Geology and Soils	
83	Provide the West-Central Florida Coastal Study data for transects 5 and 6 that was used to characterize physical characteristics of Tampa Bay and the West Florida Shelf in the vicinity of the proposed pipeline route. Provide the West-Central Florida Coastal Study data for transects in close proximity to the alternative northern and southern pipeline routes.
Response	The West-Central Florida Coastal Study data can be obtained at the following web address: http://coastal.er.usgs.gov/wfla/

Geology and Soils	
84	Please provide the references use to create Table 8-1, I. The website did not provide the actual statistics used to create table.
Response	You are correct, the current website information does not reflect the information provided in Table 8-1. We have contacted the Florida Ports Council and they verified that they updated the website with new information. The Florida Ports Council provided the attached information from the Five-Year Plan to Achieve the Mission of Florida's Seaports: 2005/2006-2009/2010 which includes the information previously found on the website and used to generate Table 8-1.

II. Cargo and Cruise Operations at Florida's Seaports

Florida's seaports set new records in FY 04/05 for the dollar value of their cargo and for their tonnage and container moves.

Record Achievements. The accomplishments of Florida's fourteen seaports, whose diversity is profiled in Appendix D, can be measured in several ways: the dollar value of their cargo, the tonnage crossing each seaport's docks, the number of containers moved, as counted in 20-foot equivalent container units or TEUs, and the number of cruise passengers embarked and disembarked. In FY 04/05, Florida's seaports continued to set records in cargo value, tonnage, and container moves. The only exception to these records was in the number of cruise passengers, which, as a result of the hurricanes that affected the state, declined slightly.

Florida's seaports moved $62.9 billion worth of goods from countries the world over in 2005. This 22.4 percent increase over2004 includes $25.2 billion in imports and $37.7 billion in exports.

Table 12: Dollar Value of Florida's Waterborne Foreign Exports and Imports by Port 2005 with 2004 Comparison

Port	Imports	Exports	Total 2005	Total 2004
Canaveral	664,414,509	105,614,629	770,029,138	$542,257,532
Everglades	9,261,922,343	5,652,788,397	14,914,710,740	11,338,752,212
Fernandina	150,347,805	180,778,295	331,126,100	294,057,907
Fort Pierce	2,461,057	71,184,961	73,646,018	27,108,251
Jacksonville	10,159,435,022	6,469,924,260	16,629,359,282	13,715,848,681
Key West*	1,762,827	25,002,503	26,765,330	20,811,614
Manatee	770,230,126	55,587,713	825,817,839	742,319,507
Miami	11,706,551,501	9,002,772,650	20,709,324,151	19,126,818,320
Palm Beach	999,335,233	1,133,129,003	2,132,464,236	1,646,626,736
Panama City	1,568,323,036	287,736,899	1,856,059,935	514,077,482
Pensacola	10,463,137	45,497,552	55,960,689	5,847,159
St. Petersburg*	1,182,718	234,790	1,417,508	3,066,178
Tampa	2,443,902,371	2,128,680,306	4,572,582,677	3,419,146,758
Total	37,740,331,685	25,158,931,958	62,899,263,643	$51,396,738,337

Source: U.S. Census Bureau, Foreign Trade Division.

*The cargo values indicated for these locations reflect operations other than at the specific port docks, as calculated by the federal government.

Dollar Value of Waterborne Cargo. Florida's seaports moved $62.9 billion worth of goods from countries the world over in 2005. This 22.4 percent increase over 2004 includes $25.2 billion in imports and $37.7 billion in exports (see Table 12). Imports represented 60.0 percent of the waterborne international trade value while exports represented 40.0 percent. These percentages are consistent with those in 2004, when imports represented 60.5 percent of the total and exports represented 39.4 percent. Eight of Florida's seaports saw double-digit percentage increases in the value of the goods moving across their docks and three of the smaller seaports actually saw extraordinary triple-digit increases.

Florida's seaports handled 127.4 million tons of commodities as different as automobiles, tile, apparel, fruits and vegetables, paper and wood products, petroleum, computers, and industrial machinery.

Seaport Tonnage. Florida's waterborne trade in FY 04/05, including the international and domestic cargo handled at both public and private terminals in port areas, increased to 127.4 million tons, a 4.4 percent increase from FY 03/04's 122.0 million tons and a new state record.

Table 13 shows the import, export, and domestic tonnage handled at each of Florida's seaports in FY 04/05, as compared with FY 03/04. Exhibit 8 shows the state's historic waterborne tonnage record since FY 94/95.

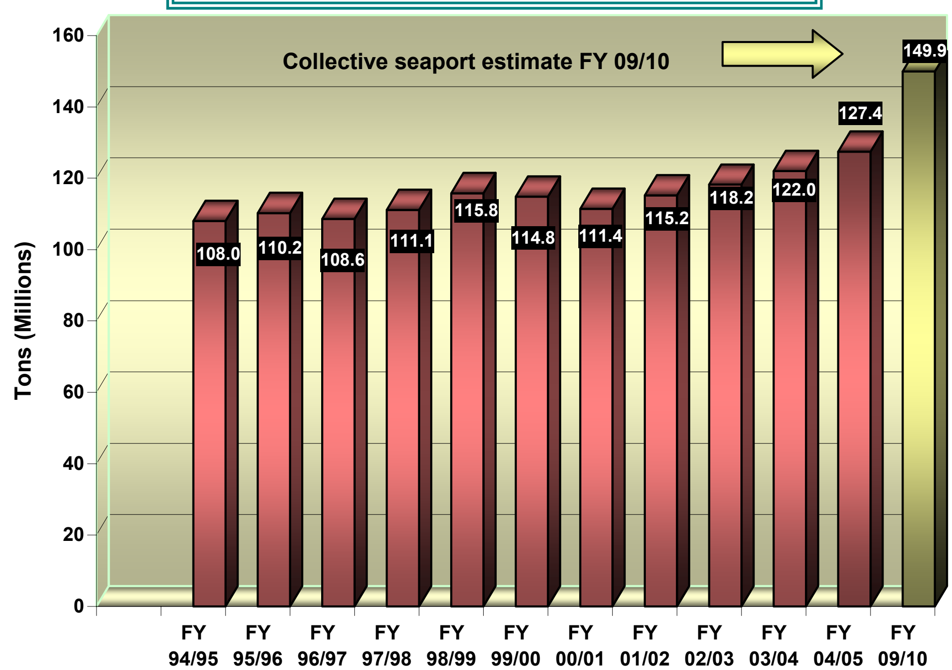
Table 13: Tonnage of Florida's Total Waterborne Trade by Port FY 04/05 with FY 03/04 Comparison

Port	Imports	Exports	Domestic	Total FY 04/05	Total FY 03/04
Canaveral	4,230,695	236,393	0	4,467,088	4,083,528
Everglades	11,801,969	2,462,055	12,248,269	26,512,293	25,462,798
Fernandina	117,018	392,020	0	509,038	514,135
Fort Pierce	4,500	141,000	100,000	245,500	203,650
Jacksonville	8,014,240	1,144,890	11,569,300	20,728,430	19,741,370
Manatee	8,355,680	1,077,396	0	9,433,076	8,360,469
Miami	5,814,529	3,657,739	0	9,472,268	9,230,036
Palm Beach	491,661	1,323,471	2,408,413	4,223,545	4,267,006
Panama City	912,988	134,811	89,658	1,137,457	886,334
Pensacola	448,831	36,093	9,082	494,006	507,912
Tampa	11,233,149	9,228,430	29,732,973	50,194,552	48,698,292
Total	**51,425,260**	**19,834,298**	**56,157,695**	**127,417,253**	**121,955,530**

Source: Individual seaport data

Of the 127.4 million tons of cargo handled in FY 04/05, 56.2 million tons, or 44.1 percent, was domestic cargo, that is, cargo transported in the coastwise trade between two or more states or between the U.S. and Puerto Rico. This cargo, which includes Florida's traditional liquid and dry bulk commodities such as petroleum and phosphate products as well as aggregates, cement, and sugar, decreased by 3.8 percent in FY 04/05 over the FY 03/04 tonnage. In addition to its significant dollar value, domestic cargo represents the predominant tonnage moving across Florida's road and rail infrastructure to consumer markets in the various regions of the state. The Port of Tampa, Port Everglades, and the Port of Jacksonville all handle millions of tons of domestic cargo, particularly petroleum; the Port of Palm Beach also carries a share of domestic cargo.

Exhibit 8: Tonnage at Florida's Seaports



Source: Individual seaport data

The balance of cargo handled by the seaports in FY 04/05 included 51.4 million tons (40.3 percent) of imports, and 19.8 million tons (15.6 percent) of exports, the sixth year the Florida's waterborne imports exceeded exports. This sustained reversal of what was once the state's equal balance of imports and exports is consistent with the nation's expanding trade deficit and is expected to continue accelerating in future years as more and more manufactured goods are imported from the Far East.

Florida's container ports moved almost 3 million TEUs in FY 04/05, an 11 percent increase over FY 03/04. Nine of the eleven Florida seaports handling containers moved more in FY 04/05 than in FY 03/04.

Table 14: Container Movements at Florida's Seaports FY 04/05 (with FY 03/04 Comparison)

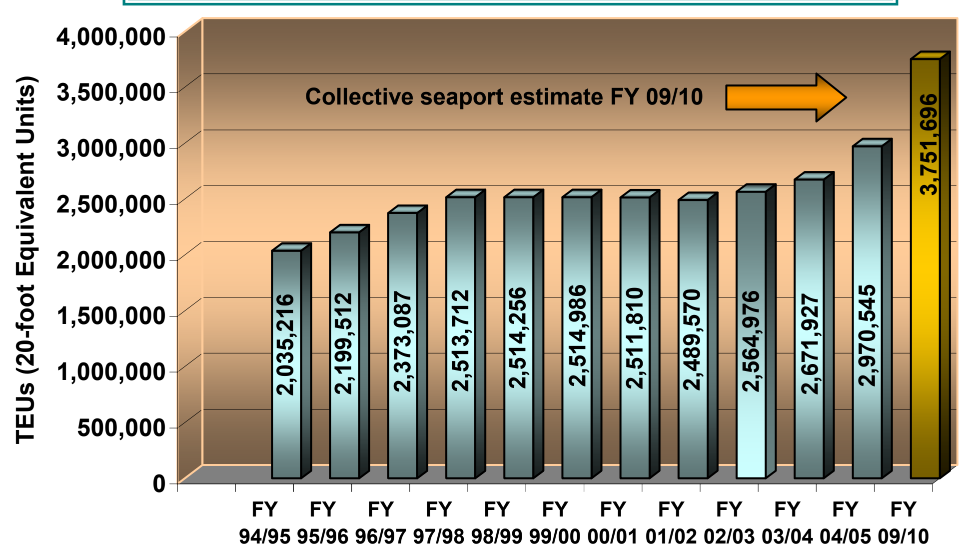
Port	TEUs FY 04/05	TEUs FY 03/04
Canaveral	2,086	813
Everglades	797,238	653 680
Fernandina	28,881	25,003
Fort Pierce	10,570	3,970
Jacksonville	777,318	727,660
Manatee	6,236	8,529
Miami	1,054,462	1,009,500
Palm Beach	248,206	226,002
Panama City	18,372	0
Pensacola	530	769
Tampa	26,646	16,000
Total	**2,970,545**	2,671,927

Source: Individual seaport data.

__Container Movements__. In FY 04/05, Florida's ports moved almost 3 million TEUs across their docks, an 11.1 percent increase over FY 03/04 and a dramatic new state record. For the third year in a row, the Port of Miami moved more than 1 million TEUs. Port Everglades recorded a 22.0 percent increase, the Port of Jacksonville a 6.8 percent increase, and the Port of Palm Beach, a 9.8 percent increase in the number of TEUs they moved. These four ports ranked eleventh, twelfth, thirteenth, and fifteenth, respectively, among the U.S. mainland container ports in 2005. Also moving more TEUs in FY 04/05 than in FY 03/04 were Port Canaveral, the Port of Fernandina, the Port of Fort Pierce, Port Panama City, and the Port of Tampa.

Table 14 shows the container movements in FY 04/05 by port and compares them with the FY 03/04 movements. Exhibit 12 shows the history of these movements since FY 94/95.

Exhibit 9: Container Movements at Florida's Seaports



Source: Individual seaport data

TEU Rank of Mainland US Seaports in 2005	
Rank	**Port**
1	Los Angeles
2	Long Beach
3	New York/New Jersey
4	Oakland
5	Seattle
6	Tacoma
7	Charleston
8	Hampton Roads
9	Savannah
10	Houston
11	**Miami**
12	**Everglades**
13	**Jacksonville**
14	Baltimore
15	**Palm Beach**

Source: AAPA

In FY 04/05, 14.5 million revenue cruise passengers crossed seaport docks, a slight decline over FY03/04, the result of hurricane interruptions to scheduled cruise operations.

Cruise Passengers. In FY 04/05, 14.5 million cruise passengers embarked and disembarked from Florida's ports, a 1.2 percent decline over FY 03/04, the result of hurricane interruptions to scheduled cruise operations, particularly one-day operations. The number of multi-day cruise passengers increased by a slight 0.25 percent, but the number of one-day cruise passengers, which represent 25 percent of the total, declined by 7.0 percent. The Port of Miami, which has only multi-day cruises, saw a 3.0 percent increase in the number of its passengers; but Port Canaveral and Port Everglades, which have both one-day and multi-day cruise operations, saw total declines of 4.3 and 6.7 percent, respectively. The Port of Jacksonville, which entered the cruise market in late 2003, experienced the strong growth anticipated for its new operations, which increased by 61 percent.

