ENVIRONMENTAL ANALYSIS

Cabrillo Port

Deepwater Port in the Vicinity of Ventura, California

Prepared for:
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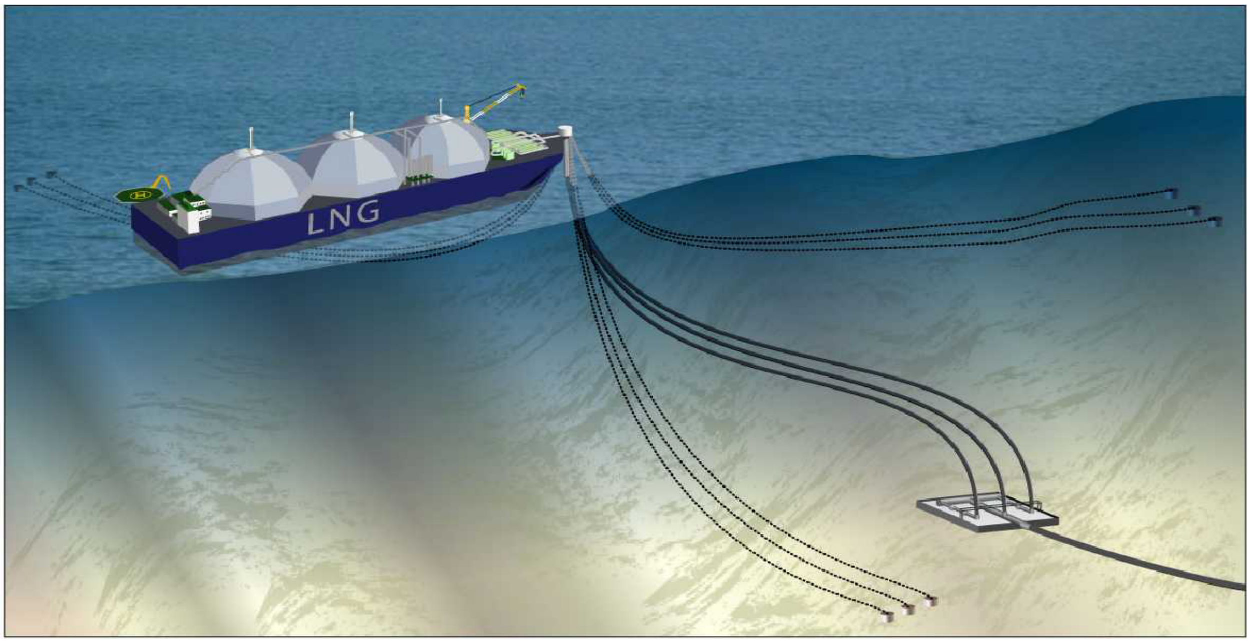

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TABLE OF CONTENTS

Section Page

TABLES

FIGURES

Figure

APPENDICES

The following appendices are identified in Chapter 3, Project Description.

Appendix A-1—Deepwater Port Act, Requirements Compliance Table.

Appendix A-2—Manufacturer specifications for the fail-safe shut-off valves at the loading area.

Appendix A-3—Specifications for the LNG storage tanks.

Appendix A-4–Specifications and other design details for the SCVs and other re-gasification plant equipment.

Appendix A-5—FSRU Design Drawings, including a detailed layout of each of the fire protection systems, showing the location of fire water pumps, piping, hydrants, hose reels, dry powder systems, CO_2 systems, and auxiliary or appurtenant service facilities, Specific layouts of the hazard detection and emergency shutdown systems, A layout of the onboard natural gas distribution system, showing the fuel distribution to the generator sets and submerged combustion vaporizers, and other process components. FSRU process and instrumentation diagrams (P&IDs) and schematic drawings.

Appendix A-6—Details of the geophysical and geotechnical testing program.

Appendix A-7—LNG cargo transfer guidelines for receipt of LNG by the FSRU.

ABBREVIATIONS AND ACRONYMS

ACHP	Advisory Council on Historic Preservation
AES	Aesthetic/Visual Resources
AHTS	anchor handling tug supply
API	American Petroleum Institute
BACT	best available control technology
barg	line pressure unit
bbl	barrels
bbl/day	barrel per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BHP	brake horsepower
BHPB	BHP Billiton
BMPs	best management practices
BOD	Biological Oxygen Demand
BOG	boil-off gas
BRMIMP	Biological Resources Mitigation Implementation and Monitoring Plan
Btu	British thermal unit
Btu/ft^3	British thermal units per cubic foot
Btu/ft^2-hr	British thermal units per feet squared hour
ºC	degrees Celsius
CalCOFI	California Cooperative Fisheries Investigations
CCC	California Coastal Commission
CDC	California Department of Conservation
CDFG	California Department of Fish and Game
CAA	Clean Air Act
CEQA	California Environmental Quality Act
CESA	California Endangered Species Act
CFR	Code of Federal Regulations
CHL	California Historical Landmarks
CINMS	Channel Islands National Marine Sanctuary
CO	carbon monoxide
CO_2	carbon dioxide
COE	U.S. Army Corps of Engineers
CP	corrosion protection
CPUC	California Public Utilities Commission

ABBREVIATIONS AND ACRONYMS (continued)

CSLC	California State Lands Commission
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
dB	decibel
dBA	decibels on the A-weighted scale (human hearing frequency range)
DEIS	Draft Environmental Impact Statement
DNV	Det Norske Veritas
DPV	Dynamic Position Vessel
DWPA	Deepwater Port Act
Dwt	dead weight tons
EA	Environmental Analysis
EEZ	Exclusive Economic Zone
EFH	Essential Fish Habitat
EIA	Energy Information Administration
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ESA	Endangered Species Act
ESD	emergency shutdown
°F	degrees Fahrenheit
FBE	fusion-bonded epoxy
FERC	Federal Energy Regulatory Commission
FMC	Fisheries Management Council
FMP	Fisheries Management Plan
Fps	feet per second
FSRU	floating storage and regasification unit
ft	feet
FWPCA	Federal Water Pollution Act
GBS	gravity based structure
GHG	Greenhouse Gas
gm/m	grams per meter
Gpm	gallons per minute
GPS	Global Positioning System
HAPs	Hazardous Air Pollutants
HDD	horizontal directional drilling
Hp	horsepower

ABBREVIATIONS AND ACRONYMS (continued)

HP	high pressure
HRI	Historical Resources Inventory
H_s	Significant wave height
Hz	hertz-a measurement of cycles per second
IFV	intermediate fluid vaporizers
IGC	International Gas Carrier
IMO	International Maritime Organization
ISM	International Safety Management
kg/h	kilograms per hour
kg/s	kilograms per second
kW	kilowatt
kV	kilovolt
Lb	pound
lb/h	pounds per hour
LP	low pressure
LPG	Liquefied petroleum gas
LP/HP	low pressure/high pressure
LNG	liquefied natural gas
m/s	meters per second
m^3	cubic meters
m^3/h	cubic meters per hour
MAOP	maximum allowable operating pressure
MAR	Marine Biology Resources
MARPOL	International Convention of the Prevention of Pollution from Ships
MCE	maximum credible earthquake
µg/m^3	micrograms per cubic meter
mg/l	milligrams per liter
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MMCF	million cubic feet
Mmgal	million gallons
MMPA	Marine Mammals Protection Act
MMS	Minerals Management Service
MP	Milepost
MPRSA	Marine Protection, Research, and Sanctuaries Act

ABBREVIATIONS AND ACRONYMS (continued)

MSFCMA	Magnuson-Stevens Fishery Conservation and Management Act
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NDE	non-destructive examination
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
ng/g	nanograms per gram
NGV	natural gas vehicle
NHPA	National Historic Preservation Act
NM	nautical miles
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxides
NO_2	Nitrogen Dioxide
NOS	National Ocean Service
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRHP	National Register of Historic Places
NSPS	New Source Performance Standards
NSR	New Source Review
NTU	Nephelometric Turbidity Units
O_3	Ozone
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OPR	Office of Planning and Research
OPS	Office of Pipeline Safety
OSPR	Office of Oil Spill Prevention and Response
P&Ids	process and instrumentation diagrams
PG &E	Pacific Gas and Electric
PHI	Points of Historical Interest
PLEM	pipeline ending manifold
$PM_{2.5}$	Particulate matter (2.5 microns in diameter)
PM_{10}	particulate matter (10 microns in diameter)
POR	period of record

ABBREVIATIONS AND ACRONYMS (continued)

POTW	Publicly Owned Treatment Works
ppb	parts per billion
ppm	parts per million
ppt	parts per thousand
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	per square inch, gauge internal pressure
RM	MMS Regional Manager
ROVs	remote-operated vehicles
ROW	right of way
SCB	Southern California Bight
SCBPP	Southern California Bight Pilot Project
SCCWRP	Southern California Coastal Water Research Project
SCR	selective catalytic reduction
SCV	submerged combustion vaporizer
SDV	safety shutdown valve
SFA	Sustainable Fisheries Act
short t	short ton
short tph	short ton per hour
SHPO	State Historic Preservation Officer
SIGTTO	Society of International Gas Tanker and Terminal Operators
SO_2	sulfur dioxide
SOC	Socioeconomic Resources
SoCalGas	Southern California Gas Company
SOLAS	International Convention for the Safety of Life at Sea
SPCC Plan	Spill Prevention, Control and Countermeasure Plan
SWRCB	California State Water Resources Control Board
STCW	Seafarers' Training, Certification and Watchkeeping
T	metric ton
T&E	Threatened and endangered
TCF	trillion cubic feet
TER	Terrestrial Resources
Tph	tons per hour
Tpy	tons per year

ABBREVIATIONS AND ACRONYMS
(continued)

U.S.C.	U.S. Code
USCG	U.S. Coast Guard
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
USDOI	U.S. Department of Interior
USDOT	U.S. Department of Transportation
USEPA	U.S. Environmental Protection Agency
UV	ultraviolet light
VOC	volatile organic compounds

COMMON CONVERSION EQUIVALENTS

Metric to U.S. Customary

Multiply	By	To Obtain
Millimeters (mm)	0.03937	Inches
Centimeters (cm)	0.3937	Inches
Meters (m)	3.281	Feet
Kilometers (km)	0.6214	Miles
Square meters (m^2)	10.76	Square feet
Square kilometers (km^2)	0.3861	Square miles
Hectares (ha)	2.471	Acres
Liters (l)	0.2642	Gallons
Cubic meters (m^3)	35.31	Cubic feet
Cubic meters	0.0008110	Acre-feet
Milligrams (mg)	0.00003527	Ounces
Grams (g)	0.03527	Ounces
Kilograms (kg)	2.205	Pounds
Metric tons (t)	2205.0	Pounds
Metric tons	1.102	Short tons
Kilocalories (kcal)	3.968	BTU
Celsius degrees	1.8(°C) +32	Fahrenheit degrees
Barg	14.504	Pounds per square inch-g

U.S. Customary to Metric

Multiply	By	To Obtain
Inches	25.40	Millimeters
Inches	2.54	Centimeters
Feet (ft)	0.3048	Meters
Fathoms	1.829	Meters
Miles (mi)	1.609	Kilometers
Nautical miles (nmi)	1.852	Kilometers
Square feet (ft^2)	0.0929	Square meters
Acres	0.4047	Hectares
Square miles (mi^2)	2.590	Square kilometers
Gallons (gal)	3.785	Liters
Cubic feet (ft^3)	0.02831	Cubic meters
Acre-feet	1233.0	Cubic meters
Ounces (oz)	28.35	Grams
Pounds (lb)	0.4536	Kilograms
Short tons (ton)	0.9072	Metric tons
British thermal units (BTU)	0.2520	Kilocalories
Pounds per square inch-g	0.0689	bargs
Fahrenheit degrees	0.5556 (°F –32)	Celsius degrees

1.0 INTRODUCTION

This Environmental Analysis (EA) is submitted together with the Deepwater Port Act (DWPA) Application to United States Coast Guard (USCG) and the Maritime Administration (MARAD) and the Application for a Lease of State Lands to The California State Lands Commission (CSLC), respectively. The EA has been prepared to assist the lead federal and state regulatory agencies with their responsibility to conduct an independent, comprehensive environmental review of the Project (described in Section 1.1) pursuant to the guidelines of the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). The review also must satisfy the requirements of the DWPA. In general, the EA is organized in the format of an Environmental Impact Report (EIR) following CEQA. This format has been augmented to ensure that NEPA and DWPA requirements are met. Appendix A-1 summarizes the requirements under the DWPA and indicates the section of the EA that contains information necessary to meet these requirements.

1.1 PROPOSED PROJECT

BHP Billiton LNG International Inc. (BHPB) is proposing to construct Cabrillo Port, a new offshore liquefied natural gas (LNG) importation terminal off the coast of Ventura County, California. The facility consists of a floating storage and regasification unit (FSRU) connected to a new subsea send out pipeline that will tie-in to existing onshore natural gas transmission systems operated by Southern California Gas Company (SoCalGas). This pipeline will be expanded by SoCalGas to accommodate the additional supply. The Cabrillo Port will be referred to as the Project in the remainder of this EA. The FSRU is a ship-shaped, double-sided, double-bottom LNG storage and regasification vessel that will be 286 meters long and 65 meters wide, and will displace approximately 190,000 dead weight metric tons (dwt). DWT is a nautical term used to describe the amount of cargo, fuels, water, stores, and crew that a vessel can carry when fully loaded.

The FSRU will be moored to the sea bed by a fixed, turret-style mooring point. The Project requires the use of a single new 30-inch-diameter subsea send out pipeline transiting from the FSRU to an onshore metering and custody transfer point, and connecting the Project to the existing gas transmission system of SoCalGas. Figure 1.0-1 illustrates these components. The FSRU and its mooring point will be located 13.9 statute miles offshore in waters about 2,900 feet deep. The pipeline will make landfall beneath Ormond Beach north of the existing Ormond Beach power generating station, where the Project pipeline will connect with the SoCalGas system. The landfall will be at an existing SoCalGas facility. The SoCalGas pipeline expansion will run from this landfall approximately 12 miles along an existing electrical power and gas pipeline right of way to one of SoCalGas's main natural gas delivery lines.

The FSRU will receive shipments of LNG from natural gas fields in the Pacific Basin, which will be regasifed on board. The FSRU can regasify up to a maximum capacity of 1.5 billion cubic feet per day (Bcf/d), with a normal rate between 0.6 and 0.9 Bcf/d. FSRU operations are anticipated to commence in calendar year 2008.

1.2 ORGANIZATION OF DOCUMENT

The EA is organized as follows:

- Chapter 1 (this chapter) introduces the Project.
- Chapter 2 describes the Project Purpose and Need.
- Chapter 3 is the Project Description. The Project Description includes the proposed facilities, construction procedures, operations, future plans and subsequent actions, decommissioning, and the regulatory permit and approval process.
- Chapter 4 discusses alternative actions to the Project, including the No-Action Alternative, or no action.
- Chapter 5 describes the environmental setting, impacts, and mitigation measures for each environmental resource category.

Appendix A-1 summarizes the requirements of the DWPA, and identifies those sections of the EA that are responsive to the requirements. Certain engineering, design, and resource-specific information also are provided in Appendices A-2 through A-7.

Figure 1.0-1. Profile of Facilities for The Project

2.0 PURPOSE AND NEED

The Secretary of Transportation must decide whether to license the Cabrillo Port Project. The purpose for the Secretary's action on the license application is to carry out the intent of the Deepwater Port Act, which is to:

- "authorize and regulate the location, ownership, construction, and operation of deepwater ports in waters beyond the territorial limits of the United States";
- "provide for the protection of the marine and coastal environment to prevent or minimize any adverse impact which might occur as a consequence of the development of such ports";
- "protect the interests of the United States and those of adjacent coastal States in the location, construction, and operation of deepwater ports";
- "protect the rights and responsibilities of States and communities to regulate growth, determine land use, and otherwise protect the environment in accordance with law";
- "promote the construction and operation of deepwater ports as a safe and effective means of importing oil and natural gas into the United States and transporting oil and natural gas from the outer continental shelf while minimizing tanker traffic and the risks attendant thereto";
- "promote oil and natural gas production on the outer continental shelf by affording an economic and safe means of transportation of outer continental shelf oil and natural gas to the United States mainland."[1]

The California State Lands Commission must decide whether to grant a lease of State Lands for the Project pipeline and the landfall. This section describes the purpose and need for the Project in this context, and serves as screening criteria for the adequacy of Project alternatives (Section 4.0).

2.1 NEED FOR NATURAL GAS

Clean-burning natural gas continues to be the fuel of choice for new power generation in the United States and its use in California is central to the achievement of air quality goals. Most fuel oil-fired power plants in southern California were converted to natural gas by the 1980s in

[1] 33 U.S.C. 1501(a) (2002)

response to clean air initiatives. In 2001, approximately 40 percent of total natural gas use in California was for generation of electric power, followed by industrial (28 percent), residential (21 percent), and commercial uses (10 percent). The increase in the use of natural gas is due in part to the efficiency gains of new technology, lower initial investment costs, relative ease of siting new plants, and lower pollutant emissions.

