terminal with two customers, Pacific Summit Energy, LLC and GAIL Global (USA) LNG LLC. These customers have entered into a 20-year agreement for the planned export/import services at the LNG Terminal, as well as a 20-year service agreement for firm transportation on the Cove Point Pipeline. DCP states that the Project customers would be responsible for procuring their own gas supplies from anywhere in the gas market, and transporting such supplies to the LNG Terminal for liquefaction and export. DCP would not own the gas or the capacity at the LNG Terminal.

A number of commentors questioned the need for the Project on the assertion that the United States should not export its natural gas resources, and that doing so would result in adverse economic and environmental impacts. As discussed in sections 1.1 and 1.5.1, the DOE-FE determines whether the proposed import or export of natural gas is not inconsistent with the public interest. DOE-FE's orders granting export authorization address the economic impacts. This EA addresses the environmental impacts of the facilities proposed before the Commission.

1.5 SCOPE OF THIS ENVIRONMENTAL ASSESSMENT

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

The 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 impact generally occurs during construction with the resource returning to preconstruction condition immediately after restoration or within a few months. Short-term impact could continue for up to 3 years following construction. Long-term impacts would last more than 3 years, but the affected resource would recover to pre-construction conditions. 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, such as the construction of aboveground facilities. An impact would be considered significant if it would result in a substantial adverse change in the physical environment.

The Energy Policy Act of 2005 (EPAct 2005) provides that the FERC shall act as the lead agency for coordinating all applicable authorizations related to jurisdictional natural gas facilities and for purposes of complying with NEPA. The FERC, as the "lead federal agency," is responsible for preparation of this EA. This effort was undertaken with the participation and assistance of the DOE-FE, USCG, DOT, COE, and MDNR as "cooperating agencies" under NEPA. Cooperating agencies have jurisdiction by law or special expertise with respect to environmental impacts involved with a proposal. The roles of the FERC, DOE-FE, USCG, DOT, COE, and MDNR in the Project review process are described below. The EA provides a basis for coordinated federal decision making in a single document, avoiding duplication among federal agencies in the NEPA environmental review processes. In addition to the lead and cooperating agencies, other federal, state, and local agencies may use this EA in approving or issuing permits for all or part of the proposed Project. Federal, state, and local permits, approvals, and consultations for the proposed Project are discussed in section 1.10.

1.5.1 Federal Energy Regulatory Commission

Based on its authority under the NGA, the FERC is the lead agency for preparation of this EA in compliance with the requirements of NEPA, the Council on Environmental Quality's regulations for implementing NEPA (40 CFR Parts 1500-1508), and FERC regulations implementing NEPA (18 CFR 380).

As the lead federal agency for the Cove Point Liquefaction Project, the FERC is required to comply with section 7 of the Endangered Species Act (ESA), as amended, the Magnuson-Stevens Fishery Conservation and Management Act, section 106 of the National Historic Preservation Act (NHPA), and section 307 of the Coastal Zone Management Act. Each of these statutes has been taken into account in the preparation of this EA. The FERC will use this document to consider the environmental impacts that could result if it authorizes the Project.

1.5.2 U.S. Department of Energy 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 FTAs that require national treatment for trade in natural gas are deemed to be consistent with the public interest and the Secretary of Energy must grant authorization without modification or delay. In the case of 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 will 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 this EA pursuant to the requirements of NEPA.

As stated in section 1.1, the DOE-FE has granted conditional authorization for export to FTA and non-FTA nations from the Cove Point facilities. The DOE will not make a final 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 the EA, the DOE may adopt it prior to issuing a Record of Decision on DCP's application for authority to export LNG.

1.5.3 U.S. Coast Guard Role

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

As required by its regulations, the USCG is responsible for issuing a Letter of Recommendation (LOR) as to the suitability of the waterway for LNG marine traffic. As described in this EA, the annual frequency of ship traffic for the Project is estimated to be 85 LNG vessels per year, which would not exceed the previously approved ship traffic of up to approximately 200 vessels per year in Dockets CP05-130, et al., and DCP would not accept LNG carriers larger than previously authorized in Docket CP09-60. In a letter to the USCG dated May 23, 2012, DCP detailed the proposed Project modifications and stated that no additional waterway impacts would result beyond the 200 ship transits already assumed in the current Waterway Suitability Assessment (WSA). In a letter dated July 2, 2012, the USCG stated that a new or revised LOR would not be required for the Project, and that DCP's current WSA and LOR dated July 29, 2008 are adequate for the service associated with the proposed Project.

1.5.4 U.S. Department of Transportation Role

Under 49 USC 60101, the DOT has prescribed the minimum federal safety standards for LNG facilities. Those standards are codified in 49 CFR 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 a conflict. In accordance with the 1985 Memorandum of Understanding on LNG Facilities and the 2004 Interagency

Agreement on the safety and security review of waterfront LNG import/export facilities, the DOT participates as a cooperating agency. The DOT does not issue a permit or license but, as a cooperating agency, assists FERC staff in evaluating whether an applicant's proposed design would meet the DOT requirements. DOT staff has reviewed FERC staff's analysis and provided comments on our conclusions regarding compliance with Part 193 regulations.

1.5.5 U.S. Army Corps of Engineers Role

The COE elected to cooperate in preparing this EA because it has jurisdictional authority pursuant to section 404 of the Clean Water Act (CWA) (33 USC 1344), which governs the discharge of dredged or fill material into waters of the United States, and section 10 of the Rivers and Harbors Act (33 USC 403), which regulates any work or structures that potentially affect the navigable capacity of navigable waters of the United States. Although this EA 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. Through the coordination of this EA, the COE will obtain the views of the public and natural resource agencies prior to reaching its decisions on the Project.

1.5.6 Maryland Department of Natural Resources Role

The MDNR has relevant expertise regarding the environmental impacts of the Project and is required under the Natural Resources Article section 3-304 of the Maryland Code to evaluate the suitability of sites being proposed for electric generation facilities.

On April 1, 2013, DCP filed an application with the Maryland PSC for a CPCN for the Project's proposed electric generating facilities. The Secretary of the MDNR, in coordination with six executive branch state agencies (hereafter referred to as the Reviewing State Agencies[3]), is tasked to assess the potential environmental and socioeconomic impacts of the application and coordinate with other state agencies to advise the PSC of the suitability of the site for the proposed facilities. The Power Plant Research Division (PPRP), a unit within the MDNR, conducts the state review and agency coordination process. In January 2014, the PPRP released its draft environmental review of the proposed electric generating facilities and initial recommended license conditions for the CPCN.[4] On April 17, 2014, the PPRP released its final recommended license conditions for the CPCN. DCP confirmed it would accept the recommended license conditions in the Maryland CPCN and we have included additional discussion of the recommended measures that DCP would adopt throughout this EA.

1.6 PUBLIC REVIEW AND COMMENT

On June 1, 2012, DCP filed a request to utilize our pre-filing process, and we approved DCP's request on June 26, 2012, in Docket No. PF12-16-000. We participated in three public open houses sponsored by DCP in the Project area in July 2011 to explain our environmental review process to interested stakeholders. On September 24, 2012, we issued an NOI entitled *Notice of Intent to Prepare an Environmental Assessment for the Planned Cove Point Liquefaction Project, Request for Comments on Environmental Issue, Notice of Onsite Environmental Review, and Notice of Public Scoping Meetings*.

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[3] The Reviewing State Agencies for the CPCN consist of: the Maryland Departments of the Environment, Natural Resources, Transportation, Planning, Business and Economic Development, and Agriculture; and the Maryland Energy Administration.

[4] The Maryland PSC Case Jacket (Case Number: 9318) for the proposed generating station is available online at the Maryland PSC's Website at: http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?CaseNumber=9318.

The NOI was published in the Federal Register[5] and was sent to over 720 parties including federal, state, and local officials; agency representatives; conservation organizations; local libraries and newspapers; Native American groups; and property owners affected by the proposed facilities.

We conducted two public scoping meetings in the Project area to provide an opportunity for agencies and the general public to learn more about the Project and to participate in the environmental analysis by identifying issues to be addressed in the EA. A total of 40 speakers presented comments at the meetings held on October 9, 2012, in Lusby, Maryland, and on October 10, 2012, in Ashburn, Virginia. The transcripts of the public scoping meetings and all written scoping comments are part of the public record for the Project and are available for viewing on the FERC Internet website (http://www.ferc.gov).[6] We also held an on-site environmental review of the Loudoun Compressor Station area on October 10, 2012, which was attended by approximately 26 members of the public.

Table 1.6-1 summarizes the environmental issues identified during the scoping process. Substantive environmental issues raised by commentors are addressed in applicable sections of the EA. During the pre-filing process, we received numerous comments related to increased compression at the Loudoun Compressor Station, which was part of DCP's initially proposed Project scope. The majority of these comments were from residents of the Greene Mill Preserve neighborhood, which is nearby to the north and east of the Loudoun Compressor Station. However, DCP's final proposal includes only minor modifications to the existing Loudoun M&R Facility and does not include increased compression at the Loudoun Compressor Station. Construction of the Loudoun M&R Facility is expected to result in limited, short-term impacts. As such, comments specifically related to the potential increased compression at the Loudoun Compressor Station are no longer within the scope of this Project and, therefore, have not been addressed in this EA.

TABLE 1.6-1

Issues Identified in the Scoping Process

Issue/Summary of Comment	EA Section Addressing Comment
GENERAL/PROJECT DESCRIPTION	
Impacts on septic systems at the LNG Terminal	1.3.1
Boiling-liquid-expanding-vapor explosions from pressurized storage tanks and tanker trucks	1.3.1
Project purpose and need	1.4
Project requires Environmental Impact Statement	1.5
Project's relationship to shale gas development and fracking	1.5
GEOLOGY AND SOILS	
Impacts on geological and fossil resources	2.1.1
WATER RESOURCES, FISHERIES, AND WETLANDS	
Impacts on drinking water	2.2.1
Potential groundwater impacts during operation at the Liquefaction Facilities	2.2.1
Potential river water intrusion into aquifers	2.2.1
Impacts on surface water quality, including the Chesapeake Bay and the Patuxent River	2.2.2
Increased sedimentation into surface waterbodies	2.2.2
Impacts from ballast water discharge, including the introduction of invasive species	2.2.2, 2.3.3
Shoreline erosion from increased shipping	2.2.2

5 See Federal Register Volume 77, Number 189, dated September 28, 2012, pages 59,601-59,603.

6 Using the "eLibrary" link, select "General Search" from the eLibrary menu and enter the docket number excluding the last three digits in the "Docket Number" field (i.e., PF12-16 and CP13-113). Select an appropriate date range.

TABLE 1.6-1 (cont'd) **Issues Identified in the Scoping Process**	
Issue/Summary of Comment	EA Section Addressing Comment
Impacts on federally managed and migratory fisheries and Essential Fish Habitat	2.2.3
Impacts on Chesapeake Bay fisheries and aquatic species	2.2.3
Impacts on wetlands associated with the Chesapeake Bay, Patuxent River, and Offsite Area A	2.2.4
VEGETATION	
Impacts on forest due to tree loss, including fragmentation	2.3.1
Introduction of invasive species	2.3.1
WILDLIFE AND THREATENED AND ENDANGERED SPECIES	
Project impacts on wildlife and wildlife habitat	2.3.2
Noise impacts on aquatic species at Offsite Area B	2.2.3, 2.3.3
Impacts on state-listed threatened and endangered species, including Torrey's Mountain-mint, Grove sandwort, Purple milkweed	2.3.3
Impacts on the Elklick Diabase Flatwoods Conservation site	2.3.1, 2.4.2
Impacts on natural heritage resources, including Piedmont Upland Depression Swamp, Northern Hardpan Basic Oak-Hickory Forest, Northern Piedmont Mafic Barren	2.3.1
LAND USE, VISUAL RESOURCES, AND RECREATION	
Impacts of the Liquefaction Facilities on nearby residences	2.4.3
Impacts on the Chesapeake Bay, including tourism, fishing, and recreational boating	2.4.2
Potential impacts on the Elklick Woodlands State Natural Area Preserve near the Pleasant Valley Compressor Station	2.4.2
Potential impacts on Calvert Cliffs State Park adjacent to the LNG Terminal property	2.4.2
Potential impacts on other parks near the LNG Terminal	2.4.2
Potential impacts on the Calvert Marine Museum near Offsite Area B	2.4.2
Visual impacts from the LNG Terminal	2.4.5
Impacts on Hellen Creek Hemlock Preserve near Offsite Area A	2.4.2
SOCIOECONOMICS	
Project will benefit foreign countries, not local communities	2.5.1, 2.5.6
Project will benefit local communities, including providing employment and increased tax revenue	2.5.1, 2.5.6
Project will provide limited benefits to communities	2.5.1, 2.5.6
Impacts on local emergency providers	2.5.3
Impacts on the Chesapeake Bay shipping channel	2.5.4
Impacts on Port of Baltimore shipping	2.5.4
Impacts of increased LNG vessel traffic	2.5.4
Impacts from traffic	2.5.4
Impacts on property values	2.5.5
Impacts on local fishing and tourism industries	2.4.2, 2.5.2
CULTURAL RESOURCES	
Potential impacts on the historic community of Solomons	2.6.1
AIR QUALITY AND NOISE	
Greenhouse gas emissions must be assessed	2.7.1
Air impacts from construction equipment	2.7.1
Air impacts from operation of the Liquefaction Facilities and Pleasant Valley Compressor Station	2.7.1
Purchase of air offsets in local area	2.7.1
Noise from machinery and construction activities	2.7.2
Noise from operation of the Liquefaction Facilities	2.7.2
RELIABILITY AND SAFETY	
FERC's role in establishing siting guidelines	2.8.2
Comments that the LNG Terminal has historically operated safely	2.8.3
Gas detectors at air intakes are not sufficient to eliminate an ignition source	2.8.3
Ensure site design, equipment separation, and operational process are safe	2.8.4

TABLE 1.6-1 (cont'd) **Issues Identified in the Scoping Process**	
Issue/Summary of Comment	EA Section Addressing Comment
Control and monitoring systems and integrity management programs	2.8.4
Impacts on the safe operation of the existing LNG Terminal during construction	2.8.4
Comments on using the quantitative risk assessment method	2.8.5
The tank release analysis in the final EIS for the Cove Point Expansion Project was based on a 1-hour release; and that all credible scenarios should be reviewed	2.8.6
Propane release must be taken into consideration	2.8.6
Impacts from a release of LNG or natural gas and the need for remote siting	2.8.6
Toxic impacts of benzene	2.8.6
Vapor clouds become explosive due to tightly packed equipment and the sound abatement wall	2.8.6
Limited evacuation route from the vicinity of the LNG Terminal	2.8.7
Potential impacts from terrorism	2.8.8
Impacts from a potential incident on an LNG tanker	2.8.8
Comment that there are no U.S. flagged LNG carriers	2.8.8
Comment that U.S. Coast Guard does not currently provide safety escorts for LNG vessels	2.8.8
CUMULATIVE IMPACTS	
Potential cumulative impacts from air emissions	2.9.7
ALTERNATIVES	
Alternatives to mitigate pollution	3.2
Alternative to reduce operating footprints of the facilities	3.4
Analyze electric compressors at the Liquefaction Facilities to reduce emissions	3.4
Consider No Action Alternative	3.7

We received comments during the scoping period recommending that an EIS, rather than an EA, be prepared to assess the impact of the Project. An EA is a concise public document for which a federal agency is responsible that serves to provide sufficient evidence and analysis for determining a finding of no significant impact. The Commission's regulations under 18 CFR 306(b) state that "If the Commission believes that a proposed action…may not be a major federal action significantly affecting the quality of the human environment, an EA, rather than an EIS, will be prepared first. Depending on the outcome of the EA, an EIS may or may not be prepared." In preparing this EA, we are fulfilling our obligation under NEPA to consider and disclose the environmental impacts of the Project. As noted above, this EA addresses the impacts that could occur on a wide range of resources should the Project be approved and constructed. Also, the USCG, DOE-FE, DOT, COE, and MDNR have special expertise with respect to certain environmental impacts associated with DCP's proposal, and assisted in preparing this EA. Based on our analysis, the extent and content of comments received during the scoping period, and considering that the Project facilities would be largely collocated with existing facilities, we conclude in section 4 that the impacts associated with this Project can be sufficiently mitigated to support a finding of no significant impact and, thus, an EA is warranted.

Commentors also assert that authorization to export natural gas will spur the development of natural gas derived from shale formations and, therefore, the environmental impacts associated with shale gas development should be included in the environmental review of the Project. More specifically, one commentor noted that Pacific Summit, one of DCP's customers for the proposed import/export services at the LNG Terminal, has contracted with Cabot Oil & Gas Corporation (Cabot) to obtain natural gas for export from the Marcellus Shale region. The commentor believes that Cabot may need to drill additional wells to meet its contractual obligations to Pacific Summit and other customers in the region, and that the environmental impacts associated with the additional drilling should be included in our analysis. Whereas the Project could export natural gas derived from shale formations, DCP states that Project customers would be responsible for procuring their own gas supplies from anywhere in the gas market and transporting such supplies to the LNG Terminal for liquefaction and export. In addition, specific details, including the timing, location, and number of additional production wells that may or may not be drilled, are speculative. As such, impacts associated with the production of natural gas that may be sourced from various locations and methods for export by the Project are not reasonably foreseeable or quantifiable. Furthermore, our authority under the NGA and NEPA review requirements relate only to natural gas facilities that are involved in interstate commerce. Thus, the facilities associated with the production of natural gas are not under FERC jurisdiction.

1.7 CONSTRUCTION, OPERATION, AND MAINTENANCE

1.7.1 General Procedures

DCP has committed to design, construct, operate, and maintain the Liquefaction Facilities in accordance with DOT regulations in 49 CFR 193, which apply to LNG facilities; NFPA Standard 59A, "*Standard for the Production, Storage, and Handling of Liquefied Natural Gas*;" USCG regulations in 33 CFR 127; and applicable federal and state environmental regulations. DCP also committed that the Virginia facilities would be designed, constructed, operated, and maintained to conform to the requirements of the DOT in 49 CFR 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards* and applicable federal and state environmental regulations.

DCP would construct, restore, and maintain the Project in conformance with the measures described in our *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures), which were developed to minimize the environmental impact of construction and operation of interstate natural gas transmission facilities. DCP also developed and would implement site-specific Erosion and Sediment Control Plans (E&SCPs) and Stormwater Management Plans (SMPs) in compliance with the MDE's *2011 Maryland Standards and Specifications for Soil Erosion and Sediment Control* and *2000 Maryland Stormwater Design Manual (Revised 2009)* (for facilities in Maryland) and the Virginia Department of Conservation and Recreation (VDCR) *1992, Third Edition, Virginia Erosion and Sediment Control Handbook* (for facilities in Virginia).[7] The preliminary E&SCP and SMP developed for the Liquefaction Facilities and Offsite Areas A and B were submitted to the Calvert County Department of Community Planning and Building and the Calvert County Soil and Water Conservation District for review and approval. Comments received to date from these agencies requested additional documentation but have not required design changes. The E&SCP and SMP for the Virginia facilities would be submitted to the Loudoun and Fairfax County Soil and Water Conservation Districts for review and approval prior to construction. Because the Project would require construction in the tidal waters of the Chesapeake Bay, DCP would conform with compliance and monitoring requirements specified in the COE permits, MDE tidal wetlands license, and/or water quality certification. DCP would implement the erosion and sediment control best management practices (BMPs) specified in the above plans and procedures immediately after initial disturbance of soil, and maintain these practices throughout construction.

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[7] DCP's E&SCP and SMPs were provided as attachments to Resource Report 2 in its April 1, 2013 Application and are available for viewing on the FERC Internet website (http://www.ferc.gov). Using the "eLibrary" link, select "General Search" from the eLibrary menu, enter the selected date range and "Docket No." excluding the last three digits (i.e., CP13-113), and follow the instructions. On the results page that appears, locate Category/Accession 20130401-5045. Under the Files, select the PDF files titled "PUBLIC - Vol I RR2 Part 1 of 3.PDF," "PUBLIC - Vol I RR2 Part 2 of 3.PDF," and "PUBLIC - Vol I RR2 Part 3 of 3.PDF." Direct access can be obtained by entering the Accession Number (20130401-5045) into the "Numbers" field of the "Advanced Search" option from the eLibrary menu. The plans are also available for public inspection at the FERC's Public Reference Room in Washington, DC (call (202) 502-8317 for instructions).

DCP would also design and implement a Project-specific Spill Prevention, Control, and Countermeasures Plan that would specify procedures and measures to avoid and minimize potential impacts from spills of fuel or other hazardous substances during Project construction and operation. Further, DCP would implement the facility design, operating, and security procedures specified in 40 CFR 112 and would fully comply with the provisions and procedures outlined in MDE's Oil Operations Permit applicable to aboveground storage tanks with a capacity of 10,000 gallons or greater.

1.7.2 Liquefaction Facilities

Construction

Construction of the Liquefaction Facilities would impact approximately 68.4 acres within the 131-acre Fenced Area (figure 1.2.1-3), and would generally proceed along the following sequence:

- Mobilization – necessary personnel and equipment would be mobilized to the LNG Terminal by road for each phase of construction;
- Installation and Maintenance of Erosion Control Measures – erosion and sediment controls would be established, inspected, and maintained throughout construction; fencing would be installed to delineate the extent of the construction workspace;
- Clearing, Grubbing, and Topsoil Removal – the workspace would be prepared for construction, including the removal of approximately 11.4 acres of trees as discussed in section 2.3.1; topsoil would be removed and segregated for use during restoration of appropriate areas**;**
- Demolition – an existing warehouse, maintenance shop, and radio tower would be removed to accommodate other Project elements;
- Rough Grading – grading, cut, and fill would establish the rough elevations throughout the construction work area; 150 feet of an intermittent stream, 866 feet of an ephemeral stream, and less than 0.1 acre of wetland within the Fenced Area would be permanently filled as discussed in sections 2.2.2 and 2.2.4;
- Pile Installation – pilings to support foundations and equipment would be installed in accordance with civil engineering and geotechnical requirements;
- Underground Utilities – underground utilities including water, fire water, electric, and communication lines would be installed;
- Foundations – foundations would be constructed for equipment, buildings and pipe racks in accordance with engineered specifications;
- Erection – equipment, buildings, the sound barrier wall, and other facilities would be constructed in accordance with engineered specifications; none of the new facilities would exceed the height of existing facilities;
- Testing – appropriate testing would be completed to ensure the integrity and safety of the various systems including hydrostatic testing of piping, tanks, and other equipment; meggering of electrical cables; and equipment calibrations;

- Commissioning and Start-up – various systems would be commissioned and started in accordance with detailed plans to ensure their readiness; and

- Final Cleanup, Stabilization, and Restoration – final cleanup, grading/stabilization, revegetation, and installation of permanent stormwater controls would proceed in accordance with approved plans.

Operation

Upon completion of the Project, the LNG Terminal would be capable of the bi-directional import and regasification of LNG, and the liquefaction of natural gas and export of LNG. Both services would utilize the existing offshore pier and Cove Point Pipeline as well as common facilities and systems including the LNG storage tanks.

DCP would update existing operations and maintenance plans for the LNG Terminal to include procedures relative to the Project, and would develop an Operations Manual that addresses specific procedures for the safe operation of the Liquefaction Facilities in accordance with 33 CFR 127.

DCP anticipates that an additional 93 staff, including administrative personnel, would be required at the LNG Terminal when the Liquefaction Facilities are operational. DCP has training programs in-place for new operating personnel that address routine operations and monitoring procedures as well as safe startup, shutdown, cool down and purging processes. DCP would develop new training protocols to ensure that all new and existing personnel understand the operating and safety procedures related to the Liquefaction Facilities. Section 2.8.7 further discusses Project operating procedures.

We received comments concerning the volume of LNG ship traffic that would occur during Project operation. The volume of ship traffic for LNG import has historically varied due primarily to market demand, and DCP expects that LNG export activity may also vary depending on demand. However, the annual frequency of ship traffic for the Project is estimated to be 85 LNG vessels per year, which would not exceed the previously approved ship traffic of up to approximately 200 vessels per year in Dockets CP05-130, et al., and DCP would not accept LNG carriers larger than previously authorized in Docket CP09-60. After reviewing the Cove Point Liquefaction Project, the USCG Sector Baltimore concurred that the Project should not result in an increase in the size and/or frequency of LNG marine traffic beyond that envisioned in the current WSA for the LNG Terminal, and that the WSA and LOR are adequate for the service associated with the Project. Other potential impacts associated with the LNG ship traffic for the Project are discussed in sections 2.2.2, 2.3.3, and 2.8.8.

Maintenance

Routine facility maintenance and minor overhauls would be conducted by full-time DCP personnel, and more substantial equipment maintenance may be conducted by contract personnel. Vegetation maintenance and inspection and maintenance of permanent erosion control measures would be conducted in accordance with our Plan and Procedures and site-specific E&SCPs and SMPs.

1.7.3 Offsite Areas

Construction, Operation, and Maintenance

As previously indicated, DCP would temporarily utilize Offsite Areas A and B in Maryland and the developed area within the existing Leesburg Compressor Station in Virginia to support Project construction. The sites would be restored upon completion of Project construction in accordance with our Plans and Procedures, permit requirements, and landowner agreements.

Construction for the temporary use of the offsite areas would follow a similar sequence as described for the Liquefaction Facilities including mobilization; installation and maintenance of erosion control measures; vegetation clearing and grubbing; topsoil removal and segregation; grading; and cleanup and restoration.

Offsite Area A

The preparation of Offsite Area A would include the phased removal of trees and other vegetation from 94.9 acres of the 179.4-acre site. As discussed in sections 2.2.2, 2.2.4, 2.3.1, and 2.3.3, DCP would preserve the existing vegetation within 100 feet of wetlands, waterbodies, and special status species to avoid or minimize impacts on those resources. The only exception to the 100-foot-wide buffer would involve the construction of a temporary, gravel road within Offsite Area A across a minor, intermittent stream and 0.2 acre of associated riparian vegetation. Based on the site configuration, orientation of the affected waterbody, and traffic considerations on Maryland Route 2/4, these impacts would be unavoidable. To minimize impacts, DCP would install a bottomless culvert over the intermittent stream, implement other measures in its E&SCP, and restore the riparian vegetation upon completion of Project construction. DCP would also preserve a 100-foot vegetation buffer along Maryland Route 2/4 for visual screening. Preparation of Offsite Area A would include construction of sheltered warehouse space, outdoor storage racks, outdoor laydown areas, temporary buildings, and office trailers. Temporary underground utilities (e.g., electricity, water, and communications) would be installed to support operations.

Deliveries to Offsite Area A would be via truck, with direct access off of Maryland Route 2/4. Upon receipt, materials would be offloaded and stored until needed at the LNG Terminal. Most deliveries to the LNG Terminal would utilize open, flatbed trailers; permits would be obtained as required for all transportation by truck. Offsite Area A would also be utilized as the personal vehicle parking area for the construction management and labor workforce. Buses would be used to transport workers between Offsite Area A and the LNG Terminal.

Maintenance and inspection of erosion and stormwater control measures would occur in accordance with our Plan and Procedures and site-specific E&SCPs and SMPs.

We received other comments concerning the environmental impacts associated with the use of Offsite Area A. The environmental impacts associated with the preparation and use of Offsite A, and DCP's proposed measures to avoid or minimize impacts, are detailed in section 2.0, and alternatives considered to Offsite Area A are discussed in section 3.0.

Offsite Area B

The preparation of Offsite Area B would impact 5.8 acres of the 11.0-acre site and would include construction of a temporary road and temporary pier in the Patuxent River for mooring barges and offloading equipment and materials.

The temporary road would extend across Offsite Area B from Solomon Islands Road to the temporary pier. Construction of the road would require the excavation of approximately 14,000 yards of soil to create a safe grade; this soil would be stored on-site until construction of the Liquefaction Facilities is completed, at which time the original grade of the site would be restored. The road would be surfaced with either crane mats or stone bedding.

Based on a bathymetry survey conducted by DCP, the pier would extend approximately 166 feet from the shore to reach sufficient water depth to avoid dredging. The pier would be constructed of steel beams and timber decking supported on 24- to 36-inch-diameter steel piles that would be driven using a vibratory hammer to the extent possible; an impact hammer would be used to complete pile installation if necessary. As many as 24 piles would be installed to support the pier. Up to four mooring dolphins would also be installed near the pier in the Patuxent River. The pier and mooring dolphins would be removed upon completion of construction of the Liquefaction Facilities. Any piles that could not be completely removed would be cut-off at or below the mud line. Following removal of the pier components, and based on a recommendation from the Reviewing State Agencies in their recommended license conditions for Maryland's CPCN, DCP would utilize suitable materials from the pier and the LNG Terminal site as artificial reef components. The design and location of the artificial reef would be approved by the MDNR, and ownership of the reef would be transferred to the MDNR after its placement is complete. Section 2.2.3 includes additional discussion of the proposed artificial reef.

During construction of the Liquefaction Facilities, DCP estimates that 42 shipments would be received via barge at Offsite Area B, requiring approximately 150 truck loads to transport equipment and materials to the LNG Terminal or Offsite Area A. The largest component of the Liquefaction Facilities to be received at Offsite Area B would be approximately 150 feet long and weigh approximately 330 tons. The required permits and approvals associated with barge operations would be obtained several weeks in advance of each transportation event.

DCP would maintain Offsite Area B in accordance with the provisions of our Plan and Procedures and site-specific E&SCPs and SMPs.

We received comments concerning environmental impacts associated with Offsite Area B and the temporary pier. Environmental impacts associated with the construction and use of Offsite Area B, including the temporary pier, and DCP's proposed measures to avoid or minimize impacts, are discussed in section 2.0. Alternatives considered to Offsite Area B are discussed in section 3.0.

Leesburg Compressor Station Contractor Staging Area

DCP would use approximately 2.4 acres of developed land and 6.0 acres of mowed and maintained land within its existing Leesburg Compressor Station property to support construction of the Virginia facilities. The staging area would be prepared and maintained in accordance with our Plan and Procedures and DCP's site-specific E&SCPs and SMPs.

1.7.4 Virginia Facilities

Construction, Operation, and Maintenance

Pleasant Valley Compressor Station

Construction of the Pleasant Valley Compressor Station expansion would impact 22.2 acres within the 37-acre property owned by DCP. After mobilizing to the site, the general sequence for constructing the expansion facilities would include the installation of erosion, sediment, and stormwater control measures in accordance with our Plan and Procedures and as specified in DCP's E&SCPs and SMPs; clearing and grading of the work area; installation of foundations; installation and hydrostatic testing of aboveground and underground piping; erection of buildings and structures, including the sound barrier wall; installation of equipment; start-up and testing; and final cleanup and stabilization.

The proposed expansion would include two new 20,000 hp compressor units, one new 15,000 hp compressor unit, and one new 7,500 hp compressor unit. All of the new compressors would be electric driven and would be located in new buildings or additions designed to reduce operating noise (e.g., sound insulated walls, roof panels, and doors). Other equipment, acoustic treatments, and operational procedures would be implemented to further reduce operating noise (section 2.7.2). Construction at the

Pleasant Valley Compressor Station would also include new gas coolers, filter/separators, valves, and electrical facilities. Northern Virginia Electric Cooperative would also expand its existing electrical substation on the site as described in section 1.3.1.

Operation of the expanded compressor station would impact 2.3 acres of land that is not currently utilized in operating the facility. Most areas in and around the new or expanded compressor buildings, and associated piping, would be covered with crushed rock or similar material to minimize the amount of maintenance required. Parking and drive areas damaged during construction would be restored and the remaining disturbed areas would be seeded with a grass in accordance with our Plan and DCP's site-specific E&SCP. DCP would operate and maintain the new facilities in accordance with applicable DOT safety standards in 49 CFR 192 and applicable state and federal environmental regulations. Standard operations would include calibration, maintenance, and inspection of equipment; monitoring of pressure, temperature, and vibration data; and routine buildings and grounds maintenance. No new permanent staff would be required to operate the expanded facility.

Pleasant Valley Suction/Discharge Pipelines and Pleasant Valley M&R Facility

As described in section 1.2.2, the Pleasant Valley Suction/Discharge Pipelines would include the installation of a new, 36-inch-diameter suction pipeline and the replacement of an existing 16-inch-diameter discharge pipeline with a new 36-inch-diameter pipeline. Construction of the pipelines and associated Pleasant Valley M&R Facility modifications would impact approximately 3.3 acres within DCP's existing 150-foot-wide pipeline easement and on the Pleasant Valley Compressor Station property. The new pipelines would be installed using a standard upland construction process consisting of surveying; clearing and grading the workspace, including topsoil removal and segregation; installation of erosion and sediment control measures; trenching; pipe stringing, bending, assembly, welding, and inspection; pipe lowering and backfilling; hydrostatic testing; and cleanup and restoration. For installation of the new 36-inch-diameter discharge pipeline, the existing 16-inch-diameter discharge pipeline would first be excavated and removed, and the new 36-inch-diameter pipeline would be installed in the vacated trench.

The workspace for the new pipelines and modified M&R facility would be restored and maintained in accordance with our Plan and DCP's site-specific E&SCP, and maintained in accordance with applicable DOT safety standards in 49 CFR 192 and applicable state and federal environmental regulations.

Loudoun M&R Facility

Modifications at the Loudoun M&R Facility would include the installation of meter runs, fittings, valves, and miscellaneous piping and measurement upgrades. All of the work would occur within the 1.9-acre fenced area around the site, which contains equipment or has been graded and covered with gravel.

The workspace for the modified M&R facility would be restored and maintained in accordance with our Plan and DCP's site-specific E&SCP, and maintained in accordance with applicable DOT safety standards in 49 CFR 192 and applicable state and federal environmental regulations.

1.8 ENVIRONMENTAL COMPLIANCE INSPECTION AND MONITORING

DCP has committed to obtaining all the necessary environmental permits and approvals (section 1.10) and would construct, operate, and maintain the proposed facilities in compliance with permit conditions and other applicable federal and state regulations and guidelines. Prior to construction, DCP would submit an Implementation Plan to the FERC for review and approval. The Implementation Plan would describe how DCP would maintain environmental compliance with applicable regulations and permit requirements; detail the environmental training program for workers; and identify the role and responsibilities of Environmental Inspectors (EIs), which would include:

- ensuring compliance with the requirements of the Plan and Procedures, environmental conditions of the FERC approval, applicable mitigation measures, other environmental permits and approvals, and environmental requirements in landowner agreements;
- verifying that the limits of authorized construction work areas and locations of access roads are properly marked before clearing;
- verifying the location of signs and highly visible flagging marking the boundaries of sensitive resource areas, waterbodies, wetlands, or areas with special requirements along the construction work area;
- identifying E&SCP and soil stabilization needs in all areas;
- ensuring restoration of contours and topsoil;
- determining the need for and ensuring that erosion controls are properly installed, as necessary to prevent sediment flow into wetlands, waterbodies, and sensitive areas, and onto roads;
- inspecting and ensuring the maintenance of temporary erosion control measures at least on a daily basis in areas of active construction or equipment operation, on a weekly basis in areas with no construction or equipment operation, and within 24 hours of each 0.5 inch of rainfall;
- keeping records of compliance; and
- identifying areas that should be given special attention to ensure stabilization and restoration after the construction phase.

DCP would conduct training for its construction personnel, including EIs, contractors, and their employees, regarding proper field implementation of its E&SCPs; Spill Prevention, Control, and Countermeasures Plan; and other Project-specific plans and mitigation measures. The training would cover Project environmental documents and all Project-specific conditions contained in the Commission approval and other applicable federal, state, and local permits and approvals.

We would also conduct routine inspections during construction and restoration of the Project facilities as well as regular annual safety inspections of the Liquefaction Facilities during the operating life of the facilities.

After construction, DCP would conduct follow-up inspections of all disturbed upland areas after the first and second growing seasons to determine the success of restoration. To ensure the restoration of all areas affected by the Project, we would continue to conduct oversight inspection and monitoring following construction as outlined in the Plan. If it is determined that post-construction monitoring is not adequate to assess the success of restoration, DCP would be required to extend its post-construction monitoring in site-specific areas of concern. All compliance inspection reports would be available for public review on the FERC’s Internet website using the eLibrary link.

1.9 LAND REQUIREMENTS

Construction of the Project would impact approximately 204.9 acres of land, including aboveground facility sites, offsite support areas, access roads, and pipeline right-of-way. Operation of the facilities would impact 15.4 acres that are not currently used in operating existing facilities. Table 1.9-1 identifies the land requirements for each Project facility and land use is further discussed in section 2.4.

TABLE 1.9-1

Summary of Land Requirements

State/County/Facility	Property Size (acres)[a]	Land Affected During Construction (acres)	Land Affected During Operation (acres)
MARYLAND			
Calvert County			
Liquefaction Facilities	1,017.0	68.4 [b]	13.1 [c]
Offsite Area A	179.4	94.9 [d]	0.0 [e]
Offsite Area B	11.0	5.8 [f]	0.0
Maryland Subtotal	NA	169.1	13.1
VIRGINIA			
Fairfax County			
Pleasant Valley Compressor Station	37.0	22.2 [g]	2.3 [h]
Pleasant Valley Suction/Discharge Pipelines and Pleasant Valley M&R Facility	3.5	3.3	0.0
Loudoun County			
Loudoun M&R Facility	39.0	1.9 [i]	0.0
Leesburg Compressor Station Contractor Staging Area	74.4	8.4 [i]	0.0
Virginia Subtotal	NA	35.8	2.3
Project Total	**NA**	**204.9**	**15.4**

[a] The property size represents the total land that is owned or leased by DCP and DTI. Construction and operation of the proposed facilities would take place within the owned or leased property boundaries.

[b] Includes 0.35-acre impact associated with re-establishment of a previously existing access road on the LNG Terminal property but outside of the Fenced Area.

[c] The Liquefaction Facilities would occupy 59.5 acres within the existing Fenced Area of the LNG Terminal. However, approximately 46.5 acres of the Liquefaction Facilities would be located on land that is currently utilized for operation of the LNG Terminal. The remaining approximately 13.1 acres of the Liquefaction Facilities would impact land that is currently unaffected by operation of the LNG Terminal.

[d] Based on information provided by DCP to the FERC; however, the Maryland DNR has stated that DCP would affect 94.5 acres of land at Offsite Area A. The final area affected would be confirmed prior to construction.

[e] Offsite Area A would not be used in the operation of the Liquefaction Facilities but would result in converting 92.7 acres of upland forest and 1.3 acres of successional woodland to open land.

[f] Does not include 0.2 acre associated with construction of the temporary pier.

[g] Does not include 0.9 acre for the nonjurisdictional substation that would be constructed by the Northern Virginia Electric Cooperative within the Pleasant Valley Compressor Station site.

[h] The expansion of the Pleasant Valley Compressor Station would occupy 3.0 acres within the existing compressor station property. However, 0.7 acre of the expansion would be located on land that is currently utilized for operation of the compressor station. The remaining 2.3 acres of the expansion facilities would impact land that is currently unaffected by operation of the compressor station.

[i] Includes reuse of existing access roads. Does not include 2.2 acres currently occupied by buildings and other structures.

1.10 PERMITS, APPROVALS, AND REGULATORY CONSULTATIONS

Table 1.10-1 identifies the major federal, state, and local environmental permits, approvals, and regulatory clearances for the Project.

TABLE 1.10-1

Major Environmental Permits, Licenses, Approvals, and Certificates for Construction, Operation, and Maintenance of the Project

Agency	Permit/Approval/Clearance	Status
FEDERAL		
Federal Energy Regulatory Commission	Natural Gas Act Section 3 Authorization and Section 7 Certificate of Public Convenience and Necessity	Application submitted April 1, 2013
U.S. Department of Energy, Office of Fossil Energy	Authorization to export LNG to Free Trade Agreement Countries	Application submitted September 1, 2011; authorization granted by DOE-FE in Order No. 3019 on October 7, 2011
	Authorization to export LNG to Non-Free Trade Agreement Countries	Application submitted October 3, 2011; conditional authorization granted by DOE-FE on in Order No. 3331 on September 11, 2013
U.S. Department of the Army Corps of Engineers (COE), Baltimore District	Clean Water Act (CWA) Section 404 and Rivers and Harbors Act Section 10 permits	Application submitted April 1, 2013; approval dated April 29, 2014
COE, Norfolk District	CWA Section 404 permit	Application submitted April 1, 2013; approval dated October 18, 2013
U.S. Fish and Wildlife Service (FWS); Maryland Field Office	Endangered Species Act (ESA) Section 7 consultation, Fish and Wildlife Coordination Act consultation, Migratory Bird Treaty Act consultation, Bald and Golden Eagle Management Act consultation	Informal consultation initiated June 14, 2012; FWS final determination dated May 30, 2013
FWS; Virginia Field Office	ESA Section 7 consultation, Fish and Wildlife Coordination Act consultation, Migratory Bird Treaty Act consultation, Bald and Golden Eagle Management Act consultation	Informal consultation initiated January 2, 2013; FWS final determination dated August 15, 2013
U.S. Department of Commerce, National and Atmospheric Administration, National Marine Fisheries Service (NMFS)	Consultation under ESA Section 7	Informal consultation initiated June 14, 2012; NMFS concurrence dated September 11, 2013
	Consultation under the Magnuson-Stevens Fishery Conservation and Management Act	Informal consultation initiated June 14, 2012; NMFS concurrence dated February 25, 2013
U.S. Environmental Protection Agency	CWA Section 401, Water Quality Certification review, CWA Section 402, National Pollutant Discharge Elimination System (NPDES) review, CWA Section 404 review, CWA Stormwater Discharge Permit review	In conjunction with state permit applications (see below)
U.S. Coast Guard (USCG)	Letter of Recommendation	Waterway Suitability Assessment request letter submitted May 23, 2012; USCG response and Letter of Recommendation dated July 2, 2012
U.S. Department of Defense (DOD)	Project consultation	Consultation initiated May 2, 2012; DOD response received February 22, 2013
Federal Aviation Administration	Notice of Proposed Construction or Alteration	DCP anticipates initiating consultation February 2014; DCP anticipates response second quarter 2014
Advisory Council on Historic Preservation	Opportunity to comment under Section 106 National Historic Preservation Act (NHPA)	

TABLE 1.10-1 (cont'd)

Major Environmental Permits, Licenses, Approvals, and Certificates for Construction, Operation, and Maintenance of the Project

Agency	Permit/Approval/Clearance	Status
MARYLAND		
Maryland Department of the Environment	CWA Section 401, Water Quality Certification	Application submitted April 1, 2013; DCP anticipates approval May 28, 2014
	NPDES Permit for Stormwater Discharge (LNG Terminal, Offsite Areas A and B)	Application submitted April 1, 2013; approval dated December 2, 2013
	NPDES Surface Water Discharge Permit (industrial) (modification to existing permit)	Application submitted December 9, 2013; approval dated February 11, 2014
	Nontidal Wetlands Permit	Application submitted April 1, 2013; DCP anticipates approval May 28, 2014
	Tidal Wetlands License	Application submitted April 1, 2013; DCP anticipates approval May 28, 2014
	Coastal Zone Management Consistency Certification	Consultation initiated April 1, 2013; DCP anticipates approval May 28, 2014
	Waterways Construction Permit	Application submitted April 1, 2013; DCP anticipates approval May 28, 2014
	General Discharge Permit for Hydrostatic Testing (tanks and pipes)	Application submitted October 2013; approval dated October 2013 (no permit required)
Maryland Department of Natural Resources	Maryland Natural Heritage Program consultation	Application submitted June 14, 2012; response received August 29, 2013; DCP anticipates final response May 2014
Maryland Historical Trust	Section 106 NHPA consultation	Consultation initiated June 14, 2012; DCP concurrences received September 23, and November 21, 2013
Maryland Public Service Commission	Certificate of Public Convenience and Necessity – Air Permit, Water Appropriations Permit (construction); Water Appropriations Permit (operation)	Application submitted April 1, 2013; DCP anticipates approval May 23, 2014
Maryland State Highway Administration	Commercial/Industrial/Residential Subdivision Access Permit	DCP submitted application February 12, 2014; approval dated March 5, 2014
Critical Area Commission for the Chesapeake and Atlantic Coastal Bays	Critical Area Approval	DCP anticipates initiating consultation July 16, 2013; approval dated October 22, 2013
VIRGINIA		
Virginia Department of Environmental Quality	CWA Section 401, Water Quality Certification	Application submitted April 1, 2013; approval dated April 26, 2013
	Coastal Zone Management Consistency Certification	Application submitted April 1, 2013; DCP approval dated October 3, 2013
	Virginia Water Protection Permit	Application submitted April 1, 2013; approval dated April 26, 2013 (no permit required)
Virginia Department of Game and Inland Fisheries	Fish and Wildlife Coordination Act Review	Consultation initiated September 26, 2012; response dated February 24, 2014
Virginia Department of Historic Resources	Section 106 NHPA consultation	Consultation initiated December 21, 2012; concurrence dated May 29, 2013
Virginia Department of Conservation and Recreation	General permit for Discharge of Stormwater for Construction Activities (Loudoun M&R Facility and Pleasant Valley Compressor Station)	Application submitted April 1, 2013; approval dated May 1, 2013
	Fish and Wildlife Coordination Act Review	Consultation initiated October 19, 2012; review response dated October 24, 2012. Consultation update initiated July 29, 2013; review response dated October 31, 2012.
Virginia Department of Agriculture and Consumer Services	Fish and Wildlife Coordination Act Review	Consultation initiated September 26, 2012; review response dated October 24, 2012

TABLE 1.10-1 (cont'd)

Major Environmental Permits, Licenses, Approvals, and Certificates for Construction, Operation, and Maintenance of the Project

Agency	Permit/Approval/Clearance	Status
LOCAL		
Calvert County Department of Community Planning and Building	Critical Area Form, Buffer Management Plan	Consultation submitted July 16, 2013; review response dated October 22, 2013
	Forest Conservation Plans (Liquefaction Facilities and Offsite Area A)	Consultations submitted July 1 and 17, 2013; review response dated December 6, 2013 (Liquefaction Facilities); review response dated January 9, 2014 (Offsite Area A)
Calvert County Division of Inspections and Permits	Review of Stormwater Management Plan (SMP), Erosion and Sediment Control Plan (E&SCP), and Site Plan for Grading Permits (Liquefaction Facilities and Offsite Areas A and B)	Initial submittals April 1, 2013; DCP anticipates final reviews by June 4, 2014
Calvert County Division of Water and Sewer	Water and Sewer Commercial Permit	DCP submittal dated January 15, 2014; DCP anticipates permit by May 31, 2014
Calvert County Department of Public Safety	Fire Marshall Plan Review	DCP submittal dated April 1, 2014; DCP anticipates review by May 31, 2014
Calvert County Department of Public Works	Commercial Access Permit	DCP submittal dated April 1, 2014; DCP anticipates permit by May 31, 2014
Fairfax County Department of Public Works	Permit Application Form (including equipment worksheet), Grading Permit, Property Owner Affidavit, Permit Authorization Affidavit, Statement of Special Inspections, Accessibility Compliance Form, Electrical Energy Certification Form	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015
	Review of SMP, E&SCP, and Site Plan	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015
Fairfax County Department of Planning and Zoning	2232 Application	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015
Fairfax County Fire and Rescue Department	Building Information Form	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015
Loudoun County Department of Building and Development	Building Permit and Land Development Permit	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015
	Electrical Permit, Fire Suppression Permit, Gas Permit, Grading Permit, Mechanical Permit, Plumbing Permit, Soils Permit; review of SMP and E&SCP	DCP anticipates submittal July 2015; DCP anticipates final approvals by December 2015

1.11 FUTURE PLANS AND ABANDONMENT

DCP states that it has no plans for future expansion or abandonment of the Project facilities. If expansion is proposed in the future, DCP would seek the appropriate federal, state, and local authorizations. At the end of the useful life of the Project facilities, DCP would obtain the necessary permission to abandon the facilities in accordance with regulations that exist at the time and any landowner requirements.

2.0 ENVIRONMENTAL ANALYSIS

The environmental consequence of constructing and operating the Cove Point Liquefaction Project facilities would vary in duration and significance. Four levels of impact duration were considered: temporary, short-term, long-term, and permanent. A temporary impact would generally occur during construction, with the resource returning to preconstruction conditions almost immediately afterward. A short-term impact could continue for up to 3 years following construction. An impact was considered long-term if the resource would require more than 3 years to recover. A permanent impact could occur as a result of an activity that modifies a resource to the extent that it would not return to preconstruction conditions during the life of the Project, such as the construction and operational impact of the Liquefaction Facilities. We[8] considered an impact to be significant if it would result in a substantial beneficial or adverse change in the physical environment and the relationship of people with the environment.

In this section, we discuss the affected environment, general construction and operational impacts, and proposed mitigation measures for each resource. We also discuss the design and construction of the facility to resist natural hazards. DCP, as part of its proposal, agreed to implement certain measures to reduce impacts on environmental resources. We evaluated the proposed mitigation measures to determine whether additional measures would be necessary to reduce impacts. Where we identified the need for additional mitigation, the measures appear as bulleted, boldfaced paragraphs in the text. We will recommend that these measures be included as specific conditions to authorizations that the Commission may issue to DCP. Conclusions in this EA are based on our analysis of the environmental impact and the following assumptions:

- DCP would comply with all applicable federal laws and regulations;
- the proposed facilities would be constructed as described in section 1.0 of this document; and
- DCP would implement the mitigation measures included in the applications and supplemental filings to the FERC.

2.1 GEOLOGY AND SOILS

2.1.1 Geologic Setting, Mineral Resources, and Geologic Hazards

Geologic Setting

Maryland Facilities

The Liquefaction Facilities and Offsite Areas A and B lie within the Atlantic Coastal Plain Physiographic Province (the Coastal Plain), a relatively low-lying region with elevations reaching a few hundred feet above mean sea level. Much of the terrain is crossed by numerous streams that readily erode the underlying geologic materials, depositing sediment as alluvial fans, deltas, and marine mud layers. The Coastal Plain is underlain by a wedge-shaped mass of unconsolidated gravel, sand, silt, and clay deposited in non-marine, marginal marine, and marine environments of Tertiary and Quaternary age. These deposits pinch out against crystalline bedrock of the Eastern Piedmont Physiographic Province to the west and continue offshore under the Chesapeake Bay to the east where they are more than 8,000 feet thick (MDNR, 2009).

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8 "We," "us," and "our" refer to the environmental staff of the Commission's Office of Energy Projects.

Information from the existing wells at the LNG Terminal (section 2.2.1) and geotechnical soil borings determined that the Fenced Area is underlain primarily by sand to a depth of at least 90 feet. The deepest excavation associated with construction of the Liquefaction Facilities would be approximately 20 feet. Thus, work within the Fenced Area would not be expected to encounter consolidated geologic material or bedrock. Grading and other work to prepare Offsite Areas A and B for temporary use during construction of the Liquefaction Facilities would also not be expected to encounter consolidated geologic materials. Thus, blasting is not expected to be required for any of the Project facilities in Maryland. Any blasting, if necessary, would be conducted according to DCP's blasting plan, which requires compliance with state blasting codes and local requirements and the use of state-licensed blasting contractors. We reviewed DCP's blasting plan and find it acceptable.

The majority of new facilities within the Fenced Area, including stormwater management structures, would be in areas that were previously modified for industrial use. Construction and operation of the Liquefaction Facilities, and the temporary use of Offsite Areas A and B, would comply with the erosion control, revegetation, and restoration provisions of our Plan and Procedures and DCP's site-specific E&SCPs and SMPs to be approved by Calvert County. Upon completion of construction, the surface of Offsite Area A would be restored to pre-construction conditions with the exception of stormwater management facilities, which would be left in place; Offsite Area B would be restored to pre-construction conditions. Thus, construction and operation of the Liquefaction Facilities and the temporary use of Offsite Areas A and B would not have a significant impact on existing geologic conditions.

<u>Virginia Facilities</u>

The Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, Loudoun M&R Facility, and the DTI Leesburg Compressor Station Contractor Staging Area are located in the Northern Piedmont Physiographic Province (the Piedmont Province). The Piedmont Province has gently rolling topography with elevations ranging from 200 to 300 feet above sea level in the east to 800 to 900 feet above sea level in the west. The terrain becomes more rugged with proximity to the Blue Ridge Province to the west.

The bedrock of the Piedmont Province comprises igneous and metamorphic rocks that range from the Proterozoic to Paleozoic era, which are overlain by Triassic sedimentary and igneous rock formed during the early stages of rifting associated with the opening of the Atlantic Ocean. Rivers and streams carrying sand, silt, and mud flowed into these lowland rift basins burying swamps and marshes, later producing small coal measures in the Piedmont Province. Near-surface bedrock within the Piedmont Province is often strongly weathered due to the humid climate, with as much as 65 feet of saprolite (weathered igneous and metamorphic rock) covering the bedrock. Outcrops are commonly restricted to stream valleys where saprolite has been removed by erosion (William and Mary, Department of Geology, ND).

The bedrock in proximity to the Pleasant Valley Compressor Station consists of sandstone from the Mesozoic Newark Supergroup. Bedrock near the Loudoun M&R Facility consists of an Upper Triassic pebble, cobble, and boulder conglomerate formation. DCP intends to conduct a geotechnical evaluation in 2015 to further characterized geologic conditions and assist in the final design of foundations for the proposed expansion of the Pleasant Valley Compressor Station.

DCP stated that bedrock was encountered during construction of the Pleasant Valley facilities but, to its knowledge, the rock was removed by conventional methods and no blasting was required. Thus, DCP does not expect that blasting would be required for any of the Project facilities in Virginia. Any blasting, if necessary, would be conducted according to DCP's blasting plan, which requires compliance with state blasting codes and local requirements and the use of state-licensed blasting contractors.

The majority of new facilities in Virginia would be in areas that were previously disturbed or modified for industrial use. Construction and operation of the Pleasant Valley Compressor Station modifications, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, and Loudoun M&R Facility, as well as the temporary use of the DTI Leesburg Compressor Station Contractor Staging Area, would comply with the erosion control, revegetation, and restoration provisions of FERC's Plan and Procedures and DCP's site-specific E&SCPs and SMPs to be approved by Loudoun and Fairfax County officials. Thus, construction and operation of the Project facilities in Virginia would not have a significant impact on existing geologic conditions.

Mineral Resources

Maryland Facilities

There are no oil or natural gas wells at or near the Liquefaction Facilities or Offsite Areas A and B according to the MDE Mining in Maryland Maps (2010). These areas are not currently viewed as prospective drilling locations for oil and gas (USGS, 2012a).

Commercially extractable non-hydrocarbon mineral resources at or near Cove Point are limited to iron, sand, gravel, titanium, and zirconium (USGS, 2012b). However, there are no active mines at or within 0.25 mile of the LNG Terminal and no potentially exploitable mineral resources have been identified at or near the proposed Project facilities. Therefore, no impacts on mineral resources would be expected during construction and operation of the Liquefaction Facilities and during use of Offsite Areas A and B.

Virginia Facilities

Historical mining produced a variety of commodities including copper, iron, dimension stone, roadstone, dolostone, lime, and marble in Fairfax and Loudoun Counties (Virginia Department of Mines, Minerals, and Energy, 2006). However, there are no active or historic mines located within 0.25 mile of any of the Project facilities in Virginia. According to the USGS Energy Resources Program, there is no historical or current production of oil or gas in Fairfax or Loudoun Counties (USGS, 2012c). Therefore, no impacts on mineral resources would be expected during construction and operation of the facilities in Virginia.

Geologic Hazards

Potential geologic hazards associated with the Project include seismicity and surface faulting, landslides, subsidence, flooding, and tsunamis.

Seismicity and Surface Faulting

Seismic earthquakes are the result of sudden movement along a fault, which can result in damaging ground motions or secondary effects including landslides and soil liquefaction. DCP conducted a seismic review for the LNG Terminal and determined that no active or inactive faults are located near the LNG Terminal or Offsite Areas A and B (MDNR, 2007). For the purpose of seismic risk analysis at the LNG Terminal, the most significant seismic zones are the Central Virginia Seismic Zone, centered approximately 125 miles southwest from the LNG Terminal, and the Giles County Seismic Zone, centered approximately 250 miles southwest from the LNG Terminal. The most recent earthquake to affect the East Coast was a magnitude 5.8 event on August 23, 2011. This earthquake was centered approximately 100 miles west-southwest from the LNG Terminal and caused light damage to structures in Washington, D.C., and other areas, but did not damage the LNG Terminal, according to DCP. Probabilistic hazard analysis, which is based on historical seismicity and geologic conditions in a region, indicates that the peak ground acceleration predicted for Calvert County, Maryland could produce weak shaking and light to very light damage. The USGS estimates the peak ground accelerations on a rock site in Calvert County that has a 2 percent probability of being exceeded in 50 years (USGS, 2005) is approximately 6 percent of the acceleration of gravity (0.06 g). Peak round accelerations in this range can be amplified by a factor of 2 or more on soil sites. As discussed in section 2.1.2, the Liquefaction Facilities would be designed and constructed in accordance with NFPA 59A and other engineering standards, which would further reduce the potential for a seismic event to impact the facilities.

Extensive literature reviews performed by DCP indicate that there are no known Quaternary faults in the Project area (Cove Point facility) and surrounding regions. We received a comment regarding concerns about the Moran Landing Fault (located over 2 miles north of the Cove Point facility) crossing over DCP gas pipelines; however, there was no evidence that this fault is active. These DCP pipelines are not part of this Project. Furthermore, geologic cross sections developed from boring logs at the Project site indicate that the contact between the Calvert Formation and the overlying Choptank/St. Mary's Formation has not been offset by fault displacement at the site. These data indicate that faulting has not occurred in the Project area since the Miocene. Therefore, we consider the possibility of seismically induced faulting in the Project area to be remote.

Historical earthquake records for Fairfax and Loudoun Counties show no active or inactive faults near the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, Loudoun M&R Facility, and the DTI Leesburg Compressor Station Contractor Staging Area. Probabilistic hazard analysis indicates that the peak ground acceleration predicted for Fairfax and Loudoun Counties could produce light damage to buildings and structures. The August 23, 2011 magnitude 5.8 earthquake was centered approximately 70 miles south-southwest from the proposed Virginia facilities but did not damage DCP's existing facilities.

Landslides

The LNG Terminal and Offsite Areas A and B lie within an area of relatively low local topographic relief with a low to moderate incidence of landslides (USGS, 2012d). Soils within the Fenced Area are designated as urban with no slopes; therefore, no landslide exposure is anticipated within the Liquefaction Facilities. The steeper banks associated with wetlands and streams at Offsite Area A could exhibit slope failure; however, DCP would observe a 100-foot-wide buffer around wetlands and waterbodies, thereby avoiding steeper slopes and preserving vegetation which would further reduce the potential for localized slope failures to occur. Offsite Area B is relatively flat and would not be subject to landslide risk.

The proposed facilities in Virginia also occur in areas with relatively low relief characterized by low landslide susceptibility (USGS, 2012d).

Subsidence

Ground settlement due to design level seismic events are not predicted to affect the structures at the site. Karst terrain, including sinkholes, can develop in areas where carbonate bedrock units occur near the land surface. We received a comment stating concerns regarding sinkholes located over 3 miles from the LNG Terminal at the Calvert Cliffs Nuclear Power Plant; however, our research indicates that none of the Liquefaction Facilities are underlain by near-surface carbonate bedrock units and no karst terrain is known to occur in proximity to the proposed facilities (MDE, 2010; USGS, 1976). In addition, none of the proposed facilities would be located near active or historical underground mines (MDE, 2010; Virginia Department of Mines, Minerals, and Energy, 2012; USGS, 2012e) and DCP has not experienced any instances of ground subsidence or collapse at any of its existing facilities where the proposed Project would be constructed and operated. However, in their recommended license conditions for the Maryland PSC CPCN, the Reviewing State Agencies (through PPRP) recommended that DCP fund a subsidence monitoring program in the Project area. The Maryland Geological Survey (a part of MDNR) would conduct the monitoring. Subsidence due to liquefaction, karst terrain, or mine collapse is not likely to cause significant impacts on the Liquefaction Facilities.

Flooding

A review of the Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRM) showed no designated flood zones at the Liquefaction Facilities, Offsite Area A, Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, Loudoun M&R Facility, or DTI Leesburg Compressor Station Contractor Staging Area. Offsite Area B is located within a FEMA flood Zone "AE," which is based on the base flood elevation from the Patuxent River. Activities at Offsite Area B during construction would not affect the flood storage capacity at this location because no permanent aboveground structures would be located within the FEMA FIRM boundary and the area would be restored to preconstruction conditions to the extent possible following construction.

Based on regional conditions, the potential for flash flooding to significantly impact construction or operation of the Project is low. DCP would monitor local weather conditions during construction to anticipate and plan for significant weather events during construction. Stormwater runoff during construction and operation of Project facilities would be managed through implementation of DCP's site-specific E&SCPs and SMPs which would be approved by appropriate local officials.

We received comments regarding the potential for tropical storm surge to impact the LNG Terminal and Liquefaction Facilities in light of rising sea level, which commentors quote may be as great as 3.4 feet along coastal Maryland by the end of the century. Although DCP's greater LNG Terminal property borders the Chesapeake Bay, the Fenced Area in which the Liquefaction Facilities would be located is situated inland. The elevation of the Fenced Area varies from approximately 70 to 130 feet above mean sea level (National Geodetic Vertical Datum 1929), with the majority of the existing and proposed facilities located at an elevation of more than 110 feet above mean sea level. Thus, tropical storm surge would not be likely to impact the industrialized Fenced Area and proposed Liquefaction Facilities. Storm surge and sea level rise impacts related to climate change are addressed in section 2.9.9.

