4.0 ENVIRONMENTAL ANALYSIS

4.1 GEOLOGY

4.1.1 Geological Setting

The proposed plant site is relatively level with grade elevations varying between 33 and 38 feet about sea level (National Geodetic Vertical Datum of 1929). A steel manufacturing facility (now abandoned) was previously located on the site. The facility has been closed for many years and was the subject of a remedial action under the EPA-supervised Superfund program. There continues to be some groundwater remediation on-going at the site. A lined and capped containment facility (land vault) for contaminated soils is adjacent to the site (see Figure 2.1-3). Many large shallow foundations and building remains exist on the site from the abandoned facility.

The Project site is underlain by a mix of sand, shell, limestone, and clay. From ground level to a depth of approximately 5 to 10 feet, the site geology is dominated by various soils, including Urban Land, Lawnwood fine sand, Myakka fine sand, Waveland sand, Immokalee sand. Below the surficial soil horizons are the Plio-Pliestocene-aged sands, sandy limestone, clay, and shell beds present to a depth below ground level of 135 feet to 175 feet. The upper six feet of these sediments is a dense hardpan layer. These sediments are representative of the Pamilco sand, Calooshatchee Marl, and the Tamiami, Anastasia and Fort Thompson Formations. The Plio-Pliestocene sediments unconformably overlie the dense, phosphatic clays of the Miocene-aged Hawthorn Group.

The Hawthorn Group sediments extend from between 175 feet and 763 feet below the ground surface. The Hawthorn Group is a complicated unit consisting of interbedded and intermixed carbonate and siliciclastic sediments containing varying percentages of phosphate grains. The upper portion of the Group is typically well indurated and contains primarily interbedded sands and clays. The lower portion of the Group is more indurated and contains primarily carbonates. The exact composition of the Hawthorn Group is of considerable importance to the proposed project structures due to the overall compressibility of the Formation. Lying below the Hawthorn Group and Suwanee Limestone sediments at depths of approximately 700 to 900 feet below the ground surface is the Ecoene-aged Ocala Limestone. Below the Ocala Limestone, Avon Park Formation extends to a depth of approximately 1,900 feet below the ground surface and below the Avon Park Formation then the Oldsmar Formation extends to depth of approximately 3,500 feet below the ground surface.

4.1.2 Seismic Design Requirements

The seismic design requirements for LNG facilities are contained in the U.S. DOT regulations at 49 CFR Part 193, which adopts the seismic design provisions of the NFPA 59-A 2001. A detailed geotechnical site investigation and a site-specific seismic hazard analysis are required.

NFPA 59-A 2001 defines two levels of earthquake motions, the Operating Basis Earthquake (OBE) and the Safe Shutdown Earthquake (SSE). The OBE and SSE ground motions must be determined by site-specific evaluations and are defined in terms of 5 percent damped response spectra with the following probability levels:

The OBE ground motions at the site are defined as the lesser of:

1. ground motion with a 10% probability of exceedance within a 50 year period (475 year return period); or
2. two-thirds (2/3) of the Maximum Considered Earthquake (MCE) ground motion.

The SSE ground motions at the site are defined as the lesser of:

1. 1% probability of exceedance within a 50 year period (4975 year return period); or
2. two times the OBE.

In NFPA 59-A 2001 the MCE is defined as future potential ground motion with a two percent probability of exceedance within a 50 year period (2,475 year return period) with deterministic limits.

These motions would be used as the basis for the earthquake-resistant design of the LNG facility, applied to the following limited specific list of critical safety-related structures, systems, and components per NFPA 59-A-2001 section 4.1.3:

1. LNG storage containers and their impounding systems;
2. System components required to isolate the LNG container and maintain it in a safe shutdown condition; and
3. Structures and systems, including fire protection systems, the failure of which could affect the integrity of (1) or (2) above.

NFPA 59-A-2001 specifies that the above-referenced structures, systems, and components must be designed to remain operable during and after an OBE, and must provide for no loss of containment capability of the primary container during and after an SSE. The facility design must also provide for the ability to isolate and maintain the LNG container during and after a SSE. After a SSE event, the container must be emptied and inspected prior to resumption of container filling operations. As a minimum, the impounding system must be designed to withstand a SSE while empty and an OBE while holding the maximum operating volume of the LNG container. Seismic recording instrumentation is also required.

4.1.3 FERC Seismic Design Guidelines for LNG Facilities

There are areas where NFPA 59-A 2001 does not provide specific seismic design requirements to enable a comprehensive philosophical approach to the overall seismic safety of an LNG facility. Consequently there can be a wide range of opinions by technical experts on how various requirements are to be applied. In our "*Draft Seismic Design Guidelines and Data Submittal Requirements for LNG Facilities*" (FERC Seismic

Guidelines), January 2007, we provide specific guidance to applicants on FERC Staff's interpretation of the requirements of NFPA 59-A 2001, providing consistent design specifications throughout the U.S., and a basis for uniform reviews of various LNG terminal sites, structures, components, and systems under FERC jurisdiction.

In general, the FERC Seismic Guidelines are based on existing rules and procedures found in ASCE 7-05, ASCE 4-98, API 650 Appendix E, and other current standards documents applicable to LNG facilities. The guidelines also rely on the National Seismic Hazard Maps and the 2006 International Building Code (IBC 2006) MCE Ground Motion Maps, which were developed specifically for use in the design of buildings and other structures in the United States by the United States Geological Survey.

The FERC Seismic Guidelines classify the structures, components, and systems identified in NFPA 59-A 2001 section 4.1.3.3 -- ((1), (2), and (3) above), as "Seismic Category I." The remaining structures, systems, and components are classified as either Seismic Category II or III.

Seismic Category II and III structures, systems, and components are to be designed in accordance with the seismic design requirements of ASCE 7-05 (i.e., IBC 2006). Category II structures, systems, and components must meet the seismic performance goals for "essential" facilities. Category II facilities are expected to survive the Design Earthquake (DE) (which is 2/3 the MCE) with potential structural damage that would not be so severe as to preclude continued occupancy and function of the facility. An "Importance Factor" ("I" or "I_p") of 1.5 is specified for design of Category II facilities.

Category III facilities are considered "non-essential." Normal, non-essential facilities would be designed for the DE in accordance with ASCE 7-05 and are expected to sustain repairable damage when subjected to DE ground motions, although it may not be economical to do so. An "Importance Factor" ("I" or "I_p") of 1.0 is specified for design of Category III facilities.

The FERC Seismic Guidelines provide guidance on lower permitted limits for site specific design ground motions. It also provide guidance in determining the appropriate Site Class spectral amplification values and long-period spectra displacement cutoff transition period per ASCE 7-05, inelastic reduction factors for the SSE, minimum safety factors for tank foundation loadings and maximum permitted foundation settlements, minimum freeboard requirements for LNG sloshing heights and the selection and location of seismic recording devices. Finally, it provides guidance on the seismic design criteria and foundation design criteria to be used for the design of Seismic Category II and III facilities.

4.1.4 Geological Hazards, Site-Specific Geotechnical Investigation and Seismic Hazard Analysis

Golder Associates, Inc. (2007) conducted a detailed geotechnical site investigation and site-specific seismic hazard analysis for the proposed Project. The findings and conclusions regarding geological hazards, foundation design requirements, and seismic design are summarized below.

The two most significant geologic hazards at the site are associated with the potential for sinkhole activity or subsidence. Based on lack of active sinkholes in vicinity of the site, published information, and the fact that clayey silt of the Hawthorn Formation was encountered at depth in all borings, sinkhole potential at the site is considered low. Anticipated subsidence and settlements associated with consolidation of clays within the Hawthorn Group are considered manageable through surcharging and engineering improvements of the subsurface soils.

The site is located in the Atlantic Coast province of the U.S. that extends along the eastern parts of Georgia and Florida. The geomorphic province is characterized generally as having one of lowest seismic hazards within the conterminous 48 states. Due to the relative stability in Florida, the 2006 IBC assigns structures that are located at the project site Seismic Category A which is the lowest seismic design requirements assignment.

Generally, there are no known major fault systems beneath the Florida Platform and there is no evidence of major active faulting or deformation in Florida during the Holocene Epoch or the Neogene Epoch. No faults are known to be active in Pleistocene time in Martin County. Therefore, the potential for surface faulting at the site is considered extremely remote.

Along the Gulf and Atlantic coasts, the potential wave run-up due to hurricane storm surge is far greater than any potential tsunami wave run-ups. The distance of the site and its elevation above sea level indicate therefore a negligible probability of significant impacts from tsunamis or hurricane storm surge at the site.

The site is located approximately eight miles to the east of Lake Okeechobee. The normal water elevation of the lake is approximately 14 feet above mean sea level. The distance of site from Lake Okeechobee, its elevation of the site above the lake level, and the low probability of strong earthquake ground motions indicate a negligible probability of significant site impacts from seiches.

Based on medium to very dense soils at the site and the low SSE design ground motions, it was concluded that liquefaction of the soils below the LNG tank foundations and at other portions has a negligible probability of occurring.

Because liquefaction is not expected to occur during the SSE, liquefaction induced settlements or lateral spreading ground movements are not expected at the site.

Because of the low level of SSE shaking and the medium to very dense soils at the site, significant seismic compaction settlements are not expected at the site.

The measured shear wave velocity of the soil profile at the site increases nonlinearly from approximately 260 feet per second (fps) from the ground surface to about 1,000 fps at a depth 100 feet below the ground surface. The weighted shear wave velocity in the upper 100 feet of the soil profile is about 750 fps. This characterizes the soil profile as Site Classification D (stiff soil) in accordance with provisions of the 2006 IBC and ASCE 7-05.

The site would be cleared, grubbed, and stripped of vegetation and existing foundations will be broken up and removed. Surficial soils will be stripped and engineering fill recompacted to a depth determined during detailed design. In the foundation areas of the

LNG tanks surcharging with soil will be applied for a limited period. The surcharge, which would require approximately 75,000 cubic yards of earthfill, would be configured as the frustum of a cone that is 20 feet in height with a surcharge footprint of approximately 3.2 acres. Surcharge material would have a dry unit weight of no less than 110 pounds per cubic foot after placement and compaction. The expected duration of constructing the surcharge for the first tank is estimated to be about one month, and the surcharge would remain in place for at least one month after it is constructed. The surcharge for the second tank would be applied using the same material during construction of the first tank, and the duration of the second surcharge would be longer than one month. About twelve settlement plates would be installed along the tank perimeter and two horizontal inclinometers would be installed on perpendicular diameters of the surcharge footprint. The induced stresses would be measured using stress cells installed at the base of the surcharge. The instrumentation would be monitored regularly to measure settlement. The material used for the surcharge could thereafter be used on-site as structural fill. The major equipment and facility's foundation (including the LNG tanks) are proposed to be supported by shallow reinforced concrete mat foundations. The foundations will in turn be supported by engineered fill. The fill elevation of all areas of the Project will be several feet above the water table and it is expected that few excavated areas will require extensive dewatering. The LNG tank mat will be 300 feet in diameter, three to four feet thick at the edge and taper to two feet thick at the center. The LNG tank foundation has the following settlement tolerances (which satisfy the recommendations in the draft FERC Seismic Design Guidelines):

- Tilting settlement of less than 6 inches;
- Out of plane settlement of the outer tank shell of less than 1.25 inches in a 100-foot arc length;
- Center to edge dishing settlements of less than 6 inches; and
- After connections to the tank are made, a total settlement of less than 1 inch.

Controlling Seismic Events

Generally, there are no known major fault systems beneath the Florida Platform and there is evidence of major active faulting or deformation in Florida during the Holocene Epoch or the Neogene Epoch. Deaggregation of the seismic hazard from a probabilistic seismic hazard assessment indicates that local moderate magnitude earthquakes (M 4.5 - 5.0) contribute most of the earthquake hazard in the region of the site. A small contribution to the hazard derives from the occurrence of large magnitude earthquakes in the southeastern United States (e.g. Charleston, South Carolina). The local earthquakes are not associated with any specific faults or seismic source zones but instead the very small possibility that moderate earthquakes could occur anywhere in the region.

Input Ground Motions

Input ground motions for the site (also called Design Ground Motions) were determined based on probabilistic seismic hazard maps developed by the USGS in 2002. These maps also form the basis of the MCE mapped values found in the 2006 IBC and ASCE 7-05.

The values have been adjusted to account for soil amplification effects based on Site Classification D. The ground motions have been determined in a manner that conservatively satisfy recommendations found in the draft FERC Seismic Design Guidelines and requirements of NFPA 59-A 2001.

- The MCE ground motion parameters (not adjusted for site effects) are S_s = 0.069 g and S_1 = 0.027 g. The value of T_L is 8 seconds. When adjusted for site effects, the MCE ground motion parameters are S_{MS} = 0.111g and S_{M1} = 0.064g.
- The DE ground motion parameters adjusted for site effects (which are 2/3rds of the MCE value adjusted for site effects) are S_{DS} = 0.074g and S_{D1} = 0.043g.
- The OBE was conservatively taken as equal to the DE. The OBE peak horizontal ground acceleration for the site is 0.034g. The vertical OBE design ground spectra is the OBE horizontal ground motion spectra multiplied by 2/3rds resulting in an OBE peak vertical ground acceleration for the site of 0.023g.
- The SSE was taken as equal to twice the OBE. Since the OBE was taken as the DE, the SSE conservatively satisfies the minimum SSE limitations provided in the draft FERC Seismic Design Guidelines. Therefore, the SSE design ground motion response spectra is twice the OBE design response spectra with an SSE peak horizontal ground acceleration of 0.067g. The vertical SSE design ground motion is the SSE horizontal ground motion spectra multiplied by 2/3rds resulting an SSE vertical ground acceleration for the site of 0.045g.

Final designs and supporting documentation for all critical structures and foundations (Seismic Category I) will be required prior to FERC approval to proceed with construction. **We recommend the following conditions to any approval the Commission might issue for the proposed project:**

1. **File a detailed plan, including calculations, for the LNG tank foundation surcharge, <u>prior to construction</u>.**
2. **File a list of all structures, systems, and components that are assigned Seismic Category I <u>prior to construction</u> for review as described in section 3.6 of Part II of the FERC Seismic Guidelines.**
3. **Seismic Design Criteria should be provided for all Seismic Design Category I structures, systems, and components as described in section 3.7 of Part II of the FERC Seismic Guidelines <u>prior to construction</u>. The Seismic Design Criteria should satisfy Part I of the FERC Seismic Guidelines.**
4. **LNG Tank and Foundation Design should comply with Part I of the FERC Seismic Guidelines. Submittals that demonstrate compliance should be provided <u>prior to construction</u>.**

5. **Final foundation design recommendations for all other Seismic Category I structures should be submitted for review and approval <u>prior to construction.</u>**

6. **All items identified in the submitted geotechnical/seismic reports which were proposed to be addressed during the detailed design should be submitted for review and approval <u>prior to construction</u>.**

7. **Seismic specifications to be used in conjunction with the procuring equipment as described in section 3.10 of Part II of the FERC Seismic Guidelines should be submitted for review <u>prior to the issuing of requests for quotations</u>.**

8. **Quality Control and Assurance procedures as described in section 3.11 of Part II of the FERC Seismic Guidelines that will be used for design and construction should be submitted for review <u>prior to construction</u> of the project.**

9. **A seismic instrumentation plan as described in section 3.12 of Part II of the FERC Seismic Guidelines should be provided <u>prior to commissioning</u>.**

10. **The results of the hydrostatic load tests on the LNG storage tanks, including settlement data as described in section 7.4.1 of the FERC Seismic Guidelines should be provided <u>prior to commissioning</u>.**

4.1.5 Extractive Resources

Florida has a variety of non-fuel minerals and isolated pockets of fossil fuel resources. Important non-fuel minerals include heavy minerals (i.e., ilmenite, rutile, zircon, and leucoxene), phosphate rock, sand and gravel, and peat (FDEP, 2006).

According to McClellan and Eades (1997), Martin County does not possess mineral resources in economic quantities; state mapping does not show any mines within 0.25 mile of the Project area (FDEP, 1996). The fossil fuel resources of Florida are generally concentrated in two areas of the state: the Sunniland Oil and Gas Field in southwestern Florida (Collier, Hendry, and Lee counties) and the Jay Oil and Gas Field in northwestern Florida (Santa Rosa and Escambia counties) (McClellan and Eades, 1997). No fossil fuel resources are found in Martin County. Therefore, the Project would not affect extractive resources.

4.1.6 Paleontological Resources

Paleontological resources are the fossilized remains of prehistoric plants and animals as well as impressions left in rock or other materials as indirect evidence of the forms and activities of such organisms. The surficial deposits at the LNG storage facility site are Quaternary (i.e., Holocene and Plio-Pleistocene-aged) deposits, which are generally unconsolidated and have poor fossil preservation potential. The major fossil-bearing units are deeply buried in the Project area and are inaccessible (Jones, 1997; MacFadden, 1997); therefore, the Project would be unlikely to affect any fossil caches of scientific significance.

4.2 SOILS

Soils at the Project were analyzed using the Web Soil Survey, which provides soil data and information produced by the U. S. Department of Agriculture - NRCS as part of the National Cooperative Soil Survey. In general, Project soils formed in sandy marine sediments of the Atlantic Coastal Plain. These soils typically occur on flatwoods where the landscape is zero to two percent slope and in depressions and drainage ways in flatwoods where slopes are five to six percent.

Table 4.2-1 provides the general soil characteristics for each of the soil map units in the Project area. None of the Project soils are classified as Prime Farmland or considered to have a high erosion potential by the NRCS.

The LNG storage facility site consists of fine sandy soils (four separate soil mapping units) that are very poorly to poorly drained, primarily because of shallow depth to groundwater and zero to two percent slopes, and considered partially hydric. Most (53 percent) of the storage facility site was disturbed by the former Florida Steel manufacturing plant that operated from 1970 to 1982 that left much of the site contaminated with polychlorinated biphenyls (PCBs), lead, and zinc (see Section 4.7.5 for additional information). As part of the EPA-supervised remediation, much of the surface soils on the site were removed, treated, and placed in an on-site landfill. The landfill (referred to as the "land vault") would not be included in the Project.

The pipeline, construction staging area, M&R station, and the pipeline interconnections primarily traverse sandy soils with small inclusions of loamy sands and muck, which encompass over 15 separate soil mapping units. These soils are generally very poorly to poorly drained and considered hydric or partially hydric.

Major soil characteristics and limitations for the LNG storage facility, pipeline and aboveground facilities, and construction staging area are summarized in Table 4.2-1.

4.2.1 Soil Composition and Limitations

Drainage Class

The drainage class of a soil is the range of its relative wetness under natural conditions. Soils with good drainage lose water and have low wetness, while soils with poor drainage retain water and have high wetness. Differences in drainage properties are typically attributed to grain size and sorting. Well-sorted or coarse-grained soils have more pore space and thus are better drained. Poorly-sorted or fine-grained soils have less pore space and prevent water from draining. Six classes of drainage, ranging from very poorly drained to excessively drained, are used to describe the relative wetness of a soil (NRCS, 1994).

Table 4.2-1

Soils at the FGS Project

Soil Unit	Acreage	Erosion Potential	Revegetation Potential	High Compaction Potential	Drainage Characteristics	Hydric	Prime Farmland
LNG Storage Facility							
Lawnwood and Myakka fine sands (L&M)	0.56	Slight	Fair	No	Very poorly, poorly	Partially	No
Waveland and Immokalee fine sands	71.63	Slight	Fair	No	Very poorly, poorly	Partially	No
Placid and Basinger fine sands (P&B)	6.73	Slight	Fair	No	Very poorly, poorly	Partially	No
L&M and P&B	48.64	Slight	Fair	No	Very poorly, poorly	Partially	No
Open Water	9.26	NA	NA	NA	NA	NA	NA
Pipeline							
Arents, 0 to 2 pct slopes	0.77	Slight	Very poor	No	Somewhat poorly	No	No
Chobee loamy sand, depressional	1.85	Slight	Poor	No	Very poorly	Yes	No
Floridana fine sand, depressional	0.87	Slight	Very poor	No	Very poorly	Yes	No
Holopaw fine sand	6.31	Slight	Fair	No	Very poorly	Partially	No
Jupiter sand	0.56	Slight	Poor	No	Very poorly	Partially	No
Lawnwood and Myakka sands	2.15	Slight	Fair	No	Very poorly	Partially	No
Placid and Basinger fine sands	2.87	Slight	Fair	No	Very poorly, poorly	Partially	No
L&M and P&B	3.38	Slight	Fair	No	Very poorly, poorly	Yes	No
Malabar fine sand, high	0.72	Slight	Poor	No	Very poorly, poorly	Partially	No
Oldsmar fine sand	3.13	Slight	Fair	No	Very poorly, poorly	Partially	No
Pineda and Riviera fine sands	1.44	Slight	Fair	No	Very poorly, poorly	Partially	No
Samsula muck	0.72	Slight	Very poor	No	Very poorly	Yes	No
Sanibel muck	1.03	Slight	Poor	No	Very poorly	Yes	No
Wabasso sand	0.72	Slight	Poor	No	Very poorly, poorly	Partially	No
Waveland and Immokalee fine sands	22.05	Slight	Fair	No	Very poorly, poorly	Partially	No
Temporary Workspaces							
Waveland and Immokalee fine sand	5.09	Slight	Fair	No	Poorly	Partially	No
Holopaw and Oldsmare fine sands	1.51	Slight	Fair	No	Poorly	Partially	No
Lawnwood and Myakka Fine Sand	1.77	Slight	Fair	No	Poorly	Partially	No
Chobee Loamy Sand, Depressional	0.66	Slight	Poor	No	Very poorly	Yes	No
Oldsmar Fine Sand	0.38	Slight	Fair	No	Poorly	Partially	No
M&R Station							
Oldsmar fine sand	1.50	Slight	Fair	No	Poorly	Partially	No
Pineda and Riviera fine sands	1.25	Slight	Fair	No	Poorly	Partially	No
Interconnection							
Holopaw Fine Sand	0.11	Slight	Fair	No	Poorly	Partially	No
Oldsmar fine sand	0.11	Slight	Fair	No	Poorly	Partially	No
Construction Staging Area							
Waveland and Immokalee fine sand	10.46	Slight	Fair	No	Poorly	Partially	No
Waveland and Lawnwood fine sands, depressional	0.04	Slight	Fair	No	Poorly	Partially	No

* Partially hydric soils are those soils in which only portions of the mapped soil unit display hydric characteristics. This is caused by changes in topography within a mapped soil unit.

All the Project soils contain high water tables leading to very poor to poor drainage classes. Project construction would, therefore, temporarily impact 127.03 acres of soils with high water tables. If active drainage tiles, culverts, or other drainage facilities are damaged during construction, FGS would replace or repair them to a condition equal to or better than their pre-construction condition. In addition, FGS would be responsible for ensuring that all areas affected by construction activities were final-graded and restored as closely as possible to pre-construction contours. Although damage to drainage structures and patterns would result in short-term impacts, the corrective procedures to be implemented by FGS would avoid or minimize any long-term effects.

Hydric Soils

Hydric soils are defined as "soils that formed under conditions of saturation, flooding or ponding long enough during the growing season to develop anaerobic conditions" (NRCS 2006). Soils that formed under hydric conditions in their unaltered state are still considered hydric when artificially drained or altered for such purposes as agricultural use. Hydric soils are typically poorly drained; the presence of hydric soils is one of the criteria used for defining wetlands. Hydric soils may also be prone to compaction and rutting. With the exception of the small Arents inclusion along the pipeline corridor, all Project soils are considered to be at least partially hydric.

Project construction would temporarily impact approximately 126.24 acres of hydric soils. Project operations would affect 78.40 acres for the LNG storage facility and pipeline right-of-way.

Shallow Bedrock

Rock can be introduced into the surface layers of soils during various construction activities such as blasting and trenching. Such introductions can reduce moisture-holding capacity, thereby reducing soil productivity and creating poor revegetation potential. The presence of shallow bedrock, defined as bedrock within 60 inches of the land surface, is often used as an indicator of the potential for introduction of rock to surface layers of soil.

Approximately 0.56 acre of the pipeline corridor crosses soil with bedrock located within 60 inches of the ground surface. According to the NRCS, the Jupiter sand soil series has hard fractured limestone bedrock beginning approximately 14 to 16 inches below the ground surface. FGS anticipates using mechanical methods to trench through this bedrock to the desired trench depth. No blasting is anticipated. Any limestone encountered would be removed, crushed, and used for fill for the internal roads at the LNG storage facility site. There is no shallow bedrock at the storage facility site.

Erosion Potential

Erosion potential is the potential for soil to erode when unprotected from erosive forces such as wind or water. Many factors influence the erodibility of soil such as soil structure, drainage characteristics, texture, slope, climate, and vegetation. Project construction can contribute to soil sensitivity to water and wind erosion. Soils are most

susceptible to erosion after vegetation is removed and before the reestablishment of vegetative cover after the pipeline is installed.

Severe erosion is not anticipated across the Project due to the relatively flat topography and sandy-textured soils. Project construction would not affect any highly erodible soils. During construction and operation, FGS would implement our Plan; therefore, we do not anticipate permanent impacts to soils from erosion hazards.

Revegetation Potential

Revegetation potential is a rating of the ability of a soil to support revegetation efforts following construction-related disturbances. The potential for revegetation of each soil type that would be affected by construction of the Project was assessed based on such factors as soil texture, drainage properties, wetness, and slope. Taking these factors into account, four general classes were defined for revegetation potential ranging from very poor to good. A poor rating includes soils with coarse-textured surface textures (i.e., fine sand or coarser) that are well drained, somewhat excessively drained, excessively drained, or soils in depressions with ponded conditions for most of the year. The majority of the soils in the Project area have a "fair" revegetation potential, including all soils at the LNG storage facility site.

Pipeline construction would temporarily impact 7.90 acres of soils classified as containing poor to very poor revegetation potential. FGS would implement the requirements in our Plan for revegetation of disturbed areas, including consultation with the NRCS and appropriate state and local land management agencies regarding Project-specific restoration measures. We conclude that if revegetation is conducted in accordance with these measures, areas disturbed by construction would be successfully revegetated. Section 4.4.2 further discusses revegetation.

4.2.2 Contaminated Soils

Section 4.7.5 discusses issues related to the inclusion of the LNG storage facility site in the Superfund Program pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act. Contaminated soils on the storage facility site have been removed, treated, and placed in a secure landfill (land vault) pursuant to the conditions of the EPA-approved Record of Decision under the Superfund Program (see Figure 2.1-3). No other sites with contaminated soils are known in the Project area.

4.2.3 Mitigation

In order to minimize and mitigate the impacts to soil resources described above, FGS would adopt and follow the guidelines described in our Plan during Project construction and operation. The intent of our Plan is to identify baseline mitigation measures for minimizing erosion and enhancing revegetation in upland areas. Mitigation measures identified in our Plan include using erosion controls (e.g., slope breakers, silt fencing, and mulch) during construction to control runoff, reducing the time of soil disturbance, and reestablishing contours and vegetative cover as soon as practicable.

FGS would also develop and implement a Stormwater Pollution Prevention (SWPP) Plan in compliance with federal and state regulations, including those of the SFWMD. The SWPP Plan would incorporate the requirements for mitigating upland erosion and revegetation described in our Plan and would further detail the erosion control best management practices, inspection procedures, and reporting protocols to be implemented during construction of the Project. FGS indicates that its SWPP Plan would also include an Erosion and Sedimentation Control Plan and incorporate best management practices for stormwater systems at the LNG storage facility.

Other potential impacts during construction would include the accidental release of petroleum hydrocarbons or other hazardous materials such as fuels, lubricants, and coolants that would be used during construction. FGS has prepared a SPCC Plan that describes the management of hazardous materials during Project construction. This plan was filed by FGS in its certificate application in October 2007 and can be found on the FERC's eLibrary website at www.ferc.gov under Docket No. CP08-13-000. FGS would implement this SPCC Plan to prevent and contain, if necessary, accidental spills of any material that may contaminate soil and water resources and ensure that inadvertent spills of fuels, lubricants, or solvents are contained and cleaned up in an appropriate manner.

Although not anticipated, contaminated soils could be encountered during construction activities. The mismanagement of contaminated material could adversely affect soil resources. FGS developed an Unanticipated Hazardous Waste Discovery Plan identifying the procedures that would be implemented during construction to identify, test, treat, and dispose of such materials in accordance with the appropriate federal and state regulations. This plan was filed by FGS in its certificate application in October 2007 and can be found on the FERC's eLibrary website at www.ferc.gov under Docket No. CP08-13-000.

With the implementation of our Plan and FGS's SPCC and SWPP plans, impacts to Project area soils would be minimized and minor in nature.

4.3 WATER RESOURCES

4.3.1 Groundwater

Groundwater is a significant source of drinking water in the State of Florida, which historically obtains nearly all of its drinking water from aquifers. The Project is located over two aquifers: the non-artesian surficial aquifer system and the artesian Floridan aquifer system. The surficial aquifer, situated approximately 15 to 150 feet below ground surface, is the principal source of fresh water in Martin County. The direction of shallow groundwater flow is to the south towards the St. Lucie Canal (Ardaman, 2006).

A silt and clay unit with low permeability (Hawthorne Group) separates the surficial aquifer from the Floridan aquifer. In contrast to the surficial aquifer, the Floridan aquifer is part of the largest, oldest, and deepest aquifer system in the southeastern United States. Ranging over 100,000 square miles, it underlies all of Florida as well as parts of southern Alabama, southeastern Georgia, and southern South Carolina.

The Indiantown Company, a local water utility which supplies drinking water to the area around the Project, uses the surficial aquifer as its water source. It is the largest permittee of groundwater use for public water supply near the LNG storage facility site. The utility's wells are located in Indiantown, approximately two to three miles south of the storage facility site. Permitted irrigation and industrial supply wells near the Project include the FPL Martin power plant, Louis Dreyfus citrus processing plant, and the Cogentrix power plant.

With the exception of the LNG storage facility site and the adjacent landfill "vault," there are no hazardous waste sites or known areas of contaminated groundwater in the area potentially affected by Project facilities. A groundwater remediation system, which was activated on the storage facility site in April 1997 to address high sodium concentrations, is still in operation (Ardaman, 2006). The remediation system consists of groundwater recovery, injection, and production wells as well as numerous monitoring wells. The water is discharged via land application on three spray fields totaling 40 acres in the northern portion of the storage facility site. FGS has incorporated the existing remediation system into the overall Project design and would comply with all on-going EPA required remediation activities.

Construction Effects

Project activities would not occur within 500 feet of any public water supply well and would not affect any sole-source aquifers or existing or planned wellhead protection areas. Pipeline trenches can redirect groundwater flow by providing a new path of less resistance or by blocking the original flow path. Most of the pipeline trenches for this Project would be oriented in the southeast direction, which is generally consistent with natural flow paths to the south; therefore, blockage should not be a significant issue. FGS does not propose any trench dewatering.

Accidental Project-related spills or leaks of hazardous materials could potentially impact groundwater. FGS has agreed to adopt the spill prevention, control, and countermeasures included in our Procedures. In addition, FGS has developed an SPCC Plan that describes the management of hazardous materials such as fuels, lubricants, and coolants that would be used during construction and operation. Given the adoption of the measures in our Procedures and the SPCC Plan, the risk of accidental spills or other introduction of hazardous materials to groundwater would be minimized.

Operations Effects

The potential for impacts to groundwater resources resulting from the Project is a function of the magnitude and location of the withdrawal. The Project would be served with potable water by the Indiantown Company, which has an existing Consumptive Use Permit from the SFWMD for groundwater withdrawals . The LNG storage facility operation would withdraw groundwater at a rate of 18 to 30 gpm for landscape irrigation. FGS would use an existing on-site production well, which was formerly used as part of the groundwater remediation system, to satisfy its landscaping water requirements. The FDEP Hazardous Waste Cleanup Section stated that it has no objection to the use of the on-site well for irrigation and fire control purposes pursuant to certain conditions (FDEP,

November 28, 2007). The proposed irrigation well was previously pumped at rates similar to or greater than the anticipated demand for landscape irrigation. The modeling performed during design of the remediation system and the performance during operation of the remediation system both demonstrate that the use of groundwater for landscape irrigation would have negligible effects on nearby wells and the on-site groundwater remediation system. The remainder of the storage facility's operational water requirements (e.g., sanitary and potable water) would be supplied via the Indiantown Company municipal water system and would not affect on-site groundwater. Given the proposed volume of water withdrawal, Project operations would have a negligible effect on groundwater levels and flow paths.

The SFWMD reviewed the compatibility of the proposed groundwater withdrawals with local groundwater resources as part of FGS' Water Use Permit applications. The rates of groundwater withdrawal would not adversely affect natural groundwater systems and existing users or degrade groundwater quality. The SFWMD approved the Water Use Permit (No. 43-02186-W) on April 10, 2008, for groundwater withdrawals for landscaping use at the storage facility.

Pipeline facility operations would not require any groundwater withdrawals.

4.3.2 Surface Water Resources

The Project is situated within the Everglades Watershed (U. S. Geological Survey Hydrologic Unit Code 03090202) and, more specifically, within the approximately 117,000-acre St. Lucie Canal drainage basin. The only major surface water feature in the Project area is the St. Lucie Canal. The St. Lucie Canal connects Lake Okeechobee to the Atlantic Ocean through the Indian River Lagoon and St. Lucie estuary. Two locks on the canal control its flow. The only waterbodies at the Project are three stormwater management ponds located on the LNG storage facility site and five drainage ditches along the pipeline right-of-way.