The Energy Information Administration (EIA) projects that natural gas demand in the United States will rise by 53 percent from 2000 to 2025—from 22.83 to 35 trillion cubic feet (tcf). Comments presented to the Federal Energy Regulatory Commission (FERC) at an October 2002 Natural Gas Markets Conference to reexamine existing policy in light of changes in the gas industry (Docket No. PL02-9-000) (October Conference) indicate that natural gas production in traditional supply regions—including California, the Permian Basin, the Anadarko Basin, the San Juan Basin, and the Western Canada Basins-are in decline. Moreover, during 2000 and 2001, natural gas prices reached record highs. These high natural gas costs contributed to the spikes in California electricity prices and the lack of a greater diversity of gas supplies exacerbated the situation. Recognizing the importance of a diverse supply portfolio, a number of participants at the October 2002 Conference noted that imported LNG will play an increasingly significant role in helping to meet gas supply demands in the U.S. and will help enhance the reliability and security of supply in U.S. markets. As reflected in the recent amendment to the Deepwater Port Act concerning offshore LNG facilities, as well as in FERC's newly articulated policy governing land-based LNG terminals, the Federal government recognizes the potential for LNG imports to become a key supply source in the United States over the next 10 years. In this regard, in *Hackberry LNG Terminal, L.L.C.*, 101 FERC 61,294 (2002), FERC announced its intent to adopt a "less intrusive degree of regulation" over LNG import facilities in an effort to encourage development of these facilities and thereby promote greater gas-on-gas competition.

The current lack of LNG transport has led to the stranding of abundant natural gas in many producing areas of the world until delivery systems can be developed. Compared to other fossil fuels, substantially fewer risks are associated with storage and transport of LNG. Its characteristics are far different from those of oil or Liquefied Petroleum Gas (LPG). In the unlikely event of a release, the LNG quickly converts to methane and dissipates in the air. Methane is not an ozone or smog precursor and has not been identified as a criteria pollutant by either the U.S. Environmental Protection Agency (USEPA) or the California Air Resources Board.

2.2 PROJECT NEED

The Project will address important environmental and economic needs in Southern California. California currently imports approximately 85 percent of its natural gas supply. The Project will deliver natural gas from the Pacific Basin into the California market. The facility's natural gas supply will add a secure and stable source to the other existing sources of natural gas. The Project will provide additional natural gas supply flexibility, energy supply diversity, natural gas supply competition, and natural gas supply security. Natural gas imported through Cabrillo Port will be delivered into existing transportation, storage, and delivery systems.

The Project is required to meet growth demands in the natural gas local distribution market and to meet the increased demand for natural gas-fired electric generation. Furthermore, natural gas is increasingly used as a fuel for transportation. In particular, natural gas vehicles (NGVs) are the first to be certified to meet California's low-emission vehicle standards to enhance the area's air quality, including the strict "ultra low" and "super ultra low" emission standards.

While natural gas in general is already considered a clean fuel, natural gas derived from LNG generally is even cleaner and exceeds domestic natural gas specifications. It has greater methane content and lower concentrations of other hydrocarbon components and contaminants. The liquefaction process removes most sulfur, nitrogen, and water as well as ethane, propane, and heavier hydrocarbons. The natural gas delivered by the Project will meet all California regulatory specifications for pipeline natural gas.

3.0 PROJECT DESCRIPTION

3.1 INTRODUCTION

This chapter describes the Project to a level of detail required for subsequent environmental analysis in the EA. Other, more detailed, information regarding design and safety are included either as appendices to this EA or as separate exhibits of the Application for a Deepwater Port License. The more detailed descriptions of project components are cited where relevant.

The Project Description is divided into the following general categories:

- ***Liquefied Natural Gas and Natural Gas*** explains some of the attributes of liquefied natural gas and natural gas.
- ***Project Facilities*** describes the FSRU, its mooring, the subsea send out pipeline, and the onshore facility.
- ***Land Requirements*** addresses the offshore and onshore rights-of-way required by the Project.
- ***Construction Procedures*** discusses the type and intensity of construction planned for the Project.
- ***Operation and Maintenance*** includes operations, maintenance, frequency of deliveries, testing, safety, and other aspects of long-term operation of the Project.
- ***Future Plans*** describes any planned or anticipated expansion or modification of the facility and any necessary subsequent activities. No expansion or modification of storage or regasification capacity is proposed.
- ***Abandonment*** describes the design life of the Project and actions proposed at the time of decommissioning.
- ***Permits and Approvals*** identify the regulatory requirements that must be complied with prior to construction and operation. This section also provides a list of responsible and permitting agencies to be consulted as part of the NEPA/CEQA environmental review of the Project.
- ***Subsequent Related Projects*** discusses whether any related project may occur as a result of the approval of this Project. If the Project is approved, the addition of a new receipt point for the natural gas into the SoCalGas system will be required; BHBP would compensate SoCalGas to design/engineer, permit, maintain, and operate this receipt point. Additionally, in order to accommodate these new volumes, SoCalGas will also loop an existing pipeline and construct certain additional ancillary facilities. SoCalGas

must obtain approval from the California Public Utilities Commission (CPUC) for this modification to their system, and the CPUC will conduct a CEQA review at that time.

The Project has been designed to avoid or minimize environmental impacts whenever practical. In addition, proposed mitigation conditions have been incorporated into the Project Description or are identified in the discussion of environmental impacts (Section 5). These measures are described throughout the EA and are highlighted in the discussion of project alternatives in Chapter 4.

3.2 LIQUEFIED NATURAL GAS AND NATURAL GAS

Natural gas is used throughout the United States as a fuel for industrial and domestic uses, ranging from electric power generation through residential gas heating and cooking. Natural gas as distributed in the United States is primarily composed of methane. Other components of typical natural gas include heavier hydrocarbons, such as ethane and propane, as well as nitrogen, oxygen, carbon dioxide (CO_2), sulfur compounds, and water. Natural gas can burn only when mixed in its flammability range, between 5 and 15 percent natural gas in air, and if an ignition source is present. Unconfined natural gas cannot explode.

LNG is natural gas that has been cooled below its atmospheric boiling point (approximately -260^{o}F), and condensed to a liquid. The resultant LNG volume is approximately 1/600th of the volume occupied by the equivalent mass of natural gas. LNG is an odorless, non-toxic clear liquid with a density less than half that of water. The liquefaction process removes materials that condense or solidify at temperatures above the boiling point of methane, thus increasing the percentage of methane. This methane-rich natural gas is cleaner burning than typical natural gas, and typical natural gas is recognized as the cleanest burning of the fossil fuels. LNG does not burn, but the methane-rich natural gas vapors from LNG can burn if mixed with air to the flammability range and ignited.

LNG is a " cryogen” or “cryogenic liquid" with a very low atmospheric boiling point. When stored, the low LNG temperature is maintained by boil-off of natural gas and by insulation. LNG at atmospheric pressure will remain at approximately -260 ^{o}F as long as both liquid and gas are present at atmospheric pressure. No refrigeration by mechanical means is required.

The rate of natural gas boil-off depends on how much heat is transferred to the LNG in the storage tank. LNG is Typically stored in a “Moss tank”. The insulation of the Moss tank is the principal control of heat transfer to the LNG and therefore of the natural gas boil-off rate, and is designed for a boil-off rate of 0.12 percent per day under normal ambient conditions. The natural gas that boils off is recovered and used as fuel for FSRU electric power generation systems, or can be exported via pipeline as described under “LNG Regasification” below.

Storing natural gas in a condensed form allows it to be economically shipped as a bulk liquid, rather than as a compressed gas. The ability to convert natural gas into LNG and then ship it via ocean-going LNG carrier allows gas from fields that otherwise would be stranded, or not able to be economically produced, to be brought to markets throughout the world. For example, once the proposed Project is operational, gas reserves throughout the Pacific Basin can be produced, the natural gas then liquefied, and LNG transported to the FSRU via LNG carriers for use in the California and western states markets.

LNG has been produced throughout the world, including the United States, in association with "peak shaving" gas plants. These peak shaving plants produce LNG when excess natural gas is available, then regasify it and put it back into the natural gas transmission system when demand and price for natural gas in the local market is high. LNG is routinely shipped via LNG carriers throughout the world, including LNG exports from the United States and LNG imports into the United States.

3.3 PROJECT FACILITIES

The proposed Project facilities consist of a new offshore FSRU connected to a new 30-inch diameter, concrete-coated subsea send out pipeline that will interconnect with the existing onshore natural gas distribution system of SoCalGas. SoCalGas will construct a 12-mile connection line from the Project tie-in to their main delivery line located near the 101 Freeway. The Project will have a capability of regasifying up to a maximum capacity of 1.0 Bcf/day, with a normal rate of between 0.6 Bcf/day and 0.9 Bcf/day. The connection from the FSRU to the subsea send out pipeline will consist of a fixed, turret-style mooring point; three flexible 16-inch diameter riser pipes; and a pipeline end manifold (PLEM) on the sea bed. The subsea pipeline will run from the PLEM, through a buried shore crossing, and onshore to the tie-in point. Figure 1.0-1 shows the general profile of the proposed facilities; each facility is described in more detail below. Figure 3.3-1 presents the southern California coastal regional setting of the proposed Project location. Figure 3.3-2 illustrates the onshore and offshore Project setting from Ventura and Ormond Beach south into the Pacific Ocean beyond the San Pedro Channel. Figure 3.3-3 illustrates the onshore and offshore Project setting from the FSRU mooring point to the onshore tie-in point with SoCalGas facilities. Figure 3.3-4 presents the nearshore and onshore portion of the Project facilities superimposed over an aerial photograph of the onshore site vicinity. Each Project component is described in the following subsections.

3.3.1 FSRU

The FSRU will receive, store, and regasify LNG. Each of these operating functions and the associated equipment are described below. Detailed plans, specifications, and other information for various systems and equipment that are provided as appendices are noted in the text. Since the FSRU is part ship, part storage tank, and part regasification unit, three separate and overlapping sets of design standards, guidance, and regulations must be satisfied. The vessel portion of the FSRU is subject to marine codes, the LNG storage tanks are subject to LNG storage and transfer rules, and the LNG regasification and send out processes are subject to process standards and codes.

The FSRU is a ship-shaped, double-sided, double-bottom new LNG storage and regasification vessel. Note that FSRU dimensions and capacities are presented in metric units, as vessel design is traditionally performed in metric units. The FSRU will be approximately 286 meters (938 feet) long, 65 meters (213 feet) wide and 45 meters (148 feet) in height (water line to the top of the LNG tanks), with a displacement of approximately 190,000 dead weight tons (dwt) (subject to weight control measures during the construction process). For comparison, most LNG tankers are approximately 100,000 dwt, while very large crude oil carriers (supertankers) are in excess of 400,000 dwt. Figure 3.3-5 presents major features of the FSRU.

The FSRU is designed to be moored to a single, turret-style mooring point in water depths greater than 66 feet. The Project FSRU will be moored at a depth of about 2,900 feet. The bow of the FSRU will be moored, and the aft will be free to circle (weather vane) about the mooring point in accordance with wind, wave, and current conditions.

LNG Receiving

The LNG receiving system includes LNG carrier mooring systems, loading arms and shutdown systems. LNG carriers will deliver LNG to the FSRU. Figure 3.3-6 contains a plan view of the FSRU with a moored LNG carrier alongside. The proposed mooring arrangement has been designed based on experience from similar operations. Hydrodynamic analyses were performed to calculate relative motion at the location of the loading arm, tension in the mooring lines, and forces in the fenders. The mooring line arrangement as illustrated in Figure 3.3-6 is based on these analyses.

Floating fenders will be deployed along the side of the FSRU to prevent bumping by the LNG carrier during the berthing and LNG transfer. Fenders are bumper-type devices that maintain safe spacing between adjacent ships. Detailed site-specific simulation of docking conditions will determine final fender type and redundancy requirements. Redundancy is designed into all critical FSRU systems, allowing uninterrupted operation when equipment is out of service for maintenance, inspection, or repair. Redundant fenders provide for adequate protection between the FSRU and the LNG carrier in the event of loss of one or more of the fenders. Current fender designs include nine Balmoral Type 30/40, or equivalent, foam filled floating fenders on either side of the FSRU. The fenders will be grouped, including three pairs strategically located along the ship side, and a single fender at both the forward and aft positions. The paired fender configuration is for safety purposes, as it allows a fender to be accidentally damaged without significant consequences to the FSRU. The specific fender plan may change as design progresses but will maintain these concepts. Figure 3.3-7 shows fenders in use between adjacent ships during ship-to-ship berthing.

The FSRU will be equipped with loading arms on the starboard side; loading arms may also be added to the port side. The starboard side will have four arms; the port side will have space for the addition of three loading arms. All seven loading arms will be identical 16-inch-diameter marine loading arms. The loading arms will be located approximately midway length-wise along the FSRU. On the starboard side, three of the four loading arms will be for the receipt of LNG. The fourth arm will be for return flow of natural gas vapor displaced from the FSRU. On the port side, two loading arms could be added and used for LNG receipt, and one could be added and used for return of natural gas vapors. To accommodate movement between the LNG carrier and the FSRU during LNG transfers, the arms have the following allowable range of motion:

- Longitudinal: ± 3 meters (10 feet);
- Vertical: ± 3 to 4.5 meters (10 to 15 feet); and
- Lateral: ± 3 to 4 meters (10 to 13 feet).

The loading arms are designed with redundant valves and emergency shutdown (ESD) systems.

The total LNG transfer rate, through the starboard side loading arms, will be approximately 80,000 gallons per minute (gpm), equivalent to 2,740 tons per hour (tph). Each LNG carrier berthing, unloading, and de-berthing event will last approximately 20 hours and will occur approximately three times per week.

The storage and handling of a cryogenic material such as LNG requires extensive safety systems to ensure operational efficiency. Tank overflows are unlikely due to the integrated safety and control systems in the LNG tanks. Manufacturer descriptions for the fail-safe shut-off valves at the loading area are included in Appendix A-2.

LNG Storage

The FSRU will store LNG in three Moss-type spherical tanks. This tank design is the most widely used in marine LNG transport because of its simplicity, relative ease of design and robust characteristics. The tanks will be designed and built in accordance with the International Maritime Organization (IMO) International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk, also known as the International Gas Carrier (IGC) Code of 1993. This code generally is referred to as IMO IGC Code 1993. Each Moss tank will have a 56-meter diameter and a LNG storage capacity of 91,000 cubic meters (m^3). The total FSRU LNG storage capacity will be 273,000 m^3. The internal tank shell will be aluminum, surrounded by layers of insulating material and clad in an external steel shell. Each Moss spherical tank will be supported on a steel skirt ring that is braced inside the double hull of the vessel. Each Moss tank will be located in a separate cargo hold, with the tank skirt mounted directly on the foundation deck.

The spherical design of the Moss tank reduces internal wave forces that can build up and cause damage in non-symmetrical tanks. The design also allows Moss tanks to be used without any filling restrictions for loading and unloading operations on the open seas. Filling restrictions are used when necessary to limit tank inventories to near full or near empty, as internal wave forces are most severe at intermediate fill levels. LNG carriers with other tank designs successfully operate with filling restrictions. Carriers with non-spherical tanks and filling restrictions do not conduct loading or unloading operations on the open seas. Their cargo tanks are near full enroute to a LNG receiving terminal, and are near empty on their return trips after offloading the LNG.

The FSRU operation will involve continuous fill level changes as LNG is received and natural gas is sent out. The dynamics of internal wave forces at various fill volumes have been studied as part of the design of the FSRU storage tanks. The tanks are designed to withstand design internal wave forces and stress from long-term internal wave action.

The entire internal and external shells of Moss-type tanks can be easily inspected and repaired if necessary. Membrane-lined tank systems, in contrast, require significant downtime for access and repair. The normal fatigue-based life expectancy of a Moss tank is about 100 years. A diagram of a typical FSRU storage tank is presented in Figure 3.3-8. Specifications for the LNG storage tanks are provided in Appendix A-3. The tanks are designed in accordance with Type B tank principles with a “leak-before-failure” philosophy with a 15-day lag designed between when a leak may be detected and when a tank failure would occur. This built-in time buffer allows for a leak to be assessed and for actions to be taken to remedy the situation. For example, LNG in the affected tank could be transferred out to the other tanks, and the affected tank removed from service for repairs.

Although the normal tank operating pressure is approximately atmospheric, the tanks will be designed for up to approximately 30 pounds per square inch, gauge [psig] internal pressure. This design pressure allows the tanks to be operated as a closed system, containing boiled-off natural gas vapors for extended periods. The design pressure also allows the tanks to be emptied using pressure to force out the contents, rather than needing to pump out the contents.

No mechanical means of refrigeration are required. The insulation on the FSRU LNG tanks will be designed to allow a boil-off of 0.12 percent per day under normal ambient conditions. The boiled-off natural gas will be sent out through the natural gas send out line, or recovered and used as fuel for FSRU electric power generation as described in more detail below.

LNG Regasification

The process area on the foredeck portion of the FSRU will include the equipment necessary to regasify the LNG, that is, converting the LNG back into natural gas. The regasification process will include LNG pumps, LNG booster pumps, and vaporizers. Specifications and other design details for the submerged combustion vaporizers (SCVs) and other re-gasification plant equipment are included in Appendix A-4.

The LNG pumps will transfer LNG from the Moss tanks to the booster pumps located in the process area. There will be nine in-tank submerged-type LNG pumps, three for each LNG tank. The LNG pumps will have a capacity to transfer up to 13,000 gpm. The number and capacities of the pumps are another example of redundant design. An individual LNG pump will be able to be taken out of service for maintenance without interrupting natural gas send out.

Up to six LNG booster pumps will be located in the process area. These four-stage centrifugal pumps will increase the LNG pressure up to approximately 1,500 pounds per square inch gauge pressure (psig). These booster pumps will discharge directly to the vaporizer inlet manifold.