Tsunamis

Maximum tsunamis inundation elevations at the site are judged to be less than maximum storm surge elevations. Therefore, a tsunami hazard would not be likely to impact the industrialized Fenced Area and proposed Liquefaction Facilities.

2.1.2 Design and Construction of the Cove Point Liquefaction Facilities and Pleasant Valley Compressor Station

Natural hazards, including those related to geology and foundation conditions, could affect the design and construction of the Liquefaction Facilities and Pleasant Valley Compressor Station. Our review and analysis of DCP's proposed design and construction of the Project is provided below.

Geotechnical Site Characterization of the Liquefaction Facilities

Two geotechnical investigations were performed at the Liquefaction Facility. The investigation performed in June 2012 consisted of 9 soil borings and 19 cone penetration tests and the results were presented in a GZA GeoEnvironmental Inc. (GZA) report dated July 2012. A supplemental investigation was performed due to changes in the locations of some of the facilities and included 9 test borings drilled between July 15 and August 2, 2013. The results of this investigation were presented in a GZA supplemental report dated August 28, 2013. The subsurface conditions consist of Upper Sand and Lower Sand. The Upper Sand is present at depths ranging from approximately 6 to 18 feet and blow counts ranging from 0 to 21 feet. The fines content ranges from 10 to 47 percent. The Lower Sand is present below the Upper Sand and blow counts range between 2 and 55. Zones of loose sands were encountered in three of the six borings in the supplemental investigation.

Groundwater was encountered between depths of 13 to 46 feet below ground surface or elevations of 56 to 96 feet above sea level.

Site Grading

The Liquefaction Facilities site would be cleared, grubbed, and prepared using standard earthmoving and compaction equipment. Up to 40 feet of fill would be placed in ravine areas on the site to raise the ground level to the finished grade elevation, which ranges between 100 and 130 feet above sea level. Where the fill is deepest (greater than 20 feet), settlement is expected during construction and over the design life of the facility. At some locations near the fenced boundaries of the construction area, retaining walls (either rigid or mechanical stabilized earth) would be constructed. Based on explorations at the site, the water table elevation is expected to range between 56 and 96 feet and, therefore, should not affect site preparation activities or construction of foundations.

Foundations

After site preparation at the Liquefaction Facilities, foundations would be excavated for the installation of new equipment. One commentor expressed concerns that the vibration of the heavy equipment could cause soil weakness, ruptured gas lines, and sinkholes. The GZA supplemental report recommends that gas turbine and Compressor Train, HRSG, steam turbines, and auxiliary boilers could be supported on mat foundations. However, considering the criticality of the equipment and the fact that loose sands are particularly susceptible to dynamic loadings including earthquake, DCP would use pile foundations for gas turbines, HRSG, and steam turbines to ensure settlement and vibration control. If settlement criteria are not satisfied, other structures may be supported on deep foundations such as auger cast piles, driven precast piles, and drilled minipiles.

Facility and Structure Design

The Liquefaction Facilities would be constructed to satisfy the design requirements of 49 CFR 193, NFPA 59A-2001, 2006 International Building Code and American Society of Civil Engineers (ASCE) 7-05. For seismic design, the facility would be designed to satisfy the requirements of NFPA 59A-2006 and ASCE 7-05.

<u>Wind Design</u>

Section 2.8.4 includes the discussion of facility design for wind speed.

Seismic Design Ground Motions

Geotechnical investigations of the Liquefaction Facilities site determined that the site is classified as Site Class D (firm soil) in accordance with the International Building Code and the ASCE 7-05. Sites with soil conditions of this type will experience significant amplifications of surface earthquake ground motions.

GZA performed a site-specific seismic hazard study for the site. The study concluded that earthquake ground motions at ground surface at the site that have 2 percent probability of being exceeded in 50 years have a 0.2-second spectral acceleration value of 0.174 g, while the 1.0-second spectral acceleration at the site is 0.102 g (GZA, 2013). These predicted spectral accelerations are relatively low compared to other locations in the United States.

Construction and operation of the Project would not materially alter the geologic conditions of the Project area, and the Project would not affect mining of resources during construction or operation. Blasting is not anticipated during construction of the Project. The Project would not be affected by any significant geologic hazards, including areas of seismic activity or subsidence. DCP committed to conducting geotechnical studies to determine general subsurface conditions at the Pleasant Valley Compressor Station site and develop engineering designs for the proposed foundations. Based on DCP's proposal, including implementation of the FERC Plan and Procedures, DCP's E&SCPs, and our recommended mitigation measures, we conclude that impacts on geological resources would be adequately minimized and would not be significant, and that the potential for impacts on the Pleasant Valley Compressor Station from geologic hazards would also be minimal.

The design of the Liquefaction Facilities is currently at the Front-End Engineering Design (FEED) level of completion. A feasible design has been proposed, and DCP would conduct a significant amount of detailed design work if the Project is authorized by the Commission. Information regarding the development of the final design would need to be reviewed by FERC staff in order to ensure that the final design addresses the requirements identified in the FEED. Therefore, **we recommend that:**

- **DCP should file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary of the Commission (Secretary) for review and written approval by the Director of the Office of Energy Projects (OEP):**

  a. structure and foundation design drawings and calculations of the Liquefaction Facilities;

  b. foundation and pile design drawings and calculations for all vibratory equipment, including gas turbines, HRSGs, steam generators, and compressors supported on piles; and

  c. quality control procedures to be used for design and construction.

  In addition, DCP should file, in its Implementation Plan, the schedule for producing this information.

DCP intends to conduct a geotechnical evaluation in 2015 to further characterize geologic conditions and assist in final design of foundations for the proposed expansion of the Pleasant Valley Compressor Station. This work still remains to be completed and reviewed by FERC before the Pleasant Valley Compressor Station facility should be authorized to proceed with any construction activities. Because this investigation has not been completed, **we recommend that:**

- **<u>Prior to starting any work on the Pleasant Valley Compressor Station</u>, DCP should file the results of the geotechnical investigation, foundation recommendations, Project design, and construction details with the Secretary for review and written approval by the Director of OEP.**

In conclusion, the Project is located in an area that presents several potential challenges related to geology, foundation conditions, and natural hazards; however, these conditions can be effectively managed through proper engineering design or shown to be minimal through additional evaluation. The recommendations included in this section ensure DCP would mitigate and or manage associated geological impacts on the proposed Project, and thus resultant impacts would be minor.

2.1.3 Soils

Soil Resources

Construction of the proposed Project would affect a total of 204.9 acres of land. A total of approximately 162.4 acres of soils would be affected during construction; the remaining approximately 42.3 acres of land is covered by previously constructed surfaces and buildings at DCP's existing facilities and is not included in the discussion of soils impacts. Operation of the proposed facilities would result in a total change of 15.4 acres of land and associated soils from a non-developed status to a commercial/industrial land use type.

The Project facilities would be underlain by 33 soil series. Appendix A lists the soil series that would be affected by construction and operation of the Project, as well as soil limitations related to erosion, compaction, revegetation potential, and prime farmland.

The majority of soils that would be affected by the Project facilities are considered to have a slight erosion hazard potential, low compaction potential, and high revegetation potential. The depth to bedrock is generally more than 20 inches, with the depth to bedrock for the majority of the Project facilities being more than 80 inches. About 25.6 acres of the total 162.4 acres of soils affected by construction of the Project are considered prime farmland; however, no active agricultural land or residential land is affected by the Liquefaction Facilities, Offsite Area A, or the facilities in Virginia. Offsite Area B is part of a larger parcel that also includes cropland; however, the portion of Offsite Area B that would be used during construction consists of mowed/maintained land and is not currently used for agricultural purposes. In addition, only 0.5 acre of Offsite Area B is considered prime farmland.

Soils affected by the Project were assessed for wind erodibility and water erosion potential. As shown in appendix A, soils affected by the Project are in Wind Erodibility Groups ranging from 1 to 8, with 1 being the highest potential for wind erosion and 8 being the lowest (U.S. Department of Agriculture, ND). The soils at the Liquefaction Facilities and Offsite Area A have moderate to high potentials for wind erosion, while the soils at the remaining facilities (Offsite Area B and the facilities in Virginia) are considered to have low potential for wind erosion.

The majority of soils affected by construction of the Project are considered to have a low potential for erosion from water, with the exception of 9.0 acres at the Liquefaction Facilities and 46.3 acres at Offsite Area A that would be affected during construction that are considered to have a high water erosion potential.

Impacts and Mitigation

The primary impacts of the Project on soils would be an increased potential for erosion and potentially reduced revegetation of disturbed areas. To limit the effects of erosion, DCP would implement best management practices outlined in FERC's Plan and Procedures and detailed in site-specific E&SCPs and SMPs. DCP's site-specific plans would be reviewed and approved by appropriate local officials and would comply with the provisions of the *Maryland Standards and Specifications for Soil Erosion and Sediment Control* and the *1992, Third Edition, Virginia Erosion and Sediment Control Handbook*. Appropriate erosion and sediment control devices would be implemented and maintained at all times during the period of construction, as well as following the completion of construction until revegetation has occurred. Following restoration and clean-up, the disturbed areas would be monitored to maintain erosion control structures and to repair any erosion that occurs.

Most soils within the Project workspaces have moderate to high revegetation potential, with areas of steep slopes being the most difficult to establish vegetation following construction. At Offsite Area A, most steep slopes would be avoided by DCP's implementation of a 100-foot-wide buffer around wetlands and waterbodies, in which no vegetative clearing or soil disturbance would occur. For other disturbed areas, DCP would implement topsoil stripping and segregation over the entire Project workspace to improve revegetation success following construction. DCP would cover or otherwise manage the topsoil stockpiles during the course of construction and then replace the topsoil for restoration, as needed. Soil grading would be implemented to restore compacted or rutted soils to pre-construction conditions and disturbed areas would be planted with native species. Restoration would also include the removal of gravel used to stabilize temporary roads and laydown areas within approved workspaces.

By implementing the above construction and restoration procedures, the Project would not result in any significant, long-term impacts on soils.

2.2 WATER RESOURCES, FISHERIES, AND WETLANDS

2.2.1 Groundwater

Existing Groundwater Resources

The Project areas in Maryland are within the Coastal Plain Physiographic Province and overlie five aquifers comprised of Tertiary and Quaternary unconsolidated gravel, sand, silt, and clay deposits that pinch out against irregular crystalline rocks of the Piedmont Physiographic Province to the west. The five hydrogeologic formations include, in order of increasing depth, the Surficial Aquifer, the Piney Point Aquifer, the Aquia Aquifer, the Upper Patapsco Aquifer, and the Lower Patapsco Aquifer (Hansen, 1996; Achmad and Hansen, 1997; and Drummond, 2007).

The Surficial Aquifer is composed of upland and lowland deposits and is recharged primarily by precipitation within the Project area. Water in the Surficial Aquifer either moves short distances before discharging into local streams or springs, or percolates into deeper aquifers (USGS, 1997).

The Piney Point Aquifer is approximately 135 feet deep at the LNG Terminal and is recharged by leakage from the Surficial Aquifer. The Piney Point Aquifer is primarily used by small water users, such as self-supplied domestic users and small businesses. Water levels in this aquifer have decreased over time as water withdrawals have increased (USGS, 1997).

The Aquia Aquifer occurs at a depth of 650 to 700 feet at the LNG Terminal and is the primary groundwater source in Calvert County. The aquifer is recharged by precipitation in Anne Arundel and

Prince George's Counties, Maryland, more than 20 miles northwest from the Project area. Water levels in the Aquia Aquifer have declined at a rate of about 0.5 foot per year since 1980 (Drummond, 2001).

The Upper Patapsco Aquifer is typically 600 to 980 feet deep in the region, and the Lower Patapsco Aquifer occurs at a depth of approximately 1,400 feet at the LNG Terminal. These aquifers are not significant water sources in southern Calvert County because of their depth and the availability of groundwater from the shallower Piney Point and Aquia Aquifers (USGS, 1997).

Groundwater withdrawals make up the majority of consumptive water use in Calvert County. Groundwater withdrawals in 2000 averaged 7.01 million gallons per day (mgd), of which 3.69 mgd were from self-supplied domestic withdrawals, 2.30 mgd were for municipal supply, 0.55 mgd for commercial and industrial use, 0.41 mgd for thermoelectric power generation, and 0.06 mgd for irrigation (USGS, 2010).

The Project facilities in Virginia are within the Mesozoic Lowlands Region of the Piedmont Physiographic Province (Bailey, 1999). The geology in the area consists of sandstone, shale, diabase dikes, and basalt flows deposited in half grabens and grabens during rifting that produced the Atlantic Ocean (The College of William and Mary, Department of Geology, ND). The Culpeper Basin is the primary aquifer in the region and lies at depths of 200 to 600 feet deep. Recharge of the Culpeper Basin is the result of precipitation in Loudoun and Fairfax Counties, Virginia (CH2M Hill, 2008).

Groundwater is an important source of drinking water for residents in the Project areas in Virginia. In Loudoun County in 1998, 2.24 mgd of groundwater was withdrawn for private domestic supply, 1.81 mgd for public water supply, 0.25 mgd for commercial and industrial use, and 0.06 mgd for agricultural use. In Fairfax County in 1998, 2.60 mgd was withdrawn for private domestic supply, 1.09 mgd for commercial and industrial uses, and 0.76 mgd for public water supply (Solley et al., 1998).

Sole Source Aquifers

The U.S. Environmental Protection Agency (EPA) defines a principal, or sole source, aquifer as one that supplies at least 50 percent of the drinking water consumed in the area overlying the aquifer. None of the Project facilities are located within an EPA-designated sole source aquifer or a state-designated primary aquifer.

Water Supply Wells and Springs

Table 2.2.1-1 identifies potable water supply wells and springs within 150 feet of the proposed Project construction workspaces. DCP owns and operates three wells within the Fenced Area of the LNG Terminal, one well within the boundary of the Pleasant Valley Compressor Station, and one well within the fenceline of the Loudoun M&R Facility. Two wells within the Fenced Area are capped and no longer operational.

DCP also identified a well within the Offsite Area B property, but outside the proposed work limits of the site. According to the landowner, the well was installed during construction of the nearby Maryland Route 2/4 bridge but subsequently collapsed and has since been out of use. There are no other private, public or community water systems within 150 feet of the Project.

DCP identified several wetlands at Offsite Area A that receive their hydrology from groundwater seeps. These seep wetlands are discussed in section 2.2.4.

TABLE 2.2.1-1

Potable Water Supply Wells and Springs within 150 feet of Proposed Project Construction Workspaces

State/County/Facility	Well Type	Approximate Location Relative to Project
MARYLAND		
Calvert County		
Liquefaction Facilities	DCP – Private	Within Fenced Area
	DCP – Private	Within Fenced Area
	DCP – Private	Within Fenced Area
	DCP – Capped and Abandoned	Within Fenced Area
	DCP – Capped and Abandoned	Within Fenced Area
VIRGINIA		
Fairfax County		
Pleasant Valley Compressor Station	DCP – Private	Within compressor station property
Loudoun County		
Loudoun M&R Facility	DCP – Private	Within Loudoun M&R Facility fenceline

Impacts and Mitigation

DCP has two permits from the MDE to appropriate groundwater from the three wells at the LNG Terminal. One permit provides for the average withdrawal of 40,000 gpd on a yearly basis and 60,000 gpd per month of maximum use from the well completed in the Lower Patapsco Aquifer. The second permit provides for the average withdrawal of 10,000 gpd on a yearly basis and 60,000 gpd per month of maximum use from the two wells completed in the Aquia Aquifer.

To support construction and operation of the Liquefaction Facilities, in its application to the Maryland PSC, DCP has applied for an appropriation of additional water from the well completed in the Lower Patapsco Aquifer.[9] More specifically, DCP has requested authorization to withdraw an additional 40,000 gpd average on a yearly basis and 60,000 gpd per month of maximum use during construction of the Liquefaction Facilities, and a total of 250,000 gpd average on a yearly basis and 375,000 gpd per month of maximum use during operation of the Liquefaction Facilities. However, in their recommended license conditions for the Maryland PSC CPCN, the Reviewing State Agencies (through PPRP) recommended a reduced water withdrawal of 233,000 gpd annual average and a monthly maximum of 275,000 gpd. In its testimony to the PSC on January 29, 2014, DCP agreed to the recommended water withdrawal limits.

DCP states that the additional groundwater needed during construction would be utilized for fugitive dust suppression, hydrostatic testing of equipment and piping, and steam flushing. The majority of the additional groundwater needed during operation of the Liquefaction Facilities would be utilized in the steam turbine system, with secondary needs including fire suppression, operation of the LNG vaporizer, drinking water, and general maintenance. DCP does not propose changes to the existing allocation from the Aquia Aquifer and would abandon one of the two wells completed in the aquifer.

DCP analyzed the potential drawdown of the Lower Patapsco Aquifer based on its initially proposed increase in water use. In the analysis, DCP compared the results of a 2008 pump test of the

[9] DCP's application to the Maryland PSC was provided as an attachment to its June 20, 2013 Supplemental Filing and is available for viewing on the FERC Internet website in the Project's docket (http://www.ferc.gov), Accession 20130620-5137. Under the Files, select the PDF file titled "Att 1- 04-01-13 CPCN Application.PDF."

onsite well to the drawdown from the increased water use predicted by the AQTESOLV software model. This comparison demonstrated a good fit between the observed and predicted drawdown levels in the well and concluded that the requested 250,000 gpd annual average withdrawal would result in approximately17.5 feet of drawdown at the well, and the requested 375,000 gpd for the month of maximum use would result in approximately 26.2 feet of drawdown at the well. In the maximum pumping scenario, the elevation of the water level in the onsite well would be approximately 46 feet below mean sea level (bmsl). However, because DCP would limit its water withdrawal to the amounts recommended by the Reviewing State Agencies, the resulting drawdown at the well would be less than DCP's initial estimates.

The primary criterion that the MDE uses in evaluating water appropriation permit applications in a confined aquifer in the Maryland Coastal Plain is the 80 percent management level, which is defined as 80 percent of the total available drawdown measured from the pre-pumping water level to the top of the aquifer. The MDE implements the 80 percent management level to prevent reduction in capacity for users, infiltration of poor quality waters, and possible land subsidence. Based on regional information, the 80 percent management level for the Lower Patapsco Aquifer in the vicinity of the LNG Terminal occurs at an approximate elevation of 1,090 feet bmsl (Drummond, 2007). Thus, under the maximum pumping scenario proposed by DCP, the predicted water level in the onsite well would remain approximately 1,044 feet above the 80 percent management level for the Lower Patapsco Aquifer. Utilizing site-specific information including a static water level of 20 feet bmsl results in an elevation of 1,028 feet bmsl for the 80 percent management level. In this case, the predicted water level in the onsite well would remain 982 feet above the 80 percent management level in the maximum use scenario. Based on the predicted drawdown for construction and operation of the Liquefaction Facilities and the substantial capacity of the Lower Patapsco Aquifer, DCP's water withdrawal from the Lower Patapsco Aquifer as recommended by the Reviewing State Agencies would not significantly impact the aquifer or other groundwater users in the area. In addition, because the Piney Point Aquifer and Aquia Aquifer are the primary groundwater sources for Calvert County, DCP's water withdrawal from the Lower Patapsco Aquifer would not significantly impact other groundwater users in the area. Alternative sources for the water needed to construct and operate the Liquefaction Facilities are discussed in section 3.5.

We received a comment during the scoping period that declining water levels in the Lower Patapsco aquifer could lead to river-water intrusion. As described above, DCP's water withdrawal from the Lower Patapsco Aquifer, as recommended by the Reviewing State Agencies, would remain above the 80 percent management level in the maximum use scenario and, therefore, would not significantly impact the aquifer or other groundwater users in the area.

New piping and other equipment would be hydrostatically tested to ensure its integrity before being placed into service. DCP estimates that 300,000 gallons of water would be required to complete testing of piping and other equipment for the Liquefaction Facilities. Test water would be obtained from wells at the LNG Terminal or from a local public water supply. Hydrostatic test water for the Pleasant Valley Compressor Station, the Pleasant Valley Suction/Discharge Pipelines, and the Pleasant Valley M&R Facility would be obtained from a public water supply and trucked to each facility. DCP estimates that 200,000 gallons of water would be required to complete testing at these facilities. DCP would use 1,000 gallons of water from its existing well at the Loudoun M&R Facility for hydrostatic testing of new piping and equipment. The small volumes of private and public water would not impact the source aquifers or other groundwater users in the appropriation area. DCP would obtain all necessary permits to appropriate and discharge hydrostatic test water.

Project construction would not result in significant groundwater impacts because the majority of construction would involve shallow, temporary, and localized excavation or grading. The depth to groundwater in the Project area would generally be below structure foundation or pipeline trench excavation depths. Geotechnical soil borings within the Fenced Area at the LNG Terminal encountered groundwater at depths below the deepest excavation or footing for the Liquefaction Facilities, and DCP does not expect to encounter groundwater in any other Project excavations. Should shallow groundwater be encountered, local water table elevations could be affected by dewatering and increased turbidity in the water table could occur. Shallow aquifers could also sustain impacts from changes in overland flow regimes and recharge fluctuations caused by facility construction and clearing and grading of the proposed pipeline right-of-way. These impacts would be minor, temporary, and localized to the construction area. DCP would minimize these impacts by implementing erosion control and water management practices described in our Plan and Procedures and its E&SCPs.

Shallow groundwater and surficial aquifers could be vulnerable to contamination caused by inadvertent surface spills of hazardous materials or fuels used during construction. DCP would implement measures in its Spill Prevention and Contaminant Control Plan to minimize the potential for groundwater impacts associated with an inadvertent spill of fuel, oil, and other hazardous fluids, which include:

- pumps operating within 100 feet of a waterbody or wetland boundary would use appropriate secondary containment systems to prevent spills;
- bulk storage of hazardous materials, including chemicals, fuels, and lubricating oils have appropriate secondary containment systems to prevent spills;
- ensuring that each construction crew has on hand sufficient supplies of absorbent and barrier material to allow the rapid containment and recovery of spilled materials and knows the procedures for reporting spills and unanticipated discoveries of contamination;
- ensuring each construction crew has sufficient tools and materials to stop leaks; and
- implementing the training, inspection, loading and unloading, oil transfer, and security measures outlined in 40 CFR 112.

Because operational water use for the proposed Liquefaction Facilities would not affect groundwater availability, ground disturbances would generally be temporary and limited to the ground surface, erosion controls and storm water management would be implemented, and natural ground contours and vegetation would be restored, we conclude the Project would not result in any significant impacts on groundwater resources or users of groundwater in the Project area.

2.2.2 Surface Water

Existing Surface Water Resources

A total of 11 waterbodies were identified within the Project sites (see table 2.2.2-1).

<u>Surface Waters at the LNG Terminal</u>

The LNG Terminal property borders the Chesapeake Bay, which is the nation's largest estuary. The Chesapeake Bay watershed encompasses over 64,000 square miles and includes parts of New York, Pennsylvania, West Virginia, Maryland, and the District of Columbia. The MDE has designated the Chesapeake Bay as Use II – Support of Estuarine and Marine Aquatic Life and Shellfish Harvesting (Code of Maryland Regulations [COMAR] 26.08.02.02.B(3)). At the existing offshore pier, the Chesapeake Bay has been further classified into two special use subcategories: "Open Water Fish and Shellfish (Open Water)" and "Seasonal Deep Water Fish and Shellfish (Deep Water)."

TABLE 2.2.2-1

Impacts on Waterbodies within the Project Sites

State/County/Facility	Stream ID [a]	Stream Flow	Construction Impacts	Operation Impacts
MARYLAND				
Calvert County				
LNG Terminal	WUS1	Ephemeral	1,035 feet	1,035 feet
		Intermittent	115 feet	115 feet
Offsite Area A	WUS2	Perennial	-	-
	WUS3	Intermittent	-	-
	WUS4	Intermittent	102 feet	-
	WUS5	Intermittent	-	-
	WUS5A	Perennial	-	-
Offsite Area B	Patuxent River/ WUS6	Perennial	0.15 acre	-
VIRGINIA				
Fairfax County				
Pleasant Valley Compressor Station	WUS12	Intermittent	-	-
	WUS13	Intermittent	-	-
Pleasant Valley Suction/Discharge Pipelines	WUS14	Intermittent	-	-

[a] Stream IDs were assigned during DCP's field surveys.

The Chesapeake Bay is classified as impaired for its nutrient special use and biological life designations. At the existing offshore pier, the Chesapeake Bay does not support its aquatic life use classification due to its low biotic integrity scores and low dissolved oxygen concentrations. The existing LNG Terminal is not a source of nutrients to the Chesapeake Bay (MDE, 2012).

Freshwater stream WUS1 is within the Fenced Area of the LNG Terminal and is classified as ephemeral in its upper reach and intermittent as the stream leaves the Fenced Area. WUS1 is a tributary to Grays Creek, which is a tributary to the Chesapeake Bay.

The LNG Terminal is within the Middle Central Chesapeake Bay Mesohaline within the "02-13-10 West Chesapeake Bay Area" watershed, as designated by the MDE (COMAR 26.08.02.08), and Hydrologic Unit Code (HUC) watershed 12-020600040408, as designated by the USGS (2012f). The MDE has designated streams and tributaries located in and adjacent to the LNG Terminal as "Use I: Water Contact Recreation and Protection of Nontidal Warm Water Aquatic Life" (COMAR 26.08.02.02.B(1)).

Surface Waters at Offsite Area A

Two perennial and three intermittent streams were identified within Offsite Area A during field surveys in April and June 2012. These streams either flow north or south from Offsite Area A because the center of the site forms a slight hill crest. Offsite Area A is within the Lower Patuxent River Mesohaline reach of the Patuxent River within the "02-13-11 Patuxent River Area" watershed (MDE, COMAR 26.08.02.08), and HUC watershed 12-020600060603 (USGS, 2012f). The MDE has designated streams and tributaries located in and adjacent to Offsite Area A as "Use I: Water Contact Recreation and Protection of Nontidal Warm Water Aquatic Life" (COMAR 26.08.02.02.B(1)). There are no water quality issues of concern for the streams located on or adjacent to Offsite Area A (MDE, 2012).

Surface Waters at Offsite Area B

Offsite Area B is located along the Patuxent River near its confluence with the Chesapeake Bay. The Patuxent River is the largest and longest river entirely within Maryland, and provides a wide variety of commercial and recreation uses. No other waterbodies were identified at Offsite Area B.

Offsite Area B is within the same MDE- and USGS-designated watershed as Offsite Area A. The MDE has designated the Patuxent River as Use II – Support of Estuarine and Marine Aquatic Life and Shellfish Harvesting (COMAR 26.08.02.02.B(3)). At Offsite Area B, the Patuxent River has been further classified into three special use subcategories: "Migratory Spawning and Nursery," "Shallow Water Submerged Aquatic Vegetation," and "Open Water Fish and Shellfish Use." The segment of the lower Patuxent River in the vicinity of Offsite Area B is listed as impaired for fishing and aquatic life and wildlife because of high mercury and polychlorinated biphenyls (PCBs) concentrations in fish tissue, as well as low fish and benthic index of biotic integrity scores. There are no known sources of mercury or PCBs in the vicinity of Offsite Area B.

Offsite Area B is located within the Bay Critical Area, which is defined as all land within 1,000 feet of the mean high water line of tidal waters, the landward edge of tidal wetlands, and all waters of and lands under the Bay and its tributaries. Based on current Calvert County zoning maps, Offsite Area B is classified as a limited development area, which permits limited new or redevelopment of land within the Critical Area as long as water quality is not impacted and existing natural areas are conserved.

Surface Waters at the Pleasant Valley Compressor Station and Suction/Discharge Pipelines

Two intermittent streams are located at the Pleasant Valley Compressor Station, and one intermittent stream is crossed by the Pleasant Valley Compressor Station Suction/Discharge Pipelines. These three streams flow into Bull Run and are in the Potomac-Shenandoah watershed as designated by the VDCR and HUC watershed 12-020700100703 (USGS, 2012f). There are no water quality issues of concern for the streams on or adjacent to the Pleasant Valley Compressor Station or the Pleasant Valley Suction/Discharge Pipelines (Virginia Department of Environmental Quality (VDEQ) and VDCR, 2012)).

Surface Waters at the Loudoun M&R Facility

No waterbodies were identified within the Loudoun M&R Facility. However, one perennial stream channel is approximately 150 feet from the Loudoun M&R Facility. This perennial stream is a tributary to Howsers Branch, which is classified as "Class III—Nontidal waters (Coastal and Piedmont Zones)" (Virginia Administrative Code Title 9 Agency 25 Chapter 260 Section 390). All Virginia State waters are designated for recreational uses, and for the propagation and growth of a balanced, indigenous population of aquatic life, wildlife, and the production of edible and marketable natural resources. Howsers Branch is impaired for its designated use of recreation because of high *Escherichia coli* (*E. coli*) concentrations (VDEQ and VDCR, 2012). The Loudoun M&R Facility is in the Potomac-Shenandoah watershed as designated by the VDCR and HUC watershed 12-020700080701 (USGS, 2012f).

Surface Waters at the Leesburg Compressor Station Contractor Staging Area

No waterbodies were identified at the Leesburg Compressor Station Contractor Staging Area. This staging area is within the same MDE- and USGS-designated watershed as the Loudoun M&R Facility.

Sensitive Waterbodies

The Chesapeake Bay and Patuxent River are considered sensitive due to their designated impairments, fisheries and recreational uses, and the habitat they provide to estuarine aquatic and sensitive species. Howsers Branch, which is approximately 1.1 miles downstream of the Loudoun M&R Facility, is considered sensitive due to high *E. coli* concentrations. Project activities would not contribute to *E. coli* concentration levels in Howsers Branch.

None of the waterbodies within the Project areas are known to contain contaminated sediment (FERC, 2006; EPA, 1998).

Surface Water Use

There are no potable surface water intakes within 3 miles downstream of any waterbody identified within the Project sites. The nearest major surface water withdrawal to the LNG Terminal and Offsite Areas A and B is the large cooling water intake at the Calvert Cliffs Nuclear Power Plant approximately 4.0 miles north of the LNG Terminal.

Hydrostatic Testing

As stated in section 2.2.1, new piping and other equipment at the LNG Terminal, Pleasant Valley Compressor Station, the Pleasant Valley Suction/Discharge Pipelines, the Pleasant Valley M&R Facility, and the Loudoun M&R Facility would be hydrostatically tested to ensure its integrity before being placed into service. Once testing is complete, the test water would be transported to an appropriate wastewater treatment facility for disposal, or a permit would be obtained from the MDE or VDEQ to discharge test water.

The discharge of hydrostatic test water to a surface waterbody could result in erosion, increased turbidity, or changes in water temperature and oxygen levels. These impacts could in turn degrade aquatic habitat and result in injury or death to aquatic species located in receiving waters. However, no significant water quality impacts are anticipated as a result of discharge from hydrostatic testing because only new pipe free of chemicals or lubricant would be tested and no water additives would be used unless approved by the appropriate state agency. In addition, hydrostatic test water discharges must comply with state effluent limitations and general permit conditions, which typically require measures to restrict flow volumes or velocities and other protection measures. By implementing the hydrostatic testing procedures summarized above, and obtaining and complying with required state permits, we conclude that the impacts associated with hydrostatic test water withdrawal and discharge would be minor and temporary.

Impacts and Mitigation

During construction, clearing and grading of vegetation could increase erosion along stream banks. Alteration of the natural drainage or compaction of soils by heavy equipment near stream banks during construction may accelerate bank erosion and the transportation of sediment carried by overland flow into the waterbodies. The extent of the impact would depend on precipitation events, sediment loads, stream velocity, turbulence, stream bank composition, and sediment particle size, as well as the length of time that a disturbed area is not stabilized. Increased sediment loading and turbidity levels, reduced dissolved oxygen concentrations, stream warming, and introduction of chemical discharges from inadvertent spills of fuels/lubricants may also affect streams.

To minimize potential impacts on surface waters during construction, DCP would implement our Plan and Procedures and its E&SCPs, which conform to the MDE's 2011 Maryland Standards and

Specifications for Soil Erosion and Sediment Control and the VDCR's 1992, Third Edition, Virginia Erosion and Sediment Control Handbook. DCP would also implement its SMPs, which were designed to comply with the Calvert County Stormwater Management Ordinance, the MDE's *2000 Maryland Stormwater Design Manual (Revised 2009)*, and the VDEQ's stormwater management requirements. As previously stated, DCP would implement a Project-specific Spill Prevention and Contaminant Control Plan to minimize potential soil and water quality impacts associated with an inadvertent spill of fuel, oil, and other hazardous fluids.

DCP would implement the measures and plans described above at all the Project sites. Site-specific impacts not described above, and the measures DCP would implement to minimize site-specific impacts, are described in the following sections. No surface waters would be impacted at the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, Loudoun M&R Facility, or the Leesburg Compressor Station Contractor Staging Area.

LNG Terminal

Construction of the Liquefaction Facilities would permanently fill 971 feet of the upper reach of waterbody WUS1 and an additional 179 feet of WUS1 that flows through a culvert. DCP consulted with the COE which determined that no mitigation would be required for this impact as it falls below mitigation requirement thresholds. The loss of this stream segment would affect DCP's ability to control and manage stormwater within the existing Fenced Area of the LNG Terminal; however, DCP would implement site-specific SMPs and E&SCPs that are designed to control and manage stormwater at the site after construction of the Liquefaction Facilities. These plans have been submitted to Calvert County for review and approval. By implementing a site-specific SMP and E&SCP, we conclude that construction of the Liquefaction Facilities would not result in significant impact on surface water resources.

Several comments were received regarding the potential for the wake from LNG ships to erode the shoreline near the Cove Point lighthouse. As part of the Pier Reinforcement Project and Cove Point Expansion Project, DCP analyzed the potential for LNG vessels to contribute to shoreline erosion in the vicinity of the LNG Terminal and Cove Point lighthouse. We and the USCG concurred that the waves generated by LNG ships would not erode the Cove Point peninsula shoreline and would be within the normal range of waves due to wind and other boat and ship traffic.

Offsite Area A

DCP would maintain a 100-foot-wide non-disturbance buffer, delineated by two rows of super silt fence, spaced 3 to 4 feet apart, around all waterbodies within Offsite Area A with the exception of WUS4. DCP proposes to construct a temporary access road across intermittent stream WUS4 which would allow access to the western portion of Offsite Area A. DCP would install a bottomless culvert over WUS4 to minimize impacts on the stream channel while the temporary access road is in use. After Project activities are complete, DCP would remove the access road and bottomless culvert and restore the streambed, as necessary, to its original condition. In addition, DCP would plant trees adjacent to the stream according to the restoration plan that DCP prepared for Offsite Area A. As a result, no permanent impacts on waterbodies would occur at Offsite Area A. DCP submitted an application to the COE regarding impacts on WUS4. In a letter dated Aril 29, 2014, the COE authorized DCP's proposed activities at Offsite Area A, and DCP has stated it would comply with the conditions provided in the COE permit. By maintaining a 100-foot-wide buffer around all waterbodies, installation of the two rows of super silt fence around each buffer, implementing site-specific E&SCPs and SMPs, and complying with COE requirements, we conclude that surface water impacts at Offsite Area A would be temporary and adequately reduced.

Offsite Area B

The construction of the access road and parking/laydown at Offsite Area B could increase stormwater runoff to the Patuxent River. To minimize potential erosion and stormwater impacts, DCP would implement our Plan and Procedures and its SMPs and E&SCPs. DCP would also comply with the conditions of a COE section 10/404 Permit, a Maryland tidal Wetlands License and Water Quality Certification, and a Maryland general discharge permit for construction activities, which would further minimize potential erosion and stormwater impacts on the Patuxent River.

As described in section 1.7.3, DCP proposes to construct a temporary barge offloading pier that would extend 166 feet into the Patuxent River. The temporary pier would be up to 40 feet wide and supported by up to 24 hollow steel piles approximately 36 inches in diameter. DCP estimates that installation of the piles would take 15 days. Pier construction, pile driving, and pier removal could suspend river sediment, increase local turbidity, and produce acoustic waves that could impact aquatic species (section 2.2.3). During use of Offsite Area B, DCP estimates that 42 barge deliveries would be made to the pier over the course of 18 months, and propeller wash from the barge traffic could increase sedimentation and turbidity in the vicinity of the pier. The pier would be removed from the river at the conclusion of the Project, and Offsite Area B would be restored to its prior use. No river dredging is proposed for this Project and no permanent impacts would occur at Offsite Area B. Based on the relatively small scale of construction and limited incidence and duration of use, and by implementing measures to protect water quality, we conclude that construction and use of Offsite Area B would be temporary on the Patuxent River, and would be adequately minimized.

Ballast Water

The proposed Project would enable DCP to liquefy natural gas and transfer the LNG to ships for export. As discussed in section 1.2.1 DCP was authorized to receive 200 LNG ships at the LNG Terminal in the Cove Point Expansion Project EIS. However, DCP estimates that only 85 LNG vessels per year would call at the LNG Terminal for export as part of operation of the Liquefaction Facilities.

During the LNG transfer process, LNG ships would discharge ballast water to maintain a constant draft at berth. Ballast water is water that is collected and carried by ships to provide balance, stability, and trim during transport. Ballast water is typically pumped into ballast tanks when a ship has delivered a cargo to a port and is departing with less cargo weight. We received several comments regarding ballast water discharge and impacts on aquatic resources in the Chesapeake Bay. The discharge of ballast water from ships could potentially affect marine organisms through the unintentional introduction of non-indigenous aquatic organisms. LNG ships discharging ballast water must comply with several U.S. laws, regulations, and policies that establish a national mandatory ballast water management program for all vessels equipped with ballast water tanks that enter or operate within U.S. waters. These laws, regulations, and policies include:

- USCG regulations (33 CFR 151, subpart D);
- Nonindigenous Aquatic Nuisance Prevention and Control Act of 1990;
- National Invasive Species Act of 1996;
- National Aquatic Invasive Species Act of 2003;
- National Ballast Water Management Program;
- Navigation and Vessel Inspection Circular 07-04, Change 1; and
- Shipboard Technology Evaluation Program.

The USCG has inspection and regulatory enforcement jurisdiction over all shipping in U.S. waters. To minimize and avoid potential impacts on wildlife species that could result from ballast water discharges, the USCG implements mandatory ballast water management requirements for all ships entering U.S. waters from outside the Exclusive Economic Zone of the U.S. and has developed and enforces a nationwide Ballast Water Management Program. Under the current Ballast Water Management Program, international ships entering U.S. ports and intending to discharge ballast water must either carry out ballast water exchange at least 200 nautical miles offshore or retain ballast water on board. The USCG recently approved new rules (Federal Register Vol. 77, No. 57) that outline standards for eliminating various sizes and concentrations of organisms in discharged ballast water. These new standards must be achieved by shippers in a phased timeframe. For newly constructed ships, the new rules became effective in December 2013. For existing vessels greater than 5,000 cubic meters ballast water capacity, the new rules become effective in 2016, which is prior to the in-service date of the proposed Project. The new rules and discharge standards provide more consistent control over the concentrations of organisms than the current ballast water exchange program and would significantly minimize the introduction and establishment of nonindigenous species. However, we acknowledge the potential still exists for nonindigenous species to be introduced into the Chesapeake Bay during ballast water discharges.

Every vessel has the potential to transport invasive species on its hull. The USCG has developed responses to exotic/invasive species associated with foreign vessels and its Office of Operating and Environmental Standards developed Mandatory Practices for All Vessels with Ballast Tanks on All Waters of the United States. The mandatory practices include requirements to rinse anchors and anchor chains during retrieval to remove organisms and sediments at their place of origin and to remove fouling organisms that may be affixed to ship hulls, piping, and tanks. The removal of organisms would be conducted on a regular basis and the disposal of any removed substances would be in accordance with local, state, and federal regulations. However, we acknowledge the potential still exists for nonindigenous species to be introduced into the Chesapeake Bay by ship hull transport.

Depending on the source of the ballast water, discharged ballast water could have a higher or lower salinity than the Chesapeake Bay. Salinity at the existing offshore pier ranges between 5 and 18 parts per thousand (ppt) depending on tidal influences and water flows volumes. More dense, higher salinity discharges would sink to the bottom of the Chesapeake Bay and naturally mix with the lower density water in the Chesapeake Bay. Conversely, lower salinity discharges would remain at the surface of the Chesapeake Bay and naturally mix with the higher density waters of the Chesapeake Bay.

Dissolved oxygen levels in the discharged ballast water may differ from the ambient dissolved oxygen levels in the Chesapeake Bay. Dissolved oxygen levels are an important aspect of the respiration of aquatic marine organisms. Dissolved oxygen levels in water can be influenced by many factors including water temperature, water depth, phytoplankton, wind, and current. In a water column profile, there is a direct correlation in a decrease in dissolved oxygen relating to an increase in depth. Factors that influence this stratification include sunlight attenuation for photosynthetic organisms that can produce oxygen, wind, wave, and current that results in mixing.

The introduction of ballast water would not significantly affect water temperature and pH levels in the Chesapeake Bay. Because ballast water is stored in the ship’s hull below the waterline, water temperatures would not deviate much from ambient temperatures of the Chesapeake Bay. The pH of the ballast water may vary slightly from that of the Chesapeake Bay.

The potential variation of salinity, dissolved oxygen, water temperature, and pH between the ballast water and the Chesapeake Bay would not have discernable impacts on water resources or existing aquatic organisms. Additionally, compliance with laws, regulations, and policies regarding ballast water discharges would minimize potential impacts on the Chesapeake Bay, including the introduction of nonindigenous species. Therefore, ship traffic and ballast water discharges would not have any noticeable, long-term impact on the Chesapeake Bay or aquatic resources beyond those that have already occurred within the Chesapeake Bay.

2.2.3 Fisheries Resources

Existing Fisheries Resources

Freshwater fishery resources in the vicinity of the Project are limited to warm water habitats. No coldwater or coolwater fisheries are near the Project. Warmwater fish species within and downstream of the Project areas generally include small fishes such as darters, shiners, and dace. The Patuxent River and the Chesapeake Bay provide estuarine habitat for a variety of warmwater and anadromous fish, as well as shellfish such as oysters and crabs. Aquatic species at each Project site are described below.

<u>LNG Terminal</u>

The existing offshore pier is located approximately 1.1 miles from the Chesapeake Bay shoreline. Approximately 350 warmwater and anadromous fish species, including commercial and recreational fish and game species, are known to occur in the Chesapeake Bay (Chesapeake Bay Program, 2012). Many of these species occur at some location or season in the waters near the offshore pier. The offshore pier provides shade and hard structure habitat for fish and prey species in the Chesapeake Bay and, therefore, fish congregate in greater numbers near the pier. Fishing is not permitted at any time within the 500-yard safety and security zone around the offshore pier.

Oyster and crab populations are stressed within the Chesapeake Bay and receive special management attention from Maryland and Virginia. The existing offshore pier is generally in water too deep to support oysters, which prefer habitat from 8 to 35 feet deep (Chesapeake Bay Program, 2008). Although oysters are stocked throughout the Chesapeake Bay, the nearest natural oyster bars are about 1.5 miles north of the offshore pier (MDNR, 2012). The blue crab is found in shallow Chesapeake Bay water during the warmer months and in deeper water (greater than 30 feet) during the winter months (MDNR, 2012; Schaffner and Diaz, 1988). Because blue crabs prefer shallow habitat during the warmer months, it is likely that they are only found near the offshore pier during the winter months.

Stream WUS1 within the Fenced Area of the LNG Terminal does not support fish populations.

<u>Offsite Area A</u>

Offsite Area A includes two perennial stream (WUS2 and WUS5A) and three intermittent streams (WUS3, WUS4, and WUS5). WUS2 could support small populations of creek chubsucker, Eastern mud minnow, Eastern mosquito fish, tessellated darter, and blacknose dace (Hook and Bullet, 2012). Stream WUS5, a tributary of Hellen Creek, could support small fish populations during periods of flow. WUS3, WUS4, and WUS5A do not support fish populations.

<u>Offsite Area B</u>

The Patuxent River supports approximately 75 species of fish, including several recreational and commercial species. Construction of the temporary pier would take place in shallow shoreline waters between 0 and 30 feet in depth. Several fish species, including commercial and recreational species, could be present near the proposed pier. Waters near the pier also support oyster beds and provide blue crab habitat during warmer months. In addition, the temporary pier at Offsite Area B would be within a Natural Oyster Bar in the Patuxent River.

Other Facilities

No streams or aquatic habitat would be impacted at the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, Loudoun M&R Facility, or the Leesburg Compressor Station Contractor Staging Area.

Managed Fish Species and Essential Fish Habitat

Essential Fish Habitat (EFH) is defined as “those waters and substrate necessary to fish for spawning, breeding, feeding, or growth to maturity” (16 USC 1802 (10)). Under the Magnuson-Stevens Fishery Conservation and Management Act, federal action agencies that fund, permit, or carry out activities that may adversely affect EFH are required to consult with National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NMFS) regarding potential adverse impacts of their actions on EFH, and respond in writing to any NMFS and Fishery Management Council conservation recommendations. Although absolute criteria have not been established for conducting EFH consultations, NMFS recommends consolidation of EFH consultations with interagency coordination procedures required by other statutes, such as NEPA, in order to reduce duplication and improve efficiency.

According to the NMFS Guide to Essential Fish Habitat Designations in the Northeastern United States, EFH has been designated in the Chesapeake Bay and in the Patuxent River for nine managed fish species. The life stages for these managed fish are presented in table 2.2.3-1.

TABLE 2.2.3-1

NMFS Managed Fish Species Near the LNG Terminal and Offsite Area B

	Life Stages [a]			
Species	Eggs	Larvae	Juvenile	Adult
Windowpane flounder (*Scopthalmus aquosus*)			C, P	C, P
Bluefish (*Pomatomus saltatrix*)			C, P	C, P
Atlantic butterfish (*Peprilus triacanthus*)	C	C	C	C
Summer flounder (*Paralicthys dentatusi*)		C, P	C, P	C, P
Black sea bass (*Centropristus striata*)			C	C
King mackerel (*Scomberomorus cavalla*)	C, P	C, P	C, P	C, P
Spanish mackerel (*Scomberomorus maculates*)	C, P	C, P	C, P	C, P
Cobia (*Rachycentron canadum*)	C, P	C, P	C, P	C, P
Red drum (*Sciaenops occelatus*)	C, P	C, P	C, P	C, P

[a] C = Life stage for the managed fish species is present in the Chesapeake Bay near the existing offshore pier.
P = Life stage for the managed fish species is present in the Patuxent River near Offsite Area B.
Source: http://www.nero.noaa.gov/hcd/est.htm#MARYLAND

Impacts and Mitigation

Construction impacts on fisheries resources may include direct contact by construction equipment with fish and other aquatic organisms; alteration or removal of adjacent riparian vegetation and aquatic habitat cover; introduction of pollutants; and an increase in sedimentation and turbidity. These impacts would result from the permanent filling and diversion of streams, the temporary loss of riparian vegetation, and an increase of impervious surfaces and stormwater runoff. Sediment loading and turbidity within and immediately downstream of work areas has the greatest potential to impact aquatic resources.

With the exception of the Patuxent River, no stream known to contain fisheries resources would be directly impacted by Project activities. DCP's commitment to buffer wetlands and waterbodies at Offsite Area A and implement our Plan and Procedures, its SMPs and E&SCPs, and comply with applicable state and federal permits, would further minimize potential impacts on any fisheries resources within or downstream of the Project area. As recommended by the Reviewing State Agencies in their recommended license conditions for Maryland's CPCN, DCP would not conduct in-water work at Offsite Area A between March 1 and June 15 of any year to protect spawning resident and anadromous fish.

Construction and use of the temporary pier in the Patuxent River at Offsite Area B could suspend river sediment, increase local turbidity, and produce acoustic waves that could impact aquatic species. As discussed in section 2.2.2, pile installation using a vibratory hammer would be completed in approximately 15 days, and approximately 42 barge trips would be required to delivery materials to the Project site over an 18 month period. If impact hammering is necessary to achieve sufficient pile depth, DCP would utilize internal strike cushions to ensure pile driving stays within sound limits specified by NMFS. As recommended by the Reviewing State Agencies in their recommended license conditions for Maryland's CPCN, DCP would not conduct work within the Patuxent River between December 16 and March 14 and between June 1 and September 30 of any year. Additionally, NMFS has concluded that the Project would not impact federally listed species within the Chesapeake Bay or Patuxent River (see section 2.3.3).

Recent field studies by MDNR and DCP indicated that the maximum anticipated area of impact on the Natural Oyster Bar associated with Offsite Area B would be approximately 2 acres. Based on the Reviewing State Agencies' recommended license conditions, DCP agreed to prepare and implement an Oyster Bar Mitigation Plan that would restore hard bottom and plant oyster shells in the vicinity of temporary barge pier. As part of the plan, DCP has agreed to provide 4 acres planting of spat-on-shell as mitigation for the Project (2:1 compensation), and would support additional surveys of the Natural Oyster Bar. DCP would also not conduct work within the Patuxent River between December 16 and March 14 and between June 1 and September 30 of any year, as recommended by the Reviewing State Agencies in their recommended license conditions for the CPCN. DCP provided its draft Oyster Bar Mitigation Plan to the MDNR on March 28, 2014. Additionally, DCP has agreed to prepare and implement an artificial reef development plan that would utilize suitable construction waste materials to generate an artificial reef near Offsite Area B. These plans would be reviewed and approved by the MDNR and other applicable agencies prior to implementation. In addition, **we recommend that:**

- **DCP should file the final Oyster Bar Mitigation Plan, approved by the MDNR, and artificial reef development plan <u>before implementation of the plans</u>.**

Based on the scale of construction and limited incidence and duration of use, and by implementing measures to protect aquatic resources, we determined that construction and use of Offsite Area B would result in temporary impacts on the Patuxent River and aquatic resources, and would be adequately minimized.

NMFS indicated that juvenile and adult summer flounder and bluefish are the managed species of concern for the Project (Nichols, 2012). DCP submitted an EFH Assessment to NMFS on December 17, 2012. The assessment concluded that the proposed action would not have a substantial adverse effect on EFH or species with designated EFH in the Project area; direct, secondary, and cumulative impacts on EFH and associated species would be minimal; and the Cove Point Liquefaction Project would comply with the Magnuson-Stevens Fishery Conservation and Management Act. On February 25, 2013, NMFS stated it has no concerns with the finding of the assessment. Upon reviewing relevant fisheries information and analyzing potential fisheries impacts, we conclude that the Project would not significantly affect EFH or managed fish species.

We concluded in section 2.2.2 that ballast water discharges associated with operation of the Liquefaction Facilities would not have any noticeable, long-term impacts on the Chesapeake Bay or aquatic resources. Additionally, DCP's EFH Assessment concluded that ballast water discharges would only have a temporary, minor effect on local water quality, and NMFS had no concerns with this finding. Because no in-water work is proposed at the existing offshore pier and LNG ship traffic would not exceed the previously approved vessel frequency as a result of this Liquefaction Project, we conclude that the Project would have no substantial impact on managed species, EFH, or other aquatic species in the Chesapeake Bay.

2.2.4 Wetlands

Existing Wetland Resources

DCP delineated wetlands within the Project areas using the COE's Wetlands Delineation Manual (COE, 1987), the Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Northcentral and Northeast Region (COE, 2011), and the Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Eastern Mountains and Piedmont Region (COE, 2012). Wetlands were classified according to Cowardin et al. (1979). Plant species identified during wetland surveys included an overstory of red maple, sweetgum, black gum, and sweetbay magnolia. Understory species included highbush blueberry, common spike rush, false nettle, soft rush, green bulrush, shallow sedge, sensitive fern, lizard tail, and coastal sweet pepperbush.

<u>LNG Terminal</u>

One wetland (Wetland 1) was delineated within the Fenced Area at the LNG Terminal. Wetland 1 is located directly below the outfall of an existing stormwater pond on the western portion of the Fenced Area. Wetland 1 appears to receive the majority of its hydrology from the stormwater pond as well as the surrounding steep slopes, and may act as the headwaters of an intermittent stream channel that is offsite to the west.

<u>Offsite Area A</u>

Seven wetlands (Wetlands 2 – 8) were identified at Offsite Area A, all of which receive their hydrology from groundwater seeps. Wetlands 2 and 3 are located on the westernmost portion of the site. Wetland 4 is a large wetland complex consisting of multiple groundwater wetland seeps along stream WUS4. Wetland 5 is a small isolated depression near the center of the site and receives hydrology from both surface runoff and groundwater. Wetland 6 originates as a groundwater seep on the southwest corner of the site and drains to Wetland 2. Wetland 7 consists of wetland seeps along stream WUS5. Wetland 8 is a large wetland complex which receives hydrology from a system of groundwater seeps along stream WUS5A.

<u>Offsite Area B</u>

The shoreline of the Patuxent River (WUS6) from the mean high tide and the streambed of the river is classified as tidal wetland (COMAR 26.24.01.02-52). The shoreline comprises sand and large angular rock with no vegetation. The remaining portion of Offsite Area B site is on uplands, and no other wetland areas would be impacted according to the site plan designs submitted by DCP on August 1, 2013.

Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility

One wetland is within the Pleasant Valley Compressor Station site. Wetland 18 is along the eastern bank of stream WUS13 on the eastern portion of the site.

One wetland would be crossed by the Pleasant Valley Suction/Discharge Pipelines. Wetland 17 is along the existing gravel site access road and continues off-site to the south across the existing utility right-of-way. The wetland appears to receive the majority of its hydrology from streams WUS13 and WUS14, as well as surficial runoff from the surrounding uplands.

No wetlands are present at the Pleasant Valley M&R Facility.

Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area

There are no wetlands within the proposed construction workspace at the Loudoun M&R Facility or the Leesburg Compressor Station Contractor Staging Area.

Impacts and Mitigation

The Project would temporarily impact less than 0.09 acre of emergent wetland, 0.23 acre of forested wetland, and less than 0.01 acre of subtidal estuarine wetland; and would permanently affect 0.06 acre of forested wetland. Wetland impacts for the Project are summarized in table 2.2.4-1.

TABLE 2.2.4-1

Summary of Wetlands Affected by the Project

County/State/Facility	Wetland ID	Cowardin Classification [a]	Wetland Size (acre)	Construction Impacts	Operational Impacts
Calvert County, Maryland					
LNG Terminal	Wetland 1	PFO	0.06	0.06	0.06
Offsite Area A	Wetland 2	PEM/PFO	0.64	-	-
	Wetland 3	PEM/PFO	0.06	-	-
	Wetland 4	PFO	5.07	0.17	-
	Wetland 5	PFO	0.03	-	-
	Wetland 6	PEM/PFO	0.50	-	-
	Wetland 7	PFO	0.72	-	-
	Wetland 8	PFO	0.76	-	-
Offsite Area B	WUS6	E1UBL	<0.01	<0.01	-
Fairfax County, Virginia					
Pleasant Valley Suction/Discharge Pipelines	Wetland 17	PEM	0.11	0.02	-
Pleasant Valley Compressor Station	Wetland 18	PFO	0.06	-	-
	Wetland 17	PEM	0.11 [b]	0.07	-
		Project Total:	**8.01**	**0.32**	**0.06**

a PEM = Palustrine emergent wetland
PFO = Palustrine forested wetland
E1UBL = Estuarine subtidal unconsolidated bottom wetland

b Wetland 17 would be temporarily impacted by construction at the Pleasant Valley Compressor Station and the Pleasant Valley Suction/Discharge Pipelines. The acreage of Wetland 17, 0.11 acre, is added only once in the Project total wetland size.

Construction and operation of the Liquefaction Facilities would result in the permanent loss of 0.06 acre of forested Wetland 1. Through consultation with the COE, it was determined that mitigation would not be required for this wetland loss. In a letter dated April 29, 2014, the COE confirmed that the permanent wetland fill at the Liquefaction Facilities is authorized under the Maryland State Programmatic General Permit-4.

Installation of the internal access road at Offsite Area A would temporarily impact 0.17 acre of emergent Wetland 4. DCP would maintain a 100-foot construction buffer around the remaining wetlands at Offsite Area A, delineated by two rows of super silt fence, spaced 3 to 4 feet apart. DCP would remove the access road once Offsite Area A is no longer required for the Project and restore Wetland 4 to its pre-construction condition. DCP submitted a joint permit application to the COE and MDE in April 2013 to obtain approval to temporarily impact Wetland 4. In a letter dated April 29, 2014, the COE confirmed that the temporary wetland impact at Offsite Area A is authorized under the Maryland State Programmatic General Permit-4.

Installation of the piles at the offloading pier would temporarily fill less than 0.01 acre of tidal wetland along the Patuxent River shoreline. Upon completion of the Project, the pier and piles would be removed and the tidal wetland and shoreline would be restored to original conditions. DCP submitted a joint permit application to the COE and MDE in April 2013 to obtain approval to construct the temporary pier. In a letter dated April 29, 2014, the COE provided its authorization of the pier installation based on current water depths, and specified that propeller dredging is not authorized.

Construction of the Pleasant Valley Compressor Station would temporarily impact 0.07 acre of Wetland 17, while installation of the Pleasant Valley Suction/Discharge Pipelines would temporarily affect 0.02 acre of Wetland 17. Wetland 17 would be restored following construction activities at the compressor station and pipeline. DCP submitted a joint permit application to the COE and VDEQ in April 2013 to obtain approval to temporarily impact Wetland 17. On October 18, 2013, the COE provided written concurrence that the temporary impacts on wetland 17 satisfy the criteria of Nationwide Permit #12. Because the COE approved the activities under its nationwide permit program, the VDEQ stated is would not issue a permit for the Project, and 401 water quality certification is granted through the COE's nationwide permit program.

DCP would minimize wetland impacts by implementing best management practices in our Procedures and its SMPs and E&SCPs, as well as obtaining and complying with all necessary COE and state permits regarding wetland impacts. We conclude wetland impacts would be small in nature and would be minimized appropriately by implementing the construction, restoration, and mitigation measures proposed by DCP and required by the COE and state agencies through the joint permit application process.

2.3 VEGETATION AND WILDLIFE

2.3.1 Vegetation

Existing Vegetation Resources

Existing upland vegetation resources were documented during environmental field surveys conducted in 2012. Major upland cover types affected by the Project include upland forest and open land. A description of the upland forest and open land vegetation types affected by the Project is provided in table 2.3.1-1. Wetland vegetation communities that would be affected by the Project are discussed in section 2.2.4.

The primary vegetation cover type that would be affected by the Project is upland forest. This community covers about 81 percent of the affected Project area, mostly at Offsite Area A. The remainder of the Project would affect mowed/maintained upland (14 percent), old field/pioneer (3 percent), and upland successional woodland (2 percent). Table 2.3.1-2 summarizes the approximate acreage of upland vegetation communities that would be affected by the Project.

TABLE 2.3.1-1

Upland Vegetation Cover Types Found within the Project Area

Vegetation Community	General Description	Common Species	Location of Vegetation Community
Upland Forest	Tulip Poplar Forest	Forest type dominated by American holly, black cherry, black gum, common pawpaw, and ironwood.	Fenced Area
	Mixed Oak Forest	Forest type dominated by white oak, chestnut oak, northern red oak, black oak, and scarlet oak.	Fenced Area, Offsite Area A
	American Beech/Red Maple Forest	Forest type dominated by American beech, red maple, and tulip poplar.	Offsite Area A
	Virginia Pine Forest	Forest type dominated by Virginia pine, sweetgum, tulip poplar, American holly, American beech, black oak, common greenbrier, Virginia pine, lowbush blueberry, sassafras, and mountain laurel.	Offsite Area A
	Oak-Hickory Forest	Forest type dominated by white oak, chestnut oak, northern red oak, tulip poplars, black gum, and southern red oak.	Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Loudoun M&R Facility
	Successional Woodland	Consists of very young forest that may eventually mature into a deciduous species dominated forest.	Offsite Area A, Offsite Area B
Open Land	Old Field/Pioneer	Vegetation dominated by Chinese bush-clover, bull thistle, Japanese bristlegrass, yellow fox tail, crabgrass, sweetgum, broomsedge bluestem, tall prairie grass, and common blackberry.	Fenced Area Offsite Area A, Offsite Area B, Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Loudoun M&R Facility, Leesburg Compressor Station Contractor Staging Area
	Mowed/Maintained Upland	In industrial facilities, vegetation consists primarily of maintained lawns and a limited amount of scrub-shrub communities.	Offsite Area B, Pleasant Valley Compressor Station, Leesburg Compressor Station Contractor Staging Area

[a] General habitat characterization is based on the categorization by Maryland's State Forest Conservation Technical Manual (Third Edition 1997).

Vegetation Communities of Special Concern or Value

Seven specimen trees as designated by the MDNR were identified during field studies at Offsite Area A. DCP has designed the workspace at Offsite Area A to include 100-foot-wide setbacks from sensitive resources including specimen trees. DCP would delineate the 100-foot buffers with double rows of super silt fence, separated by 3 to 4 feet. Therefore, no specimen trees would be impacted by the Project.

St. Paul's Branch, on the eastern side of Offsite Area A, flows into Hellen Creek and is upstream of Hellen Creek Hemlock Preserve, an isolated stand of Canadian hemlock that is the southernmost hemlock forest of the eastern United States. Some species of plants and animals found within this preserve are more typical of Appalachian forest.

The Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, and Pleasant Valley M&R Facility are within the 1,680-acre Elklick Diabase Flatwoods Conservation Site.