The COE, in cooperation with the SFWMD and numerous other federal, state, local, and tribal partners, has started construction of the St. Lucie Canal Reservoir/Stormwater Treatment Area as a component of the Comprehensive Everglades Restoration Plan. This component would collect and treat local stormwater runoff from the basin thereby decreasing flows and improving water quality in the St. Lucie estuary. The Project would not conflict with this or any other proposed Everglades restoration efforts.

The FDEP has established water quality standards to maintain water quality consistent with the associated goals of protecting public health, recreation, and the propagation and maintenance of healthy, well-balanced populations of fish and wildlife. Surface waters in the State are classified according to designated uses, with classifications arranged in order of the degree of protection required. Class I water (i.e., potable water supplies) generally has the most stringent water quality criteria, and Class V the least. The St. Lucie Canal is designated as Class III (i.e., recreation, propagation, and maintenance of healthy and well-balanced population of fish and wildlife). The site is not within or adjacent to any designated Outstanding Florida Waters or Aquatic Preserves.

The primary potential effects of Project construction and operation on surface water resources would be the potential for erosion and sedimentation during construction and stormwater runoff during operations. The potential for accidental spills of hazardous materials could occur during either facility construction or operations. Both the LNG storage tanks and the pipelines would also use surface water for hydrotesting.

LNG Storage Facility

During construction of the LNG storage facility, land required for Project development would be cleared of vegetation and graded to the desired elevations, increasing the potential for erosion and sedimentation. Temporary ditches, sediment fences, and silt traps would be installed as necessary in accordance with our Plan and applicable state and local sediment and erosion control regulations. Some of the mitigation measures identified in our Plan include using erosion controls (e.g., silt fencing) during construction to control runoff; reducing the time of soil disturbance, and re-establishing contours and vegetative cover as soon is practicable after construction is complete. Stormwater from areas disturbed during construction would be discharged under a General Construction Permit pursuant to the National Pollutant Discharge Elimination System (NPDES) program, which would include conditions requiring FGS to implement appropriate pollution prevention techniques to reduce erosion and sedimentation and properly manage stormwater. FGS would also develop and implement a site-specific SWPP Plan. Given these protective measures, any effects to surface water associated with construction of the storage facility site would be minor.

Stormwater draining from the LNG storage facility site during Project operations may carry various pollutants. FGS proposes to expand one of the three stormwater management ponds on the site to accommodate the increase in stormwater runoff. FDEP and Martin County have approved the stormwater management plans for the site through its Environmental Resource Permit (ERP) and Major Development Master Site Plan, respectively. Wastewater (principally domestic) generated at the storage facility would be disposed of through sewage lines extended by Indiantown Company to a wastewater treatment plant.

Pipeline and Aboveground Facilities

The pipeline and associated aboveground facilities would not cross any naturally occurring waterbodies, including any major, navigable, or sensitive waterbodies. The only waterbodies along the pipeline right-of-way are five small intermittent drainage ditches. FGS proposes to use the open cut/conventional lay method across four of these ditches and bore the ditch at MP 0.99. Section 2.4.2.2 describes the specialized construction procedures that FGS would implement to minimize impacts on waterbodies.

It is possible that no flow would be present during construction across the four intermittent ditches, in which case the open-cut method would have little impact on the waterbody. Nevertheless, FGS would follow our Procedures to limit water quality impacts to waterbodies during construction. Construction activities would be scheduled so that the pipeline trench would be excavated immediately prior to pipelaying activities. FGS would use rubber tire backhoe-type excavators to open a trench across the ditch.

The duration of construction would be limited to 24 hours barring unforeseen circumstances. Excavated trench spoil would be stockpiled at least 10 feet from the edge of the waterbody with appropriate erosion and sedimentation control measures. The ditch banks would be stabilized. Most impacts, therefore, would be temporary; turbidity levels would be expected to return to preconstruction levels soon after construction in each ditch is completed.

Hazardous Material Spills

Lubricants, hydraulic fluid, and fuel spills from refueling construction equipment, or equipment failure in or near a waterbody could flow or migrate to a waterbody. In the event of an accidental spill of these or other hazardous materials during Project construction or operation, FGS would follow measures specified in our Procedures. Our Procedures include, but are not limited to, the following measures:

- overall structuring of operations to reduce the risk of accidental spills or introduction of fuels or other hazardous materials into the environment;
- proper training of employees handling fuels and other hazardous materials;
- regular inspection of equipment to ensure good operating order;
- storage of hazardous materials and refueling of equipment at least 100 feet from any wetland or waterbody;
- provisions to have the necessary tools, equipment, and supplies on hand to contain and recover spilled materials at the job site; and
- prompt reporting of any spills to the appropriate agencies.

In addition, FGS has developed and would implement its own SPCC Plan. Given the adoption of the measures in our Procedures and the additional measures in FGS' site-specific SPCC Plan, the risk of accidental spills or other introduction of hazardous materials to waterbodies would be effectively minimized.

Hydrotesting

FGS would hydrotest the LNG storage tanks and pipelines after installation in compliance with DOT pipeline safety regulations (see Section 2.4.1.4 and 2.4.2.1 for further details on hydrotesting procedures). FGS proposes to use water from the St. Lucie Canal as the primary source for the hydrotest water. Hydrotesting of the LNG storage tanks and the two pipelines would require a one-time withdrawal of approximately 33.5 million and one million gallons of water, respectively, which would be pumped at a rate of approximately 1,500 gpm. Upon completion, the test water would be pumped back to the canal in a manner and at a location where erosion and damage would be minimal. FGS indicates that it would not use any biocides or other water additives.

The proposed withdrawal rate of 1,500 gpm represents less than 0.1 percent of the average annual flow in the St. Lucie Canal and would have a negligible effect on water flow. FGS would be required to obtain a general NPDES permit administered by the FDEP with EPA oversight. FGS would also avoid or adequately minimize potential effects to waterbodies resulting from hydrostatic testing by implementing our Procedures, which include, but are not limited to, the following measures:

- obtain and comply with all applicable water withdrawal permits and special-status stream permits;
- address the operation and fueling of any pumps within 100 feet of waterbodies or wetlands in the Project-specific SPCC plan;
- maintain adequate flow rates in all source waterbodies to protect aquatic life and provide for all downstream uses;
- screen all hydrostatic test water withdrawal intakes to prevent entrainment of fish and aquatic organisms; and
- regulate the discharge of hydrostatic test waters using energy dissipation devices to prevent erosion, scour, turbidity, or excessive streamflow.

Since FGS would return the water to its original source for discharge, not add any chemicals to the water, and implement our Procedures, we believe that the withdrawal and discharge of the hydrotest water would not adversely affect receiving water quality. The SFWMD approved the Water Use Permit (Permit 43-02186-W) on April 10, 2008 for hydrostatic testing of the storage tanks and pipeline.

4.4 VEGETATION

The Project encompasses both wetland and upland vegetative communities, the acreages of which are provided in Table 4.4-1.

Table 4.4-1

Existing Project Vegetative Cover

Project Components	Wetlands and Waterbodies	Uplands	Total
LNG Storage Facility	27.95	108.86	136.81
Pipeline construction ROW, construction staging area, and aboveground facilities	3.91	67.54	71.45
Total	***31.86***	***176.40***	***208.26***

4.4.1 Wetlands

The COE defines wetlands as areas that are inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in

saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas. Wetlands perform a number of valuable functions including flood flow attenuation, sediment retention, nutrient retention, provision of wildlife habitat, groundwater recharge and discharge, recreation, and erosion control.

Section 404 of the Clean Water Act established standards to minimize impacts to wetlands under the regulatory jurisdiction of the COE. These standards require avoidance of wetlands where possible and minimization of disturbance where impacts are unavoidable to the degree practical. All wetland crossings would be subject to review and approval by the Jacksonville District of the COE, including the provisions for any required wetland compensatory mitigation.

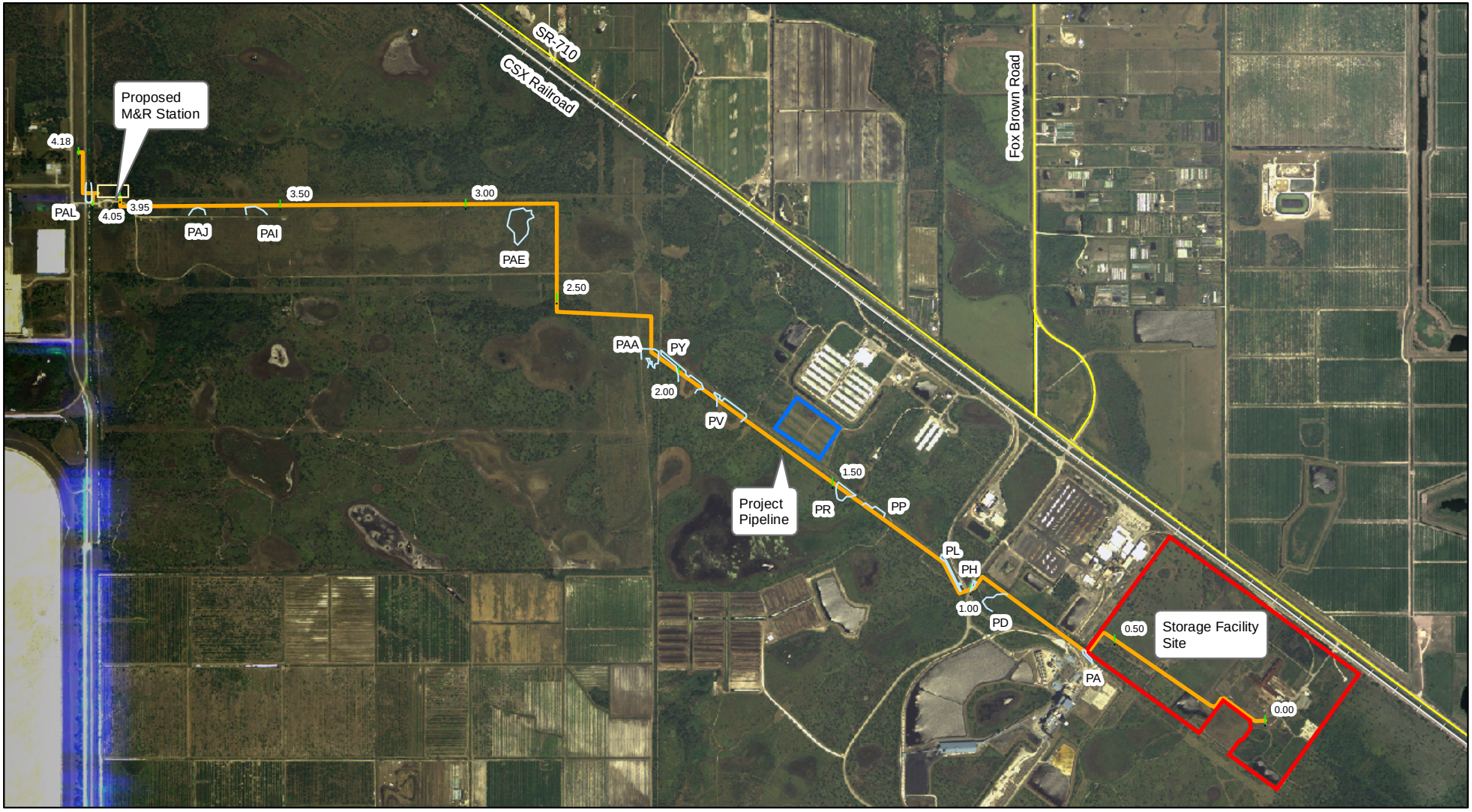
In addition to federal regulation, the FDEP regulates dredging, filling, and construction in wetlands through its ERP. The FDEP also ensures that activities in uplands, wetlands, or other surface waters do not degrade water quality or the habitat for wetland dependant wildlife. FGS submitted two ERP applications to the FDEP on July 30, 2007 - one for the storage facility site and one for the pipeline. On May 19, 2008, the FDEP issued the final ERP for the storage facility site; the pipeline ERP application is still under review.

Martin County's Land Development Regulations restrict impacts to wetlands and require maintenance of a 50- to 75-foot buffer around wetland boundaries and additional construction setbacks. The Martin County Environmental Division of the Growth Management Department is responsible for reviewing wetland permit applications for consistency with County environmental policies and regulations.

Wetland delineations were conducted for the LNG storage facility site in 2005 and along the pipeline corridor in 2007 in accordance with the requirements of the COE's Wetland Delineation Manual (Environmental Laboratory, 1987). The COE is responsible for approving wetland delineations and determining each wetland's jurisdictional status. FGS submitted a written request to the COE in July 2007 for its jurisdictional determination, but the COE has not yet formally responded. The COE indicated that most of the Project wetlands are isolated and not subject to COE jurisdiction; however, one drainage ditch near to the storage facility site is hydrologically connected to "waters of the United States" and would likely be subject to COE jurisdiction (Reusch, 2008). FDEP reviewed the wetland delineation as part of the ERP Permit (approved March 19, 2008) and no state jurisdictional wetlands were identified.

There are 27.95 acres of wetlands and waterbodies on the LNG storage facility site and 3.91 acres along the pipeline corridor (see Table 4.4-1 and Figure 4.4-1). There are no wetlands or waterbodies at the temporary workspaces, construction staging area, M&R station, or pipeline interconnection sites. The COE has indicated it will make a permit decision in the near future.

None of the wetlands at the Project qualify as high-quality, sensitive, or special-status wetlands. These wetlands have generally been degraded by disturbance or colonization by exotic and nuisance species. The Florida Natural Areas Inventory database does not identify any significant natural communities within the Project area.



Legend

- Milepost
- Roads
- Railroad
- Project Pipeline
- Project Wetlands
- Construction Staging Area
- Storage Facility Site
- M&R Station

0 0.25 0.5 1 Miles

Figure 4.4-1
FGS Project
Location of Project Wetlands

LNG Storage Facility

Construction and operation of the LNG storage facility would not affect any wetlands. The wetlands at the storage facility site would be preserved and protected by natural buffers required by Martin County.

FGS has prepared a Preserve Area Management Plan (PAMP) for the storage facility site, which is required under the provisions of the Martin County Land Development Regulations. This plan was filed by FGS in its certificate application in October 2007 and can be found on the FERC's eLibrary website at www.ferc.gov under Docket No. CP08-13-000. The PAMP sets aside in perpetuity five "preserve areas," four of which encompass the wetlands and required buffers on the storage facility site. Martin County is also requiring enhancement of these undisturbed wetlands within the preserve areas.

Pipeline and Aboveground Facilities

Construction of the pipelines would cross 2,620 linear feet of wetlands and would temporarily impact 3.91 acres. FGS avoided or minimized impacts to wetlands by reducing the nominal construction right-of-way in wetlands to 65-feet-wide, evaluating route alternatives to avoid wetland impacts (see Section 3.3.1), using a bore rather than open trenching to avoid impacting two wetlands (at MP 1.00 and 1.02), and adoption of our Procedures without any proposed variances. FGS' proposed route would be co-located with or parallel to existing electric transmission lines, pipelines, and roads. No route variations have been identified that further avoid or minimize the magnitude of wetland impacts proposed by this Project.

The wetlands affected by the pipeline can generally be described as freshwater marshes or wet prairies; no forested wetlands would be impacted. The freshwater marsh habitat, which has standing water in part of the year, has a mixture of nuisance/exotic and native species, including coastal plain willow, Brazilian pepper, wax myrtle, bushy bluestem, Peruvian primrose willow, marsh pennywort, and climbing hempvine. The wet prairies, which are not inundated at any time of year, include Peruvian primrose willow; soft rush; napier grass; wax myrtle; bushy bluestem; and smartweed. There are also several man-made drainage ditches along the pipeline right-of-way, which, although only carrying intermittent flow, are sufficiently wet to support wetland vegetation. The dominant vegetative species of the ditch wetlands include the same nuisance/exotic and native species commonly found in shallow marshes described above. Table 4.4-2 summarizes the location, wetland classification according to the Florida Land Use, Cover, and Farms Classification System (FLUCFCS), crossing length, and affected acreage for each wetland that would be impacted by pipeline construction.

Construction of the M&R station, temporary workspaces, and pipeline interconnections would not impact any wetlands. There would be no permanent wetland impacts associated with pipeline or aboveground facilities operation as all temporarily impacted wetlands would be restored.

Pipeline construction would result in short-term impacts to wetland vegetation, soils, and hydrology. Clearing and grading of wetland vegetation could affect surface water flow and promote erosion. Failure to properly segregate topsoil and rutting of wetland soils from construction equipment could affect the success of post-construction

reestablishment and natural recruitment of native wetland vegetation. Trenching could alter water tables resulting in drier soil conditions, which could inhibit reestablishment of wetland vegetation. Section 2.4.2.2 describes the specialized pipeline construction procedures, such as the push-pull technique, that FGS would implement based on site conditions to minimize wetland impacts.

Table 4.4-2

Temporary Wetland Impacts from Pipeline Construction[1]

MP Begin	MP End	Wetland Identification	Wetland Type (FLUCFCS)	Pipeline Crossing Length (ft)	Pipeline Crossing Area (ft^2)[2]	Pipeline Crossing Area (acres)[2]
0.35	0.36	Wetland/ Ditch	511 – Ditch	13	845	0.02
0.60	0.61	Wetland-PA	511 – Ditch	36	2,340	0.05
0.76	0.86	Wetland-PD	641 - Freshwater Marsh	515	33,475	0.77
1.00	1.01	Wetland-PH	511 – Ditch	0 (bored)	0 (bored)	0.00
1.02	1.03	Wetland-PL	511 – Ditch	0 (bored)	0 (bored)	0.00
1.33	1.39	Wetland-PP	641 - Freshwater Marsh	327	21,255	0.49
1.43	1.48	Wetland-PR	641 - Freshwater Marsh	248	16,120	0.37
1.79	1.87	Wetland-PV	641 - Freshwater Marsh	472	30,680	0.70
1.93	2.01	Wetland-PY	641 - Freshwater Marsh	428	27,820	0.64
2.07	2.10	Wetland-PAA	641 - Freshwater Marsh	161	10,465	0.24
2.84	2.86	Wetland-PAE	643 - Wet Prairie	129	8,385	0.19
3.57	3.59	Wetland-PAI	643 - Wet Prairie	154	10,010	0.23
3.71	3.73	Wetland-PAJ	643 - Wet Prairie	78	5,070	0.12
4.03	4.04	Wetland-PAL	511 – Ditch	59	3,835	0.09
		Total		**2,620**	**170,300**	**3.91**

Notes

[1] There would be no Project operational impacts to wetlands. All wetlands would be restored following completion of construction.

[2] Pipeline crossing area assumes a 65-foot-wide construction area.

FGS would follow our Procedures to limit wetland impacts during construction. FGS would use the minimum construction equipment necessary within wetlands for clearing, trench excavation, pipe fabrication and installation, trench backfilling, and restoration activities. If standing water or saturated soil conditions are present, or if construction equipment caused ruts or mixing of topsoil and subsoil, construction equipment operating in wetlands would be further limited to the use of low-ground-pressure equipment or normal equipment operating from timber riprap or prefabricated equipment mats.

Within the construction right-of-way, FGS would leave existing root systems intact where possible; segregate wetland topsoil from the subsoil during trenching and store in separate piles; minimize the amount of time that topsoil is segregated; backfill the soil material in the proper order; and install erosion control devices to minimize sediment flow into the wetland and adjoining wetlands. Trench breakers would be placed in the trench at the base of slopes near the wetland boundaries prior to backfilling to prevent draining of the wetland along the trench line. No upland soil or fill material would be imported into the wetland.

FGS would also minimize impacts to nearby wetlands by implementing the measures identified in our Procedures such as clearly marking wetland boundaries and buffers in the field, using sediment barriers to prevent sediment flow into a wetland, and prohibiting the storage of hazardous materials and refueling within 100 feet of a wetland.

FGS would restore all pre-construction contours immediately after pipeline installation is complete and restore wetland areas in accordance with our Procedures. The requirements for wetland restoration measures identified in our Procedures include:

- consulting with appropriate state land management agencies regarding measures for re-establishing native species;
- prohibiting the use of herbicides or pesticides within 100 feet of a wetland, except as allowed by the appropriate agencies;
- prohibiting application of lime, fertilizer, or mulch in wetlands; and
- monitoring the success of wetland vegetation annually for the first three years after construction or until wetland revegetation is considered successful.

The types of wetlands impacted by Project pipeline construction (e.g., freshwater marshes and ditches) typically recover more quickly than other wetland types (e.g., forested wetlands) and should reestablish in one or two growing seasons. Revegetation would be considered successful if the cover of herbaceous and/or woody species is at least 80 percent of the type, density, and distribution of the vegetation in adjacent wetland areas that were not disturbed by construction. The key challenge is to prevent the reestablishment of invasive and exotic species. Construction across these wetlands may provide the invasive plant species in the adjacent areas and seed stock an opportunity to further colonize and degrade the wetlands in the Project area. However, FGS proposes to re-seed the wetlands with annual ryegrass to quickly establish a short-lived vegetative cover, allowing the wetland's native seed and rhizomes (contained in the topsoil) to reestablish dominance over time. Further, FGS would remove invasive species found during pipeline maintenance inspections. We believe that the implementation of measures detailed in the Procedures and FGS's PAMP would minimize the opportunity for the introduction of invasive species.

4.4.2 Upland Vegetation

The FGS Project is located in the Outer Coastal Plain Mixed Province of the Atlantic and Gulf Coastal Plains Ecosystem, comprised of the flat and irregular Atlantic and Gulf coastal plains. Most upland areas along the Atlantic coast in this Province are covered by sub-climax pine forest with an understory of grasses and sedges called savannas.

Project lands and rights-of-way total 176.40 acres of uplands (see Table 4.4.1). Upland cover types that occur in the Project area are summarized in Table 4.4-3. The Florida Natural Areas Inventory identifies no significant natural communities within the Project area. FGS submitted letters to the FWS and Florida Fish and Wildlife Conservation Commission (FFWCC) requesting information on any significant habitats or vegetative communities within the Project area. Information received from these agencies, together

with subsequent biological field surveys, indicates that no vegetative communities of special concern or value occur in the Project area.

Overall, Project construction would temporarily disturb up to 123.12 acres of upland cover types (127.03 total impacts - 3.91 acres of wetland impacts). Project operations would permanently affect 78.40 acres of upland cover types, which includes the permanent loss of 56.07 acres of habitat for the LNG storage facility, M&R station, and interconnections, and the maintenance of 22.33 acres of permanent pipeline right-of-way in low growth (e.g., shrub and herbaceous) vegetation. The disturbed uplands not permanently affected by the Project would be restored.

Table 4.4-3

Upland Vegetative Cover Types Occurring in the Project Area

Vegetative Cover Type (FLUCFCS) Code	General Description of Cover Type [a/]	Common Species [b/]
Dry Prairie (310)	Rangeland with upland prairie grasses that occur on non-hydric soils but may be occasionally inundated by water.	Wiregrass, saw palmetto.
Palmetto Prairie (321)	Rangeland where saw palmetto is the most dominant vegetation. This cover type is usually found on seldom-flooded dry sand areas. These treeless areas are often similar to the pine flatwoods.	Saw palmetto and slash pine, with subdominants including greenbriar; American beautyberry; old-world climbing fern; Brazilian pepper, gallberry; napier grass; melaleuca; bluestem grass; winged sumac; muscadine grape; dogfennel; wiregrass; and sand live oak.
Pine Flatwoods (411)	Common upland coniferous forest dominated by either slash pine or longleaf pine.	Slash pine; saw palmetto; cabbage palm; laurel oak; live oak; Brazilian pepper; wax myrtle; gallberry; greenbriar; bluestem grass; muscadine grape; bracken fern; dogfennel.
Brazilian Pepper (422)	Upland hardwood forest community dominated by Brazilian pepper.	Brazilian pepper
Hardwood/ Conifer Mixed Forest (434)	Upland forest community where neither upland conifers nor hardwoods achieve canopy dominance.	Co-dominant species include loblolly pine; slash pine; laurel oak; live oak; and cabbage palm in the canopy. Saw palmetto dominates the ground cover.
Australian Pine (437)	Upland hardwood forest community dominated by Australian pine.	Nearby monotypic stand of Australian pine. Associate species are limited to Brazilian pepper along the periphery of the Australian pine monoculture.
Disturbed Open Lands (740)	Areas changed primarily due to human activities other than mining.	Slash pine; cabbage palm; live oak; Spanish needle; Bahia grass; torpedo grass; goosegrass; smutgrass; wiregrass.
Electrical Transmission Line (832)	Right-of-ways typically maintained in an herbaceous and/or shrubby ground cover.	Bahia grass; bushy bluestem; flatsedge; marsh pennywort; groundsel tree; Brazilian pepper.

Sources:

a/ Florida Land Use, Cover and Forms Classification System (FDOT, 1999)

b/ Resource Report 3 (Golder, 2007)

Table 4.4-4
Vegetative Communities Potentially Affected by the Project

Proposed Facility	Cover Type (FLUCFCS)	Crossing Length (miles)	Existing Conditions (acres)	Area Affected by Construction[1] (acres)	Area Affected by Operation[2] (acres)
LNG Storage Facility	Pine Flatwoods (411)	n/a	12.57	2.46	2.46
	Brazilian Pepper (422)	n/a	12.00	12.00	12.00
	Hardwood/Coniferous Mixed (434)	n/a	2.51	1.29	1.29
	Australian Pine (437)	n/a	5.24	5.24	5.24
	Ditch (511)	n/a	4.61	0.00	0.00
	Reservoirs less than 10 acres (534)	n/a	9.26	0.00	0.00
	Mixed Wetland Hardwoods (617)	n/a	0.57	0.00	0.00
	Exotic Wetland Hardwoods (619)	n/a	4.03	0.00	0.00
	Cypress/Exotic Wetland Hardwoods (621/619)	n/a	0.49	0.00	0.00
	Freshwater Marsh (641)	n/a	8.99	0.00	0.00
	Disturbed Lands (740)	n/a	75.70	33.96	31.48
	Railroads (812)	n/a	0.35	0.19	0.19
	Roads (814)	n/a	0.49	0.44	0.44
Subtotal LNG Storage Facility		**n/a**	**136.81[3]**	**55.58[3]**	**53.10**
Pipeline Corridor	Dry Prairie (320)	0.93	11.33	11.33	5.66
	Palmetto Prairie (321)	0.33	3.97	3.97	1.98
	Pine Flatwoods (411)	1.23	14.90	14.90	7.45
	Brazilian Pepper (422)	0.12	1.43	1.43	0.72
	Hardwood/Coniferous Mixed (434)	0.15	1.84	1.84	0.92
	Ditch (511)	0.02	0.16	0.16	0.00
	Freshwater Marsh (641)	0.41	3.21	3.21	0.00
	Wet Prairie (643)	0.07	0.54	0.54	0.00
	Disturbed Open Land (740)	0.52	6.37	6.37	3.19
	Electrical Power Facility (831)	0.09	1.11	1.11	0.56
	Transmission Lines (832)	0.31	3.71	3.71	1.85
Temporary Work Spaces*	Dry Prairie (320)	n/a	2.51	2.51	0.00
	Palmetto Prairie (321)	n/a	1.58	1.58	0.00
	Pine Flatwoods (411)	n/a	3.13	3.13	0.00
	Disturbed Open Land (740)	n/a	0.83	0.83	0.00
	Spoil Areas (743)	n/a	0.15	0.15	0.00
	Transmission Lines (832)	n/a	1.21	1.21	0.00
M&R Station Site	Dry Prairie (320)	n/a	0.78	0.78	0.78
	Pine Flatwoods (411)	n/a	0.58	0.58	0.58
	Hardwood/Coniferous Mixed (434)	n/a	1.39	1.39	1.39
Interconnections (0.11 acres each)	Dry Prairie (320)	n/a	0.22	0.22	0.22
Construction Staging Area	Palmetto Prairie (321)	n/a	2.89	2.89	0.00
	Pine Flatwoods (411)	n/a	6.99	6.99	0.00
	Poultry Feeding Operations (232)	n/a	0.62	0.62	0.00
Subtotal Pipeline Staging Area, and Aboveground Facilities		**4.18**	**71.45**	**71.45**	**25.30**
GRAND TOTAL		**4.18**	**208.26**	**127.03**	**78.40**

Notes: n/a = not applicable
* Where combined acreage and crossing lengths for two cover types in a single workspace were given by the applicant, the data was split evenly among cover types.
[1] Acres affected by construction consist of the LNG storage facility construction areas, pipeline construction right-of-way, including extra work areas.
[2] Areas affected by operation include the LNG storage facility, M&R stations, interconnections, and the permanent right-of-way
[3] This reflects the net acreage of the LNG storage facility site excluding the 7.82 acres affected by pipeline construction.

LNG Storage Facility Site

The LNG storage facility site is a previously-disturbed industrial area that does not contain any unique vegetative communities or support significant wildlife habitat. Construction of the LNG storage facility would disturb 55.58 acres, or 41 percent, of the net 136.81-acre site. Most of the affected area, 34.59 acres, is previously disturbed land, railroads, and roads. FGS would also remove 17.24 acres of Australian pine and Brazilian pepper as required by Martin County because they are invasive, exotic species. The only impacts to natural habitat would be the loss of 2.46 acres of pine flatwoods and 1.29 acres of mixed hardwood/coniferous forest.

Storage facility operations would result in the permanent conversion of 53.10 acres, of which only 3.75 acres would be natural vegetation. In addition, one existing stormwater pond would be expanded by 2.48 acres and is included in the remaining 83.71 acres of the site remain as open space or used as spray irrigation fields as part of the on-going site remediation.

Pipeline, Construction Staging Area, and Associated Aboveground Facilities

The pipeline corridor and aboveground facilities are generally adjacent to or co-located with maintained powerline, pipeline, and road rights-of-way. The Tampa Farms property is located adjacent to the pipeline corridor at approximately MP 1.60 and would be used as a temporary pipe storage and construction staging area. Access is already available via existing roads. This area is disturbed and was formerly used as a mulch yard, but is not currently in use. The existing vegetation at the construction staging area would be cleared, the topsoil stockpiled, and the site covered with gravel. Construction of the pipeline, construction staging area, and associated aboveground facilities would affect 71.45 acres, of which 28.83 acres would be natural forest.

Pipeline facility operations would result in the permanent loss of 2.97 acres of natural vegetation for the M&R station and the pipeline interconnections, and the maintenance of 22.33 acres of permanent right-of-way as low-growth (e.g., shrub or herbaceous) vegetation. At the completion of construction, FGS would remove the gravel, replace the stockpiled topsoil, and revegetate the area.

Mitigation Measures

Most (75 percent) of the Project impacts affect prairie, disturbed lands, marshes, or areas dominated by invasive/exotic species, the effects of which would be short-term as these communities would typically return to their herbaceous or shrub status within 1 to 2 seasons following construction. Impacts to the forested cover types within the temporary construction right-of-way would be longer term, taking up to 30 years or more to recover.

To minimize construction-related effects, FGS has agreed to adopt our Plan with no modifications. The intent of our Plan is to identify baseline mitigation measures to minimize erosion and enhance revegetation in upland areas. Our Plan requires all temporarily disturbed areas to be restored to pre-construction contours and revegetated upon completion of construction. The Martin County Field Operations Department (2007) states that sodding with Bahia grass, in lieu of seeding, is commonly used to vegetate disturbed areas in Martin County. In addition, FGS consulted with the NRCS,

which indicated that there is no state or county requirements regarding revegetation, but recommended a seed mixture of Bahia or Bermuda grass and suggested Pensacola or Argentine sod in areas sensitive to erosion.

The PAMP that FGS prepared for Martin County identifies the location and use of preserve areas; surveying, marking and barricading requirements; restoration and maintenance activities (including exotic species removal and revegetation); measures for protecting listed species; and monitoring, maintenance, reporting, and inspections requirements. Implementation of the PAMP would ensure cutting or removal of vegetation would be minimized. We received a comment from the EPA on our draft EIS recommending that rights-of-way maintenance avoid the use of herbicides, particularly aerial applications, to avoid overspray and opportunities for invasives to establish. EPA also recommended that any herbicide use be limited to EPA-registered products, applied by trained personnel according to label directions. To ensure appropriate application of herbicides as a management tool, and to minimize potential detrimental effects to the environment noted by the EPA, **we recommend that:**

- **FGS should develop a Standard Operating Procedure for Herbicide Use that meets EPA requirements.**

With the implementation of our Plan and recommendation in conjunction with the requirements of the PAMP, impacts to upland vegetation would be minimized and minor in nature.

Exotic or Invasive Plant Species

Invasive and exotic pest plants are a threat to Florida's natural areas. According to the Florida Exotic Pest Plant Council (2007), approximately 31 percent of the plant species known to occur in Florida outside cultivation are introduced. Exotic plants are introduced accidentally through shipping materials or deliberately for ornamental or commercial purposes. Invasive and exotic pest plants often lack the natural enemies that control their growth in their home range, allowing them to spread easily into Florida's native plant communities. Exotic plants can cause a reduction in biodiversity; loss of habitat and food sources for native insects, birds, and other wildlife; and changes to natural ecological systems.

Several of the upland vegetative communities listed in Table 4.4-3 contain exotic or invasive plant species. The primary invasive, exotic plants in the upland communities are Australian pine and Brazilian pepper and other herbaceous species. Where present at the Project, Australian pine and Brazilian pepper would be removed to promote conversion to native cover types in accordance with the PAMP.

4.5 WILDLIFE AND AQUATIC SPECIES

4.5.1 Wildlife

Game and non-game wildlife species are regulated and protected under various federal laws, including the Fish and Wildlife Conservation Act of 1980 (16 U.S.C. §§ 2901-

2911), Fish and Wildlife Coordination Act of 1958, and the ESA. The FFWCC also administers programs at the state level for the protection of wildlife species.