The vaporization portion of the process will re-gasify the LNG into natural gas. The process will consist of eight SCVs. Each will have a maximum capacity of 198 short tons of LNG vaporized per hour (short tph). The SCVs will heat the LNG resulting in natural gas at a temperature of 41 ^{o}F and a pressure of 1,500 psig. No additional compression of the natural gas will be required. The LNG will be pumped, as liquid, up to the natural gas send out pressure and maintained at that pressure through the vaporization process.

Combustion of natural gas will provide the SCV process with heat for regasification. The SCV process will be thermally stabilized by submersion in a water bath. The LNG and natural gas flow will be contained within process piping submerged in the water bath. Neither LNG nor natural gas will be directly released into the water bath, but combustion exhaust gas will bubble through the water bath. The water bath will provide stable heat transfer to the LNG and natural gas, with the water bath cooled as the natural gas absorbs heat from it. The normal regasification capacity will be between 579 and 821 short tph, and the maximum regasification capacity will be 1,450 tph. The quality, temperature, and pressure of regasified natural gas will be suitable for send out and delivery into the receiving natural gas transmission system in California.

No circulating seawater will be required for the SCV process; the water bath and excess freshwater are generated from condensation of atmospheric moisture. As described in the alternatives analysis (Section 4), alternate technology for regasification using seawater as the heat exchange medium would require up to 50 million gallons per day (mgd) of seawater pumped from the ocean, cooled by the process, and discharged as a plume of cold water back to the ocean. The potential environmental impacts of this technology led to the selection of the SCV process, thus avoiding these potentially adverse consequences.

The process to convert natural gas to LNG removes many impurities normally found in natural gas, such as sulfur compounds, nitrogen, water, oxygen, CO_2, ethane, and heavier hydrocarbons. Table 3-1 summarizes LNG compositions that could be delivered to the offshore terminal.

Table 3-1. Composition of Natural Gas from LNG

Source	**Bintulu (Malaysia)**	**North West Shelf (Australia)**	**Badak (Indonesia)**	**Australia Lean Gas**
Sampling Location	(Delivered in Japan)	(Delivered at Everett)	(Delivered in Japan)	Estimate
Methane	89.4200	87.8220	90.3600	99.5108
Ethane	5.4000	8.3040	6.1700	0.1130
Propane	3.4200	2.9820	2.5600	0.0113
Isobutane	0.8200	0.4000	0.4500	0.0091
Normal Butane	0.7400	0.4750	0.4300	0.0068
Isopentane	0.0100	0.0000	0.0100	0.0000
Normal Pentane	0.0000	0.0000		0.0006
Nitrogen	0.2000	0.0140	0.0200	0.0056
Oxygen				
Carbon Dioxide				0.3428
Total (mol %)	100.0100	99.9970	100.0000	100.0000

Natural Gas Send Out

The process area on the foredeck of the FSRU will include the natural gas send out equipment, including metering equipment. The only compression equipment is for boil-off gas (BOG) management, and involves two sets of compressors. To meet the FSRU operating requirements, the BOG compressor plant requires four compressors, each of capacity 8,000 kilograms per hour (kg/h): one high discharge pressure compressor plus three low discharge pressure compressors.

In practice, due to machine availability, this requirement has been configured as three low pressure (LP) compressors, which boost gas from storage tanks up to fuel gas pressure of 4.5 barg (65.3 psig), and one high pressure (HP) booster compressor, which boosts gas from fuel gas pressure up to 81 barg (1,174.5 psig).

In normal operation, one LP compressor will operate to compress the BOG into the fuel gas system or reinject it into the LNG booster pump suction. The second LP compressor will be required to operate at peak BOG rates during loading. The low pressure/high pressure (LP/HP) compressor combination will normally only operate if the FSRU is shutdown and there is no fuel requirement.

The LP/HP compressor combination will route BOG directly into the natural gas send-out line when there is no use for LP fuel gas (during shutdown). The discharge pressure of the HP BOG compressor is set at 80 barg (1,160 psig); this is less than the maximum operating pressure of the pipeline, as pipeline pressure will be reduced when the FSRU is not exporting significant quantities of gas.

By design, the natural gas sent from the FSRU will be metered and will be of a quality, pressure, and temperature to eliminate the need for any subsequent onshore process or compression facilities, with the exception of adding an odorant. The normal gas send out capacity will be 579 to 821 tph. The maximum gas send out capacity with the FSRU as designed will be 1,450 tph.

Fire Protection Systems

The primary protection and fire-fighting philosophy on the FSRU is to avoid fires through the use of preventive measures. In the event of a fire, the following fixed protection facilities will prevent further escalation of the fire:

- A main seawater deluge system—A system based on seawater will be installed to cool exposed surfaces in the cargo, deck, and process areas in the event of a fire emergency. The system will be dimensioned and arranged with hose stations and monitors located in accordance with IMO IGC Code 1993 requirements for coverage of horizontal and vertical surfaces. The deluge hydrant system must also be pressurized according to the IGC requirements. Pressurized hydrant systems typically maintain pressure by circulation of seawater, with some continuous discharge and replenishment of the circulating water. The FSRU is expected to generate excess freshwater in the submerged combustion vaporization process described previously, and as such may circulate and discharge freshwater from the deluge hydrant system.
- A foam system—A fire-fighting-foam system will be arranged for the deck and process areas. The dimensions and arrangement of fire-fighting systems throughout the cargo and process areas will comply with the IMO IGC Code 1993.
- Carbon dioxide systems—CO_2 fire suppression systems will be arranged for machinery spaces, paint lockers and all flammable materials storage areas. The dimensions and arrangement of CO_2 fire suppression systems will comply with the IMO IGC Code 1993.

A detailed layout of each of these fire protection systems, showing the location of fire water pumps, piping, hydrants, hose reels, foam systems, CO_2 systems, and auxiliary or appurtenant service facilities, is included in Appendix A-5, FSRU Design Drawings.

Hazard Detection and Emergency Shutdown Systems

The overall layout and general arrangement of the FSRU has been designed based on safety considerations. The general design concept separates the process area from the accommodation area. Likewise, the LNG storage tanks, mooring, and risers are separated from the process area. The outer tank shell of the forward tank (adjacent to the process area) is fitted with an explosion-proof cover to protect the tank facing the process area. Personnel will be able to evacuate to lifeboat stations, located aft, from all parts of the FSRU.

The FSRU will be equipped and designed to provide a high level of protection to the personnel present, the unit itself, and the environment against the effects of an uncontrolled release of hydrocarbons or other process gases.

The safety systems will include the following:

- Emergency shutdown (ESD) on two levels—The pneumatically operated trip system based on a pipe loop will extend throughout the LNG storage and process area. Thermal fuse plugs which detect heat from a fire and manual release valves will be located at strategic positions on the pneumatic pipe loop, including tank domes, loading arm areas, and the process area. This pneumatically operated trip system will initiate an ESD-2 through the electronic fire and gas panel. An emergency shutdown will be manually activated from the control room on either a berthed LNG carrier or the FSRU. The two ESD levels are ESD-1 and ESD-2. ESD 1 means the entire system is shutdown, including pumps and ESD valves on a berthed LNG carrier. ESD 2 also triggers the loading arm release valves and mooring line hooks, and initiates departure of the LNG carrier.
- Emergency depressurizing and venting system—The FSRU will be equipped with a cold stack that will be used only in the event of an emergency that requires venting natural gas vapors. The cold stack will be provided with an electric heating system to vaporize any emergency LNG releases. The cold stack, if used, will discharge natural gas to the atmosphere, without a pilot light or other device to initiate combustion. The cold stack height and diameter will be designed to safely disperse the natural gas, considering the presence of the FSRU and an adjacent LNG carrier. The cold stack height, pending final design, will be approximately 250 feet above the water line, and approximately 80 feet above the top of the storage tanks, elevated personnel walkway and elevated piping along the tops of the tanks.

- Nitrogen, for inert gas purging, will be generated on board the FSRU, using a process that separates nitrogen from the air.

- Gas detection systems—The FSRU will be equipped with a stationary gas detection system. The gas detection system will consist of continuously operating catalytic type detectors and infrared line of site detectors that are connected to the FSRU's electronic Fire & Gas panel. The gas detection system will sound audible alarms as well as initiating the shutdown of appropriate equipment and systems, dependent upon the logic within the electronic Fire and Gas panel. Gas detection will be provided for the regasification plant, other deck areas as well as machinery spaces where high-pressure gas is piped and the ventilation air inlets to safe spaces including the accommodation. Specific layouts of the hazard detection and ESD systems are presented in Appendix A-4, Preliminary Electrical Hazardous Area Classification drawings, and Appendix A-5, FSRU Design Drawings.

Spill Containment

Primary containment, the storage tanks, has been described previously. Secondary containment will be designed in areas with a greater risk of LNG release, such as the loading arm area. Secondary containment for LNG releases has two purposes, to safely contain any LNG that escapes from primary containment, and to protect the FSRU from potential damage due to direct exposure to cryogenic temperatures. Spill containment will be designed in accordance with the codes and standards applicable to LNG carriers and terminals, described below, including Spill Containment and Countermeasure Plan (SPCC), required for Deepwater Ports under 40CFR 112.1(a).

Fuel Gas System, Power Generation, and Utilities

A utility area near the stern of the FSRU, below the crew quarters, will include the onboard electric power generation equipment. Three natural gas-fired generator sets and one dual fuel diesel/gas generating set (emergency duty) will generate the onboard electric power. Each of the three primary units will have power output of 7,400 kilowatts (kW) at 6.6 kilovolts (kV), for a total power plant generating capacity of approximately 28 megawatts (MW). The dual fuel unit used for emergency duty will have a power output of 5,700 kW at 6.6 kilovolts. A diesel fuel unit used for emergency duty will have a power output of 4,000 kW at 6.6 kilovolts.

All the required motor control centers, substations, cabling, and lighting systems will be arranged in accordance with applicable regulations and standards (listed below in the discussion of “Engineering, Planning, and Design Approach”) regarding protection, insulation, and general safety. All electrical equipment within gas-dangerous zones will be designed, installed, and supplied with certificates to show that the equipment is intrinsically safe.

A layout of the onboard natural gas distribution system, showing the fuel distribution to the generator sets and SCVs, and other process components, is included in Appendix A-5, FSRU Design Drawings.

Engineering, Planning, and Design Approach

The FSRU has a design life of 25 years that can be extended to 40 years. The technology planned for the FSRU is based on industry-proven designs with extensive historical track records of superior performance. The following principles were the basis for selection of this unit:

- Well proven technology;
- Inherently safe design;
- High reliability and redundancy;
- Simplicity;
- Minimal equipment count;
- Modular design; and
- Ease of maintenance.

The use of existing technology with a long-proven successful track record is the best assurance of successful operation of the FSRU. FSRU process flow diagrams and schematic drawings are included in Appendix A-5, FSRU Design Drawings. Specifications for the LNG storage tanks are provided in Appendix A-3.

Overall safety and protection of life and property will be the foremost consideration and requirement in the facility design. The design work will be based on the IMO IGC Code 1993 and Det Norske Veritas (DNV) gas carrier’s rules for the LNG containment, and the American Petroleum Institute (API) offshore rules for the mooring and marine systems.

The main safety objectives will be:

- Low probability of unplanned incidents;
- High degree of active and passive protection against accidental loads;
- Safe escape and evacuation in case of emergency;

- Protection of the environment; and
- Satisfactory working environment.

The FSRU has been designed in accordance with codes and standards applicable to LNG carriers and terminals as follows:

- DNV rules for classification of ships (liquefied gas carriers);
- IMO IGC Code 1993;
- Industry standards (such as API, American Society of Mechanical Engineers, and the International Organization for Standardization);
- Oil Companies International Marine Forum—Standardization of Manifolds for LNG;
- Society of International Gas Tankers and Terminal Operators (SIGTTO);
- International Convention for Safety of Life at Sea (SOLAS); and
- International Convention of Load Lines;
- American Petroleum Institute Guidelines and Regulations;
- International Electrical Commission Codes & Guidelines;
- American Society of Mechanical Engineers Codes & Guidelines;
- ASME B1.20.1, Pipe Threads, General Purpose;
- ASME B16.5, Pipe Flanges and Flanged Fittings, NPS ½ through 24;
- ASME B16.9, Factory Made Wrought Steel Butt-Welding Fittings;
- ASME B31.3, Process Piping;
- ASME Boiler and Pressure Vessel Code;
  Section V, Non-Destructive Examination
  Section VIII, Rules for the Construction of Pressure Vessels
  Section IX, Welding & Brazing Qualifications
- American Petroleum Institute (API);
- API 610, Centrifugal Pumps for Petroleum, Heavy-duty Chemical, and Gas Industry Services;
- API 618 – Reciprocating Compressors for General Refinery Services;
- API 520 – Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries;
- API 521 – Guide for Pressure Relieving and Depressuring Systems;
- International Electrotechnical Commission (IEC);
- IEC 60034, all relevant Parts, Rotating Electrical;

- IEC 60079-0, Electrical Apparatus for Explosive Gas Atmospheres, General Requirements;
- API RP 14E;
- API RP 2A;
- ASME B31.3;
- ASME B31.4;
- DnV Posmoor;
- API 5LB;
- API RP75;
- API RP 2FPS;
- API RP 14J;
- API RP 2SM.

The standards described below also have been satisfied in the FSRU design.

NFPA 59A, developed by the National Fire Protection Association (NFPA), specifies siting, design, construction, equipment, and fire protection requirements that apply to new LNG facilities and to existing facilities that have been replaced, relocated, or significantly altered. The standard covers design, location, construction, and operation of facilities at any location for the liquefaction and storage of natural gas and for vaporization, transfer, handling, and truck transport of LNG. The LNG storage and LNG process areas of the FSRU are designed to comply with this NFPA standard.

49 Code of Federal Regulations (CFR) Part 193 is under the U.S. Department of Transportation (USDOT) regulations. This rule covers pipeline safety and transportation of natural gas and LNG. Subpart B specifically discusses facility-siting requirements. Although these siting requirements are not directly applicable to the offshore mooring point for the FSRU, they make the proposed location preferable over the Project alternatives.

33 CFR Part 127 is specifically related to waterfront LNG handling facilities. While the FSRU is not a waterfront LNG facility, the LNG transfer equipment will meet USCG requirements. An FSRU Operations Manual and an FSRU Emergency Manual will be prepared and submitted for USCG approval prior to receipt of LNG, in accordance with 33 CFR Part 127.019.

The Seismic Review of LNG Facilities *(NBSIR 84-2833)* is a requirement for onshore LNG facilities, and is not specifically applicable to the floating offshore terminal. Although the Project involves an offshore facility, consideration of seismic concerns and tsunami potential will be considered for the FSRU and its mooring point. DNV issued a review of technical requirements for the FSRU design in July 2001 (DNV report #2001-440-3520). The DNV report identified the standards to which the FSRU and its mooring should be designed. The DNV report states that: "The design is to be documented to survive two main scenarios, which are:

- The 100-year extreme environment event for the vessel moored alone; and
- The maximum operating environment for the vessel moored with a LNG carrier.

The DNV report states that "design documentation should also include the anchoring system covering both the structural and geotechnical strength." Further, the DNV report states that the operator normally specifies the design environment and also supplies the geotechnical data.

The facility design will address the seismic issues as recommended by DNV. In addition to requirements identified by DNV, the potential impacts of the maximum credible earthquake (MCE) will be considered. Design based only on the 100-year window specified by DNV may not capture the potential impacts of the MCE. A seismic analysis will be conducted to assess the potential for impact on the FSRU and its mooring system.

FSRU Vessel Design

The steel monohull FSRU will be designed with bow and stern shape to minimize wave response movements and provide a stable platform for LNG containment, process, and utility systems. The shape will be based on experience gained from previous projects. The hull will also be arranged for safety and convenient berthing and mooring of the LNG carriers.

The hull will be equipped with thrusters, ballast, and bilge equipment. Deck mooring equipment, winches, cranes, walkways, and platforms will also be provided as required for safe and efficient operation. An accommodation deck house with all facilities for a permanent crew of up to 40 persons and a helideck will be fitted at the aft end.

3.3.2 Offshore Turret Mooring Point

The FSRU will be stationed at an offshore mooring point. The single point, turret-style mooring will allow the FSRU to rotate fully, depending on wind, and wave conditions. Figure 3.3-9 is a photograph of the Nkossa II in Angola, which is moored to a single-point turret similar to the one planned for the Project. The mooring point will serve two purposes: to hold the FSRU in position and to connect the FSRU send out gas line to the flexible risers. The mooring position will be fixed using nine cables and associated ocean floor anchor points. The cables and anchor points will be arranged as three groups of three, separated from each other by 120^{o} angles. Anchor points will use drag-in anchors.

The mooring point location was determined from the results of a hazards and routing study completed for the Project. Using existing information, this study identified known marine hazards, pipelines, and other constraints to the location of the mooring point. In addition to marine hazards, the specific mooring location was selected based on distance from shore, distance from existing fixed offshore facilities, and sea floor slope and topography. The resultant mooring point location is at Latitude 33 51.518 N, and Longitude 119 02.015 W, in approximately 2,900 feet of water. This mooring location is 13.9 miles from the nearest shoreline, a point south of Point Mugu in Ventura County, California. The mooring location is also 4.9 miles from the centerline of the nearest shipping lane, 2.8 miles from the Eastern limit of the Pacific Missile Range, and over 18 miles from the edge of the Channel Islands National Marine Sanctuary.

The anchor cables will spread out from the mooring location to anchors located at a radial distance of about 1,200 meters (0.75 mile). Figure 3.3-10 presents the mooring location and anchor radius projected on a depiction of the variable slope of the sea floor. The mooring point, anchor cable spread, and flexible riser configuration are presented in Figure 3.3-11 and in Figure 3.3-12.