Conservation sites designate geographic areas where one or more rare plant, animal, or natural communities are known to occur and may require additional review for potential conservation action. The Elklick Diabase Flatwoods Conservation Site has been ranked as a site of very high significance (B2) due to the potential for species of concern to occur including Torrey's mountain-mint, grove sandwort, and purple milkweed. These species were not observed during surveys conducted at the facilities in the summer and fall of 2012 or the spring of 2013 (section 2.3.3).

TABLE 2.3.1-2

Project Impacts on Upland Vegetation (acres)

	Upland Forest		Mowed/Maintained Upland		Old Field/Pioneer		Upland Successional Woodland	
State/Project Site	Const. [a]	Oper. [b]	Const. [a]	Oper. [b]	Const. [a]	Oper. [b]	Const. [a]	Oper. [b]
Maryland								
Fenced Area	11.8	11.4	0.0	0.0	1.7	1.7	0.0	0.0
Offsite Area A	94.0 [c]	0.0	0.0	0.0	0.0	0.0	1.9	0.0
Offsite Area B	0.0	0.0	5.7	0.0	0.0	0.0	0.2	0.0
Virginia								
Pleasant Valley Compressor Station	6.7	0.3	6.3	1.9	2.8	0.1	0.0	0.0
Pleasant Valley Suction/ Discharge Pipelines and M&R Facility	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0
Loudoun M&R Facility	<0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Leesburg Compressor Station Contractor Staging Area	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0
Project Total	**113.4**	**11.7**	**19.9**	**1.9**	**4.6**	**1.8**	**2.1**	**0.0**

a Const. = Construction Impacts. Includes impacts associated with all areas within the construction workspace limits. This includes the total of the existing pipeline right-of-way, new permanent pipeline right-of-way, temporary workspace areas, additional temporary workspace areas, and staging areas.

b Oper. = Operational Impacts. Includes impacts associated with the permanent clearing or removal of vegetation to construct Project facilities.

c Based on information provided by DCP to the FERC; however, the Maryland DNR has stated that DCP would affect 93.6 acres of upland forest at Offsite Area A. The final area affected would be confirmed prior to construction.

Construction and operation impacts are not cumulative.

The Elklick Diabase Flatwoods Conservation Site is also considered important due to the potential presence of habitat types of concern including the Piedmont Upland Depression Swamp, Northern Hardpan Basic Oak-Hickory Forest, and Northern Piedmont Mafic Barren. Summer and fall surveys in 2012 determined these habitats were not present at the Pleasant Valley Compressor Station site or the Pleasant Valley Suction/Discharge Pipelines. DCP has consulted with the VDCR and Virginia Department of Agriculture and Consumer Services (VDACS) regarding the potential presence of the Northern Hardpan Basic Oak-Hickory Forest. The VDCR confirmed that the forest community at the Pleasant Valley Compressor Station site represents an acidic oak-hickory forest and, as such, the Project would not affect significant forest communities of concern (VDCR, 2013).

Impacts and Mitigation

Upland Forest and Woodland

The greatest impact on vegetation would be the clearing of forested areas because of the length of time required for woody vegetation to revert to its preconstruction condition. The removal of mature trees could also increase erosion potential, decrease the quality of habitat for forest wildlife species, and result in an increased opportunity for invasive plants to displace native species. As presented in table 2.3.1-2, approximately 113 acres of upland forest and 2 acres of early successional woodland would be removed by construction of the Project. The amount of forest that would be removed at the LNG Terminal and Offsite Area A represents approximately 0.1 percent of the 81,000 acres of forest in Calvert County. Operation of the Project would result in the unavoidable, permanent loss of 11.5 acres of upland forest, including 11.2 acres within the Fenced Area at the LNG Terminal and 0.3 acre within the boundary of the Pleasant Valley Compressor Station. DCP stated that it would donate the 100-acre privately held portion of Offsite Area A to Calvert County and would not utilize the site after construction of the Liquefaction Facilities is complete. Calvert County has not yet determined the final deposition of the property. The county has stated that the property would be replanted following construction, and would not be intensely or commercially developed. If the property is allowed to revert to its previous forested condition, impacts on forest resources would be long term due to the time required for the area to reforest. Any portions of Offsite Area A that are developed would be permanently impacted. Further discussion about Offsite Area A restoration is provided below.

To minimize impacts on forest areas that would be cleared for construction, DCP would implement measures outlined in our Plan and Procedures and its E&SCPs including the installation of erosion control measures following initial disturbance of the soil and topsoil removal and segregation. Following construction, DCP would seed all disturbed areas in accordance with written recommendations for seed mixes, rates, and dates obtained from the local soil conservation authority or as requested by landowners. DCP proposes to plant suitable upland and wetland tree species, along with suitable herbaceous vegetation, adjacent to stream WUS4 according to the restoration plan that was submitted for Offsite Area A. In accordance with our Plan, DCP would monitor disturbed areas to determine the post-construction revegetative success for a minimum of two growing seasons, and continue revegetation efforts until revegetation is successful.

DCP would implement the measures in its Invasive Species Management Plans during construction and restoration of Project facilities in Maryland and Virginia. The plans identify existing invasive species at the Project sites and describe measures to prevent and control the spread of invasive plant species in areas disturbed by construction. The plans also include measures to monitor and control invasive species following construction. We reviewed DCP's Invasive Species Management Plans and find them acceptable.

In Maryland, the Forest Conservation Act was enacted in 1991 to minimize the loss of Maryland's forest resources during land development. The Act provides steps to identify and protect forests and other sensitive areas as part of a site planning process. DCP submitted Forest Conservation Plans for the LNG Terminal site and Offsite Area A to Calvert County for review. At the LNG Terminal, DCP proposes to mitigate the loss of forest within the Fenced Area through the Calvert County fee-in-lieu program or the purchase of transferrable development rights. The Forest Conservation Plan for the LNG Terminal site was approved by Calvert County on December 6, 2013. At Offsite Area A, DCP configured the workspace to preserve approximately 74 acres of forest, exceeding Calvert County's minimum preservation requirement of 61 acres; therefore, DCP would not be required to mitigate for forest impacts under the Forest Conservation Act. The Forest Conservation Plan for Offsite Area A was approved by Calvert County on January 9, 2014. Although DCP would not be required to mitigate for forest impacts at Offsite Area A, DCP developed a Forest Preservation Plan for Offsite Area A that describes several mitigation and preservation proposals to offset the temporary and permanent loss of forest land. As currently proposed, DCP would mitigate for forest impacts by:

- working with Calvert County to replant trees where appropriate at Offsite Area A;

- preserving an additional 13.5 acres of forest beyond the 73 acres that are currently being conserved at Offsite Area A;
- preserving in perpetuity Offsite Area E and arranging for 88.8 acres of forest at Offsite Area E to be designated as Forest Retention Area;
- purchasing 88 transferrable development rights from landowners in Calvert County to be applied to the Offsite Area E property;
- purchasing and preserving in perpetuity the 26.2-acre Barrett Site;
- preserving in perpetuity the 9.6-acre DOH site; and
- planting 15 acres of trees and additional sites within or adjacent to Calvert County.

By minimizing tree clearing to the extent necessary, replanting trees after construction, and mitigating temporary and permanent tree clearing impacts in coordination with the MDNR and Calvert County, we conclude that forest and woodland habitats would not be significantly impacted by the Project. DCP provided its draft Forest Preservation Plan for Offsite Area A to the MDNR on March 28, 2014. This plan would be reviewed and approved by the MDNR and other applicable agencies prior to implementation. However, to document that the Forest Preservation Plan for Offsite Area A has been completed as described above to offset the temporary and permanent loss of forest land at Offsite Area A, **we recommend that:**

- **<u>Prior to the use of Offsite Area A</u>, DCP should file the final Forest Preservation Plan for Offsite Area A, approved by the MDNR.**

<u>Open Land</u>

Approximately 20 acres of mowed/maintained land and 4.5 acres of old field/pioneer land would be impacted by construction of the Project. In general, the impact on remaining open land vegetation that would be removed from the construction work area would be considered short term. After cleanup and reseeding of the Project areas, the herbaceous components of the cover type would typically regenerate quickly considering the ample annual rainfall in the region. Aside from the permanent impacts noted in table 2.3.1-2, impacts on these cover types during facility operation would be minor because these cover types would be allowed to reestablish and would not be significantly altered by facility maintenance activities.

Conclusion on Vegetation

Because DCP would implement measures contained in our Plan and Procedures and its E&SCPs and Invasive Species Management Plans, and would comply with state and local forest preservation and mitigation requirements, we conclude that vegetation impacts from constructing and operating the Project would be adequately minimized.

2.3.2 Wildlife

Existing Wildlife Resources

The Project would cross upland and wetland habitats that support a diversity of wildlife species. Wildlife species are directly dependent on the existing vegetation communities and are attracted to an area if suitable cover and/or habitat are present. As described in sections 2.2.4 and 2.3.1, the proposed facilities would cross several distinct wetland and upland vegetation communities. Each of these vegetation communities provides nesting, cover, and foraging habitat for a variety of wildlife species. Impacts on fisheries resources are described in section 2.2.3.

Upland Forest

The upland forests in the Project area provide moderate to high quality habitat for a variety of mammals, birds, amphibians, reptiles, and invertebrates. The predominance of oak is an important habitat component in upland forests in the Project area. Some mammals rely directly on oak mast as a food source, while amphibians and invertebrates rely on the soil chemistry of an oak forest. Predatory species, such as raptors and red fox are also attracted to oak-dominated forests and their edges due to the abundance and diversity of prey species. The tree and shrub layers provide food and cover for birds and larger mammals, such as white-tailed deer and wild turkey. Detritus on the forest floor provides food and cover for invertebrates, amphibians, reptiles, and smaller mammals, such as skunk, opossum, raccoons, squirrel, groundhogs, eastern chipmunk, and other rodents.

Old Field

Old field habitat at the LNG Terminal, Pleasant Valley Compressor Station, and Loudoun M&R Facility generally provide poor to moderate wildlife habitat. Birds rely on open fields and maintained utility rights-of-way for nesting and foraging, while mammals may utilize old field habitat as foraging and denning habitat. Open fields also provide habitat for smaller species such as mice, rabbits, and voles, which makes this vegetation community prime hunting grounds for predator species such as foxes and raptors.

Mowed/Maintained Areas

Mowed and maintained land at Offsite Area B, the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, and Leesburg Compressor Station Contractor Staging Area tend to provide minimal habitat for wildlife species. Wildlife diversity is often limited to species that are adapted to human presence and the associated anthropogenic changes to the landscape, such as paved and landscaped areas.

Wetlands

Wetlands provide a diverse assemblage of vegetation and an abundance of food and water sources for wildlife. Mammals such as mink, muskrat, raccoon, and white-tailed deer use these areas as foraging habitat. Many waterfowl and wading birds use wetlands and adjacent riparian habitat for nesting and foraging. Wetland communities are also vital habitat for many reptiles and amphibians.

Wildlife Habitat of Special Concern or Value

Portions of Offsite Area A and forest immediately adjacent to the Fenced Area of the LNG Terminal are designated by Calvert County as Forested Interior Dwelling Species (FIDS) habitat. FIDS habitat consists of areas where interior forest is more than 300 feet from a forest edge. Delineation of FIDS habitat is based on the existence of forests greater than 50 acres and riparian corridors greater than 300 feet wide (Chesapeake Bay Critical Area Commission, 2000). FIDS habitat is important to many wildlife species, including bird species that can only reproduce in forest interiors, including the scarlet tanager, barred owl, pileated woodpecker, and whip-poor-will (Chesapeake Bay Critical Area Commission, 2000).

Impacts and Mitigation

Potential impacts on wildlife from the Project include the temporary displacement of wildlife from the Project areas, and potential permanent displacement of wildlife from vegetated areas that are permanently lost. It is expected that most wildlife, such as birds and larger mammals, would temporarily relocate to adjacent available habitat as construction begins. This displacement could increase competition between species for forage, cover, and nesting habitat. Construction could result in the mortality of less mobile animals such as small rodents, reptiles, amphibians, and invertebrates, which may be unable to escape the immediate construction area. To minimize this potential, DCP would conduct the clearing of Offsite Area A in 20-acre phases to provide time for wildlife to relocate from the affected areas.

Project construction would require clearing of vegetation from the Project areas, temporarily decreasing the amount of wildlife habitat and reducing protective cover and foraging habitat in the immediate Project area. Depending on the season, construction could also disrupt bird courting or nesting, including destruction of nests, eggs, and chicks within the construction work area. This would be a short-term impact in open land areas because the majority of these habitats would re-establish quickly, thus remaining available for wildlife habitat and watershed functions. Longer term impacts would result from the loss of forest habitat. Approximately 113 acres of forest and 2 acres of early successional woodland would be cleared by the Project. Approximately 60 acres of FIDS land would be cleared at Offsite Area A. The clearing of forest within the Fenced Area and Offsite Area A would also convert FIDS land adjacent to these Project areas to non-FIDS land.

The degree of construction-related impacts on wildlife that inhabit wetlands would depend on the particular species and the time of year of construction. Highly mobile species, such as beavers, mink, muskrat, and birds, would likely vacate the area during construction. Amphibians and reptiles have lower mobility and hibernate in soft wetland soil. Some limited mortality to these species is likely unavoidable; however, a silt-fence barrier would be erected and maintained in an attempt to keep these species along with small mammals out of active work areas.

In summary, construction and operation of the Project would result in short-term, long-term, and permanent impacts on wildlife and its habitat. The large area of similar habitat surrounding the Project areas would allow most species to relocate from the affected areas. In addition, DCP would implement measures in our Plan and Procedures and its E&SCPs and Invasive Species Management Plans, and would comply with state and local forest preservation and mitigation requirements, which include monitoring of restored and planted vegetation habitats. Therefore, we conclude that the Project would not result in significant impacts on general wildlife species.

2.3.3 Protected Species

Migratory Birds

Migratory birds are species that nest in the United States during the summer and make short- or long-distance migrations for the non-breeding season. Neotropical migrants migrate south to the tropical regions of Mexico, Central and South America, and the Caribbean for the non-breeding season. Migratory birds are protected under the Migratory Bird Treaty Act (MBTA) (16 USC 703-711). The MBTA, as amended, prohibits the taking, killing, possession, transportation, and importation of migratory birds, their eggs, parts, or nests unless authorized under a U.S. Fish and Wildlife Service (FWS) permit. Bald and Golden Eagles are additionally protected under the Bald and Golden Eagle Protection Act (BGEPA) (16 USC 668-668d). Executive Order 13186 (66 Federal Register 3853) directs federal agencies to identify where unintentional take is likely to have a measurable negative effect on migratory bird populations and to avoid or minimize adverse impacts on migratory birds through enhanced collaboration with the FWS. Executive Order 13186 states that emphasis should be placed on species of concern, priority habitats, and key risk factors, and that particular focus should be given to addressing population-level impacts.

On March 30, 2011, the FWS and the Commission entered into a *Memorandum of Understanding Between the Federal Energy Regulatory Commission and the U.S. Department of the Interior United States Fish and Wildlife Service Regarding Implementation of Executive Order 13186, "Responsibilities of Federal Agencies to Protect Migratory Birds"* that focuses on avoiding or minimizing adverse impacts on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the two agencies. This voluntary memorandum of understanding does not waive legal requirements under the MBTA, BGEPA, ESA, Federal Power Act, NGA, or any other statutes and does not authorize the take of migratory birds.

A variety of migratory bird species, including songbirds, raptors, and waterfowl utilize the habitat found within the Project area. The FWS identified Birds of Conservation Concern (BCC) for various regions in the country in response to the 1988 amendment to the Fish and Wildlife Conservation Act, which mandated the FWS to identify migratory nongame birds that, without additional conservation actions, were likely to become candidates for listing under the ESA. The BCC lists, last updated in 2008, are divided by Bird Conservation Regions (BCR). Calvert County, Maryland and Fairfax County, Virginia are within the New England/Mid-Atlantic Coast BCR and Loudoun County, Virginia is within the Piedmont BCR (FWS, 2008). A total of 48 BCC are listed in the BCRs crossed by the Project, of which 32 are known to breed within their respective BCR. Table 2.3.3-1 lists the BCC that are known to breed within the Project area.

TABLE 2.3.3-1

Birds of Conservation Concern Potentially Occurring Within the Project Area

Bird of Conservation Concern [a]	Piedmont BCR	New England/ Mid-Atlantic Coast BCR	Preferred Habitat and Potential Presence at Project Areas
Pied-billed Grebe		X	Wetlands and ponds with dense vegetation, bays, and sloughs. Habitat not impacted by Project.
American Bittern		X	Freshwater marshes with tall vegetation. Occasionally use brackish marshes. Habitat not impacted by Project.
Least Bittern		X	Freshwater or brackish marshes with tall emergent vegetation. Habitat not impacted by Project.
Snowy Egret		X	Mangroves, saltwater lagoons, freshwater swamps, grassy ponds. Nest on isolated islands, swamps, and marshes. Habitat not impacted by Project.
Bald Eagle	X	X	Forest (riparian). Habitat present. No bald eagle nests identified during field surveys.
Peregrine Falcon	X	X	Cliffs or man-made structures (riparian). Habitat not impacted by Project.
Black Rail	X	X	Coastal salt and brackish marshes. Habitat not impacted by Project.
Wilson's Plover		X	Ocean beaches, lagoons, and salt flats. Habitat not impacted by Project.
American Oystercatcher		X	Ocean shores and salt marshes. Habitat not impacted by Project.
Upland Sandpiper		X	Agricultural lands (dry grasslands). Habitat not impacted by Project.
Least Tern		X	Seacoasts, beaches, bays, estuaries, lagoons, lakes and rivers. Habitat not impacted by Project.

TABLE 2.3.3-1 (cont'd)

Birds of Conservation Concern Potentially Occurring Within the Project Area

Bird of Conservation Concern [a]	Piedmont BCR	New England/ Mid-Atlantic Coast BCR	Preferred Habitat and Potential Presence at Project Areas
Gull-billed Tern		X	Gravelly or sandy beaches, salt marshes, and estuaries. Habitat not impacted by Project.
Black Skimmer		X	Open sandy beaches, gravel or shell bars, or mats of sea wrack. Habitat not impacted by Project.
Whip-poor-will	X	X	Open woodlands. Habitat present at Offsite Area A, Fenced Area, and Pleasant Valley Compressor Station.
Red-headed Woodpecker		X	Open woodlands with scattered trees. Habitat present at Offsite Area A, Fenced Area, and Pleasant Valley Compressor Station.
Loggerhead Shrike	X	X	Pasture and cropland with scattered trees and hedgerows. Habitat not impacted by Project.
Brown-headed Nuthatch	X	X	Mature pine stands. Habitat not impacted by Project.
Bewick's Wren	X		Open woodlands (riparian). Habitat present at Offsite Area A, Fenced Area, and Pleasant Valley Compressor Station.
Sedge Wren	X	X	Moist upland sedge meadow. Habitat not impacted by Project.
Wood Thrush	X	X	Moist, lowland deciduous forest. Low potential habitat present at Offsite Area A.
Blue-winged Warbler	X	X	Abandoned fields, swamp, wetlands. Low potential habitat present at Offsite Area A.
Golden-winged Warbler		X	Abandoned fields with small saplings (forest edge). Habitat not impacted by Project.
Prairie Warbler	X	X	Old fields/pastures with young trees. Habitat not impacted by Project.
Cerulean Warbler	X	X	Mature upland oak woods (wooded hillsides along streams and rivers). Habitat present at Offsite Area A.
Worm-eating Warbler		X	Woodlands with dense understory. Potential habitat present at Offsite Area A, Fenced Area, and Pleasant Valley Compressor Station.
Swainson's Warbler	X		Bottomland forests (cove hardwoods with dense deciduous understory). Habitat not impacted by Project.
Kentucky Warbler	X	X	Deciduous woods of floodplains, swamps, and ravines. Habitat not impacted by Project.
Bachman's Sparrow	X		Open pine forest. Habitat not impacted by Project.
Henslow's Sparrow	X	X	Ephemeral grasslands. Habitat not impacted by Project.
Nelson's Sharp-tailed Sparrow		X	Freshwater marshes, wet meadows, and salt marshes. Habitat not impacted by Project.
Saltmarsh Sharp-tailed Sparrow		X	Salt marshes. Habitat not impacted by Project.
Seaside Sparrow		X	Salt marshes. Habitat not impacted by Project.

[a] This list does not include Birds of Conservation Concern that are non-breeding in the respective bird conservation region.

Source: USFWS, 2008

The potential impacts of the Project on migratory birds, including BCC-listed birds, would include the temporary and permanent loss of habitat associated with the removal of existing vegetation. The greatest potential to impact migratory birds would occur if Project construction activities such as grading, tree clearing, and construction noise take place during the breeding and nesting season. This could result in the destruction of nests and mortality of eggs and young birds that have not yet fledged. Construction would also reduce the amount of habitat available for foraging and predator protection for migratory birds and would temporarily displace birds into adjacent habitats, which could increase the competition for food and other resources. This could result in increased stress, susceptibility to predation, and negatively impact reproductive success. Noise and other construction activities could affect courtship and breeding activities including nesting and the rearing of young.

The loss of approximately 108 acres of upland and wetland forest within the Fenced Area of the LNG Terminal and Offsite Area A (see tables 2.2.4-1 and 2.3.1-2) would present a long-term impact for migratory birds that depend on forest. However, both the Fenced Area and Offsite Area A are surrounded by large, forested tracts, and the amount of forest that would be cleared represents approximately 0.1 percent of available forest habitat in Calvert County. Thus, we conclude that the loss of forest habitat would not result in population-level impacts on migratory birds in the region. However, to further reduce the potential for the Project to impact migratory birds, especially during nesting season, and because DCP has not committed to any tree clearing timing restrictions, **we recommend that:**

- **Within 7 days prior to the start of tree clearing between the dates of April 1 and August 31, DCP should conduct a survey to identify whether any nesting BCC birds are present in the Fenced Area and Offsite Area A. If nesting BCC birds are identified, DCP should avoid tree clearing and other Project activities within 50 feet of active nests until young have fledged the nest and vacated the Project area, or it is determined by a qualified biologist that the nest has been abandoned**.

Federal Threatened and Endangered Species

Federal agencies are required under section 7 of the ESA, as amended, to ensure that any actions authorized, funded, or carried out by the agency would not jeopardize the continued existence of a federally listed endangered or threatened species, or result in the destruction or adverse modification of the designated critical habitat of a federally listed species. As the lead federal agency authorizing the Project, the FERC is required to consult with the FWS and/or NMFS to determine whether federally listed endangered or threatened species or designated critical habitat are found in the vicinity of the Project, and to evaluate the proposed action's potential effects on those species or critical habitats.

For actions involving major construction activities with the potential to affect listed species or designated critical habitat, the lead federal agency must report its findings to the FWS and/or NMFS in a Biological Assessment for those species that may be affected. If it is determined that the action is likely to adversely affect a listed species, the federal 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 the federal action would jeopardize the continued existence of a listed species, or result in the destruction or adverse modification of designated critical habitat. We have determined that the Project would not adversely affect federally listed endangered or threatened species or designated critical habitat as described in the following sections.

Species Under FWS Jurisdiction

DCP, acting as the FERC's non-federal representative for the purpose of complying with section 7(a)(2) of the ESA, initiated informal consultation with the Chesapeake Bay Field Office of the FWS on June 14, 2012, regarding federally listed threatened or endangered species potentially occurring in or near the Project areas in Maryland. The FWS did not identify any federally listed threatened or endangered species that are known to occur in the Project area in Maryland.

DCP initiated informal consultation with the Virginia Ecological Services Field Office of the FWS on December 26, 2012, regarding federally listed threatened or endangered species potentially occurring in or near the Project areas in Virginia. The FWS indicated that one federally listed threatened plant species, the small whorled pogonia, may occur at the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, and Pleasant Valley M&R Facility. DCP completed a survey for the small whorled pogonia at the Pleasant Valley Compressor Station and in the forested area adjacent to the Pleasant Valley Suction/Discharge Pipelines and the Pleasant Valley M&R Facility during the preferred flowering period for the species in June 2013. The survey identified two areas on the compressor station property as marginal habitat; however, the small whorled pogonia was not found. The areas that would be affected by construction and operation of the Pleasant Valley Suction/Discharge Pipelines and the Pleasant Valley M&R Facility were not surveyed as they are unforested, maintained pipeline right-of-way or gravel-surfaced industrial land, neither of which are considered habitat for the small whorled pogonia. On August 15, 2013, the FWS agreed with DCP's survey results and concluded the small whorled pogonia was not present and is not likely to be adversely affected by the Project. Therefore, we conclude that the Project *is not likely to adversely affect* the small whorled pogonia.

Species Under NMFS Jurisdiction

DCP initiated informal consultation with NMFS on June 14, 2012. In a letter dated July 20, 2012, NMFS identified the shortnose sturgeon (endangered), Atlantic sturgeon (endangered), loggerhead turtle (threatened), green turtle (endangered), Kemp's ridley turtle (endangered), and the leatherback turtle (endangered) as known to occur in the Chesapeake Bay. As discussed in section 1.2.1, the annual frequency of ship traffic for the Project would not exceed 200 vessels per year as previously approved in Dockets CP05-130, et al., and DCP would not accept LNG carriers larger than previously authorized in Docket CP09-60. However, DCP estimates that only 85 LNG vessels per year would call at the LNG Terminal for export as part of operation of the Liquefaction Facilities. As a result, we conclude that LNG ship traffic associated with the Project would have *no effect* on the shortnose sturgeon, Atlantic sturgeon and the four listed sea turtles. NMFS also concluded that, because the Project would not involve in-water work and assuming that LNG vessel traffic would not increase to the existing offshore pier, the Project would not likely affect the waters of the Chesapeake Bay or result in direct or indirect effects on the above-referenced species.

However, at the time of the above consultation, the NMFS was not aware of DCP's plan to utilize Offsite Areas A and B. On December 6, 2012, DCP informed NMFS of the proposed use of Offsite Areas A and B, including the construction of the temporary pier in the Patuxent River at Offsite Area B. The NMFS responded on December 12, 2012, that no species under NMFS jurisdiction occur at Offsite Area A. With regards to the temporary pier at Offsite Area B, NMFS identified the shortnose sturgeon and five Distinct Population Segments of the Atlantic sturgeon as potentially occurring within the vicinity of the pier. NMFS advised that further analysis should be conducted of the potential impact that construction of the temporary pier could have on the shortnose and Atlantic sturgeon, as well as the potential impact that increased barge traffic to the temporary pier could have on shortnose and Atlantic sturgeon and the four species of sea turtles noted above.

On February 27, 2013, DCP submitted an analysis of potential Project impacts on the shortnose and Atlantic sturgeon. The findings are listed below.

- There is no designated critical habitat for the shortnose or Atlantic sturgeon within the Chesapeake Bay.
- The Project area does not contain shortnose or Atlantic sturgeon spawning areas.

- The shortnose and Atlantic sturgeon are rare or occasional transients in proximity to Offsite Area B. No shortnose sturgeon and only one Atlantic sturgeon have been documented in the Patuxent River as part of the Sturgeon Reward Program, a FWS and MDNR program initiated in 1996 that pays fisherman to report the bycatch of shortnose and Atlantic sturgeon.

- Temporary, minor impacts on the food web may occur as a result of construction and removal of the temporary pier at Offsite Area B. Forage fish and macroinvertebrates may be displaced from the construction area, but would be expected to return to the temporary pier location once it is removed.

- The shortnose and Atlantic sturgeon are highly mobile and would be displaced by noise and activity at the temporary pier.

- DCP would implement a ballast water management program in compliance with applicable laws and regulations designed to prevent water quality degradation and the introduction of invasive species.

On May 1, 2013, NMFS issued a request for additional information regarding the construction methods that would be used to install the temporary pier at Offsite Area B. On July 3, 2013, DCP responded that the hollow steel piles for the pier and mooring dolphins would be installed with a vibratory hammer to the extent possible in approximately 15 days between September 1, 2014, and May 1, 2015. Due to the short duration of pile driving, the small diameter of the piles, and the localized area of impact, there is no anticipated need to implement sound attenuation controls that would be protective of the shortnose and Atlantic sturgeon, but DCP would implement measures as necessary to stay within sound limits specified by NMFS.

With regard to the potential for increased barge traffic to the temporary pier to impact NMFS species of concern, DCP estimates that 42 barge deliveries would be made to the temporary pier during an 18-month period, or approximately 2.3 deliveries per month. This level of traffic compares to approximately 167 commercial vessel transits of the Chesapeake Bay each month.

On September 11, 2013, NMFS responded to the information that has been submitted by DCP and concluded that no federally listed species under NMFS jurisdiction would be exposed to any direct or indirect effects of the proposed Project and additional consultation under Section 7 of the ESA is not required. On April 8, 2014, NMFS provided further clarification that its effects determination was based on the proposed Project information provided by DCP as well as previous consultations that were completed for past Cove Point projects that assessed the effects of vessel traffic of up to 200 vessels annually. The vessel traffic associated with the currently proposed Project would consist of an estimated 42 barge deliveries to the temporary pier during an 18-month period during construction and an estimated 85 LNG vessels per year during operation, both of which would be below the previously assessed effects of up to 200 vessels annually. Further, DCP has stated LNG vessels and barges would be required to comply with its Vessel Strike Avoidance Measures and Injured and Dead Protected Species Reporting Plan. As such, after reviewing DCP's and NMFS' findings, relevant fisheries information, and analyzing potential Project impacts, we find that the Project would have *no effect* on the shortnose sturgeon, Atlantic sturgeon, loggerhead turtle, green turtle, Kemp's ridley turtle, and the leatherback turtle.

We received a comment regarding the potential for the Project to affect threatened and endangered species under the jurisdiction of the NMFS, including the North Atlantic right whale. DCP has committed to continue implementation of its Vessel Strike Avoidance Measures and Injured and Dead Protected Species Reporting Plan during operation of the Liquefaction Facilities, as well as during barge transit activities associated with Offsite Area B. In additional, NOAA has implemented regulations requiring all marine vessels greater than 65 feet in length to travel 10 knots or less, during specific seasonal timeframes, in right whale management zones along the East Coast. Since the vessel speed restrictions went into effect, no known fatal ship strikes of North Atlantic right whales have occurred in the management zones. Because LNG vessels and barges would be required to comply with this regulation, and DCP would require LNG vessels and barges to comply with its Vessel Strike Avoidance Measures and Injured and Dead Protected Species Reporting Plan, we find that ship and barge traffic related to the Project *is not likely to adversely affect* the North Atlantic right whale.

Bald and Golden Eagle Protection Act

The bald eagle is a large bird of prey whose range covers virtually all of North America. Although no longer federally listed under the ESA, the bald eagle is protected under the BGEPA and the MBTA. The BGEPA and MBTA prohibit killing, selling, or harming eagles or their nests; and the BGEPA also protect eagles from disturbances that may injure them, decrease productivity, or cause nest abandonment.

Optimal roosting, foraging, and breeding habitats for the bald eagle include areas near waterbodies, such as lakes, rivers, and forested wetlands. Bald eagles typically prefer large trees for roosting and nesting. Bald eagles can be sensitive to human activity and disturbance and may abandon otherwise suitable habitat if disturbance is persistent (Fraser et al., 1985). The FWS did not identify any bald eagle nests within the vicinity of the Project area (FWS, 2012). DCP stated it would implement the National Bald Eagle Management Guidelines should any nesting bald eagles be identified near the Project areas during construction. Therefore, the Project would not have any impacts on the bald eagle.

State Threatened and Endangered Species

Maryland and Virginia have regulatory requirements for state-listed species. In Maryland, the MDNR, Wildlife Heritage Service is responsible for administering the state endangered species laws. In Virginia, three agencies are responsible for protecting threatened and endangered species: 1) the VDACS; 2) the Virginia Department of Game and Inland Fisheries (VDGIF); and 3) the VDCR. Under a Memorandum of Agreement established between VDACS and the VDCR, VDCR represents VDACS in comments regarding potential impacts on state-listed threatened and endangered plant and insect species. A list of state-listed species potentially occurring in the Project area is provided in table 2.3.3-2. The small whorled pogonia, a federal and state-listed species, is discussed under the FWS jurisdiction section above.

The MDNR has also identified several rare and uncommon plant species that adjoin St. Paul’s Branch, including wetland plant species and odonates that are highly vulnerable to changes in hydrology, water chemistry, and water quality (see table 2.3.3-3).

TABLE 2.3.3-2

State-Listed Threatened and Endangered Species Identified in the Vicinity of the Project

Species Name	Status	Habitat	Potential Location of Species	Presence or Absence in Project Area
Plant Species				
Small whorled pogonia (*Isotria medeoloides*)	Federal Threatened; Maryland Endangered; Virginia Endangered	Hardwood stands of beech, birch, maple, oak, and hickory that have an open understory. Often on slopes near small streams.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not found during field surveys in 2013. The Project would not impact this species.
Thread-leaved gerardia (*Agalinis setacea*)	Maryland Endangered	Sandy habitats and along the coast.	LNG Terminal	Not found during field surveys. The Project would not impact this species.
Potato dandelion (*Krigia dandelion*)	Maryland Endangered	Low, damp, chiefly open sites, prairies, fields, meadows, open woods, and roadsides, light acidic soils, sandstone, chert, or granite.	LNG Terminal	Not found during field surveys. The Project would not impact this species.
Tobaccoweed (*Elephantopus tomentosus*)	Maryland Endangered	Open or shaded, dry to wet pine forests and mixed forests, often on sandy soils.	Offsite Area A	Present at Offsite Area A. Protected by 100-foot avoidance buffers. The Project would not likely impact this species.
Engelmann's arrowhead (*Sagittaria engelmanniana*)	Maryland Threatened	Bog, ponds, and streams with acid water.	Offsite Area A	Not found during field surveys. The Project would not impact this species.
Kidneyleaf grass-of- parnassus (*Parnassia asarifolia*)	Maryland Endangered	Wet areas, bogs, swamps, and moist woods.	Offsite Area A	Not found during field surveys. The Project would not impact this species.
Evergreen bayberry (*Morella carolinensis*)	Maryland Endangered	Bogs, low pinelands, flatwoods, bays, savannahs, and pocosins.	Offsite Area A	Not found during field surveys. The Project would not impact this species.
Torrey's mountain mint (*Pycnanthemum torrei*)	Maryland Endangered; Virginia Species of Concern	Dry, open habitats, including red cedar barrens, rocky summits, trails, and roadsides.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not found during field surveys. The Project would not impact this species.
Purple milkweed (*Asclepias purpurascens)*	Virginia Imperiled	Rocky open woods, glades, prairies, stream banks, wet meadows and valleys, thickets, roadsides.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not found during field surveys. The Project would not impact this species.
Grove sandwort (*Moehringia lateriflora)*	Virginia Critically Imperiled	Open woods and gravelly shores.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not found during field surveys. The Project would not impact this species.

TABLE 2.3.3-2 (cont'd)

State-Listed Threatened and Endangered Species Identified in the Vicinity of the Project

Species Name	Status	Habitat	Potential Location of Species	Presence or Absence in Project Area
Mussel Species				
Green floater (*Lasmigona subviridis*)	Maryland Endangered; Virginia Threatened	Pools and eddies with gravel and sand bottoms of smaller rivers and creeks; smaller channels of large rivers or small to medium-sized streams.	Downstream of Loudoun M&R Facility	No surface water impacts proposed. The Project would not impact this species.
Brook floater (*Alamidonta varicosa*)	Maryland Endangered; Virginia Endangered	Streams and rivers with low to moderate flow velocities and stable substrate. Found among boulders in sand.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	No surface water impacts proposed. The Project would not impact this species.
Reptile Species				
Wood turtle (*Glyptemys inscupta*)	Virginia Threatened	Streams and adjacent riparian uplands	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Identified in Project area; however, suitable habitat would not be impacted by the Project.
Bird Species				
Upland sandpiper (*Bartramia longicauda*)	Maryland Endangered; Virginia Threatened	Inhabits grasslands, fallow fields, and meadows that are often associated with pastures, farms, or airports.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not identified during field surveys. Additional pre-construction surveys would identify nesting upland sandpipers, which would be protected during nesting and fledging. The Project is not likely to impact this species.
Loggerhead shrike (*Lanius ludovicianus*)	Maryland Endangered; Virginia Threatened	Open habitat of short grasses and forbs of low stature with bare ground and shrubs or low trees.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not identified during field surveys. Additional pre-construction surveys would identify nesting loggerhead shrike, which would be protected during nesting and fledging. The Project is not likely to impact this species.
Migrant loggerhead shrike (*Lanius ludovicianus migrans*)	Virginia Threatened	Grasslands and open, agricultural areas characterized by short vegetation and scattered trees, shrubs, or hedgerows.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not identified during field surveys. Additional pre-construction surveys would identify nesting loggerhead shrike, which would be protected during nesting and fledging. The Project is not likely to impact this species.
Henslow's sparrow (*Ammodramus henslowii*)	Maryland Threatened; Virginia Threatened	Large, flat fields with no woody plants and with tall, dense grass, a dense litter layer, and standing dead vegetation.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not identified during field surveys. Additional pre-construction surveys would identify nesting Henslow's sparrow, which would be protected during nesting and fledging. The Project is not likely to impact this species.
Insect species				
Appalachian grizzled skipper (*Pyrgus wyandot*)	Maryland Endangered; Virginia Threatened	Open, sparsely grassed, and barren areas in close proximity to oak or pine forests.	Pleasant Valley Compressor Station, Pleasant Valley Suction/ Discharge Pipelines, Pleasant Valley M&R Facility	Not identified during field surveys. The Project would not likely impact this species.

TABLE 2.3.3-3 **Rare and Uncommon Plant Species Identified by the MDNR at St. Paul's Branch**	
Species	State Status
Engelmann's Arrowhead (*Sagittaria engelmanniana*)	Threatened
Kidneyleaf Grass-of-Parnassus (*Parnassia asarifolia*)	Endangered
Evergreen Bayberry (*Morella carolinensis*)	Endangered
Brown Spiketail (*Cordulegaster bilineata*)	Watchlist/Greatest Conservation Need [a]
Tiger Spiketail (*Cordulegaster erronea*)	Watchlist/Greatest Conservation Need [a]

[a] Designated Greatest Conservation Need in Maryland's Wildlife Diversity Plan.

Only one state-listed species was identified during field surveys. DCP identified four patches of tobaccoweed, a Maryland state-listed endangered species, at Offsite Area A. DCP proposes to establish a 100-foot avoidance area around each patch of tobaccoweed during use and restoration of Offsite Area A, delineated by two rows of super silt fence, spaced 3 to 4 feet apart. DCP would segregate, store, and replace topsoil adjacent to the patches of tobaccoweed to conserve seed base within the topsoil. DCP would also implement stormwater management and erosion and sediment control measures that will prevent erosion or sedimentation impacts to this species. DCP's Invasive Species Management Plan for the Calvert County facilities includes measures to prevent and control the spread of invasive species. We conclude implementation of these measures would effectively avoid impacts on tobaccoweed populations at Offsite Area A. No other state-listed species were identified during field surveys. Therefore, no impacts are anticipated on state-listed species.

In Virginia, the VDCR identified the green floater and the aquatic community associated with the Little River Stream Conservation Unit as species and communities of concern potentially occurring downstream of the Loudoun M&R Facility. As indicated in section 2.2.2, proposed activities at the Loudoun M&R Facility would not directly impact any surface waterbody. In addition, DCP would implement provisions of the site-specific E&SCPs and SMPs to prevent water quality degradation during construction and operation of the Project. We conclude that implementation of these measures would effectively avoid impacts on the green floater and the Little River Stream Conservation Unit.

2.4 LAND USE, RECREATION, AND VISUAL RESOURCES

2.4.1 Existing Land Use

Three land use types would be affected by the Project, including open land/water, forest/ woodland, and commercial/industrial/disturbed land. The definitions of each land use type are as follows:

- Open Land/Water – includes mowed and maintained agricultural fields, maintained utility right-of-way, open water, and old field/shrub lands.
- Forest/Woodland – includes tree stands consisting primarily of mixed oak-hickory forest.
- Commercial/Industrial/Disturbed Land – includes the existing developed portions of the LNG Terminal, compressor station sites, M&R facilities, and paved roads.

Table 2.4.1-1 summarizes the land use requirements associated with construction and operation of the Project.

Impacts on land would result from clearing of the construction work area for the installation of Project facilities, including at the Liquefaction Facilities, Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, and Loudoun M&R Facility, as well as the use of Offsite Areas A and B during construction.

The proposed activities at the Liquefaction Facilities would take place within a 130-acre Fenced Area of the existing LNG Terminal, which is located within DCP's larger 1,017-acre property. The LNG Terminal property is located on a ridge above the western shore of the Chesapeake Bay. The Project area is zoned as industrial property; however, the existing land use types that would be affected by the Project include open land/water, forested/woodland, and commercial/industrial/disturbed land. Construction of the Liquefaction Facilities would affect approximately 1.7 acres of open land/water, 11.8 acres of forest land/woodland, and 54.8 acres of commercial/industrial/disturbed land. Operation of the Liquefaction Facilities would permanently convert 11.4 acres of forest land/woodland and 1.7 acres of open land/water to industrial use. Approximately 46.5 acres of the commercial/industrial/disturbed land would be retained as that land use type for operation of the Liquefaction Facilities. The remaining commercial/industrial/ disturbed land would remain as part of the LNG Terminal operations, and the remaining 0.4 acre of forest land/woodland would be allowed to revert to forest land/woodland.

TABLE 2.4.1-1

Land Use Affected by Construction and Operation of the Cove Point Liquefaction Project

	Open Land/Water		Forest/Woodland		Commercial/ Industrial/ Disturbed		Total	
State/County/Facility	Const.	Oper.	Const.	Oper.	Const.	Oper.	Const.	Oper.
MARYLAND								
Calvert County [a]								
Liquefaction Facilities	1.7	1.7	11.8	11.4	54.8	46.5	68.4	13.1 [b]
Offsite Area A	0	0	94.0 [c]	0	0.9	0	94.9	0 [d]
Offsite Area B [e]	5.7	0	0.1	0	0	0	5.8	0
VIRGINIA								
Fairfax County								
Pleasant Valley Compressor Station [f]	9.3	2.0	6.7	0.3	6.2	0.7	22.2	2.3 [g]
Pleasant Valley Suction/Discharge Pipelines and Pleasant Valley M&R Facility	1.9	0	0	0	1.4	0	3.3	0
Loudoun County, Virginia [a]								
Loudoun M&R Facility	0.1	0	0	0	1.8	0	1.9	0
Leesburg Compressor Station Contractor Staging Area [h]	6.0	0	0	0	2.4	0	8.4	0
Project Total	**24.7**	**3.7**	**112.6**	**11.7**	**67.5**	**47.2**	**204.9**	**15.4**

a Acreages of access roads associated with the Liquefaction Facilities, Offsite Area A, Offsite Area B, the Loudoun M&R Facility, and the Leesburg Compressor Station Contractor Staging Area are included in the construction and operations totals of the respective facilities.

b The Liquefaction Facilities would occupy 59.5 acres within the existing Fenced Area of the LNG Terminal. However, 46.5 acres of the Liquefaction Facilities would be located on land that is currently utilized for operation of the LNG Terminal. The remaining 13.1 acres of the Liquefaction Facilities would impact land that is currently unaffected by operation of the LNG Terminal.

c Based on information provided by DCP to the FERC; however, the Maryland DNR has stated that DCP would affect 93.6 acres of forest/woodland at Offsite Area A. The final area affected would be confirmed prior to construction.

d Offsite Area A would not be used during the operation of the Liquefaction Facilities, but would result in converting 94.0 acres of forest to open land.

e Does not include 0.2 acre of temporary open water impacts associated with the pier.

f Includes 0.9 acre for the nonjurisdictional substation that would be constructed by the Northern Virginia Electric Cooperative within the Pleasant Valley Compressor Station site.

g The expansion of the Pleasant Valley Compressor Station would occupy 3.0 acres within the existing compressor station property. However, 0.7 acre of the expansion would be located on land that is currently utilized for operation of the compressor station. The remaining 2.3 acres of the expansion facilities would impact land that is currently unaffected by operation of the compressor station.

h Includes reuse of the existing access road. The Leesburg Compressor Station includes 4.6 acres of commercial/industrial land; however, 2.2 acres of commercial/industrial land are currently occupied by buildings and other structures and would not be used during construction.

Note: The totals shown in this table may not equal the sum of addends due to rounding.

Offsite Area A would be located within a 179.4-acre currently undeveloped (primarily forested) area approximately 1.5 miles from the LNG Terminal. During construction, approximately 94.9 acres of the site would be cleared and utilized at Offsite Area A, including approximately 94.0 acres of forest land/woodland and 0.9 acre of commercial/industrial/disturbed land. Offsite Area A would not be used during the operation of the Liquefaction Facilities, but its use during construction would result in the conversion of 94.0 acres of forest to open land. Offsite Area A is currently owned by a private party (100 acres) and Calvert County (79.4 acres). DCP has an option to purchase the privately owned 100-acre portion of Offsite Area A, and is negotiating to lease the remaining 79.4 acres from Calvert County. Following construction activities, DCP has stated it would donate the 100-acre parcel to Calvert County (giving the County ownership of the entire 179.4-acre parcel) and restore the site in accordance with the wishes of the County.

Offsite Area B would be located within an 11.0-acre property of undeveloped land approximately 4.5 miles from the LNG Terminal. Construction activities at Offsite Area B would affect approximately 5.7 acres of open land and 0.1 acre of forest land/woodland. In addition, the temporary pier would be located on approximately 0.2 acre of open water in the Patuxent River. Following construction activities, Offsite Area B would be allowed to revert to its previous use and the temporary pier would be removed.

The proposed activities at the Pleasant Valley Compressor Station would be conducted within DCP's property boundary. Construction at the Pleasant Valley Compressor Station would affect approximately 9.3 acres of open land, 6.7 acres of forest land/woodland, and 6.2 acres of commercial/industrial/disturbed land. Following construction, approximately 2.0 acres of open land, 0.3 acre of forest land/woodland, and 0.7 acre of commercial/industrial/disturbed would be retained for operation of the new compressor station facilities. The remaining land uses would be allowed to revert to their previous use. Construction of the Pleasant Valley Suction/Discharge Pipelines and M&R Facility would affect approximately 1.9 acres of open land and 1.4 acres of commercial/industrial/disturbed. The temporary construction right-of-way associated with the Pleasant Valley Suction/Discharge Pipelines and M&R Facility would be allowed to revert to its preconstruction use. The land retained as permanent right-of-way would be allowed to revert to its preconstruction use; however, certain activities such as the construction of aboveground structures, or the planting or cultivation of trees, would continue to be prohibited in the permanent right-of-way.

Construction activities at the Loudoun M&R Facility would take place within the boundary of DCP's Loudoun Compressor Station property. Approximately 0.1 acre of open land and 1.8 acres of commercial/industrial/disturbed land would be affected during construction. No additional land would be required outside the existing facility for operation of the Loudoun M&R Facility.

Approximately 6.0 acres of open land and 2.4 acres of commercial/industrial/disturbed land would be used for equipment staging and parking at the Leesburg Compressor Station site during construction. All land would be allowed to revert to previous use after the completion of construction.

2.4.2 Recreation and Special Interest Areas

Liquefaction Facilities

The 1,017-acre property owned by DCP surrounding the Liquefaction Facilities is subject to four conservation agreements that preclude or restrict development. These include a grant to the County Commissioners of Calvert County for an easement for recreation purposes on which the county has constructed ball fields, an aquatic center, and other recreational facilities (Cove Point Park); an easement to Cove Point Beach Association, Inc., allowing beach-related recreational activities; a conservation easement granted to the Maryland Environmental Trust and The Nature Conservancy with restrictive covenants precluding development outside the industrial portions of the LNG Terminal site; and an agreement between DCP, the Sierra Club, and the Maryland Conservation Council which limits activities to the 130-acre Fenced Area within DCP's larger property.

The Calvert Shore Oyster Sanctuary is located just offshore from the LNG Terminal. In Maryland, the oyster sanctuary program is overseen by the MDNR, and the harvest of oysters within the sanctuary is prohibited. The sanctuary extends along the shoreline from Cove Point, north approximately 5.5 miles, and is approximately 3,300 feet wide in the area of the offshore LNG pier. No in-water activities are proposed at the LNG pier as part of the Project and, therefore, no impacts on the Calvert Shore Oyster Sanctuary would occur.

Recreational areas with 0.25 mile of the LNG Terminal include the Calvert Cliffs State Park, Cove Point Park, and recreational fishing in the Chesapeake Bay. Calvert Cliffs State Park is adjacent to DCP's 1,017-acre LNG Terminal property but is separated from the Fenced Area by at least 1,600 feet of heavily forested land. Calvert Cliffs State Park includes over 13 miles of hiking trails and more than 1 mile of shoreline along the Chesapeake Bay. Neither the hiking trails nor the shoreline are located within 0.25 mile of the Fenced Area. Use of the park is restricted to daytime hours.

Cove Point Park is located largely within the 1,017-acre LNG Terminal property owned by DCP, but is separated from the Fenced Area by at least 600 feet of heavily forested land. The park includes a pool, baseball and soccer fields, basketball and tennis courts, a playground, and areas for walking or jogging. The portion of the park nearest to the Liquefaction Facilities includes patches of forested land, two baseball diamonds, and parking areas. The park is open year-round and its use is restricted to daytime hours.

Construction-related noise and visual impacts could occur on nearby recreational users but would be limited to the time of construction. Operation of the Liquefaction Facilities could also result in visual and noise impacts on nearby recreational users. However, construction and operation of the Liquefaction Facilities would occur within an existing industrial facility that is surrounded by dense forest, which would prevent or reduce these impacts. In addition, the Liquefaction Facilities would be visually consistent with the industrial appearance of existing facilities, and none of the proposed facilities would exceed the height of existing facilities within the Fenced Area. DCP would also install a sound barrier around a portion of the Liquefaction Facilities to shield surrounding areas from operation sights and sounds. Also, as discussed in section 2.7.2, DCP would be required to operate the facility in compliance with minimum noise criteria. Visual resources are discussed further in section 2.4.5.

The Maryland Environmental Trust and The Nature Conservancy easement includes the 150-acre Cove Point Marsh, which is a Maryland Natural Heritage Area. Cove Point Marsh is managed by the Cove Point Natural Heritage Trust, a partnership between DCP, the Sierra Club, and the Maryland Conservation Council. DCP has worked with the Cove Point Natural Heritage Trust to fund preservation efforts at Cove Point Marsh, including a beach and marsh restoration Project associated with DCP's Pier Reinforcement Project. Construction and operation of the Liquefaction Facilities would take place entirely within the Fenced Area, and operation of the new facilities would be consistent with the current operations at the LNG Terminal. In addition, as discussed above, the Cove Point Marsh is within the existing Maryland Environmental Trust and The Nature Conservancy easement, which precludes development activities from occurring on that land. As such, the proposed Project would not affect the Cove Point Marsh.

Recreational fishing takes place in the Chesapeake Bay in the vicinity of the LNG Terminal and Calvert Cliffs State Park, as well as outside the 500-yard safety and security zone around the offshore pier. No in-water work is proposed at the existing offshore pier during construction of the Project, and

LNG ship traffic would not exceed the currently approved frequency to the LNG Terminal. In addition, DCP would implement measures contained in its approved E&SCPs and SMPs to minimize impacts on surface water quality during construction and operation of the Liquefaction Facilities. As a result, no additional impacts on recreational fishing in the Chesapeake Bay would occur due to the Project.

Offsite Area A

No conservation or natural, recreational, or scenic areas are located within 0.25 mile of Offsite Area A. We received comments from the MDNR regarding potential impacts on the Hellen Creek Hemlock Preserve. The Preserve consists of approximately 120 acres of marshes, forest, and streams. The Preserve is located approximately 1 mile southwest of Offsite Area A; therefore, no impacts on the Hellen Creek Hemlock Preserve would occur with the use of Offsite Area A during construction of the Liquefaction Facilities.

Offsite Area B

Offsite Area B is located adjacent to the Patuxent River, which is used for recreational fishing, oystering, and boating. The Solomons Island Boat Launch and Fishing Pier, a recreation area owned by Calvert County and leased to a private operator, is located adjacent to Offsite Area B. The area includes trailer parking and boat ramps with four docks that extend up to 100 feet in the Patuxent River. An estimate of 5,000 boat launches occur from the Solomons Island Boat Launch each year, with the busiest times being weekends between Memorial Day and Labor Day (Calvert County Natural Resources Division, 2013). Designated natural oyster bars are also located in the Patuxent River approximately 560 feet offshore as discussed in section 2.2.3. In addition, we received comments regarding potential impacts regarding use of the pier during local events.

Use of Offsite Area B would affect approximately 5.8 acres of an 11.0-acre site. The property where Offsite Area B would be located is currently used as overflow parking for the Calvert Marine Museum. DCP has stated that its use of Offsite Area B would not preclude continued use of the site as overflow parking for large events at the Calvert Marine Museum. In addition, DCP would work to schedule activities at Offsite Area B so that it would not interfere with use of the site for overflow parking.

Construction of the temporary barge offloading pier, as well as unloading operations at the pier during construction of the Project, may result in limits to the use of the immediate area for recreation. DCP estimates that 42 barge deliveries would be made to the pier over the course of 18 months, which would equate to an average of about 2.3 barge deliveries per month. Following construction, the pier would be removed from the river and Offsite Area B would be restored to its prior use. In addition, no river dredging is proposed for this Project. Based on the relatively small scale of construction and limited incidence and duration of use, we conclude that construction and use of the temporary pier at Offsite Area B would result in only temporary and minor impacts on recreational uses on the Patuxent River.

Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility

The Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility are within the 1,680-acre Elklick Diabase Flatwoods Conservation Site, and a portion of the Suction/ Discharge Pipelines and M&R Facility workspaces would abut the 226-acre Elklick Woodlands Natural Area Preserve. As discussed in section 2.3.1, the Elklick Diabase Flatwoods Conservation Site is designated by the VDCR due to the presence of rare plant communities in the area. However, none of the plant species of concern were identified in the Project work areas. In addition, the VDCR has concluded that there would be no impacts on sensitive forested areas on the compressor station property (VDCR, 2013) (see section 2.3.1).

The Elklick Woodlands Natural Area Preserve is managed by the Fairfax County Park Authority and protected by a conservation easement held by the Northern Virginia Conservation Trust. The Fairfax County Park Authority has a management objective to "establish communication with Dominion land managers to establish areas of common interest and to coordinate, plan, and monitor land management practices on the [existing pipeline] right-of-way to benefit both Elklick Woodlands and the right-of-way" (Fairfax County Park Authority, 2009). In a letter dated August 20, 2013, Fairfax County confirmed that the proposed Project would take place within DCP's existing easements and not impact the conservation easement and provided details on permit requirements that would be implemented by the county for the proposed activities. Further, in response to the county, DCP has stated it would obtain the appropriate permits to complete the work.

The Elklick Woodlands Natural Area Preserve has no public access facilities; thus, recreational use would be limited in proximity to the Pleasant Valley Compressor Station and associated facilities. As noted above, the Elklick Woodlands Natural Area Preserve abuts a portion of the proposed Pleasant Valley Suction/Discharge Pipelines and M&R Facility workspaces, but is separated from the Pleasant Valley Compressor Station itself by at least 500 feet of dense forest. For recreational users of the Elklick Woodlands Natural Area Preserve, this forest buffer would largely eliminate visual impacts and reduce noise impacts associated with construction and operation at the compressor station itself. Operating noise impacts would be further reduced by the sound barrier wall that DCP would install along the eastern boundary of the compressor station. Recreational users that approach the Pleasant Valley Suction/Discharge Pipelines and M&R Facility could experience increased noise and visual impacts during active construction, but these impacts would be limited to the time of construction. Operation of the Pleasant Valley Suction/Discharge Pipelines and M&R Facility would be unchanged from current pipeline and M&R operations. Based on the above discussion, construction and operation of the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility would not result in significant noise or visual impacts on recreational users in the Elklick Woodlands Natural Area Preserve. Visual resources are discussed further in section 2.4.5.

The properties located directly south of the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility are zoned as a residential conservation district. This zoning type is established to protect water courses, stream valleys, marshes, forest cover in watersheds, aquifer recharge areas, rare ecological areas, and areas of natural scenic vistas; to minimize impervious surface and to protect the quality of water in public water supply watersheds; to promote open, rural areas for the growing of crops, pasturage, horticulture, dairying, floriculture, the raising of poultry and livestock, and for low density residential uses (Fairfax County Zoning Ordinance Article 3-C01). The Pleasant Valley Compressor Station and the surrounding properties are located within water supply protection areas, which promote public health, safety, and welfare through the protection of public water supplies from water pollution. Because DCP would develop and implement site-specific E&SCPs and SMPs to minimize impacts on water resources (see section 2.2.1), we conclude that construction and operation of the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility would not result in impacts on water supply protection areas.

Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area

Construction and operation at the Loudoun M&R Facility would take place within DCP's existing property boundaries. The closest public land to the Loudoun M&R Facility is the Banshee Reeks Nature Preserve, which is approximately 0.5 mile northwest of the facility. As such, the proposed Project would not affect recreational activities at the Banshee Reeks Nature Preserve.

The Greene Mill Preserve residential development is located approximately 0.25 mile northeast from the Loudoun M&R Facility. Construction and operation of the Loudoun M&R Facility would take place within DCP's existing property boundaries and would represent a minor alteration of DCP's existing facilities. As such, the proposed Project would not significantly affect the Greene Mill Preserve development.

The existing Leesburg Compressor Station would be used as a contractor staging area during construction of the Project. The closest public land to the Leesburg Compressor Station Contractor Staging Area is the Banshee Reeks Nature Preserve, which is approximately 0.5 mile northwest of the station. As such, we conclude recreational activities in the area would not be affected by the temporary use of the Leesburg Compressor Station Contractor Staging Area.

2.4.3 Existing Residences and Planned Future Developments

Liquefaction Facilities

Approximately 145 residences are located within 0.5 mile of the Fenced Area. The nearest residences to the Liquefaction Facilities are located across Cove Point Road approximately 300 feet south of the Fenced Area. In addition, a 37-lot residential development, referred to as Hidden Treasure, is being developed south of Cove Point Road, south of the Fenced Area of the LNG Terminal. The majority of the lots in Hidden Treasure have been sold and developed; however, some remain unsold, including at least one within 0.25 mile of the LNG Terminal.

Temporary impacts on nearby residential areas could include inconvenience caused by noise and dust generated from construction equipment and traffic congestion associated with the transport of equipment, materials, and construction workers between the LNG Terminal and Offsite Areas A and B. Impacts from noise and dust during construction would diminish with distance from these areas and would be limited to the time of construction which would typically occur during daylight hours (7:00 a.m. to 6:00 p.m.), 6 days per week.

As discussed in section 2.5.4, DCP would implement measures at nearby traffic intersections to reduce potential impacts on traffic and public safety during Project construction. By implementing these measures, traffic flow impacts that do arise would be minor and temporary. In addition, the transport of large equipment would occur at night to minimize potential impacts on local traffic. The vehicles used to transport this equipment would have noise levels consistent with other large trucks that travel on Maryland Route 2/4.

Potential impacts on nearby residences during operation of the Liquefaction Facilities would be mitigated, in part, by the installation of a sound barrier around the facility to shield surrounding areas from operation sights and sounds. DCP would install the sound barrier on the western and southern sides of the Fenced Area behind the existing tree/vegetative buffer. The sound barrier would be approximately 3,500 feet long and 60 feet high and would be made of sound absorbing panels with a non-corroding exterior shell material. The sound barrier's panels would be filled with acoustical material to absorb the sounds from the Liquefaction Facilities. In order to minimize the visual impacts from the sound barrier on nearby residences and recreational users, DCP would select a color for the sound barrier that blends in with the natural vegetation. DCP is consulting with the Calvert County Department of Planning and Zoning regarding the materials and placement for the sound barrier. We conclude that the installation of DCP's proposed sound barrier would adequately reduce potential impacts on nearby residences from the addition of the proposed Liquefaction Facilities to DCP's existing LNG Terminal. Section 2.4.5 includes additional discussion of visual impacts associated with the sound barrier. Section 2.7.2 includes additional discussion of impacts from noise.

Offsite Area A

The nearest residence to Offsite Area A is approximately 150 feet west from the property boundary. DCP's clearing and grading plan for Offsite Area A would provide for at least 150 feet of mature forest to remain between the residence and the temporary operating area of Offsite Area A and, as noted above, construction activities would be limited to daylight hours. Therefore, no significant impacts on nearby residences would occur during use of Offsite Area A.

The Patuxent Business Park is a planned commercial development located approximately 230 feet from Offsite Area A. Some infrastructure (e.g., roads and stormwater management facilities) has been developed within the Patuxent Business Park site, but no buildings are currently located on the property. Use of Offsite Area A during construction would not preclude the planned nearby development, and no significant impacts on the development would occur.

Offsite Area B

The nearest residence to Offsite Area B is that of the current property owner, approximately 160 feet east of the site. No residences are located within 50 feet of the property and no nearby developments have been identified. DCP would lease the property, which includes only the mowed and maintained portion of the existing landowner's property. Potential impacts could include dust and noise during construction from the earthwork required to prepare the site, and associated with the offloading and transport of equipment to the Liquefaction Facilities site. However, these impacts would be temporary during the period of construction. Therefore, we conclude that use of Offsite Area B would not result in significant impacts on nearby residences.

Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility

The Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility are located in a sparsely populated area of Fairfax County, Virginia. No existing or planned residences are located within 0.25 mile of the existing compressor station site. No significant impacts on residences are expected during construction or operation of the proposed facilities. To further reduce potential impacts on the adjacent areas, DCP would install a sound barrier along the eastern fenceline of the Pleasant Valley Compressor Station behind the existing tree/vegetative buffer. The sound barrier would be approximately 800 feet long and 20 feet high and made of sound absorbing panels with a non-corroding exterior shell material. To minimize the visual impacts from the sound barrier on adjacent areas, DCP would select a color for the sound barrier that blends in with the natural vegetation. Visual resources are discussed further in section 2.4.5.

Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area

The nearest residence to the Loudoun M&R Facility is 65 feet west along State Route 860. In addition, a nearby residential subdivision, Greene Mill Preserve, is being developed within 0.25 mile of the Loudoun M&R Facility. The nearest Greene Mill Preserve residence is located approximately 1,620 feet to the northeast of the site.

During the scoping process we received numerous comments from the residents of Greene Mill Preserve expressing concern with the potential for DCP to install additional compression at the Loudoun Compressor Station. Although customer receipt points for the natural gas capacity on the Cove Point Pipeline to be delivered to the LNG Terminal have not been finalized, DCP stated that the Project would not include increased compression at the Loudoun Compressor Station. Rather, the proposed Project would consist of installation of miscellaneous piping and meter upgrades at the Loudoun M&R Facility.

Construction of the Loudoun M&R Facility may result in minor, short-term impacts on the transportation network in the Project area as existing public roadways would be used to transport construction equipment and materials, and workers to the site. However, due to the short-term nature of the construction, traffic flow impacts would be minor and temporary. Additional discussion of traffic impacts is provided in section 2.5.4. Because the modifications at the Loudoun M&R Facility would be relatively minor and take place within DCP's existing industrial facility, no additional impacts on nearby residences or developments would occur during operation of the Project.

The nearest residence to the Leesburg Compressor Station Contractor Staging Area is located 70 feet away. No planned developments have been identified within 0.25 mile of the site. Activities at the site would occur within the existing industrial property boundary and would be consistent with the current activities at the Leesburg Compressor Station. As such, we conclude that the temporary use of the Leesburg Compressor Station would not result in significant impacts on nearby residences or developments.

2.4.4 Coastal Zone Management

The Project facilities in Maryland and the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility in Virginia would be located within a coastal zone management area. The Federal Coastal Zone Consistency requirements are overseen by the MDE in Maryland and by the VDEQ in Virginia. DCP submitted its Coastal Use Permit applications for Coastal Zone Consistency Determinations to the MDE and VDEQ on April 1, 2013. DCP received its coastal zone consistency determination from the VDEQ on October 3, 2013, and anticipates a response from the MDE in late May 2014. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, DCP should file documentation of concurrence from MDE that the Liquefaction Facilities are consistent with the Maryland Coastal Zone Management Program.**

2.4.5 Visual Resources

Liquefaction Facilities

The proposed Liquefaction Facilities would be constructed entirely within the existing Fenced Area, an existing 130-acre industrial area within DCP's 1,017-acre LNG Terminal property. Construction of the Liquefaction Facilities would result in visual impacts associated with site and tree clearing within the existing Fenced Area. Potential visual impacts associated with operation of the Liquefaction Facilities would occur from the increase of industrial facilities and lighting within the site, as well as the operation of the two ground flares.

Visually sensitive areas near the Liquefaction Facilities include historic landmarks (i.e., Middleham Chapel and Cove Point Lighthouse), residences, Cove Point Road, Cove Point Park, and the Governor Thomas Johnson Bridge over the Patuxent River. Views of the existing facility are largely screened from these areas by existing forests and topography, except for the crest of the bridge, which is approximately 5.2 miles from the site. As such, we conclude that construction of the proposed Project would not result in significant visual impacts on nearby areas.

The surrounding tree cover would prevent most views of the Fenced Area except along Cove Point Road near to the LNG Terminal. However, the new Liquefaction Facilities would be consistent with the industrial nature of the existing facility and, therefore, would not represent a significant change in the viewshed during operation. In addition, DCP would install a sound barrier along the western and southern fence lines of the Liquefaction Facilities that would shield the surrounding areas from noise impacts associated with the operation of the Project, including ground flares (see section 2.4.3). The sound barrier would also act as a visual barrier to the facilities from Cove Point Road.

We received comments regarding potential visual impacts of the sound barrier from Cove Point Road. The sound barrier would generally be screened from views along Cove Point Road by the existing vegetation between the road and the edge of the Fenced Area where the barrier would be installed. However, during seasons of minimum foliage on the trees, the sound barrier may be visible from the road. To minimize the visual impact of the sound barrier, DCP would select a color that blends in with the natural vegetation. Whereas the sound barrier may be visible from Cove Point Road at certain times of the year, we have determined it would reduce the overall visual impact of the Project by screening views of the facilities from the road. We also find that the noise reduction benefit of the sound barrier on the surrounding area during operation would outweigh the potential seasonal visual impacts associated with the sound barrier. In addition, as part of their final recommended license conditions for the Maryland CPCN, the Reviewing State Agencies recommended that DCP develop a landscaping plan that addresses the visibility of the proposed sound barrier from Cove Point Road near the LNG Terminal site entrance, including photo simulations of the site entrance before and after new landscaping is in place, and during seasons of peak and minimum foliage. We conclude that preparation of the landscaping plan would address concerns regarding the visual impacts of the sound barrier from Cove Point Road. However, to document that the landscaping plan required by the Maryland CPCN has been completed as described above, **we recommend that:**

- **<u>Prior to construction</u>, DCP should file the final landscaping plan, approved by the MDNR, for the LNG Terminal sound barrier.**

Additional nighttime lighting would be installed in conjunction with operation of the Liquefaction Facilities. DCP would minimize nighttime visual impacts by employing a lighting design that limits the potential for light pollution outside of the Fenced Area. Lighting would typically be positioned downward toward the work areas, and utilized only where necessary for operations, safety, and security. Dusk to dawn lighting would be utilized where possible to eliminate use of continuous yard lighting. As part of their recommended license conditions for the Maryland CPCN, the Reviewing State Agencies recommended that DCP develop a lighting distribution plan in coordination with the PPRP and the Calvert County Department of Planning and Zoning for operation that would reduce intrusive night lighting and avoid undue glare onto adjoining properties. We agree that DCP's lighting design, with input from the PPRP and the Calvert County Department of Planning and Zoning, would reduce potential visual impacts on the surrounding areas. However, to document that the lighting distribution plan has been completed as described above, **we recommend that:**

- **<u>Prior to construction</u>, DCP should file the final lighting distribution plan for the Liquefaction Facilities, approved by the MDNR, with the Secretary for review and written approval by the Director of OEP.**

Offsite Area A

Visual impacts associated with the use of Offsite Area A during construction would include removal of existing forest vegetation, as well as earthwork and grading associated with site preparation. No visually sensitive areas, including scenic roads or rivers, are in the vicinity of Offsite Area A. DCP would maintain a 100-foot buffer of trees along the eastern boundary of the site to screen the site from Maryland Route 2/4. In addition, use of the site would be temporary and limited to the period of construction. As such, we find that the use of Offsite Area A would not result in significant visual impacts.

Offsite Area B

Visual impacts associated with the use of Offsite Area B during construction would include removal of existing vegetation, as well as earthwork and grading. Offsite Area B is located within an undeveloped open area along the Patuxent River. No scenic or unique viewsheds are associated with the site. Temporary impacts on visual resources would occur during the construction phase from the Governor Thomas Johnson Bridge and from users of the Patuxent River and Calvert Marine Museum. Construction of the temporary barge offloading pier at the site would be consistent with other shoreline piers and marinas in the area. Use of the site for equipment unloading and contractor parking would result in minor visual impacts on the surrounding area, and would be temporary and limited to the period of construction. As such, we find that the use of Offsite Area B would not result in significant visual impacts.

Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility

The proposed additional compression at the Pleasant Valley Compressor Station, construction of the Pleasant Valley Suction/Discharge Pipelines, and modifications to the Pleasant Valley M&R Facility would occur entirely within DCP's existing industrial facilities or maintained pipeline right-of-way. As such, no permanent changes to the current visual aspects of the surrounding area would be expected.

DCP would maintain existing trees and woodlands along the property boundaries and would add additional vegetative screening where necessary when developing the station facilities to help conceal the station facilities from public view at locations that are directly adjacent to the site. In addition, DCP would install a visual and sound barrier along the eastern fenceline of the compressor station site to shield the surrounding area from visual and noise impacts during operation of the Project (see section 2.4.3).

DCP would minimize nighttime visual impacts by employing a lighting design that would limit the potential for light pollution outside of fenced areas. Lighting would typically be positioned downward toward the work areas, and utilized only where necessary for operations and safety. Dusk to dawn lighting would be utilized where possible to eliminate use of continuous yard lighting.

With implementation of these measures combined with the distance of the views, we conclude that operation of the facilities associated with the Pleasant Valley Compressor Station would not result in significant visual impacts.

Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area

No visually sensitive areas, including scenic roads or rivers, have been identified at the Loudoun M&R Facility. The proposed modifications would occur within the existing Loudoun M&R Facility, which is located on existing industrial parcels. No additional lighting would be added at the Loudoun M&R Facility. The modifications would be consistent with the current visual character of the M&R Facility; therefore, no significant visual impacts would be anticipated.

The Leesburg Compressor Station Contractor Staging Area would be used for temporary construction laydown, parking, and staging during the period of construction. Activities at the site would occur within the existing industrial property boundary and would be consistent with the current views at the Leesburg Compressor Station. As such, we find that the temporary use of the Leesburg Compressor Station would not result in significant visual impacts.

2.5 SOCIOECONOMICS

Construction and operation of the Project could impact socioeconomic resources in the area. Some of these potential effects are related to the number of construction workers that would work on the Project and their impact on population, public services, and temporary housing during construction. Other potential effects are related to construction, such as increased traffic or disruption of normal traffic patterns. Other effects associated with the Project include increased property tax revenue, increased job opportunities, and increased income associated with local construction employment. The primary potential socioeconomic effects of the Project would be from construction and operation of the proposed Liquefaction Facilities in Calvert County, Maryland and the activities associated with the Pleasant Valley Compressor Station in Fairfax County, Virginia. The proposed modifications at the Loudoun M&R Facility and use of the Leesburg Compressor Station Contractor Staging Area in Loudoun County, Virginia, would occur within existing developed facilities and would represent relatively minor activities. Construction and operation of these facilities would not have a significant socioeconomic impact and, therefore, they are not discussed further in this section.

We received a number of comments in support of the Project based primarily on socioeconomic impacts, including increased employment, increased tax revenue, improved U.S. trade balance, and improved access to market for domestically produced natural gas. Comments in support of the Project were filed by U.S. Senator Cardin (D-MD), U.S. Congressmen Hoyer (D-MD) and Harris (R-MD), three members of the Maryland House of Delegates, one member of the Maryland Senate, the Calvert County Board of Commissioners, the St. Mary's County Board of Commissioners, the Calvert County Chamber of Commerce, the Calvert County Tourism Advisory Commission, the Tri-County Council of Southern Maryland, Maryland Conservation Council, and Calvert Cliffs Nuclear Power Plant, along with various trade unions and groups.

The Sierra Club and Cove of Calvert Homeowners Association raised concern that construction and operation of the Liquefaction Facilities could result in adverse socioeconomic impacts on surrounding communities and homeowners, including reduced property values. Homeowners near the Loudoun Compressor Station also voiced concern that increased compression originally proposed to be installed at the station could adversely impact property values and other resources. However, DCP's final proposal includes only minor modifications to the existing Loudoun M&R Facility and does not include increased compression at the Loudoun Compressor Station.

2.5.1 Population, Economy, and Employment

Table 2.5.1-1 provides a summary of selected demographic and socioeconomic conditions for affected communities in the Project area.

Construction of the Project would temporarily increase the population in the general Project area. Construction of the Liquefaction Facilities would occur over a 3-year period, between March 2014 and March 2017. The construction workforce would likely come from the general Project region, but may not be local due to the specialized construction experience required. Construction of the Liquefaction Facilities would require an average of 610 workers per quarter over the 3-year period of construction, with a peak workforce of between 1,045 and 1,441 workers per quarter between the third quarter 2015 and the second quarter 2016. With the export service that the Liquefaction Facilities would provide, operation at the LNG Terminal would require a total of about 200 employees, an approximate increase of 93 when compared to the current operational workforce of 107. The total population change during construction and operation would equal the total number of non-local workers plus any family members accompanying them. Based on the population of Calvert County, the additional people that would relocate to the area during construction of the Liquefaction Facilities would represent a temporary population increase of about 0.7 percent based on the average of 610 workers per quarter and about 1.6 percent based on the highest peak of 1,441 workers (in the third quarter 2015), assuming all temporary construction workers relocate to the Project area. Operation of the Liquefaction Facilities would result in a population increase of about 0.1 percent based on the addition of 93 new permanent employees. As such, the temporary and permanent workers associated with construction and operation of the Liquefaction Facilities would not result in a significant change in the population.

TABLE 2.5.1-1

Existing Economic Conditions in the Project Area

County/State	Population (2010) [a]	Population Density (persons/sq. mile) (2010) [b]	Per Capita Income (2007-2011) [c]	Civilian Workforce (2007-2011) [c]	Unemployment Rate (percent) (2007-2011) [c]	Top Three Industries (2007-2011) [c, d]
Maryland	5,773,552	594.8	$35,751	3,137,066	7.3	E, Pr, Pu
Calvert County	88,737	416.3	$37,321	47,794	5.3	E, Pu, Pr
Virginia	8,001,024	202.6	$33,040	4,109,104	6.5	E, Pr, R
Fairfax County	1,081,726	2,766.8	$50,145	604,317	4.7	Pr, E, Pu
Loudoun County	312,311	605.8	$46,493	168,756	4.3	Pr, E, R

[a] Source: U.S. Census Bureau, 2010.
[b] Source: U.S. Census Bureau, 2013.
[c] Source: U.S. Census Bureau, 2007-2011a.
[d] E = Educational services, and health care and social assistance
Pr = Professional, scientific, and management, and administrative and waste management services
Pu = Public administration
R = Retail trade

A short-term decrease in the unemployment rate could occur as a result of hiring local workers for construction and increased demands on the local economy in and near Calvert County. As noted earlier, the estimated 93 additional employees required to operate the LNG Terminal upon completion of the Liquefaction Facilities would have a positive, permanent impact on the unemployment rate and economy of the area.

Construction activities at the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility would occur between January 2016 and December 2017. Construction would require an average of 98 workers per quarter over the 2-year period of construction, with a peak workforce of 150 workers per quarter between the third quarter 2015 and the second quarter 2016. A decrease in the unemployment rate could result from the hiring of local workers for construction and increased demands on the local economy. Given the relatively short construction period and in our experience, most non-local workers would not be accompanied by their families. Based on the population of Fairfax County, the additional people that might temporarily relocate to the area would represent a temporary population increase of less than 0.1 percent based on the peak workforce of 150 workers, assuming all temporary construction workers relocate to the Project area. As such, the temporary workers associated with construction of the Pleasant Valley Compressor Station and associated facilities would not result in a significant change in the population. Operation of the new facilities in association with the Pleasant Valley Compressor Station would not require any additional permanent workers and, thus, no long term or permanent impacts on population or employment in Virginia would occur.

Construction of the proposed Project would result in a temporary increase in the local purchase of goods and services in the counties and regions affected by the Project. DCP estimates that construction of the Liquefaction Facilities (including use of Offsite Areas A and B) would generate about $1.2 billion of business sales for companies in Calvert County and approximately $515 million in business sales by other establishments in the State of Maryland. During operation of the Liquefaction Facilities, DCP estimates that annual business sales of $54 million in Calvert County and $12 million in the State of Maryland would occur between 2017 and 2040.

DCP estimates that construction of the Pleasant Valley Compressor Station and associated facilities would generate about $148 million of business sales for companies in Fairfax County. Operation of the Pleasant Valley facilities would not be expected to have a significant impact on local businesses.

2.5.2 Housing

Housing statistics for the counties affected by the Project are presented in table 2.5.2-1.

TABLE 2.5.2-1

Housing Statistics by County in the Project Area

County/State	Owner Occupied (2007-2011) [a]	Renter Occupied (2007-2011) [a]	Median Monthly Housing Costs (2007-2011) [a]: Owner Occupied	Median Monthly Housing Costs (2007-2011) [a]: Renter Occupied	For Seasonal or Occasional Use (2010) [b]	Vacant Housing Units (2007-2011) [a]	Rental Vacancy Rate (2007-2011) [a]	Number of Hotels/ Motels/ B&Bs [c]	Number of Camp-grounds/ RV Parks [c]
Maryland	1,461,708	666,669	2,066	2,178	55,786	240,791	8.1	818	38
Calvert	25,513	4,868	565	575	1,275	3,180	5.5	12	2
Virginia	2,046,845	944,180	1,782	408	80,468	354,873	6.9	1,868	248
Fairfax	273,783	111,787	2,612	725	2,062	20,824	4.8	67	2
Loudoun	78,987	20,774	2,873	749	665	7,795	7.9	63	0

a Source: U.S. Census Bureau, 2007-2011b.
b Source: U.S. Census Bureau, 2010.
c Sources: State of Maryland, 2013; Commonwealth of Virginia, 2013.

Temporary housing availability varies seasonally and geographically within the counties and communities near the proposed facilities and is available in the form of daily, weekly, and monthly rentals in motels, hotels, and campgrounds. The demand for temporary housing in the Project area is generally greatest during the summer months when tourism is at its height. Table 2.5.2-1 also provides the vacant housing units and median monthly housing costs along with the number of hotels/motels in the counties where Project facilities would be located. Other temporary housing is available in the Project vicinity, such as bed and breakfast facilities, apartments, and vacation properties, as well as those in other towns/ cities within commuting distance of the Project. Therefore, the availability of temporary housing is substantially greater than presented in table 2.5.2-1.

Construction of the Project could affect the availability of housing in the Project area. The Project would likely have a short-term positive impact on the area rental industry through increased demand and higher rates of occupancy. The primary impact on local housing would be from the relocation of construction workers to the Project area for work on the Liquefaction Facilities, which would result in a temporary increase in the local population. The counties within a 25-mile radius of the existing LNG Terminal include approximately 1,600 hotel rooms, in addition to the other types of housing identified in table 2.5.2-1. However, because construction activities at the Liquefaction Facilities would occur over an approximately 3-year period, most workers who relocate to the area would be expected to find housing in long-term rental situations, rather than hotels. Therefore, although construction activities would occur during peak tourism seasons, we find that the temporary influx of workers would not compete with tourists who travel to the area. In the event that rental accommodations are limited, we expect that the number of hotels, motels, and other accommodations in the region would be sufficient for the number of workers on the Project.

2.5.3 Public Services

A wide range of public services and facilities are offered in the counties affected by the Project, including hospitals, full-service law enforcement, paid and volunteer fire departments, and schools. The number of non-local workers and associated family members anticipated to enter the area would likely be small relative to the current populations in the Project area (see table 2.5.1-1). This would result in minor, temporary, or no impact on local community facilities and services, such as police, fire, and medical services. The counties, cities, and towns in the Project vicinity presently have adequate infrastructure and services to meet the needs of the non-local workers and family members.

Short-term impacts on public services could include the need for localized police assistance to control traffic flow during construction activities. Also, construction-related injuries could occur as a result of accidents or emergencies. In the event of a construction accident, DCP could require police, fire, and medical services, depending on the type of emergency. We conclude that the demand for police, fire, and medical services would not exceed the existing capabilities in the Project area because these services would only be used on an emergency basis. The nearest fire station to the Liquefaction Facilities is approximately 1.2 miles away on Little Cove Point Road in Lusby, Maryland. The nearest fire station to the Pleasant Valley Compressor Station is approximately 2.7 miles to the east. These emergency services are located in reasonable proximity to the Project area.

We received comments regarding the ability of local emergency providers to handle an incident at the LNG Terminal. DCP has established a history of assisting fire departments in areas where its existing facilities are located, including at the LNG Terminal. DCP has provided assistance to local emergency providers through training and general support, and would continue this practice with the ongoing operations at the LNG Terminal and other Project facilities.

2.5.4 Transportation and Traffic

We received comments concerning the volume of LNG ship traffic that would occur during Project operation. The LNG ship traffic to the LNG Terminal would vary yearly depending on LNG demand. The volume of ship traffic for LNG import has historically varied due primarily to market demand, and DCP expects that LNG export activity may also vary depending on demand. However, the annual frequency of ship traffic for the Project is estimated to be 85 LNG vessels per year, which would not exceed the previously approved ship traffic of up to approximately 200 vessels per year in Dockets CP05-130, et al., and DCP would not accept LNG carriers larger than previously authorized in Docket CP09-60. After reviewing the Cove Point Liquefaction Project, the USCG Sector Baltimore concurred that the Project should not result in an increase in the size and/or frequency of LNG marine traffic beyond that envisioned in the current WSA for the LNG Terminal, and that the WSA and LOR are adequate for the service associated with the Project. We agree.

We also received comments about the potential effect of LNG export on ship traffic to the Port of Baltimore and the federal navigation channels in the Chesapeake Bay. DCP's proposed export of LNG would not affect the federal navigation channels within the Chesapeake Bay or the route that ships currently use to travel to DCP's existing offshore pier because the volume and size of currently authorized LNG ship traffic would not change. Similarly, the Project would not affect existing ship traffic to and from the Port of Baltimore. If the maximum authorized ship traffic to the LNG Terminal occurs, it would only account for approximately 1.6 percent of commercial ship traffic transiting past the LNG Terminal annually.

DCP estimates that 42 barge deliveries would be made to the temporary offloading pier at Offsite Area B over the course of 18 months, which, on average, equates about 2.3 barge arrival per month. Based on the relatively small scale of construction and limited incidence and duration of use, we conclude that construction and use of Offsite Area B would result in only temporary and minor impacts on shipping in the Chesapeake Bay and Patuxent River.

The local road and highway system in the vicinity of the Liquefaction Facilities and Pleasant Valley Compressor Station consists of interstate highways, U.S. highways, state highways, secondary state highways, county roads, and private roads. Most public roads in the vicinity of the Project are paved. Construction of the Project could result in minor, short-term impacts along some roads and highways due to the movement and delivery of equipment, materials, and workers. Maps included in section 1.0 depict the roads that DCP would use to access the construction right-of-way.

We received comments regarding potential impacts on traffic using Cove Point Road, which provides the only access to the LNG Terminal, and through the surrounding neighborhood. The primary increase in traffic associated with construction at the LNG Terminal would be due to construction workers traveling to and from the work site. However, most construction workers would park at Offsite Area A and would be transported to the LNG Terminal site by bus or shuttle, thereby reducing the amount of traffic on Cove Point Road. In addition, transport of the large equipment from Offsite Area A would occur at night to minimize potential impacts on traffic. The vehicles used to transport this equipment would have noise levels consistent with other large trucks that travel on Maryland Route 2/4.

We also received comments regarding the impacts of Project-related traffic from Offsite Area B to the LNG Terminal or Offsite Area A. According to DCP, approximately 150 truck loads would originate from Offsite Area B during the course of construction of the Liquefaction Facilities. DCP would transport large equipment at night to minimize potential impacts on traffic by the slow moving vehicles. These vehicle movements would likely require support in the form of an escort. Further, the movement of large equipment and materials would be subject to local highway use permits. DCP has agreed to implement the Reviewing State Agencies' recommended license conditions for the CPCN related to traffic, including requirements that DCP consult with the MSHA and Calvert County Department of Public Works regarding potential impacts on traffic and the development of appropriate measures to reduce impacts. Therefore, we conclude that DCP's use of local roads during construction to transport equipment and materials from Offsite Area B would result in only a temporary and short-term impact on local traffic.

DCP completed a traffic impact analysis with recommendations that satisfy the Maryland State Highway Administration Guidelines and Adequate Public Facilities Ordinance requirements of Calvert County. The recommendations include installation of a traffic signal at the intersection of Maryland Route 2/4 and Maryland Route 497 (Cove Point Road). The traffic impact analysis also recommends the construction of a 200-foot right turn lane with a 150-foot taper along eastbound Maryland Route 497 at Little Cove Point Road. DCP's Traffic Impact Analysis has been approved by the State Highway Administration and Calvert County, and shows that the intersections that would be affected during construction activities at the Liquefaction Facilities (with the proposed improvements) would be sufficient to carry the proposed construction traffic. DCP's implementation of the recommended roadway improvements would reduce potential impacts on traffic in the vicinity of the LNG Terminal during construction of the Liquefaction Facilities. In addition, DCP's continued consultations with the MSHA and Calvert County related to the Reviewing State Agencies' recommended license conditions for the CPCN would result in additional measures to reduce potential traffic impacts.

2.5.5 Property Values

The majority of comments received regarding property values were related to the potential addition of compression at the Loudoun Compressor Station. However, as noted in section 2.5, DCP now proposes to construct only minor modifications at the Loudoun M&R Facility, none of which would include additional compression. We also received one comment from the Cove of Calvert Homeowners Association, located near the proposed Liquefaction Facilities, regarding potential impacts on property values in the area resulting from the additional operational activities at the LNG Terminal.

DCP's proposed Liquefaction Facilities would be located entirely within the Fenced Area of the existing LNG Terminal, which is an operating industrial facility. As discussed in section 2.4.3, the existing LNG Terminal is partially screened from the nearest residences across Cove Point Road and, in addition, DCP would install a 60-foot-tall sound barrier along the southern and western edges of the Fenced Area to shield surrounding, occupied areas from operation sights and sounds. The proposed sound barrier would be painted an appropriate color to blend in with the surrounding vegetation, and would be further shielded from adjacent views by the existing forested area around the LNG Terminal. Furthermore, DCP's LNG Terminal has operated in southern Calvert County for more than 30 years. Over that time the county's population has grown by more than 250 percent. Of 377 residential structures within 1 mile of the DCP facility (as of 2011), 323 were built after the facility commenced operations in 1978 (PPRP, 2014). This suggests that housing demand has not been significantly affected by proximity to DCP. Because the nearest residences to the Liquefaction Facilities are already near to an in-use industrial facility, and DCP would implement various measures to shield the new facilities from adjacent areas, we conclude the proposed Liquefaction Facilities would not result in a significant impact on nearby property values.

As discussed in section 2.4.3, construction activities at Offsite Areas A and B are not expected to result in significant impacts on nearby residences. The nearest resident to Offsite Area A is approximately 150 feet west from the property boundary and the nearest resident to Offsite Area B is that of the current property owner, approximately 160 feet east of the site. Construction activities at the offsite areas would be temporary, during the period of construction. Following construction, DCP would donate the 100-acre Offsite Area A parcel to Calvert County and restore the site in accordance with the wishes of the landowner. Offsite Area B would be restored and allowed to revert to its previous use, and the temporary pier would be removed. Therefore, we conclude use of Offsite Areas A and B would not significantly impact nearby property values.

Similar to the proposed Liquefaction Facilities, the proposed modifications in association with the Pleasant Valley Compressor Station would take place within DCP's existing in-use compressor station site and maintained pipeline right-of-way. Operation of the Project would be consistent with current use at the site. Although no existing residences are located within 0.25 mile of the Pleasant Valley Compressor Station, DCP would install a 20-foot-tall sound barrier along the eastern fence line of the site behind the existing tree/vegetative buffer. The proposed sound barrier would be painted an appropriate color to blend in with the surrounding vegetation. Because few residences are located near the Pleasant Valley Compressor Station, and with the installation of the proposed sound barrier, we conclude that operation of the Pleasant Valley Compressor Station and associated facilities would not result in a significant impact on nearby property values.

2.5.6 Tax Revenues

As noted in section 2.5, we received multiple comments regarding the potential benefits of construction and operation of the Liquefaction Facilities on the local economy, including increased tax revenues for Calvert County. Conversely, we received comments that the Project would not result in significant benefits to the local economy, and that the proposed export of LNG could result in adverse economic impacts throughout the United States, including increased natural gas prices. As discussed in section 1.5.1, the DOE-FE determines whether the export of natural gas is not inconsistent with the public interest and considers economic and other factors in making its decision on whether to authorize proposed exports. For the Project, DOE-FE issued Order No. 3019 on October 7, 2011, authorizing DCP to export LNG to FTA nations in accordance with section 3(c) of the NGA as amended by section 201 of the Energy Policy Act of 1992. On September 11, 2013, DOE-FE issued Order No. 3331 conditionally authorizing DCP to export LNG to non-FTA nations in accordance with section 3(a) of the NGA as amended by section 201 of the Energy Policy Act of 1992.

Construction of the Liquefaction Facilities and use of Offsite Areas A and B would generate a total of approximately $11.6 million in Calvert County income taxes during the period of construction between 2014 and 2017, and a total of $4.3 million in Calvert County income taxes during operations (between 2017 and 2040). In addition, the State of Maryland would collect income and sales taxes during construction and operation of the Project, including estimated totals of $24.3 million in income taxes and $12.4 million in sales taxes during construction (between 2014 and 2017), and totals of $8.6 million in income taxes and $4.4 million in sales taxes during operations (between 2017 and 2040).

In addition to income and sales taxes generated from construction and operation of the Project, the additional Liquefaction Facilities constructed at the LNG Terminal would be subject to additional property taxes for Calvert County, estimated to be approximately $40 million per year for the life of the Project.

Construction and operation of the new facilities associated with the Pleasant Valley Compressor Station would result in additional property taxes for Fairfax County, Virginia. DCP's investment in its existing facilities is expected to result in an annual property tax payment to the county of $746,000.

2.5.7 Environmental Justice

An environmental justice analysis is conducted in accordance with Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations" to consider disproportionately high and adverse impacts on minority or low-income populations in the surrounding community resulting from programs, policies, or activities of federal agencies. Issues considered include human health or environmental hazards, the natural or physical environment, and associated social, economic, and cultural factors.

All of the proposed operating facilities would be constructed within DCP's existing, industrial properties. No significant adverse environmental impacts inside or outside of these properties would be anticipated. Use of Offsite Areas A and B would be temporary and short-term, and these areas would be allowed to revert to previous uses or would be restored in accordance with the landowner's request. Construction and operation of the Project would not disproportionately affect any population group, including low-income and minority populations, and no environmental justice issues would occur as a result of construction or operation of the Project. In addition, the Project would have positive socioeconomic effects on the population in the Project area because it would generate new temporary jobs and economic activity in the region, and provide continuing and increased tax payments during its operational life.

2.6 CULTURAL RESOURCES

Section 106 of the NHPA, as amended, requires the FERC to take into account the effect of its undertakings on properties listed, or eligible for listing, on the NRHP, and to afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. DCP, as a non-federal party, is assisting us in meeting our obligations under section 106 and the implementing regulations found in 36 CFR 800.

2.6.1 Cultural Resources Investigations

Maryland

<u>Liquefaction Facilities</u>

Construction and operation of the Liquefaction Facilities would occur within the footprint of DCP's existing fenced area, which was previously surveyed for cultural resources. In a letter dated October 1, 2012, the Maryland State Historic Preservation Office (SHPO) indicated that the Terminal facility required no further investigation. We agree.

<u>Offsite Area A</u>

DCP completed a cultural resources survey of Offsite Area A and provided a Phase I report (Maymon, Roth, et al., 2013) to the FERC, the SHPO, and the Calvert County Department of Community Planning and Building. Two historic archaeological sites (18CV301 and 18CV505) and one isolated find were identified during the survey. All three resources were recommended as not eligible for the NRHP. In a letter dated April 26, 2013, the SHPO concurred with DCP's recommendations.

In a letter dated May 29, 2013, the Calvert County Department of Community Planning and Building requested additional testing of site 18CV505. DCP completed Phase II archaeological testing and assessed the site as eligible for the NRHP (Evans et al., 2013). Avoidance of the site, including a 50-foot buffer, was recommended. DCP indicated it would avoid the site using the 50-foot buffer. In a letter dated September 5, 2013, the Calvert County Department of Community Planning and Building concurred with DCP's recommendations. In a letter dated November 21, 2013, the SHPO also concurred with DCP's recommendations, and recommended that protective fencing be placed around the buffer area during construction. We agree with the SHPO. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, DCP should install protective fencing around the buffer area for site 18CV505 at Offsite Area A.**

<u>Offsite Area B</u>

DCP completed a cultural resources survey of the terrestrial portion of Offsite Area B and provided a Phase I report (Maymon, Roth, et al., 2013) to the FERC and SHPO. No cultural resources were identified. In a letter dated April 26, 2013, the SHPO recommended that deep testing be conducted if grading along the proposed haul road would exceed 2 feet below ground surface, to determine if intact buried archaeological deposits were present. DCP completed deep testing of the haul road area and found that the majority of the area had been previously disturbed by cutting and infilling, and it was unlikely that significant cultural components remained intact within the area. No further archaeological investigations were recommended. DCP submitted its revised Phase I report to the FERC and SHPO. In a letter dated November 21, 2013, the SHPO concurred with DCP's recommendations. We also agree.

DCP completed an underwater archaeological survey where the temporary offloading pier would be installed within the Patuxent River and provided the survey report (Schmidt et al., 2013) to the FERC and SHPO. Ten targets were recorded; four of these were identified as potential cultural resources and one was identified as a hazard. DCP recommended that these five targets be avoided by Project activities. In a letter dated April 26, 2013, the MHT concurred with the recommendations and also requested that two additional targets be avoided. DCP subsequently modified the pier alignment to avoid all but two of the targets (6 and 8) and conducted additional underwater surveys of these two locations. Based on the additional surveys, DCP concluded that these two targets consisted of modern debris and recommended no additional work (Schmidt et al., 2013, as revised). DCP's revised report was submitted to the FERC and SHPO, and in a letter dated September 23, 2013, the SHPO concurred with DCP's recommendations. However, the Reviewing State Agencies' recommended license conditions for Maryland's CPCN included minimum recommended avoidance distances from the five identified targets, and DCP has agreed to maintain the recommended distances during construction. We agree with the SHPO.

Virginia

<u>Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility</u>

Portions of the Pleasant Valley Compressor Station and all workspaces associated with the Pleasant Valley Suction/Discharge Pipelines and M&R Facility were previously surveyed and no additional field work was recommended for these areas. In a letter dated February 21, 2013, the Virginia SHPO concurred that no additional archaeological survey was warranted. DCP completed an archaeological survey for those portions of the Pleasant Valley Compressor Station not previously surveyed. No cultural resources were identified. DCP submitted a Phase I report (Maymon, Williams, et al., 2013) to the FERC and SHPO, and in a letter dated May 29, 2013, the SHPO concurred that no additional archaeological investigations were warranted. We also agree.

<u>Loudoun M&R Facility and Leesburg Compressor Station</u>

The proposed construction workspaces within the existing Loudoun M&R Facility and Leesburg Compressor Station were previously surveyed for cultural resources and none were found. In a letter dated February 21, 2013, the SHPO concurred that no additional archaeological survey was warranted. We agree with the SHPO.

We received several comments regarding potential cultural resources that may be directly or indirectly affected by the Project, including Riticor House, Watson/Old Carolina Road, rock art sites, standing architecture, "sacred landscapes on historic trails," and the Battle of Gilbert's Corner for the Virginia components of the Project, and the Calvert County Marine Museum, and the historic community of Solomons for the Maryland components of the Project. The concerns about the potential resources in Virginia were made in regard to the originally proposed expansion of the Loudoun Compressor Station. The compressor station component has subsequently been withdrawn from the Project. Additionally, the Riticor House and Watson/Old Carolina Road were addressed in DCP's report, and while in the general Project vicinity, would not be affected by the Project. No information was provided or found regarding rock art sites, standing architecture, "sacred landscapes on historic trails," or the Battle of Gilbert's Corner, and none of these were identified in the Project area. The Calvert County Marine Museum and the historic community of Solomons were also addressed in DCP's report and would not be impacted by the use of Offsite Area B. As discussed above, in letters dated April 26, 2013 and May 29, 2013, the Maryland and Virginia SHPOs, respectively, concurred with the recommendations in the survey reports that no additional investigations were required. We agree.

2.6.2 Native American Consultation

We sent our NOI to the Patawomeck Indians of Virginia, the Cedarville Band of Piscataway Indians, the Piscataway/Conoy Confederacy and Subtribes, the Piscataway Indian Nation, Inc., the Virginia Council on Indians, and the Maryland Commission on Indian Affairs. We sent our Project Update Notice to the same tribes and agencies listed above, as well as the Delaware Tribe of Indians, Delaware Nation, Tuscarora Nation of New York, Shawnee Tribe of Oklahoma, and Eastern Shawnee Tribe of Oklahoma. No responses have been received to date.

In addition to our contacts with the tribes, DCP contacted the Delaware Tribe of Indians, Delaware Nation, Tuscarora Nation of New York, Shawnee Tribe of Oklahoma, and Eastern Shawnee Tribe of Oklahoma in a letter dated January 11, 2013, to introduce the proposed Project and request comments regarding the potential for the Project to affect resources of tribal concern. DCP also followed-up with letters dated September 30, 2013. The Tuscarora Nation and the Delaware Nation responded and indicated that they had no objection to the Project, but requested to be consulted on any findings during construction. No further responses have been received from the tribes.

2.6.3 Unanticipated Discovery Plan

DCP prepared an Unanticipated Discovery Plan to deal with the unanticipated discovery of cultural resources and human remains during construction. We requested revisions to the plan. DCP provided a revised plan which we find acceptable.

2.6.4 Compliance with the National Historic Preservation Act

The Virginia and Maryland SHPOs and the FERC agree that the Project, with the recommendation described above, would not affect historic properties. Therefore, consultation under section 106 of the NHPA is complete.

2.7 AIR QUALITY AND NOISE

2.7.1 Air Quality

Air quality in Calvert County, Maryland and Loudoun and Fairfax Counties, Virginia would be affected by construction of the Project. During construction of the Project, short-term emissions would be generated by operation of equipment, land disturbance, and increased traffic from worker and delivery vehicles. Operation of the Liquefaction Facilities and Pleasant Valley Compressor Station would result in long-term air emissions. This section of the EA addresses the construction and operating emissions from the Project, as well as projected impacts and compliance with regulatory requirements.

Existing Environment

The existing LNG Terminal and Offsite Areas A and B are located in Calvert County, Maryland, which has a temperate climate. The area experiences average annual precipitation between 43.0 and 45.9 inches and monthly average daily temperatures range from 26.8 °F in January to 90.6 °F in July.

The climates of both Loudoun and Fairfax Counties, Virginia are similar to that of Calvert County. Table 2.7.1-1 illustrates the climate parameters of the three counties affected by the proposed Project.

TABLE 2.7.1-1 **Climate Data for Project Area**						
County	Monitor	U.S. Cooperative Observer Program (COOP) ID	Approximate Distance and Direction from Project Facility	Average Daily Minimum Temperature: January (°F)	Average Daily Maximum Temperature: July (°F)	Annual Precipitation (inches)
Calvert	Royal Oak 2 SSW, MD	187806	26 miles NE	28.4	88.0	45.87
	Colonial Beach, VA	441913	32 miles SW	26.8	90.6	42.69
	Vienna, MD	189140	33 miles NE	27.1	88.7	43.00
	Warsaw 2NW, VA	448894	35 miles SW	27.8	88.1	43.85
Loudoun	Lincoln, VA	444909	8.5 miles NW	20.8	87.1	43.21
	Mount Weather, VA	445851	16.5 miles NW	21.0	79.9	43.29
	Washington Dulles International, VA	448903	7 miles SE	21.9	87.4	41.8
Fairfax	Vienna, VA	448737	13 miles NE	N/A	N/A	45.12
	Warrenton 3 SE, VA	448888	18.5 miles SW	23.5	84.2	43.36
	Washington Dulles International, VA	448903	7 miles SE	21.9	87.4	41.8
	Reagan National Airport, VA	448906	25 miles E	27.3	88.3	39.35

Ambient air quality is protected by federal and state regulations. Under the Clean Air Act (CAA) and its amendments, the EPA has established National Ambient Air Quality Standards (NAAQS) for carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone, particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and sulfur dioxide (SO_2). The NAAQS include primary standards, which are designed to protect human health, including the health of sensitive subpopulations such as children and those with chronic respiratory problems. The NAAQS also include secondary standards designed to protect public welfare, including economic interests, visibility, vegetation, animal species, and other concerns not related to human health.

Individual states may set air quality standards that are at least as stringent as the NAAQS. Maryland has adopted all of the NAAQS in Title 26, Subtitle 11, Chapter 4, Section 2 of the Code of Maryland Regulations (COMAR 26.11.04.02) In addition, Maryland has defined a State Ambient Air Quality Standard for fluorides (COMAR 26.11.04.01). The State Ambient Air Quality Standard for fluorides, however, is not applicable to this Project because no emissions of fluorides are expected. Virginia has adopted all of the NAAQS in the Title 9, Agency 5, Chapter 30 of the Virginia Administrative Code. The NAAQS are summarized in table 2.7.1-2 below.

TABLE 2.7.1-2

National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary	Secondary
SO_2	3-hour [a]	None	0.5 ppm (1300 µg/m^3)
	1-hour [b]	75 ppb (196 µg/m^3)	
PM_{10}	24-hour [c]	150 µg/m^3	150 µg/m^3
$PM_{2.5}$	Annual [d]	12 µg/m^3	15 µg/m^3
	24-hour [e]	35 µg/m^3	35 µg/m^3
NO_2	Annual Mean [f]	53 ppb (100 µg/m^3)	53 ppb (100 µg/m^3)
	1-hour [g]	100 ppb (188 µg/m^3)	None
CO	8-hour [a]	9 ppm (10,000 µg/m^3)	None
	1-hour [a]	35 ppm (40,000 µg/m^3)	None
Ozone	8-hour [h]	0.075 ppm	0.075 ppm
Lead	Rolling 3-month [f]	0.15 µg/m^3	0.15 µg/m^3

[a] Not to be exceeded more than once per year.
[b] Compliance based on 3-year average of 99th percentile of daily maximum 1-hour average at each monitor within an area.
[c] Not to be exceeded more than once per year on average over 3 years.
[d] Compliance based on 3-year average of weighted annual mean $PM_{2.5}$ concentrations at community-oriented monitors.
[e] Compliance based on 3-year average of 98th percentile of 24-hour concentrations at each population-oriented monitor within an area.
[f] Not to be exceeded.
[g] Compliance based on 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area.
[h] Compliance based on 3-year average of fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area.

Ppb = parts per billion
µg/m^3 = micrograms per cubic meter
ppm = parts per million

The EPA and state and local agencies have established a network of ambient air quality monitoring stations to measure and track the background concentrations of criteria pollutants across the U.S. This data is then used by regulatory agencies to compare the air quality of an area to the NAAQS. To characterize the background air quality in the region surrounding the Project, data were obtained from representative air quality monitoring stations. These monitoring stations are located near the proposed Liquefaction Facilities and provide information on regional ambient air quality conditions. A summary of the regional ambient air quality monitoring data from the 3-year period (2009 to 2011) for the Project area is presented in table 2.7.1-3.

Air quality control regions (AQCRs) are areas established for air quality planning purposes in which implementation plans describe how ambient air quality standards would be achieved and maintained. AQCRs were established by the EPA and local agencies, in accordance with section 107 of the CAA, as a means to implement the CAA and comply with the NAAQS through State Implementation Plans (SIPs). The AQCRs are intra- and interstate regions such as large metropolitan areas where improvement of the air quality in one portion of the AQCR requires emission reductions throughout the AQCR. Each AQCR, or portion thereof, is designated based on compliance with the NAAQS. AQCR designations fall under three main categories as follows: “attainment” (areas in compliance with the NAAQS); “nonattainment” (areas not in compliance with the NAAQS); or “unclassifiable.” Unclassifiable areas are treated as attainment areas for the purpose of permitting a stationary source of pollution. Areas that have been designated nonattainment but have since demonstrated compliance with the ambient air quality standard(s) are designated maintenance for that pollutant. Maintenance areas may be subject to more stringent regulatory requirements to ensure continued attainment of the NAAQS pollutant.

The Maryland facilities are also within the Northeast Ozone Transport Region (OTR). The OTR (42 USC §7511c) includes 11 northeastern states in which ozone transports from one or more states and contributes to a violation of the ozone NAAQS in one or more other states. States in this region are required to submit a SIP, stationary sources are subject to more stringent permitting requirements, and various regulatory thresholds are lower for the pollutants that form ozone, even if they meet the ozone NAAQS.

TABLE 2.7.1-3

Ambient Air Quality Concentrations in the Project Area

Pollutant	Monitor [a]	Site ID	Distance from LNG Terminal	Averaging Period	Value (µg/m^3)	Year
SO_2	A	24-003-00-30	52 miles NW	1-hour	41.1	2009-2011
	A	24-003-00-30	52 miles NW	3-hour	54.8	2009
PM_{10}	A	24-003-00-30	52 miles NW	24-hour	25	2011
$PM_{2.5}$	B	51-059-0030	46 miles NW	24-hour	24.0	2009-2011
	B	51-059-0030	46 miles NW	annual	9.6	2009-2011
NO_2	C	51-153-0009	73 miles NW	annual	56.4	2009-2011
	C	51-153-0009	73 miles NW	1-hour	10.3	2011
CO	A	24-003-00-30	52 miles NW	1-hour	1,489	2011
	A	24-003-00-30	52 miles NW	8-hour	1,146	2010
Ozone	C	51-153-0009	73 miles NW	1-hour	175	2010
	C	51-153-0009	73 miles NW	8-hour	136	2009-2011
Lead	B	51-059-0030	46 miles NW	3 month	0.006	2009

[a] Monitoring Station Designations:
A = Howard University's Beltsville Laboratory; 12003 Old Baltimore Pike; Beltsville, Maryland.
B = Lee District Park; between Telegraph Road and Kings Highway; Groveton, Virginia.
C = James S. Long Park; Prince William County, Virginia.

The Liquefaction Facilities would be located in Calvert County, Maryland, which is in attainment for PM_{10}, $PM_{2.5}$, NO_2, CO, and Pb, and is within the Washington, DC AQCR designated nonattainment for ozone. The Virginia facilities are in Loudoun and Fairfax Counties, which are in attainment for PM_{10}, $PM_{2.5}$ (24-hour standard), NO_2, CO, and Pb. However, both Virginia Counties are also within the Washington, DC AQCR and are designated nonattainment for ozone and $PM_{2.5}$ (annual standard).

Greenhouse gases (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, nitrous oxide (N_2O), and ozone. On December 7, 2009, the EPA expanded its definition of air pollution to include six well-mixed GHGs, finding that the presence of the following GHGs in at the atmosphere endangers public health and public welfare currently and in the future: CO_2, methane, 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, methane, and N_2O. No fluorinated gases would be emitted by the Project. 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 properties of the GHG's ability to absorb solar radiation as well as the residence time within the atmosphere. Thus, CO_2 has a GWP of 1, methane has a GWP of 25, and N_2O has a GWP of 298. To obtain the CO_{2e} quantity, the mass of the particular chemical is multiplied by the corresponding GWP, the product of which is the CO_{2e} for that chemical. The CO_{2e} value for each of the GHG chemicals is summed to obtain the total CO_{2e} GHG emissions. In compliance with EPA's definition of air pollution to include GHGs, we have provided estimates of GHG emissions for construction and operation, as discussed throughout this section. Impacts from GHG emissions (climate change) are discussed in more detail under the Cumulative Impacts section of this EA.

Permitting/Regulatory Requirements

The CAA, as amended in 1977 and 1990, is the basic federal statute governing air pollution. The provisions of the CAA that are potentially relevant to the Project include the following, which are discussed further below:

- Prevention of Significant Deterioration (PSD);
- Nonattainment New Source Review (NNSR);
- Title V Operating Permits;
- New Source Performance Standards (NSPS);
- National Emission Standard for Hazardous Air Pollutants for Source Categories (NESHAP);
- Chemical Accident Prevention Provisions;
- General Conformity;
- GHG Reporting Rule; and
- State Regulations.

For the purposes of air permitting, the Liquefaction Facilities and LNG Terminal (existing LNG equipment) are considered a single stationary source for determining the regulatory applicability.

The Project would not involve any new operational air emission sources or emission increases at the Pleasant Valley M&R Facility or the Loudoun M&R Facility. Therefore, regulatory applicability is only discussed for the Liquefaction Facilities and the modified Pleasant Valley Compressor Station, with the exception of the General Conformity requirements, which apply to construction and operation emissions from mobile and stationary sources for the entire Project.

<u>Prevention of Significant Deterioration</u>

Separate procedures have been established for federal pre-construction air permit review of certain large proposed projects in attainment areas versus nonattainment areas. Federal preconstruction review for affected sources located in attainment areas is called PSD. This process is intended to keep new major sources or major modifications of air emission sources from causing deterioration of existing air quality below acceptable levels. Federal preconstruction review for affected sources located in nonattainment areas is commonly referred to as NNSR, which contains stricter thresholds and requirements. NNSR is discussed later in this section.

The PSD regulations (40 CFR 52.21) define a major source as any source type belonging to a list of named source categories that emit or have the potential to emit 100 tons per year (tpy) or more of any regulated pollutant or 250 tpy for sources not among the listed source categories. The LNG Terminal is an existing major PSD source because potential emissions for NO_2 and CO are currently over the Major Source Threshold (MST). Under the PSD permitting program, a physical change or change in the method of operation at existing major sources would be subject to PSD if it results in an increase in emissions higher than the established Significant Emission Rate (SER) for that pollutant. PSD review is triggered if emissions resulting from a modification to an existing major source exceed 100 tpy for CO; 40 tpy each for nitrogen oxides (NO_x), VOCs, and SO_2; 15 tpy for PM_{10}; or 10 tpy for $PM_{2.5}$.

As shown in table 2.7.1-6, the Liquefaction Facilities exceed PSD SER thresholds for NO_2, CO, PM, PM_{10}, and $PM_{2.5}$. Fluorides and total reduced sulfur emissions are negligible for the Liquefaction Facilities due to the nature of the emission generating activities. The PSD permitting process is being completed by the Maryland PSC, the MDNR, and PPRP in parallel with our environmental review. DCP's PSD application was included in its FERC application and elements of that application are summarized in this EA.

Table 2.7.1-7 identifies that the increases in annual emissions from the Pleasant Valley Compressor Station are below the PSD MSTs; therefore, the Pleasant Valley Compressor Station would not be subject to PSD permitting.

On May 13, 2010, the EPA issued a PSD GHG Tailoring Rule. The rule tailored specific applicability thresholds for GHG sources. The rule covers an estimated 70 percent of GHG emissions from stationary sources but does not apply to smaller sources such as apartment buildings and schools. Beginning on July 1, 2011, an existing industrial facility (of a non-listed source category) is subject to PSD review for GHGs if: 1) it is already subject to PSD review of non-GHG emissions (for another NSR pollutant) and would increase its GHG emissions by 75,000 tpy CO_{2e} or more and greater than zero tpy on a mass basis; 2) the existing potential GHGs emissions are equal to or greater than 100,000 tpy CO_{2e} and 250 tpy on a mass basis and GHG emissions as a result of the Project would increase by 75,000 tpy CO_{2e} or more and greater than zero tpy on a mas basis; or 3) the existing source is minor for PSD (including GHGs) and the modification alone would result in equal to or greater than 100,000 tpy CO_{2e} and 250 tpy of GHGs on a mass basis. The LNG Terminal is an existing PSD major source of GHG emissions and the Liquefaction Facilities have estimated CO_{2e} emissions increase above 75,000 tpy and greater than zero tpy GHG emissions on a mass basis. Therefore, the Liquefaction Facilities would be subject to the PSD GHG Tailoring Rule, and DCP included a GHG Best Available Control Technology (BACT) Analysis as part of its PSD permit application.

The potential impact on protected Class I areas must also be considered in the PSD review process. Areas of the country are categorized as Class I, Class II, or Class III. Class I areas are designated specifically as pristine natural areas or areas of natural significance, including wilderness areas and national parks, and are afforded special protection under the CAA. Class III designations, intended for heavily industrialized zones, can be made only on request, and must meet all requirements outlined in 40 CFR 51.166. The remainder of the United States is designated as Class II. The Federal Land Managers' Air Quality Related Values Work Group (FLAG) 2010 (FLAG, 2010) guidance states that a ratio of visibility-affecting emissions to distance (Q/d) value of 10 or less indicates that Air Quality Related Values analyses should not be required. Visibility-affecting pollutants are defined by the Federal Land Managers as: SO_2, NO_2, PM_{10}, and sulfuric acid mist (H_2SO_4). The nearest Class I area to the Project is Shenandoah National Park located about 158 kilometers from the LNG Terminal. Based on the minimum distance to a Class I area in this Project and the projected visibility-affecting emissions, the Q/d value would be substantially less than 10. Therefore, a PSD Class I analysis was not completed.

Nonattainment New Source Review

In nonattainment areas, a separate procedure has been established for federal pre-construction air permit review of certain large proposed projects; known as NNSR. NNSR applicability is determined separately and independently from PSD review. The applicability of the NNSR permitting program is based on the major source status of the facility and emissions increase from the Project. A physical modification or a change in the method of operation of an existing major source is subject to NNSR if the alteration would result in a significant emission increase of affected pollutants. Each NNSR pollutant and its precursor(s) are reviewed individually and compared to the applicable MST to determine major source status on a pollutant-by-pollutant basis. For each pollutant that is subject to NNSR permitting, the applicant must assess the following items in the NNSR permit application to the extent they are applicable:

- Lowest Achievable Emission Rate (LAER);
- Alternatives Analysis; and
- Purchasing of Emission Offsets.

Because the Liquefaction Facilities would be located in an area designated nonattainment for ozone, the Project has been evaluated for NNSR applicability with regards to the precursors of ozone, NO_x and VOC. Both NO_x and VOC have an NNSR SER limit of 25 tpy. As shown in table 2.7.1-6, the potential emissions increases from the Project are 279.3 tpy for NO_x and 33.3 tpy for VOC. Therefore, the Project is subject to NNSR for NO_x and VOC emissions.

The Pleasant Valley Compressor Station is also located in an area designated nonattainment for ozone and $PM_{2.5}$ (annual). As such, NNSR applicability was evaluated for NO_x, VOC, and $PM_{2.5}$. The potential emissions of the existing equipment at the Pleasant Valley Compressor Station would be below the MST for these pollutants. Emissions from the Project at the Pleasant Valley Compressor Station were compared to the applicable MSTs in order to determine NNSR applicability. As shown in table 2.7.1-7, potential emissions resulting from the Project at the Pleasant Valley Compressor station would be below the MSTs. The Project at the Pleasant Valley Compressor Station would not be subject to NNSR permitting.

Title V Operating Permit

The Title V Operating Permit program, as described in 40 CFR Part 70, requires major stationary sources of air emissions to obtain an operating permit within 1 year of initial facility startup. To determine if a facility is required to obtain a Title V permit, the potential emissions of criteria pollutants, HAPs, or GHGs from the entire facility are compared to the Title V MSTs of each pollutant. If emissions of any pollutant exceed the applicable MST, the facility must obtain a Title V permit. The MSTs for determining the need for a Title V Operating Permit are a potential to emit 100 tpy or more of any criteria pollutant, 10 tpy of any individual HAP, or 25 tpy of total HAPs (in aggregate).

The EPA also promulgated the Title V GHG Tailoring Rule, which established permitting thresholds for GHG emissions under the Title V program. Sources with an existing Title V permit or new sources obtaining a Title V permit for non-GHG pollutants are required to address GHGs. New sources and existing sources not previously subject to Title V that have a potential to emit equal to or greater than 100,000 tpy CO_{2e} would become subject to Title V requirements.

The existing LNG Terminal is considered an existing Title V major source and currently operates under a Title V permit (Permit number 24-009-00021). The facility would remain subject to the Title V program upon completion of the Liquefaction Facilities and DCP would be required to apply for a modification to the existing Title V permit to include the new facilities associated with the Project. The Liquefaction Facilities would be subject to the Title V GHG Tailoring Rule.

The Pleasant Valley Compressor Station is currently below and would remain below the Title V MSTs after completion of the Project. Therefore, the modified facility would not be subject to Title V permitting as a result of the Project. The Compressor Station would not be subject to the Title V GHG Tailoring Rule.

New Source Performance Standards

The NSPS, codified in 40 CFR Part 60, require new, modified, or reconstructed sources to control emissions as specified in the applicable source category provisions. Any source that is subject to provisions under an NSPS subpart is also subject to the general monitoring, reporting, and record keeping provisions of NSPS Subpart A, except as noted in the applicable subpart. This section outlines the applicability of NSPS subparts for the Project facilities.

NSPS Subpart D, *Standards of Performance for Fossil Fuel-Fired Steam Generators*, applies to all fossil fuel-fired steam generating units rated at more than 250 million British thermal units per hour (MMBtu/hr). The auxiliary boilers associated with the electric generation for the Liquefaction Facilities are rated at 435 MMBtu/hr and, thus, are potentially subject to the requirements of NSPS Subpart D. However, units constructed after June 19, 1986 are exempt from NSPS Subpart D per 40 CFR 60.40b(j). As such, this regulation is not applicable to the Project.

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, applies to all steam generating units with a heat capacity of more than 29 MW (100 MMBtu/hr). The auxiliary boilers associated with the electric generation for the Liquefaction Facilities are subject to the requirements of NSPS Subpart Db. The new natural gas boiler at the Pleasant Valley Compressor Station would be 5.1 MMBtu/hr. Therefore, it would not be subject to this regulation.

Per 40 CFR 60.44b(a), the auxiliary boilers associated with the Liquefaction Facilities would need to meet an emission limit of 86 nanograms of pollutant per Joule (ng/J) of NO_x (0.20 pounds per million British thermal units (lb/MMBtu)). These emission limits apply at all times including startup, shutdown, and malfunction. DCP would also be required to install a continuous emissions monitoring system (CEMS) for NO_x and either oxygen or CO_2 on each of the auxiliary boilers. DCP would also be required to conduct performance testing in accordance with 40 CFR 60.46b(c).

NSPS Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels*, applies to storage vessels that are constructed, reconstructed, or modified after July 23, 1984, with a capacity greater than 75 cubic meters (19,800 gallons) that would store volatile organic liquids. The Liquefaction Facilities would include eight tanks that are potentially subject to NSPS Subpart Kb: the four propane make-up tanks, the two ethane make-up tanks, and the two condensate storage tanks. NSPS Subpart Kb has an exemption (codified in 40 CFR 60.110b(d)(4)) for vessels with a design capacity less than 1,589.874 cubic meters used for petroleum or condensate stored, processed, or treated prior to custody transfer. The two condensate storage tanks would meet this exemption and are, therefore, not subject to NSPS Subpart Kb. The other six tanks would be subject to NSPS Subpart Kb. The four propane make-up tanks and the two ethane make-up tanks would be subject to the requirements of 40 CFR 60.112b(b) because they each have a storage capacity of more than 75 cubic meters and contain a volatile organic liquid with a true vapor pressure more than 76.6 kilopascals. To comply with these requirements, DCP would not vent emissions to the atmosphere from the tanks during normal operations. However, in the case of an emergency, the tanks could vent to a flare with a control efficiency of at least 95 percent.

The new tanks at the Pleasant Valley Compressor Station would be well below the NSPS Subpart Kb applicability volume threshold; therefore, the tanks would not be subject to this regulation.

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, applies to stationary compression ignition internal combustion engines manufactured after certain dates dependent on engine type. The fire pump engines at the Liquefaction Facilities would be subject to NSPS Subpart IIII because they would be NFPA-certified fire pumps manufactured after July 1, 2006 and ordered after July 11, 2005. The generator at the Liquefaction Facilities would be subject to NSPS Subpart IIII because it would be a stationary compression ignition internal combustion engine manufactured after April 1, 2006 and ordered after July 11, 2005.

The fire pump engines would be required to comply with emission standards in Table 4 to NSPS Subpart IIII. As an emergency use engine, the generator would be required to meet the applicable emission limitations in 40 CFR 60.4202. DCP would demonstrate compliance with the NSPS Subpart IIII emission limits by purchasing engines certified to the applicable emission limits. In addition, diesel combusted in the fire pump engines and generator would meet the requirements of 40 CFR 60.4207.

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to stationary combustion turbines with a maximum heat input equal to or greater than 10 MMBtu per hour, which were constructed, modified, or reconstructed after February 18, 2005. NSPS Subpart KKKK regulates emissions of NO_x and SO_2. The two new combustion turbines proposed as part of the Liquefaction Facilities would meet the capacity and construction date triggers and would be subject to NSPS Subpart KKKK. The microturbines at the Pleasant Valley Compressor Station would be less than 1 MMBtu/hr and, therefore, would not be subject to this regulation.

The natural gas-fired combustion turbines proposed at the Liquefaction Facilities must limit NO_x emissions from the turbines to 15 parts per million (ppm) at 15 percent O_2 or 54 ng/J (0.43 pound per megawatt-hour) of useful output. Emissions of SO_2 must also be limited to 110 ng/J (0.90 lb/MMBtu) of heat input or fuel must be limited to fuel that contains total potential sulfur emissions less than 26 ng/J (0.060 lb/MMBtu). DCP would demonstrate compliance with NSPS Subpart KKKK by installing a NO_x CEMS meeting the requirements on 40 CFR 60.4345 and burning natural gas with sulfur content below the aforementioned limit.

<u>National Emission Standards for Hazardous Air Pollutants</u>

The NESHAPs, codified in 40 CFR Parts 61 and 63, regulate the emissions of HAPs from existing and new sources.