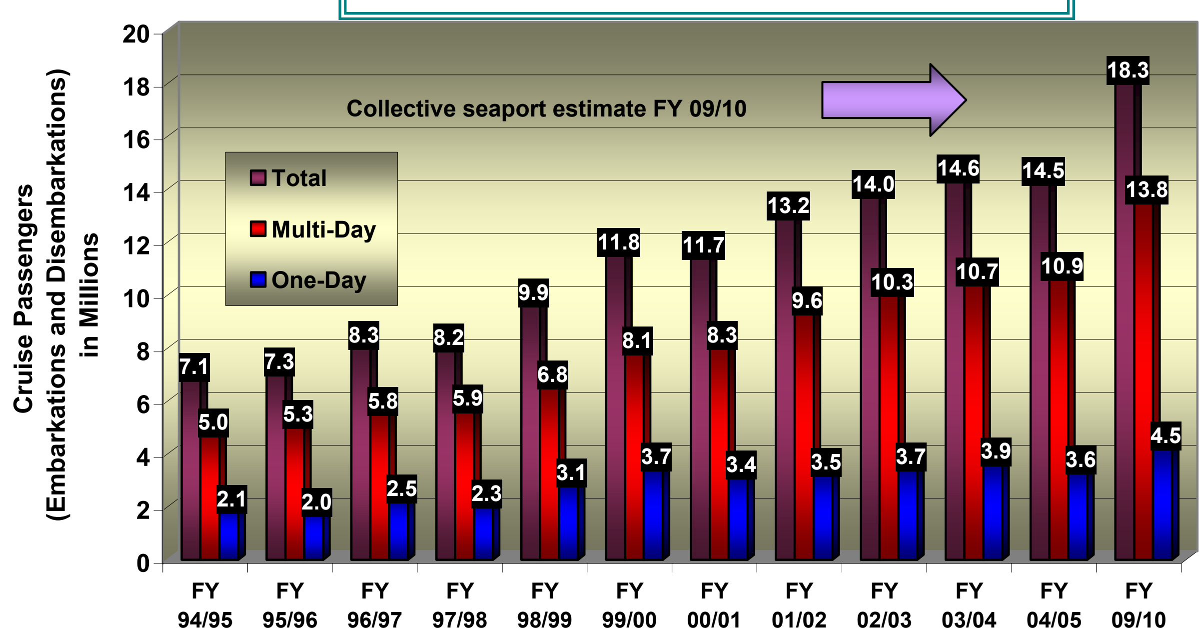
Table 15: Cruise Activities at Florida Seaports*
FY 04/05 (with FY 03/04 Comparison)
Embarkations and Disembarkations

Port	One-Day Cruise	Multi-Day Cruise	Total FY 04/05	Total FY 03/04
Canaveral	1,859,108	2,529,743	4,388,851	4,586,230
Everglades	1,113,686	2,687,778	3,801,464	4,075,406
Fernandina**	0	220	220	217
Jacksonville	0	275,123	275,123	170,708
Key West**	0	1,012,978	1,012,978	1,012,790
Miami	0	3,605,201	3,605,201	3,499,584
Palm Beach**	553,692	0	553,692	540,344
St. Petersburg	120,000	0	120,000	25,655
Tampa	0	771,227	771,227	791,772
Total	**3,646,486**	**10,882,270**	**14,528,756**	**14,702,706**

Source: Individual seaport data. *Cruise passengers are counted twice, once when they embark on their cruise and once when they disembark. **Port-of-call for passengers on multi-day cruises. The Key West figure includes 83,188 ferry passengers.

Table 15 shows the passenger movements at Florida's cruise ports in FY 04/05 and compares them with those in FY 03/04. Exhibit 10 shows the history of these movements since FY 94/95.

Exhibit 10: Cruise Passengers at Florida's Seaports



Source: Individual seaport data

The multi-day cruise passenger count at Florida's seaports also reflects the port-of call operations at several ports, including the Port of Key West, which is welcoming ferry passengers from other Florida ports as well as cruise passengers. Key West handles almost 10 percent of the cruise passengers sailing from Florida's home ports and continues to benefit from calls by the larger-capacity cruise ships sailing from the many ports whose itineraries include a stop at this popular and strategically located destination.

As the capital of the North American cruise industry and the corporate home or administrative office for 15 cruise lines, Florida derives substantial economic benefits from the cruise operations at its seaports. These benefits include the direct expenditures of the cruise lines both for administering their operations and for provisioning their ships; the indirect and induced impacts of these expenditures; and local and state tax revenues. A study released in August 2004 confirmed that Florida accounts for two-thirds of all U.S. cruise embarkations. As reported by the International Council of Cruise Lines, the cruise industry generated 130,750 jobs for Florida workers and the state received nearly $4.6 billion in direct spending in 2003, more than two-thirds of the industry's total direct expenditures.

After 9/11, the industry began diversifying its ports-of-call and bringing homeport ships closer to "drive-to" markets. In Florida, Jacksonville, for one, has benefited from this diversification and other Florida ports are hoping to initiate cruise operations in the future.

According to Cruise Lines International Association, the industry is experiencing strong growth and continues to introduce new rounds of ships, among which are ships even larger than those calling at Florida's cruise ports today. As Florida's traditional cruise ports continue to see their operations grow and other ports initiate operations, the state will continue to play a commanding role in this expansion. Again, however, additional capital improvement funding is required for the seaports to build the capacity needed to accommodate the anticipated demand and industry changes.

Geology and Soils	
85	Please provide actual numbers for the percentages discussed in Section 8.2.10.2, Offshore recreational users (p. 28 of Application).
Response	Best estimates place the number of recreational boaters discussed in **Section 8.2.10.2** at 4% based on the following: Port Dolphin is planned to be located approximately 28 miles offshore from Anna Maria. The percentage of recreational boaters whose offshore view could be visually impaired by Port Dolphin is very low. A determination of specific percentages is difficult as there are no publicly published records available that quantify or track recreational boaters. There is currently no capability of tracking commercial, cruise ship, yachts, and research vessel traffic in the Gulf of Mexico. After daily monitoring of vessel traffic on a ship logging website (http://www.sailwx.info) for one week, we found that less than three of these larger types of vessels are logged east of longitude 85.0ºW in the vicinity of Tampa Bay (latitude 26ºN to 29ºN) in the Gulf of Mexico in a 24 hour period. Of the ships observed, all were cruise ships or commercial vessels. An estimate of recreational boaters that may travel offshore into the Gulf of Mexico can be determined based on the following information. As presented in Table 8-2 of Volume II, the total number of pleasure vessels registered in Manatee, Hillsborough, and Pinellas counties in 2005 is 120,808 (http://www.hsmv.state.fl.us.). Of these boaters, the number of registered motorized pleasure vessels Class 1 (16 ft to 25 ft 11 in) and larger (16 ft to > 110 ft) is 62.3%. If canoes, kayaks, small motorless sailboats, and Class 1 vessels are removed from consideration (because it is improbable that they travel more than five miles offshore into the Gulf of Mexico) due to their size, then the percentage of recreational boats (26 ft and larger) most capable of traveling offshore into the Gulf of Mexico drops to only 11.7% of all registered pleasure vessels. Another calculation to determine the potential impact of the proposed port to recreational boaters is to calculate the distance at which Port Dolphin would become visible to boats that do travel offshore into the Gulf of Mexico. Using a mathematical equation where the distance at which an object becomes visible (in nm) is equal to the square root of the height of the object (ft)* 1.17) + (the distance to the horizon); where distance to the horizon (in nm) = 1.17 * the square root of eye height (ft) * 1.17) (http://www.boatsafe.com/tools/scale.htm). Since the 217,000 m^3 SRV is 113.3 ft (34.55 m) in height, then for Port Dolphin, a vessel whose sight of vision lies 5 feet (1.5 m) above the water line, could not see the SRV until they were a distance of 10.6 miles (17.1 km) offshore. If the sight of vision is increased to 20 ft (6.1 m) above the water line, the SRV could be first seen at 7.7 miles (12.3 km) offshore. In addition, a recent study that examined the habits of recreational boaters in the Tampa Bay region (Sidman, et al., 2004) surveyed 1659 Tampa Bay area boaters as to their water use patterns. Of the 2,329 vessels owned by the N=1,659 survey respondents, 47.3% fall into being equipped to go offshore into the Gulf (power boats with cabin accommodations accounted for 24.2%, while open fishing boats accounted for 23.1% of those surveyed (Sidman, et al., 2004). Viewing this survey as a random, yet representative subset of the local boating population, it shows that only a very small number of boaters venture offshore more than a few miles from the Florida coast and into the Gulf of Mexico (**Figure 1**) and primarily for the purpose of scuba diving or fishing.

The graphic in **Figure 2** represents the density of recreational boaters to a distance of approximately 30 miles (48 km) offshore into the Gulf of Mexico. Based on **Figure 2**, it is estimated that less than 5% of all recreational boaters go more than a few miles offshore. Of the 5% going offshore, none would be able to even spot the proposed SRV on buoy until they were approximately 8 to 11 miles offshore from the coast (see calculations above). If the westernmost (left) edge of this plot represents approximately 30 miles offshore (and the approximate location of the proposed Port Dolphin Port), the abundance of vessels going this distance is visually estimated to be less than 2.0% of the total number of recreational boaters. Moving landward to approximately 8 to 11 miles offshore in **Figure 2**, the number of boaters increases by about two additional percent. So, based on this graphic, the estimate is that a maximum of 4% of all recreational boaters going offshore into the Gulf of Mexico, would venture far enough to see the proposed port.

Figure 3 illustrates the top corridors traveled by recreational boaters. Based on this graphic, all of the popular routes lie far from the proposed Port Dolphin (that would fall near the southwest corner of **Figure 3).**

For that small percentage of recreational boaters who do travel offshore into the Gulf of Mexico the obstruction of view the port could cause to them can be calculated. In general, the further away an object is, the smaller it appears. If the angular size of an object at a known distance from that object is calculated, the degree of obstruction to our field of view relative to a circle (360°) is obtained. This angular size can be determined using the relationship where: angular size (in deg) equals the (actual size/(2* pi* distance to the object))*360º (Smithsonian, 2000). In the case of a recreational vessel located approximately 27 miles (43.5 km) offshore and 2789 ft (850 m) away from the SRV (at the edge of the mandatory SRV safety zone), and if it is assumed that the recreational vessel is facing the length of a 820 ft (250 m) SRV, then 19º (out of a 360º view) would be obstructed. If the recreational vessel is 6.2 mi (10 km) away from the SRV, then the angular size drops to only 1.6 º of view being obstructed. At 9.3 mi (15 km), the angular size drops to 1.0º, out of 360º, being obstructed.

Factors that would lessen the visual obstruction must take into account that the SRV's would rotate on a buoy. So the orientation of the vessel relative to the coastline, and thus the size of the obstructed view, is dependent on wind and tide conditions. Rotation of the SRV on buoy, that presents the bow or stern (beam view) of the vessel, translates to an 85% reduction in the total obstructed view compared to vessel length. If the recreational vessel is facing the bow or stern of a 141 ft (43 m) wide SRV, then approximately 2.9º of the view would be obstructed from 2789 ft (850 m) away, while only 0.25 º of the view would be obstructed from 6.2 mi (10 km) away.

The calculations in the preceding paragraphs prove that, once sited, the SRV would distract from only a small fraction of the total view, even when a boater is as close as allowable to the proposed port. The actual percent of horizon obstruction is not only a function of the distance a boat is from the SRV, but needs to consider other variables such as weather and the angle of approach. In addition, factors such as the earth's curvature, cloud cover, meteorological and oceanographic conditions, lighting/hour of the day, and atmospheric refraction will all affect a recreational vessels view of the SRV and increase the distance from which the SRV could

	be seen. Based on this analysis, it is estimated that the percent of recreational boaters that would ever actually see the SRV while on buoy, or whose view might be obstructed is less than 4%. Of this group, less than 1% will venture offshore far enough to have the vessel obscure the maximum possible angular size of 19.0º (out of a 360º view) of their view of the horizon that literally consists of open ocean. REFERENCES http://www.sailwx.info, Ship Tracker, accessed on 8/28/07. http://www.boatsafe.com/tools/scale.htm, Measuring Distance of Object, accessed on 8/28/07. http://www.hsmv.state.fl.us/html/revpub/revpub2004-2005.pdf, Registered Boater Statistics for Florida, accessed on 8/29/07. Sidman, C., T. Fik, and B. Sargent. 2004. A Recreational Boating Characterization for Tampa and Sarasota Bays, Sea Grant TP-130, University of Florida. Smithsonian Astrophysical Observatory, From the Ground Up, 9/2000, http://www.cfa.harvard.edu/webscope/activities/pdfs/measureSize.PDF.

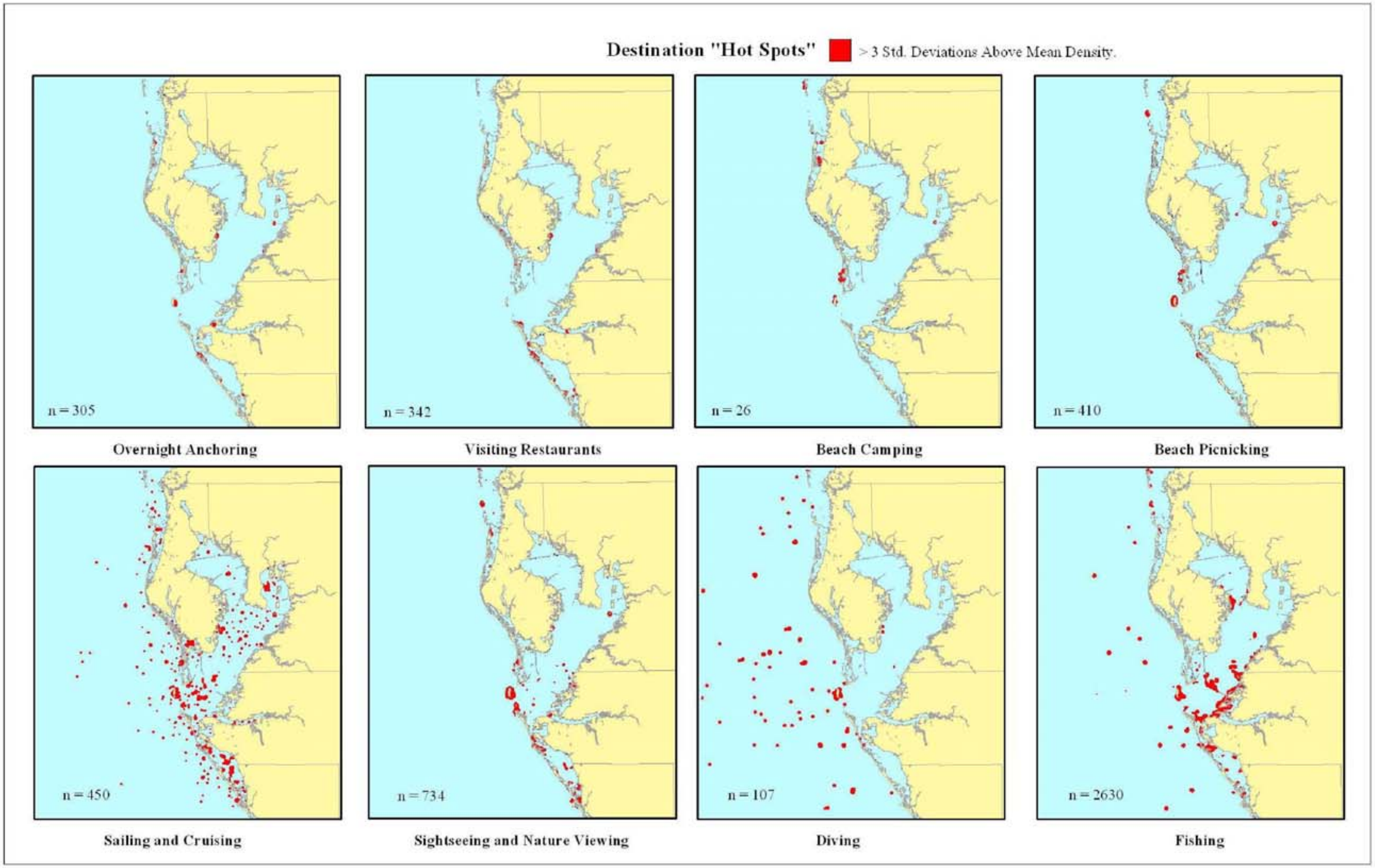


Figure 1. Spatial use patterns of recreational vessels around Tampa Bay **(**Sidman, et al., 2004).