3.3.3 Flexible Risers

The natural gas sent out from the FSRU will flow through the turret mooring point and into three 16-inch-diameter flexible risers. These specially designed pipe sections will extend from the mooring turret to the pipeline tie-in on the ocean floor. The flexible risers will be designed for redundancy and operational flexibility. Any individual riser will be able to be shut down and isolated while continuing natural gas send out in the other two. The risers will have sufficient flexibility to allow the mooring turret to move within the design range allowed by the mooring point anchors. The flexible risers will have excess length designed in the form of an “s” curve to allow for flexion and extension. Anchors to prevent the three risers from impacting each other will stabilize the risers and their associated “s” curves.

The flexible risers will be equipped with redundant shut down valves (SDVs) on each end. At the mooring point end of each flexible riser will be two valves in series. From the mooring point, there will be an isolation valve and then an automated safety SDV. Cross connections between the three risers also will have isolation valves. The cross connections will tie-in to each riser between the isolation valve and the SDV.

Similarly, the termination of the flexible risers at the sea floor will include SDVs and cross connections. This equipment is part of the PLEM described below.

The flexible risers and associated valves are depicted in Figure 3.3-13.

3.3.4 Pipeline Ending Manifold (PLEM)

The three 16-inch-diameter risers will connect to a single 30-inch-diameter subsea pipeline through the PLEM. The PLEM will be a prefabricated, skid-mounted unit. Valves on the PLEM will be operated from the FSRU via a hydraulic control cable. In addition to providing the transition between the risers and the subsea pipelines, the PLEM will act to separate the risers and will host several safety SDVs. The PLEM tie-in positions will be designed to maintain separation between the three risers. Figure 3.3-14 presents the PLEM plan diagram. The PLEM will be located on the sea floor at a radius of approximately 170 meters out from the centerline of the mooring location.

Each riser will tie-in to the PLEM via two SDVs in series. The PLEM also will contain one 30-inch-diameter SDV at the tie-in for the subsea pipeline. Both safety SDVs will be hydraulically operated from the FSRU. All SDVs will be designed to fail in the closed position. In the event of loss of the hydraulic control cable, the affected SDV will close. This also is referred to as "fail-safe"; that is, the valves fail in the safe or closed position. The valves will close, and thus natural gas flow will be stopped, in the event of control system failure.

The PLEM also will include a cross connection between each incoming riser section. The cross connections will connect to each riser between that riser's SDVs. Figure 3.3-13 illustrates the riser process flow arrangement.

3.3.5 Subsea Pipeline

The Project includes a single 30-inch-diameter subsea send out pipeline to deliver the natural gas from the FSRU and PLEM to an onshore interconnect with the intrastate natural gas distribution system of SoCalGas. The total length of the pipeline is approximately 21.5 miles. Figure 3.3-15 presents the pipeline right-of-way alignment, with coordinates given for each point where the direction of the alignment changes. Figure 3.3-16 presents an elevation view of the pipeline route. Figure 3.3-17 illustrates the bathymetry along the pipeline route, with mileposts. Figure 3.3-18 depicts the pipeline and its routing through subsea topography, based on currently available bathymetric data. Table 3-2 presents the number of miles of Project pipeline that will occur within Federal offshore waters and state coastal waters along the proposed route in California, and indicates the corresponding pipeline diameter.

Table 3-2. Pipeline Facilities for the Cabrillo Port

Facility	Pipeline Diameter (inches)	Pipeline Length (miles)	Mileposts		Location
			Begin	End	
Subsea pipeline	30	17.0	0.0	17.0	Offshore Ventura County, Federal waters
Subsea pipeline	30	4.1	17.0	21.1	Offshore Ventura County, state coastal waters

The 30-inch-diameter subsea send out pipeline will originate at the PLEM on the ocean floor below the mooring point at approximately Latitude 33 52.20000 N, and Longitude 119 04.01100 W. The pipeline will be routed to shore with three cable crossings en route: the Navy RELI cable, the Navy FOCUS cable, and the Global West Cable. The send out pipeline will not cross any other pipelines. The pipeline will make landfall and terminate at Ormond Beach to the north of the Reliant Ormond Beach Generating Station, owned and operated by Reliant Energy, Inc. Landfall will be at the existing SoCalGas facility (pig launcher) located at approximately Latitude 34 07.97431 N, Longitude 119 09.94167 W.

Figure 3.3-19 presents the landfall location projected over the U.S. Geological Survey topographic map of the area. Figure 3.3-20 presents the landfall location projected over an aerial photograph of the area. The pipeline distance from the PLEM to the mainline valve is approximately 21.5 miles, all but approximately 0.65 miles of it offshore. The send out pipeline will tie-in to SoCalGas facilities on shore at the landfall location. A mainline valve will serve as a separation between Cabrillo Port facilities and SoCalGas facilities, and will serve as an emergency SDV that will automatically close to isolate flow between the send out pipeline and SoCalGas system in the event of an emergency.

The offshore pipeline will be laid on the sea floor in waters deeper than 13 meters, which occur approximately 3,000 feet off shore. The pipeline from the shore out to waters deeper than 13 meters will be buried, in accordance with recent practice for coastal cable projects in California. Burial will be accomplished by using horizontal directional drilling (HDD) technology, from the offshore area to 0.3 miles inland. Trenching will be used for the remaining 0.35 miles to the SoGalGas tie-in.

3.3.6 Onshore Pipeline

The onshore portion of the Project is limited to the pipeline landfall, a tie-in station, and the looping of an existing SoCalGas pipeline. The length of the portion of pipe, from the high tide line on the beach up to the tie-in, will be approximately 0.65 miles. From approximately 3,000 feet offshore to 0.30 miles inland the pipeline will be buried by HDD; the remaining 0.35 miles will be trenched. The pipeline will daylight at the existing SoCalGas facility north of the Ormond Beach Generating Station. The pipeline termination tie-in station will include aboveground facilities within an approximately 200 by 200 foot fenced area. The send out pipeline will tie-in at the terminus of the existing SoCalGas 30” diameter Line 324.

From the SoCalGas tie-in, gas will flow into a new 34" pipeline, to be constructed and owned by SoCalGas, which will parallel the existing SoCalGas Line 324, for approximately 12 miles to the existing SoCalGas facility Center Road Station. From there, SoCalGas can balance gas supplies at their Saugus Junction and Quigley Station facilities. The Maximum Allowable Operating Pressure (MOAP) of the SoCalGas system at the Center Road Station is 773 psig. SoCalGas has indicated that it can accept up to 400 million cubic feet of gas per day (MMCF/day) on this section of its system, and up to 1.0 Bc/d with certain modifications. In order to receive the 1.0 Bc/d of gas some system improvements would be required by SoCalGas as further described below in Section 3.10 of this EA.

3.3.7 Location Maps, Detailed Route Maps, and Plot Plans

The Project location is presented in Figure 3.3-2 and Figure 3.3-3. Figure 3.3-21 is a series of maps superimposed on navigation charts (offshore) and topographic maps (onshore), for the length of the line from the FSRU to the SoCalGas tie-in. Upon completion of the site specific offshore surveys detailed maps presenting bathymetry and subsurface features and anomalies identified from existing navigation charts, bathymetric data, and previous side-scan sonar data from the Project area will be submitted to USCG. BHPB will also submit the configurations for the fencing and aboveground facilities at the landfall location upon completion of design details.

3.4 LAND REQUIREMENTS

3.4.1 FSRU

The FSRU will be permanently moored and surrounded by an exclusion zone. Exclusion zones are designed to protect fixed offshore facilities from impact by wayward vessels and to provide facility security. The radius of the exclusion zone for existing offshore platforms is 500 meters (1,640 feet). BHPB will request a 1.0 nautical mile (1,852 meters) exclusion zone for the FSRU. This exclusion zone will be added to navigation charts, and is to be entered only by LNG carriers bound for the FSRU and service and supply vessels associated with FSRU and LNG carrier operations. A 'Notice to Mariners' will also be published regarding this exclusion zone.

In addition to the exclusion zone, the Captain of the Ports of Los Angeles and Long Beach has temporarily established a security zone around all liquefied hazardous gas tank vessels (which includes LNG carriers) inside 3 nautical miles (3.4 miles) of the Federal breakwater near the Ports of Los Angeles and Long Beach. The FSRU will be more than 3 nautical miles from the breakwater. This security zone requirement would only be applicable to Cabrillo Port LNG carriers if their route took them in close to the breakwater at the Ports of Los Angeles and Long Beach, which is unlikely. Figure 3.4-1 presents the mooring location and exclusion zone, along with existing navigation chart data.

3.4.2 Offshore Pipeline

Typically, a 200-foot-wide right-of-way is set aside, for both the construction and permanent rights-of-way, in all offshore areas in which the pipeline will be laid. Cabrillo Port will seek permission from the operators of any existing pipelines and cables to allow routing of the new send out pipeline near existing facilities. The resulting offshore right-of-way area, based on the 21.1 - mile length and 200-foot width, will be approximately 511 acres. Approximately 412 acres of this right-of-way will be in Federal waters, and approximately 99 acres will be in California state waters. Figure 3.4-2 shows the typical cross section of the offshore right-of-way. The offshore portion of the pipeline will permanently occupy an area of approximately 7 acres, based upon the total offshore pipeline length and the diameter of 30 inches. Table 3-3 shows the area of land that will be affected by the construction and operation of Project onshore and offshore pipeline facilities.

3.4.3 Onshore Pipeline

The 30-inch-diameter send out pipeline will make landfall and terminate at a mainline valve at the existing SoCalGas facility north of the Ormond Beach Generating Station. The Cabrillo Port facilities will require a 50-foot wide permanent right-of-way for the pipeline from the high tide line up to the mainline valve and SoCalGas tie-in (approximately 0.65 miles). This onshore section will use a permanent right-of-way of about 4 acres. In addition to the pipeline right-of-way, the aboveground equipment at the SoCalGas tie-in will permanently occupy a 200-foot by 200-foot area. During construction the on shore land requirements will include a temporary 200-foot by 200-foot (0.9 acres) area for the HDD rig and associated equipment, plus pipeyards and equipment staging areas. The temporary construction area for the HDD and the permanent area for aboveground facilities will occupy the same 0.9-acre space. Once construction is completed, the above ground equipment at the tie-in location will consist of a small maintenance facility. Total land area affected by construction and operation are summarized in Table 3-3.

Table 3-3. **Cabrillo Port Pipeline Facilities**

Facility	Length (miles) Number of Sites	Land Affected during Construction (acres)	Land Affected during Operation (acres)
Subsea Segment	approx. 21.1	approx. 511	approx. 7
Onshore Segment A	approx. 0.65	approx. 4	approx. 4
Extra work areas [1]			
Pipe storage yards[1]			
Contractor office yards[1]			

Note: [1]Area to be determined

3.4.4 Aboveground Facilities

Aboveground facilities included in the Project will be limited to a tie-in facility located near the landfall at the existing SoCalGas pig launching facility. This aboveground valve facility will be located within an approximately 200-foot by 200-foot (0.9-acre) permanent fenced area. The fencing will be an 8-foot high barbed wire fence with intrusion detection or alarm. The facility will include a SDV for the pipeline, a meter station, a pig launcher/receiver, and a gas odorant injection station.

3.5 CONSTRUCTION PROCEDURES

This section describes the construction procedures to be used for the Project. The following discussions identify the type of construction, area of disturbance, number of workers required, and construction schedule.

3.5.1 FSRU

The FSRU will be fabricated outside of the United States by a competent shipbuilding facility with experience in the construction of offshore facilities, LNG carriers and spherical Moss-type LNG containment systems. It will be towed across the Pacific Ocean to the mooring point, a permanent offshore location. The bow of the FSRU will be moored, and the aft will be free to circle about (weather vane) the mooring point in accordance with wind, wave, and current conditions.

The mooring turret will be installed onto the foredeck of the FSRU during FSRU fabrication. Upon arrival, the turret will be tied in to the mooring system anchor cables, and the flexible risers will be connected. After systems are connected, the commissioning activities will begin. Commissioning activities will include hydrostatic testing of export gas systems, and testing of control and shutdown systems, power generation and air pollution control equipment, process pumps and compressors, and other equipment.

3.5.2 Mooring Point

The mooring location was determined using available data. Prior to construction, site-specific surveys and testing will be performed, including an extensive geophysical and geotechnical testing program. Appendix A-6 provides the details of this testing program. The results of the testing will be used to coordinate layout positions of the anchor leg components. This activity is important for optimization of the mooring system, as the mooring legs are designed with relatively precise location relationship requirements between the vessel turret center and anchor legs.

Drag anchors will be placed on the sea bed and positioned to within the design limit requirements. These drag anchors will require using a three-way tensioner system or laying an opposite leg to each of the three anchor leg clusters. The laying of the anchor leg will follow the anchor installation. The leg will be laid within a specific pre-surveyed corridor. All nine anchor legs will be installed and buoyed off accordingly, in anticipation of installation of the FSRU.

Upon arrival of the FSRU, each of the anchor legs will be retrieved to surface vessels for connection. The FSRU will arrive in the field with the mooring turret and anchor pulling equipment pre-installed. Hook-up vessels will make the final connection between the FSRU and the anchor leg, and then lower the leg back to the sea bed.

After all legs are connected to the FSRU, final adjustments will be made by hauling in on each leg, until the correct tension is present in each anchor leg with the vessel in the correct position. After final tensioning adjustment of the anchor legs, all risers will be installed using the pull-in equipment provided on the FSRU turret.

Construction equipment to perform the offshore installation work will consist of typical offshore vessels, such as crane barges, anchor-handling tug supply vessels (AHTS), remote-operated vehicles (ROVs), and survey equipment.

Installation and tie-in to the mooring point is anticipated to require approximately 45 days, using 12-hour workdays. Equipment required during the construction period includes an AHTS up to

15,000 Hp, an AHTS up to 12,000 Hp, two 3,200 Hp supply vessels, and two barges to transport anchors and equipment.

After completion of installation of anchor legs and the risers, a full hydrostatic test will be conducted. During this test, product swivels, piping, and valves will be checked for pressure integrity. A National Pollutant Discharge Elimination System (NPDES) permit will be obtained for pumping the test water from the ocean and then discharging it back to the ocean.

All equipment provided on the turret will be function tested, including lube systems, leak detection systems and electrical, and hydraulic systems. All facility-specific installation aid equipment will be configured for long-time storage stand-by conditions.

3.5.3 Offshore Pipeline

The installation of the offshore portion of the proposed send out pipeline system will follow site-specific pre-installation surveys. The installation sequence will be preparation, HDD, pipe fabrication, non-destructive examination (NDE), coating of completed welds, pipeline lowering, hydrostatic testing, and dewatering the pipe. In addition, offshore construction requires specific techniques for sandbagging and placement of concrete mats where the pipeline crosses existing cables.

The send out pipeline will be permitted as part of a DWPA facility. Maritime Management Services (MMS) and the US Department of Transportation (USDOT) have developed design standards. In addition, the California Coastal Commission (CCC) has reviewed cable and pipeline projects that have beach crossings. Those standards have been considered in the design for these pipelines.

The MMS standards require that the pipeline be lowered 3 feet below the sea floor where water depths are less than 200 feet, except in congested or seismically active areas. In depths greater than 200 feet, the pipeline may be laid directly on the sea floor surface. USDOT requires lowering to the mudline in waters up to 200 feet deep. USDOT has a waiver process and does grant waivers from the lowering requirement in seismically active areas. In the Project vicinity, MMS has recommended burial in water depths less than 13 meters (43 ft). The proposed pipelines will be laid on the sea floor except for the portion deeper than 13 meters and the shore crossing segment. Figure 3.5-1 indicates which sections of the pipeline will be buried and which sections will be laid on the sea bed.

Although offshore construction procedures may vary to meet different construction situations or constraints, typically three different techniques are used depending on water depth and other site-specific conditions: burial, lowering, or laying. Burial includes trenching or HDD. Lowering includes trenching and laying the pipeline in the trench. The open trench is left to be filled in over time by natural sedimentation processes. Laying involves laying the pipeline on the sea floor without trenching or cover. This Project includes only burial or laying; no lowering is proposed.

Crossings

The proposed send out pipeline does not cross any known Federal or state oil and gas leases or pipeline rights-of-way. The pipeline route may cross the Navy FOCUS cable, the Navy RELI cable, and the Global West cable. The cable owners will be notified of the proposed pipeline routing, and their approval of cable crossings will be requested prior to construction. Figure 3.5-2 identifies the routing of known cables. The send out pipeline does not cross any other pipelines.

Positioning of Installation Equipment

Alignment and profile drawings created from the pre-installation surveys will be used to identify and locate the offshore portion of the pipeline right-of-way. The coordinates on the right-of-way will be tracked by accessing orbiting satellites, using Global Positioning System (GPS) equipment installed on board the pipeline installation vessels. This system also will be used for the dynamic positioning systems of construction vessels.

Site Preparation

Preparation of the offshore pipeline right-of-way prior to the arrival of the pipe-laying equipment currently is expected to be limited to locations of cable crossings, and preparation of the exit hole location where HDD will be performed.

Crossings of existing cables will be protected by installing sandbags, concrete mats, and/or "sleepers." Sleepers are fabricated steel pipe supports designed to hold the pipeline off the sea floor while protecting against sagging and abrasion of the pipe walls. ROVs will be used to locate and monitor these cable crossings, especially during installation. Figure 3.5-3 presents a schematic for maintaining a separation between the new pipelines and existing cables that cross on the sea floor.