Part 61 NESHAP regulations apply to the following eight compounds listed as HAPs prior to the CAA Amendments of 1990: asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chlorides.

The regulations list emission limits and operating parameters that must be followed for specified sources that emit these compounds. The emission sources included in the Project would not emit these pollutants. As such, the Project has no requirements under the 40 CFR 61 NESHAP regulations.

The 1990 CAA Amendments established a list of 189 HAPs, resulting in the promulgation of 40 CFR 63 NESHAP (Part 63). Part 63, also known as the Maximum Achievable Control Technology (MACT) standards, regulates HAP emissions specific source types located at major or area sources of HAPs. The existing LNG Terminal and Pleasant Valley Compressor Station are not major sources for HAPs, because HAP emissions are below the MST of 10 tpy of any single HAP or 25 tpy of all HAPs in aggregate. The LNG Terminal (including the Liquefaction Facilities) and the Pleasant Valley Compressor Station would remain minor sources of HAPs after the Project. NESHAPs apply to sources in specifically regulated industrial source categories [CAA Section 112(d)] or on a case-by-case basis [Section

112(g)] for major sources not regulated as a specific industrial source type. Below is a detailed discussion of the NESHAP regulations that are potentially applicable to the Liquefaction Facilities. In addition to the source type-specific regulations, any source which is subject to a subpart of 40 CFR 63 is also subject to the general provision of NESHAP Subpart A, unless otherwise noted in the applicable subpart.

The following NESHAP subparts were identified as potentially applicable to the Project based on source type: Subpart HHH, Subpart EEEE, Subpart YYYY, and Subpart DDDDD. However, these subparts are not applicable because the LNG Terminal, including the Project, would not be a major source of HAP emissions.

NESHAP Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations, applies to new sources with an initial startup date after September 20, 1999 having a potential to emit less than 10 tons individual HAP and 25 tons combined HAPs. Per 40 CFR 63.560(d)(5), this rule does not apply to marine tank vessel loading operations that exclusively transfer liquids containing organic HAPs as impurities, as defined in 40 CFR 63.561. The Liquefaction Facilities would meet this exemption; therefore, this rule is not applicable to the Project.

NESHAP Subpart ZZZZ, National Emission Standards of Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) applies to stationary RICE at major and area sources of HAPs. Although the LNG Terminal would be a minor source of HAPs, the fire pump engines and the generator at the Liquefaction Facilities would be constructed after June 12, 2006 at an area source of HAPs and would be subject to Subpart ZZZZ. As discussed above, the engines would be subject to NSPS Subpart IIII. Therefore, these engines satisfy the requirements under Subpart ZZZZ.

Chemical Accident Prevention Provisions

The chemical accident prevention provisions, codified in 40 CFR Part 68, are federal regulations designed to prevent the release of hazardous materials in the event of an accident and minimize potential impacts if a release does occur. The regulations contain a list of substances (including methane, propane, and ethylene) and threshold quantities for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more substances on this list in a quantity equal to or greater than specified in the regulation, the facility must prepare and submit a risk management plan (RMP). An RMP is not required to be submitted to the EPA until the chemicals are stored onsite at the facility.

If a facility does not have a listed substance on-site, or the quantity of a listed substance is below the applicability threshold, the facility does not have to prepare an RMP. However, if there is any regulated substance or other extremely hazardous substance onsite, the facility still must comply with the requirements of the General Duty Clause in Section 112(r)(1) of the 1990 CAA. 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 that belong to the same industrial group, are located on one or more contiguous properties, and are under control of the same person (or persons under common control) from which an accidental release may occur. However, the definition also states that the term stationary source does not apply to transportation, including storage incidental to transportation, of any regulated substance or any other extremely hazardous substance. The term transportation includes transportation subject to oversight or regulation under 49 CFR parts 192, 193, or 195. Based on these definitions, the LNG Terminal and Liquefaction Facilities are subject to 49 CFR Part 193. Therefore, these facilities would not be required to have an RMP. We have included an analysis of the proposed design's compliance with Part 193, including overpressure modeling, in section 2.8.6.

General Conformity

The EPA promulgated the General Conformity Rule on November 30, 1993, and amended it in 2006 and 2010 to implement the conformity provision of Title I, Section 176(c)(1) of the CAA. The purpose of this rule is to ensure that emissions from projects that require federal action are consistent with the approved SIP. Consistent with the rule, the following terms are used in this document:

- *General Conformity applicability analysis* is the calculating and compiling of emissions data for comparison to the applicability thresholds in order to determine whether a General Conformity Determination is required.

- *General Conformity Determination* is the evaluation (made after a General Conformity applicability analysis is completed) that a federal action conforms to the applicable implementation plan (e.g., SIP) and meets the requirements of this subpart.

The General Conformity Rule is codified in Title 40 CFR Part 93, Subpart B, Determining Conformity of General Federal Actions of State of Federal Implementation Plans. Any project that requires federal action must evaluate the applicability of the General Conformity Rule for those emission-generating activities resulting from the project and are located in an area that is designated as nonattainment or a maintenance area. A General Conformity Determination must be completed by the lead federal agency if a federal action is likely to result in direct and indirect emissions (construction and operation) that would exceed the General Conformity applicability threshold levels of the pollutant(s) for which an air basin is in nonattainment or maintenance. According to the General Conformity regulations, the portion of an action that includes major or minor new or modified stationary sources that require a permit under the NSR program (Section 110(a)(2)(c) and Section 173 of the CAA) or the PSD program (title I, part C of the CAA) are exempt and are deemed to have conformed.

Section 176(c)(1) of the CAA (Title 40 CFR 51.853) states that 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 any existing violation of any NAAQS; or
- Delay timely attainment of any NAAQS or interim emission reductions.

A General Conformity applicability analysis is required for parts of the Project occurring in counties identified as nonattainment or maintenance for regulated pollutants. Calvert County, Maryland is designated as a nonattainment area for ozone, and Loudoun and Fairfax Counties, Virginia are designated as nonattainment areas for ozone and $PM_{2.5}$. NO_x and VOC are precursors to the formation of ozone and are thus treated as nonattainment pollutants. The Project is located within the OTR. Any activity resulting in 100 tpy of NO_x or 50 tpy of VOC emissions from non-permitted emissions-generating activities associated with the Liquefaction Facilities or the Pleasant Valley Compressor Station modifications must undergo a General Conformity Determination. Because SO_2 and NO_x are precursors to $PM_{2.5}$, any emission increase of 100 tpy for more of $PM_{2.5}$, SO_2, or NO_x from non-permitted emissions-generating activities associated with the Pleasant Valley Compressor Station would also trigger a General Conformity Determination.

Construction activities associated with the Project would generate air emissions; specifically, increased on-road vehicle travel, construction equipment engines, off-road vehicle travel, earthmoving fugitives, barges delivering equipment, and off-shore marine vessels, including tugboats. Emissions from each of these activities were estimated for each of the three Project sites for each calendar year of construction.

Non-permitted operational emissions are those emissions that are not required to be regulated as part of the air quality permitting process. DCP has identified three sources of non-permitted operational emissions associated with the Project (all from the Liquefaction Facilities): new permanent employees commuting to the facility; waste haulers; and marine vessels. These non-permitted operational emission sources would only be noteworthy for the Liquefaction Facilities. The non-permitted operational emissions from the modifications at the Pleasant Valley Compressor Station would be negligible.

Table 2.7.1-4 summarizes the Project emissions from construction and non-permitted emissions-generating activities.

TABLE 2.7.1-4

Total Construction and Non-Permitted Project Emissions Summary

Year [a]	Emissions (tons/year)			
	NO_x	SO_2	VOC	$PM_{2.5}$
2014	171.13	0.00	15.38	0.00
2015	326.94	0.00	35.00	0.00
2016	230.91	0.79	32.80	5.82
2017 – Construction	123.14	0.03	16.43	0.66
2017 – Operation (non-permitted) – LNG Terminal	77.23	0.00	2.29	0.00
2017 (Total)	200.37	0.03	18.72	0.66
2018 & Beyond – Operation (non-permitted) – LNG Terminal	77.23	0.00	2.29	0.00
Conformity Applicability Threshold	100	100	50	100

[a] Project construction would occur between 2014 and 2017, followed by operation of the facilities. Only the Liquefaction Facilities would have any notable non-permitted operational emissions (marine vessels, employee commuter vehicle traffic, and waste haul truck traffic).

N/A Not Applicable

As shown in table 2.7.1-4, the Project triggers a General Conformity Determination for years 2014 through 2017 for construction-related NO_x emissions. A detailed Draft General Conformity Determination, issued concurrently with this EA is included in appendix B. This determination describes the regulations for determining applicability and demonstrating conformity. As noted in the Draft General Conformity Determination, DCP has committed to fully offsetting the project construction NO_x emissions through the purchase of emission reduction credits from within the Washington, DC AQCR. DCP has stated that 625 tons for NO_x emission reduction credits have been purchased.

This amount far exceeds the projected non-permitted emissions. As described above, in order to achieve improved air quality within a non-attainment area, reductions are required throughout the entire AQCR. The amount of emission reduction credits purchased would result in a net decrease in NO_x emissions within the AQCR during construction of the Project.

Although DCP stated it purchased these credits, it has not provided final documentation that it has purchased these offsets. Therefore, to allow the Commission staff to issue a final General Conformity Determination, **we recommend that:**

- **<u>Prior to construction</u>, DCP should file the following information for the issuance of a final General Conformity Determination:**

  a. an updated estimation of Project emissions for each calendar year of construction and initial start-up based on the current Project schedule at that time;

  b. a record of NO_x offsets obtained and demonstrate that this amount is equal to the amount required under the General Conformity regulation; and

  c. letters from MDE and VDEQ concurring that the offset requirements for the Project have been met.

The Project would result in construction-related emissions from barge traffic in other AQCRs in addition to the Washington, DC AQCR. The barges would pass through other AQCRs that are nonattainment for ozone (precursors NO_x and VOC) and $PM_{2.5}$ (precursors NO_x and SO_2). Total emissions of these pollutants and their precursors from barges in any AQCR do not exceed the General Conformity thresholds. As such, a General Conformity Determination is not required for barge emissions in other AQCRs.

<u>Greenhouse Gas Reporting Rule</u>

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases rule, establishing the Greenhouse Gas Reporting Program (GHGRP) codified in 40 CFR Part 98. Since 2011, the GHGRP has required large direct emitters of GHGs, and certain suppliers (e.g., of fossil fuels, petroleum products, industrial gases, and CO_2) to report GHGs. Subpart C of Title 40 CFR Part 98 applies to combustion units and Subpart W applies to petroleum and natural gas systems, including: both onshore and offshore petroleum and natural gas production; onshore natural gas processing; natural gas transmission compression; underground natural gas storage; liquefied natural gas storage, and import and export facilities that emit greater than or equal to 25,000 metric tons of GHGs, as CO_{2e}, per year. According to EPA's GHGRP webpage, "EPA's Greenhouse Gas Reporting Program will help us better understand where greenhouse gas emissions are coming from and will improve our ability to make informed policy, business and regulatory decisions" (EPA, 2012).

Emissions of GHG pollutants associated with the construction and operation of the Project were calculated. In addition, GHG emissions were converted to total CO_{2e} emissions based on GWP of each pollutant. GHG emissions associated with operation of the Project, as discussed earlier, are shown in table 2.7.1-6 and 2.7.1-7.

The GHGRP does not apply to construction emissions; however, we have included the construction emissions in table 2.7.1-5 for accounting and disclosure purposes. Based on the emission estimates summarized in table 2.7.1-6, the GHG emissions associated with the Liquefaction Facilities may potentially exceed 25,000 metric tpy. However, the GHGRP does not require emission control devices and is strictly a reporting requirement for stationary sources based on actual emissions. If the actual emissions from the Liquefaction Facilities are equal to or greater than 25,000 metric tpy, DCP would be required to comply with all applicable requirements of 40 CFR Part 98.

State Regulations

The MDE is the lead air permitting authority for the Liquefaction Facilities, and the VDEQ administers the federal and state air quality standards for the facilities in Virginia. The applicable state regulations for each facility are summarized below. State regulations that are not applicable are not included in the summary below.

Liquefaction Facilities

Maryland state air quality regulations are codified in COMAR Tile 26, Subtitle 11. The Project would be required to obtain an air quality permit prior to initiating construction. This section discusses the applicability of state air quality regulations to the Project. Facilities also trigger review by other states if the project location is within 50 miles of an adjacent state's border. The Liquefaction Facilities would be located within 50 miles of the border of Delaware and Virginia. The air permitting authorities of these states will have the opportunity to review and comment on the application and subsequent permits.

The existing LNG Terminal currently operates under permit number 24-009-00021. DCP would be required to obtain an air permit prior to initiating construction or modifying the site. To this end, DCP is seeking a CPCN from Maryland PSC. The process of obtaining the CPCN will involve the review and implementation of state regulations, inclusive of requirements for PSD and NNSR. The state regulations summarized below are those that would establish emission limits or other restrictions that may be in addition to those required under federal regulations.

COMAR 26.11.06, *General Emission Standards, Prohibitions, and Restrictions*, establishes emission standards for various pollutants from certain source types. These emissions standards include limits on opacity, PM, SO_2, and odor/nuisance.

COMAR 26.11.09, *Control of Fuel-Burning Equipment, Stationary Internal Combustion Engines, and Certain Fuel-Burning Installations*, establishes emission limits for various pollutants from certain types of fuel burning units. The combustion turbines, auxiliary boilers, fire pumps, and emergency generator meet the definition of fuel-burning equipment and would potentially be subject to the opacity, PM, SO_2, and NO_x requirements of this chapter.

COMAR 26.11.15 and 16, *Toxic Air Pollutants and Procedures Related to Requirements for Toxic Air Pollutants*, establishes MDE's program for toxic air pollutants (TAPs). The existing LNG Terminal emits TAPs, as defined by COMAR 26.11.16. As such, DCP must demonstrate compliance with the TAP regulations. The Liquefaction Facilities must quantify emissions of each TAP; identify, install, and operate BACT for toxics on new and reconstructed source(s) of TAP emissions (COMAR 26.11.15.05); and demonstrate that emissions of TAPs (total allowable emissions from the premises) would not adversely impact public health beyond the property line (COMAR 26.11.15.06).

Pleasant Valley Compressor Station

Virginia Administrative Code, Title 9, Agency 5, Chapter 50, *New and Modified Stationary Sources*, contains provisions that generally determine methods of compliance for new and modified stationary sources including testing and continuous monitoring requirements. Due to the insignificant nature of the Project activities at the Pleasant Valley Compressor Station, these regulations would not apply. Other provisions of this Chapter include reporting and recordkeeping requirements, and opacity and odor standards. DCP would be required to comply with these standards.

Impacts and Mitigation

The Project would produce air pollutant emissions from both construction and operation. Construction of the Liquefaction Facilities would occur over a period of less than 4 years. Construction at the Pleasant Valley Compressor Station (including the Pleasant Valley Suction/Discharge Pipelines and M&R Facility) and Loudoun M&R Facility would occur over a period of less than 2 years. Therefore, the air quality impacts of Project construction are considered short-term. Following construction, air quality would not revert back to previous conditions, but rather would transition to operational emissions after commissioning and initial startup of the Project facilities.

Construction Impacts and Mitigation

Construction of the Project would result in short-term increases in emissions of some pollutants from the use of fossil fuel-fired equipment and the generation of fugitive dust due to earthmoving activities. There may also be some temporary indirect emissions attributable to construction workers commuting to and from work sites during construction, from barges transporting construction materials, and from on-road and off-road construction vehicle traffic. Large earth-moving equipment and other mobile equipment are sources of combustion-related emissions, including criteria pollutants (i.e., NO_x, CO, VOC, SO_2, and PM_{10}) and small amounts of HAPs.

TABLE 2.7.1-5

Total Construction Emissions Summary

	Emissions (tons/year)							
Year	NO_x	CO	SO_2	VOC	PM_{10}	$PM_{2.5}$	GHG (CO_2e)	HAPs
2014	171.13	182.99	9.44	15.38	57.54	26.76	32,497	3.01
2015	325.12	388.30	106.29	34.98	73.25	37.59	57,781	6.83
2016	230.91	385.55	12.38	32.49	49.03	25.27	45,727	6.35
2017	123.14	158.89	8.45	16.43	69.78	20.37	32,253	3.20

The majority of air emissions produced during construction activities would be PM_{10} and $PM_{2.5}$ in the form of fugitive dust. Fugitive dust would result from land clearing, grading, excavation, concrete work, and vehicle traffic on paved and unpaved roads. The quantity of fugitive dust generated by construction-related activities depends on several factors, including the size of area disturbed; the nature and intensity of construction activity; surface properties (such as the silt and moisture content of the soil); the wind speed; and the speed, weight, and volume of vehicular traffic. Emissions would be greater during dry periods and in areas of fine-textured soils subject to surface activity.

Several commenters are concerned about dust generation during construction. Table 2.7.1-5 includes the emissions associated with fugitive dust generation. In addition, DCP has prepared a Fugitive Dust Control Plan to identify emission reduction measures that may be implemented to achieve the emission reductions assumed in calculating the Project construction emissions (such as water suppression, covering storage piles, covering truck loads during transit, limiting on-site vehicle speed, measures to reduce track-out on public roads, etc.). However, we do not believe the Fugitive Dust Control Plan sufficiently describes how DCP would implement these measures to ensure adequate mitigation of fugitive dust emissions that would occur in the same area over a multi-year period (e.g., identification of speed limits, usage of speed limit signage, use of gravel at construction entrances to reduce track-out). In addition, DCP has not provided any information about accountability or individuals with authority regarding fugitive dust mitigation. Therefore, **we recommend that:**

- **Prior to construction, DCP should file a revised Fugitive Dust Control Plan with the Secretary, for review and written approval by the Director of OEP. The plan**

should specify the precautions that DCP would take to minimize fugitive dust emissions from construction activities and identify additional mitigation measures to control fugitive dust emissions of Total Suspended Particulates, PM_{10}, and $PM_{2.5}$, including:

a. identifying how DCP would implement these measures (e.g., identification of speed limits, usage of speed limit signage, use of gravel at construction entrances to reduce track-out);

b. clarifying that the EI has the authority to determine if/when water or a palliative needs to be used for dust control; and

c. clarifying that the EI has the authority to stop work if the contractor does not comply with dust control measures.

Work at the Liquefaction Facilities and Offsite Areas A and B may result in some increase in traffic volumes on local public roads; however, construction work would typically occur during daylight hours (7:00 a.m. to 6:00 p.m.), 6 days per week. Transport of large equipment would occur at night to minimize potential impacts to traffic by the slow movement of oversized and overweight equipment. Most construction workers would park at Offsite Area A and be transported to the Liquefaction Facilities site by bus or shuttle. The emissions from the construction traffic are included in the construction emissions.

Construction related emission estimates were based on a typical construction equipment list, hours of operation, and vehicle miles traveled by the construction equipment and supporting vehicles for each area of the Project. Construction activities at the Pleasant Valley Compressor Station, Pleasant Valley Suction/Discharge Pipelines, Pleasant Valley M&R Facility, and Loudoun M&R Facility are also expected to occur in calendar years 2016 and 2017. These emission-generating activities would include earthmoving, construction equipment exhaust, on-road vehicle traffic, and off-road vehicle traffic. Construction emissions from the Project are summarized above in table 2.7.1-5.

Construction of the Project would occur over a four-year period, resulting in short-term impacts on air quality. Once construction activities in an area are completed, fugitive dust and construction equipment emissions would subside. Conditions after completion of construction would transition to operational-phase emissions after commissioning and initial startup of the facility.

<u>Operational Impacts and Mitigation</u>

The Project would include the installation of the following stationary point sources of air pollutants at the LNG Terminal:

- Two GE Frame 7 natural gas turbines, each rated at 1,062 MMBtu/hr, equipped with SCR and an oxidation catalyst;
- Two auxiliary natural gas boilers, each rated at 435 MMBtu/hr, equipped with SCR and an oxidation catalyst;
- One diesel emergency generator, rated at 1,550 hp;
- Five fire pump diesel engines, each rated at 350 hp;
- One thermal oxidizer equipped with a burner rated at 56 MMBtu/hr, equipped with SCR and an oxidation catalyst;

- Two ground flares;
- Tanks to support the process, emissions control equipment, and combustion equipment. Most tank sizes range from 12,000 to 67,000 gallons, except small 750-gallon process tanks, and four large 102,500-gallon propane make-up tanks; and
- Other process and liquefaction equipment with minimal environmental impacts.

The Project would also include the installation of the following stationary point sources of air pollutants at the Pleasant Valley Compressor Station:

- One natural gas-fired boiler rated at 2.5 MMBtu/hr;
- Two microturbines, rated at 80 hp and used for emergency purposes;
- One 3,000-gallon waste fluid tank; and
- One 1,000-gallon coolant tank containing water and ethylene glycol.

The Project would also include miscellaneous piping and measurement upgrades at the Loudoun M&R Facility; however, there are no new emissions sources as part of the Project at this site.

We received several comments about the magnitude of criteria pollutant and GHG emissions from the Liquefaction Facilities and stating the belief that this Project would become one of the largest GHG emitters in the State of Maryland when compared to actual emissions from other facilities. The potential to emit from the existing LNG Terminal, the Liquefaction Facilities, and Pleasant Valley Compressor Station are summarized in tables 2.7.1-6 and 2.7.1-7. The emissions identified in these tables represent the maximum potential to emit, and are not directly comparable to past actual emissions from the LNG Terminal or other regional sources because the emissions below represent continuous operation (8,760 hours per year) of the emission sources at their full capacity. Past actual emissions are based on the actual load conditions and operating hours, which may be notably lower than those used to estimate the potential to emit. In addition, all new major air emission sources must obtain the appropriate PSD or NNSR permit to adequately protect air quality. The criteria pollutant emissions that trigger NNSR must be controlled to LAER levels and offsets must be obtained. The criteria pollutant emissions that trigger PSD review must be controlled to BACT levels and modeled to demonstrate compliance with ambient air quality standards. New GHG sources subject to PSD review must control the emissions to BACT levels. These air permitting programs are included in the state SIPs that account for industrial growth while reducing overall emissions in the state to meet air quality goals. The impacts associated with the criteria pollutant emissions are presented below under Air Dispersion Modeling and for GHG emissions are presented in the climate change discussion in section 2.9.9.

The Maryland PSC has reviewed DCP's proposed BACT and LAER analysis for the Liquefaction Facilities, including the combustion turbines, auxiliary boilers, emergency internal combustion engines, flares, and thermal oxidizers. Methods for reducing emissions of NOx, CO, VOCs, and PM_{10}/$PM_{2.5}$ for each of these sources were evaluated based on technical feasibility. DCP would reduce normal operating emissions of NO_x from the gas turbines, auxiliary boilers, and thermal oxidizer through the use of SCR; CO and VOC emissions would be controlled through the use of oxidation catalysts; and particulate matter (PM, PM_{10}, and $PM_{2.5}$) would be reduced through the use of good combustion practices and burning only pipeline quality natural gas and fuel gas. The emergency generators and fire pump 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 would be reduced through good combustion practices (such as maintenance of proper combustion efficiency). The resulting BACT and LAER emission rates are equal to or more stringent than any NSPS, NESHAP, and/or BACT emission standards applicable to these emission sources. The BACT determinations for GHG emissions are discussed with climate change in section 2.9.9.

The emissions presented in table 2.7.1-6 include the Maryland PSC's proposed BACT and LAER pollutant limitations or measures for the various Liquefaction Facility sources.

TABLE 2.7.1-6

Liquefaction Facilities Potential Emissions Summary

Emission Source	NO_2	CO	SO_2	PM [a]	PM_{10} [b]	$PM_{2.5}$ [b]	H_2SO_4	H_2S	VOC	HAPs	GHGs
Existing LNG Terminal	278.8	813.55	1.84	67.60	67.60	67.60	N/D	N/D	33.8	8.2	1,355,859
Combustion Turbines	102.0	37.9	2.1	31.0	61.3	61.3	3.2	1.1	9.8	10.6	1,089,376
Thermal Oxidizer	6.2	2.3	0.3	3.1	4.0	4.0	0.5	0.2	0.1	0.2	386,177
Auxiliary Boilers	50.8	45.2	0.2	19.7	51.8	51.8	0.2	0.1	4.2	0.0	446,213
Flares	110.0	49.6	0.0	1.1	4.5	4.5	0.0	0.0	14.8	0.3	64,859
Fire Pumps	0.5	0.6	0.2	0.0	0.0	0.0	0.0	0.0	0.2	0.0	104
Generator	3.8	2.2	0.0	0.1	0.1	0.1	0.0	0.0	0.3	0.0	444
Leaking Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	0.0	66
Existing Frame 5 Turbines	6.0	8.8	0.0	0.7	2.5	2.5	0.0	0.0	1.2	0.7	43,749
Total Increase	279.3	146.6	2.8	55.7	124.2	124.2	4.0	1.4	33.3	11.8	2,030,988
PSD SERs (tpy)	40	100	40	25	15	10	7	10	NA	NA	75,000
NNSR SERs (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	25	NA	NA
Over SER?	Yes	Yes	No	Yes	Yes	Yes	No	No	Yes	Yes	Yes

[a] Values include filterable emissions only

[b] Values include filterable and condensable emissions

N/D No Data Available

Note: The totals shown in this table may not equal the sum of addends due to rounding.

TABLE 2.7.1-7

Pleasant Valley Compressor Station Potential Emissions Summary (tons/year)

Emission Source	NO_2	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	GHGs
Two Microturbines	0.26	0.26	0.69	0.00	0.3	0.30	0.01	824
One Boiler	1.05	1.05	0.88	0.01	0.08	0.08	0.06	1,258
Fugitive Emissions	-	-	-	-	-	-	0.68	240
Tanks	-	-	-	-	-	-	Neg.	-
Total Increase	1.31	1.31	1.57	0.01	0.38	0.38	0.74	2,321
Existing Facility	2.54	2.54	2.20	0.01	0.77	0.77	2.64	5,073
Total After Project	3.85	3.85	3.77	0.02	1.15	1.15	3.38	7,394
PSD MST (tons/year)	250	NA	250	250	250	NA	NA	100,000
NNSR MST (tons/year)	NA	100	NA	NA	NA	100	50	NA
Title V MST (tons/year)	100	NA	100	100	100	100	100	100,000
Over MST?	No	No	No	No	No	No	No	No

Neg. Negligible

In addition to limiting operational emissions from Liquefaction Facilities to BACT and LAER levels, DCP is also required to offset operational NO_x and VOC emissions under NNSR at a ratio of 1.3 to 1 (i.e., 1.3 tons of offsets per ton of emissions from the Liquefaction Facilities). The PPRP has identified that DCP already obtained sufficient NO_x and VOC offsets for the operational NO_x and VOC emissions. We received comments requesting these offsets be purchased locally. These offsets are purchased as a result of the NNSR review process and the Maryland PSC has authority for approval of the offsets. However, as discussed above, in order to improve air quality at one location, reductions are necessary throughout the AQCR. Therefore, these emission offsets are not required to be obtained from sources within the same county but rather within the same AQCR.

Air Dispersion Modeling

In order to provide a more thorough evaluation of potential air quality in the vicinity of the Project, air dispersion modeling analyses were completed for the CPCN/air permit application to the Maryland PSC and for the FERC application. The CPCN/air permit modeling was completed for demonstrating compliance with the PSD review requirements in order to obtain an air permit. That modeling showed that the Liquefaction Facilities' stationary emission sources would not cause or significantly contribute to an exceedance of an ambient air quality standard or ambient air increment.

We received several comments requesting that impacts from LNG carriers be included as part of the Project and that the modeling analysis consider worst case emissions. Although the Project would not include any additional LNG carriers above those previously evaluated in the Pier Reinforcement and Cove Point Expansion Projects, we requested the DCP provide a separate modeling analysis (FERC Modeling). The FERC Modeling differs from the PSD modeling because it included marine vessel emissions while docked at the existing offshore pier at the LNG Terminal, in addition to stationary sources. After construction of the Project, the LNG Terminal and Liquefaction Facilities could operate under one of two scenarios (liquefaction or regasification). Market demands would determine the utilization of either liquefaction or regasification facilities. The regasification facilities were previously evaluated and authorized through FERC and MDE permitting. Because the LNG Terminal would have the capability of being bidirectional, for short-term averaging periods, the FERC Modeling assumed the worst case scenario of LNG import at the dock simultaneously with either liquefaction or gasification operations at the terminal. Because this operating scenario cannot be sustained long-term (the LNG tanks would become full), this scenario is considered conservative for the long-term modeled averaging periods. In addition, the LNG Terminal would average less than one vessel per day, resulting in a low likelihood of two vessels docked at one time. Although the modeling assumed one vessel at the dock at a time, the modeling made several conservative assumptions including: always importing LNG at the dock (importing requires the use of additional pumps onboard the LNG carriers that are not used for exporting), using the worst case fuel, and assuming continuous operation. Further, the most stringent short-term standards (1-hour NO_2 and 1-hour SO_2) are percentile standards. The Project would include intermittent emission sources that were modeled as continuous sources at their peak short term NO_x and SO_2 emission rates rather than average emission rates. This results in conservative results when compared to the percentile based short-term standards.

The modeling was performed using the AERMOD dispersion modeling program. The AERMOD modeling program is a Gaussian plume dispersion model that includes the building profile input program PRIME version for estimating impacts from building wake effects and terrain data for estimating the impacts of changing elevation on ground level pollutant concentrations. The modeling for NO_2 was performed using the plume volume molar ratio method (PVMRM) for estimating NO_2 concentrations by simulating the conversion of NO_x to NO_2. We reviewed the model selection, input parameters, and assumptions and agree with DCP's modeling methodology.

In the first step of the FERC Modeling, DCP modeled the emissions from the Project (including marine vessels) and compared the highest modeled concentration for each pollutant and averaging period to the significant impact levels (SILs). If the highest modeled concentration for any pollutant/averaging period is below the SIL, the source is presumed not to cause or contribute to an exceedance of the NAAQS and no further modeling is necessary. A summary of the significant modeling is provided in table 2.7.1-8.

As shown in table 2.7.1-8, the modeled CO 1-hour and 8-hour concentrations are the only results that were below the SILs. As such, refined modeling to demonstrate compliance with the NAAQS were performed for all other pollutants and averaging periods. For the cumulative NAAQS analysis, the Project (including marine vessels) and other off-site sources were modeled. To account for additional sources that may not have been modeled but that may contribute to background pollutant levels in the Project area, monitoring data from representative monitoring sites were added to the modeling results prior to comparison to the NAAQS.

TABLE 2.7.1-8

LNG Terminal SIL Analysis Summary [a]

Pollutant	Averaging Period	Modeled Concentration (µg/m^3)	SIL (µg/m^3)
CO	1-hour	867.3	2,000
CO	8-hour	177.2	500
PM_{10}	24-hour	11.8	5
$PM_{2.5}$	24-hour	8.9	1.2
$PM_{2.5}$	Annual	1.3	0.3
SO_2	1-hour	74.5	7.8
SO_2	3-hour	121.7	25
SO_2	24-hour	45.6	5
SO_2	Annual	3.9	1
NO_2	1-hour	228.7	7.5
NO_2	Annual	4.6	1
Lead	3-month	0.00047	NA

[a] Both gasification (LNG Terminal) and liquefaction (Liquefaction Facilities) were modeled in the FERC modeling analysis for demonstrating compliance with the ambient air quality standards. Under the liquefaction scenario, some gasification equipment were modeled that operate in a back-up capacity to the liquefaction equipment.

µg/m^3 = micrograms per cubic meter

The refined NAAQS analysis demonstrated that the Liquefaction Facilities' emissions sources (onshore stationary and marine vessel emissions at the pier) would not cause or significantly contribute to an exceedance of a standard with the exception of one receptor located on the Calvert Cliffs Nuclear Power Plant property. This receptor is located on restricted industrial property that is, therefore, not categorized as "ambient air." EPA guidance specifies that Calvert Cliffs cannot cause an exceedance on its own property. Therefore, the emissions from the Calvert Cliffs Nuclear Power Plant are allowed to be subtracted from the modeling. Upon removal of the Calvert Cliffs Nuclear Power Plant emissions from the modeled concentration at this receptor, the modeled concentration was below the standard. The results of the NAAQS analysis are provided in table 2.7.1-9. The modeling demonstrates compliance with the NAAQS. We reviewed the FERC Modeling and agree with the conclusions presented.

Because the proposed Project is located in an ozone nonattainment area, we evaluated the need for an ozone modeling analysis. The Project would be required to offset the NO_x and VOC emissions from the stationary sources at the facility at a 1.3 to 1 ratio; resulting in a net emission decrease of ozone precursors. Further, because ozone impact modeling is a regional scale assessment tool, rather than a local impact identifier, the regional emission reductions within the AQCR to offset the Project emissions can reasonably be expected to improve the regional ozone concentrations. Therefore, additional modeling was not required.

TABLE 2.7.1-9

LNG Terminal NAAQS Analysis Summary [a]

Pollutant	Averaging Period	Modeled Concentration (µg/m³) [b]	NAAQS (µg/m³)
PM_{10}	24-hour	34.4	150
$PM_{2.5}$	24-hour	34.8	35
$PM_{2.5}$	Annual	11.8	12
SO_2	1-hour	195.997	196
SO_2	3-hour	174.5	1,300
SO_2	24-hour	65.1	365
SO_2	Annual	10.88	80
NO_2	1-hour	187.9	188
NO_2	Annual	20.8	100
Lead	3-month	0.072	0.15

[a] Both gasification (LNG Terminal) and liquefaction (Liquefaction Facilities) were modeled in the FERC modeling analysis for demonstrating compliance with the ambient air quality standards. Under the liquefaction scenario, some gasification equipment were modeled that operate in a back-up capacity to the liquefaction equipment.

[b] Modeled concentration includes the ambient monitored (background) concentration.

µg/m³ = micrograms per cubic meter

SIL = Significant Impact Level.

In addition to the cumulative NAAQS analysis discussed above, DCP submitted in its CPCN/air permit application to the Maryland PSC an increment consumption analysis and an Additional Impacts Analysis to satisfy PSD permitting requirements for the Liquefaction Facilities. The results of these analyses are provided below to disclose further impacts associated with the Liquefaction Facilities.

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 an applicable PSD increment 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 Maryland PSC showed that the predicted maximum 1-hr NO_2, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ concentrations exceed the respective SILs. There is no 1-hour NO_2 PSD increment; however, a comprehensive PSD increment analysis was required for $PM_{2.5}$ emissions as part of the PSD permit application submitted to the Maryland PSC.

DCP's CPCN/air permit application was the first PSD application submitted following the $PM_{2.5}$ major source baseline date October 20, 2010 and the $PM_{2.5}$ trigger date of October 20, 2011. Therefore, DCP was the only source that needed to be considered in the $PM_{2.5}$ increment analysis. The modeled 24-hour and annual $PM_{2.5}$ concentrations of 3.7 micrograms per cubic meter (µg/m³) and 0.56 µg/m³ are below the respective PSD increments of 9 µg/m³ and 4 µg/m³.

DCP also submitted to the Maryland PSC an Additional Impacts 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 Liquefaction Facilities.

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 Liquefaction Facilities would comply with applicable secondary NAAQS; therefore, any impacts on vegetation, animals, and other public welfare concerns would not be significant.

DCP also reviewed the Project for local visibility impacts and toxic air pollutant concentrations. The local visibility impacts were assessed consistent with the EPA's Workbook for Plume Visual Impact Screening and Analysis to determine potential visibility impairment at Calvert Cliffs State Park. The analysis was completed using the VISCREEN model and demonstrated that the Project would not cause visibility impairment in the Calvert Cliffs State Park. PPRP and MDE agree with DCP's visibility analyses and conclude that it appropriately and conservatively accounts for potential visibility impairment due to the proposed Project. We agree with PPRP and MDE.

The toxic air pollutant assessment was completed in accordance with Maryland air permitting regulations that require implementation of Best Available Control Technology for Toxics (T-BACT) and limits TAP pollutant concentrations at and beyond the facility property line. Fuel burning equipment are exempt from these requirements. The primary sources of TAP emissions that would be subject to these regulations would be the flares, thermal oxidizer, ammonia slip emissions (from units using SCR emission control), and fugitive emissions (equipment leaks). DCP demonstrated in the Maryland CPCN application that these sources would comply with both of the TAP requirements. The flares and thermal oxidizer are control devices for other emission sources. Their TAP emissions would be minimized through the use of an oxidation catalyst (thermal oxidizer) and good operating practices including maintaining proper combustion efficiency (flares). There are no add-on control technologies for controlling ammonia slip from SCR systems, meanwhile SCR is BACT/LAER for NO_x emissions from these sources. Ammonia slip would be minimized through good operating practices, including not injecting ammonia into the SCR system until it reaches proper operating temperature. The fugitive emissions from the Project would be minimized through the use of an LDAR program to minimize leaks. The TAP emissions that were subject to ambient air impact assessment were completed using AERMOD, which demonstrated that the Project's TAP emissions would be well below the allowable ambient levels (AALs). PPRP and MDE concurred with DCP's proposed T-BACT determinations and verified that the TAPs analysis are adequate to demonstrate compliance with the Maryland TAPs regulations. We agree with PPRP and MDE.

2.7.2 Noise

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

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

In 1974, the EPA published its Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety. This document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has indicated that an L_{dn} of 55 dBA protects the public from indoor and outdoor activity interference. We have adopted this criterion and use it to evaluate the potential noise impacts from the proposed Project at noise sensitive areas (NSAs), such as residences, schools, or hospitals. Due to the 10 dBA nighttime penalty added prior to calculation of the Ldn, for a facility to meet the Ldn 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. Also, in general, a person's threshold of perception for a perceivable change in loudness on the A-weighted sound level is about 3 dBA, whereas a 5 dBA change is clearly noticeable, and a 10 dBA change is perceived as either twice or half the loud. Maryland noise regulations (COMAR 26.02.03) require that the sound level at residential property lines should not exceed 65 dBA during the day (7:00 a.m. to 10:00 p.m.) or 55 dBA at night (10:00 p.m. to 7:00 a.m.).

For "periodic noise," which is defined as "a noise possessing a repetitive on-and-off characteristic with a rapid rise to maximum and a short decay not exceeding two seconds," the allowable levels under Maryland noise regulations are 60 dBA during the day and 50 dBA at night. For construction, the noise standard is 90 dBA during daytime hours [COMAR 26.02.03.02.B(2)]; however pile driving between the hours of 8:00 a.m. and 5:00 p.m. and motor vehicle traffic on public roads are exempted from compliance with this noise standard [COMAR 26.02.03.02.C(2)(e) and (i)].

Fairfax County, Virginia noise regulations (Fairfax County Code Section 108-4) establish specific prohibited activities as well as maximum permissible sound pressure levels based on land use at the noise source property line or the receiving area. The Fairfax County noise ordinance specifically prohibits operating or causing to be operated any equipment used in construction, repair, alteration, or demolition work on buildings, structures, streets, alleys, or appurtenances thereto in the outdoors between the hours of 9:00 p.m. and 7:00 a.m. the following day, except that no such activity shall commence prior to 9:00 a.m. on Sundays and federal holidays. The noise ordinance also limits sound pressure levels to 55 dBA in residential areas, 60 dBA in commercial areas, and 72 dBA in industrial areas. However, despite the maximum permissible sound pressure levels, the operation of power equipment between the hours of 7:00 a.m. and 9:00 p.m. the same day is permitted as long as it does not constitute a noise disturbance (Fairfax County, 2012). Because the construction activities for the Pleasant Valley Compressor Station would be limited to daytime hours, the noise is not expected to exceed the FERC noise guideline (which is an L_{dn} metric) or the Fairfax County noise regulation (which allows noise from construction as long as it is within the allowable daytime hours).

The construction activities at the Loudoun M&R Facility and Leesburg Compressor Station Contractor Staging Area would be temporary, intermittent, and occur primarily during daytime hours. Therefore, these construction activities would be insignificant and are not discussed further in this section.

Existing Noise Conditions

<u>Liquefaction Facilities and Offsite Areas A and B</u>

The existing LNG Terminal is surrounded by undeveloped forest, owned by DCP and held within a conservation easement. Nearby land uses include undeveloped State Park forest, residential areas, recreational fields, and the Chesapeake Bay. Cove Point Road lies approximately 300 feet south of the Fenced Area. A residential area exists to the south of this road. To the west, the Fenced Area is approximately 750 feet from the nearest recreation fields at Cove Point Park. To the north, the closest boundary of Calvert Cliffs State Park is approximately 1,200 feet away, and to the east, the Chesapeake Bay lies approximately 1,500 feet away. New equipment associated with the Project would be installed to the west and south of currently operating units and would be located entirely within the Fenced Area.

DCP conducted sound survey measurements of the existing LNG Terminal at the two closest NSAs on March 9, 2010 following construction of the Cove Point Expansion Project. This noise survey represented 100 percent send-out capacity and the LNG Terminal equipment was operated at full load conditions. NSA 1 is a residence directly across Cove Point Road from the LNG Terminal, about 300 feet south of the Fenced Area. NSA 2 is within the Calvert County Park Easement, owned by DCP, on the north side of Cove Point Road about 200 feet southwest of the Fenced Area. There are several neighborhoods southwest through southeast of the LNG Terminal. These two NSAs represent the closest NSAs to the LNG Terminal. Residences, schools, churches, and other NSAs are farther away than the identified NSAs, and noise levels from the LNG Terminal would be further attenuated. During the noise survey, the highest L_{dn} levels measured were 45.2 dBA and 42.7 dBA at NSA 1 and NSA 2, respectively.

Pleasant Valley Compressor Station

The land uses surrounding the Pleasant Valley Compressor Station include mostly undeveloped, privately owned land (primarily forested), with some residential development. The property to the north and east of the Pleasant Valley Compressor Station is currently undeveloped forest. To the south and west of the compressor station, the land is currently undeveloped forest with DCP's existing pipeline right-of-way. The nearest residences are 1,800 feet southwest of the station (referred to as NSA-S6) and 3,300 feet west of the station (referred to as NSA-S8).

In February 2013, DCP conducted noise surveys at the Pleasant Valley Compressor Station property lines and nearest NSAs. The L_{dn} sound levels measured at the nearest NSAs were 41.8 dBA (NSA-S6) and 46.5 dBA (NSA-S8). Because the Fairfax County noise ordinance regulates noise levels at the property line, measurements were also taken at the compressor station property lines. The L_{eq} sound levels for the Pleasant Valley Compressor Station were only audible at the east and southwest property lines with L_{eq} sound levels at 49.3 dBA and 44.6 dBA, respectively. The compressor station was not audible at the other property line locations or the NSAs.

Impacts and Mitigation

Construction Noise Impacts and Mitigation

Construction of the Project facilities would involve operation of general construction equipment and noise would be generated during the installation of the Project components. Measures to mitigate construction noise would include compliance with federal regulations limiting noise from trucks, proper maintenance of equipment, and ensuring that sound muffling devices provided by the manufacturer are kept in good working condition. Noise levels would increase in the immediate vicinity of the construction activities; however, the noise would be localized and temporary. Nighttime noise levels are not expected to increase during construction because most construction activities would be limited to daylight hours. Nighttime activities would consist of clean-up and staging of materials, which generate less noise than other construction activities.

Construction of the Liquefaction Facilities would take approximately 4 years. Construction of the modifications to the Pleasant Valley Compressor Station (including the Pleasant Valley Suction/Discharge Pipelines and M&R Facility) and Loudoun M&R Facility would take less than 2 years. Construction noise would be highly variable because of the types of equipment in use at a construction site change with the construction phase and the types of activities. Noise from construction activities may be noticeable at nearby NSAs; however, construction equipment would be operated on an as-needed basis during the short-term construction period.

Noise generated by site preparation at Offsite Areas A and B would be from the use of heavy equipment during clearing, grading, and restoration activities within the limits of disturbance. In addition, noise would be generated during the use of Offsite Area B for unloading equipment and supplies from barges at the temporary pier and the transport of material from the offsite area to the LNG Terminal. In order to limit potential impacts on adjacent properties during site preparation and barge offloading, DCP would limit site preparation activities to occur from dawn to dusk. Noise would also be generated by the approximately 150 truckloads originating from Offsite Area B during the course of construction of the Liquefaction Facilities. DCP's transport of large equipment would typically occur at night to minimize potential impacts on traffic by the slow moving vehicles. However, the noise generated by the Project-related truck traffic would be short-term, temporary, and intermittent. DCP would perform the loudest and most persistent noise generating activities (e.g., tree clearing, stump grinding, hoe ram demolition) during daylight hours. Nighttime construction noise generating activities would primarily consist of truck traffic.

Site preparation of the temporary pier at Offsite Area B would include pile driving during daylight hours. Pile driving is expected to be the loudest of the construction activities at Offsite Area B. The initial pile installation would be completed using a vibratory hammer, with an impact hammer used for final pile driving to the required design depth. The pile driving would be performed for intermittent periods of time over a 2- to 3-week period. Removal of the temporary pier at the end of the Project would be similar in duration, and a vibratory hammer would be used to extract the piles during daytime hours.

We received comments concerning noise from the construction of the Liquefaction Facilities. Construction equipment typically emits noise between 70 and 95 dBA at 50 feet (Federal Highway Administration, 2006). The construction noise impacts would be highly variable based on the specific equipment in use, number of equipment in use, and the location of the equipment (relative to the noise receptor). Based on the types of construction equipment that may be used for construction of the Liquefaction Facilities (e.g., trucks, graders, dozers, backhoe), the noise impacts of the construction at the nearest NSAs would be below 55 dBA L_{dn} and 90 dBA L_{day}. These noise levels are based on the implementation of sound mitigation in the form of temporary sound walls around the site perimeter (i.e., block line of sight from source to receiver), and/or around the sound source, capable of a 15 dBA reduction, which DCP has committed to installing, as well as the presence of soft ground (vegetative ground cover) between the source and the NSA.

Commissioning of the Liquefaction Facilities would include the lighting of the facility flares and running them for a period of 2 to 3 days or more. Based on vendor data, these flares would emit about 100 dBA at 50 feet. The estimated maximum noise level attributable the flares would be 58 dBA L_{eq} and 60 dBA L_{eq} at the two closest NSAs, which exceeds our noise criterion of 55 dBA L_{dn}. This is equivalent to the sound of an air conditioner located 20 feet away, and normal conversation can be maintained. Commissioning activities are expected to occur 24 hours per day; however, DCP has committed to not operating the ground flares during nighttime hours without appropriate noise mitigation measures, which may include operational limitations, to ensure that the 55 dBA L_{dn} limit is not exceeded. Because the details of the mitigation have not been finalized, **we recommend that:**

- **Prior to commissioning of the Liquefaction Facilities, DCP should file with the Secretary the specific noise mitigation measures that would be used on the ground flares and a noise analysis demonstrating that the noise from all of the equipment operated during commissioning (including ground flares) would not exceed an L_{dn} of 55 dBA at the nearby NSAs.**

Noise generated by construction at the Pleasant Valley Compressor Station would be from the use of heavy construction equipment during clearing, grading, trenching, pipe installation, backfilling, and restoration activities within the limits of disturbance. In order to limit potential impacts on adjacent properties, DCP would limit construction activities to occur from dawn to dusk, typically between the hours of 7:00 a.m. and 9:00 p.m., 7 days per week.

Construction activities associated with the proposed Project would result in temporary increases in ambient noise levels. Based on the anticipated noise levels attributable to short terms construction activities and with the implementation of DCP's noise mitigation measures, we conclude that noise impact from the Project would be in compliance with applicable noise regulations.

Operational Noise Impacts and Mitigation

Liquefaction Facilities

We received several comments concerning the operational noise impacts from the Liquefaction Facilities. Operation of the Liquefaction Facilities would involve numerous noise generating sources including, but not limited to, several pumps, flares, blowers, compressors, turbines, turbine intakes, coolers fans, condenser fans, and combustion units (boiler, gas turbine, thermal oxidizer, and generator).

Noise level data for the major facility sources were obtained from equipment vendors and/or from measurements of similar sources at other facilities. DCP performed computer modeling using CadnaA noise modeling program to predict sound levels that would be generated by operation of the Project. This program uses the octave band sound power levels (i.e., the emission levels) of individual sound sources to calculate the sound pressure level at the defined receiving site(s). The sound level from each individual source at the receiving site (1.5 meters above the ground) are then combined resulting in the cumulative sound level at the receiving site.

Based on the noise modeling analysis, the Liquefaction Facilities would meet the applicable FERC and Maryland noise requirements. The following mitigation measures were assumed for the modeling analysis:

- Acoustical buildings – numerous equipment would be located inside acoustical buildings that would have a noise reduction coefficient of 0.91 and meet specified interior absorption and interior to exterior transmission losses.

- Piping noise control – all suction piping from the KO Drum to the compressor body would be installed within the compressor building and insulated with ISO Class C insulation (per ISO 15665). The discharge piping, to the extent practical, would be installed within the compressor building and insulated with Class D insulation (i.e., 2-inch-thick glass or mineral fiber insulation covered with a impervious layer with a surface density of 1.0 pound per square foot; followed by another 2-inch-thick layer of glass or mineral fiber insulation with an impervious outer layer of 2.0 pound per square foot.)

- Sound barrier – a 60-foot-high, approximately 3,500-foot-long wall along the south and west sides of the Fenced Area constructed of material with a minimum STC of 33 dBA and a noise reduction coefficient 0.8.

The results of the modeling analysis are summarized in table 2.7.2-1.

TABLE 2.7.2-1

Sound Level Predictions – Liquefaction Facilities

Noise Sensitive Area	Existing Sound Level L_{dn} (dBA)	Estimated Facility Continuous Sound Level L_{eq}	Calculated Sound Level Attributable to Facility L_{dn} (dBA)	Calculated Total Sound Level at NSAs L_{dn} (dBA)	Increase Over Existing Sound Level L_{dn} (dBA)
NSA1 (460 feet S)	45.2	46.0	52.4	53.2	8.0
NSA2 (760 feet SW)	42.7	45.3	51.7	52.2	9.5

As indicated in table 2.7.2-1, the noise attributable to the Liquefaction Facilities with implementing noise mitigation would be below FERC's criteria of an L_{dn} of 55 dBA and Maryland noise regulations. Sounds levels would be similar to a typical suburban rea or office and normal conversation can be easily maintained. However, to ensure that the actual noise levels resulting from operation of the Liquefaction Facilities are not significant, **we recommend that:**

- **DCP should file a full load noise survey at the Liquefaction Facilities with the Secretary no later than 60 days after placing the Liquefaction Facilities in service. If a full load condition noise survey is not possible, DCP should provide an interim survey at the maximum possible operation within 60 days of placing the Liquefaction Facilities in service and file the full load operational survey within 6 months. If the noise attributable to the operation of all of the equipment at the LNG Terminal, under interim or full load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, DCP should file a report on what changes are needed and should install the additional noise controls to meet the level within 1 year of the in-service date. DCP should 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.**

Pleasant Valley Compressor Station

Noise would generally be produced on a continuous basis at the Pleasant Valley Compressor Station by the compressor units and associated air handling units. Noise level data for the main noise sources are based on vendor quotes, equipment size, power information, and from experiences with similar equipment in compressor station facilities.

A noise analysis for the Pleasant Valley Compressor Station was completed using sound level data for the specific equipment planned for the facility and calculations for the noise attenuation over distance. The results of the noise analysis are summarized in table 2.7.2-2 for the impacts at the closest NSAs (for compliance with the FERC 55 dBA L_{dn} noise criterion) and highest impacts at the facility property lines (for the Fairfax County 55 dBA L_{eq} noise ordinance).

As shown in table 2.7.2-2, the noise level from the modified Pleasant Valley Compressor Station with implementing noise mitigation would be below 55 dBA L_{dn} at the nearest NSAs and 55 dBA L_{eq} at the property lines.

TABLE 2.7.2-2 **Sound Level Predictions – Pleasant Valley Compressor Station**						
Receiving Area	Calculated L_{dn} attributable to new equipment (dBA)	Existing Sound Level (dBA)	Total L_{dn} (dBA)	Estimated Increase (dBA)	Calculated L_{eq} attributable to new equipment (dBA)	Calculated Total L_{eq} (dBA)
NSA – S6 (1,800 feet SW)	41.8	40.4 (L_{dn})	44.2	0.1	NA	NA
NSA – S8 (3,300 feet W)	46.5	33.4(L_{dn})	46.7	0.2	NA	NA
Property Line – S12 (600 feet SW)	NA	44.6 (L_{eq})	NA	NA	46.2	48.5
Property Line – S15 (450 feet N)	NA	35.6 (L_{eq})	NA	NA	49.2	49.4

The noise analysis assumed that the turbine compressor unit would be enclosed in an acoustically designed building with the following noise controls:

- acoustically treated compressor building (e.g., insulated wall, roof panels, doors);
- muffler on the exhaust of the turbine, as well as acoustic insulation on the exhaust pipe from the building wall to the exhaust muffler inlet flange (including expansion joint);
- air cleaner/silencer on the air intake of the turbine, as well as acoustic insulation on the intake cleaner outlet flange (including expansion joint);
- adequate cooling to allow full load operation of the turbine unit with all doors closed:
    - air handling units;
    - ventilation air inlet mufflers in the air paths between air handling units and the compressor building wall;
    - wall air inlet fans;
    - ventilation air inlet mufflers located in the walls of the compressor building directly outside of the wall air inlet fans to reduce the sound from the turbine compressor unit that escapes through these openings; and
    - compressor station building ventilation system with roof air discharge hoods with mufflers located under each ventilation air discharge hood (but above the roof) to reduce sound from the turbine compressor unit that escapes through these openings;
- limitations on maximum noise from the lube oil cooler;
- aboveground sections of the unit suction, discharge and bypass lines (including metal pipe supports) of the turbine compressor unit would be acoustically insulated if required; and
- limitations on the maximum A-weighted sound level from the silenced unit blow down vent.

In addition, DCP would install an approximately 800-foot-long, 20-foot-high sound barrier wall along the eastern side of the compressor station site to reduce impacts from noise generated by operation of Pleasant Valley Compressor Station on the surrounding area.

As indicated in table 2.7.2-2, the noise attributable to the modified Pleasant Valley Compressor Station would be below our criteria of an L_{dn} of 55 dBA and the Fairfax County noise requirement of 55 dBA L_{eq} at the property line. Additionally, the estimated noise increase at the nearby NSAs would range from 0.1 to 0.2 dBA, which is below the 3 dBA threshold of noticeable difference for humans. However, to ensure that the actual noise levels resulting from operation of the modified Pleasant Valley Compressor Station are not significant, **we recommend that:**

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

Blow downs

We received comments concerning the noise from blow downs. In addition to normal operational noise, there may also be sources of noise due to maintenance or emergency operation. Specifically, emergencies and maintenance activities involve blow downs (depressurizing/emptying station equipment to remove natural gas). Based on information from DCP, the blow downs at the Pleasant Valley Compressor Station are typically infrequent and may be silenced or unsilenced. Annual testing of the emergency shutdown (ESD) system would be required and may include unsilenced blow downs. DCP typically attempts to provide advanced notice to nearby residents at least 2 hours before the activity begins. Unsilenced ESD blow downs typically last 1 to 2 minutes. Other activations of the ESD system due to an emergency are very infrequent (on average less than once per year).

Silenced blow down events are more frequent for schedule maintenance of the compressor equipment. These scheduled events may occur multiple times per year. DCP blow down silencers would reduce the gas velocity of the exiting gas and muffle the resulting noise to limit the noise 60 dBA at 50 feet. DCP would not plan to provide notifications for these silenced blow downs.

2.8 RELIABILITY AND SAFETY

2.8.1 Virginia Facilities

The pressurization of natural gas at a compressor station involves some risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a leak, or rupture at the facility. Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death.

The DOT is mandated to provide pipeline safety under Title 49, U.S.C. Chapter 601. The DOT's PHMSA, Office of Pipeline Safety (OPS) 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 ensures 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 US 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. OPS federal inspectors perform inspections on interstate natural gas pipeline facilities in Maryland.

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, including compressor stations.

The modifications at the Pleasant Valley Compressor Station must be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards in 49 CFR Part 192. The regulations are intended to ensure adequate protection for the public and to prevent facility accidents and failures.

Part 192.163 – 192.173 of 49 CFR specifically addresses design criteria for compressor stations, including emergency shutdowns and safety equipment. Part 192 also requires a pipeline operator to establish a written emergency plan that includes procedures to minimize the hazards in an emergency.

Additionally, the operator must establish a continuing education program to enable the public, government officials, and others to recognize an emergency at the facility and report it to appropriate public officials. DCP would provide the appropriate training to local emergency service personnel before the facilities are placed in service.

The construction and operation of the modified Pleasant Valley Compressor Station would represent a minimum increase in risk to the nearby public. With implementation of the required design criteria for the compressor station modifications, the Pleasant Valley Compressor Station would be constructed and operated safely.

2.8.2 Regulatory Agencies

Three federal agencies share regulatory authority over the siting, design, construction, and operation of LNG import terminals: the USCG, the DOT, and the FERC. The USCG regulates the safety of an LNG facility's marine transfer area and LNG marine traffic, and regulates 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. Under federal law, the DOT is the lead federal agency with the authority to establish remote siting requirements. 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 (MOU) regarding the execution of each agency's respective statutory responsibilities to ensure the safe siting and operation of

LNG facilities. In addition to the FERC's existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the MOU specified that the FERC may, with appropriate consultation with DOT, impose more stringent safety requirements than those in Part 193.

In February 2004, the USCG, DOT, and the FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals, 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 USCG, when necessary, participate as cooperating agencies. All three agencies have some oversight and responsibility for inspection and compliance during the facility's operation.

As part of the review required for a FERC authorization, we must ensure that all proposed LNG 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. FERC's filing regulations also require each applicant to identify how its proposed design would comply with DOT's siting requirements of 49 CFR 193, Subpart B. As part of our NEPA review, we use this information from the applicant, developed to comply with DOT's regulations, 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.

In accordance with 33 CFR 127, the USCG has reviewed the proposed liquefaction facilities and stated that the existing WSA and LOR are adequate for the service associated with the proposed modifications. A copy of the correspondence between DCP and the USCG is included in Appendix 1-B of Resource Report 1.[10]

2.8.3 Hazards

Before liquefaction, DCP would pre-treat the feed gas for the removal of mercury, hydrogen sulfide (H_2S), and CO_2. The hazards associated with the removal of these substances from the feed gas stream result from the physical and chemical properties, flammability, and/or toxicity of mercury, H_2S, and amine. DCP proposes a design capacity to handle up to 20 micrograms per normal cubic meter ($\mu g/Nm^3$) mercury, 4 parts per million by volume (ppm-v) H_2S, and 2 mole percent CO_2. However, lower quantities and concentrations of these substances would be expected in the natural gas feed stream and would not pose a hazard to the public. Mercury would be removed from the feed gas stream by adsorption in the Mercury Removal Unit. H_2S and CO_2 would be removed from the feed gas stream in the Acid Gas Removal Unit using 50 percent aqueous diglycolamine (amine) solution. As the CO_2 and H_2S are removed by the amine solution, these substances would accumulate within the amine solution and reduce the effectiveness of the system. Therefore, the amine solution would be regenerated periodically, where an acid gas stream with concentrations up to 190 ppm-v H_2S and 96 mole percent CO_2 would be separated from the contaminated amine solution and routed to the Sulfur Removal Unit and Thermal

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[10] Accession number: 20130401-5045.

Oxidizer for further treatment prior to discharging to the atmosphere. DCP would need to replace the Mercury Removal and Sulfur Removal beds by the end of their service life. Maintenance and safety procedures would cover the proper replacement and disposal of these beds. The amine solution would be contained, as discussed under “Impoundment Sizing” in section 2.8.6, and handled at temperatures below the point at which it could produce enough vapors to form a flammable mixture. Therefore, the amine solution would not pose a significant hazard to the public, which would have no access to the on-site areas.

DCP would install a Heavy Hydrocarbon Removal Unit (HRU) to condense pentane and heavier hydrocarbons that may be present in the feed gas. During this removal process, natural gas liquid (NGL) would be extracted and handled on-site at temperature and pressure conditions under which a loss of containment would result primarily in a vapor release and the ability to produce damaging overpressures. The resulting stabilized condensate, which includes pentane and heavier hydrocarbons, would be stored on-site at atmospheric pressure and temperature. Due to the temperature and pressure conditions under which the stabilized condensate would be stored and handled, a loss of containment would primarily result in a liquid release. However, DCP proposes to partially bury and mound the stabilized condensate storage tank under minimum 2-feet of soil. The liquid spill would be contained within the buried area and would not present an offsite hazard to the public. The principal hazards associated with the storage and sendout of condensate would result from loss of containment and the flammability and toxicity of the substances used or produced in the heavy hydrocarbon removal system.

The principal hazards associated with the liquefaction and storage of LNG and refrigerants result from loss of containment, vapor dispersion characteristics, flammability, and the ability to produce damaging overpressures. A loss of the containment provided by storage tanks or process piping would result in the formation of flammable vapor at the release location, as well as from any LNG or liquid flammable refrigerant that pooled. Releases occurring in the presence of an ignition source would most likely result in a fire at the vapor source. A spill without ignition would form a vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. In some instances, ignition of a vapor cloud may produce damaging overpressures. These hazards are described in more detail below.

Loss of Containment

A loss of 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 flammable vapors. The extent of the hazard will depend on the material released, the storage and process conditions, and the volumes released.

DCP would store the following on-site: LNG at atmospheric pressure and at a cryogenic temperature of approximately -260 °F; liquid ethane at approximately 130 psig and -30°F; liquid propane at ambient temperature and elevated pressures (similar to the conditions typically used in propane storage and distribution); and stabilized condensate at ambient temperature and pressure.