4.5.1.1 Existing Conditions

Habitats at the Project, which include upland forests, open lands and prairies, wetlands, drainage ditches, and open water provide cover and forage for a variety of wildlife. Most of the habitat suitable for wildlife occurs along the pipeline corridor and at the M&R station. The LNG storage facility site and the construction staging area have been disturbed and do not provide significant habitat for wildlife, although the area is used by a variety of common avian and mammalian species despite the historical disturbance and lack of native habitat. The Project area is not located in any federal, state, or private wildlife managed areas. Wildlife observed during field surveys at the Project site in December 2006 and January 2007 are discussed below by community type.

Upland Forests

The local upland forested communities include pine flatwood and mixed hardwood/coniferous forest. The forested canopy can be used for nesting by birds including mockingbird, morning dove, turkey vulture, cardinal, common yellowthroat, red-shouldered hawk, and white-eyed vireo. A variety of shrub and herbaceous plant species in the understory of the upland forests provide significant cover and forage for a variety of wildlife species including raccoon, eastern cottontail rabbit, bobcat, coyote, white-tailed deer, and eastern diamond back rattlesnake.

Open Lands and Prairies

The open lands in the pipeline corridor and M&R station include the cleared/ maintained transmission line rights-of-way (portions of which are cattle pasture and disturbed open land associated with the former industrial facility), palmetto prairie, and dry prairie. These habitats provide cover and forage for avian and wildlife species including loggerhead shrike, ground dove, common nighthawk, American robin, feral hog, raccoon, armadillo, coyote, white-tailed deer, and black racer. The existing transmission line rights-of-way generally provide low to moderate quality wildlife habitat except for palmetto prairie, which provides quality habitat for typical pine flatwood species such as the gopher tortoise.

Unlike most other grasslands in the southeastern United States, Florida dry prairie harbors numerous endemic vertebrates (FWS, 1991). Several rare avian taxa are near-endemic to the dry prairie region of south-central Florida. Both breeding and seasonal migrants use dry prairies extensively. The dry prairie habitat along the pipeline corridor is within or adjacent to the existing transmission line corridor, which is periodically mowed. The improved pasture, with herbaceous species such as Bahia grass, provides grazing habitat for species such as white-tailed deer. The dry prairie at the M&R station abuts cleared railroad and road right-of-way.

Forested, Scrub-Shrub, and Emergent Wetlands

There are several isolated freshwater marshes located along the pipeline corridor. These emergent wetlands are characterized by erect, rooted, herbaceous plants used for feeding,

potential nesting, and during migration by avian and wildlife species including green heron, great egret, northern harrier, eastern cottontail rabbit, and raccoon. These emergent, isolated wetlands may also be used as breeding sites for a variety of amphibians including Florida cooter, green tree frog, pig frog, and water moccasin.

Open Water and Ditches

The LNG storage facility site and pipeline corridor contain several minor waterbodies. The storage facility site has three stormwater ponds totaling 9.26 acres that support a fringe of vegetation and provide habitat for wading birds and other aquatic species such as moorhen, anhinga, green heron, black-crowned night heron, raccoon, green tree frog, and water moccasin. An American alligator inhabits at least one of the ponds on the storage facility site. The five drainage ditches present at the Project are all small and intermittent, only carrying flows during wet periods or immediately after storm events. Although only intermittent, these ditches provide suitable foraging habitat for a variety of wading birds, including the endangered wood stork.

Migratory Birds

The Migratory Bird Treaty Act regulates taking of or impacts to migratory birds, including their nests. The FWS estimates that there are approximately 398 species of migratory birds in South Florida. Migratory birds would be expected to occur at least as transients in the Project area throughout most of the year. In general, construction and maintenance of the pipeline right-of-way would benefit some species through the creation and maintenance of edge habitats; however, other species can be adversely affected, especially if nesting activities are disturbed by vegetative clearing activities associated with construction and maintenance of the Project.

Colonial Nesting Waterbirds

Colonial nesting waterbirds is a collective term used to refer to a variety of bird species that obtain all or most of their food from aquatic environments and gather in large colonies, or rookeries, during the nesting season (FWS, 2002). No rookeries have been identified by the FWS (2007), FFWCC (2007), or Florida Natural Areas Inventory (2007) sufficiently near to the Project area that warrants timing restrictions for construction during the nesting period. Foraging habitat provided by wetlands and ditches affected by construction would be restored in accordance with our Procedures. No long-term impacts to colonial nesting birds are expected.

4.5.1.2 Impacts and Mitigation

The Project would disturb 127.03 acres of potential upland and wetland wildlife habitat (see Table 4.4-4). The extent and duration of impacts to wildlife and their habitats resulting from construction and operation of the Project would depend on the species present in each habitat type and their individual life history requirements. Potential impacts to wildlife habitat from each component of the Project are discussed below.

LNG Storage Facility Site

The LNG storage facility construction would temporarily disturb 55.58 acres and operation would result in the permanent loss of 53.10 acres of potential wildlife habitat.

The storage facility site, however, does not contain significant wildlife habitat. The site is an industrial, fenced property included in the Superfund Program with ongoing remediation activities. Most (93 percent) of the LNG storage facility construction would occur in previously disturbed, sparsely vegetated open lands or areas dominated by invasive species.

No adverse impacts to wildlife are anticipated as a result of construction and operation of the LNG storage facility. Noise effects on wildlife from construction would be temporary and noise levels from facility operations would be within acceptable FERC and state levels. Existing wildlife in the area are acclimated to noise already generated by the adjacent industrial facilities, SR 710, and the CSX railroad.

Pipeline Facilities and Construction Staging Area

Pipeline facility construction would result in the clearing of 71.45 acres of vegetation that provides habitat for wildlife. Pipeline operations would result in the permanent loss of 2.97 acres of vegetation for the M&R station and pipeline interconnections and the permanent maintenance of 22.33 acres of pipeline right-of-way as low growth vegetation. FGS minimized these impacts by locating the pipeline route adjacent to existing maintained utility rights-of-way and roads, avoiding the creation of new cleared corridors through forest tracts. FGS also avoided all forested wetlands.

The clearing of vegetation for the pipeline facilities and construction staging area would reduce cover, nesting, and foraging for some wildlife until construction is complete and vegetation re-established along the right-of-way. During construction, more mobile species would be temporarily displaced from the construction right-of-way and surrounding areas to similar habitats nearby. Some wildlife species disturbed or displaced by construction may be able to return to adjacent, undisturbed habitats soon after completion of construction. Less mobile species, such as small mammals, reptiles, amphibians, and birds nesting in the rights-of-way, may be affected by construction activities due to direct mortality or permanent displacement, potentially affecting reproduction, recruitment, and survival of these individuals. Regardless of mobility, some wildlife species would be affected by the loss of cover, nesting, and foraging habitat. Similar effects, although much less extensive, would result from routine maintenance of vegetation along the permanent right-of-way.

Pipeline facility and construction staging area construction would clear 28.83 acres of forest (excluding areas dominated by the invasive Brazilian Pepper), of which 1.97 acres at the M&R station would be permanently impacted; approximately 16.74 acres within the permanent right-of-way would be permanently converted to low growth (shrub or herbaceous) vegetation; and 10.12 acres within temporary workspaces and construction staging area would be allowed to revert to forest. Effects to wildlife using forest habitats would be more substantial and longer-term (up to 30 years) than that to wildlife inhabiting other habitat types, as vegetative strata in those areas would undergo a more marked change.

Non-forested habitats that would be affected by construction and operation of the Project include open lands, palmetto prairie, dry prairie, scrub-shrub and emergent wetlands, and vegetated ditches. The impact on these habitats and associated wildlife species would be

relatively minor and either temporary or short-term. Due to the short duration of pipeline installation and the vegetative restoration measures included in our Plan, these areas would generally be restored within three to five years after construction for scrub-shrub habitats and one to two years for the other habitats. FGS proposes to re-seed the improved pastureland with Bahia grass.

FGS would minimize impacts to wildlife habitats through the implementation of our Plan. FGS would not conduct routine vegetative maintenance of the pipeline right-of-way more frequently than once every three years. Routine vegetative maintenance clearing would not occur between April 15 and August 1 in any year to minimize the potential for Project-related disturbances of migratory bird nesting periods.

4.5.2 Aquatic Resources

Game and non-game fish species are regulated and protected under various federal laws, including the Fish and Wildlife Act of 1980 (16 USC §§ 2901-2911) and the Fish and Wildlife Coordination Act of 1958 (16 USC §§ 661 et seq.). The Project would also be reviewed under Florida's state regulatory programs.

Aquatic habitats affected by the Project are limited to the St. Lucie Canal, which would be used by FGS as a source of hydrostatic test water, three stormwater ponds on the LNG storage facility site, and five drainage ditches crossed by the proposed pipeline. No fisheries of special concern, Essential Fish Habitat, commercial fisheries, Outstanding Florida Waters, or Aquatic Preserves are located in the Project area (Golder, 2007).

LNG Storage Facility

The three stormwater management ponds on the LNG storage facility site provide habitat for a variety of common forge fish, but recreational fishing is prohibited as a condition of the site's remediation plan. The southwestern pond would be enlarged by 2.48 acres to meet State and local stormwater management requirements. Temporary construction impacts are likely to be minor and of short duration. Potential impacts to alligators that may inhabit the ponds are discussed in Section 4.6.

Pipelines, Construction Staging Area, and Associated Aboveground Facilities

The pipeline would cross five intermittent drainage ditches affecting 0.16 acres of ditch wetlands. The drainage ditches contain water seasonally or during rain events and do not provide any significant habitat for fish. The ephemeral hydroperiod associated with these ditches and wetlands limit fish communities to common forage fishes such as mosquitofish, least killifish, and small sunfish. The ditches and wetlands are not considered critical habitat for any native or game fish species and do not provide habitat for recreationally important fish species.

Potential impacts to water quality and associated aquatic habitats would include sedimentation, turbidity, and physical disturbance of vegetative cover. These effects would be minor and temporary. FGS proposes to construct the Project in accordance with our Procedures, ensuring that the physical characteristics of the drainage ditches that may provide aquatic habitat are restored to pre-Project conditions.

Hydrotesting

FGS proposes to use the St. Lucie Canal as the source of water to hydrotest the LNG storage tanks and pipelines. The hydrotesting would withdraw water at approximately 1,500 gpm for several weeks. FGS would use an existing permitted irrigation intake structure, which would be screened to minimize the impingement or entrainment of fish per our Procedures. The withdrawal rate would be less than 0.1 percent of annual average flow in the St. Lucie Canal. FGS would not use any biocides or other water additives and, after completion of the hydrotesting, would return the water to the St. Lucie Canal at non-erosive velocities. Therefore, the hydrotest water withdrawal would have no significant adverse effect on the fishery or aquatic resources of the St. Lucie Canal.

4.6 THREATENED, ENDANGERED, AND SPECIAL STATUS SPECIES

4.6.1 Federally Listed Threatened and Endangered Species

In order to comply with Section 7 of the ESA, FGS, acting as our non-federal representative, consulted with the FWS regarding the presence of federally listed threatened and endangered species and their designated critical habitats within the Project area. The FWS (FWS, 2007) reported that the Project area is located within known ranges of the wood stork (*Mycteria americana*) and Audubon's crested caracara (*Polyborus plancus auduboni*). No other federally listed species were identified in the FWS database as occurring in the Project area. Appendix D includes copies of correspondence between FGS and the FWS.

Critical habitat is defined in the ESA and identified in 50 CFR 17.95 (fish and wildlife) and 50 CFR 17.96 (plants). It refers to specific geographic areas essential to the conservation of a threatened or endangered species that may require special management consideration or protection. Federal agencies that undertake, fund, or permit activities that may affect critical habitat are required to consult with the FWS to ensure such actions do not adversely modify or destroy designated critical habitat. The Project area is located outside any federally-designated critical habitat. The FWS has established critical habitat in Martin County for Johnson's seagrass (*Halophila johnsonii*), piping plover (*Charadrius melodus*), and West Indian manatee (*Trichechus manatus*), but the critical habitats for these species involve marine, coastal, and estuarine habitats, which do not occur in the Project area.

FGS conducted field reconnaissance of the Project area in December 2006 and January 2007. The wood stork and American alligator (*Alligator mississippiensis*), both federally listed species, were observed during the surveys. No other federally-listed species, including the Audubon's crested caracara, were observed during these field surveys. FGS conducted another field reconnaissance of the site and pipeline corridor with the FFWCC in June 2007 and did not observe any listed species. Although not identified or observed, suitable habitat (i.e., gopher tortoise burrows) for another federally-listed species, the Eastern indigo snake (*Drymarchon corais couperi*) was observed at the LNG storage facility site and therefore included in our analysis.

These species and their management status are listed in Table 4.6-1. The preferred habitats and potential for occurrence of these species, as well as our assessment of potential Project effects, are discussed below.

Table 4.6-1

Federally-Listed Species Potentially Occurring in the Project Area

Species	Federal Status	Florida Status	Preferred Habitat
Wood stork (*Mycteria Americana*)	E	E	Freshwater and brackish wetlands, primarily nesting in cypress or mangrove swamps and feeding in open water habitats that support small fish. Optimal feeding sites include depressions where fish become concentrated during periods of falling water levels.
Audubon's crested caracara (*Polyborus plancus audubonii*)	T	T	Cabbage palms surrounded by open habitats, such as improved pasture, with low ground cover and a low density of tall or shrubby vegetation.
American alligator (*Alligator mississippiensis*)	T (S/A)	SC	Swamps and marshes
Eastern indigo snake (*Drymarchon corais couperi*)	T	T	Variety of habitats, including pine flatwoods, dry prairies, and freshwater marshes.

Sources: FWS (2007), Florida Natural Features Inventory (2001)

Definitions: E = endangered, T = threatened, S/A = similarity of appearance, SC = species of concern

4.6.1.1 Species Descriptions

Wood Stork

The wood stork is federally and state-listed as endangered, which classifies it as in danger of extinction throughout all or a significant portion of its range. According to the FWS (2007a), the Project area is located within the core foraging area (CFA) of two active wood stork breeding colonies. The CFA extends up to 18.6 miles from the location of the breeding colony. Wood storks were observed flying over the LNG storage facility site and pipeline corridor in December 2006 and January 2007.

The wood stork is a large, long-legged wading bird, about 50 inches tall, with a wingspan of 60 to 65 inches. The plumage is white except for black primaries, secondaries, and a short tail with greenish and purplish sheen. The head and neck are unfeathered, scaly, and dark gray in color. The bill is black, long and thick at the base, and slightly decurved. Immature birds are dingy gray and have a yellowish bill. Sexes are similar in appearance.

Wood storks are birds of freshwater and brackish wetlands, primarily nesting in cypress or mangrove swamps. Nesting periods vary geographically. In South Florida, wood storks lay eggs as early as October and fledge in February or March. Nests are frequently located in the upper branches of large cypress trees or in mangroves on islands. Several nests are usually located in each tree. Wood storks have also nested in man-made structures. Storks lay two to five eggs and average two fledglings per successful nest under good conditions.

Wood storks feed in freshwater marshes, narrow tidal creeks, or flooded tidal pools. Particularly attractive feeding sites are depressions in marshes or swamps where fish become concentrated during periods of falling water levels. Wood storks eat small fish, especially topminnows and sunfish. They capture their prey by grope-feeding (i.e., capturing food by feel). Feeding often occurs in water six to 10 inches deep, where a stork probes with the bill partly open.

The Project is located outside known breeding colony locations and would not impact cypress swamp or mangrove communities. The construction of the Project would involve temporary impacts to non-forested wetlands and drainage ditches in the proposed pipeline construction right-of-way. The FWS believes that the on-site ditches provide suitable foraging habitat for wood storks because the ditches can concentrate prey. To minimize adverse effects to the wood stork, the FWS recommends that FGS replace all lost foraging habitat within the CFA due to the proposed action so no net loss of foraging habitat occurs (Wrublik, 2007).

FGS proposes to restore wetlands and drainage ditches affected by construction in accordance with our Procedures, which limits the duration of construction to 24 hours and requires re-establishing ground surface contours and vegetative cover. These measures would ensure that permanent wetland loss would not occur within the CFA and that the hydroperiod of these wetlands are returned to pre-Project conditions. For these reasons, we have determined that the Project is not likely to adversely affect the wood stork.

Audubon's Crested Caracara

The Audubon's crested caracara is federally and state-listed as threatened, which identifies it as likely to become endangered within the foreseeable future throughout all or a significant portion of its range. The region of greatest abundance for the Florida population is a five-county area north and west of Lake Okeechobee (Sprunt, 1954; Layne in Kale, 1978; Layne, 1985). The FWS (2007) identified the Project area in Martin County, east of Lake Okeechobee, to be within the caracara's geographic range.

The caracara is 21 to 23 inches in length and has a wingspread of about 48 inches. It has long yellow legs and a massive bluish bill. Sexes are similarly plumaged; younger birds are browner than adults. The caracara is an opportunistic feeder; its diet includes both carrion and living prey. Living prey are usually small turtles and turtle eggs. In addition to these items, caracaras prey on insects, fish, frogs, lizards, snakes, birds, and small mammals.

Humphrey and Morrison (1997) characterized habitat features and land use patterns at active caracara nests in south-central Florida. They found that caracaras prefer to nest in cabbage palms surrounded by open habitats with low ground cover and a low density of tall or shrubby vegetation. The FWS (2007) notes that nests have occasionally been documented in live oak, pines, cypress, Australian pine, saw palmetto, and black gum (*Nyssa sylvantica*) trees. The 1997 study also indicated that there was a strong association with improved pastureland. Humprey and Morrison (1997) postulated that vegetation height may be related to lower predation rates in lower vegetation, or it may

simply be easier for caracaras to walk around and forage in shorter vegetation. Distances to roads or other human disturbances may also contribute to nesting success.

Caracara nests are bulky, loosely woven structures, round or oval in shape and approximately two feet in diameter. The breeding peak is from January to March, with the usual clutch being two or three eggs. Incubation lasts about 32 days, and the young leave the nest at about eight weeks of age. Caracara nests are often used year after year; often nesting pairs construct two or three alternate nest trees within the same general vicinity (Morrison, 2001).

The LNG storage facility site is an abandoned industrial facility that does not provide suitable nesting or foraging habitat for the caracara. No caracara nests were found on the storage facility site during field visits in December 2006 and January 2007. The Australian pine and cabbage palm communities on the site have relatively dense understory and are located in proximity to disturbed on-site areas as well as the CSX rail line and SR 710, which reduces the suitability of these communities for caracara.

The proposed pipeline corridor and M&R station contain areas of pine flatwoods, palmetto prairie, and mixed pine/hardwoods. The pine flatwoods and palmetto prairie habitats adjacent to the proposed pipeline corridor do not provide the open understory, minimal shrub layer, and cabbage palms favored by the caracara. Although cabbage palms are present within the mixed hardwood communities, the canopy and understory are densely vegetated, which is not considered suitable caracara foraging or nesting habitat. None of these vegetative associations reflect habitat conditions preferred by the caracara, and field surveys confirmed that no caracara nests exist in the dry prairie communities along the pipeline corridor or at the M&R station.

In all, no caracara nests or suitable nesting habitat were identified in the Project area. For these reasons, we have determined that the Project would have no effect on the caracara.

American Alligator

The American alligator (*Alligator mississippiensis*) is classified by the FWS as threatened due to similarity in appearance to the federally-endangered American crocodile (*Crocodylus acutus*). The federal listing of threatened by similarity of appearance offers no formal protection from take: the designation simply helps to prevent harvest of other similar rare crocodilians by controlling illegal international trade of crocodilian skins. The FFWCC does not classify the alligator as threatened or endangered, but as a Species of Special Concern. Under Florida law, no person may take, possess, transport, or sell a Species of Special Concern.

Alligators occur in large wetlands throughout the coastal plain of the southeastern United States, with the greatest populations occurring in coastal and inland freshwater marshes and in lakes and reservoirs with dense stands of emergent vegetation along the shoreline. Some also occur in rivers and riverine wetland systems. At the LNG storage facility site, a single alligator was observed in one of the stormwater ponds and may possibly inhabit other open water habitats and wetlands in the vicinity of this pond. FGS proposes to expand one of the ponds to provide increased stormwater management capacity. Temporary construction impacts to the American alligator are likely to be minor and of short duration. During the expansion of the stormwater pond, it is likely that individual

alligators within the pond would temporarily relocate to adjacent ponds on-site. Expansion of the southwestern stormwater pond acreage would ultimately provide additional suitable habitat. FGS indicates it would develop special management considerations for alligators and notify construction workers and LNG storage facility operators not to harass or unduly disturb any alligators. Therefore, we conclude that the Project is not likely to adversely affect the American alligator.

Eastern Indigo Snake

The Eastern indigo snake is federally and state-listed as threatened. Eastern indigo snakes are the largest non-venomous snake in North America. Individuals up to 104 inches have been measured, although this species averages between 60 and 74 inches in length. It has smooth, shiny scales and a reddish chin and throat. The young are lighter in color and have a faint banded pattern. They lay from 5 to 12 eggs in May or June. Hatching occurs in August and September. Young indigos may approach two feet in length when they hatch.

Eastern indigo snakes may be found in a variety of habitats throughout most of Florida and southern Georgia and are known to use gopher tortoise burrows for egg laying, shedding, and protection from dehydration and temperature extremes. Eastern indigo snakes need relatively large areas of undeveloped land. They are active nearly year-round in southern Florida, but winter underground farther north. Major threats are habitat loss, degradation, and fragmentation, with associated highway mortality. Other threats include mortality from gassing of tortoise burrows for rattlesnakes and illegal collection as pets.

Although no Eastern indigo snakes have been observed on the LNG storage facility site or along the pipeline corridor, FGS surveys identified several gopher tortoise burrows on the proposed storage facility site. FGS would obtain a pre-clearing gopher tortoise relocation permit from the FFWCC to excavate any burrows within 25 feet of construction areas prior to initiation of construction. In addition, FGS has agreed to implement the FWS *Standard Protection Measures for the Eastern Indigo Snake*. For these reasons, we conclude that the Project is not likely to adversely affect the Eastern indigo snake.

4.6.1.2 Conclusion Regarding Federally Listed Threatened and Endangered Species

Four federally-listed threatened or endangered species may occur at the Project. Based on our review of FWS species accounts and survey information provided by FGS, we have determined that the Project would either have no effect or is not likely to adversely affect these species. We have informally consulted with the FWS, which is a cooperating agency in the preparation of this EIS, regarding Project effects on these listed species. Given the adoption of the Standard Protection Measures for the Eastern Indigo Snake, the FWS has concurred that the Project, including the Tampa Farms construction staging area, would either have no effect or is not likely to adversely affect federally-listed species (June 2, 2008 for the storage facility site and pipeline; and June 27, 2008 for the Tampa Farms construction staging area). Consequently, the Commission's required consultation under Section 7 of the ESA is complete.

4.6.2 State-listed Species

Florida's Endangered Species Protection Act prohibits the intentional wounding or killing of any fish or wildlife species designated by the FFWCC as endangered, threatened, or of special concern (University of Florida, 2007). This prohibition also extends to the intentional destruction of the nests of any such species. The Preservation of Native Flora of Florida Act addresses the protection of endangered, threatened, or "commercially exploited" plants, which are listed by the Florida Department of Agriculture and Consumer Services. The Florida Natural Areas Inventory, which includes all state-listed species and important natural communities, did not document any occurrences of listed species within the Project area. During field surveys in December 2006 and January 2007, several state-listed species were observed. These species, their status, and preferred habitat are listed in Table 4.6-2 and discussed below.

Table 4.6-2

State-Listed Species Potentially Occurring in the Project Area

Species	Florida Status	Preferred Habitat
Gopher Tortoise (*Gopherus polyphemus*)	T	Dry upland habitats, including dry pine flatwoods. Also commonly uses disturbed habitats such as pastures, old fields, and road shoulders.
Little Blue Heron (*Egretta caerulea*)	SC	Forages in freshwater lakes marshes, swamps, and streams. Nests in variety of woody vegetation, including cabbage palm. Usually breeds in mixed-species colonies in flooded vegetation or islands.
Tricolor Heron (*Egretta tricolor*)	SC	Most nesting colonies occur on mangrove islands or in willow thickets in fresh water. Seasonal variations in water levels are particularly critical to nesting success. Feeds in a variety of permanently and seasonally flooded wetlands, mangrove swamps, tidal creeks, ditches, and edges of ponds and lakes.
Snowy Egret (*Egretta thula*)	SC	Feeds in many types of permanently and seasonally flooded wetlands, streams, lakes, swamps, and man-made impoundments. Nests in both island and coastal wetlands with nests placed in many types of woody shrubs, especially mangroves and willows. A wide variety of wetland types must be available within 5-7 miles to support breeding colonies.
White Ibis (*Eudocimus albus*)	SC	Found in a variety of wetland habitats and streams. Adults prefer foraging in freshwater areas when feeding young. Nests placed on a variety of trees, shrubs, and vines.
Florida Sandhill Crane (*Grus canadensis pratensis*)	T	Prairies, freshwater marshes, and pasture lands. Uses edges and transition zones between forests and open habitats.

Source: Florida Natural Areas Inventory (2001).

Definition: E = Endangered, T = threatened, SC = species of special concern

4.6.2.1 Species Descriptions

Gopher Tortoise

Nine active gopher tortoise burrows were observed at the LNG storage facility site, primarily in the palmetto prairie habitat at the western edge of the property, although two inactive burrows were also observed along the pipeline corridor. Gopher tortoises are listed as a threatened species in the State of Florida due to loss of preferred habitat, which includes xeric upland areas that are prime parcels for development.

FGS has proposed mitigation for the gopher tortoise in its PAMP. According to the PAMP, a certified environmental professional would supervise clearing in the areas of gopher tortoise burrows. Tortoises inhabiting burrows in areas to be developed would be captured and relocated following guidelines set forth below. Tortoise burrows may be bucket trapped or excavated using methodology approved by the FFWCC and conducted by an environmental professional possessing a valid relocation permit. During clearing and grubbing operations, equipment operators would be notified of the occurrences of gopher burrows on-site and instructed to look for roaming and foraging individuals. Should gopher tortoises be seen during the clearing and grubbing, equipment operations would be stopped and the gopher tortoises captured and relocated into an approved Preserve Area on the LNG storage facility site. Once the tortoise(s) have been safely relocated to the Preserve Area and restrained by tortoise fencing, equipment operation can resume.

All gopher tortoise relocation efforts would include trapping of endangered commensal species that may live in the burrow. These commensal species include, but are not limited to, the Florida mouse, gopher frog, and Eastern indigo snake.

If the number of tortoises exceeds the carrying capacity of the on-site Preserve Areas, the Martin County Environmental Planning Administrator would be notified. In consultation with Martin County, the tortoises would be relocated to a suitable and approved off-site location. All relocations would be carried out by an environmental professional licensed for gopher tortoise relocations.

Other State-Listed Species

The observed state-listed wading birds (i.e., little blue heron, tricolor heron, snowy egret, and white ibis) occasionally use ditches and wetland habitats on the LNG storage facility site and within the pipeline corridor for foraging. Suitable habitat does not exist at the Project for nesting. Although pipeline construction would involve open cut trenching across four ditches, the trenches would only be open for no more than 24 hours and all of the ditches would be immediately restored to pre-construction conditions. There would be no permanent adverse operational effects. Therefore, construction and operation of the Project would have no effect on state-listed wading bird nesting and negligible effect on foraging.

An individual Florida sandhill crane was observed foraging for insects in an open pasture used as a turf farm adjacent to SR 710 and may occasionally use improved pasture and wet prairie habitats within the proposed pipeline corridor. Construction of the M&R station would permanently convert less than one acre of dry prairie to industrial/

commercial cover type (i.e., gravel). Due to the large acreage of suitable habitat in the surrounding area, no adverse impact to the sandhill crane population in the region is anticipated.

4.6.2.2 Conclusion Regarding State-listed Species

The Project is not likely to have an adverse effect on state-listed and rare species. FGS is pursuing approvals from the FWS and FFWCC with respect to its PAMP, which covers potential Project-related impacts to listed species and mitigation. The FFWCC conducted a site review of the Project and determined that there are no substantive threatened or endangered species issues with respect to constructing the LNG storage facility, pipelines, or M&R station (Walsh, 2007).

4.7 LAND USE, RECREATION, AND VISUAL RESOURCES

4.7.1 Land Use

In this section we discuss the land requirements for Project construction and operation; describe the current use of those lands; and evaluate the significance of Project-related impacts to those lands.

4.7.1.1 Existing Land Use

The Project is located approximately two miles north of Indiantown, an unincorporated area within Martin County. The Project area (e.g., an approximately two-mile radius of the LNG storage facility site and pipeline) is dominated by industrial and agri-business uses, citrus groves, pastures, some wetlands, and road, railroad, and transmission line corridors.

The proposed LNG storage facility site and most of the surrounding area is zoned for industrial use (i.e., M-3 zoning); the Martin County Future Land Use Map also designates much of this area for industrial use (Martin County, 2007) (Figure 4.7-1). There are three new industrial parks proposed in the Project area, including Venture Park, Indiantown Commerce & Technology Park, and Prism Business Park, as well as one mixed-use (residential and commercial) development (Table 4.7-1).

The LNG storage facility site is located on 144.63 gross acres that was the former location of the Florida Steel manufacturing facility. The storage facility site is bounded by SR 710 and the CSX rail line to the east and northeast; the Louis Dreyfus juicing plant to the north, the Cogentrix 330 MW coal-fired generating plant to the west, the FPL powerline right-of-way and open forest land dominated by pine flatwoods and Brazilian pepper (Post Family Trust property) to the south and east. Citrus groves and improved pasture are located north and east across SR 710 from the site.

The site itself includes several remnant Florida Steel structures. Much of the remaining portion of the site includes spray irrigation fields (related to the on-going groundwater remediation at the site), a small pine flatwood, stands of invasive Australian pine and Brazilian pepper, and three small stormwater management ponds.

Table 4.7-1

Planned Development in the Project Area

Development Name	Location	Type / Size	Facilities
Venture Park	Across SR 710 from the northern corner of SRS project site.	Industrial[a] / 139 acres	22 industrial lots and 2 agricultural ranchettes[b]
Indiantown Commerce & Technology Park	West side of CSX Railroad, north of the Booker Park Community of Indiantown	Industrial/ 97.4 acres	31 industrial lots
Prism Business Park	Northwest corner of SR 710 and County Road 609 in Indiantown	Industrial/ 21 acres	Details unknown
Quillen Development	Northwest corner of SR 710 and County Road 609 in Indiantown approximately 1.25 miles from FGS site	Mixed use/ 586 acres	2,250 residential units and 150,000 square feet of commercial space

Notes:

[a] Industrial classification includes manufacturing, warehousing and other high-impact uses.

[b] Agricultural Ranchette classification includes commercial agriculture, along with uses supportive of agriculture.

4.7.1.2 Project Effects

The effects of the Project on existing land use and land cover include construction-related disturbances, limitations on land use within the LNG storage facility site and right-of-way, and effects on future development patterns in the Project area. The effects would be a function of the construction methods employed, restoration actions implemented upon completion of construction, and nature of the affected land. Section 2.4 describes the construction methods proposed for this Project along with post-construction restoration plans.

FGS has an exclusive option to purchase the former Florida Steel site. FGS would also obtain 35.65 acres of temporary construction easement in addition to 25.30 acres of permanent easements for operation of the pipelines, M&R station, and interconnections. FGS has obtained an agreement to use 10.50 acres of land at the nearby Tampa Farms Property for temporary pipe storage and construction staging. Project construction could affect as much as 127.03 acres, of which 48.63 acres would be restored to natural vegetative cover and 78.40 acres would remain in permanent Project use (i.e., LNG storage facility, permanent pipeline right-of-way, M&R station, and interconnections).