Preparation of the predetermined HDD exit hole location will be required. The exit hole location will be excavated to provide a low point for accumulation of drill cuttings. The onshore HDD entry location will require a staging area for the drill rig and drill pipe. The sediment to be excavated will be analyzed to determine chemical composition and likelihood of turbidity. Based on these data, final turbidity control measures and sediment disposal options will be determined.

Landfall

The Project will use an HDD boring and trenching to install the 0.65-mile onshore portion of the pipeline. Approximately 0.3 mile of the onshore portion will be included in the HDD alignment that extends across the shoreline out to a water depth of 13 meters. The HDD rig will be located onshore, in a construction work area along the proposed pipeline right of way adjacent to the Reliant Ormond Beach Generating Station at Ormond Beach. Approximately 0.35 mile of the onshore pipeline, from the HDD termination to the SoCalGas tie-in, will be installed using standard pipeline trenching techniques.

The Project will use HDD in lieu of marine-to-shore trenching in order to minimize environmental impacts, including disruption of wetland habitat and beach habitat for endangered shore birds. Typical shoreline crossing HDD involves use of an HDD rig located onshore, with drilling from onshore to a predetermined exit hole in the ocean floor offshore. A receiving barge attends the exit hole location, where there is a transition zone from the HDD arc to the next segment of the pipeline. Figure 3.5-1 indicates which sections of the pipelines will be installed by HDD and which sections will be laid on the sea bed.

Before starting the HDD, survey crews will identify buried utilities at the onshore work site and flag them accordingly. The One-Call system in southern California will be contacted and both SoCalGas and Reliant will be consulted. Figure 3.5-4 is a schematic depicting the construction sequence for the HDD shoreline crossing.

The pipe string for the HDD segment will be pre-welded and laid along the sea floor, along the pipeline right of way beginning near the previously prepared exit hole. The HDD rig will first drill through to the exit hole. The borehole will then be reamed to increase the diameter. During drilling and reaming, the hole is stabilized using drilling mud. Drilling mud is a dense fluid that keeps pressure on the borehole walls to prevent borehole collapse. The drilling mud also lubricates the drill bit and carries drill cuttings away from the bit. The receiving pit at the exit hole location will collect drilling mud as the drill bit emerges from the sediment. After drilling the bore hole, the pipeline either can be pulled from shore through to the exit hole, using barge-mounted pulling equipment, or it can be pulled back from the barge to the onshore drill site, using onshore pull-back equipment. The pulling operation is continuous to minimize the chance of hole collapse.

Trenching will be used to install the pipeline from 0.3 miles inland from the shore to the SoCalGas tie-in. This 0.35 mile trench will be on already disturbed, unvegetated land formerly in industrial use.

Pipeline Installation

Laying of the pipeline will be used outside the 13-meter water depth. In these offshore areas, burial is not required because the Project is within a seismically active region; consequently, the pipe will be laid directly on the sea floor. For this offshore segment, a dynamic position pipe-laying vessel (DPV) will be used to install the pipeline. Figure 3.5-5 is a schematic depicting the construction sequence for laying an offshore pipeline on the sea floor.

Prior to shipment offshore, the joints of pipe to be installed offshore will be coated with fusion-bonded epoxy (FBE) to protect the steel from corrosion. Sacrificial anodes will be added for cathodic protection. Corrosion will occur to any steel surfaces immersed in a common electrolyte such as seawater. Sacrificial anodes prevent corrosion of the pipeline steel by introducing another metal (the anode) that will waste, or be sacrificed. The quantity of pipe joints equipped with anodes and their spacing will be determined by site-specific engineering calculations. Each joint of pipe also will receive concrete weight coating prior to delivery to the lay barge, in order to add weight to the installed pipe. After application of the FBE and weight coating to the pipe joints, the pipe will be loaded and secured onto material barges, and then towed to the location of the lay vessel.

Typically, a lay vessel has several welding stations, an NDE station, and a field joint-coating station. Lay barges use tension machines, which can hold the pipeline in a calculated configuration to prevent overstressing of the pipe. A structure off the stern of the lay vessel, known as a stinger, also will be used as necessary to help support the pipeline as it leaves the barge.

During pipe fabrication on the lay vessel, the ends of the pipe joints will be cleaned, a lineup clamp will align the ends of the pipe joints, and the first welding passes will be made. In the standard pipe-laying mode, once the initial welding passes have been completed in the lineup station, the lay barge will be moved forward, thus incrementally moving the barge beneath the pipe string. The new field joint effectively will be “moved” to the next station in the pipeline assembly line until the entire welding procedure has been completed. The field joint then will pass through the NDE station, where qualified personnel will examine the completed weld to verify its quality. If the weld contains an unacceptable defect, the defect will be removed, repaired, and re-examined.

After completion of the NDE, the field joint will be corrosion coated with a coating system compatible with that applied onshore. The coating of all field welds will be visually inspected and examined with an electronic device to detect coating defects. All coating defects will be repaired prior to the pipe entering the water. Concrete or polyurethane foam also will be applied to the field joint to make the outside diameter of that area flush with the concrete coating, in order to facilitate the passage of the pipeline over support rollers. All welding and coating will be completed in accordance with 49 CFR Part 192 and the current edition of the American Petroleum Institute Standard 1104.

Hydrostatic Testing

Testing of the offshore pipelinesegment will be conducted in accordance with 49 CFR Part 192. During detailed design, BHPB will develop a testing plan that will identify the number and location of test sections. Determination of exact locations of test sections will depend on a number of factors, including pipeline class location, elevation differences along the route, and construction constraints.

Prior to hydrostatic testing, a sizing plate will be installed on a pig and pushed through the pipeline. This plate will verify that the pipeline did not sustain any unforeseen damage during installation. Filtered seawater will be used to propel the sizing plate pig and to fill the pipeline for the hydrostatic test. Test water intake and discharge will comply with all applicable state and Federal discharge regulations. Test water will be drawn only from appropriate and approved sources, including the Pacific Ocean, and will be screened to minimize entrainment of aquatic organisms. After the testing is complete, the water in the pipeline will be discharged with two or more dewatering pigs.

Every reasonable effort will be made to discharge the test water into the source from which it was obtained. BHPB will not chemically treat the hydrostatic test water for sections of the pipeline where the residence time of the water in the pipeline is less than 10 to 14 days. Because that duration is expected to be sufficient for all pipeline segments, no chemical addition is proposed. If a longer residence time is required, only oxygen scavengers and biocides that have been proven to be non-detrimental to the environment will be added to the hydrostatic test water, to limit corrosion and marine growth. Oxygen scavengers will be removed by aeration during discharge, allowing the oxygen in the air to eliminate the scavenging agent. The percentage of biocide will be kept sufficiently small and the residence time in the pipeline kept sufficiently long to render the biocide no longer harmful to sea life upon discharge.

Pipeline Installation Spreads

Pipeline construction will require the use of one deepwater pipe lay spread. It will include a 37,800 horse power (Hp) DPV, ten diesel welding units, and two 3,200 Hp AHTS vessels on a 24-hour basis for forty-five days. There will be two 100-ton capacity diesel cranes and two 35-ton capacity diesel cranes working 8-hour days and four pipe barges needed to transport pipe and material offshore.

The total anticipated work force is approximately 45 workers, consisting of approximately 15% local hires and 85% non-local workers.

3.5.4 Special Offshore Construction Techniques

BHPB selected the proposed pipeline offshore route based on information obtained from review of public records, discussions with installation contractors, and consultation with various regulatory agencies and owners of existing offshore facilities. Sonar and magnetometer equipment will be used during pre-installation surveys to identify various human-made and naturally occurring features within the proposed offshore pipeline right-of-way. When the installation operation approaches an obstacle that is deemed potentially sensitive or hazardous, divers, scanning sonar, underwater marking beacons, or ROVs may be used as required to ensure avoidance of these objects. Placement of all anchors and the anchor for the mooring system will be monitored for accuracy with GPS equipment on board each vessel.

BHPB will not bury the pipeline in waters up to 43 feet deep because of the exemption in the MMS rule and under a requested variance from USDOT standards for seismically active areas. A pipeline on the sea floor has greater freedom of movement, and thus less likelihood of damage from a seismic event, than a buried pipeline. Existing pipelines from offshore oil and gas platforms also are laid on the sea floor in waters less than 43 feet deep. In areas where the pipe is laid on the sea floor, the pipeline engineers will evaluate the need for specific stabilization measures beyond the stabilization that will be achieved by including the proposed concrete coating.

3.5.5 Onshore Pipeline

The onshore pipeline segment is limited to a 0.65-mile segment from the existing SoCalGas facility to the high tide line. 0.3 miles of this segment will be built using HDD as described in the landfall section above. Trenching will be used to install the remaining 0.35 miles of onshore pipeline. No onshore waterbody crossings or wetlands are associated with this short section of onshore pipeline. An approximate 12-mile pipe loop from the SoCalGas facility alongside an existing SoCalGas pipeline will be installed by SoCalGas within a SoCalGas existing right-of-way.

Before the start of onshore pipeline construction, BHPB will finalize the land survey; locate the pipeline centerlines, construction right-of-way, and extra works spaces; and complete land or easement acquisition. HDD will require additional temporary work space. The size of that work space depends on the direction of the pipeline pull (i.e., the location of the pipe section staging and welding).

Site Safety and Access

No excavation would be left uncovered when not being actively worked or monitored by construction crews. Excavations would either be back-filled or covered with steel trench plates prior to completing work on any given work day. If the right of way with trenching crosses public or private roads that must remain open, then trenching and the use of cover plates will be staged to allow at least one lane of traffic to remain in service, or a detour will be provided during the construction period.

Right-of-Way Survey

Land survey crews will mark the boundaries of the construction right-of-way and extra work spaces to show the approved work areas. Any existing utility lines and sensitive resources identified by Federal or state agencies during environmental and archeological surveys will be located and marked to prevent accidental damage during pipeline construction.

Clearing and Grading

Onshore pipeline construction work would begin with a right of way survey, property owner notifications and one-call notification to identify utilities, road crossings, and other uses that may be impacted by the construction. The construction right-of-way and extra work spaces necessary for HDD work space and the right of way required for trenching will be cleared to remove obstructions. Fences will be cut and braced as necessary.

Trenching

Pipeline segments would be pre-staged, double jointed, and laid along the right of way. Due to the relatively short length of the segment (0.35 miles), it is likely the entire segment would be trenched at one time. Topsoil will be staged separately from other trench excavation spoils. Then the double-jointed line sections would be welded together, welds would be inspected and tested, and side boom tractors would lift the pipeline and place it into the trench. The trench would be backfilled, and disturbed landscaping would be repaired or replaced.

Drilling

The pipeline route will be drilled by a HDD rig as described under the shoreline crossing section above.

Hydrostatic Testing

The onshore portion of the pipelines will be hydrostatically pressure tested simultaneously with the offshore pipelines, as described above.

3.5.6 Special Onshore Construction Techniques

Within 10 days of completion of HDD, all remaining trash, debris, surplus materials, and temporary structures will be removed from the right-of-way and disposed of in accordance with applicable Federal, state, and local regulations. All disturbed areas will be finish graded and, as closely as possible, restored to pre-construction contours. BHPB will implement erosion control measures, including site-specific contouring, permanent slope breakers, mulch, and reseeding or sodding as appropriate. The soil erosion control measures will be in accordance with a Soil and Erosion Control Plan, prepared by BHPB and approved by the local soil conservation districts and appropriate state agencies, and BHPB's best management practices (BMPs). Private property, such as fences, gates, and driveways, will be restored to a condition equal to or better than pre-construction condition. The onshore aboveground facilities will include an SDV, meter station, pig launcher/receiver, odorant injection and cathodic protection test stations. Pipeline markers will be located along the right-of-way and installed in accordance with 49 CFR Part 192.

3.5.7 Aboveground Facilities

The aboveground facilities for the landfall and short length of pipeline are limited to the single fenced pipeline tie-in facility located at the onshore termination of the send out pipeline at the existing SoCalGas facility. Project facilities will include a pig launcher/receiver, metering, SDVs, and odorant injection. Cathodic protection equipment and pipeline markers also will be installed along the pipeline right-of-way. The pipeline station will be constructed within a permanent 200-foot by 200-foot right-of-way. A preliminary footprint for the pipeline station is presented in Figure 3.3-23.

3.6 OPERATION AND MAINTENANCE

This section describes operation and maintenance procedures for the Cabrillo Port facilities. The emphasis during design, and the continuing emphasis during operation, will be safety. The FSRU and send out pipeline will be operated and maintained to provide a safe working environment for the life of the Project. Specific operating and maintenance aspects are described below, first for the FSRU and then for the send out pipeline.

3.6.1 FSRU

FSRU Safety Procedures

The day-to-day operations of the LNG terminal will follow standard marine safety procedures, in compliance with the regulations and industry guidance notes from the IMO, USCG, International Safety Management (ISM), and Seafarers' Training, Certification and Watchkeeping (STCW).

IMO's first task when it came into being in 1959 was to adopt a new version of SOLAS, the most important of all treaties dealing with maritime safety and one that is followed by all shipping nations.

IMO also has developed and adopted international collision regulations and global standards for seafarers, as well as international conventions and codes relating to search and rescue, the facilitation of international maritime traffic, load lines, the carriage of dangerous goods and tonnage measurement. The Maritime Safety Committee is IMO's senior technical body on safety-related matters. The committee is aided in its work by a number of subcommittees, such as flag States, Port State Control, and Internationally Accredited Certification Societies.

Port State Control inspects foreign ships in national ports to verify that the condition of the ship and its equipment comply with the requirements of international regulations and that the ship is manned and operated in compliance with these rules. The primary responsibility for the vessel's standards rests with the flag State, which licenses the vessel. But Port State Control provides a "safety net" to catch substandard ships. The LNG terminal will be in compliance with local regulations, as required by local Port State Control.

LNG Receipts

Each LNG carrier will approach the FSRU in accordance with strict berthing procedures developed as part of the facility operations manual. LNG cargo transfer guidelines for receipt of LNG by the FSRU are provided in Appendix A-7. After the LNG carrier is securely berthed adjacent to the FSRU, the loading arms will be connected.

LNG Carrier Supply and Waste Transfers

The LNG carrier will be visiting the FSRU in lieu of a land-based terminal. As such, the FSRU becomes the port of call for the LNG carrier and the opportunity for the LNG carrier to re-supply. LNG carrier wastes will not be transferred to the FSRU, nor will the FSRU replenish supplies for the LNG carrier. Re-supply and logistical support for the LNG carrier will be accomplished by supply boat(s) that will attend the LNG carrier during the period in which it is moored to the FSRU, providing supplies and removing waste cargo.

LNG Carrier Ballast Water Transfers

The LNG carriers will come to the FSRU carrying some ballast water. Ballast water will be exchanged outside the 200 nautical mile limit of waters of the United States, and ballast water exchanges will be recorded and reported in accordance with MMS requirements. The State of California also has ballast water rules, but they are applicable only to ships entering within the 3 nautical mile limit of state waters. The FSRU will be 13.9 miles, or 12.1 nautical miles from shore, so LNG carriers would not be entering state waters to complete LNG deliveries. There are ballast water regulations pending in California, including AB 433, which call for mid-ocean transfer of ballast water.

Nitrogen and Inert Gas Purging System

Nitrogen will be used when necessary to purge natural gas out of FSRU equipment. This is a safety procedure. The use of nitrogen, or any inert gas, to remove natural gas is a standard industry practice. The process prevents the introduction of air that, when mixed with residual natural gas, could result in a mixture within its flammable limits. Nitrogen will be generated on board the FSRU, using a process that separates nitrogen from the air.

LNG Spill Scenarios

Spill scenarios under which LNG would come in contact with the surface of the water are both highly unlikely and, if they were to occur, short duration events due to the rapid vaporization of LNG once it hits the water. The resultant unconfined mixture of methane and air would be non-explosive, but likely would include some mixture within the flammable limits until dissipated in the atmosphere. The vessel will be designed to eliminate potential ignition sources in process equipment areas where leaks could occur. The vessel also will be equipped with gas detection systems, fire detection systems, and fire suppression systems. As such, consequences of most LNG releases would be a brief increase in the methane content of the atmosphere in the vicinity of the FSRU. In the event of complete tank failure and rapid release of LNG, some LNG would reach the water surface and float. According to thermodynamic models the affected area would cover an area with a diameter only about three times the length of the vessel and would dissipate within 10 minutes. All LNG spill scenarios either result in substantially less consequence than even small spills of oil or are inconsequential because LNG rapidly boils off and dissipates. LNG release scenarios are described in more detail in the section on Hazards and Hazardous Materials.

Crew Size and Crew Transfers

While the FSRU will include an accommodation deck house with all facilities capable of accommodating a permanent crew of up to 50 persons, the FSRU will typically carry a crew of 30 people. Crew will be rotated every 7 days and transferred by boat. These personnel transfers will occur at the aft end of the FSRU, where a transfer platform will be located to facilitate safe transfers.

Helicopter Operations

Although the FSRU will be equipped with a helicopter platform, routine helicopter operations will not be part of the Project. The helicopter deck will be used for emergencies, such as the removal of a seriously injured crew member, and periodic helicopter visits by company executives and other official visits. No helicopter fuel will be stored on the FSRU.

Ballast Operations

The FSRU will arrive for commissioning ballasted, and continuous ballast water exchange will take place during normal operations. For the initial arrival of the FSRU from the overseas fabrication port, the FSRU will follow established ballast water exchange protocol, including notification and exchange of ballast water outside the 200-nautical mile limit. During normal operations, the LNG cargo will be constantly shifting as LNG loads are received and natural gas is sent out. To maintain FSRU stability, the LNG inventory changes will be offset by ballast water pumping. Ocean water will be pumped into various ballast tanks, shifted from one tank to another, or discharged back to the ocean. Ballast water will not be chemically treated, and pumps will be screened to minimize entrainment of aquatic organisms.