The MR process stream would consist of methane, ethane, propane, and nitrogen. Cryogenic temperatures as low as -258°F would occur within the MR process stream used to liquefy the feed gas. The temperature of NGL in the heavy hydrocarbon removal process stream would be as low as -67°F. Loss of containment of LNG, mixed refrigerant liquid (MRL), and NGL could lead to the release of both liquid and vapor into the immediate area. Exposure to either cold liquid or vapor could cause freeze burns and, depending on the length of exposure, more serious injury or death. However, spills would be contained to on-site areas and the cold state of these releases would be greatly limited due to the continuous mixing with the warmer air. The cold temperatures from the release would not present a hazard to the public, which would not have access to on-site areas.

LNG and MRL are cryogenic liquids that would 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.

Vapor Dispersion

In the event of a loss of containment, LNG, ethane, propane, and NGL would vaporize on release from any storage or process facilities. Depending on the size of the release, cryogenic liquids, such as LNG and MRL, as well as NGL may 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. Ethane will produce approximately 370 ft^3 of gas for each cubic foot of liquid. Propane will produce approximately 274 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 275 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.

If the loss of containment does not result in immediate ignition of the hydrocarbons, the vapor cloud would travel with the prevailing wind until it either encountered an ignition source or dispersed below its flammable limits. An LNG release would form a denser-than-air vapor cloud that would sink to the ground due to the cold temperature of the vapor. As the LNG vapor cloud disperses downwind and mixes with the warm surrounding air, the LNG vapor cloud may become buoyant. However, experimental observations and vapor dispersion modeling indicate the 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 flammability limit (LFL). A liquid ethane release would form a denser-than-air vapor cloud that would sink to the ground due to the cold temperature of the vapor. As the ethane vapor cloud disperses downwind and mixes with the warm surrounding air, the ethane vapor would become neutrally buoyant. A propane release would form a denser-than-air vapor cloud that would sink to the ground; however, propane would remain denser than the surrounding air, even after warming to ambient temperatures. The composition of NGL would vary throughout the heavy hydrocarbon removal process; therefore, a release in the NGL stream may form either a neutrally buoyant or a denser-than-air vapor cloud, even after warming to ambient temperatures.

Methane and heavier hydrocarbons are classified as simple asphyxiates and may pose extreme health hazards, including death, if inhaled in significant quantities within a limited time. Very cold methane and heavier hydrocarbons vapors may also cause freeze burns. However, the locations of concentrations where cold temperatures and oxygen-deprivation effects could occur are greatly limited due to the continuous mixing with the warmer air surrounding the spill site. For that reason, exposure injuries from contact with releases of methane and heavier hydrocarbons normally represent negligible risks to the public.

Vapor Cloud Ignition

Flammability of the vapor cloud is dependent 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. Mixtures occurring between the LFL and the upper flammability limit (UFL) can be ignited. Concentrations above the UFL or below the LFL would not ignite.

The LFL and UFL for methane are approximately 5%-vol and 15%-vol in air, respectively. Propane has a narrower flammability range, with a LFL of approximately 2%-vol and a UFL of 9.5%-vol in air. Ethane has a wider flammability range and a LFL of approximately 2.9% vol and a UFL of 13%-vol in air. NGL has a LFL of approximately 2.8%- vol and a UFL of approximately 13%-vol. Condensate has a LFL of approximately 1.2%-vol and a UFL of approximately 7.8%-vol.

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. An LNG vapor cloud deflagration in an uncongested and unconfined area travels at slower speeds and does not produce significant pressure waves. However, exposure to this LNG vapor cloud fire can cause severe burns and death, and can ignite combustible materials within the cloud. Overpressures of LNG, NGL, and refrigerant vapor clouds are discussed later in this section under "Overpressures."

A deflagration 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 either within an ignited cloud or in the vicinity of a pool fire would primarily be dependent on the quantity and duration of the initial release, the surrounding terrain, and the environmental conditions present during the dispersion of the cloud. Radiant heat and dispersion modeling are discussed in section 2.8.6.

Fires may also cause failures of nearby storage vessels, piping, and equipment. 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 of flammable liquids can produce overpressures and a subsequent fireball when the superheated liquid rapidly changes from a liquid to a vapor upon the release from the vessel. The refrigerant make-up tanks and condensate storage tanks would be partially buried and mounded under a minimum of 2-feet of soil to mitigate radiant heat from nearby fires. This mitigation addresses a fire from one tank causing a failure to an adjacent tank(s) and would effectively result in a negligible risk of a BLEVE from the refrigerant and condensate storage area.

Overpressures

If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves would be generated. As a deflagration accelerates to super-sonic speeds, larger pressure waves are produced, and a shock wave created. This shock wave, rather than the heat, would begin to drive the flame, resulting in a detonation. Deflagrations or detonations are often characterized more generally as explosions when the rapid movement of the flame and pressure waves associated with them cause additional damage. The amount of damage an explosion causes is dependent on the amount the pressure wave is above atmospheric pressure (i.e. an overpressure) and its duration (i.e., pulse). For example, a 1 psi overpressure is often cited as a safety limit in regulations and is associated with glass shattering and traveling with velocities high enough to lacerate skin.

Flame speeds and overpressures are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance.

The potential for unconfined LNG vapor cloud detonations was investigated by the USCG in the late 1970s at the Naval Weapons Center in China Lake, California. Using methane, the primary component of natural gas, several experiments were conducted to determine whether unconfined LNG vapor clouds would detonate. Unconfined methane vapor clouds ignited with low-energy ignition sources (13.5 joules), produced flame speeds ranging from 12 to 20 mph. These flame speeds are much lower than the flame speeds associated with a deflagration with damaging overpressures or a detonation.

To examine the potential for detonation of an unconfined natural gas cloud containing heavier hydrocarbons that are more reactive, such as ethane and propane, the USCG conducted further tests on ambient-temperature fuel mixtures of methane-ethane and methane- propane. The tests indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined natural gas vapor cloud to detonate. Natural gas with greater amounts of heavier hydrocarbons would be more sensitive to detonation.

Although it has been possible to produce damaging overpressures and detonations of unconfined LNG vapor clouds, the feed gas stream proposed for the Project would have lower ethane and propane concentrations than those that resulted in damaging overpressures and detonations. The substantial amount of initiating explosives needed to create the shock initiation during the limited range of vapor-air concentrations also renders the possibility of detonation of these vapors at an LNG plant as unrealistic. As discussed in the "Vapor Dispersion" and "Vapor Cloud Ignition" sections above, 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.

Ignition of a confined LNG vapor cloud could result in higher overpressures. In order to prevent such an occurrence, DCP would take measures to mitigate the vapor dispersion and ignition into confined areas, such as buildings. DCP plans to 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. We are including a recommendation that DCP file detailed information and locations of these hazard detection devices (see section 2.8.4).

We received a comment that gas detection devices installed at the gas turbine air intakes are not sufficient to eliminate an ignition source from released flammable vapors. There are approximately 250 gas detection devices currently installed at the LNG Terminal, and DCP proposes to install at least 180 additional gas detection devices throughout the Liquefaction Facilities. The preliminary hazard detection layouts for the proposed Liquefaction Facilities show gas detection devices strategically located in proximity to potential release sources. In addition, there would be numerous measures in place such as spill containment, instrumentation, alarms, safety instrumented systems, and ESD systems that would mitigate a hydrocarbon release before a flammable vapor cloud would reach an air intake. Furthermore, we are recommending that the gas detection devices would be calibrated to detect any hydrocarbon release (methane, propane, ethane, or condensate) to ensure any process release would be detected (see section 2.8.4).

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 ethane vapor clouds to produce damaging overpressures. Unconfined ethane 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 (Pierorazio, 2005). 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 MRL and NGL process streams would contain a mixture of components such as the ones discussed above (i.e., ethane and propane). Therefore, a potential exists for these process streams to produce unconfined vapor clouds that could produce damaging overpressures in the event of a release.

Discussions of these hazards and potential mitigation are in section 2.8.6 for the liquefaction facilities.

Past LNG Facility Incidents

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. 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 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 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. As indicated in section 2.8.3 "Overpressures," DCP would install hazard detection devices at all combustion and ventilation systems to enable isolation and deactivation of any combustion equipment whose continued operation could add to, or sustain, an emergency. We would review the final design to confirm the location and shutdown capabilities of these devices.

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. If measures to address any causal factors which led to this incident are developed, they will be applied to all facilities under the Commission's jurisdiction.

Throughout its operational life, the Cove Point facility has been subject to FERC's reporting and inspection requirements for LNG facilities and must regularly report facility changes in operating conditions and any abnormal operating experiences.[11] We received a comment requesting a list and description of incidents that have occurred at the facility, along with explanations of causes and subsequent changes made to address the causes. DCP reported the following incidents related to either the commissioning of equipment or activities by outside contractors performing maintenance activities. In 2003, a lap weld on the bottom of one of the LNG tanks failed due to excessive contraction during tank cool-down. The tank was isolated from the rest of the facility, warmed up, and repaired. DCP's corrective actions included additional flow rate monitoring and communications procedures during tank cool-down activities. In 2007, contractors erected scaffolding near a heating coil and one of the wooden scaffolding boards ignited. In order to address this, DCP instituted additional oversight procedures for the activities of contractors when on site. In 2010, a contractor drowned while performing maintenance on the offshore pier piles. The contracting company subsequently updated its safety plan.

DCP has also reported minor natural gas leaks from piping and valve packing during normal operations. In these cases, staff monitoring, instrumentation, and detection devices identified the issue, allowing the equipment to be shut-down and isolated for repair or maintenance. None of these natural gas releases resulted in impacts on the public. DCP's corrective actions included targeted piping connection inspections and increased monitoring.

The most significant event involving facility operations occurred in 1979. 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 ensure that flammable vapors do not migrate through the electrical system.

2.8.4 Technical Review of the 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 2.8.3. 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 multiple protection systems or safeguards 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 should be independent of one another so that each could perform its function regardless of the action or failure of any other protection layer or initiating event. Such design features and safeguards typically include:

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[11] LNG import operations at the Cove Point facility began in 1978, but ended in 1980 when major changes in the market for natural gas led to a suspension of LNG importation activity. Between 1980 and 1995 the facility remained in a standby mode with no LNG operations. In 1995, the facility installed liquefaction equipment and resumed operations by providing peaking and storage services. Import operations and maritime transit resumed in 2003.

- a facility design that prevents hazardous events through the use of suitable materials of construction; operating and design limits for process piping, process vessels, and storage tanks; adequate design for wind, flood, seismic, and other environmental 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 ESD systems, to prevent a release if operating and design limits are exceeded;

- equipment protection systems, such as pressure relief valves, proper equipment and building spacing, appropriate electrical area classification, spill containment, and structural fire protection, to prevent escalation to a more severe event;

- emergency response, including hazard detection and control equipment, firewater systems, on-site fire-fighting personnel and equipment, and coordination with local first responders to mitigate the consequences of a release and prevent it from escalating to a larger event; and

- 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.

We find that the inclusion of such protection systems or safeguards in a facility design would 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 2.8.5, DOT's regulations in 49 CFR 193, Subpart B require a siting analysis be performed by DCP.

As part of its application, DCP provided a FEED for the Project. In developing the FEED, DCP conducted a pre-Process Hazards Analysis (PHA) and a pre-Hazards and Operability Study (HAZOP) to identify potential risk scenarios. These studies provided a qualitative evaluation of a range of possible safety, health, and environmental effects which may result from the operation of the facility. Based on these major hazards, DCP included process and safety instrumentation, mitigation, and/or administrative controls to address the identified issues.

As part of our review of this Project, we analyzed the information filed by DCP to determine the extent that layers of protection or safeguards were included. Our 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, fabricated, assembled, erected, inspected, examined, and tested in accordance with American Society of Mechanical Engineers (ASME) B31.1 and ASME B31.3. Pressure vessels would be designed in accordance with ASME Section VIII and the storage tanks would be designed in accordance with API Standard 620, per 49 CFR 193 and the NFPA's Standard 59A (NFPA 59A). Valves and other equipment would be designed to accepted good engineering practices.

As proposed in the NFPA 59A Preliminary Fire Protection Review filed on January 24, 2014, DCP would design facilities that contain LNG (such as the MCHE, expander, reboiler, nitrogen stripper, LNG pump structure, and pipe rack supporting LNG lines), as well as the condensate stabilizer column, to withstand a sustained design wind speed of 150 mph (183.3 mph with a gust of 3-second duration). For equipment and piping not containing LNG, DCP proposes a design wind speed of 110 mph with a gust of 3-second duration. DCP states storage, piping, compressors, condensers, and process vessels associated with the refrigerant systems would be designed to this 110-mph wind speed. As part of its role as a cooperating agency on this document, DOT provided comments stating that use of this wind speed for this equipment may not meet its regulatory requirements. Under 49 CFR § 193.2067, DOT requires the use of an assumed sustained wind velocity of not less than 150 mph for all equipment used for liquefying, transferring, storing, or vaporizing LNG. Alternative wind speeds may be approved by DOT provided they are justified by adequate wind data and an acceptable probabilistic methodology. As such, DCP either must design the facilities to accommodate wind forces based on a sustained wind velocity of 150 mph or may request DOT approval for use of a lower wind speed under the regulatory means listed in § 193.2067(b). As a result, **we recommend that:**

- **<u>Prior to the construction of the final design</u>, DCP should file with the Secretary for review and written approval by the Director of OEP, certification that the final design has been modified to be consistent with the wind speed requirements of 49 CFR § 193.2067 or that DOT has approved the use of a lower wind speed as allowed by § 193.2067(b). DCP should consult with DOT on any actions necessary to demonstrate compliance with Part 193.**

The site elevation ranges from 70 feet to 130 feet above mean sea level (NGVD29), with the majority of the existing and proposed facilities located at an elevation of more than 110 feet above mean sea level. The seismic and structural design of the liquefaction facilities are discussed in section 2.1.2.

DCP 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. DCP would expand the existing facility operation procedures to include the liquefaction facilities after completion of the final design; this timing is fully consistent with accepted industry practice. We are recommending that DCP provide updated operating and maintenance procedures for FERC review as they are developed, as listed in this section. In addition, we are recommending measures such as labeling of instrumentation and valves (i.e., car-sealed and/or locked valves) to address human error 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 Standard 84.01 and other generally accepted good engineering practices. As listed below, we are also including 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. This would ensure that the design includes sufficient safeguards to react to process upsets and hazardous conditions.

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 Sections I, IV, VIII, and would be designed based on API recommended practices as well as other generally accepted good engineering practices. As listed below, we are including recommendations to ensure the pressure and vacuum relief valves would be sufficiently sized for major process equipment, vessels, and storage tanks.

In the event of a release, drainage systems from the liquefaction 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. Our analysis of the impoundment systems is discussed in section 2.8.6.

DCP performed a preliminary fire protection review 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 generally accepted good engineering practices. DCP 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. These systems would meet NFPA 72 as well as other 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, 11, 12, 13, and generally accepted good engineering practices. DCP 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. These systems would be designed to meet NFPA 59A, and NFPA 15, 20, 22, and 24 requirements. We are recommending that DCP provide more information on the design, installation, and commissioning of hazard detection, hazard control, and firewater systems as DCP would further develop this information during the final design phase. We would review this information to confirm that the final design, installation, and capabilities of the hazard detection and control equipment would be consistent with the equipment proposed in the application.

DCP would also update its existing emergency procedures to include the Project, as required by 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. In order to minimize the risk of an intentional event, DCP would update its existing security fencing, gates, lighting, camera systems, and intrusion detection to deter, monitor, and detect intruders into the facility. In addition, as discussed in section 2.8.8, DCP must update the existing Facility Security Plan in accordance with the USCG's regulations found in 33 CFR 105, Subpart D.

We conclude 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 our technical review of the information provided by DCP in its application, we did identify a number of concerns in letters issued on June 26 and September 3, 2013. DCP provided written responses on July 16, July 17, August 1, August 30, September 23, October 4, and December 27, 2013. Some of these responses indicated that DCP would correct or modify its design in order to address the identified issues. As a result, **we recommend that:**

- **<u>Prior to construction of the final design</u>, DCP should file information/revisions with the Secretary, for review and written approval by the Director of OEP, pertaining to DCP's response numbers 3, 19, 21, and 64 of its July 16, 2013 filing, which indicated features to be included or considered in the final design.**

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. It is unlikely 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 which were presented as part of DCP's FEED.

Prior to finalizing the design as "Issued for Construction," a more detailed and thorough PHA and HAZOP as well as a Layers of Protection Analysis and Safety Integrity Level would be performed by DCP. These studies would further refine the required safety control levels and identify whether additional process and safety instrumentation, mitigation, and/or administrative controls would be needed. Once the design has been subjected to hazard design reviews, DCP's design development team would track changes in the facility design, operations, documentation, and personnel. DCP would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled.

Information regarding the development of the final design, as detailed below, would need to be reviewed by FERC staff before equipment construction at the site would be authorized. To ensure the final design would be consistent with the safety and operability characteristics identified in the FEED, **we recommend that the following measures should apply to the Dominion Cove Point Liquefaction 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, will 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>, DCP should provide procedures for controlling access during construction.**

- **<u>Prior to initial site preparation</u>, DCP should file the quality assurance and quality control procedures for construction activities.**

- **<u>Prior to initial site preparation</u>, DCP should file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**

- **<u>Prior to initial site preparation</u>, a technical review of facility design should be filed that:**

  a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids, and flammable gases); and

  b. demonstrates that these areas are adequately covered by hazard detection devices and indicate how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.

- **The <u>final design</u> should include change logs that list and explain any changes made from the FEED provided in DCP'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 <u>final design</u> should provide up-to-date Process Flow Diagrams with heat and material balances and piping and instrumentation diagrams (P&IDs), which include the following information:**

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

  b. equipment insulation type and thickness;

  c. valve high pressure side and internal and external vent locations;

  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. relief valves with set points; and

  h. drawing revision number and date.

- **The <u>final design</u> should provide P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect the Project to the existing facility.**

- **The <u>final design</u> should provide an up-to-date complete equipment list, process and mechanical data sheets, and specifications.**

- **The <u>final design</u> should provide complete drawings and a list of the hazard detection equipment. The drawings should clearly show the location and elevation of all detection equipment. The list should include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.**

- **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 provide facility plans and drawings that show the location of the firewater and foam systems. Drawings should clearly show: firewater and foam piping; post indicator valves; and the location of, and area covered by, each monitor, hydrant, deluge system, foam system, water-mist system, and sprinkler. The drawings should also include P&IDs of the firewater and foam system.**

- **The <u>final design</u> 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 Part 193. A copy of the evaluation, a list**

of recommendations and supporting justifications, and actions taken on the recommendations should be filed.

- **The final design should specify that for hazardous fluids, piping and piping nipples 2 inches or less are consistent with the existing facility's piping specifications.**

- **The final design should include drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.**

- **The final design 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 shutdown the appropriate systems.**

- **The final design should provide electrical area classification drawings.**

- **The final design should provide spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments.**

- **The final design of the hazard detectors should account for the calibration gas when determining the LFL set points for methane, propane, ethane, and condensate.**

- **The final design should include a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of recommendations, and actions taken on the recommendations, should be filed.**

- **The final design should include the cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD system. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points.**

- **The final design should include a drawing that shows the location of the ESD buttons. ESD buttons should be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.**

- **The final design 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 final design should include the sizing basis and capacity for the final design of pressure and vacuum relief valves for major process equipment, vessels, and storage tanks.**

- **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 <u>final design</u> should provide the specification, procedures, and schedule to modify the tunnel expansion joints.**

- **The <u>final design</u> should either set the pressure relief valves at the Mole Sieve Gas Dehydrators to the design pressure of the closed loop system or design the Mole Sieve Gas Dehydrators and the associated hot piping system for the regeneration design temperature and the feed gas design pressure of the pretreatment system.**

- **The <u>final design</u> should include double isolation for each sulfur removal vessel. Manual isolation valves should be installed upstream of the inlet pneumatic valve and downstream of the outlet pneumatic valve with vent and purge connections between the manual and pneumatic valves.**

- **The <u>final design</u> should provide coarse mesh strainers in the bottom outlet piping of the adsorbers to prevent support material and molecular sieve migrating from Mole Sieve Gas Dehydrators to the piping system.**

- **The <u>final design</u> should provide a redundant low temperature shutdown system for the Flash Gas Compressors. The set point should be set at no less than -50°F.**

- **The <u>final design</u> of the Ethane Make-Up Drum and associated piping system should include stress analysis of the system at the equilibrium temperature of the Ethane at barometric pressure.**

- **The <u>final design</u> should provide all tests, investigations, and reports to ensure the existing firewater system's compatibility and reliability.**

- **The <u>final design</u> should equip the HRU Column with permanent drainage piping to the cold flare system, designed for cryogenic conditions.**

- **The <u>final design</u> should provide drainage piping to the cold flare from the Nitrogen Stripper Reboiler bottom inlet piping and Nitrogen Stripper bottom outlet piping upstream of the shutoff valve.**

- **The <u>final design</u> should equip the Stabilizer with permanent drainage piping to the flare system.**

- **The <u>final design</u> of the refrigerant and stabilized condensate storage systems should provide dual full capacity relief valves that allow the isolation of individual pressure relief valves while providing full relief capacity during pressure relief valve maintenance or testing.**

- **<u>Prior to commissioning</u>, DCP 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>, DCP 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. DCP 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>, DCP should tag all equipment, instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**

- **<u>Prior to commissioning</u>, DCP 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>, DCP should file updates addressing the liquefaction facilities in the operation and maintenance procedures and manuals, as well as safety procedures.**

- **<u>Prior to commissioning</u>, DCP should maintain a detailed training log to demonstrate that operating staff has completed the required training.**

- **<u>Prior to introduction of hazardous fluids</u>, DCP 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 introduction of hazardous fluids</u>, DCP should complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System and the Safety Instrumented System that demonstrates full functionality and operability of the system.**

- **<u>Prior to commencement of service</u>, DCP should label 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>, progress on the construction of the proposed systems should be reported in <u>monthly</u> reports filed with the Secretary. Details should include a summary of activities, problems encountered, contractor non-conformance/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 basis</u> or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, DCP should respond to a specific data request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports**

described below, including facility events that have taken place since the previously submitted semi-annual report, should be submitted.

- **Semi-annual operational reports should be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), plant modifications, including future plans and progress thereof. Abnormalities should include, but not be limited to: unloading/loading/shipping problems, potential hazardous conditions from 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, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boil-off rates. Adverse weather conditions and the effect on the facility also should be reported. Reports should be submitted <u>within 45 days after each period ending June 30 and December 31</u>. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" also should be included in the semi-annual operational reports. Such information would provide FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.**

- **Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) should be reported to 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 <u>immediately</u>, 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 <u>within 24 hours</u>. This notification practice should be incorporated into the LNG facility's emergency plan. Examples of reportable hazardous fluids related incidents include:**

    a. fire;

    b. explosion;

    c. estimated property damage of $50,000 or more;

    d. death or personal injury necessitating in-patient hospitalization;

    e. release of hazardous fluids for 5 minutes or more;

    f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

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

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

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

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

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

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

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

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

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, non-conformance reports, 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, we conclude that the FEED presented by DCP 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.

We received a comment regarding the control and monitoring systems and integrity management programs used at the existing facility, particularly for the LNG storage tanks. DCP has a maintenance plan in place to ensure storage tanks, piping, process equipment, vessels, instrumentation, and utilities are functioning properly. The facility has an inspection program that continually monitors and examines this equipment. The inspection and maintenance regime for the existing LNG storage tanks include cathodic protection and elevation surveys, thermal scanning of the outer tank, and examination and repair of the outer tank shell paint.

We received a comment on whether the existing LNG Terminal could be safely operated during construction of the proposed Liquefaction Facilities. DCP would use temporary fencing or other restrictive measures to delineate the battery limits of the construction area from the operating portions of the plant. In addition, we are also recommending DCP to provide measures to control access during construction of the proposed Liquefaction Facilities (see section 2.8.4).

2.8.5 Siting Requirements

The principal hazards associated with the substances involved in the liquefaction of LNG result from cryogenic and flashing liquid releases; flammable vapor dispersion; vapor cloud ignition; pool fires; and overpressures. As discussed in section 2.8.4, 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 to ensure that impact to the public would be minimized. The Commission's regulations under 18 CFR 380.12(o)(14) require DCP to identify how the proposed design complies with DOT's siting requirements. As part of our review, we used DCP'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); and

- 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:

- seven 8,240-gallon per minute (gpm) LNG loading pumps (four new pumps and three existing pumps upgraded to 8,240 gpm) used for ship loading and associated piping and appurtenances; and two 6,543 gpm LNG product pumps used for LNG storage tank loading and associated piping and appurtenances – Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) does not address LNG transfer systems; however, 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; and

- one liquefaction heat exchanger and associated piping and appurtenances, including an 18-inch-diameter LNG rundown line – 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.

FERC EAs/EISs 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 addressed some of these issues in a March 2010 letter of interpretation. In that letter, DOT stated that: (1) the requirements in the NFPA 59A (2001) for transfer areas 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 determined that an exclusion zone analysis of the marine cargo transfer system is required.

In the 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 ethane 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 PSM 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 British thermal units per square foot-hour (Btu/ft^2-hr) from reaching beyond a property line that can be built upon. The distance to this flux level is to be calculated with 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, the FERC staff identified that the refrigerant siting requirements from Part 193 and NFPA 59A would be applicable to the following equipment:

- one liquefaction heat exchanger and associated piping and appurtenances;

- two partially buried and mounded ethane make-up bullets with a combined total capacity of 68,000 gallons and associated piping;

- four partially buried and mounded propane make-up bullets with a combined total capacity of 410,000 gallons and associated piping;

- two partially buried and mounded stabilized condensate storage tanks with a combined total capacity of 70,000 gallons and associated piping;

- one 133-gpm Propane Make-up Transfer Pump and associated piping and appurtenances;

- two 133-gpm Ethane Charge Pumps and associated piping and appurtenances;

- two 125-gpm condensate loading pumps and associated piping; and

- two 98-gpm NGL reinjection pumps and associated piping and appurtenances; and two 108-gpm Stabilizer Reflux Pumps and associated piping and appurtenances.

2.8.6 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 consider it prudent design practice to size impoundments based on the greatest flow capacity from any single pipe for 10 minutes, recognizing that different spill scenarios are used for the single accidental leakage sources for calculation of Part 193 exclusion zones. A similar approach is used with impoundments for process vessels, where the impoundments should be able to contain the contents of the largest process vessel served while recognizing that smaller design spills are used for Part 193 exclusion zone calculations.

Impoundment Sizing

Potential spills from the 36-inch-diameter ship loading header would be contained within the existing LNG Tank sub-impoundments located at LNG Storage Tanks 101-FF and 101-FG. As discussed in the FEIS for the Cove Point Expansion Project (Docket No. CP05-130), each LNG Tank sub-impoundment is sized to contain a 1-hour release from the LNG storage tank and has a capacity of 3,549,757 gallons. A 10-minute spill from the 36-inch-diameter LNG pump discharge header, with 6 LNG pumps in operation, would result in a volume of 494,400 gallons. We determined that each existing LNG Tank sub-impoundment would sufficiently contain a 10-minute spill volume, including pump runout volume, from the LNG pump discharge header.

DCP proposes to install five impoundment basins including LNG Impoundment Basin #1, LNG Impoundment Basin #2, the Hydrocarbon Sump, the Amine Sump, and the Trucking Area Sump at the liquefaction process area. The LNG Impoundment Basin #1 would be 28.3-feet-wide, 33.25-feet-long, and 33-feet-deep, with a volume of 232,286 gallons. LNG Impoundment Basin #1 would be lined with perlite concrete and located adjacent to the liquefaction heat exchanger, within the 1-foot curbed liquefaction process area. Potential spills from the liquefaction heat exchanger and the propane condenser within the 1-foot curbed area would be sloped into the LNG collection trench system that ties into LNG

Impoundment Basin #1. The largest spill into LNG Impoundment Basin #1 would be a guillotine rupture of the 42-inch-diameter propane condenser outlet piping, which would result in a 10-minute spill volume of 220,133 gallons. Without accounting for liquid volume reduction due to rapid evaporation, the 10-minute propane spill volume would be contained within LNG Impoundment Basin #1. LNG Impoundment Basin #1 would also contain a 10-minute spill volume from the guillotine rupture of the 18-inch-diameter LNG rundown line, which would be 79,980 gallons. This spill volume accounts for the LNG product pump runout condition and would be contained within LNG Impoundment Basin #1.

The perlite concrete LNG Impoundment Basin #2 would be 33-feet-long, 36-feet-wide, and 16-feet-deep, with a volume of 142,190 gallons. LNG Impoundment Basin #2 would be located approximately 500 feet north of the proposed liquefaction area and within the existing vaporization area. Any spills from the 18-inch-diameter LNG rundown line occurring north of the liquefaction process area would be sloped into an existing trench system that connects to LNG Impoundment Basin #2. A 10-minute spill volume from the 18-inch LNG rundown line would be 79,980 gallons and would be contained within LNG Impoundment Basin #2.

The proposed Hydrocarbon Sump would be 28-feet-long, 28-feet-wide, and 10-feet-deep, with a volume of 58,647 gallons. The Hydrocarbon Sump would be located adjacent to the Heavy Removal Unit and approximately 130 feet east of LNG Impoundment Basin #1. The largest process spill into the Hydrocarbon Sump would be from the 6-inch-diameter Heavies Removal Unit outlet piping, which would result in a 10-minute spill of 2,344 gallons. This spill would be contained within the 6-inch curb and sloped toward the Hydrocarbon Sump.

The proposed Amine Sump would be 30-feet-long, 30-feet-wide, and 18-feet-deep, with a volume of 121,184 gallons to contain rainwater from a 1-year storm event. The Amine Sump would be located in the pre-treatment area, which would be between the refrigerant storage area and the liquefaction process area. Any spills from the refrigerant make-up piping in the pre-treatment area would be directed to the Amine Sump. Since all refrigerant make-up pumps would be at rated 133 gpm, a guillotine rupture from either the ethane or propane make-up line would result in a 10-minute spill volume of 1,330 gallons. Either spill volume would be contained within the Amine Sump.

DCP proposes to install a 40,000-gallon Fresh Amine Tank within a 51.5-foot long by 32.6-foot wide by 7-foot-high diked area. The diked area would have a volumetric capacity of 87,913 gallons and would hold the entire contents of the Fresh Amine Tank. DCP also proposes to install a 26,438-gallon Contaminated Amine Tank within a 32.6-foot-long by 30.5-foot-wide by 8-foot-high diked area. This diked area would have a volumetric capacity of 59,503 gallons and would hold the entire contents of the Contaminated Amine Tank. DCP would also install a 25,000-gallon Aqueous Ammonia Tank within a 50-foot long by 25-foot wide by 3.9-foot-high diked area. This diked area would have a volumetric capacity of 36,468 gallons and would hold the entire contents of the Aqueous Ammonia Tank.

DCP proposes to install three Propane Make-up Tanks, one Propane Make-up Transfer Tank, two Ethane Make-up Drums, and two Condensate Storage Tanks. These tanks would be partially buried and mounded under a minimum of 2-feet of soil. DCP proposes to install a Trucking Area Sump with dimensions of 5-feet-long by 5-feet-wide by 11-feet-deep, with a volume of 2,057 gallons, to contain any potential liquid spills from the condensate truck loading hose. While DCP sized the Trucking Area Sump based on a guillotine rupture of the condensate loading hose, a hose rupture could also involve a release from the tanker truck's inventory. As a result, **we recommend that:**

- **<u>Prior to initial site preparation</u>, DCP should resize the Trucking Area Sump to adequately contain the maximum content of a condensate truck. DCP should file information on the resized Trucking Area Sump with the Secretary for review and written approval by the Director of OEP.**

Table 2.8.6-1 lists the spill volumes and their corresponding impoundment systems.

TABLE 2.8.6-1

Impoundment Area Sizing

Source	Spill Size (gallons)	Impoundment System	Impoundment Size (gallons)
Pump Withdrawal Header	494,400	Tank Sub-Impoundment	3,549,757
18-inch LNG Rundown Line (south)	79,980	LNG Impoundment Basin #1	232,286
18-inch LNG Rundown Line (north)	79,980	LNG Impoundment Basin #2	142,190
42-inch Propane Condenser Discharge (largest spill into Basin #1)	220,133	LNG Impoundment Basin #1	232,286
6-inch HRU Discharge Piping	2,344	Hydrocarbon Sump	58,647
Propane or Ethane Makeup Line	1,330	Amine Sump	121,184
Fresh Amine Tank	40,000	Fresh Amine Diked Area	87,913
Contaminated Amine Tank	26,438	Contaminated Amine Diked Area	59,503
Aqueous Ammonia Tank	25,000	Aqueous Ammonia Diked Area	36,468
Condensate Truck Hose	1,786	Trucking Area Sump	2,057

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 the FERC staff, dated August 6, 2013, DOT requested that LNG facility applicants contact the OPS' Engineering and Research Division regarding the Part 193 siting requirements.[12] 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, DCP provided DOT with its design spill criteria and identified leakage scenarios. This information included all of the proposed equipment, but did not include DCP's existing facilities. DOT reviewed the data and methodology DCP 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 flammable fluids. DCP's methodology considers the failure probability of over 400 piping segments and process vessels containing hazardous fluids for the purpose for selecting credible design spills using a list of nominal failures rates developed by FERC staff and presented by DOT on its webpage for "LNG Facility Siting" (http://primis.phmsa.dot.gov/lng/index.htm). This methodology also includes over 160 propane release scenarios. On February 27, 2014, DOT provided a letter to the FERC staff stating that DOT had no objection to DCP'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.[13] This letter was contingent on

[12] 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 CP13-113 on August 13, 2013. Accession Number 20140813-4011.

[13] February 27, 2014 Letter "Re: Dominion Cove Point LNG, LP, Cove Point Liquefaction Project, CP13-113-000, Design Spill Determination" from Kenneth Lee to Lauren H. O'Donnell. Filed in Docket Number CP13-113-000 on February 27, 2014. Accession Number 20140227-4004.

DCP filing supplemental models in support of the DOT Design Spill Determination for FERC review (Accession Number 20140227-5111). The design spills produced by this method were identified in the documents reviewed by DOT and have been filed in the docket for this Project. DCP also filed supplemental Design Spill modeling information on March 7, March 14, and April 11, 2014. These filings contain information on the design spills described in the following sections.

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 DCP'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:**

- **Prior to the construction of the final design, DCP should file with the Secretary for review and written 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 27, 2014 (Accession Number 20140227-4004) and supplemental information filed by DCP on March 7, 2014 (Accession Numbers 20140307-5050 and 20140307-5051), March 14, 2014 (Accession Numbers 20140314-5099 and 20140317-5100), and April 11, 2014 (Accession Numbers 20140411-5252 and 20140411-5253). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR 193 siting analysis was based, DCP should consult with DOT on any actions necessary to comply with Part 193.**

As design spills vary depending on the hazard (vapor dispersion, overpressure, toxic or radiant heat), the specific design spills used for the DCP siting analysis are discussed under "Vapor Dispersion Analysis" and "Thermal Radiation Analysis" in this section.

We received comments requesting that a quantitative risk assessment (QRA) be performed for the proposed Project and that no dangerous condition should be allowed to extend off-property. The proposed Project must comply with DOT's federal safety standards for siting of onshore LNG facilities under 49 CFR 193. These regulations require consequence calculations for a defined range of failures, rather than use of a QRA. Efforts are underway to develop a QRA method for LNG facility siting with the most notable method being described in Chapter 15 of the 2013 edition of NFPA 59A. Establishing specific assumptions/databases/models on which to base the risk methodology is critically important in ensuring that results are consistent and meaningful. As we have communicated to NFPA, differing failure rate data (often by several orders of magnitude), choice of consequence models, and hazard scenario selection that can be used under its QRA method can lead to inconsistent results for essentially identical facilities. The NFPA 59A Chapter 15 method has not yet addressed these issues.

Vapor Dispersion Analysis

As discussed in section 2.8.3, a large quantity of LNG spilled 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 this hazard, 49 CFR § 193.2059 requires each LNG container and LNG transfer system to have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001). 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. This is the Part 193 standard that we used in analyzing the siting of the proposed Project.

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.

The regulations in Part 193 specifically approve the use of two models for performing these dispersion calculations, DEGADIS and FEM3A. In October 2011, two additional 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.

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:

- 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

- 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.

DCP reviewed multiple releases for the liquid scenarios and for the flashing and jetting scenarios. DCP used the following conditions, corresponding to 49 CFR §193.2059, for the vapor dispersion calculations: ambient temperature of 57.4°F, relative humidity of 50 percent, atmospheric stability class of F, and a ground surface roughness of 0.03 m. 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.

DCP accounted for the facility geometry, including the impoundment and trench geometry details as established by available plant layout drawings. Including the plant geometry accounts for any on-site wind channeling that could occur and allows for inclusion of mitigation measures, such as vapor barriers. 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 Analyses for LNG

In order to address the highest rate of LNG flow (i.e., liquid scenario) into the liquefaction process area, DCP specified the design spill as a guillotine rupture of the 18-inch rundown line. This liquid spill would result in a maximum runout flow rate for one LNG product pump of 7,998 gpm for a 10-minute duration. DCP used FLACS to predict the extent of the ½-LFL dispersion distance from the liquid spill into the trench system. A sensitivity analysis was conducted at different wind speeds and directions. To mitigate the extent of the vapor dispersion, DCP proposes to install 20-foot-high vapor barriers at various locations in the plant as well as a 60-foot-high sound control barrier that would be located along the western and southern property lines of the plant. The locations of the vapor barriers and the 60-foot sound control barrier are shown in figure 2.8.6-1. The FLACS results indicate that the flammable vapor cloud would be contained within the 60-foot sound control barrier and would remain within DCP's property. 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>, DCP 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.**

DCP utilized PHAST Version 6.7 to conduct hole diameter and wind sensitivity studies in order to determine that the worst case jetting and flashing scenario would result from a 7-inch hole on the 18-inch-diameter LNG rundown line. FLACS was used to model three different release locations along the LNG rundown line at different wind speeds and directions. The FLACS modeling results shows that the flammable vapor cloud would be contained within the 60-foot sound control barrier and would remain within DCP's property.

For LNG ship loading operations, DCP specified the design spill as a 1-inch hole on the 36-inch-diameter LNG ship loading header (i.e., jetting and flashing scenario) with six LNG pumps operating. A portion of the ship loading header and new piping associated with the LNG ship loading pumps would be located within the existing sub-impoundments located at LNG Storage Tanks 101-FF and 101-FG. The operating ranges for flows and pressures in existing marine transfer piping outside of the existing sub-impoundments would not change and therefore were not evaluated. For the new equipment located within the existing sub-impoundments, PHAST was used to predict the extent of unmitigated and unobstructed dispersion distance to the ½-LFL vapor cloud from the 1-inch hole on the LNG ship loading header. DCP selected three wind speeds in the modeling to demonstrate the longest downwind dispersion distance. The PHAST dispersion distance of 724 feet would be centered at the existing sub-impoundments and would remain within DCP's property. As DCP's calculations show the dispersion from flammable vapors would stay within DCP property, 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.

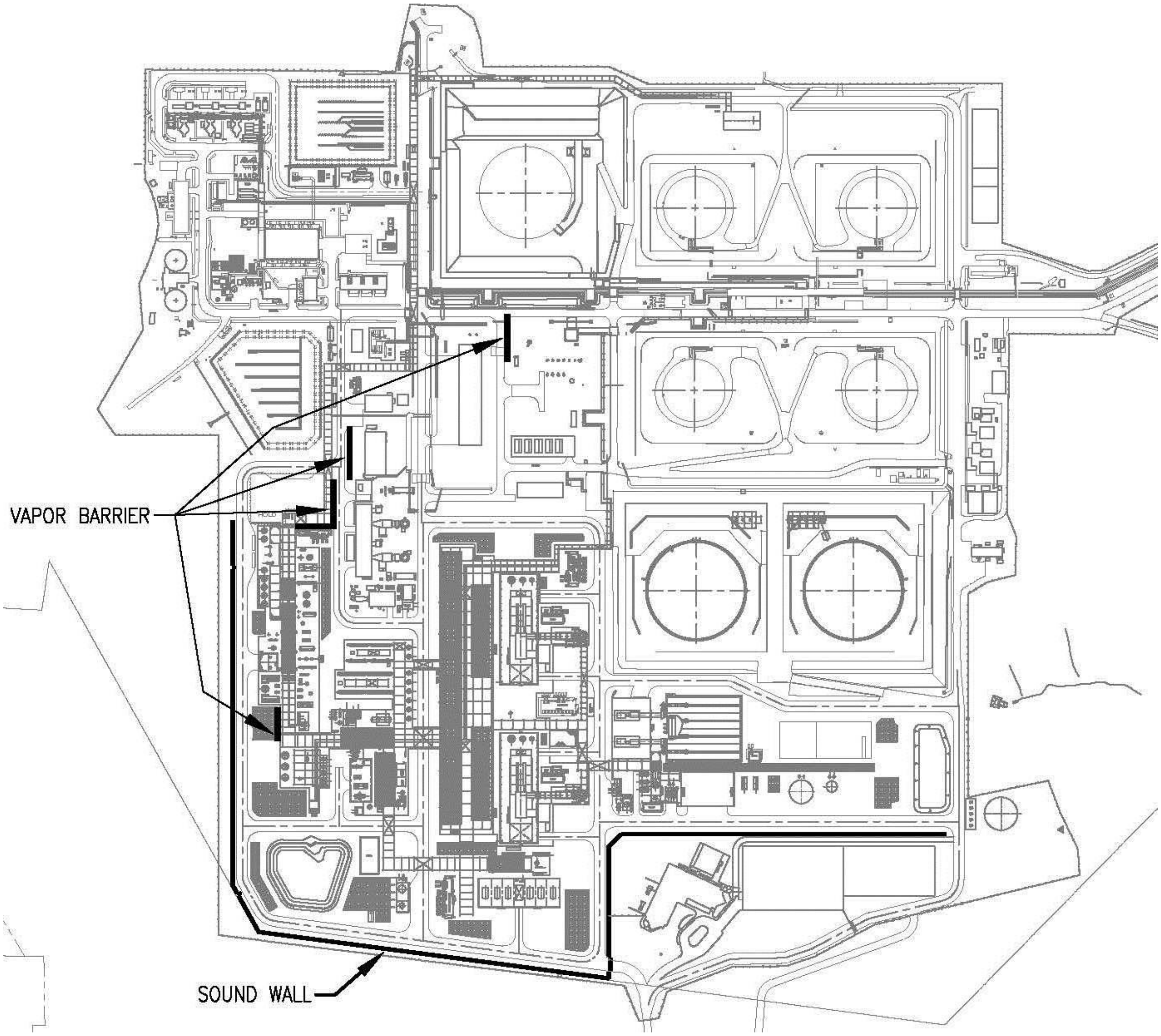

Figure 2.8.6-1

Vapor and Sound Barrier Locations

Vapor Dispersion Analyses for Other Hazardous Fluids

Even though DCP considered all possible releases from the MRL process system, the propane pre-cool system, and the heavy hydrocarbon removal system at the liquefaction process area, only the spills that produced the highest release rates and consequently the longest ½-LFL vapor clouds are discussed in this section. The highest rate of MRL release would be from a 2-inch-diameter hole on the MR piping from the MR/LP Propane Cooler to the MR Separator. PHAST was used to predict the releases MR vapor dispersion distance based on 3 different wind speeds. The PHAST results did not indicate any liquid rainout and calculated a ½-LFL distance of 750 feet that would remain within DCP's property.

Propane would be used in the liquefaction cycle to pre-cool the feed gas, and both propane and ethane would be used as components of the MR vapor. The worst case scenario for a propane release at the liquefaction process area would be a 14.7-inch hole on the Propane Compressor discharge piping. FLACS was used to model a horizontal release at different wind speeds and wind directions. FLACS calculated that the ½-LFL vapor dispersion distance for propane would extend about 775 feet and would be contained within DCP's property.

During the heavy hydrocarbon removal process, NGL and condensate would be extracted from the feed gas stream in the liquefaction area. For the NGL, the worst case scenario would be a 3-inch guillotine release from the NGL Reinjection Pump discharge piping. PHAST was used to model a horizontal release at different wind speeds and calculated a ½-LFL dispersion distance of 159 feet. For the condensate worst case, PHAST was used to model a 1.5-inch guillotine release from the Stabilizer outlet piping. PHAST calculated a ½-LFL distance of 162 feet. Each ½-LFL vapor cloud distance would remain within DCP's property.

The refrigerant make-up tanks and condensate storage tanks would be partially buried and mounded under a minimum of 2-feet of soil. For process releases outside of the refrigerant make-up tanks, a guillotine rupture of the 4-inch-diameter ethane make-up line would result in the longest downwind ½-LFL distance. PHAST was used to calculate a ½-LFL dispersion distance from a horizontal release at varying wind speeds. PHAST results showed a dispersion distance of 135 feet, which would remain within DCP's property.

In the refrigerant and condensate trucking area, DCP considered releases from the ethane, propane, stabilized condensate truck hose connections for both refrigerant truck unloading and stabilized condensate truck loading operations. The largest release would be from a guillotine rupture of the 3-inch-diameter propane hose connection. The maximum spill duration was assumed to be the de-inventory time of the propane truck for 3.4 minutes. PHAST simulations showed that a release from the propane trucking hose in the horizontal direction would result in a ½-LFL dispersion distance of 930 feet. This ½-LFL vapor cloud would remain within DCP's property.

The distances to the ½-LFL vapor cloud for all refrigerant and NGL release scenarios discussed above are provided in table 2.8.6-2 and would remain within the DCP's property. As DCP's calculations show the vapor dispersion would stay within DCP property, 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.

TABLE 2.8.6-2 **Vapor Dispersion Scenarios from Process Releases**			
Scenario	Material	Release Location	Approximate downwind distance to ½-LFL (feet)
1	Mixed Refrigerant	Liquefaction Process	750
2	Propane	Liquefaction Process	775
3	Ethane	Make-up Piping	135
4	NGL	Process Piping	159
5	Condensate	Process Piping	162
7	Propane	Truck Unloading	930

Since the stabilized condensate would contain benzene, a toxic product, DCP used PHAST Version 6.7 to calculate the dispersion distances to toxic threshold exposure limits based on the Acute Exposure Guideline Level (AEGLs). Additionally, DCP calculated the AEGLs for H_2S and ammonia. AEGLs 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. Other federal agencies, such as the DOE, use AEGLs as the primary measure of toxicity.

There are three AEGLs which are distinguished by varying degrees of severity of toxic effects with AEGL-1 (level 1) being the least severe to AEGL-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 nonsensory effects. However, these effects are not disabling and are transient and reversible upon cessation of the exposure. AEGL-2 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape. AEGL-3 is the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death. The EPA provides AEGLs for a list of chemicals at varying exposure times (10 minutes, 30 minutes, 1 hour, 4 hours, and 8 hours). Table 2.8.6-3 shows the toxic concentrations of benzene, H_2S, and Ammonia at the 10-minute exposure time AEGLs based on EPA's published information (EPA 2012).

TABLE 2.8.6-3 **Acute Exposure Guideline Levels (in ppm) at 10 minutes**			
Substance	AEGL-1	AEGL-2	AEGL-3
Benzene	130	2,000	9,700
H2S	0.75	41	76
Ammonia	30	220	2,700

DCP's toxicity analysis considers a 1.5-inch-diameter guillotine release from the Stabilizer outlet piping for benzene, a 0.707-inch gasket loss on the Acid Gas Blower Aftercooler discharge piping for H_2S, and a 0.4-inch hole on the Aqueous Ammonia Storage Tank for aqueous ammonia. DCP used PHAST Version 6.7 to model each release. Similar to flammability concentrations, a safety factor of 2 (i.e. ½ AEGL) was also applied to reflect uncertainties associated with the model. DCP submitted the benzene toxicity analysis to 65 ppm (i.e., ½ AEGL-1 at 10-minutes). The toxic dispersion distance was calculated to extend 314 feet from the release point. For the H_2S in the acid gas stream, PHAST did not calculate any toxic hazards. The warm temperatures and low operating pressures allows the release to dissipate quickly. For the aqueous ammonia release, PHAST calculated the maximum distance to 15 ppm ammonia concentration (i.e., ½ AEGL-1 at 10 minutes) to 452 feet from a release point located at the Aqueous Ammonia Storage Tank. Each toxic dispersion distance for the AEGL-1, which are non-disabling and reversible, would remain within property under control of DCP. Dispersion distances associated with AEGL-2, and -3 would be shorter than these AEGL-1 distances. As a result, we conclude that the releases of the toxic components (i.e., stabilized condensate, H_2S, and aqueous ammonia) would not present a significant impact to the public. 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.

Overpressure Considerations

As discussed in section 2.8.3, 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.

LNG Vapor Clouds

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 "Overpressures" in section 2.8.3, unconfined LNG vapor clouds would not be expected to produce damaging overpressures. The presence of heavier hydrocarbons influences the propensity for a detonation or deflagration with damaging overpressures. Less processed product with greater amounts of heavier hydrocarbons is more sensitive to detonation. The Project would be designed to receive feed gas with methane concentrations as low as 91 percent. These compositions are not in the range shown to exhibit overpressures and flame speeds associated with high-order explosions and detonations.

The USCG studies referenced under "Overpressures" in section 2.8.3 indicated overpressures of 4 bar and flame speeds of 35 meters per second (m/s) 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. However, unconfined methane vapor clouds ignited with low energy ignition sources have been shown to produce flame speeds ranging from 5.2 to 7.3 m/s, which is much less than the flame speeds associated with explosions or detonations.

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. Given the LNG compositions which would be handled onsite, potential ignition sources, and the expected vapor dispersion characteristics, damaging overpressures would not be expected to occur from ignition of an unconfined vapor cloud. However, ignition of a confined natural gas vapor cloud could result in higher overpressures. In order to prevent such an occurrence, DCP proposes to install flammable gas detectors in occupied building heating, ventilation, and air conditioning (HVAC) inlets to reduce the likelihood of flammable vapors dispersing into these buildings. We conclude that these measures provide sufficient protection and that the potential for overpressures from confined vapor clouds would be negligible.

Vapor Clouds from Other Hazardous Fluids

The refrigerants which would be used in the liquefaction process streams have a higher reactivity than LNG, and in some circumstances may produce damaging overpressures when ignited. In order to evaluate this hazard, DCP used the Baker-Strehlow-Tang Explosion model in PHAST Version 6.7 to perform an explosion overpressure analysis. With the assumption that the obstructed volume includes the entire vapor cloud, PHAST estimated the distances to the 1-psig threshold resulting from an ethane, propane, NGL, or MR releases at different wind speeds. The flammable vapor cloud was ignited at the greatest LFL cloud extent. Table 2.8.6-4 provides the worst-case results of the five explosion scenarios modeled by DCP. The PHAST results show that the maximum overpressure from the ignition of the ethane, propane, or NGL vapor clouds would remain on DCP property. However, PHAST results showed that the distance to 1-psig for the MR overpressure scenario would extend beyond DCP's property boundary. Therefore, the MR overpressure scenario was identified for modeling using FLACS to account for the detailed geometry model of the Cove Point facility. Distances were determined with a safety factor of 2 (i.e., ½ psi), as a result of previous validation studies and peak-pressure averaging (Hansen, et al., 2010). Four congested regions were identified: Pretreatment, Propane Cooling, Liquefaction, and Main Air Coolers. The levels of confinement are input parameters in the overpressure modeling software. The overpressure threshold were calculated by placing an uniform, stoichiometric fuel/air mixture within each congested region and several vapor cloud explosion simulations were performed on FLACS. The results show that the distance to ½ psig overpressure from vapor cloud explosion would extend approximately 400 feet but would remain within DCP's boundary. This overpressure would not reach the LNG storage tanks. FLACS also calculated an overpressure scenario from the 3-inch-diameter propane truck loading hose guillotine release. This release would disperse over the wooded area located west of the proposed facility. The FLACS geometry included the trees and geographic features of the Cove Point facility and modeled an ignition of the propane cloud in the wooded area. All of the overpressure scenarios calculated by DCP would remain within the DCP property. 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.

TABLE 2.8.6-4

Overpressure Distances from Refrigerant and Heavy Hydrocarbon Releases

Scenario	Material and Leak Location	Approximate overpressure distance
1	2-inch hole on MR piping to MR Separator	400 feet
2	2-inch hole on propane header to Propane Receiver	337 feet
3	1-inch hole on propane header to MR/HHP Propane Cooler	477 feet
4	3-inch guillotine on NGL reinjection pump discharge	263 feet
5	4-inch guillotine on Ethane Make-up Piping	247 feet
6	3-inch guillotine on Propane Truck Loading Hose	615 feet

Thermal Radiation Analysis

As discussed in section 2.8.3, 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 Section 193.2057 specifies hazard endpoints in terms of flux levels for spills into LNG storage tank containment and spills into impoundments for process or transfer areas. For any distance from a pool fire, a flux level which expresses how much thermal radiation would be received at that point can be calculated. Each LNG container and LNG transfer system is required to have a thermal exclusion zone in accordance with Section 2.2.3.2 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 spills from the process or transfer areas, the 1,600 Btu/ft^2-hr flux level from the impoundments cannot extend beyond the facility's property line that can be built upon. These are the Part 193 standards that we used in analyzing the siting of the proposed Project.

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. DCP submitted a thermal radiation analysis that showed the following ambient conditions resulted in the maximum exclusion distances: wind speeds of 12.7 mph, ambient temperature of 28°F, and 35 percent relative humidity. We agree with DCP's selection of atmospheric conditions.

For its analysis, DCP used LNGFIRE3 to predict the thermal radiation distances for fires from the Impoundment Basin #1, Impoundment Basin #2, Amine Sump, Hydrocarbon Sump, and Trucking Area Sump. As indicated in section "Impoundment Sizing," we recommended DCP to resize the Trucking Area Sump accounting for the maximum content of a condensate truck. Therefore, FERC staff used a larger surface area of 134 square feet in LNGFIRE3 and calculated a distance of 80 feet to the 1,600-Btu/ft^2-hr heat flux from a resized Trucking Area Sump. This would remain on DCP property. The larger surface area is based on a conservative assumption that the Trucking Area Sump's depth of 11 feet would remain the same. 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 ethane, propane, NGL, and condensate. Two of the parameters used by LNGFIRE3 to calculate the thermal radiation flux is 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 ethane, propane, NGL, or condensate fire would be less than an equally sized LNG fire. Because the thermal radiation from a pool fire is dependent on the mass burning rate and SEP, the thermal radiation distances required for ethane, 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.

The resulting maximum thermal radiation distances are shown in table 2.8.6-5 and figure 2.8.6-2. The 1,600-Btu/ft^2-hr heat flux from the proposed Impoundment Basins would remain within the facility property lines. As DCP's calculations of Impoundment Basin #1, Impoundment Basin #2, Amine Sump, Hydrocarbon Sump and our calculation of the Trucking Area Sump show the radiant heat limits for Part 193 would stay within DCP property, 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.

TABLE 2.8.6-5

Thermal Radiation Exclusion Zones for Impoundment Basins

Impoundment Basins	1,600 Btu/ft^2-hr Flux Distance (feet from center of impoundment)
Impoundment Basin #1	184
Impoundment Basin #2	204
Amine Sump	180
Hydrocarbon Sump	173
Trucking Area Sump	39 [a]

[a] For a resized Trucking Area Sump, FERC staff calculated 80 feet. This distance is based on our assumed dimensions of the Trucking Area Sump. Thermal radiation analysis based on actual Trucking Area Sump dimensions would be performed prior to initial site preparation.

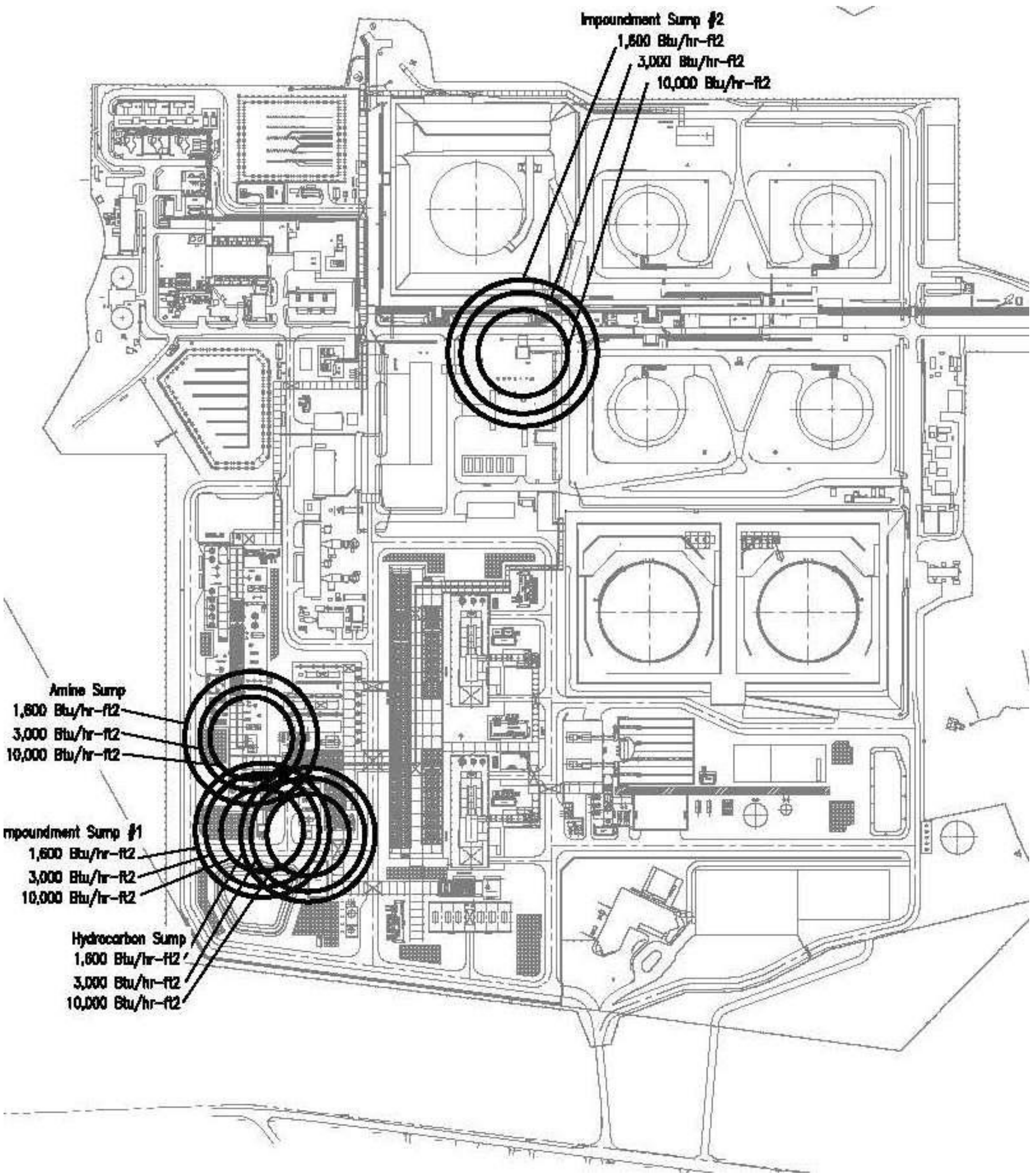

Figure 2.8.6-2

Impoundment 10,000, 3,000, and 1,600-Btu/ft^2-hr Thermal Radiation Exclusion Zones

2.8.7 Emergency Response

Section 3A(e) of the NGA, added by Section 311 of the EPAct, stipulated that in any order authorizing an LNG terminal, the Commission shall require the LNG terminal operator to develop an emergency response plan (ERP) in consultation with the USCG and state and local agencies. The ERP has been in place since the Cove Point LNG Terminal began operation in 1978 and has been updated as new projects have changed the configuration of the LNG Terminal. The existing ERP would need to be updated to include the proposed liquefaction facilities and emergencies related to refrigerant handling. Therefore, **we recommend that:**

- **<u>Prior to initial site preparation</u>, DCP should file its updated ERP to include the Liquefaction Facilities as well as instructions to handle on-site refrigerant and NGL-related emergencies. DCP should file the updated ERP with the Secretary for review and written approval by the Director of OEP.**

- **<u>Prior to initial site preparation</u>, DCP should file an ERP that includes 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. DCP should file the ERP, including the Cost-Sharing Plan, with the Secretary for review and written approval by the Director of OEP.**

We received a comment on the evacuation route due to an LNG related incident. We did not identify any incident from the siting analysis that would change or impact the evacuation routes that have been established for the existing facility. Furthermore, DCP's existing emergency response plan indicates coordination with the Maryland State Police and Calvert County Sheriff's Office for offsite emergency organization. The Maryland State Police and Calvert County Sheriff's Office would provide the necessary law enforcement assistance, which includes evacuating individuals from designated public and private areas. Our recommendation above would address any new emergency situations associated with this Project.

2.8.8 Facility Security and LNG Vessel Safety

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 USCG regulations in 33 CFR 127. Requirements for maintaining security of the terminal are in 33 CFR 105. The Cove Point LNG Terminal has an existing Facility Security Plan, as required by 33 CFR 105, which has been approved by the USCG.