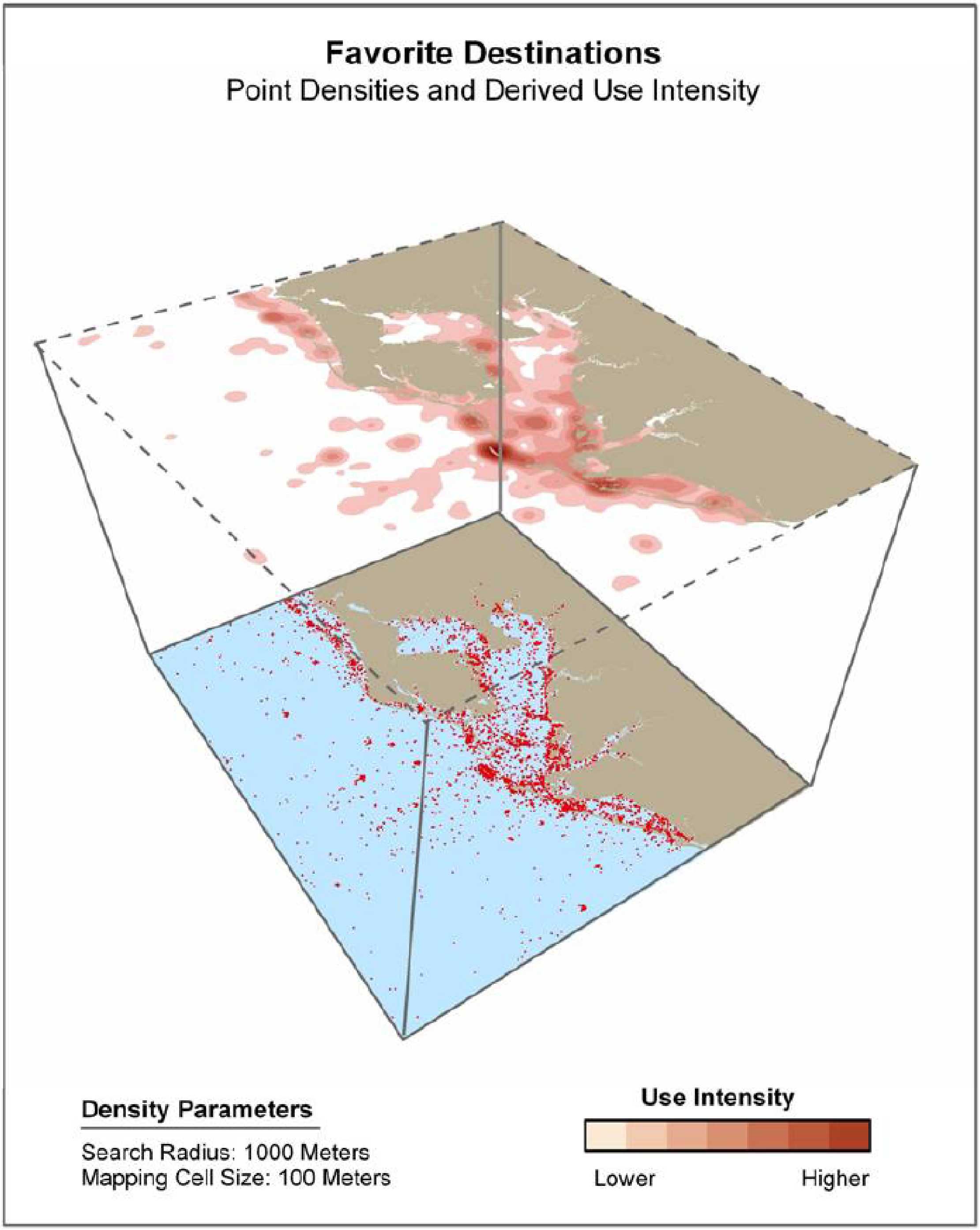


Figure 2. Point densities and derived density use of Tampa Bay recreational boaters (From Sidman, et al., 2004). Here, the lower left corner of the plot represents the approximate location of the proposed SRV site (30 mi offshore). Less than 1% of recreational boaters responding to this survey ventures this far offshore.

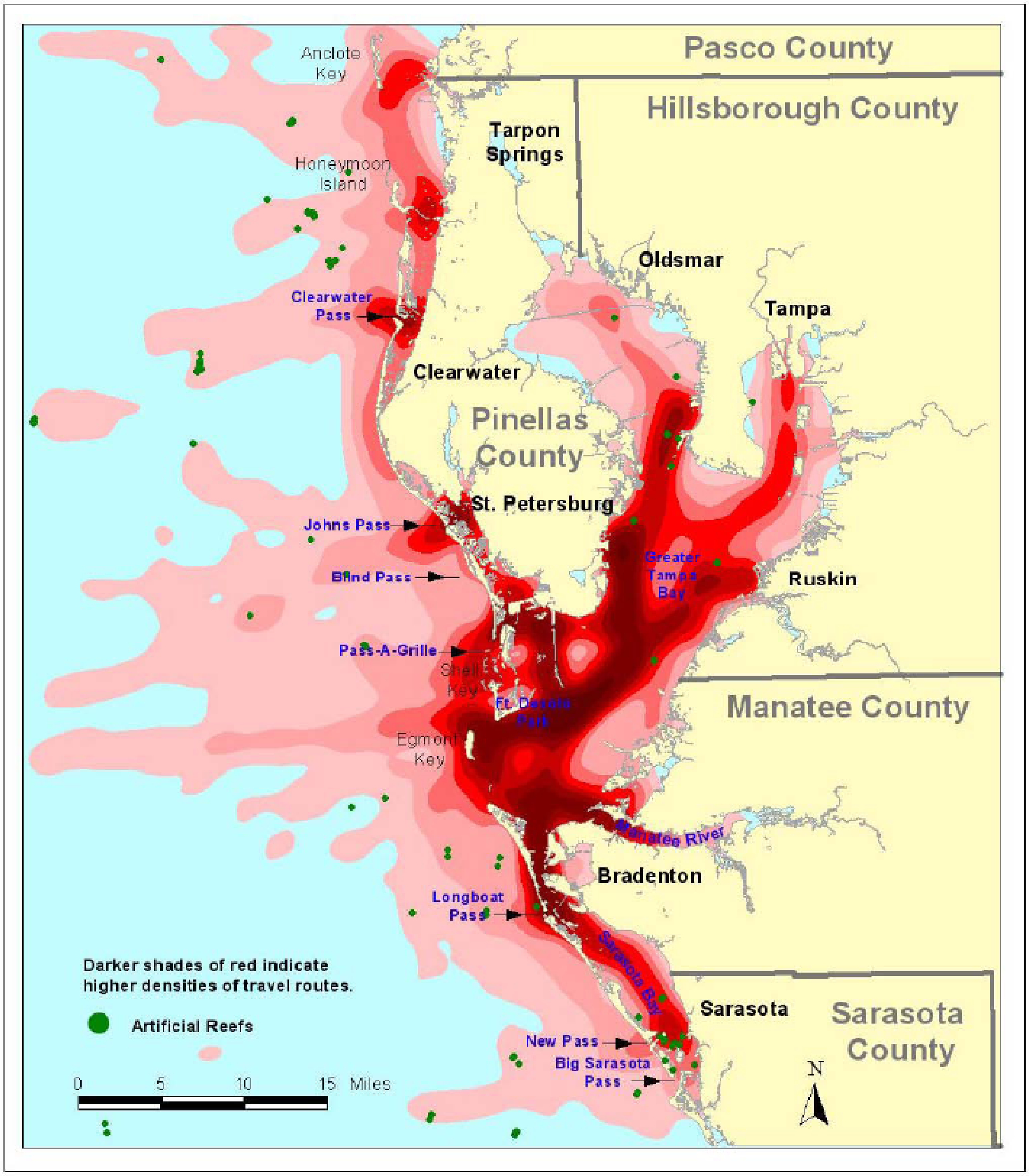


Figure 3. Recreational boaters top traveled corridors. Port Dolphin would lie approximately at the southwest edge of the map, where no recreational boater travel routes are observed (From: Sidman, et al., 2004).

Geology and Soils	
86	Please provide a citation and reference for the SWFWMD report referenced in Section 8.2.9.3 (p. 21of Application).
Response	The reference for the SWFWMD report was provided in Section 13 of Volume II and is: SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT, 1999. *Tampa Bay Surface Water Improvement and Management (SWIM) Plan*, 52-55. 108 pp. It is available at the following website: http://www.swfwmd.state.fl.us/documents/plans/tampabay_1998.pdf

Geology and Soils	
87	Please provide references to support the statement "…rapid re-establishment of mosquito fish populations is expected…" (p. 34 Terrestrial Piping Section 10.3.1.1).
Response	During the construction activities only the construction corridor of Curiosity Creek would be impacted. If mosquitofish are present in the creek, once the construction activities were competed in that portion of the creek, the hydrologic connection would be restored and the mosquitofish population, if present, would return to the area through the hydrologic connection. Mosquitofish are extremely hardy and survive in a wide range of environments as indicted in the referenced websites. A discussion of *Gambusia affinis* is included at the following websites: http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Gambusia+affinis, http://www.issg.org/database/species/ecology.asp?si=126&fr=1&sts=sss

Geology and Soils	
88	Section 10.3.1.1, "As well, efforts will be made to minimize impacts to the sites." Please provide the mitigation plan or BMP that will be used for this site. Also provide references for successful implementation of a mitigation plan at a similar site.
Response	The site-specific wetland mitigation plan has not been developed to date. The site-specific wetland mitigation plan will be developed in coordination with FDEP during the Environmental Resource Permitting (ERP) process. The FERC *Wetland and Waterbody Construction and Mitigation Procedures* will be modified to cover the site-specific conditions. Attached for your reference are the FERC document and the Gulfstream pipeline mitigation plan that was utilized for the Gulfstream pipeline in the area that was successfully implemented.

WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES

01/17/2003 VERSION

WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES

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WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES (PROCEDURES)

I. APPLICABILITY

A. The intent of these Procedures is to assist applicants by identifying baseline mitigation measures for minimizing the extent and duration of project-related disturbance on wetlands and waterbodies. The project sponsors should specify in their applications for a FERC Certificate (Certificate) any individual measures in these Procedures they consider unnecessary, technically infeasible, or unsuitable due to local conditions and to fully describe any alternative measures they would use. Applicants should also explain how those alternative measures would achieve a comparable level of mitigation.

Once a project is certificated, further changes can be approved. Any such changes from the measures in these Procedures (or the applicant’s approved procedures) will be approved by the Director of the Office of Energy Projects (Director), upon the applicant’s written request, if the Director agrees that an alternative measure:

1. provides equal or better environmental protection;

2. is necessary because a portion of these Procedures is infeasible or unworkable based on project-specific conditions; or

3. is specifically required in writing by another Federal, state, or Native American land management agency for the portion of the project on its land or under its jurisdiction.

Any requirements in these Procedures to file material with the Secretary of the FERC (Secretary) do not apply to projects undertaken under the provisions of the blanket certificate program. This exemption does not apply to a request for alternative measures.

Project-related impacts on non-wetland areas are addressed in the staff’s Upland Erosion Control, Revegetation, and Maintenance Plan (Plan).

B. DEFINITIONS

1. "Waterbody" includes any natural or artificial stream, river, or drainage with perceptible flow at the time of crossing, and other permanent waterbodies such as ponds and lakes:

   a. "minor waterbody" includes all waterbodies less than or equal to 10 feet wide at the water's edge at the time of crossing;

   b. "intermediate waterbody" includes all waterbodies greater than 10 feet wide but less than or equal to 100 feet wide at the water's edge at the time of crossing; and

   c. "major waterbody" includes all waterbodies greater than 100 feet wide at the water's edge at the time of crossing.

2. "Wetland" includes any area that is not in actively cultivated or rotated cropland and that satisfies the requirements of the current Federal methodology for identifying and delineating wetlands.

II. <u>PRECONSTRUCTION FILING</u>

A. The following information shall be filed with the Secretary prior to the beginning of construction:

1. the hydrostatic testing information specified in section VII.B.3. and a wetland delineation report as described in section VI.A.1., if applicable; and

2. a schedule identifying when trenching or blasting would occur within each waterbody greater than 10 feet wide, or within any designated coldwater fishery. The project sponsor shall revise the schedule as necessary to provide FERC staff at least 14 days advance notice. Changes within this last 14-day period must provide for at least 48 hours advance notice.

B. The following site-specific construction plans required by these Procedures must be filed with the Secretary for the review and written approval by the Director:

1. plans for extra work areas that would be closer than 50 feet from a waterbody or wetland;

2. plans for major waterbody crossings;

3. plans for the use of a construction right-of-way greater than 75 feet wide in wetlands; and

4. plans for horizontal directional drill (HDD) "crossings" of wetlands or waterbodies.

III. ENVIRONMENTAL INSPECTORS

A. At least one Environmental Inspector having knowledge of the wetland and waterbody conditions in the project area is required for each construction spread. The number and experience of Environmental Inspectors assigned to each construction spread should be appropriate for the length of the construction spread and the number/significance of resources affected.

B. The Environmental Inspector's responsibilities are outlined in the Upland Erosion Control, Revegetation, and Maintenance Plan (Plan).

IV. PRECONSTRUCTION PLANNING

A. A copy of the Stormwater Pollution Prevention Plan (SWPPP) prepared for compliance with the U.S. Environmental Protection Agency's (EPA) National Stormwater Program General Permit requirements must be available in the field on each construction spread. The SWPPP shall contain Spill Prevention and Response Procedures that meet the requirements of state and Federal agencies.