Natural Gas Odorization

In order to deliver natural gas that is suitable for delivery to the SoCalGas system and consistent with USDOT safety requirements, the natural gas will be odorized prior to entering SoCalGas facilities. Methane gas, which constitutes a minimum of 85 percent of the natural gas sent out from the FSRU, is odorless. An odorant (typically mercaptan gas) is added so that leaks of natural gas can be detected by its unique sulfur odor. The BHPB odorant injection facility will be located at the onshore pipeline station.

Blackstart Diesel Fuel

The FSRU will be loaded with 1,000 m^3 (6,290-bbl) gallons of diesel fuel prior to departure from the fabrication shipyard. That fuel will be used for initial power generation needs during installation and commissioning prior to receipt of LNG. After receipt of LNG, the FSRU will be fueled by natural gas from the gas send out line or BOG. After LNG operations have begun, the diesel fuel will be retained as an emergency fuel supply. The diesel fuel will be used in monthly tests of the power generator and firewater pumps to ensure their continued operability, and to operate a diesel crane for material handling. The diesel fuel storage tank will be topped off approximately once annually. Diesel fuel will be brought on board in re-useable transportable tote containers; the fuel will be transferred into the FSRU storage tank, and the empty totes then will be transferred back to shore. Diesel fuel will be managed in accordance with USEPA and State of California requirements. BHPB will develop and implement a facility-specific Spill Prevention, Control, and Countermeasure Plan (SPCC Plan) as required for DWPA facilities under 40 CFR 112.1(a)(1).

Fuel Gas System

The fuel gas system is described in a process schematic in Appendix A-5, FSRU Design Drawings. The fuel gas system is supplied by BOG that is compressed up to 4 bar. Additional natural gas from BOG or the send out line will be sent as fuel to the SCVs to provide heat in order to vaporize LNG.

Lubricating Oils

The onboard rotating equipment, including power generation units, BOG compressors, LNG booster pumps, firewater deluge system pumps, and ballast water pumps, will hold an inventory of lubricating oil. Lubricating oil will require periodic change-out. Replacement oil will be brought on board in 210-liter (55-gallon) drums or 1,300-liter (350-gallon) totes. Used oil will be returned to shore in the same containers that are used to provide the replacement oil. Used oil will be managed, disposed of, or recycled in accordance with USEPA and State of California requirements. All oil will be managed in accordance with the facility-specific SPCC Plan.

Incidental Paints and Solvents

FSRU maintenance activities will require the use of small quantities of various paints, solvents, and other hazardous materials. These materials will be brought on board and stored in retail-sized containers, in suitable fire-proof cabinets. Empty containers will be hauled to shore for appropriate recycling or disposal.

Urea

The power generation equipment aboard the FSRU will be equipped with air emissions control equipment designed to reduce the emission of oxides of nitrogen (NO_x). Selective catalytic reduction (SCR) using ammonia is typical for onshore facilities. Due to safety concerns with ammonia in the offshore environment, the FSRU emissions abatement equipment will instead use urea. Urea can be transported as bagged solid pellets and mixed into an aqueous solution on board.

Potable Water

The condenser portion of the SCV units generates freshwater by condensing moisture out of the air. This water will be collected into the SCV water bath. This system will generate excess freshwater, some of which will be diverted for urea mixing and some for potable water. Bath water diverted for use as potable water will first be treated using ultraviolet light (UV) in a UV oxidation unit, then filtered through a 1 micron filter and finally filtered through an activated charcoal filter (potable water use). This method avoids the need for storing or using chlorine gas or sodium hypochlorite on board the FSRU.

Gray Water Discharge

Gray water, such as water from showers and sinks, will be accumulated for onboard treatment to NPDES standards and discharge. Gray water will be treated using filtration to separate particulate matter and UV oxidation to destroy dissolved organic materials. Water discharge will be in conformance with a facility-specific wastewater discharge permit issued by the California Regional Water Quality Control Board, Los Angeles Region, implementing the State Ocean Plan.

FSRU Supply and Waste Transfers

Incoming supplies and outgoing wastes will be transferred by boat. During normal operations, a supply boat visit will occur once a week. Supplies will range from food, toiletries, and office supplies for crew use in the living quarters to tools, small parts, and other maintenance and repair materials. Solid wastes from the FSRU will be containerized for transfer to the supply vessel. Black water sanitary wastes from the FSRU also will be containerized for transfer to the supply ship or treated and discharged under a NPDES permit. Supply and waste transfers will be made by crane lifts from a supply vessel moored to the aft of the FSRU.

3.6.2 Pipeline

The send out pipeline will be maintained through both use of visual inspections and maintenance pigging. Title 49, Parts 190-199 of the Code of Federal Regulations governs the construction, operation, and maintenance of the on and offshore portions of the send out pipeline. A discussion of the maintenance operations for both onshore and offshore maintenance is set forth below:

Regular pipeline maintenance includes maintenance pigging, and intelligent pigging at intervals specified by USDOT and BHPB Standard Operating Procedures, and when conditions warrant. A pipeline is internally cleaned with devices called pipeline “maintenance pigs”. The interval of maintenance pigging is based on operational data. The condition of the pipe can be determined with “intelligent pigs”. Intelligent pigs are instrumented to inspect the condition of the pipe with respect to corrosion. The data from intelligent pigging will be used as a baseline to determine if changes (such as corrosion) have occurred to the pipeline. This pigging program is proven to adequately monitor and ensure the integrity of a pipeline.

There is no maintenance required on the offshore segment of the send out pipeline other than the above referenced pigging, and surveillance required by the regulations and standards of the USDOT. In the event that the pigging and surveillance operations determine that there is excessive corrosion or damage to the pipeline, additional analysis will be required to determine corrective actions up to replacement of pipeline segments.

For the onshore segment of pipeline, the onshore maintenance will include the following in addition to the pigging described above:

- Visual inspection of the right-of–way (ROW)
- Inspection and maintenance of the corrosion protection (CP) system
- Pipeline identification and location for nearby third-party activities
- ROW area clearing, access maintenance, and pipeline marker maintenance

There is not necessarily a life expectancy for a pipeline. A properly designed and maintained pipeline may last indefinitely. There are existing pipelines currently in use that were constructed over 50 years ago.

The intervals for the above maintenance activities vary, but will be in accordance with USDOT regulations and BHPB Standard Operating Procedures.

3.7 FUTURE PLANS

The FSRU design life is 25 years, expandable to 40 years. There are no reasonably foreseeable plans for extension beyond 40 years. The FSRU is designed and will be built to its current foreseeable LNG storage and regasification capacity. The receipt capacity could be increased. As planned, the FSRU will be equipped with LNG carrier unloading berths only on the starboard side. The FSRU receipt capacity could be increased by installing loading arms on the port side. Increasing the LNG storage capacity will be possible only by replacing the FSRU with a larger vessel or structure; the FSRU as designed does not have space available to add storage capacity. The LNG regasification capacity will be the maximum within the available deck space. Eight vaporization units are planned; they will provide the maximum foreseeable vaporization capacity.

The mooring point, anchor cables and anchors, flexible risers, PLEM, and send out pipeline are all designed specifically for the FSRU. Design considerations include the FSRU natural gas send out capacity and the wave, wind, and seismic forces that the mooring devices must withstand to maintain the mooring position. Because the FSRU is designed to the maximum foreseeable natural gas send out capacity, there are no reasonably foreseeable expansions of these facilities.

3.8 DECOMMISSIONING

The FSRU is designed for a 25-year useful life, expandable to 40 years. Recent experience with LNG tankers shows that the useful life can be extended through detailed inspection and re-certifications of LNG storage tanks and equipment. At the end of the 25-year design life, the FSRU will undergo extensive inspection and recertification if extension to 40 years is desired at that time.

Upon decommissioning, after either 25 or 40 years, the FSRU will be removed from the mooring point and towed to a shipyard to be overhauled and recertified, or to be scrapped and salvaged as appropriate. Ocean floor anchors will be removed or left in place, depending on anchor type, ocean floor environmental conditions, and regulatory requirements applicable at that time. Mooring cables, the mooring turret, flexible risers, and the PLEM will be removed and brought to shore for final salvage or other appropriate disposition. Pipeline abandonment will begin with pigging the line to remove any debris, scale, or other materials. Buried portions of the subsea pipeline then will be abandoned in place. The abandoned-in-place buried pipeline will be filled with concrete slurry, from the onshore termination point to the end of the buried portion offshore. The addition of concrete slurry further weights the abandoned pipeline to reduce shifting that might otherwise occur. Portions of the pipeline that were laid on the sea bed will be evaluated to determine whether removal or leaving in place would provide the most environmental benefit.

If the pipeline were to be removed, it would be cut, raised to a salvage barge, and brought to shore.

The onshore meter, mainline valve, odorant injection facility, and any other aboveground facilities will be removed and scrapped or salvaged as appropriate.

3.9 PERMITS AND APPROVALS

The Project is subject to the DWPA (Title 33 U.S. Code [U.S.C.], Section 1501 et seq.) with the USCG and MARAD as the agencies responsible for processing applications to own, construct and operate deepwater ports, and the USDOT responsible for issuance of the Deepwater Port License. In addition, The California State Lands Commission (CSLC) must provide a lease for the use of state lands. These agencies are the likely Federal and State lead agencies for the NEPA/CEQA review. In addition, several Federal, state, and local government agencies regulate development and other activities within the Project area. In addition to a Deepwater Port License and Lease of State Lands, the Project requires review, consultation, approval, and permitting from other agencies before construction can begin. Table 3-4 identifies the regulatory approvals and consultation that may be triggered by the Project.

Table 3-4. Major Federal and State Permit, Approval, and Consultation Requirements for the Project

Agency	Permit/Regulatory Act	Agency Action
FEDERAL		
U.S. Dept. of Transportation	Deepwater Port License	Issuance of License
U.S. Coast Guard/ Maritime Administration	Deepwater Port License	Review FSRU, mooring point, and offshore pipeline permit application
U.S. Environmental Protection Agency (USEPA)	Title V Federal Operating Permit PSD Preconstruction Review	Issue air permits
USEPA	Clean Water Act Stormwater and Wastewater Discharge Permits	Evaluate compliance with nationwide discharge permit conditions
USEPA	National Pollutant Discharge Elimination System Permit	Review application and issue permits
Advisory Council on Historic Preservation	Section 106, National Historic Protection Act	Review of and comment if the project may affect cultural resources that are listed in or eligible for listing in the National Register of Historic Places
U.S. Army Corps of Engineers (COE)	Waterways Permit under Section 404, Clean Water Act	Consultation and water quality determination
COE	Section 10, Rivers and Harbors Act	Issue a Nationwide 12 Permit
U.S. Department of the Interior, Fish and Wildlife Service (USFWS)	Section 7, Endangered Species Act (ESA)	Consult on threatened and endangered species; Migratory Bird Treaty Act coordination
U.S. Department of the Interior, National Marine Fisheries Service (NMFS)	Section 7, ESA	Consult on threatened and endangered species
NMFS	Magnuson-Stevens Fishery and Conservation and Management Act	Essential fish habitat coordination
USFWS	Marine Mammal Protection Act	Consult on threatened and endangered species
Federal Communications Commission	Telecommunications license	Review application and issue license
CALIFORNIA		
California Department of Transportation	Encroachment permits	Issue permit to cross state-funded roadways

Agency	Permit/Regulatory Act	Agency Action
Los Angeles Regional Water Quality Control Board	Clean Water Act Section 401 Certification	Review application and concur with COE in issuance of permit.
Los Angeles Regional Water Quality Control Board	Hydrostatic Test Water Discharge Permit	Review application and issue permits
California Department of Fish and Game	Consultation	Review records to determine whether state species of concern may be present in the project area
State Historic Preservation Officer	Section 106 National Historic Preservation Act Consultation	Review and comment on applicant-completed studies
California State Lands Commission	Right-of-way lease	Review and approve application for lease of submerged state lands for pipeline right-of-way
California Coastal Commission	Compliance with California Coastal Act	Permit review and consistency determination
LOCAL		
Ventura County	Land use requirements	Review for land use consistency and permitting if necessary
City of Oxnard	Land use requirements	Review for land use consistency and permitting if necessary

3.10 SUBSEQUENT RELATED PROJECTS

Under NEPA and CEQA, an EIR/EIS must disclose any related projects that may occur as a result of the approval of this Project. The lead agency may need to consider the environmental impact of related facilities that will be constructed upstream or downstream of the specific Project facilities for the purpose of delivering, receiving, or using the proposed gas volumes. Integrally related facilities could include major power facilities as well as less significant facilities. Under NEPA, the extent of the Federal lead agency's analyses of these related facilities depends on that agency's determination of its and other Federal agencies' control and responsibility over these facilities. To assist in these determinations, the COE has developed a decision tool based on four criteria. The four criteria are considered by COE in determining whether there is sufficient Federal control and responsibility over a project as a whole to warrant environmental analysis of portions of the project outside its direct sphere of influence. These factors, which are set forth below, have also been adopted by other Federal agencies to determine if nonjurisdictional facilities should be included in an environmental analysis of jurisdictional facilities.

- Whether the regulated activity comprises "merely a link" in a corridor-type project (e.g., a transportation or utility transmission project),

- Whether aspects of the non-jurisdictional facility in the immediate vicinity of the regulated activity affect the location and configuration of the regulated activity,

- The extent to which the entire project will be within the Federal agency's jurisdiction, and

- The extent of cumulative Federal control and responsibility.

Non jurisdictional facilities associated with this project include the potential modifications to existing SoCalGas facilities in order to accommodate the flow from the Project. SoCalGas has indicated that it could accept 400 MMcf/day into the existing system, and up to 1 Bcf/day by implementing certain modifications to the existing system. In order to receive the 1 Bcf/day of gas the following system modifications would be required:

- a 34-inch diameter, 12 mile long loop of line 324 would be required from the landfall at Ormond Beach to the Center Road Station,

- a 30-inch diameter loop of Line 225, 5.2 miles long would be required between Saugus Junction and Quigley Station, and,

- the capacity of the Quigley Station would have to be increased with new piping, control valves, and a separator vessel.

SoCalGas would permit, design, build, own, and operate these system improvements at BHPB's cost.

As for the first of the four above-listed criteria, this loop is "merely a link" in a corridor type project. The proposed project delivers natural gas supply via a send out pipeline. The SoCalGas loop would provide extra capacity to link the send out pipeline to existing SoCalGas systems.

As for the second criteria, the loop did not determine the FSRU location or the routing of the send out pipeline. Access to existing natural gas storage and distribution systems is just one of several criteria used to site the FSRU and to determine the landfall location of the send out pipeline.

As for the third criteria, the Ormond Beach to Center Road Station loop would not be subject to the jurisdiction of the Federal lead agency or any other Federal agency. The loop would be part of an intrastate system, and not part of a federally regulated interstate system.

As for the fourth criteria, the pipeline loop would be subject only to limited, indirect federal control through permit authorities that are delegated to California State agencies. This includes USEPA Clean Air Act compliance, USEPA Clean Water Act compliance, USFWS endangered species act compliance, etc.

The SoCalGas modification would be subject to the review and approval of the California Public Utilities Commission (CPCU). As part of its review responsibility, the CPUC must conduct a CEQA review of the Project.

Figure 3.3-1. Southern California Coastal Region

Figure 3.3-2. Project Setting

Figure 3.3-3. Project Vicinity Map

Figure 3.3-4. Nearshore and Onshore Pipeline Location

Figure 3.3-5. FSRU Plan and Elevation Diagram

Figure 3.3-6. LNG Carrier Berthing

Figure 3.3-7. Typical Fenders

Figure 3.3-8. Moss Storage Tank Cross Section

Figure 3.3-9. Example Mooring Turret

Figure 3.3-10. Mooring Point Sea Floor Slope

Figure 3.3-11. Mooring Point General Arrangement

Figure 3.3-12. Mooring Point Plan and Elevation

Figure 3.3-13. Riser Process Flow Diagram

Figure 3.3-14. PLEM Plan and Elevation

Figure 3.3-15. Pipeline Route by Segments (six pages)

Figure 3.3-16 Subsea Pipeline Profile

Figure 3.3-17. Pipeline Route Bathymetry

Figure 3.3-18 Subsea Pipeline Perspective

Figure 3.3-19. Pipeline Landing Topographic Features

Figure 3.3-20. Pipeline Landing Aerial Image

Figure 3.3-21 Pipeline Alignment Sheets (six pages)

Figure 3.4-1. FSRU Exclusion Zone

Figure 3.4-2. Typical Cross Section–Non-Buried Subsea Pipeline

Figure 3.5-1. Buried Pipeline Alignments

Figure 3.5-2. Existing Leases and Rights of Way

Figure 3.5-3. Cable Crossing Schematic

Figure 3-5-4. Marine-to-Shore Horizontal Directional Drilling

Figure 3.5-5. Offshore Pipeline Laying

4.0 ALTERNATIVES

A guiding philosophy in the design and siting of the Project has been to minimize adverse environmental consequences. Studies to evaluate siting, terminal design, mooring and pipeline design, and offshore marine conditions have all led to the selection of the proposed Cabrillo Port as described in Chapter 3. The life cycle of the Project includes FSRU fabrication, construction, installation, operation, and decommissioning. The FSRU will be fabricated outside of the United States. As such, consideration of alternatives do not directly address this aspect. This section summarizes the screening of alternatives against the Purpose and Need.