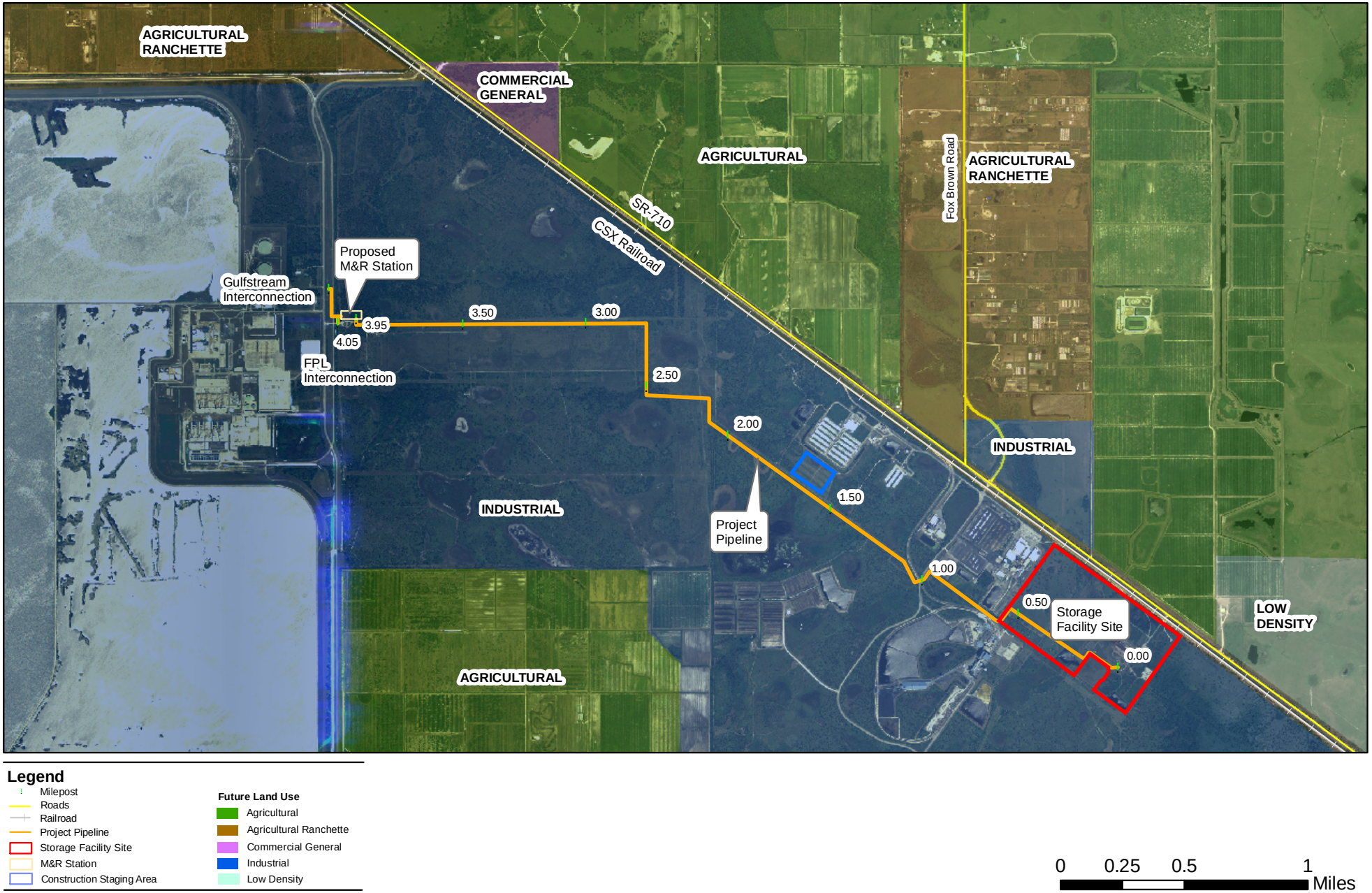


Figure 4.7-1
FGS Project
Planned Future Project Area Land Use Map

LNG Storage Facility

Construction and operation of the LNG storage facilities would temporarily affect approximately 55.58 acres. Storage facility operations would permanently affect 53.10 acres of the site. Table 4.7-2 identifies the existing land cover on the LNG storage facility site that would be affected by Project construction and operation.

Table 4.7-2

Land Cover Potentially Affected by LNG Storage Facility Development

Land Cover	Existing Land Cover (Acres)	Area affected by Construction (Acres)	Proposed Land Cover (Project Operation) (Acres)
Disturbed Land[1]	83.64	41.69	44.43
Forest[2]	15.78	4.45	11.33
Invasive Species[3]	17.24	17.24	0.00
Wetlands[4]	14.08	0.00	14.08
Open Water and Ditches	13.89	0.02	13.87
LNG Storage Facility	0.00	0.00	53.10
Pipeline Right-of-way	0.00	0.00	3.55
Total Acres	*144.63*	*63.40*	*144.63*

Notes:

[1] Disturbed land includes FLUCFCS cover types for disturbed lands, railroads, and roads.

[2] Forest includes FLUCFCS cover types for pine flatwoods and mixed hardwood/coniferous forest.

[4] Invasive species includes FLUCFCS cover types for Brazilian pepper and Australian pine.

[4] Wetlands includes FLUCFCS cover types for mixed wetland hardwoods, exotic wetland hardwoods, freshwater marsh, and cypress/exotic wetland hardwoods.

Given the historical use of the LNG storage facility site for industrial purposes, the presence of other industrial facilities in the area, the current industrial zoning and planned future industrial use of the property by Martin County, development of the Project at this site would be compatible with existing and proposed land use in the Project area. Storage facility construction and operation would have no adverse effect on existing land use or planned development in the area.

Pipelines, Construction Staging Area, and Aboveground Facilities

Prior to initiating construction, FGS would secure easements for both temporary (for construction) and permanent (for operation) rights-of-way. During the easement acquisition process, FGS would compensate landowners for loss of value to specific parcels. The easement agreement between the company and landowner typically specifies compensation for loss of use during construction; loss of nonrenewable or other resources; damage to property during construction; and allowable uses of the permanent right-of-way after construction. During negotiations, FGS and affected landowners would address the following:

- allowable uses within the right-of-way;
- mechanisms required to allow the pipeline to be traversed by heavy equipment such as log skidders; and

- minor route adjustments to accommodate landowner needs, provided the route adjustments do not affect environmentally sensitive areas or other non-consenting landowners.

If an easement cannot be negotiated with a landowner and the Project has been certificated by the FERC, FGS could use the right of eminent domain granted to it under Section 7(h) of the Natural Gas Act and the procedure set forth under the Federal Rules of Civil Procedure (Rule 71A) to obtain the right-of-way and extra workspace areas. FGS would still be required to compensate the landowner for the right-of-way and for any damages incurred during construction; however, a court would determine the level of compensation if a Certificate were issued. In either case, the landowner would be compensated for use of the land.

Construction of the Project pipelines, construction staging area, and aboveground facilities would disturb 71.45 acres of land (Table 4.7-3). The proposed pipeline corridor crosses open land, forest, and wetlands, but would not affect any agricultural land. No residences or federal or state-designated areas are located within 50 feet of the proposed pipeline corridor. Table 4.7-3 identifies the acreage of each land use/cover in the pipeline corridor, construction staging area, and aboveground facilities.

Table 4.7-3

Land Cover Potentially Affected by the Pipeline, Construction Staging Area, and Aboveground Facilities (acres)

Land Cover	Temporary Construction Impacts	Permanent Operations Impacts)
Disturbed Land[1]	13.38	3.75
Prairie	23.28	7.64
Forest and shrub[2]	28.83	8.27
Invasive Species	1.43	0.72
Wetlands[3] & Ditches	3.91	1.95
Pipeline Facilities	0.00	2.97
Poultry Feeding Operations	0.62	0.00
Total Acres	*71.45*	*25.30*

Notes:

[1] Disturbed land includes FLUCFCS cover types for disturbed lands, railroads, and roads FLUCFCS cover types.

[2] Forest includes FLUCFCS cover types for pine flatwoods and hardwood/coniferous mixed.

[3] Wetlands includes FLUCFCS cover types for mixed wetland hardwoods, exotic wetland hardwoods, freshwater marsh, and cypress/exotic wetland hardwoods.

Upon completion of construction, the temporary workspaces would be graded, seeded, or otherwise restored. The portion of the Tampa Farms property used for temporary pipe storage during construction would be restored in accordance with FGS' agreement with the property owner. Because non-woody vegetation would be expected to return to pre-construction conditions within two growing seasons, impacts to acreage currently classified as industrial or open land and not needed for permanent right-of-way or facilities would be short term and minor.

4.7.2 Residences and Structures

The Project is located in an industrial and agricultural area with few residents. There are three residences within 0.50 mile of the LNG storage facility, with the nearest residence located approximately 0.46 mile away. There are no residences within 0.6 mile, and no structures within 50 feet, of the proposed pipeline construction easement. Therefore, construction and operation of the Project would have no adverse effect on any residences or structures.

4.7.3 Recreation and Special Interest Areas

There are no federal, state, or local public lands, recreation areas, nature preserves, conservation areas, wildlife management areas, locally significant natural or scenic areas, or other special use areas in the immediate Project area and none would be affected by Project construction or operation. The closest recreation or special use area is the St. Lucie Canal located approximately two miles south of the LNG storage facility site. The St. Lucie Canal is used locally for recreational fishing and boating. FGS proposes to withdraw water from the St. Lucie Canal for hydrotesting of the LNG storage tanks and the pipelines. This withdrawal would occur at an existing irrigation intake with screening to minimize the entrainment of fish. After the hydrotesting is completed, FGS would return the test water to the St. Lucie Canal. The entire hydrotesting process would take about five weeks. The Project, including the proposed water withdrawal, would have no effect on recreational use of the river.

4.7.4 Coastal Zone Management

The entire state of Florida, including the Project area, is within the State of Florida's designated Coastal Zone (FDEP, 2007). On July 30, 2007, FGS filed an application for an ERP under Part IV of Chapter 373 of the Florida Statutes. The ERP permit serves as the State of Florida's final Coastal Zone Management Act (CZMA) federal consistency determination. The FDEP approved the ERP for the LNG storage facility site on March 19, 2008; therefore, the Project has been determined to be consistent with the CZMA.

4.7.5 Hazardous Waste Sites

The only landfill or hazardous waste site within 0.25 mile of the Project is the FGS property itself and the adjoining remediated soil landfill, both of which were the site of the former Florida Steel plant. From 1970 to 1982, Florida Steel recycled steel from old cars into steel reinforcement bars for concrete at the Project site, which FGS proposes to develop for the LNG storage facility. This process resulted in on-site soil (lead, zinc, and PCB) and groundwater (sodium) contamination. In 1982, the EPA included the Florida Steel site on the National Priorities List under the provisions of the Comprehensive Environmental Response, Compensation, and Liability Act.

The site is currently part of the EPA's Superfund Program and is nearing completion of its remediation. The soil remediation has been completed and primarily involved the removal, treatment, and placement of the contaminated soils in a double-lined landfill (referred to as the "land vault") constructed at the site. It should be noted that FGS would

not acquire the vault and it would not be included in the Project site. The current property owner, Gerdau Ameristeel, would retain ownership of the landfill vault and rights of access through the LNG storage facility site to inspect and maintain the vault. The groundwater remedial system involved the extraction, treatment, and disposal of the treated groundwater via an on-site spray irrigation system. According to EPA (2006), groundwater contaminant concentrations have decreased and are nearing cleanup standards.

As a result of its past use and condition, the following deed restrictions have been imposed on the property by EPA:

1. The Property shall not be used for residential purposes;
2. No day-care facilities, kindergartens, playgrounds, schools, or other facilities catering to children under the age of 16 years shall be operated on the property;
3. The Property shall not be used for swimming, fishing, camping, or hunting;
4. No structures or improvements intended for use for recreational purposes shall be constructed or operated on the property; and
5. The Property shall not be used for the purpose of growing any crops to provide food for humans or animals.

EPA has completed two five-year reviews (i.e., 2001 and 2006) of the site. Both reviews determined that the remedial actions taken remain protective of human health and the environment. Subsequent reviews are required to be conducted every five years. In a letter to FGS (EPA, 2006a), EPA stated that "based upon the facts presently known to EPA, the Agency is of the opinion that the proposed used of the Property does not pose significant incompatibility issues with potential future cleanup activities."

The Project would be consistent with the deed restrictions; however, FGS would be responsible for ensuring that the proposed use does not interfere with or impede the cleanup at the site. Therefore, the Project would not affect, or be affected by, any hazardous waste or other contaminated sites.

4.7.6 Visual Resources

4.7.6.1 Existing Visual Character

Visual resources refer to the composite of basic terrain, geologic features, vegetative patterns, and anthropogenic features that comprise the visual character of an area. The existing LNG storage facility site has been historically used for industrial purposes and is adjacent to two industrial neighbors, the Cogentrix 330 MW coal-fired generating plant and Louis Dreyfus citrus processing facility. As a result, the visual character of the proposed FGS site and neighboring areas is currently industrial.

The elevation of the tallest structure at the Louis Dreyfus citrus processing facility is 138 feet. The Cogentrix generating plant includes a 235-foot-high power plant and a 495-

foot-high stack. Other visual features of the area include electric transmission lines, citrus groves, roads, forested land, and open fields.

4.7.6.2 Project Effects

The significance of visual impact that may result from a proposed project depends on the general character of the existing landscape, degree of alteration of that view, number of potential viewers, and perspective of the viewer.

LNG Storage Facility

The two proposed LNG storage tanks would be the dominant visual feature on the LNG storage facility site. Each tank would be approximately 280 feet in diameter and 174 feet above grade. The other FGS facilities would be at least partially screened by vegetation from viewers driving on SR 710 or from other pubic viewing locations around the area.

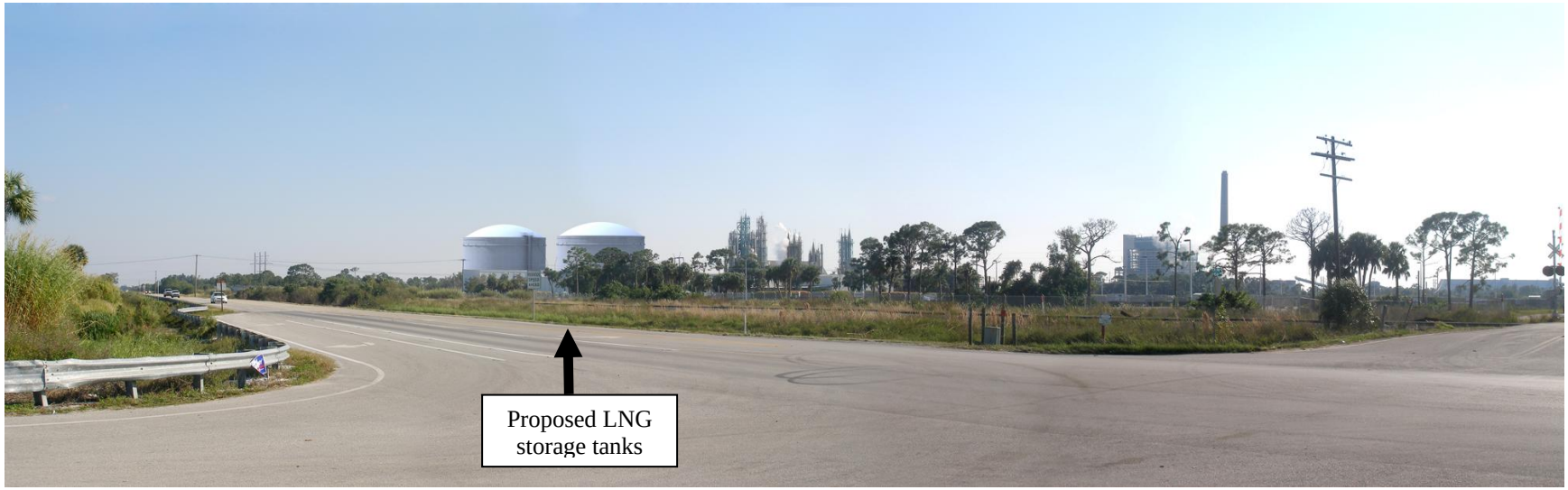
We evaluated the view of the LNG storage tanks from the intersection of SR 710 and Fox Brown Road, approximately 0.25 mile northwest of the LNG storage facility site, as a representative view from the major road in the area. As Figure 4.7-2 shows, the LNG storage tanks would be visible from vehicles traveling along SR 710; however, other industrial features, such as the Cogentrix stack and the Louis Dreyfus citrus processing facility are also prominent.

Overall, we believe that the industrial character of the Project would be consistent with other industrial facilities in the area and would not represent a significant visual impact.

To minimize visual effects, FGS would avoid removal of mature trees (other than Australian pine, which is required to be removed by Martin County because it is an invasive species) and provide a dense landscape buffer along the edge of the property adjacent to SR 710. In addition, FGS would establish a PAMP that includes provisions to provide visual buffers around the LNG storage facility. To minimize light pollution at night, FGS would use downcast lighting fixtures.

Pipelines, Construction Staging Area, and Associated Aboveground Facilities

The primary visual impact during pipeline and M&R station construction would result from clearing of vegetation. Upon completion of construction, the temporary pipeline construction right-of-way (35.65 acres) and construction staging area (10.50 acres) would be restored to pre-construction conditions. The permanent pipeline right-of-way (22.33 acres) would be maintained with low-growth (e.g., shrub or herbaceous) vegetation that would allow for continued access to the pipeline corridor for inspection and maintenance. The M&R station and the interconnections would not be restored, but would be stabilized with gravel and fenced for security purposes.



The vantage point on the figure is looking southeast from Fox Brown Road, just north of SR-710.

Figure 4.7-2
FGS Project
Storage Facility Visual Simulation

4.8 SOCIOECONOMICS

The Project would be located in an unincorporated portion of Martin County classified by the U.S. Census Bureau as the Indiantown Census County Division (CCD), which comprises the majority of land area in Martin County. The nearest concentration of population to the Project is also unincorporated and identified by the U.S. Census as the Indiantown Census Designated Place (CDP). The socioeconomic effects of the Project would likely extend beyond the Indiantown CCD and CDP; therefore, for the purpose of this socioeconomic analysis, we define Martin County as the Project's area of influence. We include information, where available, for the Indiantown CCD and CDP and the State of Florida for comparison purposes. Figure 4.8-1 shows the boundaries of Martin County and the Indiantown CCD and CDP.

4.8.1 Population

Martin County has a total population of 126,731 in 2000 (U.S. Census, 2000a). Martin County experienced slightly higher growth rates than the State of Florida, but slightly lower growth rates than the Indiantown CCD between 1990 and 2000 (Table 4.8-1).

Table 4.8-1

Existing Population in the Project Area of Influence

Place Name	Total 2000 Population	Population Change Since 1990 (%)	Population Density (persons/sq. mi.)
State of Florida	15,982,378	23.5	296.4
Martin County	126,731	25.6	227.9
Indiantown CCD	15,530	29.3	37.1
Indiantown CDP	5,588	12.3	156.0

Source: U.S. Census Bureau, 2000 Census

Population density for Martin County is less than the average for the State of Florida. Most of Martin County's population is located along the Atlantic coast, while the population density of the inland portions of the County, as represented by the Indiantown CCD, is quite low reflecting the rural character of this portion of the County (U.S. Census, 2000a).

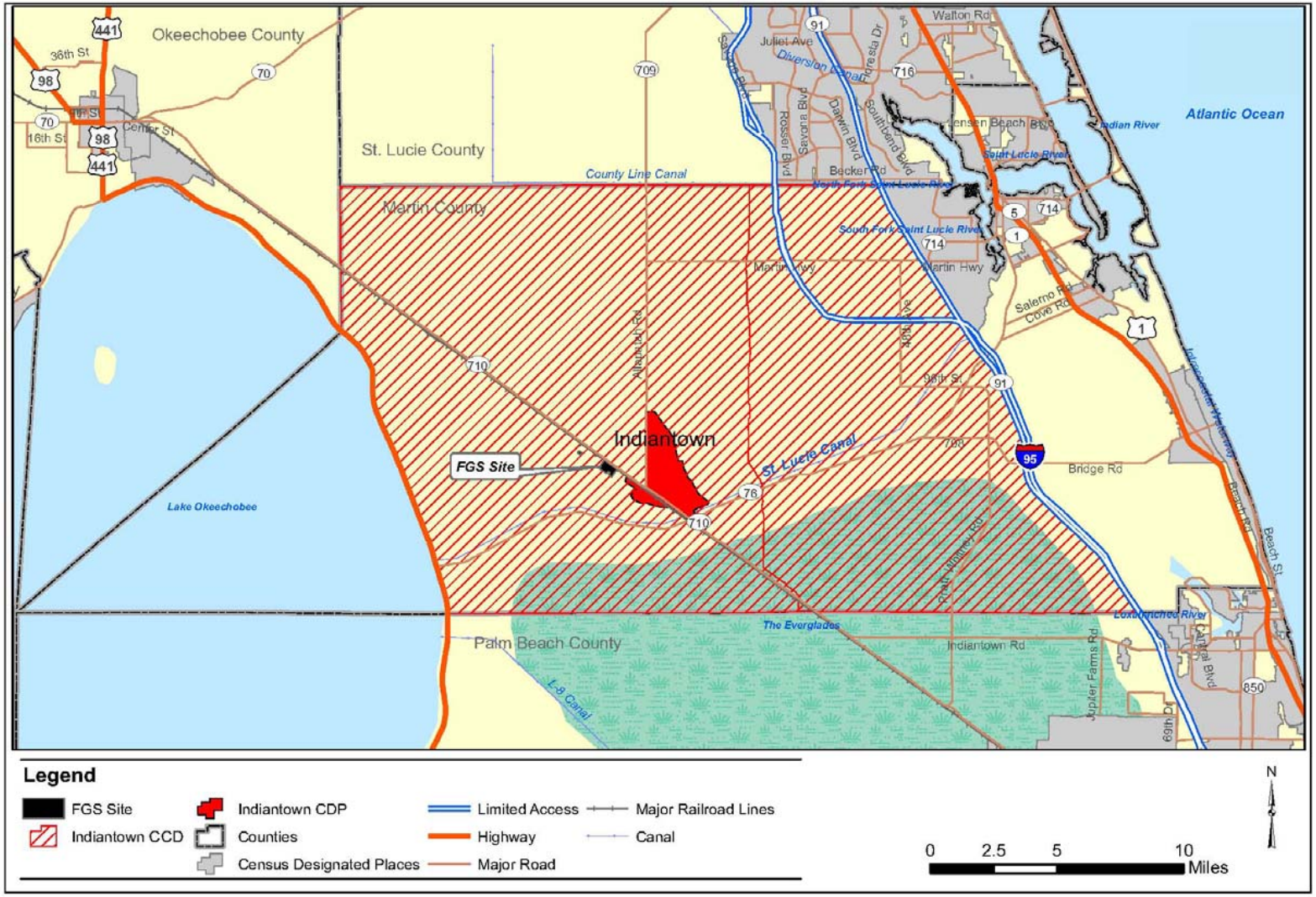


Figure 4.8-1
FGS Project
US Census Track Boundaries

Project-related population effects are expected to be temporary and relatively minor. Project construction is estimated at approximately 36 months. During construction, the total population change would equal the number of non-local construction workers plus any family members accompanying them. Project construction would require an average of 270 supervisory personnel and crafts workers (including skilled, semi-skilled, and unskilled workers), with a peak of around 450 personnel during construction months 14 and 15. FGS proposes to use local workers for construction to the extent that they are available and is encouraging local companies to implement training programs to ensure that many of the construction jobs would be filled by workers from the area. The potential pool of construction workers within commuting distance of the Project is large, including most or all of Martin, Palm Beach, and St. Lucie counties. Therefore we anticipate that relatively few construction workers would actually move to the Project area during construction.

Project operations would require up to 33 permanent staff. This small staff would likely be comprised of existing residents and some non-local personnel who would move to the Project area. Even if all 33 staff were non-local and moved to the Project area with their families, the overall effect on the population of Martin County (126,731 residents) would be minor. As a result, we do not anticipate any significant long-term population growth to occur as a direct effect of the Project.

4.8.2 Economy and Employment

The civilian labor force within Martin County includes an estimated 53,301 individuals (Census, 2000), with the largest percentage employed in sales (17 percent) and construction/extraction industries (10 percent). Martin County has a relatively high per capita income that is approximately 27 percent greater than that of Florida, although per capita income in the Indiantown CCD is below the State average and the poverty rate is above the State average. The unemployment rates of Martin County and the Indiantown CCD are higher than that of the State of Florida as a whole; however, the unemployment rate in the Indiantown CDP was less than the State of Florida. Within the Indiantown CCD and CDP, income is lower than the County as a whole and the portion of the population living below the poverty level is significantly higher. Table 4.8-2 reports unemployment rates and per capita income for Martin County, the State of Florida, and the Indiantown CCD and CDP.

Table 4.8-2

Income and Unemployment Data for the Project Area of Influence

State/County/ Town	1999 Per Capita Income ($)	1999 Population Below Poverty Level (number and %)	2000 Civilian Labor Force	2000 Unemployment Rate (%)
State of Florida	$21,557	1,952,629 (12%)	7,407,458	3.8
Martin County	$29,584	10,844 (9%)	53,301	4.2
Indiantown CCD	$18,530	2,418 (17%)	6,670	5.7
Indiantown CDP	$11,085	1,250 (24%)	2,252	3.6

Source: U.S. Census, 2000

Project construction would occur over a period of 36 months and require an average workforce of 270 personnel with a maximum of 450 personnel in construction months 14 and 1 5. To the extent available, workers would be hired from the local area and their salaries would directly benefit the regional economy. These jobs would also create a multiplier effect as the purchase of goods by construction workers (e.g., food, clothing, lodging, gasoline, and entertainment) would create additional jobs temporarily stimulating the local economy. These jobs would represent a temporary, moderate increase in employment opportunities within the area. During operation, the Project would create up to 33 full-time positions, which would represent a minor, permanent increase in employment opportunities in the area.

During Project construction, expenditures would include approximately $19 million for goods and services and approximately $100 to $110 million for salaries, with a monthly average of approximately $3 million. During operation, the Project would pay approximately $2.2 million annually in wages and provide an estimated beneficial economic impact, including Project spending, sales and payroll, of nearly $19 million (2006 dollars) annually (FAU, 2007).

4.8.3 Housing and Property Values

Table 4.8-3 provides information on available housing units in the area of influence. As discussed in Section 4.8.1, relatively few construction workers are expected to move to the Project area. Even if all long-term construction workers (i.e., 270 workers) temporarily relocate, they would only occupy approximately 2 percent of the available rental units in Martin County. With a rental vacancy rate of about 9.5 percent, there is adequate rental housing available. Housing demand for the 33 permanent staff during operation would represent a negligible, though permanent, increase in housing demand.

Table 4.8-3
Rental Units in Martin County

State/ County/ Town	Rental Units*	Rental Vacancy Rate*	Units for Seasonal, Recreational or Occasional Use*	Number of Hotel/Motel Rooms**	Total Units
Martin County	11,152	9.5%	6,720	985	18,857

Sources:*U.S. Census Bureau State and County Quick Facts, 2000 Census.
**U.S. Economics Characteristics, 2005

The Project is not anticipated to adversely affect property values. The surrounding area is predominantly in industrial and agricultural use, with the nearest residence approximately 0.46 miles away. Based on the surrounding land uses, zoning, and the distance to the nearest residence, it is unlikely that the Project would adversely affect property values.

4.8.4 Government Revenues from the Project

Government tax revenues would increase as a direct result of the Project. In addition to Martin County Building Department fees to be paid by FGS, the County would also

experience an increase in sales tax revenue resulting from local spending by construction employees as well as by the Project. In addition, Project operation would have a positive effect on state and local tax revenues. State revenues from Project operation would include corporate income tax revenue of approximately 5.5 percent of income. FGS would pay at least $1.6 million annually in property taxes to Martin County (FAU, 2007). The property tax benefits would continue through the life of the Project.

4.8.5 Public Services

Table 4.8-4 summarizes the number of full-time equivalent educational, medical, police, and fire protection employees in the area of influence. A temporary increase in the demand for public services would occur during the construction phase of the Project. This increase in demand would be related to support for construction activities as well as the temporary in-migration of some construction personnel and their families.

Table 4.8-4

Existing Medical, Police, Education, and Fire Full-Time Equivalents in the Area of Influence

State/County/Town	Education	Health and Hospitals	Police Protection	Fire Protection	Total Full-Time Equivalents
Martin County	1,912	81	378	106	3,357

Source: U.S. Census Bureau 1997 Federal State and County Area Finance and Employment Fastfacts

During Project operation, the facility would have self-contained safety, fire, and security resources and would thus not place an increased demand on the local public service infrastructure's capacity in terms of resources or personnel. Because only 33 permanent staff would be hired, the addition of those individuals and their families to the local population would represent a negligible increase in demand for public services.

4.8.6 Environmental Justice

Executive Order 12898 on Environmental Justice recognizes the importance of using the NEPA process to identify and address, as appropriate, any disproportionately high and adverse health or environmental effects of its programs, policies, or activities on minority populations and low-income groups. The provisions of Executive Order 12898 apply equally to Native American programs. Consistent with Executive Order 12898, the CEQ called upon federal agencies to actively scrutinize the following issues with respect to environmental justice (CEQ, 1997):

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

The EPA provides guidance on determining whether there is a minority or low income community to be addressed in a NEPA analysis. Minority population issues must be addressed when they comprise over 50 percent of an affected area or when the minority population percentage of the affected area is substantially greater than the minority percentage in the larger area of the general population. Low income populations are those that fall within the annual statistical poverty thresholds from the U.S. Department of Commerce, Bureau of the Census Population Reports, Series P-60 on Income and Poverty.

4.8.6.1 Potential for Disproportionate and Adverse Impacts

Minority populations comprise less than 50 percent of the population in the State of Florida, Martin County, and the Indiantown CCD (Table 4.8-5). As a whole, Martin County contains a significantly smaller proportion of minorities (approximately 10 percent) within its population than the State; however, the proportion of minorities in the Indiantown CCD (approximately 32 percent) is similar to the racial distribution of the State (approximately 22 percent). Although the minority population with the Indiantown CCD is not greater than 50 percent, the Indiantown CDP, which is only approximately one mile from the Project site, does have a minority population that is meaningfully greater than in the general area.

Table 4.8-5

Racial/Ethnic Characteristics of the Area Surrounding the FGS Storage Project

Place	Racial/Ethnic Group (percent)							Persons of Hispanic or Latino Origin
	White	African American	Native American and Alaskan Native	Asian	Native Hawaiian and other Pacific Islander	Persons reporting some Other Race	Persons reporting two or more races	
State of Florida	78.0	14.6	0.3	1.7	0.0	3.0	2.4	16.8
Martin County	90.0	5.3	0.3	0.6	0.1	0.3	2.4	7.5
Indiantown CCD	68.8	13.6	1.2	0.3	0.4	13.3	1.1	3.3
Indiantown CDP	45.9	21.0	0.2	0.0	0.1	26.5	0.3	48.9

Source: U.S. Census Bureau, 2000 Census

As discussed in Section 4.8.2, per capita income in Indiantown CCD ($18,530) is lower than the County ($29,584) and State ($21,557) averages. Approximately 17 percent of the Indiantown CCD is below the poverty level (Table 4.8-2), which is greater than the State of Florida (12 percent) and Martin County (9 percent). Although the percentage of population below the poverty line is greater in the Indiantown CCD, it is not meaningfully higher than the State average (17 vs 12 percent).

Although there does not appear to be a minority or low-income community by EPA definitions within the Indiantown CCD, there is a minority population relatively close by in the adjoining census unit (Indiantown CDP). Therefore, we evaluated whether the

Project would have disproportionately high and adverse environmental or human health effects on the minority population within the Indiantown CDP.

As described in Section 4.8.2, the proposed Project would have positive effects on the socioeconomic characteristics and economies within the region of influence. The proposed Project would provide employment opportunities and added revenues in the form of taxes and spending. When available, local workers would be used for construction. FGS is sponsoring a welding training program at the Indian River Community College to develop skilled welders for pipe and plate welding. The welder training course will teach unskilled personnel a transferrable skill plus safe work habits. The proposed Project would be located on a parcel of land zoned for industrial use and located approximately a half mile from the nearest residence. In addition, the proposed FGS Project would productively use property on which a non-industrial use would be unacceptable due to prior contamination. Although the racial and economic composition of the Indiantown CCD shows some deviations from state and county-level statistics, as described above, there is no evidence that the proposed Project would cause a disproportionate share of adverse environmental or socioeconomic impacts on any racial, ethnic, or socioeconomic group.

The primary health issue related to the proposed Project would be the risk associated with the rare potential of pipeline failure or LNG storage accident. Section 4.12 discusses the risks and associated impacts to public safety that would result from an accident at the facility or a pipeline failure and describes how applicable safety regulations and standards would minimize the potential for these risks. The proposed LNG storage facility and pipeline corridor avoid populated areas, minimizing the number of persons at risk of injury. Although the proposed LNG storage facility would emit some air emissions during normal Project operation, these emissions would be minor, below PSD applicability thresholds, and not a public health hazard. Based on our analysis, there is no evidence that health risks would be disproportionately borne by any racial, ethnic, or socioeconomic group.

To summarize, although the racial and economic composition of the Indiantown CCD does not appear to meet the EPA definition of a minority or low-income community, it is proximate (within about one mile) of the Indiantown CDP, which does have a minority population that is meaningfully higher than the general area. There is no evidence however, that the Project would have any significantly high or adverse environmental or human health effects. Overall, we conclude that the Project would not result in any environmental justice issues. The socioeconomic impacts of the proposed Project are generally beneficial, and there is no evidence that the slight risk of a pipeline or LNG tank failure would be disproportionately borne by any group.

4.8.6.2 Public Participation Strategies

Under Executive Order 12898, each federal agency must ensure that public documents, notices, and hearings related to human health or environmental issues are concise, understandable, and readily available to the public. The public review and comment process that the FERC implemented in association with the environmental review of the proposed Project is discussed in section 1.3. The environmental mailing list for the FGS

Project was developed when the Commission issued the NOI for the Project on February 15, 2007. Since then the mailing list has been continually updated. All interested parties or property owners affected by the Project received notices about the Project without distinction based upon minority or income status. In addition to landowners, the distribution list for this EIS includes federal, state, and local officials; agency representatives; conservation organizations; Native American tribes; and local libraries and news media outlets.

In addition to our public review and comment process, FGS has communicated directly with the property owners who would be affected by the proposed Project, irrespective of minority or income status. FGS established an Internet Website at http://www.floridiangasstorage.com; a toll-free telephone number, 1-800-621-6843; and an e-mail address, info@floridiangasstorage.com to provide potentially affected landowners and stakeholders with a venue for providing comments or requesting additional information about the proposed Project. FERC staff encourages FGS to continue its commitment to maintain open communications with affected landowners during construction through similar methods, should the Project ultimately be certified.