1. It shall be the responsibility of the project sponsor and its contractors to structure their operations in a manner that reduces the risk of spills or the accidental exposure of fuels or hazardous materials to waterbodies or wetlands. The project sponsor and its contractors must, at a minimum, ensure that:

a. all employees handling fuels and other hazardous materials are properly trained;

b. all equipment is in good operating order and inspected on a regular basis;

c. fuel trucks transporting fuel to on-site equipment travel only on approved access roads;

d. all equipment is parked overnight and/or fueled at least 100 feet from a waterbody or in an upland area at least 100 feet from a wetland boundary. These activities can occur closer only if the Environmental Inspector finds, in advance, no reasonable alternative and the project sponsor and its contractors have taken appropriate steps (including secondary containment structures) to prevent spills and provide for prompt cleanup in the event of a spill;

e. hazardous materials, including chemicals, fuels, and lubricating oils, are not stored within 100 feet of a wetland, waterbody, or designated municipal watershed area, unless the location is designated for such use by an appropriate governmental authority. This applies to storage of these materials and does not apply to normal operation or use of equipment in these areas; and

f. concrete coating activities are not performed within 100 feet of a wetland or waterbody boundary, unless the location is an existing industrial site designated for such use.

2. The project sponsor and its contractors must structure their operations in a manner that provides for the prompt and effective cleanup of spills of fuel and other hazardous materials. At a minimum, the project sponsor and its contractors must:

   a. ensure that each construction crew (including cleanup crews) has on hand sufficient supplies of absorbent and barrier materials to allow the rapid containment and recovery of spilled materials and knows the procedure for reporting spills;

   b. ensure that each construction crew has on hand sufficient tools and material to stop leaks;

c. know the contact names and telephone numbers for all local, state, and Federal agencies (including, if necessary, the U. S. Coast Guard and the National Response Center) that must be notified of a spill; and

d. follow the requirements of those agencies in cleaning up the spill, in excavating and disposing of soils or other materials contaminated by a spill, and in collecting and disposing of waste generated during spill cleanup.

B. AGENCY COORDINATION

The project sponsor must coordinate with the appropriate local, state, and Federal agencies as outlined in these Procedures and in the Certificate.

V. WATERBODY CROSSINGS

A. NOTIFICATION PROCEDURES AND PERMITS

1. Apply to the U.S. Army Corps of Engineers (COE), or its delegated agency, for the appropriate wetland and waterbody crossing permits.

2. Provide written notification to authorities responsible for potable surface water supply intakes located within 3 miles downstream of the crossing at least 1 week before beginning work in the waterbody, or as otherwise specified by that authority.

3. Apply for state-issued waterbody crossing permits and obtain individual or generic section 401 water quality certification or waiver.

4. Notify appropriate state authorities at least 48 hours before beginning trenching or blasting within the waterbody, or as specified in state permits.

B. INSTALLATION

1. Time Window for Construction

Unless expressly permitted or further restricted by the appropriate state agency in writing on a site-specific basis, instream work, except that required to install or remove equipment bridges, must occur during the following time windows:

a. coldwater fisheries - June 1 through September 30; and

b. coolwater and warmwater fisheries - June 1 through November 30.

2. Extra Work Areas

a. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from water’s edge, except where the adjacent upland consists of actively cultivated or rotated cropland or other disturbed land.

b. The project sponsor shall file with the Secretary for review and written approval by the Director, a site-specific construction plan for each extra work area with a less than 50-foot setback from the water's edge, (except where the adjacent upland consists of actively cultivated or rotated cropland or other disturbed land) and a site-specific explanation of the conditions that will not permit a 50-foot setback.

c. Limit clearing of vegetation between extra work areas and the edge of the waterbody to the certificated construction right-of-way.

d. Limit the size of extra work areas to the minimum needed to construct the waterbody crossing.

3. General Crossing Procedures

a. Comply with the COE, or its delegated agency, permit terms and conditions.

b. Construct crossings as close to perpendicular to the axis of the waterbody channel as engineering and routing conditions permit.

c. If the pipeline parallels a waterbody, attempt to maintain at least 15 feet of undisturbed vegetation between the waterbody (and any adjacent wetland) and the construction right-of-way.

d. Where waterbodies meander or have multiple channels, route the pipeline to minimize the number of waterbody crossings.

e. Maintain adequate flow rates to protect aquatic life, and prevent the interruption of existing downstream uses.

f. Waterbody buffers (extra work area setbacks, refueling restrictions, etc.) must be clearly marked in the field with signs and/or highly visible flagging until construction-related ground disturbing activities are complete.

4. Spoil Pile Placement and Control

a. All spoil from minor and intermediate waterbody crossings, and upland spoil from major waterbody crossings, must be placed in the construction right-of-way at least 10 feet from the water's edge or in additional extra work areas as described in section V.B.2.

b. Use sediment barriers to prevent the flow of spoil or heavily silt-laden water into any waterbody.

5. Equipment Bridges

a. Only clearing equipment and equipment necessary for installation of equipment bridges may cross waterbodies prior to bridge installation. Limit the number of such crossings of each waterbody to one per piece of clearing equipment.

b. Construct equipment bridges to maintain unrestricted flow and to prevent soil from entering the waterbody. Examples of such bridges include:

   (1) equipment pads and culvert(s);
   (2) equipment pads or railroad car bridges without culverts;
   (3) clean rock fill and culvert(s); and
   (4) flexi-float or portable bridges.

   Additional options for equipment bridges may be utilized that achieve the performance objectives noted above. Do not use soil to construct or stabilize equipment bridges.

c. Design and maintain each equipment bridge to withstand and pass the highest flow expected to occur while the bridge is in place. Align culverts to prevent bank erosion or streambed scour. If necessary, install energy dissipating devices downstream of the culverts.

d. Design and maintain equipment bridges to prevent soil from entering the waterbody.

e. Remove equipment bridges as soon as possible after permanent seeding unless the COE, or its delegated agency, authorizes it as a permanent bridge.

f. If there will be more than 1 month between final cleanup and the beginning of permanent seeding and reasonable alternative access to the right-of-way is available, remove equipment bridges as soon as possible after final cleanup.

6. Dry-Ditch Crossing Methods

   a. Unless approved otherwise by the appropriate state agency, install the pipeline using one of the dry-ditch methods outlined below for crossings of waterbodies up to 30 feet wide (at the water's edge at the time of construction) that are state-designated as either coldwater or significant coolwater or warmwater fisheries.

b. Dam and Pump

(1) The dam-and-pump method may be used without prior approval for crossings of waterbodies where pumps can adequately transfer streamflow volumes around the work area, and there are no concerns about sensitive species passage.

(2) Implementation of the dam-and-pump crossing method must meet the following performance criteria:

(i) use sufficient pumps, including on-site backup pumps, to maintain downstream flows;
(ii) construct dams with materials that prevent sediment and other pollutants from entering the waterbody (e.g., sandbags or clean gravel with plastic liner);
(iii) screen pump intakes;
(iv) prevent streambed scour at pump discharge; and
(v) monitor the dam and pumps to ensure proper operation throughout the waterbody crossing.

c. Flume Crossing

The flume crossing method requires implementation of the following steps:

(1) install flume pipe after blasting (if necessary), but before any trenching;

(2) use sand bag or sand bag and plastic sheeting diversion structure or equivalent to develop an effective seal and to divert stream flow through the flume pipe (some modifications to the stream bottom may be required in to achieve an effective seal);

(3) properly align flume pipe(s) to prevent bank erosion and streambed scour;

(4) do not remove flume pipe during trenching, pipelaying, or backfilling activities, or initial streambed restoration efforts; and

(5) remove all flume pipes and dams that are not also part of the equipment bridge as soon as final cleanup of the stream bed and bank is complete.

d. Horizontal Directional Drill (HDD)

To the extent they were not provided as part of the pre-certification process, for each waterbody or wetland that would be crossed using the HDD method, provide a plan that includes:

(1) site-specific construction diagrams that show the location of mud pits, pipe assembly areas, and all areas to be disturbed or cleared for construction;

(2) a description of how an inadvertent release of drilling mud would be contained and cleaned up; and

(3) a contingency plan for crossing the waterbody or wetland in the event the directional drill is unsuccessful and how the abandoned drill hole would be sealed, if necessary.

7. Crossings of Minor Waterbodies

Where a dry-ditch crossing is not required, minor waterbodies may be crossed using the open-cut crossing method, with the following restrictions:

a. except for blasting and other rock breaking measures, complete instream construction activities (including trenching, pipe installation, backfill, and restoration of the streambed contours) within 24 hours. Streambanks and unconsolidated streambeds may require additional restoration after this period;

b. limit use of equipment operating in the waterbody to that needed to construct the crossing; and

c. equipment bridges are not required at minor waterbodies that do not have a state-designated fishery classification (e.g., agricultural or intermittent drainage ditches). However, if an equipment bridge is used it must be constructed as described in section V.B.5.

8. Crossings of Intermediate Waterbodies

Where a dry-ditch crossing is not required, intermediate waterbodies may be crossed using the open-cut crossing method, with the following restrictions:

a. complete instream construction activities (not including blasting and other rock breaking measures) within 48 hours, unless site-specific conditions make completion within 48 hours infeasible;

b. limit use of equipment operating in the waterbody to that needed to construct the crossing; and

c. all other construction equipment must cross on an equipment bridge as specified in section V.B.5.

9. Crossings of Major Waterbodies

Before construction, the project sponsor shall file with the Secretary for the review and written approval by the Director a detailed, site-specific construction plan and scaled drawings identifying all areas to be disturbed by construction for each major waterbody crossing (the scaled drawings are not required for any offshore portions of pipeline projects). This plan should be developed in consultation with the appropriate state and Federal agencies and should include extra work areas, spoil storage areas, sediment control structures, etc., as well as mitigation for navigational issues.

The Environmental Inspector may adjust the final placement of the erosion and sediment control structures in the field to maximize effectiveness.

10. Temporary Erosion and Sediment Control

Install sediment barriers (as defined in section IV.F.2.a. of the Plan) immediately after initial disturbance of the waterbody or adjacent upland. Sediment barriers must be properly maintained throughout construction and reinstalled as necessary (such as after backfilling of the trench) until replaced by permanent erosion controls or restoration of adjacent upland areas is complete. Temporary erosion and sediment control measures are addressed in more detail in the Plan; however, the following specific measures must be implemented at stream crossings:

a. install sediment barriers across the entire construction right-of-way at all waterbody crossings, where necessary to prevent the flow of sediments into the waterbody. In the travel lane, these may consist of removable sediment barriers or driveable berms. Removable sediment barriers can be removed during the construction day, but must be re-installed after construction has stopped for the day and/or when heavy precipitation is imminent;

b. where waterbodies are adjacent to the construction right-of-way, install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the construction right-of-way; and

c. use trench plugs at all waterbody crossings, as necessary, to prevent diversion of water into upland portions of the pipeline trench and to keep any accumulated trench water out of the waterbody.

11. Trench Dewatering

Dewater the trench (either on or off the construction right-of-way) in a manner that does not cause erosion and does not result in heavily silt-laden water flowing into any waterbody. Remove the dewatering structures as soon as possible after the completion of dewatering activities.

C. RESTORATION

1. Use clean gravel or native cobbles for the upper 1 foot of trench backfill in all waterbodies that contain coldwater fisheries.

2. For open-cut crossings, stabilize waterbody banks and install temporary sediment barriers within 24 hours of completing instream construction activities. For dry-ditch crossings, complete streambed and bank stabilization before returning flow to the waterbody channel.

3. Return all waterbody banks to preconstruction contours or to a stable angle of repose as approved by the Environmental Inspector.

4. Application of riprap for bank stabilization must comply with COE, or its delegated agency, permit terms and conditions.

5. Unless otherwise specified by state permit, limit the use of riprap to areas where flow conditions preclude effective vegetative stabilization techniques such as seeding and erosion control fabric.

6. Revegetate disturbed riparian areas with conservation grasses and legumes or native plant species, preferably woody species.

7. Install a permanent slope breaker across the construction right-of-way at the base of slopes greater than 5 percent that are less than 50 feet from the waterbody, or as needed to prevent sediment transport into the waterbody. In addition, install sediment barriers as outlined in the Plan.
   In some areas, with the approval of the Environmental Inspector, an earthen berm may be suitable as a sediment barrier adjacent to the waterbody.

8. Sections V.C.3. through V.C.6. above also apply to those perennial or intermittent streams not flowing at the time of construction.

D. POST-CONSTRUCTION MAINTENANCE

1. Limit vegetation maintenance adjacent to waterbodies to allow a riparian strip at least 25 feet wide, as measured from the waterbody's mean high water mark, to permanently revegetate with native plant species across the entire construction right-of-way. However, to facilitate periodic pipeline corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be maintained in a herbaceous state. In addition, trees that are located within 15 feet of the pipeline that are greater than 15 feet in height may be cut and removed from the permanent right-of-way.

2. Do not use herbicides or pesticides in or within 100 feet of a waterbody except as allowed by the appropriate land management or state agency.

VI. WETLAND CROSSINGS

A. GENERAL

1. The project sponsor shall conduct a wetland delineation using the current Federal methodology and file a wetland delineation report with the Secretary before construction. This report shall identify:

   a. by milepost all wetlands that would be affected;

   b. the National Wetlands Inventory (NWI) classification for each wetland;

   c. the crossing length of each wetland in feet; and

   d. the area of permanent and temporary disturbance that would occur in each wetland by NWI classification type.

   The requirements outlined in this section do not apply to wetlands in actively cultivated or rotated cropland. Standard upland protective measures, including workspace and topsoiling requirements, apply to these agricultural wetlands.

2. Route the pipeline to avoid wetland areas to the maximum extent possible. If a wetland cannot be avoided or crossed by following an existing right-of-way, route the new pipeline in a manner that minimizes disturbance to wetlands. Where looping an existing pipeline, overlap the existing pipeline right-of-way with the new construction right-of-way. In addition, locate the loop line no more than 25 feet away from the existing pipeline unless site-specific constraints would adversely affect the stability of the existing pipeline.

3. Limit the width of the construction right-of-way to 75 feet or less. Prior written approval of the Director is required where topographic conditions or soil limitations require that the construction right-of-way width within the boundaries of a federally delineated wetland be expanded beyond 75 feet. Early in the planning process the project sponsor is encouraged to identify site-specific areas where existing soils lack adequate unconfined compressive strength that would result in excessively wide ditches and/or difficult to contain spoil piles.

4. Wetland boundaries and buffers must be clearly marked in the field with signs and/or highly visible flagging until construction-related ground disturbing activities are complete.

5. Implement the measures of sections V. <u>and</u> VI. in the event a waterbody crossing is located within or adjacent to a wetland crossing. If all measures of sections V. and VI. cannot be met, the project sponsor must file with the Secretary a site-specific crossing plan for review and written approval by the Director before construction. This crossing plan shall address at a minimum:

    a. spoil control;

    b. equipment bridges;

    c. restoration of waterbody banks and wetland hydrology;

    d. timing of the waterbody crossing;

e. method of crossing; and

f. size and location of all extra work areas.