The results of the screening are three alternatives that are then analyzed in this EA along with the Project: 1) No Action; 2) Santa Barbara Channel Alternative; and 3) Technology Alternative of Intermediate Fluid Vaporizers rather than Submerged Combustion Vaporizers. Table 4-1 summarizes the environmental consequences of the alternatives.

The heart of NEPA is that an agency should consider reasonable alternatives to a proposed action. The Secretary may approve or deny an application[2] for a license under the Deepwater Port Act. In approving a license application, the Secretary may impose enforceable conditions as part of the license. Consistent with NEPA, in determining the provisions of the license the Secretary may also consider alternative means to construct and operate a deepwater port. Alternatives for a natural gas deepwater port may extend to matters such as its specific location, methods of construction and platform layout, and technologies for storing and regasifying LNG. Considering alternatives helps to ensure that ultimate decisions concerning the license are well founded and as required by the Deepwater Port Act, are in the national interest and consistent with national security and other national policy goals and objectives.

In a Project of this type, alternatives can be developed on several levels. The alternatives analysis includes regional alternatives, local alternatives, and technology alternatives. An initial screening of regional alternatives was performed, evaluating the feasibility of several regions along the west coast of the United States and Mexico. Local alternatives to the Project were then evaluated to determine whether they would be reasonably and environmentally preferable to the proposed Cabrillo Port. These include alternative mooring point locations, alternative shore crossing locations, major pipeline route alternatives, and pipeline route variations. Finally, technology alternatives were considered for the FSRU and for the pipeline, based upon relative environmental impacts, safety, reliability, and other factors.

The evaluation criteria for selecting potentially environmental preferable alternatives include:

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[2] For the application at hand, the No Action Alternative and denial of the license are considered to be the same.

- Ability to satisfy Project purpose and need;
- Technical and economic feasibility and practicality; and
- Significant environmental advantage over the proposed Project.

This chapter summarizes those considerations. The No Action Alternative is described first, followed by location alternatives, pipeline route alternatives, technology alternatives, and FSRU alternatives. The conclusion of the chapter is that three alternatives are retained for detailed analysis in the EA. A comparative summary of the Project and alternatives retained for analysis (No Action, Santa Barbara Channel, and Intermediate Fluid Vaporizers) is presented in Table 4-1.

4.1 NO ACTION

This section addresses the consequences of not constructing the Project. Potential impacts associated with the construction of the Project (water quality, fisheries, marine mammals, aquatic vegetation, soft bottom habitat, other marine resources, visual, and sedimentation) would be avoided under the no-action alternative. However, under the No Action alternative, the energy benefits of the Project would not be realized. A new, long-term and reliable source of clean-burning natural gas would not be available to California consumers. These consumers would continue to be subject to the increasing cost of reliance upon declining North American gas sources delivered by few pipeline systems.

Denial of the Project could stimulate other LNG and natural gas import projects in the region, including on-shore LNG terminals, which could result in more adverse environmental impacts than the Project. Denial of the Project could also result in restriction of natural gas supplies and higher natural gas prices, if the natural gas to be supplied by the Project cannot be obtained from other new natural gas sources.

Local and regional energy alternatives to the natural gas supply from the proposed Project include oil, coal, nuclear, and alternative fuels. The potential impacts associated with using these alternative fuels rather than natural gas include impacts on air quality (oil or coal have greater emissions of criteria pollutants than natural gas), on transportation, and other environmental and economic impacts associated with the construction of natural gas-based facilities rather than alternative fuel-based facilities. The use of less-clean burning alternative fuels would decrease air quality by increasing emissions of SO_2 and other priority pollutants.

Development of additional renewable energy sources, such as solar and wind, present their own environmental difficulties. These energy sources are generally not capable of supplying the energy demand adequately. Wind energy expansion requires suitable acreage in a location that has appropriate wind conditions. While wind energy can be a valuable supplemental source of electric power, it is subject to significant fluctuations and is not an appropriately reliable source of energy to replace electric power generated using natural gas. While solar energy has applications in building-specific water heating and electric power generation, it is not available as a significant source of electric power and, like wind energy, can not be relied on to replace electric power generated using natural gas.

The Project will introduce a competitive gas supply to meet growing demand for natural gas in the Western United States. This increased demand will not be met by domestic natural gas production, or through existing import pipeline infrastructure. Given the projected energy demand, the Cabrillo Port satisfies the Project objectives while the no-action alternative does not.

4.2 LOCATION ALTERNATIVES

The proposed Project location was selected based upon LNG carrier access, access to regional natural gas transmission systems and proximity to a region of high natural gas market demand, while maintaining safe clearance from shipping lanes, residential and recreational areas, and other existing uses. The siting process included a screening study that compared alternative West Coast locations listed in Table 4-2 and mapped in Figure 4.3-1.

The selection of the Cabrillo Port FSRU location and pipeline route was determined as a result of alternatives assessment considering technical requirements, environmental impact assessment and preliminary input received from state and local agencies and other parties.

An onshore facility was considered but dismissed owing to increased onshore hazards, potential disruption of marine-traffic, increased onshore environmental impacts, and difficulty in identifying an acceptable site based on these constraints.

Table 4-1. Comparison of Alternatives

	Preferred Alternative	**Seawater Regasification using Intermediate Fluid Vaporizers**	**Santa Barbara Channel Alternative**	**No Action**
Terrestrial and Marine Biology	FSRU 18 miles from National Marine Sanctuary. No hard bottom, kelp, or sensitive habitat in Project area. Potential impacts from FSRU, LNG, and construction vessels striking marine mammals and turtles. Horizontal Directional Drilling will avoid subtidal, tidal, dune, and wetland habitat. All indirect impacts including construction noise and dust will be mitigated to avoid impacts to biological resources.	FSRU 18 miles from National Marine Sanctuary. Usage of large amounts of seawater can impinge and entrain marine life. Sodium hypochlorite or other oxidizers used to control growth of marine organisms in equipment impacts biological productivity.	FSRU approximately 14 miles from National Marine Sanctuary. Location in Santa Barbara Channel increases chance of hard bottom or kelp habitat in Project area. Project would be closer to California gray whale migration routes. Potential impacts from FSRU, LNG, and construction vessels striking marine mammals and turtles. Horizontal Directional Drilling will avoid subtidal, tidal, dune, and wetland habitat. All indirect impacts including construction noise and dust will be mitigated to avoid impacts to biological resources.	No potential terrestrial or marine impacts from Project. Potential impacts from alternative fuels and energy including wind, which requires significant acreage and oil production.
Geologic Resources and Hazards	Sea bottom slopes do not exceed 10%. No active faults in area.	No impacts to geologic resources.	Pipeline would need to be routed away from Hueneme Canyon, where slopes of over 10% exist.	No potential impacts from Project.
Physical Oceanography Sediment & Water Quality	Only expected discharges are gray water treated with chemical or biological systems from crew quarters and other areas, runoff from the deck of the FSRU, and a one-time hydrostatic test water discharge. No other significant impacts to water quality.	Use of seawater for heating produces thermal plumes, turbidity, and treated water discharge. Additional discharges of gray water treated with chemical or biological systems from crew quarters and other areas, runoff from the deck of the FSRU, and a one time hydrostatic test water discharge	Only expected discharges are gray water treated with chemical or biological systems from crew quarters and other areas, runoff from the deck of the FSRU, and a one time hydrostatic test water discharge. No other significant impacts to water quality.	No potential impacts from Project.

Hazards and Site Safety	Far from shipping and ferry lanes, missile testing zones, zones of naval activity and other pipelines.	No increase/decrease in risk or safety associated with IFV technology.	Close to existing pipelines for Gilda and Gina Platforms. Far from shipping and ferry lanes, missile testing zones, and zones of naval activity.	No potential impacts from Project. More risks associated with transportation of alternative fuels including oil.
Air Quality	Emissions from submerged combustion vaporizers that use natural gas to heat LNG. Emissions, with appropriate control technologies will not violate any air quality standards.	Low emissions from vaporizers that use seawater to heat LNG.	Emissions from submerged combustion vaporizers that use natural gas to heat LNG. Emissions, with appropriate control technologies will not violate any air quality standards.	No potential impacts from Project. No new source of clean burning natural gas available to consumers who will be forced to use other fuels like coal and oil with increased air quality impacts.
Noise	Noise levels on FSRU low; primarily ship engines. No significant impacts to noise levels onshore during operation or construction.	Seawater pumps can be noisy.	Noise levels on FSRU low, primarily ship engines. No significant impacts to noise levels onshore during operation or construction.	No potential impacts from Project.
Aesthetic and Visual Resources	FSRU approximately 13.9 miles from shore. FSRU would be visible from some elevated locations and have the appearance of a ship.	FSRU approximately 13.9 miles from shore. FSRU would be visible from some elevated locations and have the appearance of a ship.	FSRU approximately 8.5 miles from shore. FSRU would be visible from high density residential areas and other scenic areas, but would have the appearance of a ship.	No potential impacts from Project.
Community Compatibility and Concerns	No significant impacts to cultural resources, agricultural resources, socioeconomics, land use, environmental justice, or recreation.	No significant impacts to cultural resources, agricultural resources, socioeconomics, land use, environmental justice, or recreation.	No significant impacts to cultural resources, agricultural resources, socioeconomics, land use, environmental justice, or recreation.	New long-term and reliable source of clean-burning natural gas would not be available to California consumers.

Table 4-2. Summary of Regional Alternatives Identified for the BHPB Project		
Site Alternative	**State**	**Analysis in Section**
Columbia River,	Washington	4.2-1
Eureka,	California	4.2-2
San Francisco,	California	4.2-3
Monterey Bay,	California	4.2-4
Port Hueneme	California	4.2-5
San Diego	California	4.2-6
Rosarito	Baja California, Mexico	4.2-7

This regional alternatives screening was carried out in order to identify suitable and preferred Project locations. None of these locations are retained for detailed analysis. The main comparison criteria were as follows:

Proximity to Gas Consuming Region

The terminal site should be located within an optimal distance to gas consuming regions. This can include major metropolitan areas, industrial areas, and gas fired power generation facilities.

Proximity to Existing Gas Transmission Systems

The terminal facility should be located within a distance that provides reasonable access to significant gas transmission systems. Optimally, the transmission system should also provide for wide distribution of the gas, line pack, back haul, and swaps for gas sales and distribution efficiency.

Site Safety

The terminal facility should be sited in an area such that it poses the minimum risk to the public, nearby industry, the environment and terminal operations. A site selected within or nearby densely populated areas would not be advisable, due to public safety and security concerns. As such, the site should be selected so that it is not located in an area that will pose excessive risk to the public. Suitable climate conditions to ensure maximum terminal uptime availability was also assessed under this criteria.

Site Security

The terminal facility should be located in consideration of security issues. The security criteria encompassed security of the Project facility and also considered other facilities in the vicinity.

Carrier Ingress / Egress

The location of the terminal facility should be such that LNG carriers can safely and efficiently transit to and from the facility. There should be no unusual hazards to navigation, nor any exceptional risks that pose a hazard to the carriers, the facility, the public or the environment.

Environment and Community

The site selection process should avoid sites that would have a negative impact on endangered species, or areas that have sensitive environmental characteristics. Siting should also consider factors such as disruption of sport or commercial fishing, recreation, and obtrusiveness to the public view-shed.

Columbia River, Washington

A location at the mouth of the Columbia River, along the border between Washington and Oregon, was evaluated as an alternative site location. The result of the study showed that this site would be unsuitable primarily due to LNG carrier access issues and the distance from existing gas transmission systems. Longer travel time increases the cost of the gas supply. The location would require substantial upgrade of existing pipeline infrastructure over a long distance. The screening study also found no existing harbor of sufficient size to accommodate a marine-based terminal and LNG carrier.

Eureka, California

The Eureka area was examined, as it is the only location in the Northern California / Southern Oregon region with access to the Pacific Gas and Electric (PG&E) main gas transmission systems. Costs to improve existing access to this gas transmission system were deemed prohibitive, making the alternative unsuitable. This alternative is also remote from gas consuming regions. This alternative would require significant new pipeline construction, thereby incurring high pipeline tariffs. The harbor is inadequate for LNG carriers, and climatic conditions outside the harbor can be severe, therefore, not conducive to this type of marine traffic.

San Francisco, California

This alternative location is unsuitable due primarily to population density and associated community, safety and security concerns. This area has an extremely high population density.

Congested waterways and navigation areas, especially inside San Francisco Bay, present a hazard for LNG carriers. Waters outside San Francisco Bay are a National Marine Sanctuary.

Monterey Bay, California

The existing pipeline infrastructure would require significant upgrade to deliver Project flow to the PG&E main gas transmission system. Lack of protected areas for the LNG carriers raises safety concerns and access/egress would also be a concern because of the severity of winter storms.

Port Hueneme, California

The site location in Port Hueneme was evaluated and it was determined that the harbor is not capable of handling vessels the size of LNG carriers without significant dredging. The area inside the harbor is not large enough to accommodate a marine based LNG terminal.

San Diego, California

The Navy maintains its headquarters for the 6th Fleet inside San Diego Harbor. This alternative location is unsuitable because it would likely interfere with naval operations. There is also a significant presence of recreational boating inside San Diego Harbor that would pose a difficult security and safety issue for the terminal and for LNG carriers. Locations outside San Diego harbor would also be unsuitable because there are significant numbers of chemical and conventional weapons dumpsites. In order for the terminal facility and pipeline to avoid these sites, the terminal would have to be sited near the major North – South shipping lanes.

Rosarito, Mexico

This alternative provides uncertainty in terms of regulatory issues and jurisdiction and the lack of regulatory regime for LNG projects. A regulatory framework is being developed, but initially will only address land-based facilities. There is a lack of pipeline infrastructure and therefore high gas transportation costs. Although the Baja Norte line under construction by Sempra and PG&E ties into the El Paso system at Ehrenburg, Arizona, and terminates near Rosarito Mexico, the use of this system would mean long back-hauls of gas, east to the Arizona-California border. From Ehrenburg the gas would then be required to be transported west on the SoCalGas system. This inefficient transportation arrangement would be costly in pipeline tariffs. Landing gas supplies in Mexico for transshipment to the United States does little to ensure the energy security of the United States as this new supply could become subject to adverse factors of the host Country. These factors make this alternative location unsuitable for the proposed Project.

4.2.1 Local Alternatives

Introduction

The location of the Cabrillo Port FSRU in the waters off of Ventura County, the location of the shoreline crossing and tie-in to a natural gas transmission system, and the route of the subsea send out pipeline were selected after consideration of several alternatives.

Alternative locations for the mooring point of the FSRU are presented in Figure 4.3-1 and are listed in Table 4.3.1. The alternatives assessment used safety, security, environment and community criteria. The Santa Barbara Channel alternative is retained for detailed analysis in the EA. The alternative mooring points were evaluated based on the following:

Distance from Shipping Lanes

The mooring point should be at least three nautical miles from the centerline of the nearest shipping lane. A Project-specific risk analysis was included an assessment of the risk of impact from a vessel that has lost power and is drifting. The risk analysis determined that the three nautical mile buffer would reduce this risk to a negligible value.

Distance from Shore

The mooring point should be several miles from shore to mitigate visual impact and to mitigate perceived risk of fire related to an LNG release. Visual impact is a qualitative judgement. The degree of impact may be influenced not only by distance from shore and size of the facility, but also by the setting and receptors.

Subsurface Slope

The mooring point should be over an area of relatively smooth bottom and relatively flat slope. The mooring cables will spread over a seafloor area with a radius of almost approximately one mile. The mooring cables and mooring anchors will be designed in accordance with bottom conditions, but design can be simplified if the bottom conditions are flat.

Existing Facilities

The mooring point should be at least two nautical miles from existing offshore oil production platforms. The clearance is to provide a safety buffer for the LNG carriers that will visit the FSRU three time per week, and to prevent any serious fire incidents on one facility from escalating to another facility. Existing cables crossed by the Cabrillo Port pipelines will have to be protected from damage prior to laying the send out pipeline.

Ferry Routes

Ferry routes and other designated routes for smaller vessels and vessels carrying passengers should be avoided to the extent possible. A buffer of four statute miles was used for siting purposes. This buffer is greater than the buffer for established coastal shipping lanes because the routes are designated as single lines, rather than lanes, so some variance off the specific line was allowed.

Fishing and Recreation Areas

Areas known for specific commercial or recreational uses that are not designated on navigation charts were assessed only to the extent to which they were known based upon literature review. General data on commercial fishing fleet catches by region, and number of boats by region was considered. Recreational boating activities were estimated using charter operation and boat registration data.

Jurisdictional Boundaries

The boundaries of national marine sanctuaries, military use areas, and state waters limits were considered in the local alternatives analysis. Jurisdictional boundaries and their relevance to mooring point locations were considered on a case by case basis.

Santa Barbara Channel Alternative

The Santa Barbara Channel Alternative mooring point location is about 8.5 statute miles offshore from Rincon Beach, and about midway between the existing Grace and Habitat production platforms in the Santa Barbara Channel. The alternative mooring location is specifically located at latitude 34^{o} 14.410’ N longitude 119^{o} 30.916’ W. This alternative meets all of the criteria for clearances from shipping lanes, and existing facilities. It is landward, about 5.8 nautical miles, from the coastal shipping lanes, and over 4.2 nautical miles from the nearest offshore production platform. Visual impact is a concern for this alternative. Visual impact is perhaps less because of the presence of existing oil platforms, and it is mitigated by the FSRU being ship-shaped. However, due to the population density along the wide sweep of the coast from which the FSRU would be visible, this alternative was found to be less preferable than the Project, as the viewshed of a very large number of receptors would likely be impacted. This alternative is retained for further analysis in the EA.