The environmental mailing list for the final EIS includes affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; Native American tribes; local libraries and newspapers; and other parties who provided scoping comments, asked to remain on the mailing list, or wrote the FERC or one of the cooperating agencies asking to receive a copy of the document. A formal notice was published in the Federal Register, indicating that the final EIS is available and has been mailed to individuals and organizations on the environmental mailing list prepared for the proposed Project (see Appendix A). Section 1.4 further describes the public notification and participation process completed for the proposed Project, and section 4.10 describes contacts with Native American tribes that traditionally occupied, or currently occupy the Project area.

4.8.6.3 Environmental Justice Summary

In summary, information about the proposed Project has been readily available to the public and no disproportionately high and adverse human health or environmental effects on minority and/or low-income communities or Native American tribes have been identified. Furthermore, Project construction would provide short-term job opportunities in the region of influence and the welding training program provides a long-term, transferrable skill to local workers in the program. The only long-term socioeconomic effects of the Project are likely to be beneficial, based on the increase in tax revenues that would accrue to the counties affected by the Project. A more specific discussion of the Project-related impacts on residential areas, air quality and noise, and safety is presented in sections 4.7, 4.9, and 4.11 respectively. Cumulative impacts are discussed in section 4.13.

4.9 TRANSPORTATION

SR 710 would provide direct vehicular access to the LNG storage facility site. The average annual daily traffic volume on SR 710, measured just northwest of Allapattah

Road approximately 0.5 miles from the storage facility site, is 7,800 vehicles per day. Figure 2.1-2 shows other local roads in the Project area including Fox Brown Road, Allapattah Road, and SR 76 (Kanner Highway). The Florida Turnpike and I-95 are approximately 24 and 25 miles to the east, respectively, and provide good access to the remainder of the State. The Project would also have direct access to rail (CSX Transportation System), which runs adjacent to the site and parallel to SR 710, and nearby access for barges on the St. Lucie Canal. Construction of the Project could affect area transportation if the volume of construction or operation-related traffic caused delays or other inconveniences, or if construction resulted in temporary road closures or lane blockages.

One full access driveway connection to SR 710 between Fox Brown Road and Allapattah Road would serve as the main entrance to the LNG storage facility and provide primary site access for construction and operational traffic. Any site access from the state highway system would be subject to the requirements of the State Highway System Connection Permits Administrative Process as well as the Access Management Classification System and Standards. FGS is also working on an agreement that would establish a permanent secondary access road connection between the Indiantown Commerce and Technology Park and the LNG storage facility site. This road would only be used to provide emergency access to the Project if the primary entrance was blocked by a train on the CSX rail line.

Project construction is proposed to be completed over a 36-month period. Construction activities would require an average of 270 workers and a peak of approximately 450 workers during construction months 14 and 15. All construction activities would occur during a single shift, with morning traffic assumed to be inbound to the site and afternoon traffic outbound. To minimize the potential for traffic congestion, shift changes would occur outside the normal peak hours. All construction materials would be delivered by trucks during off-peak hours. The largest number of truck trips would occur in the 17th month of construction, when an estimated 1,640 truck trips, or an average of 106 truck trips per day would occur. Peak truck traffic from the Project would be minor (less than 7 percent) compared to the average daily truck traffic on SR 710, which is approximately 1,670 trips per day. The maximum daily truck traffic during project operations would be 4 truck trips per day, which is negligible compared to the average daily truck traffic on SR 710.

FGS proposes traffic control at the SR 710 LNG storage facility entrance consisting of temporary traffic lights and the use of off-duty representatives of the Martin County Sheriff's Department. The temporary traffic lights would be programmed for periodic "controlled stoppage" of SR 710 traffic during the morning start work hours and the afternoon/evening stop work hours. The stoppage would allow construction traffic to enter SR 710 and/or allow northbound traffic to make left turns into the LNG storage facility site. During those hours not requiring controlled stoppage, the temporary traffic lights would be programmed to blink yellow for both directions of SR 710 and red for traffic leaving the storage facility site. The traffic light would also be equipped with a switch to allow the off-duty representative of the Sheriff's Department to override the system to ensure that traffic moved through the intersection smoothly with as little disruption as possible to SR 710 traffic during high-use periods. Because the access road

between the Indiantown Commerce and Technology Park and the LNG storage facility site would only be used for emergencies, traffic controls are not proposed for this access point. No construction would occur on public roads, so no road closures or detours are expected.

Florida Department of Transportation (FDOT) plans several traffic signalization and turn lane improvements along SR 710 in the next few years to maintain the desired level of service standards. In addition, the FDOT is expected to begin a resurfacing project in February 2008 for SR 710 between the Okeechobee County Line, northwest of the LNG storage facility site, and Martin Luther King Jr. Boulevard, just southeast of the storage facility site, including the full frontage of the property. FDOT indicates that any work that would occur within FDOT rights-of-way would be conducted in accordance with the FDOT Utility Accommodation Manual, dated January 1999 (FDOT, 2007).

FGS would employ three shifts daily during Project operation, with 20 employees at the largest shift. The Project would also receive approximately two daily truck trips (Kimley-Horn, 2007). This volume of vehicular traffic would not cause any traffic problems at the LNG storage facility's driveway intersection with SR 710 or elsewhere in the local traffic network. As a result, traffic control at the storage facility entrance from SR 710 would not be required for Project operation and the temporary traffic lights would be removed once construction was completed.

During emergency events (i.e., the aftermath of a hurricane or other supply interruption) when pipeline delivery is not possible, LNG would be transported from the storage facility by truck to FGS capacity holders. Specific locations of the truck destinations are not known at this time; however, it is expected that hospitals, gas distribution companies, power plants, and other essential services would be likely destinations during emergencies. Trucks traveling north would not travel through residential areas until they reached the city of Okeechobee, roughly 25 miles from the LNG storage facility site. Trucks traveling south would pass through Indiantown. Since these additional truck trips would only occur during emergency conditions, we do not anticipate that they would create any significant traffic problems.

4.10 CULTURAL RESOURCES

Section 106 of the NHPA, as amended, requires the FERC to take into account the effect of its undertakings (including the issuance of Certificates) on any properties listed in, or eligible for listing in, the National Register of Historic Places and to provide the ACHP an opportunity to comment on the undertaking. FGS, as a non-federal party, is assisting the FERC in meeting its obligation under Section 106 of the NHPA by conducting the field surveys and evaluations required by ACHP regulations at 36 CFR 800.

The area of potential effect (APE) of a project is the geographic area or areas within which an undertaking may directly or indirectly cause change in the character or use of historic properties, if any such properties exist. The APE is influenced by the scale and nature of an undertaking and may be different for different kinds of effects caused by the undertaking (36 CFR §800.16[d], amended 1999). The direct APE for this Project includes the 144.63-acre storage facility site as well as an approximately four-mile-long, 210-foot-wide pipeline corridor, which encompasses the proposed pipeline construction

easement as well as potential route variations. The visual APE includes those properties or areas within the viewshed of the Project.

4.10.1 Results of Cultural Resources Surveys

FGS conducted research and cultural resource surveys of the Project APE in February 2007. Review of the Florida Master Site File determined that 14 prior cultural resource management surveys have been conducted in the Project area, although none of these studies identified any archaeological resources within one mile of the Project. FGS also conducted a pedestrian survey of the entire direct APE and subsurface testing of the approximately four-mile-long pipeline corridor. In addition to the archaeological surveys, FGS conducted a survey of historic buildings 50 years of age or older within the entire APE, including the LNG storage facility site, pipeline corridor, and surrounding areas.

FGS submitted Cultural Resource Assessment Survey Reports to the Florida Department of State - Division of Historical Resources, which functions as the State Historic Preservation Office (SHPO) in Florida. In letters dated May 25, 2007 and June 2, 2008, for the Project facilities and the Tampa Farms staging area, respectively, the Florida SHPO concurred with the findings of FGS' reports that the Project would have no effect on any properties listed in, or eligible for listing in, the National Register of Historic Places, and agreed that no further investigation of the Project was necessary. We also concur.

FGS has filed an acceptable Unanticipated Discoveries Plan with the Commission that outlines the procedures to be followed in the event that unanticipated cultural materials or human remains are encountered during construction of the Project. This plan was filed by FGS in its certificate application in October 2007 and can be found on the FERC's eLibrary website at www.ferc.gov under Docket No. CP08-13-000.

4.10.2 Native American Consultation

FGS sent letters describing the Project, together with a location map showing the location of proposed Project facilities, to each of the five federally-recognized tribes with ties to the area: the Miccosukee Tribe of Indians of Florida, Muscogee Creek Indians, Band of Creek Indians, Seminole Nation of Oklahoma, and Seminole Tribe of Florida.

FGS held informal conversations with both the Seminole Tribal Historic Preservation Officer (THPO) and Miccosukee Section 106 representative prior to the initiation of field work, at which time no concerns or issues were identified. A copy of the Cultural Resource Assessment Report was submitted to the Seminole THPO, who responded with a concurrence e-mail on May 31, 2007. During an April 11, 2007, meeting, the Miccosukee Tribal representative also concurred with the report findings.

4.10.3 Compliance with NHPA

FGS has completed cultural resource surveys on the LNG storage facility site, construction staging area, and pipelines corridor, submitted reports on the results; and conducted consultation with the SHPO, Seminole THPO, and Miccosukee Tribal Section 106 representative. All concur that the proposed development would have no effect on

cultural resources listed or eligible for listing in the National Register of Historic Places and agree that no further surveys are required. We also concur. Consequently, the Commission's required consultation under Section 106 of the NHPA is complete.

4.11 AIR QUALITY AND NOISE

4.11.1 Air Quality

4.11.1.1 Existing Air Quality

Ambient air quality is protected by federal and state regulations. The Clean Air Act designates six pollutants as criteria pollutants for which the National Ambient Air Quality Standards (NAAQS) are promulgated. The NAAQS for sulfur dioxide (SO_2); nitrogen dioxide (NO_2); particulate matter (PM_{10} particulates and $PM_{2.5}$ particulates); carbon monoxide (CO); ozone (O_3,); and lead were set to protect human health (i.e., primary standards) and human welfare (i.e., secondary standards). These standards are summarized in Table 4.11-1. State air quality standards cannot be less stringent than the NAAQS. The State of Florida has its own ambient air quality standards that are more stringent than the NAAQS for some pollutants and the same as NAAQS for other pollutants. The NAAQS program also classifies areas, where sufficient data are available, as either attainment (i.e., does not exceed NAAQS) or non-attainment (i.e., exceeds NAAQS). The Project would be located in Martin County, which is in attainment for all criteria pollutants.

Currently, Martin County has no active continuous air quality monitoring stations. The closest air quality monitoring stations to the Project are in Palm Beach County, which has seven. Over the past three years (i.e., 2004 to 2007), the NAAQS standards were only exceeded once for $PM_{2.5}$ (i.e., 51 micrograms per cubic meters) at the Delray Beach monitoring station in Palm Beach County.

4.11.1.2 Project Effects

Air quality would be affected by construction and operation of the Project. Although air emissions would be generated by operation of equipment during construction of the pipeline and aboveground facilities proposed by FGS, most air emissions associated with the Project would result from the long-term operation of the LNG storage facility.

The LNG storage facility would contain vaporization, liquefaction, and metering systems, including:

- eight natural gas-fired WEG heaters, each rated at 98 MMBtu/hr heat input that would operate 2,400 hours per year and be equipped with a low nitrogen oxide (NO_x) burner to control NOx emissions;
- two natural gas-fired regeneration gas heaters each rated at eight MMBtu/hr that would operate a maximum of 2,880 hours per year;
- two natural gas-fired amine system heaters, each rated at 10 MMBtu/hr that would operate 5,760 hours per year; and

- two natural gas-fired M&R station heaters, each rated at 52 MMBtu/hr that would operate a maximum of 2,400 hours per year.

Table 4.11-1

National and State Ambient Air Quality Standards

Pollutant	Averaging Time	National AAQS ($\mu g/m^3$) Primary Standard	National AAQS ($\mu g/m^3$) Secondary Standard	Florida AAQS[a] ($\mu g/m^3$)
Particulate matter less than 10 microns in diameter [c]	Annual Arithmetic Mean	NA	NA	50
(PM_{10})	24-Hour Maximum	150	150	150
Particulate matter less than 2.5 microns in diameter [c]	Annual Arithmetic Mean	15	15	15
($PM_{2.5}$)	24-Hour Maximum	35	35	35
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60
	24-Hour Maximum	365	NA	260
	3-Hour Maximum	NA	1,300	1,300
Carbon Monoxide	eight-hour Maximum	10,000	10,000	10,000
	1-Hour Maximum	40,000	40,000	40,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100
Ozone [c]	1-Hour Maximum [d]	NA	NA	235
	eight-hour Maximum	0.08 ppm	0.08 ppm	
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

Notes:

$\mu g/m^3$ = micrograms per cubic meters; ppm = parts per million

NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year, except PM_{10} and O_3 AAQS, which are based on expected exceedances.

[b] Maximum concentrations are not to be exceeded.

[c] Due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution, EPA revoked the annual PM_{10} standard in 2006 (effective December 17, 2006). On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour average standard of 35 $\mu g/m^3$ (based on the three-year averages of the 98th percentile values) and an annual standard of15 $\mu g/m^3$ (three-year averages at community monitors). The O_3 standard was modified to be 0.08 ppm (i.e., 160 $\mu g/m^3$) for the eight-hour average; achieved when the three-year average of 99th percentile values is 0.08 ppm or less. These standards must be implemented in the 2007-2008 timeframe. The FDEP has not yet adopted the revised standards.

[d] To attain this standard, the three-year average of the fourth-highest daily maximum eight-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm. One-hour ozone standard was revoked in June 2005.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Florida Chapter 62.204, F.A.C.

In addition to the pipeline and LNG storage facility, FGS would also install:

- four diesel-fired emergency generators rated at 3,500 and 3,000 kilowatts, respectively, which would each operate a maximum of 250 hours per year;
- one emergency fire water pump engine rated at 400 hp, which would operate a maximum of 250 hours per year;
- two Amine System vents, which would each operate at a maximum of 5,760 hours per year; and
- a cooling tower consisting of four cells with a total circulating water flow rate of 300 gpm and unlimited hours of operation.

Construction Emissions

Air quality impacts associated with Project construction would include emissions from fossil-fueled construction equipment and fugitive dust. Such air quality impacts, however, would generally be temporary and localized. Large earth-moving equipment, wheel loaders, trucks, and other mobile sources may be powered by diesel or gasoline and are sources of combustion emissions, including NO_x, CO, volatile organic compounds (VOCs - a precursor of ozone), SO_2, PM_{10}, $PM_{2.5}$, and hazardous air pollutants (HAPs). These temporary impacts would be generally limited to the immediate vicinity of the construction area. FGS would maintain all fossil-fueled construction equipment in accordance with manufacturer's recommendations to minimize construction-related emissions.

The majority of air emissions during construction activities would be respirable particulate matter (PM_{10} and $PM_{2.5}$) and total suspended particles in the form of fugitive dust. Fugitive dust would result from land clearing, grading, excavation, concrete work, and vehicle traffic on unpaved roads. The amount of dust generated would be a function of construction activities, soil type, moisture content, wind speed, frequency of precipitation, vehicle traffic, vehicle type, and roadway characteristics. Emissions would be greater during drier periods in areas of fine-textured soils. FGS would apply water sprays as appropriate to prevent excessive fugitive dust generation. Table 4.11-2 summarizes the anticipated combustion emissions from construction equipment engines and fugitive dust emissions from unpaved roads.

Operations Emissions

The LNG storage facility would emit air pollutants as a result of combustion of natural gas in the heaters (i.e., WEG heaters, regeneration gas heaters, amine system heaters, and M&R station heaters) and in association with the periodic operation of the diesel-fired emergency generators, diesel-fired water pump, amine system vent, and cooling tower cells. Table 4.11-3 summarizes the anticipated emissions of NO_x, CO, VOCs, SO_2, total PM, and HAPs associated with the FGS Project during operations. The FGS Project emissions would be minimized through the use of low NO_x burners for the WEG heaters; clean-burning natural gas fuels; and appropriate operation and maintenance procedures.

Table 4.11-2

Summary of Air Emissions from Project Construction (tons/year)

	Year 1			Year 2			Year 3		
Pollutants	**Equip. Engines**	**Unpaved Roads**	**Total**	**Equip. Engines**	**Unpaved Roads**	**Total**	**Equip. Engines**	**Unpaved Roads**	**Total**
NOx	144.50	--	**144.50**	145.10	--	**145.10**	49.70	--	**49.70**
VOCs	17.00	--	**17.00**	21.20	--	**21.20**	6.70	--	**6.70**
SO_2	7.24	--	**7.24**	7.25	--	**7.25**	2.48	--	**2.48**
CO	242.00	--	**242.00**	284.00	--	**284.00**	83.20	--	**83.20**
TSP	NA	155.00	**155.00**	NA	70.00	**70.00**	NA	23.00	**23.00**
PM_{10}	5.10	48.10	**53.20**	5.20	23.10	**28.30**	1.80	6.50	**8.30**
$PM_{2.5}$	5.00	0.48	**5.48**	5.00	0.23	**5.23**	1.70	0.06	**1.76**
HAPs	0.60	--	**0.60**	0.60	--	**0.60**	0.20	--	**0.20**

Note:

NA = Not Applicable

Emissions based on equipment hours of operation provided by FGS (Monday through Friday, with occasional Saturday use for some equipment) and appropriate emission factors for Tier II engines.

VOC, CO, NOx, and PM emission factors were taken from EPA's Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling-Compression-Ignition, Report No. NR-009c, April 2004; $PM_{2.5}$ assumed equal to 97% of PM.

SO_2 emissions based on 0.05 % S Diesel and 100% conversion to SO_2. SO_2 gasoline emission factors are based on AP-42 Table 3.3-1. SO_2 emission factor = 5.91E-4 lb/hp-hr equivalent to 0.268 g/hp-hr.

Diesel fuel use based on 14.75 hp-hr/gals.

Gasoline emission factors from EPA AP-42 Section 3.3 Table 3.3-1 (EPA, 1996); $PM_{2.5}$ assumed equal to 97% of PM.

HAP emission factors were taken from Section 3.4 of EPA's AP-42 (EPA, 1996)

Fugitive dust emissions from unpaved roads were calculated in accordance with EPA methods in AP-42, Section 13.2.2.2 (EPA, 2006b); includes 60% emission control removal efficiency from water sprays.

Operation of the proposed pipeline and ancillary facilities would not result in substantial air emissions under normal operating conditions. Typically, only minor fugitive emissions of natural gas occur from small connections at M&R stations and valve sites. Because such emissions are very small and discountable, they are not regulated by permit or source-specific requirements.

Table 4.11-3

Summary of Air Emissions from Project Operations (Tons/Year)

Pollutant	WEG Heaters	Regen Gas Heaters	Amine System Heaters	Emergency Generators	Fire Water Pump	Let Down Heaters	Amine System Vent	Cooling Tower	Total	PSD Significant Emission Rate	PSD Review Required?
SO_2	5.6	0.1	0.32	0.85	0.019	0.68	NA	NA	7.58	100	No
Total PM	6.9	0.2	0.42	0.40	0.009	0.91	NA	2.0	11.00	100	No
NO_x	43.2	2.2	5.50	26.10	0.453	11.95	NA	NA	89.00	100	No
CO	77.5	1.9	4.70	2.10	0.028	10.03	NA	NA	96.00	100	No
VOC (as methane)	5.1	0.1	0.30	0.52	0.007	0.66	41	NA	48.00	100	No
HAPs	0.1	2.83E-3	0.01	7.16E-02	1.62E-03	0.02	NA	NA	0.22	NA	No

Notes:

- NA - Not Applicable
- The WEG heaters will employ Low NO_x burners to achieve a NO_x emission rate of 30 ppmvd, at 3 percent O_2.
- Natural gas fired equipment emissions based on EPA AP-42, Tables 1.4-1 and 1.4-2 (EPA, 1998). Total PM (condensable plus filterable) assumed less than one micrometer in diameter.
- Diesel fired emergency equipment based on EPA, AP-42 Table 1.3-1 and 1.3-2 (EPA, 1998). VOC emissions from Amine System Vent was provided by equipment manufacturer.

Source: Golder, 2007.

Regulatory Requirements

The Clean Air Act (CAA), 42 USC 7401 et seq., as amended in 1977 and 1990, is the basic federal statute governing air pollution. The provisions of the CAA that are potentially relevant to the Project include the following, which are discussed further below:

- Air Quality Control Regions (AQCRs);
- Prevention of Significant Deterioration (PSD);
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAPs);
- Title V Operating Permits; and
- General Conformity.

In addition, the Project would be subject to any applicable Florida state regulations that are more stringent than federal regulations.

Air Quality Control Regions

AQCRs are areas in which implementation plans describe how ambient air quality standards will be achieved and maintained. AQCRs were defined by EPA and state agencies in accordance with Section 107 of the CAA. The AQCRs are intra- and interstate regions such as large metropolitan areas where improvement of air quality in one portion of the AQCR requires emission reductions throughout the AQCR. The proposed Project would be in the Southeast Florida Intrastate AQCR as defined at 40

CFR 81.49, which includes Broward, Dade, Indian River, Martin, Monroe, Okeechobee, Palm Beach, and St. Lucie counties in Florida. These eight counties are classified as attainment areas for all criteria pollutants for which EPA has made attainment designations.

Prevention of Significant Deterioration

The PSD regulations apply to proposed new major sources or major modifications to existing major sources located in an attainment area. The PSD regulations (40 CFR 52.21) define a major source as any source type belonging to a list of 28 named source categories that emit or have the potential to emit 100 tons per year (tpy) or more of any regulated pollutant. A major source under PSD also can be defined as any source not on the list of named source categories with the potential to emit such pollutants in amounts equal to or greater than 250 tpy.

The PSD review evaluates existing ambient air quality and the potential impacts of the proposed source on ambient air quality, noting in particular whether the source would contribute to any violation of the NAAQS, and reviews the best available control technology (BACT) to minimize emissions. The PSD regulations contain restrictions on the degree of ambient air quality deterioration that would be allowed. These increments for criteria pollutants are based on the PSD review classification of the area. Class I areas are specifically designated as pristine natural areas or areas of natural significance and receive special protections under the CAA because of their good air quality. If a new source or major modification is subject to the PSD program requirements and is within 62 miles (i.e., 100 kilometers) of a Class I area, the facility is required to notify the appropriate federal officials and assess the impacts of the Project on the Class I area. Class II areas are designed to allow moderate, controlled growth. Class III areas allow for heavy industrial use. The Project would be located in a Class II area. The nearest Class I area, the Everglades National Park, is located approximately 100 miles south of the Project; therefore a full Class I analysis is not required.

The WEG heaters are one of the 28 named source categories (i.e., Fossil Fuel Boilers (or combination thereof)) totaling more than 250 MMBtu/hr heat input. The Project would emit less than 100 tpy of any criteria pollutant at the LNG storage facility. Table 4.11-3 summarizes the anticipated annual operational emissions from the LNG storage facility for each regulated pollutant, including NO_x, CO, VOCs, PM_{10}, SO_2, and hazardous air pollutants HAPs. The net emissions from the LNG storage facility for each of the criteria pollutants would be less than the major source applicability thresholds; PSD permitting is, therefore, not applicable. The Project would be considered a “minor source” with regards to PSD review, and BACT or PSD (i.e., air dispersion) modeling would not be required.

New Source Performance Standards

The NSPS, codified at 40 CFR 60, establish emission limits, monitoring, reporting, and record keeping for specific source categories. The following NSPS requirements were identified as potentially applicable to the specified sources at the proposed LNG storage facility.

Subpart Dc of 40 CFR 60.40c applies to steam generating units that have heat input capacities from fuels combusted in the steam generating unit of between 10 and 100

MMBtu/hr. The WEG heaters would be natural gas-fired with a design heat input rating of 98 MMBtu/hr; therefore, these units would be subject to the requirements of Subpart Dc.

Subpart Kb of 40 CFR 60, Standards of Performance for Volatile Organic Liquid Storage Vessels, lists affected emission sources as storage vessels containing volatile organic liquids. Regulatory applicability is dependent on the construction date, size, and vapor pressure of the storage vessel and its contents. On October 15, 2003, EPA promulgated changes to 40 CFR Part 60, Subpart Kb that would exempt light oil tanks containing No. 2 light oil by virtue of its vapor pressure; therefore, the diesel fuel tanks associated with the Project are exempt from NSPS Subpart Kb.

The applicable NSPS for emergency generators and fire water pumps are codified in 40 CFR 60 Subpart III, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The format of the final standard is an output-based emissions standard for PM, NO_x, CO, and non-methane hydrocarbons and is tiered based on model year. The Project would utilize emergency generators and a fire water pump that comply with the recently promulgated NSPS.

National Emission Standards for Hazardous Air Pollutants

The NESHAPs (40 CFR Parts 61 and 63) regulate HAP emissions from existing and new sources. The Project is not expected to operate any processes that are regulated by Part 61. Part 63 establishes Maximum Applicable Control Technology standards for major sources of HAPs. Maximum Applicable Control Technology standards are intended to reduce emissions of airborne toxins or HAPs through installation of control equipment rather than enforcement of risk-based emission limits. Applicability is triggered if potential emissions are greater than 10 tpy of any single listed HAP or if total HAP emissions exceed 25 tpy for the listed HAPs. Table 4.11-3 indicates that the potential HAP emissions resulting from operation of the Project would be well below these thresholds; therefore, no Maximum Applicable Control Technology standards apply to the Project.

Title V Permitting

The Title V permit program, as described in 40 CFR 70, requires sources of air emissions with criteria pollutant emissions that reach or exceed major source levels to obtain federal operating permits. These permits list all applicable air regulations and include a compliance demonstration for each applicable requirement. The major source threshold level in attainment areas is 100 tpy of any regulated air pollutant, 10 tpy of any individual HAP, or 25 tpy for all HAPs. The Project would not exceed any of these criteria thresholds, as shown in Table 4.11-3; therefore, the Project would not require a Title V permit.

General Conformity

A conformity determination must be conducted by the lead federal agency if a federal action would generate emissions exceeding the conformity threshold levels (de minimis) of the pollutant(s) for which an air basin is designated as a nonattainment area or a

maintenance area. Since the Project area is classified as in attainment for all criteria pollutants, a General Conformity Determination is not required.

State Regulations

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD requirements as discussed previously. Required permits and approvals for air pollution sources include PSD, NSPS, NESHAPs, Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, Florida Administrative Code. Specific emission standards are set forth in Chapter 62-296. The Project is not subject to PSD or NESHAP regulations. On March 12, 2008, FDEP issued a minor source air construction permit for the FGS Project.

Based on the above analysis, construction and operation of the FGS Project would not have a significant impact on air quality in the Project area; therefore, no additional air mitigation measures are proposed.

Greenhouse Gas Emissions

Combustion of fossil fuels during Project construction and operation would result in the emission of greenhouse gasses such as carbon dioxide (CO_2), nitrous oxide, and methane. Greenhouse gas emissions are currently not subject to regulation in the United States. Although there are some regional initiatives to develop greenhouse regulations (i.e., the Regional Greenhouse Gas Initiative), none have been approved or would apply to the Project.

Greenhouse gases are usually expressed in terms of carbon dioxide equivalents ($CO_{2\text{-}e}$), where the potential of each gas to increase heating in the atmosphere is expressed as a multiple of the heating potential of CO_2, or its global warming potential. Projected greenhouse gas emissions from Project construction and operation are provided in Tables 4.11-4 and 4.11-5 respectively.

Table 4.11-4
Summary of Greenhouse Gas Emissions from Project Construction (Tons/Year)[1]

Greenhouse Gases (GHG)	Year 1	Year 2	Year 3
Carbon dioxide	6,429	6,513	2,206
Nitrous oxide	0.2	0.2	0.1
methane	0.4	0.4	0.1
Total GHG emissions in CO_2 equivalents (CO_2-e)[2]	6,491	6,575	2,227

Notes:
[1] Greenhouse gas emissions (CO_2, N_2O, and CH_4) were calculated based on emission factors taken from the Intergovernmental Panel on Climate Change Emission Factor Database: http://www.ipcc-nggip.iges.or.jp/efdb/find_ef.php.
Gasoline emission factors for CO_2 are based on EPA's AP-42 Section 3.3 Table 3.3-1 (EPA, 1996).
[2] Total GHG emissions in CO_2 equivalents (CO_2-e) were calculated based on the global warming potential of 1, 310, and 21 for CO_2, N_2O, and CH_4, respectively (EPA, 2007).

Table 4.11-5

Summary of Greenhouse Gas Emissions from Project Operations (Tons/Year)[1]

Greenhouse Gases (GHG)	Amine System Vent[3]	Emergency Firewater Pump	Amine System Heaters	M&R Let Down Heater	Regen. Gas Heaters	WEG Heaters	Emergency Generators	Total
Carbon dioxide	28,800	61	3,323	7,167	1,329	117,228	2,705	160,614
Nitrous oxide	NA	0.00030	142	306	57	5,003	0.013	5,508
methane	NA	0.00014	148	320	59	5,231	0.0063	5,758
Total GHG emissions in CO_2 equivalents (CO_2-e)[2]	28,800	61	50,401	108,713	20,160	1,778,063	2,710	1,988,909

Notes:

[1] The Greenhouse gas emissions (CO_2, N_2O, and CH_4) were calculated based on emission factors taken from U.S EPA AP-42 - Table 1.4-2 for natural gas combustion and Tables 1.3-2, 1.3-8, and 1.3-12 for diesel oil combustion (EPA, 1998)

[2] Total GHG emissions in CO_2 equivalents (CO_2-e) were calculated based on the global warming potential of 1, 310, and 21 for CO_2, N_2O, and CH_4, respectively (EPA, 2007).

[3] CO_2 emissions from amine system vent is based on vendor information (5,000 lbCO_2/hr)

NA = data not available

Although construction equipment (e.g., wheel loaders, trucks, cranes, pumps) would be powered by diesel or gasoline fuels, which generate higher greenhouse gas emissions compared to natural gas combustion, such impacts would be minor and temporary. FGS would maintain all construction equipment in accordance with manufacturer's recommendations to minimize construction-related emissions.

Project operation is likely to cause an overall net reduction of greenhouse gas emissions due to the increased availability of natural gas as a substitute for alternative fuels such as oil and coal that emit more CO_2 per unit of energy. In addition, most of the operational equipment would burn natural gas during normal day-to-day operations, further mitigating CO_2 and other greenhouse gas emissions in comparison to other fuels.

4.11.2 Noise Quality

Project construction and operation would affect ambient noise levels in the surrounding area. The ambient sound level of a region is defined by the total noise generated, including sounds from both natural and artificial sources. The magnitude and frequency of noise may vary considerably over the course of the day and throughout the week, in part due to changing weather conditions and the effects of seasonal vegetative cover.

Two measurement metrics commonly used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level ($L_{eq(24)}$) and the day-night sound level (L_{dn}). The $L_{eq(24)}$ is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the $L_{eq(24)}$ with 10 decibels on the A-weighted scale (dBA) added to nighttime sound levels between the hours of 10 p.m. and 7 a.m. to account for people's greater sensitivity to sound during nighttime hours.

In 1974, EPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*. This document provides information for state and local governments to use in developing their ambient noise standards. The EPA determined that an L_{dn} of 55 dBA protects the public from indoor and outdoor activity interference. The FERC has adopted this criterion and generally uses it to evaluate the impact of new facilities on noise quality. Specifically, FERC limits sound levels attributable to new compressor facilities (e.g., liquefaction gas compressors associated with the LNG storage facility) to an L_{dn} of 55 dBA at any noise sensitive area (NSA) such as a school, hospital, or residence.

Due to the 10 dBA nighttime penalty added prior to calculation of the L_{dn}, the actuaconstant noise level required to produce a L_{dn} of 55 dBA is 48.6 dBA L_{eq}. Thus, for a facility to meet the L_{dn} 55 dBA limit, it must be designed such that actual noise levels do not exceed a constant hourly average of 48.6 dBA L_{eq} at any identified NSA.

The State of Florida does not have noise regulations applicable to the Project; however, Martin County has a countywide noise control ordinance that establishes daytime (7 a.m. to 9 p.m.) and nighttime (9 p.m. to 7 a.m.) sound level limits ranging from 55 to 70 dBA and 50 dBA to 65 dBA, respectively, for different receiving land use categories (e.g., institutional, residential, commercial, industrial, and agricultural). The Martin County ordinance prohibits any source from projecting noise across a real property boundary in such a manner as to create a sound level that exceeds the limits set forth for the receiving land use designation described above.

4.11.2.1 Existing Noise Levels

The Project would be located in a predominantly industrial and agricultural area. The nearest noise sensitive area (NSA) consists of three single-family residences (i.e., NSA #1) located approximately 0.46 mile south of the LNG storage facility boundary. Another single-family residence (i.e., NSA #2) is located approximately 6,500 feet (1.23 miles) east of the Project on southwest Allapattah Road. No other NSAs were identified. Other potential NSAs, such as schools, hospitals, churches, playgrounds, farms, and camping facilities were too far away to be considered NSAs.

Surveys were performed at the two NSAs and four property boundary sites (six site locations) to document ambient noise levels. Table 4.11-6 summarizes the existing sound levels and noise limits for the six monitoring site locations.