The DCP reactivated the offshore pier of the Cove Point LNG Terminal in 2003 and has been receiving LNG import shipments. Exporting operations would alter the direction of loaded LNG carrier transits, with ships arriving empty but departing with a full cargo. However, there would be no changes in the marine systems or the expected number of vessels for the export Project. The operations for LNG tankers would remain the same regardless of the direction of the shipment. The mooring, connection, and disconnection of the LNG tankers, as well as the shipping routes from/to the offshore pier, would remain the same. Currently, there are no U.S. flagged LNG vessels used in either import or export service.

In a letter to the USCG dated May 23, 2012, DCP detailed the proposed Project modifications and estimated the ship traffic would not exceed the previously approved 200 vessels per year in Docket CP05-130, et al., and DCP would not accept LNG carriers larger than previously authorized in Docket CP09-60. In a letter dated July 2, 2012, the USCG stated that the existing WSA and LOR are adequate for the service associated with the proposed Project. However, the USCG specified that applicable amendments to the Operations Manual, Emergency Manual, and Facility Security Plan must be made that capture changes to the operations associated with the Project. As required by 33 CFR 105 and 127, DCP would amend these documents and submit them to the USCG prior to operation of the facility as an export terminal. Furthermore, the Memorandums of Understanding established between the USCG, Calvert County Sheriff's Office, and the MDNR ensures enforcement of the safety/security zone while LNG vessels are in transit and moored at the facility.

2.8.9 Conclusions on Facility Reliability and Safety

The principal hazards associated with the substances involved in the liquefaction, storage, and vaporization of LNG result from cryogenic and flashing liquid releases; flammable vapor dispersion; vapor cloud ignition; pool fires; overpressures, and toxicity. 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 safety impacts. Based on our technical review of the preliminary engineering designs, as well as our suggested mitigation measures, we conclude that sufficient layers of safeguards would be included in the facility designs to mitigate the potential for an incident that could impact the safety of the off-site public. 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. 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 which were presented as part of DCP's FEED. However, we are recommending that the final design be provided for further staff review to ensure it would be consistent with the safety and operability characteristics identified in the FEED. In addition, we are recommending that the facility, during construction and operation, be subject to regular FERC staff technical reviews and site inspections on at least an annual basis.

Siting of the facility with regard to potential off-site consequences from these hazards is also required by DOT's regulations in 49 CFR 193, Subpart B. As part of its application to FERC, DCP identified how its proposed design would comply with DOT's Part 193 siting requirements. We used this information to assess whether or not a facility would have a public safety impact and DOT, as a cooperating agency, assisted in this evaluation. As provided, DCP's siting analysis indicates that the siting of the proposed facility would not have a significant impact on public safety. If this facility is approved and becomes operational, the facility would also be subject to DOT's inspection program under 49 CFR 193. Final determination of whether a facility is in compliance with the requirements of Part 193 would be made by DOT staff during those inspections.

2.9 CUMULATIVE IMPACTS

NEPA requires the lead federal agency to consider the potential cumulative impacts of proposals under their 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, we believe that 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 potentially affected by the Project;
- cause this impact within all, or part, of the Project area; and
- cause this impact within all, or part, of the time span for the potential impact of the Project.

2.9.1 Projects and Activities Considered

Construction and operation of the Pleasant Valley Compressor Station, Suction/Discharge Pipelines, and M&R Facility would occur within DCP's existing property and rights-of-way that are located in a relatively undeveloped area. As described in section 1.3.1, Nonjurisdictional Facilities, the existing electrical substation at the Pleasant Valley Compressor Station would also be expanded to support the additional compressor units proposed by DCP. The expansion would affect 0.9 acre within the fence line of the compressor station and would be constructed, owned, and operated by the Northern Virginia Electric Cooperative, which would obtain the necessary permits and approvals for the project. Based on the relatively small scale of the substation expansion and considering that the project would occur within the workspace of the Pleasant Valley Compressor Station modifications, we conclude that contemporaneous construction and operation of the Pleasant Valley Compressor Station and the expansion of the existing electrical substation would not result in any significant cumulative impacts.

No substantial developments have occurred recently in the vicinity of the Pleasant Valley facilities and no other known, projects are proposed in the area. Thus, the Pleasant Valley facilities would not result in construction-related cumulative impacts in the area. Operation of the modified compressor station could impact regional air quality and locally contribute to existing noise. However, only minor increases in air emissions and noise would occur because the additional compression would be achieved by electric-driven compressor units and DCP would implement measures, including installation of a sound barrier wall, to mitigate for noise. Thus, construction and operation of the proposed Pleasant Valley facilities (including the electrical substation expansion) would not result in any significant cumulative impacts, and they are not discussed further in this analysis.

The proposed modifications of the Loudoun M&R Facility would occur within DCP's existing Loudoun Compressor Station site, and DCP would utilize developed and maintained space at the nearby Leesburg Compressor Station during construction. The primary recent development near the Loudoun M&R Facility is Greene Mill Preserve, a residential subdivision located approximately 1,500 feet northeast from the site. Development at the Greene Mill Preserve is ongoing, with additional homes being proposed and under construction. No other substantial development activities are known in the area. As described throughout section 2.0, construction of the Loudoun M&R Facility and temporary use of the Leesburg Compressor Station Contractor Staging Area would have only minor impacts on environmental resources associated with piping and measurement upgrades and material laydown and storage, respectively. As such, no increased operational impacts would occur. Thus, construction and operation of the proposed Loudoun M&R Facility would result in negligible, cumulative impacts on the environment and it is not discussed further in this analysis.

As described in section 1.1, the LNG Terminal has undergone four expansions or modifications since the original construction of the facility was completed in 1978. The most recent of these, the Pier Reinforcement Project, was completed and placed into service in 2011. Whereas the Liquefaction Facilities would result in incremental environmental impacts as described in section 2.0, we conclude that the proposed facilities and previous projects at the LNG Terminal would not have a cumulative impact on the environment largely because all of the on-shore components of the previous projects at the LNG Terminal occurred within the industrial Fenced Area where the proposed Liquefaction Facilities, if approved, would be constructed, and because the construction of the most recent previous project ended at least 3 years before construction of the proposed Project is scheduled to begin. Therefore, the previous expansions and modifications at the LNG Terminal or offshore pier are not considered further in this analysis.

The proposed Liquefaction Facilities and Offsite Areas A and B would affect confined areas within Calvert County for an approximately 3-year construction timeframe. For this analysis, we considered Calvert County as the main region of influence in which impacts have the potential to be cumulative, extending our review as necessary to the watershed and air shed encompassing the Project area. In addition, we considered projects that could potentially be or are connected to the proposed Project in our analysis (i.e., the Keys Energy Center and the temporary warehouse, respectively). More distant projects are not addressed because these projects generally do not have regional effects, and therefore, do not contribute substantially to cumulative impacts in the proposed Project area. Table 2.9-1 summarizes other ongoing or planned projects in proximity to the LNG Terminal that we considered in our cumulative impacts analysis.

TABLE 2.9-1

Existing or Proposed Projects Evaluated for Potential Cumulative Impacts

Project	Description	Status	Location Relative to Cove Point Liquefaction Project
Projects Near the Liquefaction Facilities, Offsite Area A, and Offsite Area B			
Calvert Cliffs Unit 3 Project	Potential addition of a third unit at the Calvert Cliffs Nuclear Power Plant.	Initial permitting underway. The project does not have a required U.S. sponsor; therefore, construction is speculative and would likely occur after completion of the proposed Cove Point Liquefaction Project (Project).	Approximately 2.9 miles north of the Liquefaction Facilities.
Maryland Route 4 Upgrades	Upgrades to the Thomas Jefferson Bridge and Maryland Route 4 to the south of the bridge, potentially resulting in a widening of the bridge from two lanes to four.	Planning phase scheduled to be completed in 2014. Maryland State Highway Administration conducted its environmental review and is drafting a Finding of No Significant Impact. Construction would likely occur after completion of the proposed Project.	West and south of Offsite Area B along Maryland Route 4.
Hidden Treasure Development	37-lot residential development.	Majority of lots have been sold with homes constructed; some unsold lots remain.	Within 0.25 mile south of the Fenced Area.
Keys Energy Center	A nominal 735 megawatt power generating facility; may require construction of a new natural gas lateral pipeline from DCP’s existing Cove Point Pipeline.	Initial planning phase; environmental review underway.	Approximately 30 miles northwest of the Liquefaction Facilities.

TABLE 2.9-1 (cont'd)

Existing or Proposed Projects Evaluated for Potential Cumulative Impacts

Project	Description	Status	Location Relative to Cove Point Liquefaction Project
Nonjurisdictional Facilities Associated with the Cove Point Liquefaction Project			
Road Improvements	Addition of a signal at the intersection of Maryland Route 2/4 and Maryland Route 497 and construction of a 200-foot-long right turn lane with a 150-foot-long taper along eastbound Maryland Route 497 at Cove Point Road.	Construction underway.	Approximately 1.5 miles west of the LNG Terminal property, near Offsite Area A.
	Utility modifications, including relocation of poles; guy wires and cables; and power and telecommunications wiring; relocation of planned municipal improvements (e.g., road, water, sewer) along Cove Point Road. Modifications to traffic signals, signage, and road crossings may also be required.	Prior to construction of the Liquefaction Facilities.	Cove Point Road, between Offsite Area B and the LNG Terminal.
Calvert County sewer extension external to the LNG Terminal	Extension of the existing Calvert County septic sewer system approximately 2 miles to the LNG Terminal entrance. Work would be contracted by DCP but constructed under guidance of the Calvert County Department of Public Works. Approximately 1.7 acres affected.	Proposed completion in 2014.	Extending approximately 2 miles west of the LNG Terminal property.
Calvert County sewer service internal to the LNG Terminal	Construction of a new sewer system at the LNG Terminal to connect to the Calvert County sewer extension described above.	Proposed construction in 2014.	Within the Fenced Area and offshore pier tunnel and along the existing LNG Terminal access road.
Other Related Activities Associated with the Cove Point Liquefaction Project			
Warehouse and storage yard	Temporary use of an existing 19,500 square-foot warehouse and 1-acre storage yard to store stock from an existing warehouse within the Fenced Area that would be removed as part of the Project.	Relocation of materials to the warehouse is underway.	Approximately 16 miles northwest of the Liquefaction Facilities in Prince Frederick, Maryland.
Temporary maintenance shop/ permanent warehouse, and new radio tower	Construction of an approximately 9,600 square-foot building to be used as a maintenance shop during construction and as a warehouse during operation of the proposed Project. A new radio tower is to be erected next to the building.	Permit applications have been submitted. Proposed early 2014.	Within the northeast corner of the Fenced Area.
Permanent maintenance shop	Construction of a new maintenance shop to be used during operation of the proposed Project.	Permit applications have been submitted. Proposed early 2014.	Within the Fenced Area, near the existing Administration Building.

TABLE 2.9-1 (cont'd) **Existing or Proposed Projects Evaluated for Potential Cumulative Impacts**			
Project	Description	Status	Location Relative to Cove Point Liquefaction Project
New and relocated security fence	Temporary and permanent fencing to separate construction areas and secure areas within the Fenced Area.	Temporary fence installation is underway. Permanent gates/ access points would be activated after the USCG approves the facility security plan.	Within the Fenced Area.

Regarding the other related activities, the new buildings and radio tower would be constructed within the industrial Fenced Area at the LNG Terminal. The temporary and permanent security fencing would also be erected within the Fenced Area. Construction and restoration within these areas would be in accordance with our Plan and Procedures and DCP's Project-specific E&SCPs, SMP, and other permit conditions as may be required, thereby minimizing impacts associated with construction and operation of the other related activities. In addition, the other related activities would be visually consistent with the existing industrial appearance within the Fenced Area, and would not contribute appreciably to noise in the surrounding area. We conclude that the other related activities within the Fenced Area would not result in significant cumulative impacts and, therefore, they are not discussed further in this analysis.

DCP's temporary use of the existing warehouse in Prince Frederick, Maryland, would create additional traffic on area roads between the LNG Terminal and warehouse; however, we find that the existing road system could accommodate the added traffic. Based on the above and considering that DCP's proposed use of the warehouse would be consistent with the purpose of the facility, we conclude that the temporary use of the warehouse would not result in significant cumulative impacts and, therefore, it is not discussed further in this analysis.

Construction and operation of the Calvert County sewer system within the LNG Terminal boundaries would largely take place within the workspace of the Liquefaction Facilities. The portions of the sewer system that would be constructed outside of the workspace for the Liquefaction Facilities would be installed within the existing developed LNG Terminal boundaries, including the offshore pier tunnel and existing access road entrance to the LNG Terminal site. Because the sewer system installation would occur within the workspace for the proposed Project and DCP's existing industrial facilities, we conclude that contemporaneous construction and operation of the proposed Liquefaction Facilities would not result in any significant cumulative impacts.

We received comments suggesting our analysis include projects related to natural gas development and gathering (including Marcellus Shale development), natural gas transportation, and natural gas distribution in areas that are well beyond the proposed Project area, in some cases they would be hundreds of miles away. In addition, no such development is occurring in the State of Maryland. As discussed in section 1.2, the FERC's authority under the NGA and NEPA review requirements relate only to natural gas facilities that are involved in interstate commerce. A more specific analysis of Marcellus Shale upstream facilities is outside the scope of this analysis because the exact location, scale, and timing of future facilities are unknown. In addition, the potential cumulative impacts of Marcellus Shale drilling activities are not sufficiently casually related to the Project to warrant the comprehensive consideration of those impacts in this EA. As such, these projects were not included in our cumulative analysis.

The remaining projects listed in table 2.9-1, including the four projects in proximity to the LNG Terminal, as well as the nonjurisdictional road improvements and Calvert County sewer extension outside the LNG Terminal, have the potential to cumulatively affect resources during construction and operation of the proposed Project. These potential cumulative impacts are discussed below by affected resource.

2.9.2 Geology and Soils

Construction of the Liquefaction Facilities and use of Offsite Areas A and B would have a direct but temporary impact on near-surface geology and soils. Impacts on geology and soils could lead to poor revegetation potential and indirectly affect wildlife and aquatic resources as a result of poor vegetation cover and increased erosion and sedimentation. However, the soil stabilization and revegetation requirements in our Plan and Procedures and DCP's E&SCPs would prevent or minimize any direct impacts. Because the direct effects would be highly localized and limited primarily to the period of construction, cumulative impacts on geology and soils would only occur if other projects are constructed at the same time and place as the proposed facilities. The construction schedules for the Calvert Cliffs Unit 3 Project and Maryland Route 4 upgrades have not yet been determined. Both projects are currently in the environmental review stage; however, construction is not expected to begin until after construction of the proposed Project. Road improvements are currently occurring near Offsite Area A and include vegetation clearing and grading to prepare for installation of the turn lane. These improvements would occur in compliance with erosion control measures required by the MSHA and Calvert County. The construction of the projects that require significant excavation or grading, such as the Maryland Route 4 upgrades and road improvements, would also have temporary direct impacts on near-surface geology. However, the cumulative impacts on these resources would be minimized by the implementation of erosion control and restoration measures during the construction and restoration of the projects. Therefore, the additive impact of the Cove Point Liquefaction Project and associated nonjurisdictional and other related activities on most of these projects would be minimal because they would not occur within the same timeframe or the same local vicinity.

2.9.3 Waterbodies and Wetlands

Construction of the proposed Project would affect three surface waterbodies and three wetlands. Operation of the Liquefaction Facilities would permanently fill one of the waterbodies (WUS1) and one of the wetlands (Wetland 1). The remaining waterbodies and wetlands affected by construction of the Project would be restored to preconstruction conditions following construction.

Cumulative impacts on surface water resources and wetlands would be limited primarily to waterbodies and wetlands that are affected by other projects located within the same watershed as the proposed Project. Runoff from construction activities near waterbodies could also result in cumulative impacts, although this effect would be relatively minor and would be controlled by implementation of erosion and sediment control measures and by compliance with federal, state, and local requirements.

Construction of the Maryland Route 4 upgrades could include in-water activities in the Patuxent River associated with the upgrades to the Thomas Jefferson Bridge; however, because construction of the Maryland Route 4 upgrades is not expected to occur until after construction of the proposed Project is complete and the bridge work would be required to comply with federal, state, and local requirements, no cumulative impacts on the Patuxent River would be expected.

If the proposed Project were constructed at the same time as the other proposed projects in the area, the geographic extent and duration of disturbances to waterbodies and wetlands by construction of the Project would be minimal, and further minimized by DCP's implementation of our Plan and Procedures and its E&SCPs. While the proposed Project would result in the permanent loss of a portion of stream WUS1 and Wetland 1, the COE has determined that no mitigation would be required for these impacts. As such, we conclude that construction and operation of the proposed Project would not result in a significant cumulative impact on surface waters and wetlands.

2.9.4 Vegetation and Wildlife

When projects are constructed at the same time or close to the same time, they would have a cumulative impact on vegetation and wildlife occurring in the areas where the projects would be built. Clearing and grading and other activities associated with the Project, including the nonjurisdictional and other related activities, along with the projects described above, would result in the removal of vegetation; alteration of wildlife habitat; displacement of wildlife; and other potential secondary effects such as increased population stress, predation, and the establishment of invasive plant species. These effects would be greatest where the other projects are constructed within the same timeframe and in close proximity to the proposed Project facilities.

As discussed in section 2.3.1, the greatest impact on vegetation would be the clearing of forested areas because of the length of time required for woody vegetation to revert to its preconstruction condition. Approximately 113 acres of upland forest and 2 acres of early successional woodland would be removed by construction of the Project. The amount of forest that would be removed at the LNG Terminal and Offsite Area A represents approximately 0.1 percent of the 81,000 acres of forest in Calvert County. Operation of the Project would result in the permanent loss of 11.5 acres of upland forest, including 11.2 acres within the Fenced Area at the LNG Terminal and 0.3 acre within the boundary of the Pleasant Valley Compressor Station.

At Offsite Area A, DCP configured its workspace to preserve approximately 73 acres of forest, exceeding a minimum requirement of 61 acres that was required by Calvert County. In addition, DCP would mitigate the loss of forest land at the Liquefaction Facilities through the Calvert County fee-in-lieu program or the purchase of transferrable development rights, and by placing a 102-acre undeveloped parcel of land approximately 1 mile west of Offsite Area A into a preservation easement to offset forest and natural resource impacts associated with the Project.

The impacts on vegetation and wildlife habitat associated with the projects listed in table 2.9-1 would be minimal because many of the projects would primarily occur at locations that are already developed or along existing rights-of-way. The road improvements require the removal of vegetation immediately adjacent to Maryland Route 2/4 and Maryland Route 497. In addition, both the Liquefaction Facilities and Calvert Cliffs Nuclear Power Plant are adjacent to significant areas of undeveloped forested land placed in preservation trusts. Further, the proposed projects would be required to implement measures to reduce potential impacts on vegetation and wildlife, and DCP would implement the measures in our Plan and Procedures and its E&SCPs to reduce impacts associated with the proposed Project and promote revegetation following construction. As such, we conclude that the proposed Project would not contribute to a cumulative impact on vegetation or wildlife.

2.9.5 Land Use, Recreation, and Visual Resources

The proposed Project and the other potential future projects in table 2.9-1 would result in both temporary and permanent changes to the current land uses. Much of the land that would be disturbed by construction at the Liquefaction Facilities, Calvert Cliffs Nuclear Power Plant, and the Maryland Route 4 upgrades is currently developed or adjacent to previously developed land. As such, construction and operation of the projects would be consistent with existing uses of the site and views of the area. Residential development projects would convert additional acres of land from primarily undeveloped to developed. However, the change in land use would likewise be consistent with surrounding residential developments in the area.

The use of Offsite Areas A and B would be limited to the 3-year period of construction. Offsite Area A is currently undeveloped and would be restored and replanted as requested by the landowner. Offsite Area B would be allowed to revert to its previous use following construction and no permanent change to the land use would occur.

The proposed Project, if built during the same timeframe as other foreseeable future projects, could result in cumulative impacts on recreational or special interest areas if these projects would affect the same area or features (e.g., parkland, recreational river uses) at the same time. However, because the Liquefaction Facilities would primarily occur within an existing industrial facility and would not substantially affect the surrounding current land uses, most Project-related impacts would be limited to the 3-year period of construction. Recreational users of the Solomons Island Boat Launch and Pier, which is adjacent to Offsite Area B, and users on the Patuxent River could experience short term cumulative impacts related to recreational activities on the water if construction of the Maryland Route 4 upgrades and DCP's use of Offsite Area B occur at the same time. However, construction of the Maryland Route 4 upgrades is not expected to occur until after construction of the proposed Project. In addition, DCP's use of the temporary pier would include only 42 barge deliveries over the course of 18 months, and DCP has committed to avoiding impacts on recreational users. During operations, the Maryland Route 4 upgrades would not result in impacts on recreational users of the Patuxent River or Solomons Island Boat Launch and Fishing Pier after construction (DOT and MSHA, 2010), and Offsite Area B would not be used beyond construction of the proposed Project. Therefore, we conclude that construction and operation of the proposed facilities would not result in a significant cumulative impact on recreational activities.

The visual character of the existing landscape is defined by the historic and current land uses such as agriculture, recreation, conservation, and development. The visual qualities of the landscape are further developed by existing linear installations such as highways, railroads, pipelines, and electrical transmission and distribution lines. Within this context, DCP's proposed Liquefaction Facilities, nonjurisdictional facilities, and other related activities, as well as the other foreseeable future projects described in table 2.9-1, could have a visual impact in the area. In addition, the removal of forest vegetation at Offsite Area A would result in a permanent visual impact. However, as previously discussed, the various proposed projects would be consistent with existing uses of the sites and views of the area. At Offsite Area A, DCP would maintain a 60-foot buffer of trees along the eastern boundary of the site to screen it from Maryland Route 2/4. Therefore, we conclude that the proposed Project would not contribute to a significant cumulative impact on visual resources.

2.9.6 Socioeconomics

Present and reasonably foreseeable future projects and activities could cumulatively impact socioeconomic conditions in the Project area. Employment, housing, infrastructure, and public services could experience both beneficial and detrimental impacts. No environmental justice issues have been identified.

The proposed Project and the reasonably foreseeable future projects would generate temporary employment from construction jobs, as well as provide an influx of associated spending on local goods and services, including temporary housing. This influx would provide a temporary economic benefit to the individuals and communities in which they reside. In addition to the temporary influx of non-local construction workers and associated spending, there would be a cumulative economic benefit from the proposed Project and the other potential future projects. Annual tax revenues would be expected to increase from operation of the proposed Project. In addition, permanent employment would increase slightly as a result of operation of the projects.

The influx of non-local construction workers would temporarily impact housing availability in the area. However, given the vacancy rates, and the number of rental housing units and hotel/motel rooms in the area, construction crews should not encounter difficulty in finding temporary housing. If construction occurs concurrently with other projects, temporary housing would still be available but may be slightly more difficult to find and/or more expensive to secure. However, construction of the two largest projects, the Calvert Cliffs Unit 3 Project and Maryland Route 4 upgrades, would likely occur after construction of the proposed Project. Regardless, these effects would be temporary, lasting only for the duration of construction, and there would be no long-term impacts on housing.

Construction of the Maryland Route 4 upgrades and other non-jurisdictional road improvements would have the potential to cumulatively affect traffic if DCP's proposed transport of materials from Offsite Area B to the Liquefaction Facilities were to occur during the same time. However, the northern extent of the Maryland Route 4 upgrades may not extend to a point such that it would be affected by DCP's transport of equipment. In addition, the construction scheduled for the Maryland Route 4 upgrades has not yet been determined and is likely to begin after construction of the proposed Project. The non-jurisdictional road improvements of Maryland Route 2/4 and Maryland Route 497 would serve to lessen traffic impacts associated with DCP's transport of workers and materials upon completion of the turn lane and traffic signal. DCP would coordinate with state and local officials to minimize the effect of other improvements along Cove Point Road. During construction of the proposed Project, DCP's movement of large equipment and materials would be subject to local highway use permits, and any such permits would be expected to take into account the current traffic conditions on Maryland Route 4 in the event construction of the upgrade is underway. Therefore, we conclude that DCP's transport of equipment would not be expected to have a cumulative effect on traffic when combined with other potential impacts associated with the Maryland Route 4 upgrades and other non-jurisdictional road improvements.

2.9.7 Cultural Resources

Past disturbances to cultural resources in the Project area have been related to construction and maintenance operations associated with existing roads, railroads, utility lines, electrical transmission lines, and other associated developments; accidental disturbances; intentional destruction or vandalism; and lack of awareness of historical value. The currently proposed projects in the area that require environmental review by a state or federal agency, including the Calvert Cliffs Unit 3 Project and the Maryland Route 4 upgrades, would include mitigation measures designed to avoid or minimize additional direct impacts on cultural resources. Where direct impacts on significant cultural resources are unavoidable, mitigation (e.g., data recovery) would occur before construction. Non-federal actions would comply with any mitigation measures required by the state. The Liquefaction Facilities, Calvert Cliffs Unit 3 Project, the Maryland Route 4 upgrades, and other non-jurisdictional road improvements would largely occur in areas that have been previously developed, which would likely reduce the potential for new impacts on cultural resources. DCP would avoid all potentially significant cultural resources identified by its surveys. Therefore, the proposed Project would not add to the effects of the other projects on cultural resources in the area.

2.9.8 Air Quality and Noise

Air Quality

The cumulative impact area for air quality during construction of the Project is the area adjacent to and near the physical boundary of the construction area. The cumulative impact area for operation of the Project is the area covered by the cumulative NAAQS analysis discussed in section 2.7.1.

Air emissions, including fugitive dust, generated during the construction of the Project and any future projects, could potentially result in cumulative impacts on air quality. Emissions from construction equipment would be primarily limited to daylight hours and would be minimized through mandated engine emission control equipment. Fugitive dust generated by construction activities would also be primarily limited to daylight hours and minimized through dust mitigation measures such as water suppression. The construction emissions would result in short-term, localized impacts. Cumulative impacts from the construction emissions would only occur if construction of the Liquefaction Facilities and other projects in the area overlap in schedule and location. Of the existing or proposed projects identified in table 2.9-1, only the Maryland Route 4 upgrades, Hidden Treasure Development, and nonjurisdictional facilities associated with the Cove Point Liquefaction Project are close enough to the Project to have construction-related air quality impacts on the same area. Construction of the Hidden Treasure Development and nonjurisdictional facilities associated with the Cove Point Liquefaction Project would be completed before the Project commences construction. Construction of the Maryland Route 4 upgrade would occur after the Project. In addition, those Project construction emissions (NO_x and VOC) that would potentially contribute to the ozone pollution in the region would be fully offset under General Conformity, thereby eliminating contribution to the regional ozone levels. As such, construction of the Project would not result in cumulatively significant air quality impacts in the area.

As discussed in section 2.7.1, detailed modeling was performed to quantitatively evaluate the impacts from operation of the Liquefaction Facilities and associated marine vessels. The modeling also included other existing sources of air emissions in the Project area and background concentrations. The cumulative impacts of the FERC Modeling (modeled concentrations plus existing background concentration) demonstrated that the Project would not cause or significantly contribute to a violation of a NAAQS. The NAAQS are designed to be protective of human health and the environment. Projects that would potentially be constructed in the future, and are considered to be major sources of air emissions, would be required to conduct a similar modeling analysis. If operation of a new project would result in a significant impact on air quality, the MDE would enforce operational limitations or require emissions controls that ensure the facility's compliance with the SIP and attainment with the NAAQS. In addition, DCP would be required to comply with extensive permit conditions during operation of the Liquefaction Facilities stationary emission sources, including implementation of LAER and BACT level emission controls and NO_x and VOC emission offsets. Based on the FERC Modeling and the required emission controls, we conclude that there would be no significant cumulative impact on air quality as a result of the Project operation.

Noise

Noise impacts are particularly localized and attenuate quickly as the distance from the noise source increases. Therefore, cumulative noise impacts would only occur if construction of the Liquefaction Facilities and other projects in the area overlap in schedule and location. As discussed above, the projects that would occur in close proximity to the Project would not occur at the same time as the Project. Therefore, the construction of the Project would not result in significant cumulative noise impacts.

During operation of the Liquefaction Facilities, DCP's use of acoustical buildings, piping noise control measures, and installation of the sound barrier would reduce noise impacts on the nearest NSAs to meet the applicable FERC and Maryland requirements. Because noise attenuates with increasing distances, no other projects have been identified in the immediate vicinity that would contribute to the operational noise impacts of the Project. Therefore, the Project's operation would not result in a significant cumulative noise impact.

2.9.9 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 single annual events or individual weather anomalies. For example, a single large flood event or abnormally hot summer may not be an indication of climate change, but a series of floods or hot summers that statistically change the average precipitation or temperature over decades may indicate climate change.

The Intergovernmental Panel on Climate Change (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 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);
- 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 Northeast region:

- annual average temperatures have risen about 2 °F since 1970 with winter months rising twice this much;

- temperatures are projected to increase another 2.5 to 4 °F in winter months and 1.5 to 3.3 °F in summer months during the next several decades;

- substantial increases in the extent and frequency of storm surge, coastal flooding, erosion, property damage, and loss of wetlands;

- Heat waves, which are currently rare in the region, are projected to become much more commonplace in a warmer future, with major implications for human health;

- the number of days that fail to meet federal air quality standards is projected to increase with rising temperatures if there are no additional controls on ozone-causing pollutants;

- large portions of the Northeast are likely to become unsuitable for growing popular varieties of apples, blueberries, and cranberries under a higher emissions scenario;

- the southern extent of the commercial lobster harvest appears to be limited by a temperature-sensitive bacterial shell disease, and these effects are expected to increase as near-shore water temperatures rise above the threshold for this disease;

- additional stress to the already-stressed regional cod fishery;

- increasing acidification resulting from the uptake of CO_2 by ocean waters threatens corals, shellfish, and other living things that form their shells and skeletons from calcium carbonate;

- within the past century in the U.S., relative sea level changes ranged from falling several inches to rising about 2 feet and is expected to rise at least another 2 feet in Chesapeake Bay;

- 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

- the warming of the Chesapeake Bay's waters will make survival there difficult for northern species such as eelgrass and soft clams, while allowing southern species and invaders riding in ships' ballast water to move in and change the mix of species that are caught and must be managed.

The GHG emissions associated with construction and operation of the Project were identified and quantified in section 2.7.1. Based on the total annual potential emissions for the constructed Liquefaction Facilities, Project operations would increase energy-related CO_2 emissions in Maryland by approximately 2.6 percent (based on 2010 emissions for Maryland [DOE, 2013]).

Operational GHG emissions from Project facilities would be minimized by application of EPA-approved BACT under the PSD permitting programs. DCP prepared a BACT analysis for the proposed compressor turbines, boilers, standby generator, fire pump engines, flares, thermal oxidizer, and fugitive emissions from the Liquefaction Facilities. This analysis was reviewed by the MDE with support from PPRP. This analysis will also be reviewed by EPA prior to final approval of the power plant project by the Maryland PSC. GHG emissions from the turbines at the Liquefaction Facilities would be minimized through use of natural gas and LNG process fuel gas as fuels and energy efficient design as BACT. The energy efficient design includes the use of HRSG on the turbines and a nitrogen stripper for off gas combustion as fuel. DCP estimated that without these measures, a similar facility would result in a typical combustion rate of 4,500 MMBtu/hr (compared to the 2,500 MMBtu/hr estimate for the Liquefaction Facilities for this Project). BACT for the boilers is the use of process fuel gas for fuel with natural gas only during start-up and efficient boiler design. The offgas stream from the acid gas process would consistent mainly of CO_2 (94 percent). BACT was determined to be oxidation of the offgas using a thermal oxidizer supplemented with process fuel gas. The flares are used for controlling VOC and GHG emissions during specific events (such as ship cool- down, plant start-ups and emergencies/upset conditions). Therefore, these units function as the GHG emission control to prevent methane from being emitted during these events, and additional controls are not practical. BACT for the flares include minimizing the duration of flare events. The fire pump engines and emergency generator operating hours would be limited making them a relatively small source of GHG emissions for the Project. BACT for fugitive emissions from equipment leaks is the implementation of a gas leak detection and repair program. This program would follow the procedures outlined in the 28 LAER leak detection and repair program from the Texas Commission of Environmental Quality (TCEQ), *Control Efficiencies for TCEQ Leak Detection and Repair Programs*. The use of process fuel gas (as noted above) would yield substantial GHG emission reductions for a facility of this size. The use of low carbon containing fuels (natural gas and process fuel gas) would also minimize GHG emissions.

In the BACT analysis, DCP evaluated the feasibility of a carbon capture and sequestration (CCS) for the Project and specific sources at the Liquefaction Facilities. CCS involves deploying a method to capture carbon from the exhaust stream and then finding a method for permanent storage (such as injecting the recovered CO_2 underground through various means, including enhanced oil recovery, saline aquifers, and un-mineable coal seams). In the GHG BACT analysis, DCP stated that there is no commercially available carbon capture system of the scale that would be required to control the CO_2 emissions from the Project. Additionally, there are significant adverse energy and environmental impacts due to the additional water and energy needs for CCS operation, with the associated generation of additional GHGs and other criteria pollutants from natural gas firing in combustion units. Based on these considerations and the significant costs for implementing CCS, it was not determined to be BACT.

The criteria pollutant BACT limits for the Liquefaction Facilities are summarized in section 2.7.1.

We received comments regarding the impacts climate change could have on the Project, particularly as a result of sea level rise and storm surge. Climate change in the northeast region could have two effects that may cause increased storm surges: temperature increase of the Chesapeake Bay waters, which would increase storm intensity; and a rising sea level. The final grade elevation of the Liquefaction Facilities Project site would range between 70 and 130 feet above mean sea level. Therefore, even with increased sea levels due to climate change and increased storm surge, the Project facilities would not be vulnerable to even a 100-year climate change-enhanced storm surge because of its significant elevation above sea level.

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.

2.9.10 Safety

Impacts on reliability and public safety would be mitigated through the use of the DOT Minimum Federal Safety Standards in 49 CFR 192 and 49 CFR 193, which are intended to protect the public and to prevent natural gas facility accidents and failures. No cumulative impacts on reliability and public safety would be anticipated to occur.

For the proposed Liquefaction Facilities, we considered the cumulative impact area for marine vessel traffic to include the Chesapeake Bay from Cape Henry, Virginia where LNG vessels would enter the Bay from the Atlantic Ocean. The cumulative impact area for the Liquefaction Facilities is the area adjacent to and in the vicinity of the existing LNG Terminal site. The cumulative impact area for emergency services includes the area in the general vicinity of the proposed Liquefaction Facilities.

DCP 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 2.8. 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.

The USCG Sector Baltimore concurred that operation of the proposed Liquefaction Facilities would not result in an increase in the size and/or frequency of LNG marine traffic beyond that envisioned in the current WSA for the LNG Terminal, and that the WSA and LOR are adequate for the service associated with the Project. Because DCP has not requested an increase in the number of LNG carriers calling on the LNG Terminal, the Liquefaction Facilities would not add to the current risk assessment of public safety on the Chesapeake Bay or of an intentional attack on an LNG carrier at berth or in transit to the offshore pier.

Emergency response time is a key aspect of public health and safety. Key emergency services are currently provided by the existing Cove Point LNG Terminal in Calvert County. In accordance with our regulations, DCP would prepare a comprehensive plan that identifies the cost sharing mechanisms for funding emergency response costs. Therefore, we conclude that the proposed Project would not result in a significant cumulative impact on public safety.

2.9.11 Conclusion

The adverse cumulative impacts that could occur in conjunction with the Project would be temporary and minor. Temporary cumulative benefits could occur through temporary jobs and wages, and the purchases of local goods and materials. Overall, we have determined that the Project, in association with other projects in the area, would not result in significant cumulative impacts.

3.0 ALTERNATIVES

In accordance with NEPA and FERC policy, we[14] evaluated a range of alternatives to the Project including the No Action Alternative, energy conservation and alternative sources of energy, system alternatives, design alternatives of the Liquefaction Facilities, alternative sources of water for construction and operation of the Liquefaction Facilities, and alternative offsite locations to support construction of the Liquefaction Facilities. The criteria used to evaluate potential alternatives included whether they:

- Offer a significant environmental advantage over the proposed Project;
- Are technically and/or economically feasible and practical;
- Are permittable within the same general timeframe of the proposed Project; and
- Meet DCP's stated purpose to liquefy for export domestically produced natural gas.

DCP participated in our pre-filing process during the preliminary design stage for the Project (see section 1.6). This process emphasized identification of potential stakeholder issues, as well as identification and evaluation of alternatives that could avoid or minimize impacts. We analyzed Project alternatives based on published information, comments, and suggestions from regulatory agencies; analysis prepared for similar projects; public comments; and data and analysis provided on the public record by DCP. The results of the alternatives analyses are provided in the following sections.

3.1 NO ACTION ALTERNATIVE

Under the No Action Alternative, the objectives of the Project would not be met and DCP would not provide proposed natural gas capacity for export. In addition, environmental impacts identified in this EA would not occur. If the Project is not built, DCP's export customers would likely seek alternatives to meet the contracted service, which could include the construction and operation of other facilities and/or the use of alternative forms of energy, resulting in environmental impacts commensurate with the facilities and energy source. Also, the beneficial impacts of the Project, including increased employment, increased tax revenues, stimulation of the local economy, improved national trade balance, and providing a market for U.S. natural gas reserves, would not be realized.

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, energy needs may be met by alternate energy sources (see discussion below).

3.2 ALTERNATIVE ENERGY

We believe 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

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

produces half as much CO_2, less than a third as much NO_x, 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 and 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 promising 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 the 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 a 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 policymakers 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, SO_2, 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 this alternative as a reasonable alternative to meet the Project objectives.

3.3 SYSTEM ALTERNATIVES

System alternatives would make use of other existing, modified, or proposed systems to meet the stated objectives of the Project. A system alternative would make it unnecessary to construct all or part of the Project, although some modifications or additions to the alternative system may be required. Such modifications or additions would result in environmental impacts; however, the impacts could be less than, similar to, or greater than that associated with the Project.

3.3.1 Other LNG Terminal Alternatives

There are 11 existing LNG terminals in the lower 48 states of the United States, including 6 on the Gulf Coast and 5 on the East Coast. Of the five facilities on the East Coast, two are currently seeking authorization to export LNG (DCP's LNG Terminal at Cove Point, Maryland; and El Paso Corporation's Southern LNG Terminal at Elba Island, Georgia). All six of the existing facilities on the Gulf Coast have received or are seeking LNG export authorization.

Six other LNG terminals have been approved in the United States, including five on the Gulf Coast and one on the East Coast. Five of these six facilities have been approved for LNG import, none of which are under construction. The remaining facility, Cheniere/Sabine Pass LNG in Sabine, Louisiana, has been approved for LNG export and is under review to add additional LNG processing and export capability.

Sixteen other LNG terminals have been proposed in the lower 48 states of the United States, including 13 facilities for LNG export and 3 facilities for LNG import. Of the 13 proposed LNG export facilities, 9 are located on the Gulf Coast, 2 are located in the northwestern United States, and 2 are located on the East Coast (DCP's LNG Terminal at Cove Point, Maryland; and El Paso Corporation's Southern LNG Terminal at Elba Island, Georgia). Similar to the Project, most of the proposed export facilities would be constructed at existing LNG import facilities.

Existing, approved, and proposed LNG terminals located other than on the East Coast of the United States are not considered as viable system alternatives to the Project. DCP states that the existing interconnects with the Cove Point Pipeline would allow feed gas for the Project to be sourced from a wide variety of regions in the United States, depending on market forces and circumstances at any given time, but presumes that the Project customers selected DCP's facility as their location for export due to its proximity to natural gas supplies in the northeastern United States. Due to added transportation costs, it is not reasonable to consider that the Project customers would transport natural gas sourced in the northeastern U.S. to facilities on the Gulf Coast or West Coast of the United States for overseas export. In addition, the use of other approved and proposed facilities to meet the Project objectives would be unlikely to offer an environmental advantage over the Project as the facilities would require construction and operation of similar, if not greater, pipeline, LNG production, storage, and marine facilities when compared to the proposed Project.

For similar reasons as discussed above, we also did not consider further modification of the existing Southern LNG Terminal in coastal Georgia as a viable system alternative to the proposed Project. The FERC is currently evaluating El Paso Corporation's proposal to modify the facility to export LNG under Docket No. CP14-103-000, and DOE is currently evaluating an application submitted by Southern LNG Company, L.L.C. to export LNG to non-FTA nations. Further, the capacity of the existing Southern LNG Terminal is fully contracted with subsidiaries of BG Group and Shell and, therefore, would require the construction of new facilities to meet DCP's commitments for the proposed Project.

Regarding the three other, existing LNG terminals on the East Coast, the Distrigas of Massachusetts, LLC facility is an LNG import facility on the banks of the Mystic River in Everett, Massachusetts, and the Excelerate Energy Northeast Gateway and Neptune LNG Deepwater Port are LNG import facilities located approximately 10 miles offshore from Boston and Gloucester, Massachusetts, respectively. Modification of these facilities to liquefy and export natural gas would require the construction of new facilities, including large floating liquefaction and storage units (FLSUs) in the case of the offshore import terminals. As a result, the modification of these facilities to export natural gas as LNG would be unlikely to provide a significant, comparative environmental advantage, or meet the timeframe of the proposed Project and, thus, are not preferred or viable alternatives to DCP's proposal.

3.3.2 Other Pipeline Alternatives

The existing LNG Terminal is connected to three interstate natural gas transmission systems via the Cove Point Pipeline, which would allow the Project customers to transport their supplies of natural gas to the proposed Liquefaction Facilities without construction of a new transmission pipeline.

The nearest interstate pipeline to the Liquefaction Facilities that is not operated by DCP is the mainline system of Transcontinental Gas Pipe Line Company. Expansion of this system to the Liquefaction Facilities would require at least 90 miles of new, large diameter pipeline and at least one new compressor station to meet the feed gas requirements of the Project. Such an expansion would result in substantially greater environmental impact on landowners and most resources (e.g. vegetation, soil, water, and air quality) than the use of the existing Cove Point Pipeline and, thus, is not environmentally preferable to DCP's proposal. Similarly, no alternative to the proposed Pleasant Valley Suction/ Discharge Pipelines was considered because the pipelines would be the shortest length possible between the Pleasant Valley Compressor Station and M&R Facility and would be constructed and operated within DCP's existing, maintained right-of-way.

3.3.3 Compression Alternatives

During development of the proposed Project, DCP considered various modifications to its system as alternatives to the proposed additional compression at the Pleasant Valley Compressor Station.

Due to relatively low pressure in the pipelines that the Project customers would use to deliver natural gas into the Cove Point Pipeline, a higher operating pressure on the Cove Point Pipeline would be necessary to meet DCP's existing contractual obligations and deliver the incremental capacity of the Project to the Liquefaction Facilities. In some cases, pipeline looping can be used instead of additional compression to increase the overall capacity of a system. However, looping would not resolve the pressure differentials between pipelines and, therefore, looping is not a viable alternative to additional compression.

Some of the additional compression needed for the Project could potentially be installed at a new compressor station located between the Loudoun Compressor Station and the Pleasant Valley Compressor Station. However, a new compressor station would not eliminate the need for some additional compression at the Pleasant Valley Compressor Station, and construction and operation of a new greenfield compressor station would result in overall greater environmental impacts than DCP's proposed expansion of the Pleasant Valley Compressor Station. Therefore, we determined that construction and operation of a new compressor station is not an environmentally preferable system alternative to DCP's proposal.

DCP originally considered splitting the compression requirements of the Project between the Pleasant Valley Compressor Station and the Loudoun Compressor Station. The Loudoun Compressor Station is located in proximity to substantially more homes than the Pleasant Valley Compressor Station and, during the scoping process, nearby homeowners raised concerns regarding potential impacts of additional compression at the Loudoun Compressor Station. In addition, the existing compressor units at the Loudoun Compression Station are fueled by natural gas, whereas the existing units at the Pleasant Valley Compressor Station are electric driven, resulting in substantially lower air emissions. DCP also proposes to install electric driven compressors at the Pleasant Valley Compressor Station, which would only require expansion of the existing Northern Virginia Electric Cooperation substation on the site. In contrast, an approximately 3.25-mile-long electric transmission line and new electric substation would be required for DCP to operate electric driven compressor units at the Loudoun Compressor Station. Finally, DCP determined that adding compression at the Pleasant Valley Compressor Station would satisfy the potential customer receipt scenarios to supply gas into the system and the Liquefaction Facilities. Based on the above discussion, we agree with DCP's Project change and conclude that splitting the Project's additional compression requirements between the Pleasant Valley Compressor Station and Loudoun Compressor Station is not environmentally preferable to DCP's proposed expansion of the Pleasant Valley Compressor Station only.

3.4 LIQUEFACTION FACILITIES DESIGN ALTERNATIVES

DCP considered proprietary designs for the Liquefaction Facilities from two separate engineering contractors during preliminary Project development. Both of these alternative designs were vetted and reviewed by our LNG engineering staff during the pre-filing phase for this Project. In addition to improved operating efficiencies, DCP selected the proposed design in its application because it offered the following environmental advantages over the alternative design:

- Use of waste heat from two gas turbines to produce steam utilized to produce electrical power via two steam turbine generators;
- reduced fuel consumption and resulting emissions with steam power generation instead of gas turbines for power generation;
- reduced impact on the existing facilities and, therefore, existing customers;
- reduced construction workspace and duration of construction;
- no offshore structural work; and
- less land disturbance at Offsite Area A.

Both the proposed and alternative designs for the Liquefaction Facilities would be constructed and operated within the Fenced Area of the LNG Terminal. However, based on the above environmental factors and our evaluation of the alternative design during pre-filing, we conclude that the alternative design is not environmentally preferable to DCP's proposed design.

We received comments about the feasibility of using electric driven compressors instead of the natural gas driven turbines to reduce potential air quality impacts. There currently is not sufficient electric transmission capacity in the vicinity of the Liquefaction Facilities to provide the approximately 240 MW that would be necessary. Providing the electric transmission capacity to the Liquefaction Facilities would require new rights-of-way, permits, and modifications to the existing conservation easements that surround the LNG Terminal. Onsite generation is not feasible because there would not be sufficient space on the site to build both a stand-alone generation facility and the Liquefaction Facilities. In addition, the waste gas generated by the process would be used as the primary fuel for the turbines and auxiliary boilers. Because the waste gas is, at times, a lower Btu gas with elevated nitrogen levels that could not be used as pipeline gas, the onsite combustion of the waste gas for fuel provides a use for the waste gas energy and eliminates energy requirements to compress it to enter the transmission pipeline. Therefore, we conclude that the use of electric driven compressors at the Liquefaction Facilities is not environmental preferable to DCP's proposed design.

3.5 ALTERNATIVE WATER SOURCES FOR THE LIQUEFACTION FACILITIES

DCP proposes to utilize groundwater obtained from existing wells at the LNG Terminal for construction and subsequent operation of the Liquefaction Facilities. We received comments about potential impacts from groundwater withdrawals associated with the Project. In addition, as part of the MDNR water appropriations permitting process, DCP evaluated the alternative use of water from the Chesapeake Bay, using surface waters on DCP's property, or obtaining water from the existing Calvert County public water supply system.

DCP does not have an existing water intake system in the Chesapeake Bay and, according to DCP, environmental covenants on the land surrounding the Fenced Area of the LNG Terminal (see section 1.2.1) preclude installation of a water line from the Chesapeake Bay to the Fenced Area. In addition, brackish water from the Chesapeake Bay would require costly treatment, which would generate large volumes of wastewater that would need to be properly managed. DCP also stated that pumping water from either Lake Levy or Osborne Pond, which are located on the 1,017-acre LNG Terminal property, is not a viable alternative due to the environmental covenants noted above.

The Calvert County public water supply system was considered as a potential source of water for the Project. However, DCP's consultations with Calvert County determined that the current system has insufficient capacity to meet the Project's water requirements as described in section 2.2.

As discussed in section 2.2.1, the Lower Patapsco Aquifer from which the groundwater would be withdrawn for the Project has substantial capacity in the area, and pump test data and modeling indicate that DCP's proposed withdrawal, as revised by the MDE, would not significantly impact the aquifer or other groundwater users. Therefore, based on the above discussion, we conclude that there are no other viable, environmentally preferable sources of water for construction and operation of the Liquefaction Facilities.

3.6 OFFSITE AREA ALTERNATIVES

During Project planning and based on consultation with us and MDNR, DCP identified and evaluated alternative locations for Offsite Areas A and B as discussed below. DCP would utilize Offsite Areas A and B to support construction of the Liquefaction Facilities, after which the properties would be restored in accordance with our Plan and Procedures, DCP's site-specific E&SCPs, environmental permit conditions, and landowner agreements. DCP would not own or operate the properties after construction is complete.

3.6.1 Offsite Area A Alternatives

As indicated in sections 1.2.3 and 1.7.3, Offsite Area A consists of 179.4 acres of largely wooded, undeveloped land approximately 1.5 miles west of the LNG Terminal. DCP designed the proposed workspace of Offsite Area A to minimize the amount of land needed, and incorporated 100-foot-wide buffers around wetlands, waterbodies, and other sensitive resources, as well as to provide visual screening from Maryland Route 2/4. As a result, approximately 95 acres of the property would be cleared, which DCP states is the area needed to support construction of the Liquefaction Facilities.

Alternative Offsite Areas Considered but Eliminated from Further Analysis

During Project design and in response to agency comments, we evaluated 10 parcels in the LNG Terminal region as potential alternatives to proposed Offsite Area A. These parcels, referred to as Alternative Offsite Areas C through L, are depicted on figure 3.6.1-1. We eliminated the following seven parcels from more detailed analysis for the indicated reasons and they are not discussed further:

<u>Alternative Offsite Area C</u>

Alternative Offsite Area C encompasses 40 acres, of which only 18.2 acres would be available for use after incorporating buffers around sensitive resources. Thus, Alternative Offsite Area C is of insufficient size on its own to support construction of the Liquefaction Facilities.

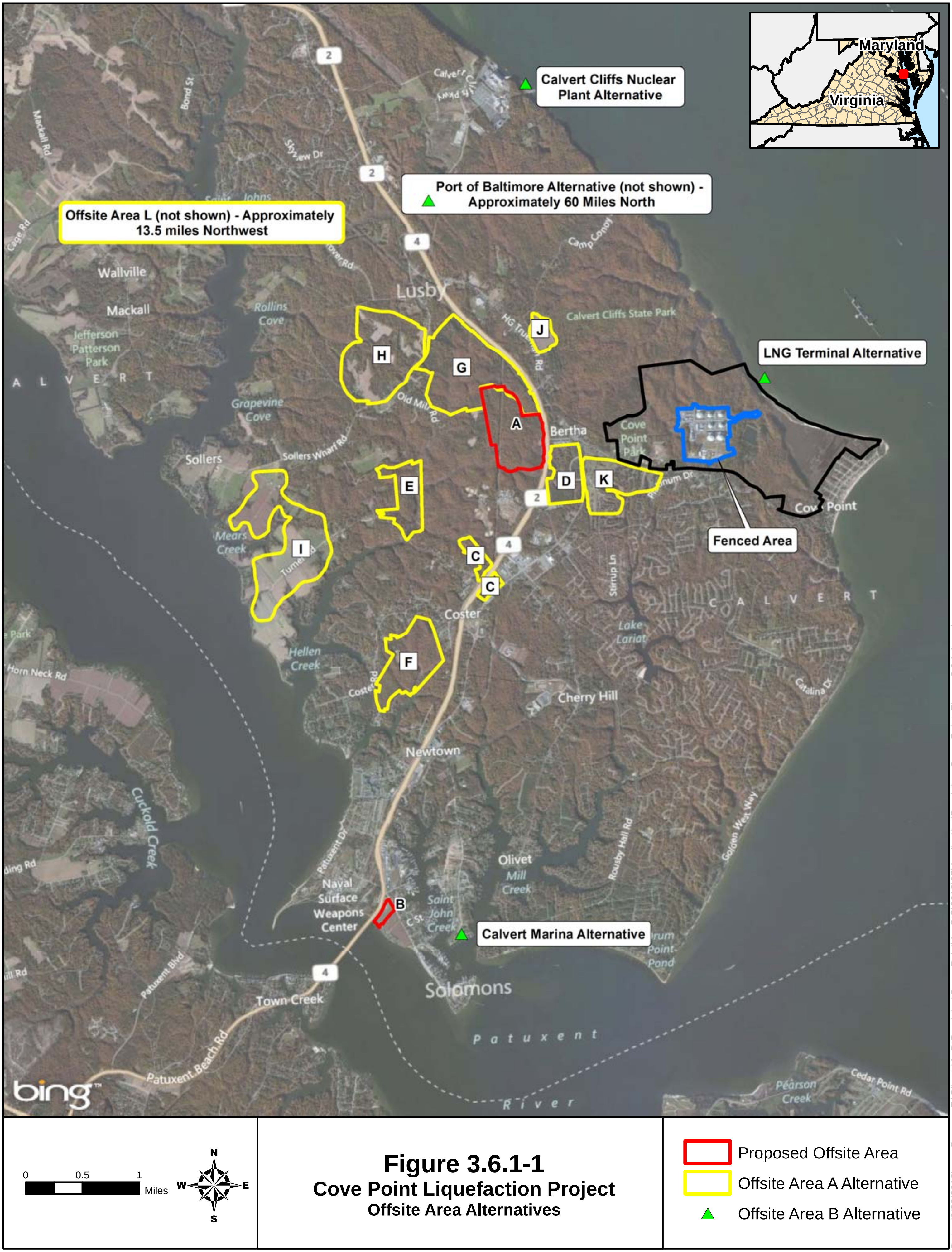

Figure 3.6.1-1
Cove Point Liquefaction Project
Offsite Area Alternatives

Proposed Offsite Area
Offsite Area A Alternative
Offsite Area B Alternative

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Date: (8/23/2013)

Alternative Offsite Area D

Alternative Offsite Area D encompasses 82 acres, of which only 59.4 acres would be available for use after incorporating buffers around sensitive resources. Thus, Alternative Offsite Area D is of insufficient size on its own to support construction of the Liquefaction Facilities. In addition, the site is encumbered by a Declaration of Covenants, Easements, Charges, and Liens which prohibits the types of activities that would be conducted at the site.

Alternative Offsite Area H

Alternative Offsite Area H encompasses 282 acres and, thus, could likely meet DCP's minimum workspace requirements. A portion of the site is open, farmed land which could reduce the amount of tree clearing for the Project. However, approximately 5 residences would be directly adjacent to the workspace and access to the site would be via a county road through a residential area. A trip between Alternative Offsite Area H and the LNG Terminal would be approximately 3.0 miles longer than a trip between proposed Offsite Area A and the LNG Terminal, and homeowners along the access road would experience Project-related traffic for the 3-year period of construction.

Alternative Offsite Area I

Alternative Offsite Area I encompasses 347 acres and, thus, could likely meet DCP's minimum workspace requirements. The majority of the site is open, farmed land which would reduce the amount of tree clearing for the Project. However, the site is crossed by several roads which would require residents and other traffic to cross through the workspace. The site also borders Hellen Creek, Mears Creek, and the Patuxent River, which would raise increased water quality concerns. In addition, site access would be via a county road through residential areas. A trip between Alternative Offsite Area I and the LNG Terminal would be approximately 3.3 miles longer than a trip between proposed Offsite Area A and the LNG Terminal, and homeowners along the access road would experience Project-related traffic for the 3-year period of construction.

Alternative Offsite Area J

Alternative Offsite Area J encompasses 34 acres of largely open land that would require little or no tree clearing, but is of insufficient size to support construction of the Liquefaction Facilities on its own. The site also abuts Calvert Cliffs State Park and a cemetery, and homeowners along the existing access road would experience Project-related traffic for the 3-year period of construction.

Alternative Offsite Area K

Alternative Offsite Area K is a 138-acre parcel occupied by the Calvert County Golf Course. The site is partly adjacent to the LNG Terminal and would thus reduce traffic impacts in the area and potentially reduce the amount of tree clearing for the Project. However, the site is not available for acquisition.

Alternative Offsite Area L

Alternative Offsite Area L encompasses 197 acres of largely open farm land and, thus, would meet DCP's minimum workspace requirements and reduce the amount of tree clearing for the Project. However, the site is more than 25 miles away and across the Patuxent River from the LNG Terminal, and more than 30 miles from Offsite Area B. In addition, DCP inquired and found that the property is not for sale or available for lease.

Alternative Offsite Areas C, D, and E

In response to agency comments, we considered a combination of Alternative Offsite Areas C, D, and E (discussed below) as an alternative to DCP's proposed use of Offsite Area A. Use of these combined areas would meet DCP's minimum workspace requirements and would reduce the required amount of forest clearing by approximately 7 acres after incorporating 100-foot-wide buffers around sensitive resources. However, the use of three separate parcels would create logistical inefficiencies and result in increased traffic between Offsite Area B and the parcels, between each parcel and the LNG Terminal, and between the individual parcels themselves. Residences along the various access roads would experience this increased traffic for the 3-year period of construction. In addition, as discussed below, Alternative Offsite Area E contains a number of sensitive resources; DCP has acquired the property and intends to place it into a conservation easement to offset some of the environmental impacts associated with the Project. Therefore, on balance, we conclude that a combination of Alternative Offsite Areas C, D, and E is not environmentally preferable or practical when compared to DCP's proposed use of Offsite Area A.

Alternative Offsite Areas Considered for Further Analysis

The three remaining sites considered as alternatives to proposed Offsite Area A are discussed in greater detail in the following sections. A comparison of environmental factors of Offsite Area A and the alternatives is provided in table 3.6.1-1.

TABLE 3.6.1-1

Comparison of Offsite Area A Alternatives

	Offsite Areas			
Factor	A	E [a]	F	G
Size (acres)	179	102	167	315
Usable Size (acres)[b]	97.0	28.6	87.4	91.7
Wetlands (acres)	8.7	24.4	10.6	15.9
Streams (linear feet)	4,675	7,604	6,858	13,314
Wetland/Stream Crossings (no.)	1	3	3	2
Existing Land Use	Forest/ Undeveloped	Forest/ Undeveloped	Forest/ Undeveloped	Forest/ Undeveloped
Forested Land (acres)	171.5	88.0	156.9	307.0
Forest Clearing Required (acres)	95.0	28.6	87.4	90.0
Rare, Threatened, Endangered Species (no./ impacts)	1 (no impacts)	1 (no impacts)	1 (no impacts)	0
Access to Adequate Roads (Y/N)	Y	N	N	N
Distance to LNG Terminal via Road (miles)	1.5	4.3	3.7	4.5

a DCP has acquired Offsite Area E and intends to place the parcel into a preservation easement to offset forest and natural resources impacts associated with the Project.

b The Usable Size is the area that remains after incorporating 100-foot-wide protective buffers around sensitive resources including wetlands, waterbodies, and rare or protected species.

Alternative Offsite Area E

As indicated in table 3.6.1-1, Alternative Offsite Area E encompasses 102 acres and is approximately 2.5 miles west of the LNG Terminal. DCP conducted natural resource inventories of the site, including wetland delineations, forest stand delineations, and rare, threatened, and endangered plant surveys. Based on these surveys, the site was found to include 88 acres of forest, 24.4 acres of wetlands, and 7,604 feet of stream channel, including over 3,000 feet of Hellen Creek (Alternative Offsite Area E is situated 1,200 feet upstream of the Hellen Creek Hemlock Preserve, a preserve of the Cove Point Natural

Heritage Trust). In addition, the parcel contains documented occurrences of state listed plant species and is identified by Calvert County as potential FIDS habitat.

Although the overall size of Alternative Offsite Area E would meet DCP's minimum workspace requirements, only 28.6 acres would be available for use after incorporating 100-foot-wide buffers around sensitive resources. Thus, Alternative Offsite Area E is of insufficient size, on its own, to support construction of the Liquefaction Facilities. DCP also noted that the orientation of streams on the property would require at least three wetland and waterbody crossings of a similar scope to the one crossing required at Offsite Area A. In addition, use of the site would require road improvements to provide access to Maryland Route 2/4, and a trip between Alternative Offsite Area E and the LNG Terminal would be approximately 2.8 miles longer than a trip between proposed Offsite Area A and the LNG Terminal. Residences located along the access road would experience Project-related traffic for the 3-year period of construction.

Based on the above discussion, we conclude that Alternative Offsite Area E is not environmentally preferable to proposed Offsite Area A. As discussed in section 2.3.1, DCP has purchased Alternative Offsite Area E because of its sensitive resources and intends to donate the parcel to a conservation group for placement into a preservation easement to offset forest and natural resource impacts associated with the Project.

Alternative Offsite Area F

Alternative Offsite Area F encompasses 167 acres and is approximately 3.5 miles southwest of the LNG Terminal. Natural resource inventories identified 156.9 acres of forest, 10.6 acres of wetlands, and 6,858 feet of stream channel on the site. Approximately 87.4 acres of useable space would remain after incorporating 100-foot-wide buffers around sensitive resources, which is slightly less than the workspace requirements identified by DCP. DCP also noted that streams on the property separate the parcel into four distinct areas which would require three wetland and waterbody crossings of a similar scope to the one crossing required at Offsite Area A. Access to the site would require local road improvements, and a trip between Alternative Offsite Area F and the LNG Terminal would be approximately 2.2 miles longer than a trip between proposed Offsite Area A and the LNG Terminal. The majority of the additional road traffic would occur on Maryland Route 2/4 for the 3-year period of construction.