6. Do not locate aboveground facilities in any wetland, except where the location of such facilities outside of wetlands would prohibit compliance with U.S. Department of Transportation regulations.

B. INSTALLATION

1. Extra Work Areas and Access Roads

a. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries, except where the adjacent upland consists of actively cultivated or rotated cropland or other disturbed land.

b. The project sponsor shall file with the Secretary for review and written approval by the Director, a site-specific construction plan for each extra work area with a less than 50-foot setback from wetland boundaries (except where adjacent upland consists of actively cultivated or rotated cropland or other disturbed land) and a site-specific explanation of the conditions that will not permit a 50-foot setback.

c. Limit clearing of vegetation between extra work areas and the edge of the wetland to the certificated construction right-of-way.

d. The construction right-of-way may be used for access when the wetland soil is firm enough to avoid rutting or the construction right-of-way has been appropriately stabilized to avoid rutting (e.g., with timber riprap, prefabricated equipment mats, or terra mats).

In wetlands that cannot be appropriately stabilized, all construction equipment other than that needed to install the wetland crossing shall use access roads located in upland areas. Where access roads in upland areas do not provide reasonable access, limit all other construction equipment to one pass through the wetland using the construction right-of-way.

e. The only access roads, other than the construction right-of-way, that can be used in wetlands without Director approval, are those existing roads that can be used with no modification and no impact on the wetland.

2. Crossing Procedures

a. Comply with COE, or its delegated agency, permit terms and conditions

b. Assemble the pipeline in an upland area unless the wetland is dry enough to adequately support skids and pipe.

c. Use "push-pull" or "float" techniques to place the pipe in the trench where water and other site conditions allow.

d. Minimize the length of time that topsoil is segregated and the trench is open.

e. Limit construction equipment operating in wetland areas to that needed to clear the construction right-of-way, dig the trench, fabricate and install the pipeline, backfill the trench, and restore the construction right-of-way.

f. Cut vegetation just aboveground level, leaving existing root systems in place, and remove it from the wetland for disposal.

g. Limit pulling of tree stumps and grading activities to directly over the trenchline. Do not grade or remove stumps or root systems from the rest of the construction right-of-way in wetlands unless the Chief Inspector and Environmental Inspector determine that safety-related construction constraints require grading or the removal of tree stumps from under the working side of the construction right-of-way.

h. Segregate the top 1 foot of topsoil from the area disturbed by trenching, except in areas where standing water is present or soils are saturated or frozen. Immediately after backfilling is complete, restore the segregated topsoil to its original location.

i. Do not use rock, soil imported from outside the wetland, tree stumps, or brush riprap to support equipment on the construction right-of-way.

j. If standing water or saturated soils are present, or if construction equipment causes ruts or mixing of the topsoil and subsoil in wetlands, use low-ground-weight construction equipment, or operate normal equipment on timber riprap, prefabricated equipment mats, or terra mats.

k. Do not cut trees outside of the approved construction work area to obtain timber for riprap or equipment mats.

l. Attempt to use no more than two layers of timber riprap to support equipment on the construction right-of-way.

m. Remove all project-related material used to support equipment on the construction right-of-way upon completion of construction.

3. Temporary Sediment Control

Install sediment barriers (as defined in section IV.F.2.a. of the Plan) immediately after initial disturbance of the wetland or adjacent upland. Sediment barriers must be properly maintained throughout construction and reinstalled as necessary (such as after backfilling of the trench). Except as noted below in section VI.B.3.c., maintain sediment barriers until replaced by permanent erosion controls or restoration of adjacent upland areas is complete. Temporary erosion and sediment control measures are addressed in more detail in the Plan.

a. Install sediment barriers across the entire construction right-of-way at all wetland crossings where necessary to prevent sediment flow into the wetland. In the travel lane, these may consist of removable sediment barriers or driveable berms. Removable sediment barriers can be removed during the construction day, but must be re-installed after construction has stopped for the day and/or when heavy precipitation is imminent

b. Where wetlands are adjacent to the construction right-of-way and the right-of-way slopes toward the wetland, install sediment barriers along the edge of the construction right-of-way as necessary to prevent sediment flow into the wetland.

c. Install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the construction right-of-way through wetlands. Remove these sediment barriers during right-of-way cleanup.

4. Trench Dewatering

Dewater the trench (either on or off the construction right-of-way) in a manner that does not cause erosion and does not result in heavily silt-laden water flowing into any wetland. Remove the dewatering structures as soon as possible after the completion of dewatering activities.

C. RESTORATION

1. Where the pipeline trench may drain a wetland, construct trench breakers and/or seal the trench bottom as necessary to maintain the original wetland hydrology.

2. For each wetland crossed, install a trench breaker at the base of slopes near the boundary between the wetland and adjacent upland areas. Install a permanent slope breaker across the construction right-of-way at the base of a slopes greater than 5 percent where the base of the slope is less than 50 feet from the wetland, or as needed to prevent sediment transport into the wetland. In addition, install sediment barriers as outlined in the Plan. In some areas, with the approval of the Environmental Inspector, an earthen berm may be suitable as a sediment barrier adjacent to the wetland.

3. Do not use fertilizer, lime, or mulch unless required in writing by the appropriate land management or state agency.

4. Consult with the appropriate land management or state agency to develop a project-specific wetland restoration plan. The restoration plan should include measures for re-establishing herbaceous and/or woody species, controlling the invasion and spread of undesirable exotic species (e.g., purple loosestrife and phragmites), and monitoring the success of the revegetation and weed control efforts. Provide this plan to the FERC staff upon request.

5. Until a project-specific wetland restoration plan is developed and/or implemented, temporarily revegetate the construction right-of-way with annual ryegrass at a rate of 40 pounds/acre (unless standing water is present).

6. Ensure that all disturbed areas successfully revegetate with wetland herbaceous and/or woody plant species.

7. Remove temporary sediment barriers located at the boundary between wetland and adjacent upland areas after upland revegetation and stabilization of adjacent upland areas are judged to be successful as specified in section VII.A.5. of the Plan.

D. POST-CONSTRUCTION MAINTENANCE

1. Do not conduct vegetation maintenance over the full width of the permanent right-of-way in wetlands. However, to facilitate periodic pipeline corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be maintained in a herbaceous state. In addition, trees within 15 feet of the pipeline that are greater than 15 feet in height may be selectively cut and removed from the permanent right-of-way.

2. Do not use herbicides or pesticides in or within 100 feet of a wetland, except as allowed by the appropriate land management agency or state agency.

3. Monitor and record the success of wetland revegetation annually for the first 3 years after construction or until wetland revegetation is successful. At the end of 3 years after construction, file a report with the Secretary identifying the status of the wetland revegetation efforts. Include the percent cover achieved and problem areas (weed invasion issues, poor revegetation, etc.). Continue to file a report annually until wetland revegetation is successful.

4. Wetland revegetation shall 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. If revegetation is not successful at the end of 3 years, develop and implement (in consultation with a professional wetland ecologist) a remedial revegetation plan to actively revegetate the wetland. Continue revegetation efforts until wetland revegetation is successful.

VII. HYDROSTATIC TESTING

A. NOTIFICATION PROCEDURES AND PERMITS

1. Apply for state-issued water withdrawal permits, as required.

2. Apply for National Pollutant Discharge Elimination System (NPDES) or state-issued discharge permits, as required.

3. Notify appropriate state agencies of intent to use specific sources at least 48 hours before testing activities unless they waive this requirement in writing.

B. GENERAL

1. Perform non-destructive testing of all pipeline section welds or hydrotest the pipeline sections, before installation under waterbodies or wetlands.

2. If pumps used for hydrostatic testing are within 100 feet of any waterbody or wetland, address the operation and refueling of these pumps in the project’s Spill Prevention and Response Procedures.

3. The project sponsor shall file with the Secretary before construction a list identifying the location of all waterbodies proposed for use as a hydrostatic test water source or discharge location.

C. INTAKE SOURCE AND RATE

1. Screen the intake hose to prevent entrainment of fish.

2. Do not use state-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, unless appropriate Federal, state, and/or local permitting agencies grant written permission.

3. Maintain adequate flow rates to protect aquatic life, provide for all waterbody uses, and provide for downstream withdrawals of water by existing users.

4. Locate hydrostatic test manifolds outside wetlands and riparian areas to the maximum extent practicable.

D. DISCHARGE LOCATION, METHOD, AND RATE

1. Regulate discharge rate, use energy dissipation device(s), and install sediment barriers, as necessary, to prevent erosion, streambed scour, suspension of sediments, or excessive streamflow.

2. Do not discharge into state-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, unless appropriate Federal, state, and local permitting agencies grant written permission.

APPENDIX D

GULFSTREAM'S MODIFIED FERC WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES

GULFSTREAM'S MODIFIED FERC
WETLAND AND WATERBODY CONSTRUCTION AND
MITIGATION PROCEDURES

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WETLAND AND WATERBODY CONSTRUCTION
AND MITIGATION PROCEDURES (PROCEDURES)

I. <u>APPLICABILITY</u>

A. These Procedures apply to all natural gas construction projects where they are imposed by the Commission or agreed to by Gulfstream and shall be used for all wetlands and waterbodies affected by a project. Deviations that involve measures different from those contained in these Procedures will only be permitted as certificated by the Commission or by written approval of the Director of the Office of Energy Projects (OEP), or his/her designee, unless specifically required in writing by another Federal, state, or Native American land management agency for the portion of the project on its land. Gulfstream shall file other agency requirements with the Secretary of the Commission (Secretary) before construction.

Gulfstream has prepared exceptions to portions of these procedures and noted them in the text. The exception arguments are attached to these procedures.

B. The intent of these Procedures is to minimize the extent and duration of project-related disturbance of wetlands and waterbodies. Any project-related ground disturbance (including erosion) inside or outside of the certificated areas is subject to compliance with all applicable survey and mitigation requirements.

C. DEFINITIONS

1. "waterbody" includes any natural or artificial stream, river, or drainage with perceptible flow at the time of crossing, and other permanent waterbodies such as ponds and lakes:

a. "minor waterbody" includes all waterbodies less than or equal to 10 feet wide at the water's edge at the time of construction;

b. "intermediate waterbody" includes all waterbodies greater than 10 feet wide but less than or equal to 100 feet wide at the water's edge at the time of construction;

c. "major waterbody" includes all waterbodies greater than 100 feet wide at the water's edge at the time of construction.

2. "wetland" includes any area that satisfies the requirements of the current Federal and FLDEP methodology for identifying and delineating wetlands.

II. <u>PRECONSTRUCTION FILING</u>

A. Gulfstream shall file with the Secretary before construction the hydrostatic testing information specified in section VII.B.3. and a wetland delineation report as described in section VI.B.1., if applicable.

B. Gulfstream shall file with the Secretary site-specific construction plans prepared to comply with sections V.B.2.c., V.B.6.c., V.B.9.b., VI.B.4., and VI.C.1.b. for review and written approval by the Director of OEP before construction.

C. Before construction begins on a project that will disturb more than 5 acres of land, Gulfstream shall file with the Secretary a copy of its Stormwater Pollution Prevention Plan prepared for compliance with the U.S. Environmental Protection Agency's (EPA) National Stormwater Program General Permit requirements. This plan must be available in the field on each construction spread and shall include a Spill Prevention, Containment, and Countermeasure Plan (see section IV.A.).

D. Gulfstream shall prepare a schedule identifying when trenching or blasting would occur within each waterbody greater than 10 feet wide, or within any coldwater fishery. Gulfstream shall file the schedule with the Secretary within 30 days of the acceptance of the certificate and revise it as necessary to provide at least 14 days advance notice. Changes within this last 14-day period must provide for at least 48 hours advance notice.

III. <u>ENVIRONMENTAL INSPECTORS</u>

A. At least one Environmental Inspector having knowledge of the wetland and waterbody conditions in the project area is required for each construction spread.

B. The Environmental Inspector's responsibilities are outlined in the Upland Erosion Control, Revegetation, and Maintenance Plan (Plan).

IV. <u>PRECONSTRUCTION PLANNING</u>

A. SPILL PREVENTION, CONTAINMENT, AND COUNTERMEASURE (SPCC) PLAN

Prepare a SPCC Plan that, at a minimum:

1. Identifies typical fuel, lubricants, and hazardous materials stored or used in the project area, and the location, quantity, and method of storage;

2. Describes the preventive and mitigative measures to avoid or minimize impacts of spills of fuel, lubricants, or hazardous materials, especially within any municipal watershed area or within 100 feet of any waterbody or wetland;

3. Requires fueling and lubricating to be done in areas designated for such purposes and specifies measures to avoid or minimize spills when construction equipment (such as pontoon-mounted backhoes and pumps) will be refueled in or within 100 feet of any waterbody or wetland;

4. Identifies emergency notification procedures in the event of a spill;

5. Requires each construction crew to have sufficient supplies of absorbent and barrier materials on-hand to allow the rapid containment and recovery of any spills;

6. Includes procedures for collection and disposal of waste generated during spill cleanup or equipment maintenance;

7. Includes procedures regarding excavation and disposal of any soil or materials contaminated by a spill; and

8. Identifies names and telephone numbers of all state agencies and individuals that will be contacted in the event of a spill.

B. AGENCY COORDINATION

Coordinate with the appropriate agencies as specified in sections V.A., VI.A., VI.D.4., VI.D.5.c., VI.D.7., and VII.A.

V. WATERBODY CROSSINGS

A. NOTIFICATION PROCEDURES AND PERMITS

1. Provide written notification to the U.S. Army Corps of Engineers (COE), FLDEP, ALDCNR and MSDWFP of the proposed construction activities.

2. Provide written notification to authorities responsible for potable surface water supply intakes located within 3 miles downstream of the crossing at least 1 week before beginning work in the waterbody.

3. Apply for state-issued waterbody crossing permits and obtain individual or generic section 401 water quality certification or waiver.

4. Notify state authorities that request such notification at least 48 hours before beginning trenching or blasting within the waterbody.

B. INSTALLATION

1. Time Window for Construction

   Unless expressly permitted or further restricted by the appropriate state agency in writing on a site-specific basis, crossings must be constructed during the following time windows:

   a. Coldwater Fisheries *(None in Project Area)*

   b. Coolwater and Warmwater Fisheries considered significant fisheries *(None in project area).*

2. Extra Work Areas

   a. Access roads across a waterbody must use an equipment bridge as specified in section V.B.5.*except as noted in V.B.7.b.*

   b. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from waterbody boundaries, where topographic conditions permit. If topographic conditions do not permit a 50-foot setback, these areas must be located at least 10 feet from the water's edge. *This condition is applicable only when the full construction right-of-way, (110 feet for 30 to 36 inch pipe, 95 feet for 24 inch pipe and 80 feet* *for16-inch pipe) as a minimum, is available to the waterbody boundaries. Where the working right-of-way is reduced due to wetland restrictions, extra workspace will be required within 10 feet of the waterbody boundary for spoil storage and/or staging. Additionally, where the 50 foot setback comprises cultivated land or non-woody vegetation, the setback can be reduced to 10 feet.*

c. Gulfstream shall file with the Secretary for review and written approval by the Director of OEP before construction site-specific construction plans for those extra work areas with a less than 50-foot setback from waterbody boundaries and a site-specific explanation of the conditions that will not permit a 50-foot setback.

d. Limit clearing of vegetation between extra work areas and the edge of the waterbody to the certificated construction right-of-way.

e. Limit the size of extra work areas to the minimum needed to construct the waterbody crossing.