Table 4.11-6

Existing Sound Levels and Noise Limits

	Distance/ Direction of NSA to Storage Site (feet)	Measured L_{90} Daytime L_d (dBA)	Measured L_{90} Nighttime L_n (dBA)	Calculated L_{dn} (dBA) using Measured L_{90}	FERC Sound Level Limits at NSA		Martin County Noise Limit for Residential Land Use at Property Boundary	
					L_{dn} (dBA)	L_{Aeq} (dBA)	L_d (dBA)	L_n (dBA)
Northwestern Property Boundary (Site 1)	--	57	59	65	NA	NA	60	55
Northeastern Property Boundary (Site 2)	--	57	58	64	NA	NA	60	55
Southwestern Property Boundary (Site 3)	--	43	38	46	NA	NA	60	55
Southeastern Property Boundary (Site 4)	--	53	38	52	NA	NA	60	55
NSA # 1 (Site 5)	2,450 – southeast	44	45	51	55	48.6	NA	NA
NSA #2 (Site 6)	6,500 – east	42	44	50	55	48.6	NA	NA

Notes:

NA = not applicable

NSA = noise sensitive area

4.11.2.2 General Impacts and Mitigation

Construction Noise

Project construction would be typical of other pipeline and natural gas storage projects in terms of schedule, equipment used, mode of operation, length of time the equipment is in use, and amount of equipment used simultaneously. All of these factors would be constantly changing throughout the construction period; therefore, the quantification of impacts would fluctuate. Construction equipment would be operated on an as-needed basis, mostly during daylight hours, and would be maintained to manufacturers' specifications to minimize noise impacts. The major noise sources associated with the construction activities include bulldozers, front-end loaders, and dump trucks. Extremely noisy activities such as pile driving would not be associated with the construction of the LNG storage facility, including the storage tank foundation.

We used the CADNA-A noise model to evaluate construction noise effects at the four property boundary locations and at the two NSAs. Table 4.11-7 shows that total estimated Project construction plus ambient L_{dn} noise levels are below FERC's sound level limit of 55 dBA at both NSAs. The predicted noise increase at NSA #1 and NSA #2 would be 1.1 dBA and 0.2 dBA, respectively.

Noise levels that are less than 3 dBA above background levels are generally considered to be undetectable by the human ear for instantaneous measurements and for day-night levels (L_{dn} or DNL) within a quiet background of 60 - 65 dBA L_{dn}. For background noise levels of less than 60 dB L_{dn}, an increase of 5 dBA or more is considered to be a major change. For background levels greater than 65 dBA L_{dn}, an increase of 1.5 dBA or greater is considered a major change (FICON 1992). Since the predicted noise level increase at

the nearest NSAs would be less than 2 dBA, and the background levels measured at the NSAs are less than 60 dBA, we anticipate that typical construction activities at the LNG storage facility would result in a small and insignificant effect on the noise environment. Although the predicted construction noise levels at two of the four property boundary sites would exceed the FERC benchmark of 55 dBA, the FERC standard only applies at NSAs, not at the property boundary.

Table 4.11-7

Predicted Construction Noise Impacts for the FGS Project

Monitoring Site Location	Distance/ Direction of NSA to LNG Storage Facility (feet)	Existing Ambient L_{dn} (dBA)	Predicted Project Construction Noise Levels: Modeled L_{Aeq} (dBA)[a]	Predicted Project Construction Noise Levels: Calculated L_{dn} (dBA)[b]	Total Project Plus Ambient L_{dn} (dBA)[c]	Predicted Noise Increase (dBA)[d]
Northwestern Property Boundary (Site1)	--	65	44.2	50.6	65.2	0.2
Northeastern Property Boundary (Site 2)	--	64	42.9	49.3	64.1	0.1
Southwestern Property Boundary (Site 3)	--	46	52.1	58.5	58.7	12.7
Southeastern Property Boundary (Site 4)	--	52	65	71.4	71.4	19.4
NSA # 1 (Site 5)	2,450 southeast	51	39.3	45.7	52.1	1.1
NSA #2 (Site 6)	6,500 east	50	30.8	37.2	50.2	0.2

Notes:

[a] Average hourly noise levels, L_{Aeq} during Project construction were modeled using Datakustic's CADNA_A noise propagation model

[b] Project construction L_{dn} = modeled steady L_{Aeq} plus 6.4 dBA.

[c] Total Project construction plus ambient L_{dn} = 10 Log ($10^{(\text{Ambient Ldn}/10)} + 10^{(\text{Project construction Ldn}/10)}$).

[d] Estimated increase in the ambient L_{dn} sound levels due to Phase 1 and Phase 2 construction.

The noise impacts associated with construction activities would be temporary and FGS would ensure that the impacts do not exceed allowable levels by limiting nighttime construction activities to those that do not generate high noise levels. Construction activities, as authorized by a Martin County Building Permit, are considered exempt from the noise restrictions identified in the Martin County Noise Control Ordinance. In addition, the predicted noise impact levels are conservative because the model does not incorporate any reduction in noise levels due to intervening vegetation.

Operational Noise

Operation of the pipeline facilities would not adversely affect noise quality, since the pipeline would be installed underground and no compressor stations are proposed. Project operational noise effects would therefore be limited to the vicinity of the LNG storage facility. Principal noise sources would include WEG heaters, BOG compressors, vaporizers, air compressors, gas meters, and emergency generators (only used during power outages). Other equipment such as pumps and other compressors would not

produce significant noise. Equipment noise levels for the proposed facility are based on specifications provided by equipment manufacturers or actual field measurements.

We used the CADNA-A model to estimate the noise impacts that would result from Project operations at the four property boundary locations and at the nearest NSAs (Table 4.11-8). The noise model assumed all sources to be point sources and accounted for hemispherical spreading (i.e., a ground level noise source rather than an elevated source, such as an airplane), atmospheric attenuation, and soft ground attenuation. Table 4.11-8 shows that total estimated Project operations plus ambient L_{dn} noise levels are below the FERC's sound level limit of 55 dBA at both NSAs. The predicted noise increase at NSA #1 and NSA #2 would be 2.0 dBA and 0.3 dBA, respectively.

Table 4.11-8

Predicted Operating Noise Impacts for the FGS Project

Monitoring Site Location	Distance/ Direction of NSA to LNG Storage Facility (feet)	Existing Ambient L_{dn} (dBA)	Predicted Project Operating Noise Levels: Modeled L_{Aeq} (dBA)[a]	Predicted Project Operating Noise Levels: Calculated L_{dn} (dBA)[b]	Total Project Plus Ambient L_{dn} (dBA)[c]	Predicted Noise Increase (dBA)[d]
Northwestern Property Boundary (Site1)	--	65	49.8	56.2	65.5	0.5
Northeastern Property Boundary (Site 2)	--	64	42.7	49.1	64.1	0.1
Southwestern Property Boundary (Site 3)	--	46	58.1	64.5	64.6	18.6
Southeastern Property Boundary (Site 4)	--	52	61.7	68.1	68.2	16.2
NSA # 1 (Site 5)	2,450 southeast	51	42.4	48.8	53.0	2.0
NSA #2 (Site 6)	6,500 east	50	32.3	38.7	50.3	0.3

Notes:

[a] Average hourly noise levels, L_{Aeq} during Project operation were modeled using Datakustic's CADNA_A noise propagation model

[b] Project operation L_{dn} = modeled steady L_{Aeq} plus 6.4 dBA.

[c] Total Project operations plus Ambient L_{dn} = 10 Log ($10^{(\text{Ambient Ldn}/10)} + 10^{(\text{Project operation Ldn}/10)}$).

[d] Estimated increase in the ambient L_{dn} sound levels due to Phase 1 and Phase 2 operation.

Since the predicted noise level increase at the nearest NSAs would not exceed 2 dBA, we anticipate that typical operations at the LNG storage facility would result in a small and insignificant effect on the noise environment. Because the LNG storage facility is expected to contribute a 19 dBA and 16 dBA noise increase at the southwestern and southeastern property boundary locations (Sites 3 and 4), respectively, FGS proposes to contain all major noise-generating equipment within shelters or enclosures to attenuate operational noise levels and ensure that noise impacts do not exceed Martin County standards. Other non-major noise-generating equipment, such as booster air compressor, would not be contained in outside shelters; however, the insignificant noise levels from the unsheltered equipment are not expected to impact nearby NSAs.

Although this analysis is conservative in that it does not incorporate any reduction in noise levels due to intervening vegetation, we believe that the actual noise levels resulting from operation of the proposed LNG storage facility should be measured to ensure that they do not exceed those levels analyzed in this EIS. Therefore, **we recommend that:**

- **FGS should make all reasonable efforts to assure its predicted noise levels from the LNG storage facility are not exceeded at nearby NSAs and file noise surveys showing this with the Secretary no later than 60 days after placing the LNG storage facility in service. However, if the noise attributable to the operation of the LNG storage facility at full load exceeds an L_{dn} of 55 dBA at any nearby NSAs, FGS should file a report on what changes are needed and should install additional noise controls to meet the level within 1 year of the in-service date. FGS should confirm compliance with this requirement by filing a second noise survey with the Secretary <u>no later than 60 days</u> after it installs the additional noise controls.**

If FGS provides assurance that any noise impacts have been mitigated as required by the above recommendations, we believe that the Project-related operations would not result in a significant effect on the noise environment.

4.12 RELIABILITY AND SAFETY

The operation of the proposed Project poses a potential hazard that could affect public safety without strict design and operational measures to control potential accidents. The primary concerns are those events that could lead to an LNG spill of sufficient magnitude to create an offsite hazard. However, it is also important to recognize the stringent requirements for the design, construction, operation, and maintenance of the facility as well as the extensive safety systems to detect and control potential hazards.

With the exception of the October 20, 1944 fire at the LNG facility in Cleveland, Ohio, the operating history of U.S. LNG facilities has been free of LNG safety-related incidents resulting in adverse effects to the public or the environment. The 1944 Cleveland incident was attributed to the use of materials inadequately suited for cryogenic temperatures and the lack of spill impoundments at the site.[1] An operational accident occurred in 1979 at the Cove Point LNG facility in Lusby, Maryland, when a pump seal failed, resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, resulting in heavy damage to the building and a worker fatality. Lessons learned from this accident resulted in changing the national fire codes, with the participation of the FERC, to ensure that the situation would not occur again. The proposed facilities would be designed, constructed, and operated in compliance with these codes.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria LNG liquefaction facility that killed 27 and injured 56 workers. No members of the public were injured.

[1] For a description of the incident and the findings of the investigation, see "U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944, "dated February 1946.

Preliminary findings of the accident investigation suggest that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced to the high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler fire box which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 to 1999, Train 40 had been operating with its original equipment since start-up in 1981.

Although there are major differences between the equipment involved in the accident to Skikda and that of the proposal by FGS (i.e., high-pressure steam boilers that power refrigerant compressors would not be used here nor are they used at any LNG facility under FERC jurisdiction), the sequence of cascading events identifies potential failure modes that warrant further evaluation. To ensure that all potential hazards are addressed, we have provided a recommendation Section 4.12.2, Front-End-Engineering Design Review, to address this issue.

A discussion of the principal properties and hazards associated with LNG is presented in Section 4.12.1. A summary of our preliminary design and technical review of the front-end engineering design (FEED) and cryogenic aspects of the LNG facility is presented in Section 4.12.2. An analysis of the thermal radiation and flammable vapor cloud hazards used as siting criteria is presented in Section 4.12.3. LNG and NGL truck safety issues are examined in Section 4.12.4. Emergency response and evacuation planning is discussed in Section 4.12.5. A discussion on security awareness related to terrorism is presented in Section 4.12.6. The reliability and safety issues related to natural gas pipelines are discussed in Section 4.12.7.

4.12.1 LNG Hazards

LNG's principal hazards result from its cryogenic temperature (-260°F), flammability, and vapor dispersion characteristics. As a liquid, LNG will neither burn nor explode. Although it can cause freeze burns and, depending on the length of exposure, more serious injury or death, its extremely cold state does not present a significant hazard to the public, which rarely, if ever, comes in contact with it as a liquid. As a cryogenic liquid, LNG will quickly cool materials it contacts, causing extreme thermal stress in materials not specifically designed for ultra-cold conditions. Such thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength. These hazards, however, are not substantially different from the hazards associated with the storage and transportation of liquid oxygen (-296°F) or several other cryogenic gases that have been routinely produced and transported in the United States.

LNG vaporizes rapidly when exposed to ambient heat sources such as water or soil. When released from its containment vessel and/or transfer system, LNG will generally produce 620 to 630 standard cubic feet of natural gas for each cubic foot of liquid. A large quantity of LNG spilled without ignition would form a vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. If a large quantity of LNG is spilled in the presence of an

ignition source, the resulting pool fire would produce high levels of radiant heat in the area surrounding the LNG pool.

A rapid phase transition (RPT) can occur when a portion of LNG spilled onto water changes from liquid to gas, virtually instantaneously. Unlike an explosion that releases energy and combustion products from a chemical reaction, an RPT is the result of heat transferred to the liquid inducing a change to the vapor state. The rapid expansion from the liquid to vapor state can cause locally large overpressures. RPTs have been observed during LNG test spills onto water. In some test cases, the events were strong enough to damage test equipment in the immediate vicinity of the LNG release point. The sizes of the overpressure events have been generally small and are estimated to be equivalent to several pounds of trinitrotoluene (TNT). The RPT may increase the rate of LNG pool spreading and the LNG vaporization rate for a spill on water.

Methane vapors, the primary component of natural gas, are colorless, odorless, and tasteless, and are classified as a simple asphyxiant. Methane vapors may cause extreme health hazards, including death, if inhaled in significant quantities within a limited time. Although very cold methane vapors could cause freeze burns, any cloud resulting from an LNG spill would be continuously mixing with the warmer air surrounding the spill site. Dispersion modeling indicates the majority of the cloud would generally be within 25°F of the surrounding atmospheric temperature, with colder temperatures closest to the spill source. In addition, this modeling estimates that most of the cloud would be below concentrations resulting in oxygen deprivation effects, including asphyxiation, with the highest methane concentrations closest to the spill source. Therefore, asphyxiation and freezing normally represent a negligible risk to the public from LNG facilities.

Although LNG will not burn, methane vapors in a 5 to 15 percent mixture by volume with air are flammable. Once a flammable vapor-air mixture from an LNG spill has been ignited, the flame front will propagate back to the spill site if the vapor concentration along this path is sufficiently high to support the combustion process. Combustible materials within the flammable portion of the cloud may be within the flame and could be ignited. However, any events leading to a containment failure would most likely be accompanied by a number of ignition sources. The result would be an LNG pool fire, and subsequent radiant heat hazards, rather than the formation of a large unconfined vapor cloud.

Although LNG is not explosive as it is normally transported and stored, natural gas vapors (primarily methane) can explode if contained within a confined space, such as a building or structure, and ignited. Occasionally, various parties have expressed the energy content of an LNG storage tank in equivalent tons of TNT as an implied measure of its explosive potential. However, such a simplistic analogy fails to consider that explosive forces are not just a function of the total energy content but also of the rate of energy release. For a detonation to occur, the rate of energy release must be nearly instantaneous, such as with a TNT charge initiated by a blasting cap. Unlike TNT or other explosives, which inherently contain an oxidizer, an unconfined vapor cloud must be mixed with oxygen within the flammability range of the fuel for combustion to occur. For a large unconfined vapor cloud, the flammability range tends to exist at the mixing zone at the edges of the cloud. When ignited, flame speeds of about 20 to 25 meters per

second (66 to 82 feet per second) and local over pressures up to 0.2 psig have been estimated for unconfined methane-rich vapor clouds. These are well below the flame speeds and over-pressures associated with detonation.

The potential for unconfined LNG vapor cloud detonations was investigated by the USCG in the late 1970s at the Naval Weapons Center at China Lake, California. These experiments, as well as other subsequent tests, are mentioned in Appendix C of the Sandia National Laboratories report entitled, *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*, December 2004 (Sandia Report). Using methane, the primary component of natural gas, several experiments were conducted to determine if unconfined vapor clouds would detonate. The tests indicated unconfined methane-air mixtures could be ignited, but no test produced unconfined detonation. There is no evidence suggesting that methane-air mixtures will detonate in unconfined open areas.

Further tests were conducted in the late 1970s to examine the level of sensitivity of an unconfined cloud to the presence of heavier hydrocarbons such as ethane and propane. As stated in section 5 of Appendix C of the Sandia Report, detonation sensitivity is affected by the level of refinement of natural gas stored as LNG. The series of tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined vapor cloud to detonate. Less processed product with greater amounts of heavier hydrocarbons is more sensitive to detonation. During these experiments, all successful detonations were initiated with an explosive charge in well mixed vapor clouds at correct stoichiometric proportions. These are not representative of conditions that would be expected during a large scale LNG spill. The precise timing, necessary mixing, and required amount of initiating explosives render the possibility for detonation of a large unconfined vapor cloud as unrealistic. Detonation of the unconfined natural gas cloud is extremely difficult to achieve and is generally considered by scientists and researchers to be very unlikely to occur during an LNG spill.

Consequently, the primary hazards to the public from an LNG spill either on land or water would be from dispersion of the flammable vapors or from radiant heat generated by a pool fire.

4.12.2 Front-End Engineering Design Review

Two federal agencies share in the oversight of the safety and security of LNG peakshaver and storage facilities: the FERC and DOT. The FERC authorizes the siting and construction of LNG facilities involved in interstate commerce and is the lead federal agency under NEPA to analyze the environmental safety, security, and cryogenic design of proposed facilities. The DOT has exclusive authority to promulgate and enforce safety regulations and standards over onshore LNG facilities. In 1980, the DOT established a set of safety standards, *Liquefied Natural Gas Facilities: Federal Safety Standards*, under Title 49, CFR, Part 193 which apply to the construction, operation, and maintenance of the on-shore LNG facilities. The FERC closely coordinates its pre-authorization review of proposals with the DOT to ensure a seamless safety and security review.

As part of its application and in response to FERC staff's data requests, FGS provided a FEED for the Project. The FEED and technical review emphasizes the engineering design and safety concepts, as well as the projected operational reliability of the proposed facilities. The principle areas of coverage include materials in cryogenic environments; insulation systems; cryogenic safety; thermodynamics; heat transfer; instrumentation; cryogenic processes; and other relevant safety systems.

In the course of the application review, FERC staff has evaluated information for the proposed design and installation of the LNG storage facility. As a result of the technical review of the information provided by FGS in the submittal documents, a number of concerns were identified by FERC staff relating to the reliability, operability, and safety of the proposed design. In response to staff's questions, FGS provided written responses prior to the technical conference held on February 20, 2008. However, 39 of FGS's responses indicated that corrections or modifications would be made to the design in order to address issues raised in the information request. As a result, **we recommend that**:

- **FGS should provide information/revisions related to the 39 responses to the January 17, 2008 Engineering Information Request which stated that corrections, or modifications would be made to the design. The <u>final design</u> should specifically address response numbers 4, 6, 7, 11, 17, 18, 21, 22, 24, 27, 28, 29, 30, 33, 35, 36, 37, 38, 41, 42, 43, 49, 55, 58, 60, 61, 62, 63, 65, 67, 73, 76, 77, 78, 80, 83, 91, 94, and 99 using management of change procedures.**

The FEED and specifications submitted for the proposed facilities are considered to be preliminary but would be the basis for any detailed design to follow. A significant amount of the design involving final selection of equipment manufacturers, process conditions, and resolution of some safety related issues would be completed in the next phase of project development if authorization is granted by the Commission. This information would need to be submitted to the FERC staff for review and approval. In addition, several areas of concern related to the LNG storage facility design and construction details have been noted and require additional consideration and/or action on behalf of the company. Follow up on those items requiring additional action should be documented in reports to be filed with the FERC**.** On May 5, 2008, FGS submitted comments to the engineering recommendations contained in the draft EIS. Responses to these comments are included in Appendix D and, where appropriate, the recommendations have been revised. As a result, **we now recommend that:**

The following measures should apply to the FGS design and construction details. Information pertaining to these specific recommendations should be filed with the Secretary for review and approval by the Director of OEP either: prior to initial site preparation; prior to construction of final design; prior to commissioning; or prior to commencement of service as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, should be submitted as critical energy infrastructure information (CEII) pursuant to 18 CFR 388.112. See Critical Energy Infrastructure Information, Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006). FERC Stats. &

Regs. ¶ 31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements would be subject to public disclosure. This information should be submitted a minimum of 30 days before approval to proceed is required.

- **Complete plan drawings and a list of the hazard detection equipment should be filed <u>prior to initial site preparation</u>. The list should include the instrument tag number, type and location, alarm locations, and shutdown functions of the proposed hazard detection equipment. Plan drawings should clearly show the location of all detection equipment.**
- **FGS should provide a technical review of its proposed facility design that:**
  - **a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids and flammable gases); and**
  - **b. demonstrates that these areas are adequately covered by hazard detection devices and indicate how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.**

  FGS should file this review <u>prior to initial site preparation</u>.
- **Complete plan drawings and a list of the fixed and wheeled dry-chemical, fire extinguishing, and other hazard control equipment should be filed <u>prior to initial site preparation</u>. The list should include the equipment tag number, type, size, equipment covered, and automatic and manual remote signals initiating discharge of the units. Plan drawings should clearly show the planned location of all fixed and wheeled extinguishers.**
- **Facility plan drawings showing the proposed location of, and area covered by, each monitor, hydrant, deluge system, hose, and sprinkler, as well as piping and instrumentation diagrams of the fire water system, should be filed <u>prior to initial site preparation</u>.**
- **FGS should perform a hazard design review, which addresses operability, reliability, and safety, of the updated intermediate process and instrumentation diagrams (P&IDs). A copy of the hazard design review, the list of recommendations that are to be incorporated in the final facility design, and the updated intermediate P&IDs should be filed <u>prior to initial site preparation</u>.**
- **Drawings of the storage tank piping support structure and support of horizontal piping at grade should be filed <u>prior to initial site preparation</u>.**
- **Procedures should be developed for offsite contractors' responsibilities, restrictions, limitations and supervision of these contractors by FGS staff, <u>prior to initial site preparation</u>.**

- **The final design should clearly and consistently show the design of the process systems on both the process flow diagrams (PFDs) and P&IDs.**
- **The P&IDs in the final design should show and number all valves including drain, vent, main, and car sealed.**
- **The final design should specify that the set pressure of PAH-11055 should not be greater than 50 psig below the design pressure of the system.**
- **The final design should include layout provisions for the installation of an adsorber feed gas cooler and chiller system.**
- **In the event that ceramic support material is used to retain the molecular sieve, the final design should include a witch hat type strainer at the bottom outlet of each adsorber, designed to retain support material.**
- **The final design should include a shutoff valve at the inlet to the NGL extraction exchanger. This valve may be the proposed manual isolation valve equipped with an actuator operated by the Safety Instrumentation System (SIS).**
- **The final design should include an isolation valve downstream of the ethylene pressure regulator.**
- **The final design should include a hazard and operability review of the completed design. A copy of the review and a list of the recommendations should be filed with the Secretary.**
- **The final design should specify that the LNG tank carbon steel piping support plates and connections to piping supports should be designed to ensure that corrosion protection is adequately provided and provisions for corrosion instrumentation diagrams of the fire water systems, should be filed prior to initial site preparation.**
- **The final design of the tank foundation should include an inclinometer, instrumented to record and display tank settlement, with a minimum of eight permanent reference points equally spaced round the base for elevation survey measurement.**
- **The final design should include details of the LNG tank tilt settlement and differential settlement limits between each LNG tank and piping and procedures to be implemented in the event that limits would be exceeded.**
- **The final design should include detailed drawings of the spill control system to be applied to the LNG tank roof.**
- **The final design should provide a discretionary vent for each LNG tank that can relieve the tank pressure when the tank is isolated from the boiloff vapor system.**
- **The final design should include a recycle line from the top of the sendout pump suction header to storage.**

- **The final design should specify that the first isolation valve at the inlet to the sendout pumps would be a weld end shutoff valve. In the case that flanged valves would be specified, the sendout system should be shutdown in the event of a leak.**
- **The final design should provide a minimum flow recycle line from the sendout pumps to the LNG storage tanks. The piping including the isolation valve upstream of the discharge to the storage tanks should be the same pressure and temperature rating as the piping at the discharge of the sendout pumps.**
- **The final design should include provisions to drain and purge the LNG inlet piping to the vaporizer to a safe location.**
- **The final design should specify that the LNG isolation valve from the inlet header to the vaporizer is to be a weld end shutoff valve operated by the SIS. In the case that flanged valves would be specified, the sendout system should be shutdown in the event of a leak.**
- **The final design should specify the vaporizer discharge valve to the outlet header to be a weld end shutoff valve operated by the SIS. In the case that flanged valves would be specified, the sendout system should be shutdown in the event of a leak.**
- **The final design should specify that the shell side of the LNG vaporizer is to be equipped with a full flow bursting disc sized for tube failure.**
- **The final design should include provisions to transmit the flow measurement of the WEG solution to each LNG vaporizer to the distributed control system (DCS).**
- **The final design should include provisions to limit the LNG flow to the effective vaporization capacity of the circulating WEG at any time.**
- **The final design should include a pilot relief valve, or operated vent valve, sized for thermal relief and located at the discharge of each vaporizer upstream of the isolation valves.**
- **The final design should include shutoff valves operated by the SIS at the suction and discharge of the boiloff, tail gas, and NGL compressors.**
- **The final design should specify that manual bypass valves should be car sealed closed.**
- **The final design should specify that all drains from LNG and refrigerant systems are to be equipped with double isolation and bleed valves.**
- **The final design should specify that, for LNG and natural gas service, branch piping and piping nipples less than 50mm (2 inches), are to be no less than schedule 160.**

- **The final design should include provisions to flare cryogenic and heavy hydrocarbon vapors currently shown as being discharged to atmosphere through the vent stack.**
- **The final design should specify that the vent/flare stack separator vessel should be equipped with low level alarm, high level alarm and high-high level alarm.**
- **The final design should specify that in the event that high-high level occurs in vent/flare stack separator vessel, the facility should be shut down until the liquid has been removed to below the low level alarm limit.**
- **The final design should provide P&IDs, specifications and procedures that clearly show and specify the tie-in details required to safely connect the Phase 2 expansion.**
- **Layout and elevation drawings of the process equipment that are appropriate for the proposed operation and maintenance of the facility should be included in the final design and submitted to the FERC at the time that the EPC contractor issues the drawing for review. This milestone should be included in the project schedule.**
- **The final design should specify that the hazardous area classification of the areas containing liquefaction exchangers, LNG pumps, LNG vessels, and inlet and outlet of LNG vaporizers would be as Class 1, Group D, Division 1.**
- **The final design should include details of the air gaps to be installed downstream of all seals or isolations that are located at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that: should continuously monitor for the presence of a flammable fluid; should alarm the hazardous condition; and should shutdown the appropriate systems.**
- **The final design should include audible and visual warning at buildings with instrument air service when nitrogen is supplied to the instrument air system.**
- **The final design should provide automatic shutoff of the fuel gas to the fuel gas heaters, upstream of the pressure regulators.**
- **The final design should include detection of flammable gas from the shell side vent of the LNG vaporizer and in the WEG system. Alarm and shutdown of equipment should be provided as appropriate.**
- **The final design of the hazard detection equipment should identify manufacturer and model.**
- **The final design should specify that all hazard detection equipment should include redundancy fault detection and fault alarm monitoring in all potentially hazardous areas and enclosures.**
- **The final design of the fixed and wheeled dry-chemical, fire extinguishing and high expansion foam hazard control equipment should identify manufacturer and model.**

- **The final design should include an updated fire protection evaluation in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2.**
- **The final design should specify that multiple cameras should be installed to monitor the entry/exit gate and approach to the facility entrance.**
- **The final design of the firewater system should include provisions to measure and record the discharge flow and pressure from each of the firewater pumps.**
- **The final design should include an uninstalled spare firewater jockey pump.**
- **The final design should include details of the shut down logic, including cause and effect matrices for alarms and shutdowns.**
- **The final design should specify that all ESD valves are to be equipped with open and closed position switches connected to the DCS/SIS.**
- **The final design should include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable.**
- **The maintenance procedures to be filed prior to commissioning should state that a foundation elevation survey of all LNG tanks should be made on an annual basis.**
- **All valves including drain, vent, main, and car sealed, or locked valves should be tagged in the field during construction and prior to commissioning.**
- **The car seal procedure and car seal control logs for all valves should be provided prior to commissioning.**
- **A tabulated list of the proposed hand-held fire extinguishers should be filed prior to commissioning. The information should include a list with the equipment number, type, size, number, and location. Plan drawings should include the type, size, and number of all hand-held fire extinguishers.**
- **Operation and Maintenance procedures and manuals, as well as emergency response plans and safety procedures, should be filed prior to commissioning.**
- **The Operations and Maintenance procedures to be provided prior to commissioning, should state that filters are not to be opened unless the unit can be completely depressurized when isolated.**
- **The contingency plan for failure of the LNG tank outer containment should be filed prior to commissioning.**
- **A copy of the criteria for horizontal and rotational movement of the inner tank for use during and after cool down should be filed prior to commissioning.**
- **The FERC staff should be notified of any proposed revisions to the security plan and physical security of the facility prior to commencement of service.**

- **Progress on construction of the project should be reported in monthly reports filed with the Secretary. Details should include a summary of activities, projected schedule for completion, problems encountered and remedial actions taken. Problems of significant magnitude should be reported to the FERC within 24 hours.**

In addition, we recommend that the following measures should apply throughout the life of the facility:

- **The facility should be subject to regular FERC staff technical reviews and site inspections on at least a biennial basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, FGS should respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed piping and instrumentation diagrams reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted annual report, should be submitted.**

- **Semi-annual operational reports should be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including trucking, quantity and composition of feed gas and trucked LNG, vaporization quantities, boil-off/flash gas, etc.), plant modifications including future plans and progress thereof. Abnormalities should include, but not be limited to: trucking problems, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, vapor or liquid releases, fires involving natural gas and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boiloff rates. Adverse weather conditions and the effect on the facility also should be reported. Reports should be submitted within 45 days after each period ending June 30 and December 31. In addition to the above items, a section entitled "Significant plant modifications proposed for the next 12 months (dates)" also should be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.**

- **FGS should include completed car seal control logs with the first two Semi-annual operational reports filed with the Commission.**

- **In the event the temperature of any region of any secondary containment becomes less than the minimum specified operating temperature for the material, the Commission should be notified within 24 hours and procedures for corrective action should be specified.**

- **Significant non-scheduled events, including safety-related incidents (i.e., LNG or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) should be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to the Commission within 24 hours. This notification practice should be incorporated into the LNG facility's emergency plan. Examples of reportable LNG-related incidents include:**

  a. fire;

  b. explosion;

  c. estimated property damage of $50,000 or more;

  d. death or personal injury necessitating in-patient hospitalization;

  e. free flow of LNG that results in pooling;

  f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes gas or LNG;

  g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG;

  h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;

  i. a leak in an LNG facility that contains or processes gas or LNG that constitutes an emergency;

  j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

  k. any condition that could lead to a hazard and cause a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility;

  l. safety-related incidents with LNG and NGL trucks at or en route to and from the LNG facility; or

  m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, the Commission staff would determine the need for an on-site inspection by Commission staff, and the timing of an initial incident report (normally within 10 days) and follow-up reports.

As part of the FEED, FGS performed a wind speed analysis using available wind speed historical data from 1950 to March 2007 to determine design wind conditions for the proposed site. FGS determined that the highest wind speed based on a 10,000-year return period storm event with a probability of exceedance of 0.01 percent would cause wind speeds for the proposed site of 118 mile per hour (mph). The storage tanks and control building would be designed to withstand sustained wind speeds up to 200 mph. However, the LNG Tank Data Sheet (1592609-000-TK-DS-2001) in FGS' application also stated that a wind speed of 184 mph (3-second gust) would be used for the LNG storage tanks. This discrepancy was discussed at the cryogenic technical conference held on February 20, 2008 and FGS agreed to correct the discrepancy in the final design through its management of change procedure. In addition, FGS would be designing all other facilities to withstand sustained wind speeds up to 130 mph. The wind design criteria were established in accordance with the wind velocity requirements of 49 CFR 193.2067.

The terminal site elevations were established based on storm surge and flood elevation data available for Indiantown in Martin County, Florida. The site location is approximately 15 miles from any areas affected by storm zone flooding from a Category 5 hurricane. FGS stated that the predicted storm surge height in Martin County due to a Category 5 hurricane would be nearly equivalent to the 500-year return storm at an elevation of approximately 13 feet. The proposed location of the FGS facility would be at an approximate elevation of 36 feet NGVD. All process areas and major equipment would be located at 38 feet NGVD. In addition, the tertiary earthen berm around the storage tanks and vaporization area would be constructed to an elevation of 43 feet NGVD. Since the proposed site would be at an approximate elevation of 36 feet NGVD, no storm surge effects would be likely at the proposed site.

4.12.3 Siting Requirements – Thermal and Dispersion Exclusion Zones

Regulatory Requirements

The LNG facilities proposed in this project must comply with the siting requirements of 49 CFR 193, Subpart B. On March 30, 2000, the DOT revised 49 CFR 193 to incorporate the 1996 edition of NFPA 59A into the LNG regulations. On April 9, 2004, the DOT further revised 49 CFR 193 to incorporate the 2001 edition of NFPA 59A. The following sections specifically address siting requirements:

- **Part 193.2051, Scope**, states that each LNG facility designed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with subpart B and

NFPA 59A, 2001 edition. In the event of a conflict with NFPA 59A, then Part 193 prevails.

- **Part 193.2057, Thermal radiation protection**, requires that each LNG container and LNG transfer system have thermal exclusion zones based on three radiation flux levels in accordance with Section 2.2.3.2 of NFPA 59A, 2001 edition.
- **Part 193.2059, Flammable vapor-gas dispersion protection**, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with Section 2.2.3.3 and 2.2.3.4 of NFPA 59A, 2001 edition.
- **Part 193.2155(b), Structural requirements,** requires that an LNG storage tank must be at least 1 mile from the ends of an airport runway and 0.25 mile from the nearest point on a runway. The proposed storage tanks would be located more than 13 miles from the William P. Gwinn private airport.