In conclusion, Alternative Offsite Area F could not meet DCP's workspace requirements due to the 100-foot-wide buffers that would be required around sensitive resources and without clearing a similar amount of forest. Use of the alternative would also result in increased impacts on wetlands, waterbodies, and traffic. Therefore, we conclude that Alternative Offsite Area F is not environmentally preferable to proposed Offsite Area A.

Alternative Offsite Area G

Alternative Offsite Area G encompasses 315 acres and is north and adjacent to Offsite Area A and approximately 1.5 miles northwest of the LNG Terminal. Natural resource inventories identified 307 acres of forest, 15.9 acres of wetlands, and 13,314 feet of stream channel on the site. A large portion of the property is also subject to a Maryland Environmental Trust conservation easement which is intended to preserve and limit development of natural areas. Approximately 91.7 acres of the site would be available for use after excluding the conservation easement area and providing for a 100-foot-wide buffer around sensitive resources. Thus, the site would meet DCP's stated workspace requirements. Use of the site would require the removal of approximately 90 acres of trees, or approximately 5 fewer acres of tree removal compared to Offsite Area A. However, streams on the property would require a minimum of two wetland and waterbody crossings of a similar scope to the one crossing required at Offsite Area A.

Regarding construction traffic, the environmental easement would prevent direct access onto Maryland Route 2/4, requiring DCP to utilize a local road and impacting residences along the road for the 3-year period of construction at the Liquefaction Facilities. A trip between Alternative Offsite Area G and the LNG Terminal would also be approximately 3.0 miles longer than a trip between Offsite Area A and the LNG Terminal.

In summary, compared to Offsite Area A, Alternative Offsite Area G would require clearing approximately 5 fewer acres of trees but would increase impacts on wetlands, waterbodies, traffic, and local residents, and is subject to a Maryland Environmental Trust conservation easement. Therefore, we conclude that Alternative Offsite Area G is not environmentally preferable to proposed Offsite Area A.

3.6.2 Offsite Area B Alternatives

As discussed in section 1.2.3 and 1.7.3, Offsite Area B would be used to receive marine deliveries of large and heavy equipment to be installed at the Liquefaction Facilities. DCP estimates that 42 shipments would be received via barge at Offsite Area B, requiring approximately 150 truck loads to the LNG Terminal and/or Offsite Area A.

We considered four alternative locations for receiving marine shipments, including construction of a barge offloading pier at the LNG Terminal; use of the existing barge area at Calvert Cliffs Nuclear Plant; use of the existing Calvert Marina in Solomon's Island; and utilizing the existing facilities at the Port of Baltimore. The alternative locations are depicted on figure 3.6.1-1.

LNG Terminal Alternative

A barge offloading pier at the LNG Terminal would avoid the use of an offsite location and eliminate the need to utilize public roads for overland transport of large equipment and materials. However, a Maryland Natural Heritage Area, Cove Point Marsh, occupies the majority of the beach front and coastal area of the LNG Terminal property and the shoreline is potential habitat for the federally listed northeastern beach tiger beetle. In addition, the southern extent of the Calvert Shore Oyster Sanctuary is offshore from the LNG Terminal between the shoreline and the offshore pier. Further, the LNG Terminal property between the Fenced Area and the Chesapeake Bay is subject to environmental conservation easements that restrict development in these areas. Lastly, DCP determined that construction of a barge offloading pier at the LNG Terminal would likely require dredging, which would result in greater impacts on the nearshore and marine environment than the proposed use of Offsite Area B. For these reasons we conclude that construction and use of a barge offloading pier and associated facilities at the LNG Terminal is not a viable or environmentally preferable alternative to Offsite Area B.

Calvert Cliffs Nuclear Plant Alternative

The Calvert Cliffs Nuclear Plant operates an existing barge offloading facility approximately 3 miles north of the LNG Terminal on the Chesapeake Bay. We have determined that use of this facility would not be feasible due to potential security constraints and conflict with operations of the nuclear plant, upgrades to the pier to support the heavy loads proposed for offloading, and upgrades to the existing offloading road.

Calvert Marina Alternative

We evaluated the use of the existing Calvert Marina, approximately 0.5 mile from proposed Offsite Area B. The Calvert Marina is an active marina, and use of the facility to support the Project would require the removal of boat slips and relocation of boats for up to a 3-year period, therefore potentially affecting recreation and operations of the marina and boat owners. Use of the facility would also likely require widening of the existing access road that is located in the state designated critical buffer area of the Chesapeake Bay, as well as major road upgrades to access Maryland Route 2/4. In contrast, the proposed use of Offsite Area B would not impact marina activities or require upgrades to public roads. For these reasons we conclude that use of the Calvert Marina is not preferable to the use of Offsite Area B.

Port of Baltimore Alternative

In response to agency comments, we considered the use of existing facilities at the Port of Baltimore near the head of the Chesapeake Bay. This alternative location would require each Project barge to travel approximately 125 miles further on the Chesapeake Bay than if delivering to Offsite Area B, resulting in increased fuel use, air emissions, and marine impacts. Use of the Port of Baltimore would also require each heavy load to traverse an additional minimum of 75 miles of road to reach the LNG Terminal, resulting in increased logistical and safety concerns. Due to the size of the anticipated loads, substantial road upgrades, bridge reinforcements, and overhead utility relocations could also be required. Although the Port of Baltimore location would avoid the use of Offsite Area B, we determined that most impacts at Offsite Area B would be temporary and minor and, therefore, conclude that the Port of Baltimore is not environmentally preferable to DCP's proposed use of Offsite Area B.

4.0 CONCLUSIONS AND RECOMMENDATIONS

Based upon the analysis in this EA, we[15] have determined that if DCP constructs and operates the proposed facilities in accordance with its application, supplements, and our mitigation measures below, approval of this Project would not constitute a major federal action significantly affecting the quality of the human environment.

We recommend that the Commission Order contain a finding of no significant impact and include the measures listed below as conditions in any authorization the Commission may issue to DCP.

1. DCP shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA, unless modified by the Order. DCP 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 the OEP **before using that modification**.

2. Director of 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 Project. 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 assure continued compliance with the intent of the conditions of the Order.

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

4. The authorized facility locations shall be as shown in the EA, as supplemented by filed drawings and plans. **As soon as they are available, and before the start of construction**, DCP shall file with the Secretary any revised detailed drawings or plans 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 drawings or plans.

5. DCP shall file with the Secretary detailed drawings or plans and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas,

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15 "We," "us," and "our" refer to the environmental staff of the Commission's Office of Energy Projects.

pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area**.

This requirement does not apply to extra workspace allowed by our Plan and/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 facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

6. **Within 60 days of the acceptance of the authorization and before construction begins**, DCP shall file an Implementation Plan for the review and written approval by the Director of OEP. DCP must file revisions to the plan as schedules change. The plan shall identify:

a. how DCP will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by the Order;

b. how DCP 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 for the 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 DCP 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 DCP's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) DCP will follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:

i. the completion of all required surveys and reports;
ii. the environmental compliance training of onsite personnel;
iii. the start of construction; and
iv. the start and completion of restoration.

7. DCP shall employ at least two EIs for the Project, one for the Liquefaction Facilities and one for the facilities in Virginia. The EIs shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 6 above) and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. a full-time position, separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

8. Beginning with the filing of its Implementation Plan, DCP shall file updated status reports on a **monthly** basis for the Project 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 DCP's efforts to obtain the necessary federal authorizations;

b. the construction status of the Project sites, 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(s) 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 DCP from other federal, state, or local permitting agencies concerning instances of noncompliance, and DCP's response.

9. DCP shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the Project and restoration of the Project facility sites. **Prior to construction**, DCP shall mail the complaint procedures to each landowner whose property would be adjacent to the Project or within 0.5 mile of the Project facilities.

   a. In its letter to landowners, DCP shall:

      i. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

      ii. instruct the landowners that if they are not satisfied with the response, they should call DCP's Hotline; the letter should indicate how soon to expect a response; and

      iii. instruct the landowners that if they are still not satisfied with the response from DCP's Hotline, they should contact the Commission's Dispute Resolution Division Helpline at 877-337-2237 or at ferc.adr@ferc.gov.

   b. In addition, DCP shall include in its monthly status report a copy of a table that contains the following information for each problem/concern:

      i. the identity of the caller and date of the call;

      ii. the location of the affected property;

      iii. a description of the problem/concern; and

      iv. an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

10. **Prior to receiving written authorization from the Director of OEP to commence construction of any Project facilities**, DCP shall file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

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

12. DCP must receive written authorization from the Director of OEP **before placing into service** the Project facilities. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval and applicable standards, can be expected to operate safely as designed, and the rehabilitation and restoration of the right-of-way and other areas affected by the Project are proceeding satisfactorily.

13. **Within 30 days of placing the authorized facilities in service**, DCP 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 DCP 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.

14. DCP shall file the following information, stamped and sealed by the professional engineer-of-record, with the Secretary for review and written approval by the Director of OEP:

    a. structure and foundation design drawings and calculations of the Liquefaction Facilities;

    b. foundations and pile design drawings and calculations for all vibratory equipment, including gas turbines, HRSGs, steam generators, and compressors supported on piles; and

    c. quality control procedures to be used for design and construction.

    In addition, DCP shall file, in its Implementation Plan, the schedule for producing this information.

15. **Prior to starting any work on the Pleasant Valley Compressor Station**, DCP shall file the results of the geotechnical investigation, foundation recommendations, Project design, and construction details with the Secretary for review and written approval by the Director of OEP.

16. DCP shall file the final Oyster Bar Mitigation Plan, approved by the MDNR, and artificial reef development plan **before implementation of the plans**.

17. **Prior to the use of Offsite Area A**, DCP shall file the final Forest Preservation Plan for Offsite Area A, approved by the MDNR.

18. **Within 7 days prior to the start of tree clearing between the dates of April 1 and August 31**, DCP shall conduct a survey to identify whether any nesting BCC birds are present in the Fenced Area and Offsite Area A. If nesting BCC birds are identified, DCP shall avoid tree clearing and other Project activities within 50 feet of active nests until young have fledged the nest and vacated the Project area, or it is determined by a qualified biologist that the nest has been abandoned.

19. **Prior to construction**, DCP shall file documentation of concurrence from MDE that the Liquefaction Facilities are consistent with the Maryland Coastal Zone Management Program.

20. **Prior to construction**, DCP shall file the final landscaping plan, approved by the MDNR, for the LNG Terminal sound barrier.

21. **Prior to construction**, DCP shall file the final lighting distribution plan for the Liquefaction Facilities, approved by the MDNR, with the Secretary for review and written approval by the Director of OEP.

22. **Prior to construction**, DCP shall install protective fencing around the buffer area for site 18CV505 at Offsite Area A.

23. **Prior to construction**, DCP shall file the following information for the issuance of a final General Conformity Determination:

    a. an updated estimation of Project emissions for each calendar year of construction and initial start-up based on the current Project schedule at that time;

    b. a record of NO_x offsets obtained and demonstrate that this amount is equal to the amount required under the General Conformity regulation; and

    c. letters from MDE and VDEQ concurring that the offset requirements for the Project have been met.

24. **Prior to construction**, DCP shall file a revised Fugitive Dust Control Plan with the Secretary for review and written approval by the Director of OEP. The plan shall specify the precautions that DCP would take to minimize fugitive dust emissions from construction activities and identify additional mitigation measures to control fugitive dust emissions of Total Suspended Particulates, PM_{10}, and $PM_{2.5}$, including:

    a. identifying how DCP would implement these measures (e.g., identification of speed limits, usage of speed limit signage, use of gravel at construction entrances to reduce track-out);

    b. clarifying that the EI has the authority to determine if/when water or a palliative needs to be used for dust control; and

    c. clarifying that the EI has the authority to stop work if the contractor does not comply with dust control measures.

25. **Prior to commissioning of the Liquefaction Facilities**, DCP shall file with the Secretary the specific noise mitigation measures that would be used on the ground flares and a noise analysis demonstrating that the noise from all of the equipment operated during commissioning (including ground flares) would not exceed an L_{dn} of 55 dBA at the nearby NSAs.

26. DCP shall file a full load noise survey at the Liquefaction Facilities with the Secretary **no later than 60 days** after placing the Liquefaction Facilities in service. If a full load condition noise survey is not possible, DCP shall provide an interim survey at the maximum possible operation **within 60 days** of placing the Liquefaction Facilities in service and file the full load operational survey **within 6 months**. If the noise attributable to the operation of all of the equipment at the LNG Terminal, under interim or full load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSAs, DCP shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. DCP 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.

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

The following measures shall apply to the proposed Liquefaction Facilities at Dominion Cove Point's LNG Terminal. Information pertaining to these 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, 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, will be subject to public disclosure. All information shall be filed **a minimum of 30 days** before approval to proceed is requested.

28. **Prior to initial site preparation**, DCP shall provide procedures for controlling access during construction.

29. **Prior to initial site preparation**, DCP shall file the quality assurance and quality control procedures for construction activities.

30. **Prior to initial site preparation**, DCP shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.

31. **Prior to initial site preparation**, a technical review of facility design shall be filed that:

    a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids, and flammable gases); and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicate how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.

32. **Prior to initial site preparation**, DCP shall resize the Trucking Area Sump to adequately contain the maximum content of a condensate truck.

33. **Prior to initial site preparation**, DCP shall file its updated ERP to include the Liquefaction Facilities as well as instructions to handle on-site refrigerant and NGL-related emergencies.

34. **Prior to initial site preparation**, DCP shall file an ERP that includes 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.

35. DCP shall certify that the **final design** has been modified to be consistent with the wind speed requirements of 49 CFR § 193.2067 or that DOT has approved the use of a lower wind speed as allowed by § 193.2067(b). DCP shall consult with DOT on any actions necessary to demonstrate compliance with Part 193.

36. The **final design**, DCP shall include information/revisions pertaining to DCP's response numbers 3, 19, 21, and 64 of its July 16, 2013 filing, which indicated features to be included or considered in the final design.

37. The **final design** shall include change logs that list and explain any changes made from the FEED provided in DCP'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.

38. The **final design** shall provide up-to-date Process Flow Diagrams with heat and material balances and P&IDs, which include the following information:

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

    b. equipment insulation type and thickness;

    c. valve high pressure side and internal and external vent locations;

    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. relief valves with set points; and

    h. drawing revision number and date.

39. The **final design** shall provide P&IDs, specifications, and procedure that clearly show and specify the tie-in details required to safely connect the Project to the existing facility.

40. The **final design** shall provide an up-to-date complete equipment list, process and mechanical data sheets, and specifications.

41. The **final design** shall provide complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list

shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.

42. 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.

43. The **final design** shall provide facility plans and drawings that show the location of the firewater and foam systems. Drawings shall clearly show: firewater and foam piping; post indicator valves; and the location of, and area covered by, each monitor, hydrant, deluge system, foam system, water-mist system, and sprinkler. The drawings shall also include P&IDs of the firewater and foam system.

44. 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 Part 193. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed.

45. The **final design** shall specify that for hazardous fluids, piping and piping nipples 2 inches or less are consistent with the existing facility's piping specifications.

46. The **final design** shall include drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.

47. 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.

48. The **final design** shall provide electrical area classification drawings.

49. The **final design** shall provide spill containment system drawings with dimensions and slopes of curbing, trenches, and impoundments.

50. The **final design** of the hazard detectors shall account for the calibration gas when determining the LFL set points for methane, propane, ethane, and condensate.

51. The **final design** shall include a hazard and operability review of the completed design prior to issuing the P&IDs for construction. A copy of the review, a list of recommendations, and actions taken on the recommendations, shall be filed.

52. The **final design** shall include the cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD system. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points.

53. The **final design** shall include a drawing that shows the location of the ESD buttons. ESD buttons shall be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.

54. 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.

55. 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, and storage tanks.

56. 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.

57. The **final design** shall provide the specifications, procedures, and schedule to modify the tunnel expansion joints.

58. The **final design** shall either set the pressure relief valves at the Mole Sieve Gas Dehydrators to the design pressure of the closed loop system or design the Mole Sieve Gas Dehydrators and the associated hot piping system for the regeneration design temperature and the feed gas design pressure of the pretreatment system.

59. The **final design** shall include double isolation for each sulfur removal vessel. Manual isolation valves shall be installed upstream of the inlet pneumatic valve and downstream of the outlet pneumatic valve with vent and purge connections between the manual and pneumatic valves.

60. The **final design** shall provide coarse mesh strainers in the bottom outlet piping of the adsorbers to prevent support material and molecular sieve migrating from Mole Sieve Gas Dehydrators to the piping system.

61. The **final design** shall provide a redundant low temperature shutdown system for the Flash Gas Compressors. The set point shall be set at no less than -50°F.

62. The **final design** of the Ethane Make-Up Drum and associated piping system shall include stress analysis of the system at the equilibrium temperature of the Ethane at barometric pressure.

63. The **final design** shall provide all tests, investigations, and reports to ensure the existing firewater system's compatibility and reliability.

64. The **final design** shall equip the HRU Column with permanent drainage piping to the cold flare, designed for cryogenic conditions.

65. The **final design** shall provide drainage piping to the cold flare from the Nitrogen Stripper Reboiler bottom inlet piping and Nitrogen Stripper bottom outlet piping upstream of the shutoff valve.

66. The **final design** shall equip the Stabilizer with permanent drainage piping to the flare system.

67. The **final design** of the refrigerant and stabilized condensate storage system shall provide dual full capacity relief valves that allow the isolation of individual pressure relief valves while providing full relief capacity during pressure relief valve maintenance or testing.

68. DCP shall certify that the **final design** is consistent with the information provided to DOT as described in the design spill determination letter dated February 27, 2014 (Accession Number 20140227-4004) and supplemental information filed by DCP on March 7, 2014 (Accession Numbers 20140307-5050 and 20140307-5051), March 14, 2014 (Accession Numbers 20140314-5099 and 20140317-5100), and April 11, 2014 (Accession Numbers 20140411-5252 and 20140411-5253). In the event that any modifications to the design alters the candidate design spills on which the Title 49 CFR 193 siting analysis was based, DCP shall consult with DOT on any actions necessary to comply with Part 193.

69. 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.

70. **Prior to commissioning**, DCP 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.

71. **Prior to commissioning**, DCP 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. DCP 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.

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

73. **Prior to commissioning**, DCP 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.

74. **Prior to commissioning**, DCP shall file updates addressing the liquefaction facilities in the operation and maintenance procedures and manuals, as well as safety procedures.

75. **Prior to commissioning**, DCP shall maintain a detailed training log to demonstrate that operating staff has completed the required training.

76. **Prior to introduction of hazardous fluids**, DCP 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).

77. **Prior to introduction of hazardous fluids**, DCP shall complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the Distributed Control System and the Safety Instrumented System that demonstrates full functionality and operability of the system.

78. **Prior to commencement of service**, DCP shall label piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A

79. **Prior to commencement of service**, progress on the construction of the proposed systems shall be reported in **monthly** reports filed with the Secretary. 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**.

The following measures shall apply throughout the life of the facility:

80. 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, DCP shall respond to a specific data request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted.

81. 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, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading/shipping problems, potential hazardous conditions from 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, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boil-off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" also shall be included in the semi-annual operational reports. Such information would provide FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.

82. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to 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 fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

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

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

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

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

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

l. safety-related incidents to hazardous fluids vessels 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 investigation results and recommendations to minimize a reoccurrence of the incident.

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APPENDIX A

SOIL CHARACTERISTICS AFFECTED BY THE PROJECT

APPENDIX A

Soil Characteristics Affected by the Project

Facility/Soils Series/Description	Disturbed (acres) [a] Const.	Disturbed (acres) [a] Oper	Composed on Site [a] On-site Acres	Composed on Site [a] On-site Percent	Prime Farmland	Soil Limitations: Water Erosion Hazard	Compaction Potential	Depth to Rock (inches)	Revegetation Potential	WEG	K-factor
Liquefaction Facilities											
Aquasco and Beltsville; BeB Beltsville-Aquasco complex (silt loam and sandy clay loam), 2 to 5 percent slopes	0.3	<0.1	<0.1	<0.1	Yes	Slight	Low	20-40	Low	5	0.4
Downer and Dodon; DoG Downer-Dodon complex (loamy sand, and sandy loam), 25 to 80 percent slopes	9.0	7.8	8.5	22.7	No	High	Moderate	80+	Moderate	2	0.2
Keyport; KwB Keyport silt loam, 2 to 5 percent slopes	0.1	<0.1	0.1	0.3	No	Slight	Low	80+	High	5	0.5
Matapeake and Beltsville; MeB Matapeake-Beltsville complex (silt and sandy loam), 2 to 5 percent slopes	0.3	0	0.3	0.8	Yes	Slight	Low	80+	High	5	0.4
Urban; Ub Urban land	24.8	18.5	25.4	67.7	No	Not rated	No rated	-	Not rated	Not rated	Not rated
Woodstown; WdB Woodstown sandy loam, 2 to 5 percent slopes	2.1	2.1	2.1	5.6	Yes	Slight	Low	80+	High	3	0.2
Woodstown; WdC Woodstown sandy loam, 5 to 10 percent slopes	1.1	1.1	1.1	2.9	No	Slight	Low	80+	High	3	0.2
Subtotal	**37.7**	**29.5**	**37.5**	**100.0**							
Offsite Area A											
Aquasco and Beltsville; BeB Beltsville-Aquasco complex (silt loam and sandy clay loam), 2 to 5 percent slopes	13.3	0	13.7	7.6	Yes	Slight	Low	20-40	Low	5	0.4
Downer and Dodon; DoG Downer-Dodon complex (loamy sand, and sandy loam), 25 to 80 percent slopes	46.3	0	105.9	59.0	No	High	Moderate	80+	Moderate	2	0.2
Fort Mott-Cedartown; FcE Fort Mott-Cedartown complex (sand, loamy sand, and sandy loam), 15 to 25 percent slopes	0	0	6.4	3.6	No	High	Moderate	80+	High	2	0.1

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Facility/Soils Series/Description	Disturbed (acres) [a] Const.	Disturbed (acres) [a] Oper	Composed on Site [a] On-site Acres	Composed on Site [a] On-site Percent	Prime Farmland	Soil Limitations: Water Erosion Hazard	Compaction Potential	Depth to Rock (inches)	Revegetation Potential	WEG	K-factor
Galstown-Woodstown; GwC Galstown-Woodstown complex (sandy loam and loamy sand), 5 to 10 percent slopes	3.4	0	4.9	2.7	No	Slight	Low	80+	High	2-3	0.1
Galstown-Woodstown; GwD Galstown-Woodstown complex (sand and loamy), 10 to 15 percent slopes	2.2	0	2.2	1.2	No	Slight	Low	80+	High	2-3	0.1
Ingleside-Evesboro; IeC Ingleside-Evesboro complex (loamy sand and sandy loam), 5 to 10 percent slopes	1.9	0	6.2	3.5	Yes	Slight	Low	80+	High	3-1	0.2
Ingleside-Galestown; IgB Ingleside-Galestown complex (loamy sand, sandy loam, and silt loam), 5 to 10 percent slopes	2.2	0	2.2	1.2	No	Slight	Low	80+	High	2	0.2
Ingleside-Woodstown; IwC Ingleside- Woodstown complex (loamy sand and sandy loam), 5 to 10 percent slopes	19.7	0	25.4	14.2	No	Slight	Low	80+	High	2-3	0.2
Matapeake and Beltsville; MeA Matapeake-Beltsville complex (silt loam and sandy loam), 0 to 2 percent slopes	1.5	0	1.9	1.1	Yes	Slight	Low	80+	High	5	0.4
Matapeake and Beltsville; MeB Matapeake-Beltsville complex (silt and sandy loam), 2 to 5 percent slopes	4.5	0	7.9	4.4	Yes	Slight	Low	80+	High	5	0.4
Woodstown; WdC Woodstown sandy loam, 5 to 10 percent slopes	0.1	0	0.6	0.3	No	Slight	Low	80+	High	3	0.2
Zekiah and Issue; ZBA Zekiah and Issue soils (silt loam, loam, and fine sandy loam), 0 to 2 percent slopes	0	0	2.1	1.2	No	Slight	High	80+	Low	5	0.4
Subtotal	**94.9**	**0**	**179.4**	**100.0**							

APPENDIX A

Soil Characteristics Affected by the Project

	Disturbed (acres) [a]		Composed on Site [a]			Soil Limitations					
Facility/Soils Series/Description	Const.	Oper	On-site Acres	On-site Percent	Prime Farmland	Water Erosion Hazard	Compaction Potential	Depth to Rock (inches)	Revegetation Potential	WEG	K-factor
Offsite Area B											
Annemessex; AsA Annemessex silt loam, 0 to 2 percent slopes	2.9	0	3.9	35.1	No	Slight	Low	80+	Moderate	5	0.4
Ingleside and Woodstown; IwB Ingleside-Woodstown complex (loamy sand and sandy loam), 2 to 5 percent slopes	0.5	0	2.8	25.2	Yes	Slight	Low	80+	High	5	0.2
Piccowaxen; PcB Piccowaxen Loam, 2 to 5 percent slopes	1.4	0	3.0	27.0	No	Slight	Low	80+	Moderate	5	0.2
Water; W Water	0	0	0.1	0.9	No	-	-	-	-	-	-
Woodstown and Piccowaxen; WpD Woodstown-Piccowaxen complex (sandy loam, fine sandy loam, loam, and loamy sand), 5 to 15 percent slopes	1.0	0	1.3	11.7	No	Slight	Low	80+	High	5	0.2
Subtotal	**5.8**	**0**	**11.1**	**99.9**							
Pleasant Valley Compressor Station											
Albano; 1A Albano silt loam, 0 to 2 percent slopes	2.4	<0.1	6.8	25.0	No	Slight	Low	40-60	Low	4	0.4
Ashburn; 2B Ashburn silt loam, 0 to 7 percent slopes	11.6	2.1	12.9	47.4	No	Slight	Low	20-40	High	5	0.4
Penn; 85B Penn silt loam, 2 to 7 percent slopes	<0.1	0	1.6	5.9	Yes	Slight	Low	20-40 to paralithic bedrock; 40-60 to lithic bedrock	High	5	0.3
Penn; 85C Penn silt loam, 7 to 15 percent slopes	1.0	0.1	1.4	5.1	No	Slight	Low	20-40 to paralithic bedrock; 40-60 to lithic bedrock	High	5	0.3

APPENDIX A

Soil Characteristics Affected by the Project

Facility/Soils Series/Description	Disturbed (acres) [a]		Composed on Site [a]			Soil Limitations					
	Const.	Oper	On-site Acres	On-site Percent	Prime Farmland	Water Erosion Hazard	Compaction Potential	Depth to Rock (inches)	Revegetation Potential	WEG	K-factor
Sycoline-Kelly; 94B Sycoline-Kelly complex, 2 to 7 percent slopes	1.0	0	4.5	16.5	Yes	Slight	High	20-40	Low	5	0.4
Subtotal	**16.0**	**2.2**	**27.2**	**99.9**							
Pleasant Valley Suction/Discharge Pipelines											
Albano; 1A Albano silt loam, 0 to 2 percent slopes	0.7	0	0.7	38.3	No	Slight	Low	40-60	Low	4	0.4
Catlett; 11C Catlett gravelly silt loam, 7 to 15 percent slopes	1.0	0	1.0	53.7	No	Slight	High	10-20 to paralithic bedrock; 20-40 to lithic bedrock	High	5	0.2
Chantilly-Sycoline-Kelly; 27B Chantilly-Sycoline-Kelly loam, 0 to 15 percent slopes	0.1	0	0.1	6.5	No	Slight	Low	40-60 to lithic bedrock	High	5	0.3
Sycoline-Kelly; 94B Sycoline-Kelly complex, 2 to 7 percent slopes	<0.1	0	<0.1	1.5	Yes	Slight	High	20-40	Low	5	0.4
Subtotal	**1.8**	**0**	**1.8**	**100.0**							
Loudoun M&R Facility											
Panorama; 71B Panorama silt loam, 2 to 7 percent slopes	<0.1	<0.1	<0.1	20.3	Yes	Slight	Low	40-60	High	3	0.4
Penn; 73C Penn silt loam, 7 to 15 percent slopes	<0.1	<0.1	<0.1	79.7	No	Slight	Low	20-40 to paralithic bedrock; 40-60 to lithic bedrock	High	5	0.3
Subtotal	**0.1**	**0.1**	**0.1**	**100**							
Leesburg Compressor Station											
Albano; 79A Albano silt loam, 0 to 2 percent slopes	0.2	0	0.2	3.3	No	Slight	Low	40-60	Low	4	0.4

APPENDIX A

Soil Characteristics Affected by the Project

	Disturbed (acres) [a]		Composed on Site [a]			Soil Limitations					
Facility/Soils Series/Description	Const.	Oper	On-site Acres	On-site Percent	Prime Farmland	Water Erosion Hazard	Compaction Potential	Depth to Rock (inches)	Revegetation Potential	WEG	K-factor
Manassas; 14B Manassas silt loam, 0 to 7 percent slopes	0.2	0	0.2	3.3	Yes	Slight	Low	80+	High	4	0.4
Leedsville; 70B Leedsville cobbly silt loam, 2 to 7 percent slopes	2.0	0	2.0	32.8	No	Slight	Low	80+	High	8	0.3
Leedsville; 70C Leedsville cobbly silt loam, 7 to 15 percent slopes	3.7	0	3.7	60.7	No	Slight	Low	80+	High	8	0.3
Subtotal	**6.1**	**0**	**6.1**	**100.1**							
Project Total	**162.4**	**31.8**	**263.2**								

[a] Impervious surfaces and buildings not included from the composition and impacts totals.

WEG = Wind Erodibility Group.

Sources: NRCS, 2012; USDA, 2011.

Note: The totals shown in this table may not equal the sum of addends due to rounding.

APPENDIX B

GENERAL CONFORMITY ANALYSIS

Appendix B

Draft General Conformity Determination for the Cove Point Liquefaction Project

May 2014

Dominion Cove Point LNG, LP
Docket No. CP13-113-000

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Cove Point Liquefaction Project
General Conformity Determination

LIST OF TABLES

1.0 INTRODUCTION

Dominion Cove Point LNG, LP (DCP) owns and operates a liquefied natural gas (LNG) import terminal, the Cove Point LNG Terminal (LNG Terminal), in Lusby, Calvert County, Maryland. DCP filed an application in April 2013 with the Federal Energy Regulatory Commission (FERC or Commission) to construct, modify, and operate facilities to liquefy and export LNG. The Project would involve installation of one LNG train with two natural gas fired turbines and expansion of existing DCP facilities to provide gas liquefaction and LNG export services to customers that would provide their own gas supply. Using facilities proposed as part of the Cove Point Liquefaction Project (Project), combined with existing facilities, DCP would provide a bi-directional service of receiving and regasification of imported LNG from LNG vessels (import service), and liquefaction of natural gas for loading onto LNG ships for export at the LNG Terminal (export service). DCP is requesting authorization to construct and operate liquefaction facilities with LNG production capacity of up to 5.75 million metric tons per annum (MTPA). DCP would construct the liquefaction facilities on 49 acres within the 131-acre fenced area of the LNG Terminal site. DCP would also use 96.9 acres of Offsite Area A as a temporary construction laydown/parking area, including temporary buildings and office trailers, and 5.9 acres of Offsite Area B as a temporary barge offloading area including a temporary pier (both areas within Calvert County, Maryland).

Natural gas would be delivered to the LNG Terminal via the existing Cove Point Pipeline. No modifications are needed to the underground pipeline. However, additional compression on the Cove Point Pipeline is required to deliver the inlet gas to the LNG Terminal. To accommodate the gas associated with the Project moving through the Cove Point Pipeline system, DCP proposes to install four new electric-driven compressor units and install and/or replace suction and discharge piping at the existing Pleasant Valley Compressor Station in Fairfax County, Virginia. DCP would also modify the Loudoun Meter and Regulating Station and use the Leesburg Compressor Station for construction laydown, parking, and staging all within Loudoun County, Virginia.

With the exception of some construction and operational marine vessel emissions, the entire proposed Project would occur in Calvert County, Maryland and Fairfax and Loudoun Counties, Virginia. All of these counties are within the Washington DC-MD-VA Ozone Nonattainment Area. Fairfax and Loudoun Counties are also designated nonattainment for the annual particulate matter less than 2.5 microns ($PM_{2.5}$) standard.

2.0 GENERAL CONFORMITY – REGULATORY BACKGROUND

The U.S. Environmental Protection Agency (EPA) promulgated the General Conformity Rule on November 30, 1993 to implement the conformity provision of Title I, section 176(c)(1) of the federal Clean Air Act (CAA). Section 176(c)(1) states that any department, agency, or instrumentality of the Federal Government shall not engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to an approved CAA implementation plan. The General Conformity Rule is codified in Title 40 Code of Federal Regulations (CFR) Part 93, Subpart B, "Determining Conformity of General Federal Actions to State or Federal Implementation Plans."

The General Conformity Rule applies to all federal actions occurring in non-attainment or maintenance areas. However, the General Conformity Rule excludes programs and projects that require funds or approval from the U.S. Department of Transportation, the Federal Highway Administration, the Federal Transit Administration, or the Metropolitan Planning Organization. In lieu of a conformity analysis, these latter types of programs and projects must comply with the Transportation Conformity Rule promulgated by EPA on November 24, 1993.

2.1 General Conformity Requirements

Conformity under Title I, section 176(c)(1) of the CAA, means to conform to an implementation plan's purpose of eliminating or reducing the severity and number of violations of the National Ambient Air Quality Standards (NAAQS) and achieving expeditious attainment of such standards. A proposed action or activity cannot:

- Cause or contribute to new violations of any NAAQS in any area;
- Increase the frequency or severity of any existing violation of any NAAQS in the area; or
- Delay timely attainment of any NAAQS, interim emission reductions, or other milestones in the area.

The General Conformity Rule allows for a conformity determination to be performed in coordination with and as part of the National Environmental Policy Act (NEPA) process, although this is not required. The General Conformity Rule applies to air pollutant emissions (direct and indirect) associated with "federal actions" as defined in 40 CFR 93.152 and ensures that the emissions do not contribute to air quality degradation or prevent the achievement of state and federal air quality goals. General Conformity, if applicable to the action, basically refers to the process to evaluate the action to determine and demonstrate that it satisfies the requirements of the approved state implementation plan (SIP). The purpose of the General Conformity Rule is to encourage federal agencies to consult with state and local air quality districts so that these regulatory entities are aware of the expected impacts of the federal action and ensure the action meets their SIP.

2.2 General Conformity Process

The General Conformity process for a proposed action involves two distinct steps: applicability analysis and conformity determination. The applicability analysis is an assessment of whether a proposed action is subject to the General Conformity Rule. If the General Conformity Rule is applicable for the proposed action, then a General Conformity Determination may be required. A General Conformity Determination is an assessment of whether the proposed action conforms to the applicable SIP.

An applicability analysis is required for any "federal action", as defined in 40 CFR 93.152, that is in a nonattainment or maintenance area and the emissions associated with the project may have the potential to exceed the rates listed specified in 40 CFR 93.153(b)(1) and (2). If emissions exceed these rates, then a General Conformity Determination is required. A "federal Action" is defined in 40 CFR 93.152 as *"any activity engaged in by a department, agency, or instrumentality of the federal government, or any activity that a department, agency or instrumentality of the federal government supports in any way, provides financial assistance for, licenses, permits, or approves, other than activities related to transportation plans, programs and projects developed, funded, or approved under Title 23 U.S.C. or the Federal transit Act (49 U.S.C. 1601 et seq.). Where the "federal action" is a permit, license, or other approval for some aspect of a non-federal undertaking, the relevant activity is the part, portion, or phase of the non-federal undertaking that requires the federal permit, license or approval."*

The General Conformity process does not include a review of new sources or existing source modifications that are subject to state or federal New Source Review permitting. Under the General Conformity Rule, these sources are presumed to comply with the SIP by completing the applicable air permitting process with the jurisdictional agency.

If a General Conformity Determination is required for the proposed action, then an evaluation must be performed to determine if the action conforms to the SIP. Where an action would exceed the applicability threshold in multiple states, or where the air quality control region (AQCR) encompasses multiple states, a General Conformity Determination is prepared and conformance documented for each state where the thresholds are exceeded. This may be performed in one document or separately for each state or AQCR.

The FERC is the lead agency responsible for authorizing applications to construct and operate onshore LNG export and interstate natural gas facilities. The Project is considered a "federal action" and the FERC is the lead agency responsible for making the General Conformity Determination. As required under General Conformity, an applicability analysis was performed for the Project to determine if the total direct and indirect emissions for criteria pollutants in non-attainment or maintenance areas exceeded the rates specified in 40 CFR 58.853(b)(1) and (2) and the results are presented in Section 3.0 below. The Project would exceed applicability thresholds and a General Conformity Determination is presented in Section 4.0, below.

3.0 GENERAL CONFORMITY APPLICABILITY

The General Conformity Rule applies only to actions in a nonattainment or maintenance area and the applicability thresholds apply for those portions of the project within that nonattainment area. The General Conformity applicability thresholds are based on the attainment classification for each pollutant. Table 3-1 provides a summary of the attainment status and applicability thresholds for the Project area (LNG terminal, Offsite Areas A and B, and pipeline facilities).

TABLE 3-1

General Conformity Thresholds

	Calvert County, MD		Fairfax and Loudoun Counties, VA	
Pollutant	Status	Threshold (tons/year)	Status	Threshold (tons/year)
Particulate matter less than 10 microns	Attainment	NA	Attainment	NA
Particulate matter less than 2.5 microns ($PM_{2.5}$)	Attainment	NA	Nonattainment (Annual only) [a]	100 $PM_{2.5}$ 100 NOx 100 SO_2
SO_2	Attainment	NA	Attainment	NA
Nitrogen dioxide	Attainment	NA	Attainment	NA
Ozone	Nonattainment [b]	100 NOx 50 VOC	Nonattainment [b]	100 NOx 50 VOC
Carbon monoxide	Attainment	NA	Attainment	NA
Lead	Attainment	NA	Attainment	NA

a NO_x and SO_2 are considered precursor pollutants to the formation of $PM_{2.5}$ and have thresholds as well.
b NO_x and VOC are considered precursor pollutants to the formation of ozone and have thresholds as well. The Washington, DC-MD-VA Ozone Nonattainment Area is also located within an ozone transport region, resulting in more stringent VOC thresholds.

All three Counties are within the Washington, DC-MD-VA Ozone Nonattainment Area.
Loudoun and Fairfax Counties are Washington, DC-MD-VA $PM_{2.5}$ Nonattainment Area.

NA = not applicable

The marine vessel emissions were included for LNG carriers, and related support vessels, traveling through the Chesapeake Bay to and from the LNG terminal within Calvert and Saint Mary's

Counties, Maryland. Calvert County is the only county currently designated non-attainment. Therefore, the marine vessel emissions that are included in this analysis for the Washington, DC-MD-VA Ozone Nonattainment Area are conservative. LNG carriers and support vessels would also pass through waters adjacent to counties in the Norfolk-Virginia Beach-New Port News (Hampton Roads) 8-hour ozone maintenance area, specifically Virginia Beach City, Poquoson City, and York Counties. These counties are part of a different air quality control region and need to be assessed separately from the Washington, DC-MD-VA Ozone Nonattainment Area. Based on experience with other National Environmental Policy Act (NEPA) analyses and General Conformity Applicability analyses, the LNG carrier and support vessel transit emissions in the Virginia maintenance counties are not expected to exceed the general conformity applicability thresholds.[1] Therefore, these emissions are not included in the detailed general conformity applicability analysis.

3.1 Emission Sources

Project emissions sources that are subject to the General Conformity Applicability Analysis include the following:

Construction Emissions

- Barges – Emissions from the transport of equipment and materials to the Project.
- Construction equipment – Emissions from air compressors, backhoes, cranes, and other construction equipment.
- On-road vehicles – Emissions from commuter buses, passenger vehicles, and diesel and gasoline trucks.
- Off-road construction vehicle traffic – Emissions from commuter buses, dump trucks, light/medium duty trucks, and water/fuel trucks.
- Marine construction vessels – Emissions from offshore construction equipment (e.g., survey boats, barges, cranes, and tugboats).
- Earthmoving activities – Emissions resulting from bulldozing, grading, and land disturbance.
- Construction storage piles – Particulate matter emissions from active storage piles that would be used during construction.

Non-Permitted Operational Emissions

- New Employees Commuting – Vehicle emissions from an increase in the number of DCP employees commuting to the facility.

[1] Based on the Sparrows Point LNG Terminal and Pipeline Project (Docket Nos. CP07-62-000 and CP07-63-000), the marine vessel emissions from 180 LNG carriers passing through these same counties were estimated at 39.4 tons per year (TPY) NO_x and 1.1 TPY VOC. The proposed Project would involve less than half as many carriers. The applicability thresholds are 100 TPY NO_x and 50 TPY VOC.

- Waste Haulers – Truck emissions from the increase in waste hauling trucks needed for the site.

- Marine Vessels – Emissions from the LNG export activities, including LNG carriers and supporting marine vessels, such as tugboats and security vessels. The estimated emissions are based on 85 LNG export carriers per year, one security boat per LNG export carrier, and three tugs per LNG export carrier.

The emissions from these sources were calculated using the expected equipment counts and equipment utilizations along with emission factors from various EPA guidance documents and modeling software.[2]

These Project emissions are summarized in table 3.1-1 and compared to the general conformity applicability thresholds.

TABLE 3.1-1

Construction and Non-Permitted Operating Project Emissions Summary

	Ozone Nonattainment Area [a]		$PM_{2.5}$ Nonattainment Area [b]		
	Emissions (tons/year)		Emissions (tons/year)		
Year	NO_x	VOC	NO_x	SO_2	$PM_{2.5}$
2014	**171.13**	15.38	0.00	0.00	0.00
2015	**326.94**	35.00	0.00	0.00	0.00
2016	**230.91**	32.80	20.61	0.79	5.82
2017 – Construction	123.14	16.43	0.82	0.03	0.66
2017 – Operation (non-permitted) – LNG Terminal	77.23	2.29	0.00	0.00	0.00
2017 (Total)	**200.37**	18.72	0.82	0.03	0.66
2018 & Beyond (Operational – LNG Terminal)	77.23	2.29	0.00	0.00	0.00
Conformity Applicability Threshold	100	50	100	100	100

[a] Emissions are summarized for activities that would occur in Calvert County, MD and Loudoun and Fairfax Counties, VA (Ozone Nonattainment Area).

[b] Emissions are provided only for the activities that would occur in Loudoun and Fairfax Counties ($PM_{2.5}$ Nonattainment Area).

Project construction would occur in 2014 – 2017. Construction would be completed in 2017 and operation would begin. Only the LNG Terminal would have any notable non-permitted operational emissions (marine vessels, employee commuter vehicle traffic, and waste haul truck traffic).

NO_x = nitrogen oxides

SO_2 = sulfur dioxide

VOC = volatile organic compounds

$PM_{2.5}$ = particulate matter less than 2.5 microns

The emissions in table 3.1-1 include all nitrogen oxides (NO_x) and VOC that would occur in the Washington DC-MD-VA Ozone Nonattainment Area (Calvert County, Maryland; Loudoun and Fairfax Counties, Virginia). Also included in table 3.1-1 are the NO_x, sulfur dioxide (SO_2) and $PM_{2.5}$ emissions for those activities that would occur in the Washington, DC-VA-MD $PM_{2.5}$ Nonattainment Area (Loudoun and Fairfax Counties, Virginia). As shown in table 3.1-1, the estimated direct and indirect NO_x emissions could exceed the applicability thresholds for 2014 through 2017. It is also conservatively

[2] Detailed information on calculation methodology for each emission source is available on the FERC website, http://www.ferc.gov, using the "elibrary" link and the project docket number CP13-113.

assumed that in 2017, an entire year of marine vessel emissions (due to LNG operations) would occur in addition to the construction emissions.

Because the emissions from the Project would exceed the applicability threshold for NO_x, a general conformity determination must be completed to assess the Project's NO_x emissions conformance to the approved SIP(s) for years 2014 through 2017. These emissions are referred to within this determination as the "General Conformity Project emissions."

Multi-year projects of this scale often encounter schedule modifications. It is possible that construction emissions from one year would shift to another. As discussed below, DCP would offset its maximum year projected emissions for all years. This would account for any schedule adjustment that may result in greater emissions than originally projected in earlier years. The General Conformity Rule also provides for a reassessment if the final General Conformity Determination becomes outdated or if emissions are significantly greater than originally anticipated.

4.0 GENERAL CONFORMITY

A SIP is completed by each jurisdictional agency tasked with implementing the CAA. For SIP matters relating specifically to the Washington DC-MD-VA Nonattainment Area, the District of Columbia, Maryland, and Virginia have formed the Metropolitan Washington Air Quality Committee (MWAQC) to generate the SIP measures for the area that are then incorporated into each state's/ territory's SIP. The measures in the SIPs are implemented by the Maryland Department of the Environment (MDE) in Maryland and the Virginia Department of Environmental Quality (VDEQ) in Virginia; including those measures in the Washington DC Area. Therefore, the Project emission summarized above must comply with the Washington DC Area SIP submittals as well as other NO_x SIP submittals for Maryland or Virginia that may apply.

The potentially applicable requirements were determined through a review of the following SIP documents:

- Plan to Improve Air Quality in the Washington, DC-MD-VA Region, SIP for 8-Hour Ozone Standard, May 23, 2007, MWAQC.
- Maryland State Implementation Plan for CAA Section 110(a)(2) for Nitrogen Dioxide and Section 128 for all National Ambient Air Quality Standards, December 21, 2012, MDE.
- Baltimore Nonattainment Area 8-hour Ozone State Implementation Plan and Base Year Inventory, June 15, 2007, MDE.
- Washington DC-MD-VA 1997 $PM_{2.5}$ Maintenance Plan and Redesignation Request, May 22, 2013, MWAQC.

The list above includes two Washington DC Area SIP documents and two State of Maryland SIP documents. The VDEQ does not maintain SIP document postings. A search of the EPA Region III SIP Index[3] did not show any other approved SIP documents that may apply to the construction emissions from the Loudoun and Pleasant Valley facilities. Barges would originate from Fairless Hills, Pennsylvania; Baltimore, Maryland; and Corpus Christi, Texas. As such, barge emissions would primarily occur in

[3] http://yosemite.epa.gov/r3/r3sips.nsf/SIPIndex!OpenForm&Start=1&Count=1000&Expand=5.1&Seq=4

other air quality control regions, but the barge emissions were quantified and determined to be well below the general conformity threshold for these other AQCRs. Therefore, they were not analyzed any further in this General Conformity Determination.

4.1 General Conformity Determination – Maryland

With the exception of barges delivering equipment for the Liquefaction Facilities, all of the emissions from the Liquefaction Facilities construction are expected to occur in Maryland. The criteria for determining conformity are provided in 40 CFR 93.158. An action would be determined to conform for a specific pollutant if it meets the requirements of 40 CFR 93.158(c) and any of the applicable requirements in 40 CFR 93.158(a)(1) through (5). Section 40 CFR 93.158(c) requires the total of direct and indirect emissions from the action be in compliance with all relevant requirements and milestones contained in the applicable SIP. Section 40 CFR 93.158(a)(1) through (5) provide a number of pollutant- and state-specific options for demonstrating conformity. The demonstration of compliance with the Maryland SIP requirements, in accordance with 40 CFR 93.158(c), is provided in Section 4.1.1 of this document, and an analysis of the options the Project would use to demonstrate conformity under 40 CFR 93.158(a) is documented in Section 4.1.2.

4.1.1 Consistency with Relevant Maryland SIP Requirements

The NO_x emission control measures and regulations included in the Maryland SIP that may potentially apply to the Liquefaction Facilities and related activities are listed in table 4.1.1-1.

TABLE 4.1.1-1

Control Measures in the Maryland SIP

Emission Control Measures	Type	Potential Applicability to the Liquefaction Facilities and Related Activities
Seasonal Open Burning Restrictions	Local	Open Burning During Construction
EPA Non-road Diesel Engines Rule	Federal	Diesel powered construction equipment greater than 50 horsepower
Emissions Standards for Large Spark Ignition Engines	Federal	Industrial spark-ignition engines rated over 19 kilowatts
Reformulated Gasoline for Off-Road Applications	State	Gasoline construction equipment
Enhanced Inspections/Maintenance	Federal	Delivery and commuter vehicles
Federal Tier 1 and 2 Vehicle Standards	Federal	Delivery and commuter vehicles
National Low Emission Vehicle Standards	Federal	Delivery and commuter vehicles
Heavy Duty Diesel Engine Rule	Federal	Construction and Heavy Duty On-Road Vehicles
California Low Emission Vehicle	State	Delivery and commuter vehicles

Several of the regulations identified in table 4.1.1-1 would indirectly affect the emissions from the proposed Project through implementation of new standards for manufacturers (such as reformulated fuel and engines). Construction equipment and delivery/commuter vehicles would be powered by engines that are subject to these programs. Implementation and compliance with these programs would be required by the manufacturers and refiners; not DCP. Therefore, it is assumed that the Project would be in compliance with these regulations. There is also a requirement in the MWAQC 8-hour ozone SIP to restrict open burning at the local level. DCP has committed not to conduct open burning during construction. Therefore, the Project meets the requirements of 40 CFR 93.158(c) for complying with all relevant requirements and milestones contained in the applicable SIP.

4.1.2 Maryland SIP Budgets and Project Emission Offsets

In addition to complying with the control measures and regulations relied upon in the applicable SIP, 40 CFR 93.158(a) of the General Conformity Rule requires that the project comply with one of the following:

- 40 CFR 93.158(a)(1) – *For any criteria pollutant or precursor, the total of direct and indirect emissions from the action are specifically identified and accounted for in the applicable SIP's attainment or maintenance demonstration or reasonable further progress milestone or in a facility-wide emission budget included in a SIP in accordance with 40 CFR 93.161.*;

  Annual emissions from LNG import vessels were included in the 2002 and 2009 SIP baseline emission inventories. These are operational emissions from sources not subject to stationary source permitting. However, the Maryland SIP budgets do not specifically include the General Conformity Project emissions (i.e., emissions from construction, LNG export vessels, and associated LNG export support vessels). Therefore, this conformity option is not applicable.

- 40 CFR 93.158(a)(2) - *For precursors of ozone, nitrogen dioxide, or Particulate Matter, the total of direct and indirect emissions from the action are fully offset within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violations in the past, in the area with the Federal action) through a revision to the applicable SIP or similar enforceable measure that effects emissions reductions so that there is no net increase in emissions of that pollutant.*

  Similar to this conformity option, the Maryland Nonattainment New Source Review (NNSR) program (COMAR 26.11.17) requires that new major stationary sources or major modifications completely offset the proposed Project NO_x emissions. These offsets may be obtained through the purchase of emission reduction credits (ERC) from the MDE ERC program. The ERCs are credits generated by local air emissions sources that have made an enforceable, permanent, and quantifiable emission reduction. DCP has already stated in supplemental information filed with the Commission, that DCP has purchased sufficient NO_x ERCs to meet the General Conformity regulation. These ERCs are from sources within the Washington DC-MD-VA Air Quality Control Region including Essroc Cement Corporation.

  Because this is the method of conformance selected, DCP must demonstrate that it has purchased these offsets and that MDE finds their use acceptable under General Conformity. Therefore, the Environmental Assessment for this Project includes a recommendation that prior to any construction, DCP is required to provide documentation demonstrating that it has purchased sufficient offsets under General Conformity and DCP is required to provide a letter from MDE indicating the ERCs are acceptable.

- 40 CFR 93.158(a)(3) - *For any directly-emitted criteria pollutant, the total of direct and indirect emissions from the action meets the requirements:*

  - *(i) Specified in paragraph (b) of this section based on areawide air quality modeling analysis and local air quality modeling analysis; or*

- *(ii) Meet the requirements of paragraph (a)(5) of this section and, for local air quality modeling analysis the requirement of paragraph (b) of this section.*

The NO_x General Conformity Project emissions would be emitted as ozone or particulate matter precursor pollutants. Therefore, this conformity option is not applicable.

- 40 CFR 93.158(a)(4) **-** *For carbon monoxide or directly emitted particulate matter:*

  - *(i) Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (b) of this section, based on local air quality modeling analysis; or*

  - *(ii)Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is appropriate and that a local air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (b) of this section, based on areawide modeling, or meet the requirements of paragraph (a)(5) of this section.*

This conformity option is not applicable because the only General Conformity Project emissions are NO_x, as ozone and particulate matter precursor emissions.

- 40 CFR 93.158(a)(5) **-** *For ozone or nitrogen dioxide, and for purposes of paragraphs (a)(3)(ii) and (a)(4)(ii) of this section, each portion of the action or the action as a whole meets any of the following requirements:*

  - *(i) Where EPA has approved a revision to the applicable implementation plan after the area was designated as nonattainment and the State or Tribe makes a determination as provided in paragraph (a)(5)(i)(A) of this section or where the State or Tribe makes a commitment as provided in paragraph (a)(5)(i)(B) of this section;*

  - *(ii) The action (or portion thereof), as determined by the MPO, is specifically included in a current transportation plan and transportation improvement program which have been found to conform to the applicable SIP under 40 CFR part 51, subpart T, or 40 CFR part 93, subpart A;*

  - *(iii) The action (or portion thereof) fully offsets its emissions within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violation in the past, in the area with the Federal action) through a revision to the applicable SIP or an equally enforceable measure that effects emissions reductions equal to or greater than the total of direct and indirect emissions from the action so that there is no net increase in emissions of that pollutant;*

  - *(iv) Where EPA has not approved a revision to the relevant SIP since the area was designated or reclassified, the total of direct and indirect emissions from the action for the future years (described in §93.159(d)) do not increase emissions with respect to the baseline emissions:*

- *(v) Where the action involves regional water and/or wastewater projects, such projects are sized to meet only the needs of population projections that are in the applicable SIP*.

Sections 93.158(a)(5)(i), (ii), (iv), and (v) are not applicable to the Project. Section 93.158(a)5(iii) is identical to Section 93.158(a)(2). Therefore, this conformity option is not applicable.

4.1.3 Finding of Conformity – Maryland

DCP has entered into contractual agreements and purchased all offsets required for construction of the Project. In addition, we included a recommendation for any order Granting Authority and issuing Certificate (Order) approving this Project that prior to the Commission granting any construction, DCP must provide a record of NO_x offsets obtained and demonstrate that this amount is equal to the amount required under the final General Conformity Determination. DCP must also obtain and submit a letter from MDE concurring that the offset requirement has been met. This recommendation ensures that no emissions would occur from the Project before offsets are obtained and that once offsets are obtained, any emissions from the Project would be completely offset and cause a net reduction in emissions within the nonattainment area. In addition, DCP has provided information to demonstrate that sufficient offsets are available to it to completely offset NO_x emissions from the Project, and FERC staff have determined that offsetting is a viable approach to demonstration conformance.

We have determined that the Project will achieve conformity in Maryland through compliance with 40 CFR 93.158(a)(2) and 40 CFR 93.158(c).

4.2 General Conformity Determination – Virginia

Emissions from construction in Loudoun and Fairfax Counties, Virginia would occur in 2016 and 2017. The NO_x emissions from these activities would be subject to the general conformity determination requirements, as codified in 40 CFR 93.185(a) and (c) and discussed in Section 4.0 above.

4.2.1 Consistency with all Relevant Virginia SIP Requirements

The emission control measures and regulations that have been included in the Virginia SIP that may potentially apply to the Project are summarized in table 4.2.1-1.

TABLE 4.2.1-1

Control Measures in the Virginia SIP

Emission Control Measures	Type	Potential Applicability to the Liquefaction Facilities and Related Activities
Seasonal Open Burning Restrictions	Local	Open Burning During Construction
EPA Non-road Diesel Engines Rule	Federal	Diesel powered construction equipment greater than 50 horsepower
Emissions Standards for Large Spark Ignition Engines	Federal	Industrial spark-ignition engines rated over 19 kilowatts
Reformulated Gasoline for Off-Road Applications	State	Gasoline construction equipment
Enhanced Inspections/Maintenance	Federal	Delivery and commuter vehicles
Federal Tier 1 and 2 Vehicle Standards	Federal	Delivery and commuter vehicles
National Low Emission Vehicle Standards	Federal	Delivery and commuter vehicles
Heavy Duty Diesel Engine Rule	Federal	Construction and Heavy Duty On-Road Vehicles

Several of the regulations identified in table 4.2.1-1 would indirectly affect the emissions from the proposed Project through implementation of new standards for manufacturers (such as reformulated fuel and engines). Construction equipment and delivery/commuter vehicles would be powered by engines that are subject to these programs. Implementation and compliance with these programs would be required by the manufacturers and refiners; not DCP. Therefore, it is assumed that the Project would be in compliance with these regulations. There is also a requirement in the MWAQC 8-hour ozone SIP to restrict open burning at the local level. DCP has committed not to conduct open burning during construction. Therefore, the Project meets the requirements of 40 CFR 93.158(c) for complying with all relevant requirements and milestones contained in the applicable SIP.

4.2.2 Virginia SIP Budgets and Project Emission Offsets

In addition to complying with the control measures and regulations relied upon in the applicable SIP, 40 CFR 93.158(a) of the General Conformity Rule requires that the project comply with one of the following:

- 40 CFR 93.158(a)(1)) – *For any criteria pollutant or precursor, the total of direct and indirect emissions from the action are specifically identified and accounted for in the applicable SIP's attainment* or *maintenance demonstration or reasonable further progress milestone or in a facility-wide emission budget included in a SIP in accordance with 40 CFR 93.161.*

  The Virginia SIP budgets do not specifically include the emissions from the subject Project emissions.

- 40 CFR 93.158(a)(2) - *For precursors of ozone, nitrogen dioxide, or Particulate Matter, the total of direct and indirect emissions from the action are fully offset within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violations in the past, in the area with the Federal action) through a revision to the applicable SIP or similar enforceable measure that effects emissions reductions so that there is no net increase in emissions of that pollutant.*

  As noted above in section 4.1.2, the ERCs that DCP plans to purchase would be sufficient to completely offset the General Conformity Project emissions (including the NO_x emission related to the construction of the Loudoun and Pleasant Valley facilities), thereby meeting 40 CFR 93.158 (a)(2) of the general conformity regulations.

- 40 CFR 93.158(a)(3) - *For any directly-emitted criteria pollutant, the total of direct and indirect emissions from the action meets the requirements:*

  - *(i) Specified in paragraph (b) of this section based on areawide air quality modeling analysis and local air quality modeling analysis; or*

  - *(ii) Meet the requirement sof paragraph (a)(5) of this section and, for local air quality modeling analysis the requirement of paragraph (b) of this section.*

  The NO_x General Conformity Project emissions would be emitted as ozone or particulate matter precursor pollutants. Therefore, this conformity option is not applicable.

- 40 CFR 93.158(a)(4) - *For carbon monoxide or directly emitted particulate matter:*

- *(i) Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (b) of this section, based on local air quality modeling analysis; or*

- *(ii)Where the State agency primarily responsible for the applicable SIP determines that an areawide air quality modeling analysis is appropriate and that a local air quality modeling analysis is not needed, the total of direct and indirect emissions from the action meet the requirements specified in paragraph (b) of this section, based on areawide modeling, or meet the requirements of paragraph (a)(5) of this section.*

This conformity option is not applicable because the only General Conformity Project emissions are NO_x, as ozone and particulate matter precursor emissions.

- 40 CFR 93.158(a)(5) - *For ozone or nitrogen dioxide, and for purposes of paragraphs (a)(3)(ii) and (a)(4)(ii) of this section, each portion of the action or the action as a whole meets any of the following requirements:*

  - *(i) Where EPA has approved a revision to the applicable implementation plan after the area was designated as nonattainment and the State or Tribe makes a determination as provided in paragraph (a)(5)(i)(A) of this section or where the State or Tribe makes a commitment as provided in paragraph (a)(5)(i)(B) of this section;*

  - *(ii) The action (or portion thereof), as determined by the MPO, is specifically included in a current transportation plan and transportation improvement program which have been found to conform to the applicable SIP under 40 CFR part 51, subpart T, or 40 CFR part 93, subpart A;*

  - *(iii) The action (or portion thereof) fully offsets its emissions within the same nonattainment or maintenance area (or nearby area of equal or higher classification provided the emissions from that area contribute to the violations, or have contributed to violation in the past, in the area with the Federal action) through a revision to the applicable SIP or an equally enforceable measure that effects emissions reductions equal to or greater than the total of direct and indirect emissions from the action so that there is no net increase in emissions of that pollutant;*

  - *(iv) Where EPA has not approved a revision to the relevant SIP since the area was designated or reclassified, the total of direct and indirect emissions from the action for the future years (described in §93.159(d)) do not increase emissions with respect to the baseline emissions:*

  - *(v) Where the action involves regional water and/or wastewater projects, such projects are sized to meet only the needs of population projections that are in the applicable SIP.*

  Sections 93.158(a)(5)(i), (ii), (iv), and (v) are not applicable to the Project. Section 93.158(a)5(iii) is identical to Section 93.158(a)(2). Therefore, this conformity option is not applicable.

4.2.3 Finding of Conformity – Virginia

As noted in Section 4.1.3, the General Conformity Project emissions will be completely offset at a ratio of at least 1 to 1, thereby meeting the requirement of 40 CFR 93.158(a)(2). In addition, the General Conformity Project emissions would be consistent with the applicable SIP requirements, thereby meeting the requirements of 40 CFR 93.128(c). Therefore, we have determined that the Project will conform to the Virginia SIP and meet the requirements of the General Conformity Rule. However, DCP must also obtain and submit a letter from VDEQ concurring that the offset requirement has been met.