3. General Crossing Procedures

a. Comply with section 404 nationwide permit program terms and conditions (33 CFR Part 330) and FLDEP permit conditions.

b. Construct crossings as close to perpendicular to the axis of the waterbody channel as engineering and routing conditions permit.

c. If the pipeline parallels a waterbody, attempt to maintain at least 15 feet of undisturbed vegetation between the waterbody and the right-of-way except at the crossing location.

d. Where waterbodies meander or have multiple channels, route the pipeline to minimize the number of waterbody crossings.

e. Maintain adequate flow rates to protect aquatic life, and prevent the interruption of existing downstream uses.

f. Do not store hazardous materials, chemicals, fuels, lubricating oils, within 100 feet of any waterbody or within any designated municipal watershed area (except at locations designated for these purposes by an appropriate governmental authority).

g. Attempt to refuel all construction equipment at least 100 feet from any waterbody. If construction equipment must be refueled within 100 feet of a waterbody, follow the procedures outlined in the project-specific SPCC Plan. See section IV.A.

4. Spoil Pile Placement and Control

   a. All spoil from minor and intermediate waterbody crossings *less than 50 feet in width,* and upland spoil from major waterbody crossings, must be placed in the construction right-of-way at least 10 feet from the water's edge or in additional extra work areas as described in section V.B.2.b .

   b. Use sediment barriers to prevent the flow of spoil into any waterbody.

5. Equipment Bridges

   a. Only clearing equipment may cross waterbodies before installation of equipment bridges. Limit the number of such crossings of each waterbody to one per piece of equipment.

   b. Construct equipment bridges using one of the following methods

      (1) equipment pads and culvert(s) *where culverts are necessary to support the equipment pads;*
      (2) clean rockfill, *timber rip rap, and/or sand bags* and culvert(s);
      (3) *Salvaged flat bed rail cars or equivalent, or*
      (4) flexi-float or portable bridges.

      Do not use soil to construct or stabilize equipment bridges.

   c. Design and maintain each equipment bridge to *accommodate the highest flow reasonably expected to occur while the bridge is in place as determined by historical records for the expected construction period or by an engineer in consultation with applicable state agencies and the USCOE.*

   d. Maintain equipment bridges to prevent soil from entering the waterbody.

   e. Remove equipment bridges as soon as possible after permanent seeding unless the COE and/or FLDEP authorize it as a permanent bridge.

   f. If there will be more than 1 month between final cleanup and the beginning of permanent seeding and reasonable alternative access to the right-of-way is available, remove equipment bridges as soon as possible after final cleanup.

6. Dam-and-Pump

   a. The dam-and-pump method may be used without prior approval for crossings of minor waterbodies where fluming is not required by these procedures.

   b. Prior written approval from the Director of OEP is required to dam-and-pump where:

      (1) fluming is required by these Procedures; or
      (2) the waterbody is greater than 10 feet wide.

c. To request approval to use the dam-and-pump method, Gulfstream shall file with the Secretary a project-specific plan for review and written approval by the Director of OEP before construction. This plan must list all waterbodies where the dam-and-pump method would be used and describe all measures that would be used to maintain downstream flows, including:

(1) number and capacity of active pumps;
(2) number and capacity of backup pumps;
(3) the types of dams to be used up- and downstream of the crossing;
(4) how streambed scour would be prevented at the pump discharge; and
(5) how the operation would be monitored if the crossing is prolonged beyond one normal construction day.

7. Crossings of Minor Waterbodies

For crossings of all state-designated fisheries, all construction equipment must cross the waterbody on an equipment bridge as specified in section V.B.5.

b. Equipment bridges are not required at minor waterbodies that do not have a state-designated fishery classification (for example, agricultural or intermittent drainage ditches). *Gulfstream may install timber mats or similar support to stabilize the channel bottom at the point of crossing.*

c. For crossings of all coldwater fisheries, and all coolwater and warmwater fisheries considered significant by the state, route waterbody flow across the trench using a flume pipe, and install the pipeline using all of the following "dry-ditch" techniques:

(1) install flume pipe after blasting, but before trenching;
(2) use sand bag or sand bag and plastic sheeting diversion structure, or equivalent;
(3) properly align flume pipe;
(4) do not remove flume pipe during trenching, pipelaying, or backfilling activities; and
(5) remove all flume pipes and dams that are not also part of the equipment after final cleanup but before permanent seeding.

This requirement is only applicable where the topography allows the use of a pipe string which can be manipulated under the installed flumes and to streams where the monthly mean flow can be accommodated by 42- inch flume pipes based on inlet control and a safety factor of 1.3.

d. For minor waterbody crossings not covered by section V.7.c., complete construction in the waterbody (not including blasting) within 24 hours. Limit use of equipment operating in the waterbody to that needed to construct the crossing.

8. Crossings of Intermediate Waterbodies

   a. Limit use of equipment operating in the waterbody to that needed to construct the crossing.

   b. All other construction equipment must cross on an equipment bridge as specified in section V.B.5.

   c. Attempt to complete trenching and backfill work within the waterbody (not including blasting) within 48 hours, unless site-specific conditions make completion within 48 hours infeasible.

9. Crossings of Major Waterbodies

   a. All major waterbody crossings must be constructed in accordance with the measures contained in these Procedures to the maximum extent practicable.

   b. Gulfstream shall develop and file with the Secretary detailed, site-specific construction procedures (including scaled drawings identifying all areas to be disturbed by construction) for each major waterbody crossing, as defined in section I.C.1.c. for review and written approval by the Director of OEP before construction. This requirement does not apply to offshore pipeline construction.

10. Temporary Erosion and Sediment Control

    Install sediment barriers (as defined in section V.F.2.a. of the plan) immediately after initial disturbance of the waterbody or adjacent upland. Sediment barriers must be properly maintained throughout construction and reinstalled as necessary (such as after backfilling of the trench) until replaced by permanent erosion controls or restoration or of adjacent upland areas is complete. Temporary erosion and sediment control measures are addressed in more detail in the Plan.

    a. Install sediment barriers across the entire construction right-of-way at all waterbody crossings *with provisions to access any equipment bridges present.*

    b. Where waterbodies are adjacent to the construction right-of-way, install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the right-of-way.

    c. Use trench plugs at all non-flumed waterbody crossings to prevent diversion of water into upland portions of the pipeline trench and to keep any accumulated trench water out of the waterbody. Trench plugs must be of sufficient size to withstand upslope water pressure.

11. Trench Dewatering

    Dewater trench in such a manner that no heavily silt-laden water flows into any waterbody.

C. RESTORATION

1. Use clean gravel or native cobbles for the upper 1 foot of trench backfill in all waterbodies that contain coldwater fisheries *and where similar materials are naturally present at the crossing location* .

2. Stabilize waterbody banks and install temporary sediment barriers within 24 hours of completing the crossing. For dry ditch crossings, complete bank stabilization before returning flow to the waterbody channel.

3. Return all waterbody banks to preconstruction contours *or to a stable configuration when the pre-construction contour was deemed unstable by an engineer or similarly qualified personnel.*

4. Application of riprap must comply with section 404 nationwide permit program terms and conditions (33 CFR Part 330) and FLDEP permit conditions.

5. Unless otherwise specified by state permit, limit the use of riprap to areas where flow conditions preclude effective vegetative stabilization techniques such as *flexible channel liners.*

6. Revegetate disturbed riparian areas with conservation grasses and legumes or native plant species, preferably woody species.

7. Remove all temporary sediment barriers when restoration of adjacent upland areas is successful as specified in section VIII.A.6. of the Plan.

8. For each waterbody crossed, install a permanent slope breaker and a trench breaker at the base of slopes near the waterbody. Locate the trench breaker immediately upslope of the slope breaker. *This requirement is not applicable where the slope breaker must be installed on cultivated land or where the approach slope does not exceed 10% within 50 feet of the waterbody."*

9. Sections V.C.2. through V.C.7. above also apply to any streams mapped (as perennial or intermittent) on U.S. Geological Survey 7.5-minute topographic quadrangles but not flowing at the time of construction.

D. POST-CONSTRUCTION MAINTENANCE

1. Limit vegetation maintenance adjacent to waterbodies to allow a riparian strip at least 25 feet wide, as measured from the waterbody's mean high water mark, to permanently revegetate with native plant species across the entire right-of-way. However, to facilitate periodic pipeline corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be maintained in a herbaceous state. In addition, trees that are located within 15 feet of the pipeline that are greater than 15 feet in height may be cut and removed from the right-of-way.

2. Do not use herbicides or pesticides in or within 100 feet of a waterbody except as specified by the appropriate land management or state agency.

VI. WETLAND CROSSINGS

A. NOTIFICATION PROCEDURES AND PERMITS

1. Provide written notification to the COE, FLDEP, ALDCNR and MSDWFP concerning the proposed construction activities.

2. Apply for state-issued wetland crossing permit(s) and obtain individual or generic section 401 water quality certification or waiver.

B. GENERAL

1. Gulfstream shall conduct a wetland delineation using the current Federal methodology and meet with the FLDEP, as applicable, and file a wetland delineation report with the Secretary before construction. This report shall identify:

    a. by milepost all federally delineated wetlands that would be affected;

    b. the National Wetlands Inventory (NWI) classification for each wetland;

    c. the crossing length of each wetland in feet; and

    d. the area of permanent and temporary disturbance that would occur in each NWI classification type.

2. Route the pipeline to avoid wetland areas to the maximum extent possible. If a wetland cannot be avoided or crossed by following an existing right-of-way, route the new pipeline in a manner that minimizes disturbance to wetlands. In addition, locate the *new pipeline* no more than *35 to 50 feet* away from the existing pipeline unless site-specific constraints would adversely affect the stability of the existing pipeline.

Gulfstream is proposing the use of three techniques to effect wetland crossings. The three techniques include:

Type I Dry or Moist Wetlands with Low Groundwater Level
Unsaturated or cohesive soils where equipment can traverse the wetland without the support of mats and the trench is stable. Topsoil stripping is possible.

Type II Saturated, Non-Cohesive Soils
Difficult trenching conditions where trench widths for a 36-inch pipeline can readily approach 40 feet in width and supplemental support in the form of timber rip-rap or prefabricated equipment mats is required. Topsoil stripping is impossible due to saturation.

Type III Flooded Wetland
Areas of standing surface water or groundwater at the surface. Supplemental support is required for excavation equipment only. All other equipment must move around. Topsoil stripping is impossible due to the flooded conditions.

Techniques will be selected based on site specific wetland conditions. Workspace requirements within the wetlands for each of the three techniques are as follows:

30 to 36 Inch Pipe

	Workspace	Reason
Type I	110 feet working right-of-way	Lg. Diameter Pipe; topsoil stripping
Type II	110 feet working right-of-way	Lg. Diameter Pipe; wide unstable ditch; large and unstable spoil pile
Type III	75 feet working right-of-way in the wetland with extra workspace required in an adjacent upland area or Type I or II wetland to stage the crossing	Push-Ditch construction, pipe make-up in staging area, general spread access across wetland not needed

24 Inch Pipe

	Workspace	Reason
Type I	95 feet working right-of-way	topsoil stripping, general spread access
Type II	95 feet working right-of-way	wide unstable ditch; large and unstable spoil pile
Type III	75 feet working right-of-way in the wetland with extra workspace required in an adjacent upland area or Type I or II wetland to stage the crossing	Push-Ditch construction, pipe make-up in staging area, general spread access across wetland not needed

16 Inch Pipe

	Work space	Reason
Type I	80 feet working right-of-way	Topsoil stripping, general spread access necessary
Type II	80 feet working right-of-way	Wide unstable ditch; large and unstable spoil pile
Type III	75 feet working right-of-way in the wetland with extra work space required in an adjacent upland area or Type I or II Wetland to stage the crossing	Push-Ditch construction, pipe make-up in staging area, general spread access across wetland not needed.

Figures 1 to 3 present each crossing technique and the required working right-of-way and extra workspace requirements."

Wetland requirements, including work space limitations are not applicable to farmed wetlands which are, or have been, cultivated. For these farmed wetlands, the normal 110 foot working right-of-way width for 30 to 36 inch pipe (95 feet for 24 inch pipe, 80 feet for 16 inch) and normal upland construction with topsoil stripping will be utilized.

3. Implement the provisions of sections V. and VI. in the event a waterbody crossing is located within or adjacent to a wetland crossing. If all provisions of sections V. and VI. cannot be met, Gulfstream must file with the Secretary a site-specific crossing plan for review and written approval by the Director of OEP before construction. This crossing plan shall address at a minimum:

   a. spoil control;

   b. equipment bridges;

   c. restoration of waterbody banks and wetland hydrology;

   d. timing of the waterbody crossing;

   e. method of crossing; and

   f. size and location of all extra work areas.

4. Do not locate aboveground facilities in any wetland, except where the location of such facilities outside of wetlands would prohibit compliance with U.S. Department of Transportation regulations.

C. INSTALLATION

1. Extra Work Areas and Access Roads

   a. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries, where topographic conditions permit. If topographic conditions do not permit a 50-foot setback, these areas must be located at least 10 feet from the wetland's edge. *This requirement is not applicable where the wetland is adjacent to a waterbody crossing where extra workspace is required for spoil stockpiles and staging of the waterbody crossing."*

   b. Gulfstream shall file with the Secretary for review and written approval by the Director of OEP before construction site-specific construction plans for those extra work areas with a less than 50-foot setback from wetland boundaries and a site-specific explanation of the conditions that will not permit a 50-foot setback.

   c. Limit clearing of vegetation between extra work areas and the edge of the wetland to the certificated construction right-of-way.

   d. Limit the size of extra work areas to the minimum needed to construct the wetland crossing.

   e. The only access roads, other than the construction right-of-way, that can be used in wetlands are those existing roads that can be used with no modification and no impact on the wetland.