For the following LNG facilities that are proposed in this project, we have identified the applicable siting requirements from Part 193 and NFPA 59A, 2001 edition:

- Two 1,162,000 barrel (184,750 m^3) full containment LNG storage tanks - Parts 193.2057 and 2059 require the establishment of thermal and flammable vapor exclusion zones for LNG tanks. NFPA 59A, 2001 edition, Section 2.2.3.2 specifies four thermal exclusion zones based on the design spill and the impounding area. Sections 2.2.3.3 and 2.2.3.4 specify a flammable vapor exclusion zone for the design spill which is determined in accordance with Section 2.2.3.5;
- Six 2,100 gpm in-tank pumps (two per tank, two spares) and five 1,800 gpm booster pumps (one spare) - Parts 193.2057 and 2059 require thermal radiation and flammable vapor exclusion zones. NFPA 59A, 2001 edition, Section 2.2.3.2 specifies the thermal exclusion zone and Sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spill;
- Four shell and tube vaporizers each rated for 200 MMscfd - Same requirements as for LNG pumps;
- Four liquefaction platefin heat exchangers each rated for 86.33 MMBTU/hr – Same requirements as for the LNG pumps;
- Two LNG truck loading stations – Same requirements as for the LNG pumps.

The incorporation of the NFPA 59A requirements into Part 193 has resulted in some confusion and possible misinterpretation in applying the siting requirements. Parts 193.2057 and 2059 require exclusion zones for LNG transfer systems, which are designed to include transfer piping. However, NFPA 59A only requires exclusion zones for "transfer areas," which are defined as the part of the plant where liquids are

introduced or removed from the facility, such as truck loading or where piping connections are connected or disconnected routinely. The definition of transfer area in NFPA 59A specifically excludes permanent plant piping or product sampling devices. When the DOT originally incorporated NFPA 59A into its regulations, it removed the requirement for impounding systems around transfer piping (old Part 193.2149). In the preamble to the final rule, the DOT determined that the most likely sources of leaks within an LNG plant are LNG storage tanks, cargo transfer areas, and vaporizers and process equipment, which are all addressed in NFPA 59A Section 2.2.1.2. The result is that while Part 193 requires exclusion zones for LNG transfer systems, neither Part 193 nor NFPA 59A requires the impoundment from which to base the calculations. We do not believe that this was the intent, nor do we believe that omitting containment for transfer piping is a sound engineering practice. The FERC staff will continue to require containment for all LNG transfer piping within a plant site.

The incorporation of NFPA 59A also changed the way in which design spills and impoundment capacities may be determined. Under Section 2.2.2.2, the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume during a 10-minute period from any single accidental leakage source or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction. Similar criteria appear in Section 2.2.3.5 for determining the design spill used in thermal and flammable vapor exclusion zone calculations. Prior to the incorporation of NFPA 59A, the design spill in Part 193 assumed the rupture of a single transfer pipe with the greatest overall flow capacity for not less than 10 minutes (old Part 193.2059(d)). After the adoption of NFPA 59A, the spill rate for vaporization, process, or LNG transfer areas may be assumed to be a "leakage source" rather than a full pipe rupture; however, the spill duration must be 10 minutes unless the authority having jurisdiction (i.e., DOT or PHMSA), determines that a shorter time is acceptable. Again, given the confusion in applying the two requirements, the FERC staff will continue to use the 10-minute spill criteria at the maximum flow possible for containment sizing. This will ensure that impoundments are sized for a catastrophic failure, while recognizing that less conservative spill scenarios may be appropriate to calculate exclusion zones. In giving recognition to the integrity of all-welded transfer piping, the determination of the single accidental leakage source should be based on an evaluation of all small diameter attachments to the transfer piping (e.g., instrumentation, pressure relief, recirculation), and any flanges that may be used at valves or other equipment, in order to determine the largest spill rate. This approach is the result of discussion with DOT concerning the basis for design spills and application to exclusion zone determinations for proposals before the Commission.

Impoundment Systems and Design Spills

Title 49, CFR, Part 193.2181 specifies that the impoundment system serving a single LNG storage tank must have a volumetric capacity of 110 percent of the LNG tank's maximum liquid capacity. FGS proposes two full containment LNG storage tanks (Tank T-1001 and T-1002) in which the outer tank wall serves as the impoundment system. Each LNG storage tank's maximum liquid capacity would be 52,401,854 gallons. The outer tank would have an impounding volumetric capacity of 59,211,917 gallons, which

exceeds the 110 percent requirement by 1,569,878 gallons when accounting for the volume of perlite in the annular space.

In addition, FGS proposes to construct a tertiary earthen berm around the perimeter of the LNG tanks and vaporization area. The structure would be constructed to an elevation of seven feet above the finished grade level and would enclose an area of approximately 27 acres. After accounting for the estimated space occupied by features inside the berm, the available volume would be 56,954,184 gallons. This tertiary earthern berm would confine LNG on the project site in the event of any hypothetical catastrophic event.

Potential spills occurring from piping to and from the storage tanks and piping serving the vaporization area would be contained in concrete curbing that slopes towards the concrete transmission troughs to the sendout spill sump. In accordance with Section 2.2.3.5 of NFPA 59A, 2001 edition, the design spill for an LNG storage tank with over-the-top fill and no penetrations below the liquid level is defined as the largest flow from any single line that could be pumped into the impounding area with the tank withdrawal pumps considered to be operating at full rated capacity over a 10-minute period. For the proposed design, this would be a guillotine rupture of the 14-inch-diameter in-tank pump common withdrawal header. Each LNG storage tank would be equipped with three in-tank pumps (two operating, one spare) individually rated for 2,111 gpm. With two pumps operating for two storage tanks, the volume for a 10-minute spill from the in-tank pump withdrawal header would be 97,110 gallons. FGS also included a contingency of 15 percent to account for increased pump run out flow after the line break. The sendout spill sump would be 50-feet-long by 50-feet-wide and 6-foot-deep. The total containment capacity would be 112,208 gallons. Therefore, any potential spills from the 14-inch-diameter in-tank pump common withdrawal header would be contained in the sendout spill sump located within the berm surrounding the tank area.

Any potential spills from the transfer piping between the pretreatment/liquefaction area and the storage tanks and between the storage tanks and truck station would be captured by the truck station and process area sump. The largest potential spill would be from the 4-inch-diameter truck station liquid fill line from the LNG storage tanks, corresponding to a 10-minute spill volume of 13,686 gallons. The truck station and process area sump would be 21-feet-wide by 21-feet-long by 6-feet-deep, with an impoundment capacity of 19,793 gallons. The truck station and process area sump would be capable of containing a full rupture of the truck station fill line piping for 10 minutes.

Table 4.12-1 presents the impoundment sizes and design spill volumes used in the thermal radiation and flammable vapor dispersion modeling.

Table 4.12-1

Impoundment Areas

Source	Spill Size (gallons)	Impoundment System	Impoundment Size (gallons)
Impoundment Sizing Spills:			
LNG Storage Tank	52,401,854	Outer concrete tank	59,211,917
In-Tank Pump Withdrawal Header - 14-inch line	97,110	Sendout spill sump	112,208
Truck Station Liquid Fill Line- 4-inch line	13,686	Truck station and process area sump	19,793*
NGL Storage Vessel Discharge Line - 4-inch line	89,216	NGL spill sump	90,888
Design Spills:			
In-Tank Pump Withdrawal Header	97,110	Sendout spill sump	112,208
Truck Station Liquid Fill Line - 4-inch connection	13,686	Truck station and process area sump	19,793*
NGL Vessel Discharge Line - 4-inch connection	89,216	NGL spill sump	90,888

*Pretreatment/liquefaction area and truck loading area share a common impoundment system.

FGS proposes to install a natural gas liquids (NGL) storage system that would be constructed in accordance with all applicable design codes and standards, including NFPA 58 Liquefied Petroleum Gas Code. The NGL storage system would consist of two 60,000-gallon horizontal pressurized storage vessels for Phase 1. Phase 2 would include two additional 60,000-gallon horizontal pressurized storage vessels. The stored NGLs would consist of heavy hydrocarbons (primarily n-butane, propane, and hexane) removed from the feed gas prior to the liquefaction process.

The NGL extraction system would be designed to remove high molecular weight components typically present in the feed gas. During normal operations, FGS would re-inject NGLs back into the sendout gas to meet pipeline tariff requirements and for BTU adjustment. However, during the aftermath of a hurricane or other natural gas supply interruption, excessive high molecular weight components would be present in the feed gas. Therefore, FGS proposes to install a NGL storage system to accommodate the additional NGLs that would accumulate during an upset condition. In addition, FGS proposes to use a NGL truck loading station to remove the excessive NGLs stored on-site.

At the cryogenic technical conference held on February 20, 2008, FGS indicated it was considering revising the design to mound the NGL storage vessels. On May 5, 2008, FGS filed a response to the draft EIS recommendation requesting information on whether the NGL storage vessels would be installed as proposed in the application or whether the vessels would be mounded. FGS also indicated in that response one 12,000-gallon propane vessel and one 2,000-gallon iso-pentane vessel would be mounded. These vessels are part of the MR cycle that would be used in the liquefaction system as discussed in Section 2.1.1.1 of the EIS. All vessels would be buried or mounded in accordance with the mounding requirements specified in Section 3.2.9 of the NFPA 58

Liquefied Petroleum Gas Code and enclosed within concrete retaining walls. A concrete floor would be cast inside the retaining walls to provide containment of the contents of any spills from the vessels. A drainage system would be provided to evacuate water from the mounded earth and direct the flow into the NGL spill sump.

The NGL spill sump would be located at the lowest drainage point within the curbed area around the NGL storage vessels. The NGL spill sump would be 45-feet-wide by 45-feet-long by 6-feet-deep, with an impoundment capacity of 90,888 gallons.

On May 29, 2008, FERC issued a data request to FGS requesting a description of how the mounded vessels would be protected against corrosion and a description of the maintenance and inspection procedures for the mounded vessels. On June 18, 2008, FGS responded to the data response and proposed to protect the vessels against external corrosion by using a paint system that satisfies the requirements of the National Association of Underground Corrosion Engineers (NACE). In addition, the vessels would be designed with a cathodic protection system. FGS stated that more details of the coatings and cathodic protection system would be provided during the final design. FGS also stated that the vessels would have a maintenance program of periodic inspection and written procedures would be developed in the event that the vessel(s) would need to be removed for further evaluation or repair. Therefore, **we recommend that**:

- **The <u>final design</u> should include drawings, P&IDs, and specifications for the mounding system and the coatings and cathodic protection system for the vessels.**

Thermal Radiation Exclusion Zone

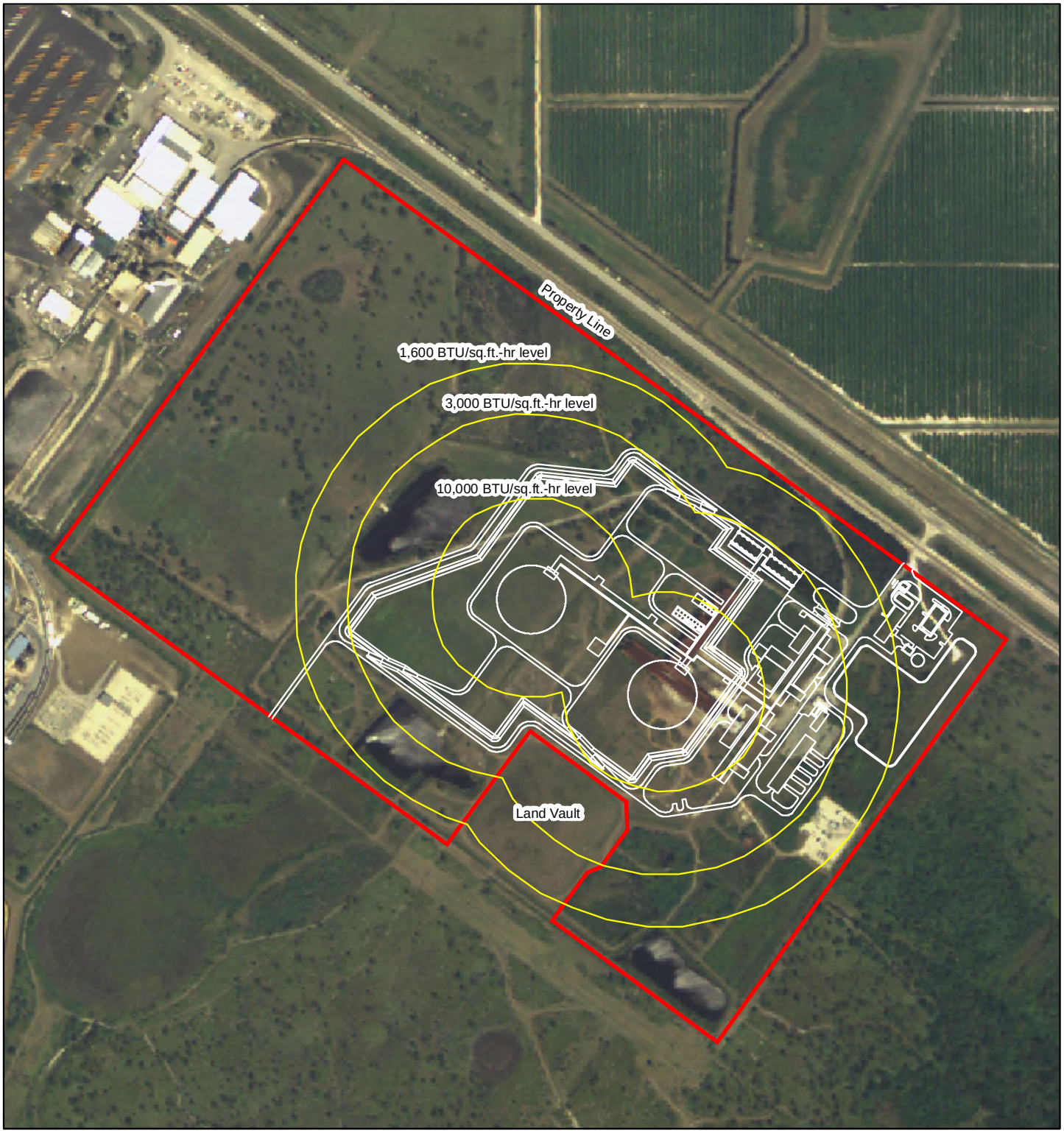
If a large quantity of LNG is spilled in the presence of an ignition source, the resulting pool fire would produce high levels of radiant heat in the area surrounding the impoundment. Exclusion distances for various flux levels were calculated according to 49 CFR 193.2057 and Section 2.2.3.2 of NFPA 59A, 2001 edition, using the "LNGFIRE III" computer program model developed by the Gas Research Institute. NFPA 59A, 2001 edition, establishes certain atmospheric conditions (0 mph wind speed, 70°F, and 50 percent relative humidity), which are to be used in calculating the distances. However, Part 193.2057 supersedes these requirements and stipulates that the wind speed, ambient temperature, and relative humidity that produce the maximum exclusion distances must be used, except for conditions that occur less than 5 percent of the time based on recorded data for the area. For its analysis, FGS selected the following ambient conditions to produce the maximum distances: wind speed of 18.7 mph; ambient temperature of 66°F; and 50 percent relative humidity. These conditions yield longer distances than the 0 mph wind speed, 70°F ambient temperature, and 50 percent relative humidity specified in NFPA 59A, 2001 edition. FERC staff agrees with FGS's selection of atmospheric conditions.

Under Title 49, Code of Federal Regulations, Section 193.2057, the LNG storage tank impoundment must have a thermal exclusion zone in accordance with NFPA 59A, 2001 edition. The referenced Section 2.2.3.2 of NFPA 59A, 2001 edition, requires thermal radiation distances ranging from 1,600 to 10,000 British thermal units per square foot per

hour (Btu/ft^2-hr) to be calculated for a volume of LNG determined in accordance with Section 2.2.2.1.

Thermal radiation distances calculated for 1,600 to 10,000 Btu/ft^2-hr incident flux levels for an LNG storage tank impoundment fire were based on the outer tank's concrete wall diameter (280 feet) as the pool diameter and the flame height equal to the top of the concrete wall (133 feet). The target height was set at ground level (0 feet). The resulting distances would be 401 feet for the 10,000 Btu/ft^2-hr zone; 742 feet for the 3,000 Btu/ft^2-hr zone; and 951 feet for the 1,600 Btu/ft^2-hr- zone (see Figure 4.12-1). The exclusion zones for the 1,600 and 3,000 Btu/ft^2-hr incident fluxes from the storage tanks would extend beyond the property line of the site onto a five (5) acre double-lined landfill (referred to as the "vault") containing remediated soil as discussed in Section 4.7.5. The vault is owned by Gerdau Ameristeel US Inc. On April 7, 2007, FGS entered into an option agreement with Ameristeel restricting the use or occupancy of the landfill vault in any manner that would conflict with the prohibited uses under the provisions of NFPA 59A, 2001 edition. Therefore, the thermal exclusion zones for an LNG storage tank impoundment fire would remain on the site, with the exception of the landfill vault, and would be in compliance with 49 CFR 193.2057.

The thermal radiation distances were determined for 1,600 Btu/ft^2-hr incident flux levels centered on the sendout spill sump, truck station and process area sump in accordance with 49 CFR 193.2057. The 1,600 Btu/ft^2-hr flux level would extend 274 feet from the center of the sendout spill sump and 137 feet from the center of the truck station and process area sump. These zones would not extend beyond the property line of the site. Therefore, the thermal exclusion zones would remain on the site and would be in compliance with 49 CFR 193.2057.



Legend

Storage Facility Site

Thermal Radiation Exclusion Zones for LNG Tanks

0 305 610 1,220 Feet

Figure 4.12-1
FGS Project
Thermal Radiation Exclusion Zones

Although LNGFIRE III is specifically designed to calculate thermal radiation flux levels for LNG pool fires, LNGFIRE III was used by FGS to calculate the thermal radiation distance for the 1,600 Btu/ft^2-hr incident flux level for the NGL spill sump. The 1,600 Btu/ft^2-hr flux level would extend 251 feet from the center of the NGL spill sump. This thermal radiation distance would not extend beyond the property line of the site. The potential for high levels of radiant heat in the area surrounding the impoundment would be minimized in the event that FGS decides to mound the NGL storage vessels.

Table 4.12-2 presents the calculated maximum distances for thermal radiation flux levels ranging from 1,600 to 10,000 Btu/ft^2-hr, as verified by FERC staff.

Table 4.12-2

Thermal Radiation Exclusion Zones

Source	Exclusion Area NFPA 59A Section 2.2.3.2(a)	Incident Flux (Btu/ft^2-hr) a/	Exclusion Zone (feet) b/
LNG Storage Tank Impoundment	Outdoor assembly area occupied by 50 or more people.	1,600	951
LNG Storage Tank Impoundment	Off-site structures used for occupancies or residences.	3,000	742
LNG Storage Tank Impoundment	Property line that can be built upon.	10,000	401
Sendout Spill Sump	Property line that can be built upon	1,600	274
Truck Station and Process Area Sump	Property line that can be built upon	1,600	137

a/ The 1,600 Btu/ft^2-hr flux level is associated with an exposed person experiencing burns within about 30 seconds. At 3,000 Btu/ft^2-hr, an exposed person would experience burns within 10 seconds; however, a wooden structure would not be expected to burn and affords protection to sheltered persons. At 10,000 Btu/ft^2-hr, clothing and wood can ignite spontaneously.

b/ Exclusion zone distances are measured from the center of the impoundment. For rectangular sumps, the longest exclusion zone distance is listed.

Vapor Dispersion Zone

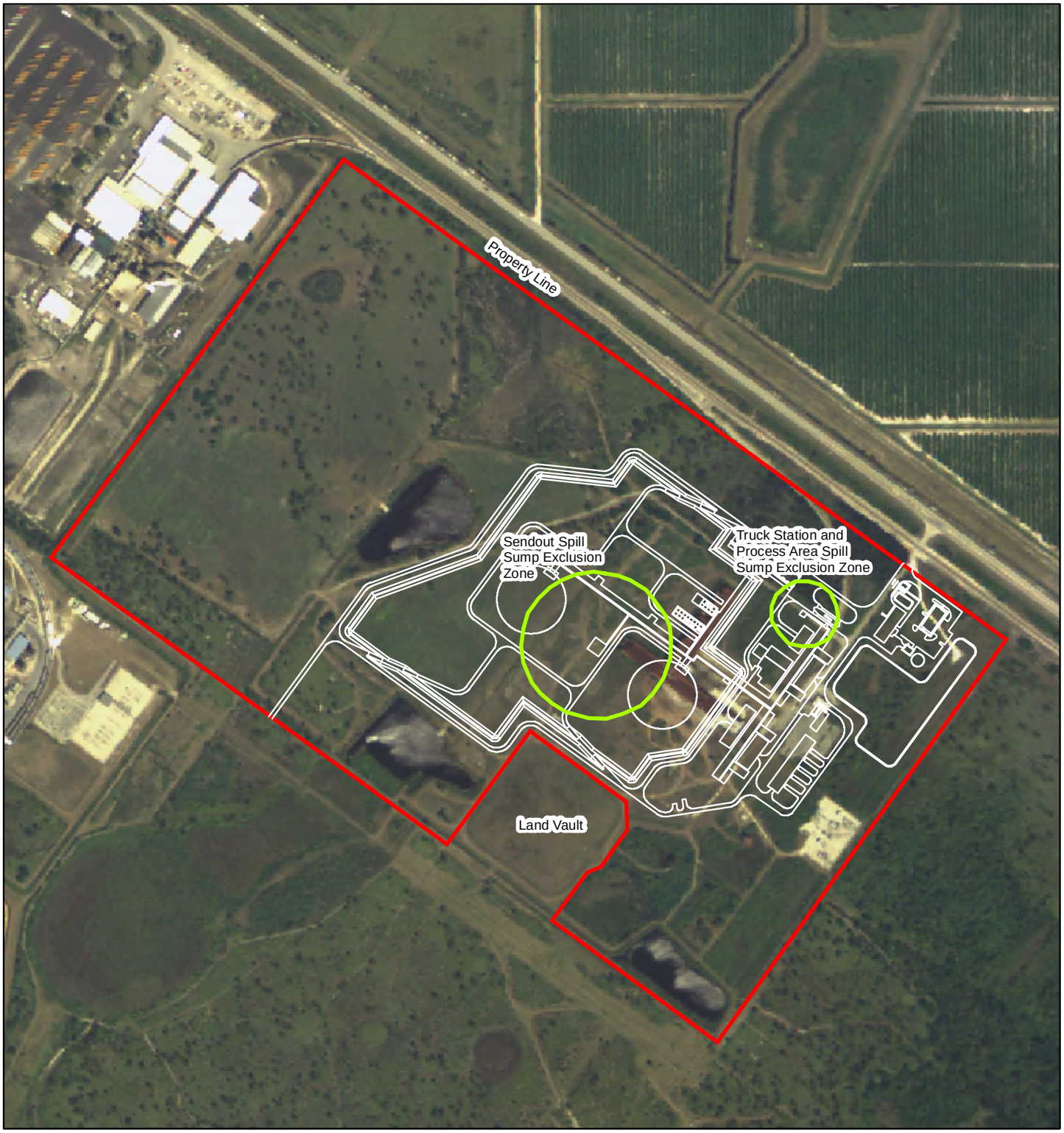
A large quantity of LNG spilled without ignition could form a flammable vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A, 2001 edition, and Part 193.2059 require that provisions be made to minimize the possibility of flammable vapors from reaching a property line that can be built upon and that would result in a distinct hazard. Part 193.2059 requires that dispersion distances be calculated for a 2.5 percent average gas concentration (one-half the lower flammability limit of LNG vapor) under meteorological conditions that result in the longest downwind distances at least 90 percent of the time. Alternatively, maximum downwind distances

may be estimated for stability Class F, a wind speed of 4.5 mph, 50 percent relative humidity, and the average regional temperature. The section allows the use of the DEGADIS Dense Gas Dispersion Model, or the FEM3A model, to compute dispersion distances. Design spills into impounding areas serving LNG containers, transfer systems and piping are to be determined in accordance with Section 2.2.3.5 of NFPA 59A, 2001 edition. In accordance with Section 2.2.3.3 of NFPA 59A, 2001 edition, an average concentration of methane in air of one-half of the lower flammability level cannot cross the property line from a design spill into each tank impoundment. In this case, compliance with Section 2.2.3.3 would also meet the requirements of Section 2.2.3.4 of NFPA 59A, 2001 edition.

In performing the vapor dispersion analysis required by 49 CFR 103.2059, FGS selected a wind speed 4.5 mph, an atmospheric temperature of 85°F, a relative humidity of 50 percent, and atmospheric Stability Class F. FGS selected the largest design spill that would be directed to the sendout spill sump based on a guillotine failure of the 14-inch-diameter in-tank pump common withdrawal header. This design spill rate would be 9,711 gallons per minute. For this design spill rate, FGS calculated a distance of 298 feet to the 2.5 percent average gas concentration isopleths. Based on historical weather data, FERC selected an atmospheric temperature of 75°F to predict the longest downwind flammable vapor dispersion distance for all sumps. FERC staff performed a vapor dispersion analyses for the sendout spill sump using SOURCE5 and DEGADIS. A distance of 326 feet to the 2.5 percent average gas concentration isopleths was calculated (Figure 4.12-2). However, the flammable vapor exclusion zone associated with the sendout spill sump would still remain within the facility property.

FGS selected a spill that would be directed to the truck station and process area spill sump based on complete failure of the 4-inch-diameter truck station fill line. The spill rate from this line would be approximately 1,369 gpm. Using this spill rate, FGS calculated a distance of 121 feet to the 2.5 percent average gas concentration isopleths. FERC staff also used SOURCE5 and DEGADIS to verify the vapor dispersion distances for the truck station and process area spill sump. A distance of 128 feet to the 2.5 percent average gas concentration isopleths was calculated. This exclusion zone associated with the truck station and process area sump would remain on-site. Based on our review, the proposed LNG facility location would satisfy the vapor exclusion zone requirements of 49 CFR 193.2059.

FGS selected a spill that would be directed to the NGL spill sump based on complete failure of the 4-inch-diameter discharge line from the NGL storage vessel. The corresponding spill rate would be approximately 8,922 gpm. FGS assumed since the NGLs are denser than air, the resulting vapors would stay very low to ground level and spread width–wise. As a result, FGS approximated the furthest distance that the cloud would travel to be 406 feet. FERC staff performed a similar vapor dispersion analysis using SOURCE5 and DEGADIS for the NGL spill using the same spill rate. Properties of n-butane were used to simulate NGL. This spill would result in a calculated distance of 394 feet to the 2.5 percent average gas concentration isopleths, which is comparable to FGS' results. This vapor dispersion distance associated with the NGL spill sump would remain on-site. The potential for the formation of a flammable vapor cloud would be minimized in the event that FGS decides to mound the NGL storage vessels.



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Storage Facility Site

Vapor Dispersion Exclusion Zones

Note: Vapor dispersion exclusion zones are the distance to the 1/2 lower flammability limit of methane.

0 260 520 1,040 Feet

Figure 4.12-2
FGS Project
Vapor Dispersion Exclusion Zones

Although the impoundment system technically complies with 49 CFR 193.2059, the issue of the lengthy distance from potential spill locations to the sumps needs to be addressed. As a result, the control of vapors produced in the channels or trenches leading to these sumps must be considered. Long trenches increase the surface area available for heat transfer and, correspondingly, increase vapor generation.

On September 27, 2007, FERC issued a data request to FGS requesting detailed vapor production rate (source strength) and vapor dispersion calculations for the trenches. On February 15, 2008, FGS responded to the data request with a report entitled, "Vapor Generation and Flammable Dispersion Modeling of LNG Releases in the Floridian Gas Storage Facility." The report, prepared by Quest Consultants Inc., provided vapor production rates and dispersion calculations for wind blowing from west to east, and south to north, for the following LNG spill scenarios:

1. LNG spill from the 14-inch-diameter in-tank pump withdrawal header at a volumetric flow rate of 9,711 gpm into a 3-ft wide by 2-ft deep trench;
2. LNG spill from the truck loading piping located inside the tertiary earthen berm at a volumetric flow rate of 1,366 gpm into a 3-ft wide by 2-ft deep trench. In addition, a LNG spill from the truck loading piping outside the tertiary earthen berm based on the same volumetric flow rate into a 2-ft wide by 1-ft deep trench was modeled; and
3. LNG spill at the process area at a volumetric flow rate of 1,190 gpm into a 2-ft. wide by 1-ft deep trench.

However, the report did not justify the trench geometry and LNG flow velocity assumptions that were used to calculate the vapor production rate for the LNG releases listed above. For scenario 1, the flow velocity was determined by assuming the depth of flow was equal to the trench height. For scenarios 2 and 3, the depth of flow was determined using the flow velocity established for scenario 1 rather than with the spill rate, geometry, and slope associated with those trenches. This approach assumes that the LNG flow velocity calculated for scenario 1 would be the same for all trenches even though the trench geometry and design spill flows are different. Additionally, FGS referenced the 1974 Arthur D. Little report, "Evaluation of LNG Vapor Control Methods," but did not provide the calculations demonstrating the methodology used to determine the vapor production rates. As a result, we recommended in the draft EIS that FGS revise the vapor production calculations to reflect LNG flow velocities and LNG liquid heights consistent with those that were calculated when sizing the trenches and to provide the calculations showing how the vapor production rate from a single trench element over a 10 minute period were determined. On May 5, 2008, FGS responded with the supplementary report to their original February 15, 2008 report. The report provided revised vapor production calculations, as requested, and provided some information regarding the methodology to determine the vapor production rate. The variations in the vapor production rates using the revised LNG velocities and LNG heights within the trenches were small compared to the previously calculated vapor production rates in the February 15, 2008 report and therefore no significant difference in the downwind distance to the ½ LFL would be expected. However, the vapor production rate methodology used in the reports produced vapor production rates that are approximately

one-half that of other applications with similar spill rates and trench configurations. FGS' information pertaining to the methodology still did not provide step-by-step calculations showing how the vapor production rates were determined. As a result, FERC staff issued a data request on May 29, 2008, requesting more information on some of the assumptions for the vapor production rate calculations and for the technical justifications for those assumptions. On June 18, 2008, FGS responded with information pertaining to some of the assumptions in the methodology; however the information provided still did not clarify the step-by-step calculation methodology showing how the vapor production rates were calculated. As a result, **we recommend that:**

- **FGS should file with the Secretary, for review and approval by the Director of OEP, step-by-step calculations showing how the vapor production rate from a single trench element over a 10 minute period was determined, prior to initial site preparation.**

Using the source strength calculations, FGS employed the Fire Dynamics Simulator (FDS) Version 5.0 to simulate the vapor dispersion distances. Although, the results of the report indicated that the flammable vapors would remain within the facility property, FGS did not provide justification for the meteorological conditions used in the vapor dispersion modeling. In addition, similar dispersion modeling efforts have indicated that longer dispersion distances may result when the wind direction is opposite to the LNG flow direction, which in this case, would be in a north to south direction. FGS also did not provide the input files for FERC staff's review or a grid sensitivity analysis that demonstrates the convergence of the downwind dispersion distances. As a result, FERC staff recommended in the draft EIS that FGS should provide: 1) justification for the selected weather conditions, and subsequently revise the vapor dispersion calculations, as appropriate, 2) provide a third simulation for wind blowing from north to south towards the property line for the spill at the process area, 3) provide a grid sensitivity analysis demonstrating that the results converge, and 4) provide the input files and output files used to determine the downwind dispersion distances for FERC review.

On May 5, 2008, FGS submitted a report that concluded that the vapor dispersion distances were insensitive to weather conditions. The report did not provide any quantitative results to demonstrate that the solution converges. Additionally, FERC staff noted several concerns in the submitted input files for the FDS simulations. Therefore, on May 29, 2008, FERC staff issued an additional data request regarding the concerns in the submitted input files for the FDS simulations.

The input files indicated the use of "open" boundaries along the direction of flow/wind (sides and top) in the simulations. It has been shown that prescribing open boundaries will cause artificial mixing and subsequent dilution near those boundaries. FGS maintains that prescribing a "mirror" boundary condition will produce idealized "smooth" clouds since this forces the wind profile to remain laminar and no terrain elements are represented that would, in reality, generate turbulence in the domain. FERC staff does not agree with this approach. The prescription of "open" boundary conditions at the boundaries parallel to the flow/wind (top and sides) will cause artificial mixing near those boundaries that may greatly reduce and/or limit the dispersion distances close to the boundaries. Since the boundaries are specified at locations

representative of the facility property line, this may essentially prevent vapors from ever exceeding the property line. FERC's recommendation to mitigate this artificial mixing near the boundary conditions is consistent with recommendations made by Sandia in the report, "Review of the Independent Risk Assessment of the Proposed Cabrillo Liquefied Natural Gas Deepwater Port Project" (Cabrillo Report), which evaluated the use of the same model, FDS, for determining dispersion distances in the Cabrillo Deepwater Port Project. The Cabrillo Report was also referenced in the FGS submittal. Additionally, the ingress of LNG vapors into the domain was initiated before the wind profile reached a quasi-steady state, which could cause excess mixing and dilution. FGS stated that Quest conducted internal sensitivity analyses showing that the effect of initial wind speed is minor at the low wind speeds used for this analysis. However, FGS did not provide this internal sensitivity analysis. Furthermore, other submittals, including others prepared by Quest, have consistently allowed the wind profile to reach a steady or quasi-steady state before injecting LNG vapor into the domain. This recommendation is also consistent with the recommendations made in the Cabrillo Report.