Anacapa Alternative

The Anacapa Alternative mooring point location is about 16 statute miles offshore from Point Mugu, and about 11 miles from Anacapa Island, which is part of the Channel Islands National Park. The coordinates for this mooring alternative are 33^{o} 52.20000' N and 119^{o} 04.01100' W. This alternative location is inside the limits of the Pacific Missile Range, but meets other location criteria. Visual impact is mitigated by the distance from the mainland, the distance from Anacapa Island, and the low population density in the areas from which the mooring location could be viewed. This alternative was found to be unsuitable because of the risk that the Navy would not allow the Project to be located within the limits of the Pacific Missile Range.

Shoreline Crossing Alternatives

One Alternative location for the shoreline crossing of the pipeline running from the FSRU was assessed and is presented in Figure 4.3-2. The alternatives assessment used safety, security, environment, and community criteria. The alternative shoreline crossing was evaluated based on the following:

Access to SoCalGas Natural Gas Transmission System

The shoreline crossing should be at a location that provides existing access to the SoCalGas pipeline, or access with limited improvement of existing SoCalGas facilities. The required SoCalGas improvements should avoid areas of high population density.

Population Density

Many shoreline areas have been developed into high density residential areas where the noise and traffic associated with construction work could be considered a nuisance and the installation of high pressure natural gas pipelines might be opposed.

Sensitive Habitat

Shorelines offer unique habitat that may be home to endangered species such as the snowy plover. Sensitive habitat should be avoided, or work may have to be scheduled to avoid certain seasons when species of concern are present.

Mandalay Power Generating Station Alternative

The Mandalay Power Generating Station Alternative anticipates a shoreline crossing adjacent to the Reliant Mandalay Generating Station. Existing pipelines from the Gina and Gilda platforms already cross the shoreline at this location. The natural gas from the Project would be delivered into a tie-in with the SoCalGas system at the Generating Station. This shoreline alternative was deemed unsuitable based upon preliminary discussions with SoCalGas about the feasibility of connecting from the Generating Station to the SoCalGas Center Road Station.

4.2.2 Pipeline Routing Alternatives

Pipeline route alternatives from the Santa Barbara Channel and Anacapa alternative mooring locations were considered but are not relevant because those mooring points were found to be unsuitable as discussed above. Three pipeline route alternatives, between the proposed Cabrillo Port mooring point and the proposed shoreline crossing at Ormond Beach were evaluated. In all cases the shore crossing would be installed using HDD to avoid beach impacts that would be caused by trenching. The HDD would extend out to waters greater than 13 meters in depth. The portions of the pipelines from the HDD segment to the mooring location would be laid directly on the seafloor. The three pipeline route alternatives are presented in Figure 4.3-3. Pipeline route alternatives were evaluated based upon the following criteria:

Sea Floor Slope

The mooring point is beyond the continental shelf in 880 meters of water. The climb from the seafloor up to the OCS includes steep slopes and canyons. For the greatest stability the pipelines should be routed directly up the slope, perpendicular to contour lines, and should be routed along the mildest slopes possible.

Slides, Faults and other Geologic Hazards

The Project is located in a region of seismic activity. The pipeline routing should avoid directly crossing active faults and areas of historic slide activity. The pipeline route alternatives all assume that the pipelines will be laid upon the seafloor instead of buried to reduce the risk of damage from seismic activity.

Existing Cables and Pipelines

The pipelines may present a reduced environmental impact, or at least can take less right of way (ROW) space on the seafloor if they are routed along existing lines and share overlapping ROW. When cables or pipelines are crossed it is best to cross perpendicular to the existing line. Pipeline and cable crossings require protective concrete mats or other methods to maintain adequate clearance and prevent damage.

Buoys, Anchorages and Other Nautical Hazards

A buffer of at least one quarter-mile should be maintained between pipeline routes and buoys to prevent the buoy from interfering with barges, lay vessels and other equipment during pipeline construction. Designated anchorages must be avoided to prevent third party impact to subsea pipelines. Ports, harbors and channel crossings may present a risk of third party damage to an unburied pipeline due to anchor dragging

Constructability

The pipeline route must lend itself to the use of existing, available construction technology and equipment. Constructability issues may be related to factors such as pipeline burial depth, water depth, and seafloor slope. Nautical hazards such as shipping lanes may present complex logistical challenges during pipeline construction.

Pipeline Length

It is desirable that the send out pipeline be as short as is practicable since the length of the pipeline will be directly related to the cost of the pipeline. Additionally, increased pipeline lengths also pose a greater risk if a natural gas release occurs because the line would hold a greater volume of gas that could escape. Longer pipelines also carry some greater risk of third party impact simply because they cover more distance along the seafloor.

Alternative Route 1

This route was the initial route considered from the Cabrillo Port proposed mooring location to shore. Below 100 meters water depth, it runs between two small canyons through one of the safest possible paths across the continental slope. There are no major natural obstructions along the proposed pipeline route, but it runs parallel and in close proximity to, or across, several known man-made structures and restricted areas. These include two surface-laid Navy cables (FOCUS and RELI), one potentially buried telecommunication cable (Global West Segment F), and a Navy cable corridor and firing range. The total length of Alternative Route 1 is 20.2 miles, about 0.9 miles shorter than the proposed route. After detailed route surveys and specific confirmation of cable locations, the crossings and the separation between the proposed pipelines and the existing cables would be adjusted to comply with cable industry standards. It is anticipated that the Navy may require burial of their cables prior to the installation of the pipeline at cable crossings. Permits to cross the Navy cables and to run within the Navy cable corridor could severely impact the scheduling of the pipeline project. Because of the risk of Project delay related to routing parallel and in close proximity to the Navy cables this alternative was considered unsuitable, and was abandoned in favor of the proposed Cabrillo Port pipeline routing.

Alternative Route 2

Alternative Route 2 was designed to run to the west of the proposed pipeline route and west (as much as possible) of both the Navy cables and their safety corridor. From there the route runs toward the Navy cable corridor, across a relatively featureless seabed. Around 800 meters water depth, the route heads to the northwest and enters the Navy cable corridor. In order to ensure compliance with the anticipated Navy engineering requirements, this section of the route was planned to accommodate crossings of the RELI and FOCUS cables with an angle as close as possible to 90°. Around 600 meters water depth the route leaves the Navy cable corridor and enters Hueneme Canyon and, because it cannot be avoided, the alternate route runs through this feature, not always perpendicularly to the slope, to water depth of approximately 300 meters. Slope gradients in this area are likely greater than 10° in places. For this reason, and because this study has shown that the canyon is still active and may be affected by slope failure, slides and turbidity currents (particularly in the event of an earthquake), the pipeline is likely at greater risk in this area and this alternative route is unsuitable. The total length of Alternative route 2 is 23.6 statute miles long, i.e. about 2.5 statute miles longer than the proposed route.

Alternative Route 3

Alternative Route 3 was designed to avoid the Navy cable corridor as much as possible by staying to the east of the Navy cables, except for the crossing point. From the mooring point the route follows Alternative Route 1 to the northwest for about 4 miles, then runs to the north. The route crosses the Global West cable at a water depth of approximately 800 meters. It then climbs up the continental slope in an area with maximum gradients of about 6°, along a smooth and wide ridge between Mugu Canyon and a smaller channel to the west. In the upper part of the slope, between 40 and 60 meters water depth, the route passes 700 to 800 meters to the east of a buoy testing area. Alternative route 3 then turns to the west to cross the Navy cable corridor and to avoid the head of Mugu Canyon. Alternative route 3 runs between the two navigation buoys, through the Navy cable corridor and across both the RELI and FOCUS cables. This route crosses portions of the Navy cables that have been buried to a depth of 1 to 2 feet. The total length of Alternative route 3 is 20.9 statute miles, or 0.2 statute miles shorter than the proposed route. This route runs parallel to the beach and in shallow waters over a distance of approximately 2.86 miles. In this depth, the pipeline would likely be exposed to wave surge during large storms. Running parallel to the shoreline will exacerbate this hazard. In addition, the route runs relatively close to the head of Mugu Canyon, which is potentially seismically active, particularly during periods of flooding and strong storms. For these reasons, Alternative route 3 is not suitable and is not preferred compared to the proposed route.

4.3 TECHNOLOGY ALTERNATIVES

Technology alternatives are alternatives to the proposed Project that would make use of other existing, modified, or proposed LNG terminal and pipeline technologies to meet the stated objectives of the proposed Project. Technology alternatives include using an entirely different approach to meeting the Project objectives, such as use of a fixed, on-shore LNG receiving terminal. Technology alternatives may also be related to specific aspects of the proposed Project such as LNG vaporizer technology.

The Intermediate Fluid Vaporizor (IFV) alternative is retained for detailed analysis in the EA.

4.3.1 FSRU Alternatives

Fixed offshore LNG terminal alternative

An alternative offshore design concept is a fixed terminal design based on gravity-based structures (GBSs). Factors influencing the concept decision include constructability, weather, safety, shipping, environmental setting and regulatory permitting. A GBS would be built on foundation piles that would be driven or drilled into the seabed, comparable to existing fixed offshore oil and gas production platforms in the Santa Barbara Channel.

Such a facility could also be placed on a leveled and stabilized portion of the seabed. GBSs are not well suited to the depth of Cabrillo Port, and so would be located closer to shore. The overall construction schedule for the proposed FSRU would be shorter than that for a GBS, because the fabrication process is very similar to standard LNG tanker dry-dock fabrication. A GBS could also be built in a dry dock and floated into place, but the level of completion of the facility would not be comparable to the completion and pre-testing of the FSRU. The building of a facility on the west coast to build a GBS would take longer than the time to build a FSRU at an existing overseas facility.

The GBS would require much more extensive work to complete the on-site installation and commissioning. Upon decommissioning the GBS would again require much more work than the proposed FSRU. The GBS, after shutdown and purging, would have to be partially dismantled for removal, and foundation piles would have to be cut at the seafloor.

The GBS foundation and support structure, during its operating life, may provide some artificial reef benefit for fish and haul-out areas for marine mammals, and removal of those benefits would be an impact upon decommissioning.

Assuming comparable LNG storage capacity, the visual impact of a GBS would be comparable to or greater than that of the proposed FSRU. The visual impact would be greater if the fixed facility was designed and built completely above the waterline, similar to most fixed oil and gas production platforms. Because the profile of the FSRU is ship-shaped, and because of the more expedient fabrication and commissioning time, the GBS alternative does not present any significant environmental benefit compared to the proposed FSRU.

A variation on the GBS alternative is re-use of an existing oil platform. At this time, the extent of design and restructuring to certify an existing oil production platform for services as an LNG terminal is not known with certainty. Conversion of both operational mode and jurisdictional mode, however, is frequently more costly, and time-consuming than design and installation of a site-specific design. In addition, addition of berthing capability to the platform would create a larger object in the view shed. This option would extend the life of an existing adverse visual impact.

Flow-through regasification facility alternative

In lieu of a facility that provides LNG storage, a LNG terminal, fixed, floating, or on-shore, could be designed simply to receive and regasify the LNG, immediately sending out natural gas to shore. An advantage of this alternative is the absence of LNG storage tanks, thus reduced visual impact. The impact of this alternative compared to the proposed FSRU would be partially dependent upon the regasification technology used. This approach requires the LNG carrier to remain moored for a longer period of time. With the proposed FSRU the LNG carrier can rapidly offload LNG at high flow rates, with an estimated 20-hour span between berthing and de-berthing. In a separate operation, LNG is regasified at a rate dependent upon operational parameters and the demand in the marketplace. With a flow-through facility there is little to no ability to store LNG, so the LNG carrier would be required to offload LNG at a rate comparable to the market-driven natural gas send-out rate. This alternative approach requires longer mooring times for the LNG carrier, which increases the risk of mooring incidents and LNG transfer incidents. This alternative approach is also problematic for customers because the natural gas flow is interrupted in between LNG carrier berthings. This flow interruption would not satisfy the Project objectives of a steady supply rate. Finally, in order to maximize natural gas delivery time and minimize down-time, LNG carriers would be sequenced with narrow time windows between departure of one and arrival of another. This close spacing of LNG carriers unnecessarily increases the risk of a maritime accident. The close spacing of LNG carriers also offsets the benefit of reduced visual impact of the terminal, because the duration of LNG carrier presence would be increased relative to the FSRU. The flow-through alternative approach does not appear to provide any environmental benefits sufficient to offset the increased commercial, safety and maritime risks.

Flow-through mooring point, on-board regasification alternative

Another technology alternative to the proposed FSRU is a flow-through mooring point. The concept provides for an offshore mooring point that rests on the sea floor when inactive. LNG carriers with regasification equipment on board would tie-in to the mooring point, which can be raised to the surface when desired. After mooring, the LNG carrier would initiate regasification, with the natural gas being sent out through the mooring point to a subsea pipeline. This alternative further reduces the visual impact, essentially leaving only the LNG carrier with no visible terminal equipment. The impact of this alternative relative to the proposed FSRU is dependent upon the regasification technology used. This alternative also has the drawbacks of the flow-through alternative, with intermittent natural gas flows, LNG carrier offloading at the rate determined by market conditions, and extended mooring time, and a need to tightly sequence LNG carriers to maximize operations time. The duration of LNG carrier moorings, and the tight sequencing of LNG carrier visits would present a visual impact comparable to that of the proposed FSRU.

4.3.2 Seawater Regasification (IFV Alternative)

The regasification process requires a heat source. The LNG must be pumped through some heating system, where it would absorb heat and vaporize, or regasify, into natural gas. The dominant technologies used for heating are intermediate fluid vaporizers (IFV) and the proposed method of submerged combustion vaporizers (SCV). IFV uses seawater and SCV uses natural gas combustion. The IFV alternative would require about 50 million gallons of seawater per day. That seawater would flow through the vaporizers and then would be returned to the ocean at a lower than ambient temperature.

The primary benefit of IFV relative to the proposed SCV is lower air emissions. SCV uses combustion to generate heat. The combustion process relies on natural gas from LNG, so it is a clean fuel. With SCV the exhaust gases also flow directly through a water bath, which acts as a quench and abatement system. The SCV air emissions will include NO_x, and CO_2. NO_x is a regulated ozone precursor, and CO_2 is a non-regulated greenhouse gas. IFV would introduce some air emissions because of the incremental electricity necessary to operate the large seawater pumps.

The use of this large quantity of seawater for IFV raises concerns over entrainment and impingement of marine species, thermal plumes, turbidity, treated water discharge and noise. Impingement could occur when fish and other aquatic life are trapped against the IFV water intake screens. These screens prevent marine organisms and debris from entering and interfering with the IFV process. Entrainment occurs when aquatic organisms, including eggs and larvae, are drawn into the IFV water intakes, through the facility, and then pumped back out. Thermal plumes could result from the constant discharge of large quantities of relatively cold, and therefore relatively dense, water. Turbidity would be a result of the thermal plumes disturbing seafloor sediments. The IFV alternative would periodically use sodium hypochlorite or another oxidizer to control the growth of marine organisms in the IFV equipment. Discharge of the residual sodium hypochlorite in IFV water could impact marine organisms. Noise would be generated by the large seawater pumps required for the IFV alternative. In general, the use of IFV would be difficult to permit and operate because of water discharge rules and restrictions. The IFV alternative does not provide a clear environmental benefit.

Membrane LNG storage tank alternative

The proposed Moss storage tank design is one of the most common used for LNG transport. The other major tank type is the membrane storage tank. Membrane type storage tanks are built into the inner ship hull, and avoid the spherical shape of Moss tanks. An FSRU or LNG carrier using the membrane type alternative would have a lower profile on the water, and less visual impact. Membrane tanks, however, are more susceptible to failure by rupture due to free-surface-wave forces. For LNG carrier service, these forces in storage tanks are less critical than for the FSRU. This is because LNG carriers' tanks tend to be either full or empty. Free-surface-wave forces are higher in partially filled tanks. The FSRU tanks will operate at variable LNG levels, depending on whether they are receiving, holding, or sending out LNG. Models of the proposed Moss type tanks have been run, and experience has shown that they have the structural strength to withstand forces at all inventory levels. Because of the variable inventory levels that are required for LNG terminal operations, the benefits associated with membrane type tanks are far outweighed by the certainty of the structural integrity of the FSRU storage tank selected.

4.3.3 Pipeline Alternatives

Trenching alternative

The proposed Project uses HDD to cross the shoreline. Trenching is an alternative technology for crossing the shoreline and for continuing to bury the pipeline out to the 13 meter water depth. HDD may require 24-hour a day operation once the drilling is initiated, to reduce the likelihood of the borehole collapsing. Trenching could be performed on a daytime-only schedule, to reduce the noise level. Trenching would, however, be substantially more disruptive to beach and seafloor habitat.

4.3.4 Alternatives Retained for Analysis

Based on the screening of alternatives, the following three were retained for further analysis in the EA, in addition to the Project.

- No Action is described in Section 4.1. In the environmental analysis, No Action conditions are taken as conditions over the next 40 years.

- The Santa Barbara Channel alternative is described in Section 4.2.2. It is located 8.5 miles from the coast, between existing production platforms Grace and Habitat.

- The intermediate Fluid Vaporizer alternative is described in Section 4.3.2. This is a commonly used alternative for regasification.

Figure 4.1-1. Regional Alternatives

Figure 4.3-1. Mooring Point Alternative

Figure 4.3-2. Shoreline Crossing Alternative

Figure 4.3-3. Pipeline Routing Alternative