2. Crossing Procedures

a. Comply with section 404 nationwide permit program terms and conditions (33 CFR Part 330).

b. *For Type III wetlands* assemble the pipeline in an upland area and use "push-pull" or "float" techniques to place pipe in trench where water and other site conditions allow.

c. Minimize the duration of construction-related disturbance within wetlands.

d. Limit construction equipment operating in *Type II and Type III* wetland areas to that needed to clear the right-of-way, dig the trench, fabricate and install the pipeline, backfill the trench, and restore the right-of-way. All other construction equipment shall use access roads located in upland areas to the maximum extent practicable. Where access roads in upland areas do not provide reasonable access, limit all other construction equipment to one pass through the wetland using the right-of-way.

e. Cut vegetation off at ground level, leaving existing root systems in place, and remove it from the wetland for disposal.

f. Limit pulling of tree stumps and grading activities to directly over the trenchline. Do not grade or remove stumps or root systems from the rest of the right-of-way in wetlands unless the Chief Inspector and Environmental Inspector determine that safety-related construction constraints require removal of tree stumps from under the working side of the right-of-way.

g. Segregate the top 1 foot of topsoil from the area disturbed by trenching, except in areas where standing water or saturated soils are present. After backfilling is complete, restore the segregated topsoil to its original location.

h. Do not store hazardous materials, chemicals, fuels, lubricating, oils, in a wetland, or within 100 feet of any wetland boundary.

i. Attempt to refuel all construction equipment in an upland area at least 100 feet from a wetland boundary. If construction equipment must be refueled in a wetland or within 100 feet of any wetland boundary, follow the procedures outlined in the project-specific SPCC Plan. See section IV. A.

j. Do not use rock (except as allowed by item k. below), soil imported from outside the wetland, tree stumps, or brush riprap to stabilize the right-of-way.

k. If standing water or saturated soils are present, use low-ground-weight construction equipment, or operate normal equipment on timber riprap, prefabricated equipment mats, or geotextile fabric overlain with gravel. Geotextile fabric used for this purpose must be strong enough to allow removal of all gravel and fabric from the wetland.

l. Do not cut trees outside of the construction right-of-way to obtain timber for riprap or equipment mats. *Upland timber may be used for riprap provided it was obtained from the certificated right-of-way.*

m. Attempt to use no more than two layers of timber riprap to stabilize the right-of-way.

n. Remove all timber riprap, prefabricated equipment mats, geotextile fabric, and overlying gravel upon completion of construction.

3. Temporary Sediment Control

Install sediment barriers (as defined in section V.F.2.a. of the Plan) immediately after initial disturbance of the wetland or adjacent upland. Sediment barriers must be properly maintained throughout construction and reinstalled as necessary (such as after backfilling of the trench). Except as noted below in section VI.3.c., maintain sediment barriers until replaced by permanent erosion controls or restoration of adjacent upland areas is complete. Temporary erosion and sediment control measures are addressed in more detail in the Plan. *Best management practices for temporary sediment control are not required for wetlands that have been or are cultivated.*

a. Install sediment barriers across the entire construction right-of-way *(with provisions for access where necessary)* immediately upslope of the wetland boundary (at the edge of the disturbance) at all wetland crossings, as necessary to prevent sediment flow into the wetland.

b. Where wetlands are adjacent to the construction right-of-way, install sediment barriers along the edge of the construction right-of-way as necessary to prevent sediment flow into the wetland.

c. Install sediment barriers along the *downslope* edge of the construction right-of-way as necessary to contain spoil and sediment within the right-of-way. Remove these sediment barriers during right-of-way cleanup.

4. Trench Dewatering

Dewater trench in such a manner that no heavily silt-laden water flows into any wetland or waterbody *except as authorized by a relevant NPDES point source discharge permit.*

D. RESTORATION

1. Where the pipeline trench may drain a wetland, construct trench breakers and/or seal the trench bottom as necessary to maintain the original wetland hydrology.

2. For each wetland crossed, install a permanent slope breaker and a trench breaker at the base of slopes near the boundary between the wetland and adjacent upland areas. Locate the trench breaker immediately upslope of the slope breaker. *This requirement is not applicable where the slope breaker must be installed on cultivated land or where approach slopes do not exceed 10% within 50 feet of the crossing.*

3. Do not use fertilizer, lime, or mulch unless required in writing by the appropriate land management or state agency.

4. Consult with the appropriate land management or state agency and develop plans for active revegetation of wetlands affected by construction. The revegetation plans should include specifications for the planting of native wetland species. Provide these plans to the FERC staff upon request. In the absence of detailed revegetation plans or until the appropriate seeding season for permanent wetland vegetation, temporarily revegetate the right-of-way with annual ryegrass at a rate of 40 pounds/acre, unless standing water is present.

5. For all forested wetlands affected:

Gulfstream will consult with the USCOE, USFWS, USEPA, FLDEP, ALDCNR, MSDWFP and FERC to develop the appropriate mitigation program for permanent forested wetland conversion to emergent wetland."

6. Ensure that all disturbed areas permanently revegetate with native wetland herbaceous and/or woody plant species.

7. Develop specific procedures in coordination with the appropriate land management or state agency, where necessary, to prevent the invasion or spread of undesirable exotic vegetation (such as purple loosestrife and phragmites).

8. Remove temporary sediment barriers located at the boundary between wetland and adjacent upland areas after upland revegetation and stabilization of adjacent upland areas are judged to be successful as specified in section VIII.A.6. of the Plan.

E. POST-CONSTRUCTION MAINTENANCE

1. Do not conduct vegetation maintenance over the full width of the permanent right-of-way in wetlands. However, to facilitate periodic pipeline corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be maintained in a herbaceous state. In addition, trees within 15 feet of the pipeline that are greater than 15 feet in height may be selectively cut and removed from the right-of-way.

2. Do not use herbicides or pesticides in or within 100 feet of a wetland, except as specified by the appropriate land management agency or state agency.

3. Monitor the success of wetland revegetation annually for the first 3 to 5 years after construction. Revegetation should be considered successful if the cover of native herbaceous and/or woody species is at least 80 percent of the total area, and the diversity of native species is at least 50 percent of the diversity originally found in the wetland. If revegetation is not successful at the end of 3 years, develop and implement (in consultation with a professional wetland ecologist) a remedial revegetation plan to actively revegetate the wetland with native wetland herbaceous and woody plant species. Continue revegetation efforts until wetland revegetation is successful.

VII. HYDROSTATIC TESTING

A. NOTIFICATION PROCEDURES AND PERMITS

1. Apply for state-issued withdrawal permits, as required.

2. Apply for National Pollutant Discharge Elimination System (NPDES) or state-issued discharge permits, as required.

3. Notify appropriate state agencies of intent to use specific sources at least 48 hours before testing activities unless they waive this requirement in writing.

B. GENERAL

1. Perform 100 percent radiographic inspection of all pipeline section welds or hydrotest the pipeline sections, before installation under waterbodies or wetlands.

2. If pumps used for hydrostatic testing are within 100 feet of any waterbody or wetlands, address the operation and refuelling of these pumps in the SPCC Plan prepared as described in section IV.A.

3. Gulfstream shall file with the Secretary before construction a list identifying the location of all waterbodies proposed for use as a hydrostatic test water source or discharge location.

C. INTAKE SOURCE AND RATE

1. Screen the intake hose to prevent entrainment of fish.

2. Do not use state-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, unless appropriate Federal, state, and/or local permitting agencies grant written permission.

3. Maintain adequate flow rates to protect aquatic life, provide for all waterbody uses, and provide for downstream withdrawals of water by existing users.

4. Locate hydrostatic test manifolds outside wetlands and riparian areas to the maximum extent practicable.

D. DISCHARGE LOCATION, METHOD, AND RATE

1. Regulate discharge rate, use energy dissipation device(s), and install sediment barriers, as necessary, to prevent erosion, streambed scour, suspension of sediments, or excessive streamflow.

2. Do not discharge into state-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, unless appropriate Federal, state, and local permitting agencies grant written permission.

3. Provide a copy of the results of sampling conducted in accordance with NPDES or state-issued discharge permit requirements to the Commission's environmental staff upon request.

Geology and Soils	
89	Section 10.3.1.1, "Wildlife…are expected to relocate during construction…but are also expected to return once the construction is completed." Please provide references to support this statement.
Response	During the preliminary field surveys, no wildlife was observed along the pipeline corridor. The pipeline corridor is located predominantly on Port Manatee and along existing ROWs where the habitat is already disturbed and consists of primarily grass fields with small isolated herbaceous wetlands. Any wildlife that may be present will undoubtedly move out of the area during the construction activities due to human and equipment presence. However, after the construction activities onshore are complete, the area will be restored to pre-construction conditions and will not create an impediment to wildlife usage or crossing. Although there is limited literature on this subject, one example M.G. Jalkotzy, P.I. Ross, and M.D. Nasserden, 1997. *The Effects of Linear Developments on Wildlife: A Review of Selected Scientific Literature*, May 1997 indicates that the disturbance of linear facility installation usually results in wildlife leaving the corridor area during the disturbance, that completely buried pipelines were not significant filters to wildlife movement, and that pipeline corridors appear to be narrow enough to preclude significant wildlife avoidance effects.

Geology and Soils	
90	Please provide details on the field surveys discussed in Section 10.2.4 (p. 23 of Application). Please describe the procedures/instruments used to establish the requirements used if an area was a wetland, and details about when the studies were conducted.
Response	Preliminary field surveys were performed in January 2007 which included walking the entire terrestrial route and identifying wetlands present using the 1987 USACE Wetland Delineation Manual as indicated on page 10-24, Section 10.2.4 of Volume II. This manual can be downloaded at the following website: http://www.wetlands.com/regs/tlpge02e.htm. During this wetland survey, wildlife observations were made.

Geology and Soils	
91	Please provide references for the following: 1. Speybroeck et al. 2006 (p. 9 of Application) 2. Hatchett et al. 2006 (p. 9 of Application) 3. Finkl et al. 1997 (p. 9 of Application) 4. Adams et al. 2006 (p. 13 of Application) 5. Phillips et al. 1990; Parker et al. 1983 (p. 21 of Application) 6. Lewis and Estevez 1988 (p.21 of Application) 7. Draft EIS prepared for the Gulf of Mexico Oil and Gas Lease Sales (p. 33 of Application) 8. Ashton and Ashton 1981 (Table 10-1, p. 10 of Application) 9. Rogers et al. 1996 (Table 10-1, p. 10 of Application) 10. Bartlett and Bartlett (Table 10-1, p. 10 of Application)
Response	1. Speybroeck et al. 2006 (p. 9 of Application) The reference is included in Volume II, Section 13 and is: SPEYBROECK, J., D. BONTE, W. COURTENS, T. GHESHIERE, P. GROOTAERT, J. MAELFAIT, M. MATHYS, S. PROVOOST, K. SABBE, E.M. STIENEN, V. VAN LANCKER, M. VINCX, and S. DEGRAER, 2006. Beach nourishment: an ecologically sound coastal defense alternative? A review. *Aquatic Conservation: Marine and Freshwater Ecosystems*, 16 (4), 419-435. 2. Hatchett et al. 2006 (p. 9 of Application) The reference is included in Volume II, Section 13 and is: HATCHETT, L., A. NIEDORODA, T. CAMPBELL, J. ANDREWS, M. LARENAS, C. FINKL, and L. BENEDET, 2006. *Reconnaissance Offshore Sand Search of the Florida Southwest Gulf Coast*. Unpublished report prepared for the Florida Department of Environmental Protection, Bureau of Beaches and Coastal Systems by URS Corporation and Coastal Planning and Engineering Inc. 143 pp. 3. Finkl et al. 1997 (p. 9 of Application) The reference is included in Volume II, Section 13 and is: FINKL, Jr., C.W., S.M. KHALIL, and J.L. ANDREWS, 1997. Offshore Sand Sources for Beach Replenishment: Potential Borrows on the Continental Shelf of the Eastern Gulf of Mexico. *Marine Georesources and Geotechnology*, 15, 155-173. 4. Adams et al. 2006 (p. 13 of Application) The reference is included in Volume II, Section 13 and is: ADAMS, C., B. LINDBERG, and J. STEVELY, 2006. *The Economic Benefits Associated with Florida's Artificial Reefs.* Gainesville, Florida: Food and Resource Economics Department, Florida Cooperative Extension Service, Institute of Food and Agricultural Services, Univ. of FL, EDIS Document No. FE649. 5. Phillips et al. 1990; Parker et al. 1983 (p. 21 of Application) The references are included in Volume II, Section 13 and are: PHILLIPS, N., D. GETTLESON, and K. SPRING, 1990. Benthic Biological Studies of the Southwest Florida Shelf. *Amer. Zool*, 30, 65-75. PARKER, Jr., R.O., D.R. COLBY, and T.D. WILLIS, 1983. Estimated Amount of Reef Habitat on a Portion of the U.S. South Atlantic and Gulf of Mexico Continental Shelf. *Bulletin of Marine Science*, 33 (4), 935-940.

	6. Lewis and Estevez 1988 (p.21 of Application) The reference is included in Volume II, Section 13 and is: LEWIS, R. R., III, and E.D. ESTEVEZ, 1988. *The ecology of Tampa Bay, Florida: and estuarine profile*. U.S. Fish and Wildlife Service Biological Report, 85 (7.18), 132. 7. Draft EIS prepared for the Gulf of Mexico Oil and Gas Lease Sales (p. 8-33 of Application) The reference is included in Volume II, Section 13 and is: U.S. DEPARTMENT OF THE INTERIOR, MINERALS MANAGEMENT SERVICE. 2006. *Gulf of Mexico OCS Oil and Gas Lease Sales*: 2007-2012, *Western Planning Area Sales* 204, 207, 210, 215, and 218; *Central Planning Area Sales* 205, 206, 208, 213, 216, and 222; *Draft Environmental Impact Statement*, Volume I: Chapters 1-8 and Appendices. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, OCS EIS/EA, MMS 2006-062. 8. Ashton and Ashton 1981 (Table 10-1, p. 10 of Application) The reference is included in Volume II, Section 13 and is: ASHTON, Jr., R.E., P.S. ASHTON, 1981. Handbook of Reptiles and Amphibians of Florida, The Snakes. Windward Publishing. 9. Rogers et al. 1996 (Table 10-1, p. 10 of Application) The reference is included in Volume II, Section 13 and is: ROGERS, J.A., Jr., H.W. KALE II, and H.T. SMITH (eds), 1996. *Rare and endangered Biota of Florida*, *Volume V*. Birds. University Press of Florida. 10. Bartlett and Bartlett (Table 10-1, p. 10 of Application) The reference is included in Volume II, Section 13 and is: BARTLETT, R.D., P.P. BARTLETT, 1999. *A field Guide to Reptiles and Amphibians.* Gulf Publishing Co.