Another concern that affects the wind profile is the effect of the slip factor on the "ground" or "bottom" boundary condition. The slip factor is not specified for the ground boundary condition, resulting in a default value of 0.5 being used. Values other than 1 (a free-slip condition) affect the wind profile. Consequently, the slip factor may also affect the spreading and dispersion of the LNG vapors. Therefore, FERC staff requested a technical justification for their selection of the slip factor or a sensitivity analysis supporting the use of the selected slip factor. FGS pointed to the FDS manual for its technical justification, which states that it is not recommended that the default velocity boundary condition is changed unless the effect on the overall flow is of interest. We believe that the slip factor may have a significant impact on the overall flow and flammable vapor downwind dispersion distance and therefore we feel the selection of the slip factor value warrants further study.

In addition, a "reaction flag" in the source code of FDS may cause a local temperature increase shortly after the initial release of methane. This local temperature rise indicates the call of this reaction flag signifying a combustion process and may have an effect on the dispersion of the LNG vapors. FGS erroneously interpreted the question and assumed that we were referring to a parameter in the input file that was not specified. We were actually referring to the source code of FDS. The source code would have to be modified and recompiled to eradicate the reaction flag. Once again, this recommendation is also consistent with the Cabrillo report.

Other questions regarding the selection of temperature, relative humidity, lapse rate, and ground surface material were also presented. FGS did not provide sufficient technical justifications for why the appropriate values were not prescribed, but rather argued that the values selected are fairly insensitive to these parameters.

The recommended modifications to the dispersion calculations may cause the LNG vapors to go offsite. However, this is largely because the dispersion modeling has not accounted for the variation in terrain or obstacles that would actually be present. Other dispersion modeling submittals have shown that the turbulent kinetic energy near obstacles in the flow field may be more than an order of magnitude larger than the

turbulent kinetic energy associated with the atmospheric wind profile of F stability. We believe the inclusion of obstacles in the flow field would greatly reduce the vapor dispersion distances due to increased turbulence. In addition, mitigation measures (i.e. vapor fences) may be implemented to reduce the downwind dispersion distance. We believe if these measures are taken into consideration the vapors would remain on-site. In order to prove quantitatively that the flammable vapors would remain on-site, **we recommend that:**

- **FGS should file with the Secretary, for review and approval by the Director of OEP, revised vapor dispersion simulations with the following information, <u>prior to initial site preparation</u>:**
    - **a. a quantitative grid sensitivity analysis that supports the selection of grid size and demonstrates the convergence of the downwind dispersion distances;**
    - **b. simulations with mirror boundary conditions for the side and top boundaries;**
    - **c. simulations that allow the wind profile to reach a steady or quasi-steady state before injecting LNG vapor into the domain;**
    - **d. a sensitivity analysis and technical justification that supports the slip factor value used to determine the downwind dispersion distances;**
    - **e. an evaluation of the effect that the "reaction flag" in the source code to FDS has on the downwind dispersion distances;**
    - **f. technical justification and/or sensitivity analyses that support the selection of the lapse rate, ground surface material properties, temperature, humidity, and wind profile used to determine the downwind dispersion distances; and**
    - **g. all pertinent input files (*.fds) and output files (*.out) used to determine the downwind dispersion distances.**

4.12.4 LNG and NGL Truck Operations

FGS is proposing to install a dual LNG truck loading station at the facility to be used only for emergency events, such as during the aftermath of a hurricane or other natural gas supply interruption. Loaded LNG trucks from the facility could be sent to hospitals, gas distribution companies, power plants, and other essential services during emergency events. The proposed travel route for outbound LNG trucks would be along SR 710 adjacent to the facility, either north through Okeechobee, Florida, or south through Indiantown, Florida. FGS does not expect to receive any LNG trucks at its facility.

LNG trailers are of a double-shell construction – an inner tank constructed of a cryogenic alloy to contain the LNG, an outer tank of carbon steel, and an evacuated annular space containing perlite insulation. Stiffening rings are incorporated into the outer shell to improve its structural strength and prevent its collapse. A typical LNG truck carries between 10,000 to 12,000 gallons of LNG. LNG trailer design must comply with the

requirements of 49 CFR Part 173, while truck drivers must meet the training requirements of Title 49 CFR Part 172.

Additionally, FGS is proposing to install a NGL truck loading station to remove excess NGLs that could not be stored or re-injected into the vaporized gas or tailgas. During the cryogenic technical conference, FGS indicated that NGLs could be sent to power plants for use in boilers. The NGL trucks would utilize the same travel route as proposed for LNG trucks. The capacity of a NGL truck is also typically between 10,000 and 12,000 gallons. However, weight, rather than volume, is the controlling factor in determining NGL truck capacity due to the NGL compositions and truck "on-road" weight limitations. The NGL truck capacity is dependent whether heavier NGLs are being transported, which would reduce the volumetric capacity of the truck. NGL truck transportation must comply with the requirements of 49 CFR Part 180.

The proposed LNG and NGL truck loading stations would be equipped with multiple safety features. The LNG truck loading area would be provided with concrete curbing to direct any potential LNG spills into spill transmission troughs and into an impoundment sump. A hazard detection system would consist of separate detection units for combustible gas, fire, and high and low temperature and would be hard wired to the main control system for alarm and emergency shutdown. A dry chemical fire suppression system would also be provided. In addition, hydrants, manual monitors, and hose reels would be located throughout the facility.

At the cryogenic technical conference, representatives from the Martin County Emergency Services raised concerns about loaded LNG trucks exiting the FGS property and merging with faster traffic onto SR 710. Therefore, in the event trucking operations would be conducted, **we recommend that:**

- **FGS should develop a traffic control plan coordinated with local authorities to address LNG and NGL truck transportation from the facility. This plan should be incorporated into the facility's operation and maintenance procedures and manuals <u>prior to any trucking activities</u> at the LNG facility.**

4.12.5 Emergency Response and Evacuation Planning

Prior to commencing operations, FGS would have to prepare emergency procedures manuals, as required by 49 CFR Part 193.2509, that provide for: (a) responding to controllable emergencies and recognizing an uncontrollable emergency; (b) taking action to minimize harm to the public including the possible need to evacuate the public; and (c) coordination and cooperation with appropriate local officials. Specifically, Section 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…" To aid in the preparation of emergency response procedures, FGS would coordinate with the State Fire Marshal's office, Indiantown Fire Department, and Martin County Emergency Services Department, Martin County Fire & Rescue, and the Indiantown Sheriff's Department. In its application, FGS has stated that it would provide for installation of safety systems and specific gas detection equipment on the Martin County emergency service providers' vehicles. In addition, FGS would provide direct communication systems and training to the Martin County emergency service providers.

4.12.6 Terrorism and Security Issues

Since September 11, 2001, the FERC has been involved with other federal agencies in developing a coordinated approach to protecting the energy facilities of the United States. The FERC continues to coordinate with these agencies to address this issue. Safety and security are important considerations in any Commission action. The attacks of September 11, 2001 have changed the way pipeline operators as well as regulators must consider terrorism, both in approving new projects and in operating existing facilities. The likelihood of future acts of terrorism or sabotage occurring at the proposed FGS project, or at any of the myriad of natural gas facilities throughout the United States is unpredictable given the disparate motives and abilities of terrorist groups.

It is possible that a release from the LNG storage tanks could be caused by an intentional act, such as a terrorist attack. Although an intentional breach scenario could result in greater thermal radiation in the immediate vicinity of the release, such scenarios are typically associated with the desire to inflict damage to major infrastructure and heavily populated areas, rather than a remote industrial area. The continuing need to construct facilities to support the future natural gas pipeline infrastructure is not diminished from the threat of any such unpredictable acts.

The security requirements for the Project would be governed by 49 CFR Part 193, Subpart J - Security, and include the following:

- conducting security inspections and patrols;
- providing a liaison with local law enforcement officials;
- providing protective enclosures specified in Section 193.2905 for the following facilities: (1) Storage tanks; (2) Impounding systems; (3) Vapor barriers; (4) Process, liquefaction, and vaporization equipment; (5) Control rooms and stations; (6) Control systems; (7) Fire control equipment; (8) Security communication systems; and (9) Alternative power sources;
- complying with the design and construction requirements specified in Section 193.2907;
- providing prompt security communication between supervisory security and law enforcement officials. In addition, direct communication between on-duty security personnel and control room personnel must be ensured;
- providing security lighting for protective enclosures;
- providing security monitoring for all protective enclosures;
- providing alternative power source required for security lighting and security warning systems; and
- displaying warning signs for all protective enclosures.

In the application, FGS described the proposed facility's preliminary security plan and stated that final plans would be developed as part of the emergency response procedures in accordance with 49 CFR Part 193.2903. FGS stated that the final plans would be developed with the input of appropriate agencies including the State Fire Marshal's office, Indiantown Fire Department, and Martin County Emergency Services Department, Martin County Fire Marshal, Martin County Fire Rescue, and the Indiantown Sheriff's Department.

Under Section 550 of the Homeland Security Appropriations Act of 2007, the U.S. Department of Homeland Security (DHS) was provided with the authority to regulate the security of certain chemical facilities in the United States. Accordingly on April 9, 2007, DHS created the "Chemical Facility Anti-Terrorism Standards" under Title 6, CFR, Part 27 to establish risk-based performance standards related to facility security. On November 20, 2007, DHS issued the list of threshold quantities of chemicals of interest which trigger Part 27 review. The quantities of methane typically stored on-site at LNG peakshaving facilities under FERC jurisdiction exceed the screening threshold quantities specified in Appendix A to Part 27. As a result, the proposed FGS project would be required to comply with the regulations under 6 CFR 27 within 60 calendar days of receiving natural gas.

All facilities regulated under Part 27 must participate in an initial screening process, termed "Top-Screen," to establish the risk level associated with the facility. Facilities for which the Top-Screen process indicates the potential that a terrorist attack could result in significant adverse consequences for human life or health, national security or critical economic assets are designated by the DHS as "covered facilities". If the DHS determines that the FGS project would be considered a covered facility, the LNG plant would be preliminarily assigned to one of four risk-based tiers, ranging from highest risk in Tier 1 to lowest risk in Tier 4.

In accordance with 6 CFR 27.215, covered facilities must complete a Security Vulnerability Assessment (SVA) which identifies:

- hazards and consequences of concern for the facility and its surroundings;
- existing layers of protection;
- possible internal threats, external threats, and internally-assisted threats;
- potential security vulnerabilities and existing countermeasures; and
- strategies that reduce the probability of a successful attack or reduce the probable degree of success.

Following review of the SVA, the DHS would reassess the facility's preliminary ranking. If the FGS project still qualified as a covered facility, DHS would determine the facility's final placement within Tiers 1 through 4. After final placement, covered facilities are to provide the DHS with a plan which describes how on-site security measures would meet or exceed the performance standard associated with the facility's Tier ranking. This Site Security Plan, which must be approved by the DHS, would list the security measures to

be used to address the vulnerabilities identified by the SVA and potential modes of terrorist attack.

4.12.7 Natural Gas Pipelines

The transportation of natural gas by pipeline involves some risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture.

The DOT is mandated to provide pipeline safety under Title 49, U.S.C. Chapter 601. Within the DOT, the Pipeline and Hazardous Materials Safety Administration (PHMSA), OPS, administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety.

PHMSA ensures that people and the environment are protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. Section 5(a) of the Natural Gas Pipeline Safety Act provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards, while Section 5(b) permits a state agency that does not qualify under Section 5(a) to perform certain inspection and monitoring functions. A state may also act as DOT's agent to inspect interstate facilities within its boundaries; however, the DOT is responsible for enforcement action. The majority of the states have either 5(a) certifications or 5(b) agreements, while nine states act as interstate agents.

The DOT pipeline standards are published in 49 CFR Parts 190 to 199, Part 192 of 49 CFR specifically addresses natural gas pipeline safety issues. Under a Memorandum of Understanding on Natural Gas Transportation Facilities (Memorandum) dated January 15, 1993, between the DOT and FERC, the DOT has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it would design, install, inspect, test, construct, operate, replace, and maintain the facility for which a certificate is requested in accordance with federal safety standards and plans for maintenance and inspection, or shall certify that it has been granted a waiver of the requirements of the safety standards by the DOT in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act.

The FERC accepts this certification and does not impose additional safety standards other than the DOT standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Memorandum to promptly alert DOT. The Memorandum also provides for referral of complaints and inquiries made by state and local governments and the general public involving safety matters related to pipelines under the Commission's jurisdiction. The FERC also participates as a member of the DOT's Technical Pipeline Safety Standards Committee, which determines whether proposed safety regulations are reasonable, feasible, and practicable.

The pipeline and M&R station associated with the Project must be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and prevent natural gas facility accidents and failures. Part 192 specifies material selection and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion.

49 CFR 192 also defines area classifications, based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous one-mile length of pipeline. The four area classifications are defined as follows:

Class 1 Location with 10 or fewer buildings intended for human occupancy.

Class 2 Location with more than 10 but less than 46 buildings intended for human occupancy.

Class 3 Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people during normal use.

Class 4 Location where buildings with four or more stories above ground are prevalent.

The pipeline corridor is in a Class 1 location. Pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated rock. Class locations also specify a maximum distance to a sectionalizing block valve of 10.0 miles in Class 1 areas. If a subsequent increase in population density adjacent to the right-of-way causes a change in class location above existing design for the pipeline, FGS would be required to reduce the maximum allowable operating pressure or replace the segment with pipe of sufficient grade and wall thickness to comply with the DOT code of regulations for the new class location.

In 2002, Congress passed an act to strengthen the Nation's pipeline safety laws. The pipeline Safety Improvement Act of 2002 (HR 3609) was passed by Congress on November 15, 2002, and signed into law by the President in December 2002. Since December 17, 2004, gas transmission operators are required to develop and follow a written integrity management program that contains all the elements described in Section 192.911 and addresses the risks on each covered transmission pipeline segment. Specifically, the law establishes an integrity management program that applies to all high-consequence areas (HCAs). The DOT (68 FR 69778, 69 FR 18228, and 69 FR 29903) defines HCAs as they relate to the different class zones, potential impact circles, or areas containing an identified site as defined in Section 192.903 of the DOT regulations.

HCAs include: buildings or outside areas occupied by persons who are confined, of impaired mobility, or difficult to evacuate, such as hospitals, schools, prisons, or retirement facilities; and buildings or sites used by at least 20 or more persons on at least 50 days in any 12-month period, such as beaches, playgrounds, campgrounds, stadiums,

or religious facilities. For a pipeline not more than 12 inches in diameter and operating at a maximum achievable operating pressure, the area for consideration of HCAs is within 300 feet of the center line of the pipeline; for a 12 to 30–inch-diameter pipeline, the area of concern for HCAs would extend 660 feet. There are no HCAs in the vicinity of the proposed FGS pipeline corridor.

49 CFR 192 prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Under Section 192.615, each pipeline operator must also establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- emergency shutdown of system and safe restoration of service;
- making personnel, equipment, tools, and materials available at the scene of an emergency; and
- protecting people first and then property, and making them safe from actual or potential hazards.

Part 192 requires that each operator establish and maintain liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency, and to coordinate mutual assistance. The operator must also establish a continuing education program to enable customers, the public, government officials, and those engaged in excavation activities to recognize a gas pipeline emergency and report it to appropriate public officials. FGS has met with the Martin County Emergency Services Organization to inform it of the Project and proposed safety systems. FGS and the County have agreed to coordinate activities. In addition, FGS would have direct communications systems in place when the Project is constructed, make a contribution to install safety systems and specific gas detection equipment on its trucks, and provide training.

Based on approximately 302,000 miles in service, the rate of public fatalities for the nationwide mix of transmission and gathering lines in service is 0.01 per year per 1,000 miles of pipeline. Using this rate, the pipeline associated with the Project is not likely to result in more than one public fatality every 23,923 plus years. This would represent a negligible risk to the nearby public.

4.13 CUMULATIVE IMPACTS

The CEQ defines cumulative impacts as the "impacts on the environment which result from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions." Although the individual impact of each separate project may be minor, the additive or synergistic effects of multiple projects

could be significant. The cumulative impact assessment includes determining the resources to be evaluated, establishing the geographic scope and temporal scale for the analysis, and identifying the other past, present, and reasonable foreseeable future actions that have affected, or could affect, the resources of concern.

4.13.1 Potentially Cumulatively-Affected Resources

Resources subject to cumulative impact assessment include those resources upon which the Project would have long-term impacts. Resources that are not impacted by the Project or are only subject to temporary effects were excluded from this analysis. Table 4.13-1 summarizes the screening process to determine the resources included in the cumulative effects analysis.

Based on this analysis, we have identified eight resources that have the potential for cumulative effects: water resources, vegetation and wildlife, visual resources, socioeconomics, transportation, air quality, noise, and reliability and safety.

4.13.2 Geographic Scope and Temporal Scale

The geographic scope of the cumulative impact assessment for most resource areas includes lands within a two-mile radius of the proposed storage site, pipeline, and M&R station (see Figure 4.13-1). Due to the dispersion potential of air emissions, the geographic scope for this resource includes all of Martin County to ensure compliance with federal, state, and local air quality standards. The socioeconomic analysis considers all of Martin County within the Project's area of influence; therefore, the geographic scope for this resource includes all of Martin County.

4.13.3 Other Actions Potentially Contributing to Cumulative Effects

Existing environmental conditions in the study area reflect changes based on past activities. Historically, the site was a combination of marshland, forested wetlands, upland forests, and grasslands. Much of the study area has been in agricultural use (e.g., cattle ranching, citrus orchards) since the 1890s. Residential development in Indiantown began in the early 1900s, but increased since 1953 when the Indiantown Company purchased and subsequently developed much of the land in this unincorporated town.

Industrialization of the study area included agri-businesses such as Tampa Farms and Louis Dreyfus. The Florida Steel manufacturing facility was constructed in 1970, operated until February 1982, and was placed on the Superfund list in December 1982. With the extension of gas pipelines, the study area became attractive for power generation and distribution, with the construction of the FPL Martin power plant and associated electric transmission lines, and subsequently the Cogentrix power plant.

Table 4.13-1

Summary of Potential Cumulative Effects of the Proposed Project

Resource	Would Project have long term adverse effect on resource? (Yes or No)	Cumulative Effects analysis required	Potential Cumulative Effect
Geology	No, Project would have no effect on geology.	No	None
Soils	No, Project would only have minor temporary effects on soils during construction. All disturbed soils would be stabilized and restored.	No	None
Water Resources	Yes	Yes	The Project would have a long-term affect on water resources through groundwater withdrawals for landscaping and increases in stormwater runoff.
Wetlands	No, Project would only have minor temporary effects on wetlands during construction. All wetlands would be restored with permanent impacts.	No	None
Vegetation and Wildlife	Yes.	Yes	Project would permanently affect 78.40 acres of vegetation that provides habitat for a variety of wildlife species.
Aquatic Resources	No, Project would only have minor temporary adverse effects on drainage ditches and stormwater ponds during construction.	No	None
Threatened and Endangered Species	No, Project either would have no effect or would be not likely to adversely affect all federally- listed species.	No	None
Land Use	No, Project is consistent with current local zoning and future land use plan and compatible with neighboring land uses.	No	None
Recreation and Special Interest Areas	No, Project would have no effect any recreation or other special interest areas.	No	None
Visual Resources	Yes	Yes	Project would be visible from public roads and would result in minor permanent change in the visual landscape of Project area.
Socioeconomics	Yes	Yes	Project would have a long-term beneficial effect on local economy through job creation and payment of taxes and fees.
Transportation	Yes	Yes	Project would result in minor long-term increase in traffic.
Cultural Resources	No, the Project would have no effect on cultural resources.	No	None
Air Quality	Yes	Yes	Project would result in minor long-term increase in air emissions.
Noise	Yes	Yes	Project would result in minor long-term increase in noise levels in the immediate Project area.
Reliability and Safety	Yes	Yes	Project would affect reliability and public safety.

These projects cumulatively resulted in the loss of natural vegetation and wetlands, reduction in water quality, fragmentation of the remaining natural habitat, and introduction of exotic and invasive species. Future development would further contribute to these impacts.

There are no known expansion plans for the FPL Martin, Cogentrix, or Louis Dreyfus plants; however, these facilities would be expected to continue industrial operations during the life of the Project. Three industrial projects - Venture Park, Indiantown Commerce & Technology Park, and Prism Business Park - are planned within approximately one mile of the LNG storage facility site; one mixed-use (i.e., residential and commercial) project is planned within about 1.25 miles. Table 4.13-2 lists present or reasonably foreseeable future projects or activities that may cumulatively or additively impact resources affected by construction and operation of the FGS LNG facility. Figure 4.13-1 shows the location of the existing and planned development actions in relation to the Project.

Table 4.13-2

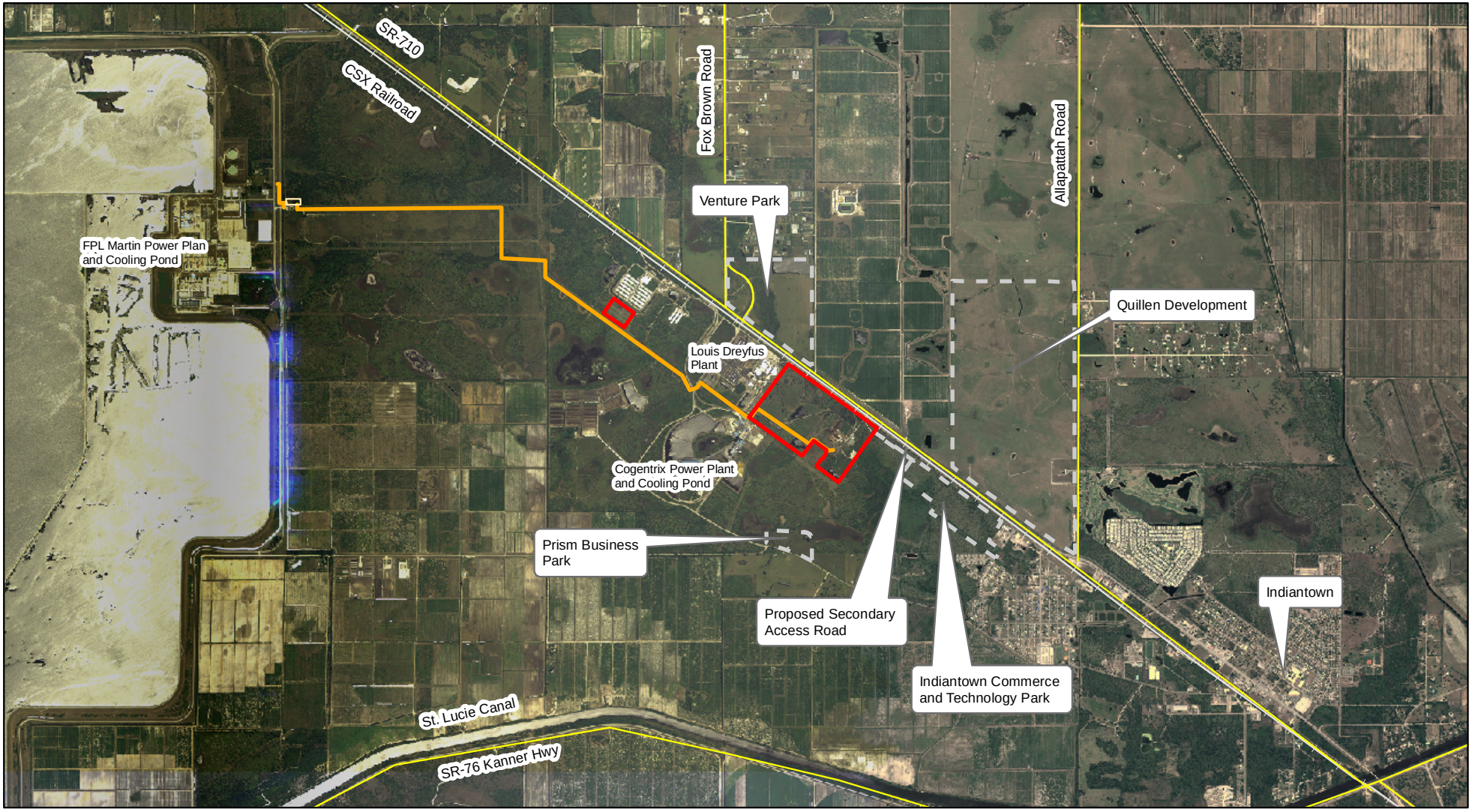
Potential Future Actions in the FGS Project Area

Activity	Description
Venture Park	Industrial lots (22) and agricultural ranchettes on 139 acres across SR 710 from the northern corner of SRS project site.
Indiantown Commerce & Technology Park	Industrial lots (31) on 97.4 acres of the west side of CSX Railroad, north of the Booker Park Community of Indiantown.
Prism Business Park	21-acre industrial development at the Northwest corner of SR 710 and County Road 609 in Indiantown.
Quillen Development	Mixed-use residential (2,250 units) and commercial (150,000 square feet) at the Northwest corner of SR 710 and County Road 609 in Indiantown approximately 1.25 miles from FGS site.

4.13.4 Resource-Specific Cumulative Effects Analysis

Water Resources

The Project would not affect any major waterbodies. It would disturb three drainage ditches and withdraw hydrotest water from the St. Lucie Canal; but these effects would be temporary, the ditches would be restored in accordance with our Procedures, and the hydrotest water returned to the canal.



Legend

- Roads
- Railroad
- Project Pipeline
- Storage Facility Site
- M&R Station
- Potential Future Actions

0 0.25 0.5 1 Miles

Figure 4.13-1
FGS Project
Current and Potential Future Actions in the Project Area

The only long-term Project effects on water resources involve increased groundwater withdrawals for landscaping, stormwater runoff from impervious surfaces, and wastewater generation. Groundwater withdrawals for landscaping would be a maximum of 30 gpm and most of the water (allowing for evaporative losses) would be returned to the surficial aquifer. The creation of impervious surface would reduce the available surface area for groundwater recharge; however, relative to the total recharge area for the aquifer, this reduction in pervious surface would not be significant. These impervious surfaces would also increase the volume of stormwater runoff, but the Project would provide on-site stormwater management in accordance with state and local requirements and implement site-specific SPCC and SWPP plans. The Project would generate domestic wastewater from the approximately 32 full-time employees, but this wastewater volume would be small and it would be treated at a publicly-owned wastewater treatment plant. Therefore, the Project would have little effect on groundwater or surface water quantity or quality.

The current and potential future actions in the Project area would also contribute to additional withdrawals from the local aquifer and wastewater discharges to the local wastewater utilities. These activities would all likely be constructed in accordance with the applicable federal, state, and local permit requirements and would likely not cause the aquifer or utility systems to exceed their capacity. Therefore, the Project, other existing development, and potential future actions would not result in a significant cumulative impact on water resources in the study area.

Vegetation and Wildlife

Construction of the Project would result in the permanent loss of 56.07 acres of potential wildlife habitat and the permanent maintenance of 22.33 acres of pipeline right-of-way in low growth (i.e., shrub or herbaceous) cover. More mobile species would be displaced, while smaller, less mobile species would suffer localized mortality. Much of the affected land, however, was previously disturbed and contaminated and does not represent valuable habitat. The proposed pipeline route does not intersect any rare or significant habitats. Pipeline construction and right-of-way maintenance could fragment wildlife habitat reducing its value, but in this case the pipeline follows an existing transmission line right-of-way for much of its length. A major issue in Florida is the proliferation of invasive and exotic species. The Project would remove stands of Australian pine and Brazilian pepper.

The Prism Business Park, Venture Park, and Quillen Development sites are dominated by open prairie, residential areas, and agricultural fields while the Indiantown Commerce and Technology Park is dominated by pine flatwoods. These habitat types are common throughout the region and likely would not provide significant wildlife habitat. The majority of wildlife species displaced by these projects would likely be able to relocate and would not suffer long-term, population-level impacts to biodiversity within the region. Therefore, there would be no significant cumulative impact to wildlife resources.

Visual Resources

The primary Project effect on visual resources would be the two 174-foot-high LNG storage tanks. These storage tanks would be visible to the surrounding area; however, the visual character of the Project area is currently industrial. The adjoining Louis Dreyfus plant and Cogentrix power plant have structures that are 138- and 495-feet-high, respectively. Other nearby tall structures include the FPL's Martin power plant stacks and electric transmission line, which are visible throughout the Project area. The Project would be visually compatible with other industrial facilities in the study area and consistent with the industrial zoning of the area.

The current and potential future actions would further contribute to the trend of converting the landscape character of the Project area from rural/agricultural to industrial/commercial. This change in visual character is consistent with the current zoning and planning guidelines for Indiantown and would not introduce structural elements out of character with surrounding developments.

Socioeconomics

Project operations would provide long-term benefits to the economy of the study area and Martin County through the creation of 270 temporary construction jobs with a peak of 450 temporary construction jobs during months 14 and 15 of the construction period, up to 33 full time employees, purchase of construction materials, and the annual payment of corporate income taxes to the State of Florida and property taxes to Martin County.

The current and potential future actions in the Project area would similarly provide economic benefits through increased employment opportunities and payment of taxes. Overall, the Project, other existing development, and potential future actions would benefit the socioeconomic conditions of the study area.

Transportation

The Project would primarily affect traffic during construction when as many as 450 workers would commute to the site, but these effects would be temporary. The Project would employ approximately 33 full time employees during operation, but these employees would have a negligible effect on traffic volumes in the study area considering that SR 710 currently carries 7,800 vehicles per day.

Other existing development and potential future actions would likely generate much more traffic than the 32 employees at the LNG storage facility. Traffic volumes along SR 710 are increasing and FDOT has plans for road resurfacing, intersection signalization and turn lane improvements to maintain the desired level of service. With proper coordination of land use and transportation planning, the Project and current and potential future actions should not reduce the level of service below acceptable standards.

Air Quality

Operation of the Project would result in the emission of a variety of criteria air pollutants. The net emissions from the Project for each of the criteria pollutants would be less than

applicable thresholds so the Project would be considered a minor source. The Project is implementing a variety of control technologies such as the use of low NO_x burners to reduce air emissions. The Project would comply with all applicable federal and state permits.

The current and potential future actions in the Project area also have the potential to emit air emissions. There are three existing major emissions sources in the vicinity of the proposed Project: the FPL Martin power plant, the Cogentrix power plant, and the Louis Dreyfus Citrus processing plant. These facilities are regulated under Title V of the CAA and the combined annual permitted emissions for these facilities and the proposed Project are identified in Table 4.13-3. The proposed Project would account for less than a 5 percent increase in any single criteria pollutant.

Table 4.13-3

Cumulative Existing Criteria Air Pollutant Emissions in the Vicinity of the Proposed Project

	SO_2	PM	NO_x	CO	VOC	HAPs
Existing Emissions (tons/year)[1]	33,435.2	4,260.9	17,118.5	3,784.8	1,037.7	92.9
Proposed Project Emissions (tons/year)	7.6	11.0	89.0	96.0	48.0	0.2
Project Emissions as a Percent of Total	0.02%	0.26%	0.52%	2.54%	4.63%	0.24%

[1] FDEP, 2008c

There are currently three industrial facilities and one mixed-use development proposed in the Project area. When emissions from the proposed Project are combined with emissions from current industrial operations in Martin County, the Project would not contribute to an exceedence of the NAAQS or violate the PSD requirements of the CAA. The degree to which the Project and current and potential future actions would contribute to regional air quality is dependent upon the specific activities conducted at each location. Should these activities receive the required permits and comply with all federal and state air quality regulations, these activities would have no significant cumulative impact on regional air quality.

Project operations would emit approximately 2 million tons of $CO_{2\text{-}e}$ annually; however, the Project would likely cause an overall net reduction in greenhouse gas emissions by increasing the availability of natural gas as a substitute for alternative fuels that emit more $CO_{2\text{-}e}$ per unit of energy.

Noise

The operation of the LNG storage facility would increase noise levels by about 2 dBA at the nearest NSA thereby resulting in an insignificant impact on the noise environment.. This noise analysis already takes into consideration existing background noise levels.

The potential future actions in the Project area would also increase noise levels either directly through their operation, or indirectly by increases in traffic and other noise-generating activities. These activities, however, would be located in areas zoned for their respective use (e.g., industrial, commercial, residential) and Martin County implements a strict noise control ordinance. Based on the lack of NSAs, compatible land use zoning, and likely implementation of noise minimization measures, the Project and current and

potential future actions would increase noise levels in the Project area; but the increase would be minor and would result in no significant cumulative impacts.

Reliability and Safety

Impacts on reliability and public safety would be mitigated through the implementation of applicable federal, state, and local rules and regulations for each individual project. The implementation of federal, state, and local rules and regulations concerning safety; implementation of the Emergency Response Plan; and close coordination and communication with emergency responders would minimize the risk to the LNG storage facility and the public.

4.13.5 Conclusions about Cumulative Impacts

A determination of significance for the cumulative impacts for specific resources is problematic because well-defined thresholds are typically undetermined; however, most of the cumulative impacts we have identified for the proposed Project would be temporary and minor. Consequently, their addition to other past, present, and reasonably foreseeable actions in the area does not result in an overall significant increase in impacts.

Although the Project would result in some minor adverse environmental impacts, the Project would also cumulatively benefit the local economy through job creation and wages, purchases of goods and materials, tax revenues, and provision of a new source of competitively priced natural gas.