Socioeconomics	
92	Please provide the references for the following documents: a. Request references Impact Analysis, Inc. 2005a and 2005b b. VanVorhees and Pritchard 2005
Response	a. The reference is included in Volume II, Seciton 13 and is: IMPACT ANALYSIS, INC., 2005b. *Identifying Communities Associated with the Fishing Industry along the Florida Gulf Coast. Volume III: Apollo Beach to Royal Palm Hammock.* St. Petersburg, Florida: U.S. Department of Commerce NOAA Fisheries, Southeast Regional Office. 240 pp. b. The reference is included in Volume II, Section 13 and is: VAN VORHEES, D. and E. PRITCHARD, 2005. *Fisheries of the United State 2004, Current Fisheries Statistics No. 2004.* Silver Spring, Maryland: National Marine Fisheries Service, Office of Marine Technology, 124.

Socioeconomics	
93	Please provide information on lease activities in the blocks that would be traversed by the pipeline.
Response	As indicated in Volume I, Section 12 of the filing documents, there are no lease block activities within the blocks that would be traversed by the pipeline.

Socioeconomics	
94	Please describe impacts to recreational and commercial fisheries from establishment of a Safety Zone or Area To Be Avoided (ATBA) as defined by USCG.
Response	The impacts to recreational and commercial fisheries from the Safety Zone is discussed in Section 6.3.1.1starting on Page 6-41. The No Anchoring (Precautionary) Zone is the area that fishing activities would be precluded from during operations.

Socioeconomics	
95	Section 6.4.1 provides very general information on potential projects for the cumulative effects analysis. Please provide the references for the projects discussed in this section.
Response	Several sources of information were used to develop the list or projects for the cumulative impacts analysis including the following: • The permit databases for the FDEP and USACE to identify permitted projects to be implemented within the Port Dolphin project area; • The two most recent Port Master planning documents from Port Manatee and Tampa Port Authority; • Web-based searches of publicly available information; and • Web-based searches of local news and marine sources. The FDEP permits and Port Master Planning documents have been placed on an FTP site for download.

Project Description and Alternatives	
96	From Section 1.5 of the Volume 1 application - Please provide more information regarding the number of trips by vessels for construction purposes (including supplies and crew replacement) during each of the 2 construction phases.
Response	Table 4-25 in Volume II – Section 4 (page 4-107) provides a detailed breakdown of expected vessel trips during construction, operations, and decommissioning.

Transportation	
97	It is assumed that the use of commercial and recreational vessels would be precluded in some areas during construction. Please outline those areas and provide a timeline for restrictions, including a contingency plan for bad weather.
Response	During the construction of the Port Dolphin offshore facilities and transmission pipeline into Port Manatee, it is imperative that all commercial and civilian boat traffic stay clear of the construction vessels. The proposed construction approach would involve the implementation of a moving exclusion zone during project construction. The footprint of this moving exclusion zone is defined by the lay barge's greatest anchoring line distances which would be 3,000 ft wide by 2,500 ft long. This area is based on the following anchor deployment assumptions: • 10-anchor spread vessel; • Port and starboard anchors are deployed symmetrically on each side of the vessel, approximately 1,400 ft from pipe centerline (1 per side, anchors 3 and 8 – see attached anchor placement diagram); • Quarter anchors are deployed symmetrically on each side of the vessel, approximately 1,200 ft from the pipe centerline (2 per side, anchors 2, 4, 7 and 9); and • Forward and aft anchors deployed symmetrically on each side of the vessel, approximately 1,000 ft from the pipe centerline (2 per side, anchors 1, 5, 6 and 10). In Tampa Bay, all pipe lay, pipe burial, and diving operations will be conducted under either anchored vessels or fixed jack up barges. Each construction vessel will fly the correct day signals; while at night will display the correct lighting advising marine traffic that they are basically stationary. Prior to beginning construction, Port Dolphin will submit a detailed offshore construction plan for review of interested agencies. The project construction team will stay in daily communication with the local USCG on vessel movement and construction activities. Notice to Mariners will also be issued to the proper local authorities informing of areas where construction activities would be occurring at a given time. Prior to beginning construction, Port Dolphin will also submit a communications plan for review and approval of interested agencies. During construction of Port Dolphin and the laying of the pipeline to Port Manatee, hurricane forecasts will be watched closely throughout the hurricane season. In the event a hurricane approached the project area during any phase of the construction, project operations will cease and the site will be secured. Both the STL buoy and the gas transmission pipeline are sub-surface facilities. If a hurricane forced abandonment of the site during construction, the buoy housing and pipeline can be flooded and anchored to the sea floor before the construction vessels leave the site.

Transportation	
98	What shipping routes/lanes would SRVs take in transit to Port Dolphin? (this information can also be provided in the requested GPS layers)
Response	The shipping routes/lanes that the SRVs would take in transit to Port Dolphin in US waters are shown in Figure 11-11 of Volume II. The shipping routes prior to reaching US territorial waters will be dependent on where the cargo is obtained from. The GIS layers of the shipping routes illustrated in Figure 11-11 have been placed on an FTP site for download.

Transportation	
99	Please provide information on the number and type of vessels that call on Tampa Bay ports. If available, also provide the draft, size, or other distinguishing information on the vessels or vessel types.
Response	Specific vessel traffic for the project area is very limited in scope. Vessel data is discussed in Volume II, Section 11.9. In addition, below are additional data available for number and type of vessels that call on Tampa Bay Ports. The source of this data is from the Port of Tampa Operations Center and was provided on request to Port Dolphin by the Port of Tampa.

Port of Tampa, Florida
Historical Vessel Counts
FY1982- FY2006

	Barge	Cruise*	Tug	Vessels	Total
FY2006	1,041	223	1,005	1,430	3,699
FY2005	1,016	194	982	1,496	3,688
FY2004	969	207	936	1,419	3,531
FY2003	1,069	244	1,015	1,487	3,815
FY2002	1,214	168	1,177	1,444	4,003
FY2001	1,069	151	1,040	1,486	3,746
FY2000	1,320	158	1,318	1,473	4,269
FY1999	1,295	170	1,303	1,525	4,293
FY1998	1,251	110	1,171	1,480	4,012
FY1997	1,343	86	1,282	1,388	4,099
FY1996	1,426	126	1,279	1,383	4,214
FY1995	1,312	190	1,217	1,417	4,136
FY1994	1,361	213	1,265	1,489	4,328
FY1993	1,271	118	1,218	1,420	4,027
FY1992	1,302	49	1,240	1,492	4,083
FY1991	1,244	29	1,164	1,560	3,997
FY1990	1,196	39	1,182	1,600	4,017
FY1989	1,258	138	1,244	1,693	4,333
FY1988	1,306	225	1,269	1,705	4,505
FY1987	1,395	451	1,388	1,661	4,895
FY1986	1,411	396	1,381	1,403	4,591
FY1985	1,321	346	1,299	1,567	4,533
FY1984	1,305	41	1,287	1,704	4,337
FY1983	1,109	61	1,081	1,617	3,868
FY1982	1,006	31	964	1,679	3,680

*Cruise includes lay up, repair, etc.

U.S. Port Calls by Port and Vessel Type

Year	Port/State	State	Coastal Region	All Types		Tanker*		Product Tanker		Crude Tanker		Container			Dry Bulk	
				Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Capacity (TEU)	Calls	Capacity
2002	Port Manatee	FL	USG	44	839,836	1	72,910	0	0	1	72,910	0	0	0	4	205,126
	Tampa	FL	USG	879	29,346,252	171	5,607,737	170	5,500,476	1	107,261	8	183,004	6,500	413	16,626,663
2003	Port Manatee	FL	USG	122	3,863,275	10	390,483	10	390,483	0	0	0	0	0	64	2,673,348
	Tampa	FL	USG	769	25,851,435	179	6,187,155	176	5,962,291	3	224,864	17	337,355	23,417	348	13,531,889
2004	Port Manatee	FL	USG	137	4,411,605	8	302,947	7	232,520	1	70,427	1	22,778	450	57	2,355,210
	Tampa	FL	USG	859	30,410,513	297	10,973,470	295	10,761,189	2	212,281	32	535,246	34,524	370	14,056,007
2004	Port Manatee	FL	USG	159	5,544,357	21	873,999	16	515,481	5	358,518	0	0	0	76	3,150,968
	Tampa	FL	USG	1,003	36,366,002	401	14,912,990	398	14,637,575	3	275,415	38	586,624	38,413	396	15,884,888

* Tanker includes Product Tanker and Crude Tanker
** Ro-Ro includes Vechicle Carriers

Source: http://www.lloydsmiu.com/mtmarlin/marlin/system/render.jsp?MarlinViewType=MARKT_EFFORT&siteid=20001000683&marketingid=20001147162&forcedBounce=true&code

U.S. Port Calls by Port and Vessel Type

Year	Port/State	State	Coastal Region	Ro-Ro*		Vehicle		Gas Carrier		Combination		General Cargo	
				Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity
2002	Port Manatee	FL	USG	0	0	0	0	0	0	0	0	39	561,800
	Tampa	FL	USG	26	349,481	25	331,631	140	3,994,238	2	111,955	119	2,473,174
2003	Port Manatee	FL	USG	2	23,700	0	0	0	0	0	0	46	775,744
	Tampa	FL	USG	25	357,874	19	244,875	106	3,419,402	1	48,062	93	1,969,698
2004	Port Manatee	FL	USG	3	36,870	0	0	0	0	0	0	68	1,693,800
	Tampa	FL	USG	21	304,154	15	199,614	89	3,138,744	2	124,154	48	1,278,738
2004	Port Manatee	FL	USG	0	0	0	0	0	0	0	0	62	1,519,390
	Tampa	FL	USG	26	388,184	24	358,870	94	3,382,907	1	45,727	47	1,164,682

* Tanker includes Product Tanker
** Ro-Ro includes Vechicle Carrie

Source: http://www.lloydsmiu.com/

Project Description and Alternatives	
100	What is the maximum number of SRVs that would be expected to use Port Dolphin in the first year, and in subsequent years?
Response	For the average sendout rates range proposed by Port Dolphin, the larger numbers of vessel visits correspond to operational scenarios that would exclusively rely on the smaller size of SRV that would serve this Port (i.e., 145,000 m^3). Port Dolphin's base case scenario is based on the following assumptions: Vessels size: 145,000 m^3 Average daily sendout: 400 Mscfd Number of days on buoy per 145,000 m^3 cargo: 8 days Number of calls given year round deliveries: 45 Number of calls with no winter deliveries: 35 Port Dolphin's extreme case scenario is based on the following assumptions: Vessels size: 145,000 m^3 Average maximum daily sendout: 800 Mscfd Number of days on buoy per 145,000 m^3 cargo: 4 days Maximum number of calls given year round deliveries: 90

Project Description and Alternatives	
101	What is the expected average speed of the SRVs in the shipping lanes and when they are coming into the Port?
Response	The Master of the vessel will have discretion to determine the speed, heading, and approach to the buoy system. This will be determined by the prevailing weather conditions at the time of the approach to the port and the Master's professional opinion. The SRV will always keep a safe speed with regards to traffic, obstructions and weather conditions. In case of severe weather or poor visibility, the speed will be reduced accordingly and to as low as 6 knots. Under normal conditions the average speed in the arrival zone will be less than about 14 knots. Outside of the arrival zone the SRV may travel at up to its nominal cruising speed of 19.5 knots. There should be no need for the SRVs to enter the existing shipping channel serving the port of Tampa. The approach to the terminal will be generally west until the SRV passes west of Key West. At this point the course will change to generally north, roughly paralleling the west coast of Florida until reaching the general area of the terminal. At this point the captain will designate an approach point approximately two nautical miles away from the port which will be determined by the weather conditions present at the time of approach. The approach will bring the vessel to that point at reduced speed according to the plan provided in the attached table. Since there is no loading terminal in Gulf of Mexico, the SRV will navigate out of the Gulf with the shortest route west of Key West, always with a minimum 12 NM to nearest shallow water. Where Traffic Separation Schemes or Safety Fairways are arranged, this will apply.

Zone	Description	Speed limit	Remarks
>15 nautical miles off point A	(Full service speed)	Full service speed allowed	
11 – 15 nautical miles off point A	(Full maneuver speed)	< 14,0 knots	
6 – 11 nautical miles off point A	(Half ahead)	< 10,0 knots	
0 – 6 nautical miles off point A	(Slow ahead)	< 6,0 knots	
From point A to safety zone	(Dead slow ahead) D.P.	< 4,5 knots	Bow and stern thrusters in operation
Inside safety zone	(Dead show ahead) D.P.	< 3.0 knots	Bow and stern thrusters in operation

Project Description and Alternatives	
102	How many trips (annually) and what vessels would be used to maintain the buoys after the Port becomes operational? Where would maintenance vessels come from?
Response	Based on information provided by APL, regular inspection and maintenance of the buoys would occur once per year (worst case), primarily by ROV (operated from suitable supply vessel). It is estimated that each inspection would take 5 days.

Air	
103	Air Quality Impacts – Please provide documentation demonstrating agency approval of the use of an alternative model (CALPUFF) for the near-field analysis, as well as an agency response to the Modeling Protocol. The letter requesting approval was provided, but no approval documentation is present.
Response	Due to the schedule for finalization of the submittal documents, we currently do not have a formal letter approving the Modeling Protocol. A number of consultation calls with EPA were held to develop the Protocol and as you know from our June 28, 2007 conference call with EPA, we are currently working with EPA on addressing their modeling and Protocol questions. As soon as we receive the approval documentation, we will provide it to the USCG.

Noise	
104	Please provide any studies of ambient noise for the Tampa area for both underwater and above-water noise. Any noise studies in the specific area of the Proposed Action would be preferred.
Response	An extensive literature search of the internet, library catalogs, scientific article databases and gray literature sites was performed to locate studies available and very limited information was identified. The only applicable information found was the Environmental Impact Statement for the Gulfstream pipeline (FERC Docket No. CP00-6-000) which indicates that they performed ambient sound surveys at the proposed compressor station on Buckeye Rd which measured 47.5 L_{dn} (dBA) 1,400 feet away (FERC 2001).

Noise	
105	Please provide any studies or modeling of noise propagation from project construction, operations and decommissioning activities. The potential noise sources from construction should include both anchored and dynamically positioned barges, since both are discussed as potential vessels for buoy and pipeline construction. For operations, both normal port revaporization activities, and vessel maneuvering to moor to the buoys, maintain station in high wind, current or wave conditions, including the anticipated frequency and duration of thrusters should be discussed. For decommissioning include the potential use of explosives to remove project structures.
Response	Please see the attached noise modeling report. The use of explosives will not be used for decommissioning activities.

PORT DOLPHIN ENERGY LLC DEEP WATER PORT: ASSESSMENT OF UNDERWATER NOISE

Version 2.0

By

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23 Jan 2008

Version	Date	Description	Approved by:
1.0	18 Jan. 2008	First release version	Isabelle Gaboury
2.0	23 Jan. 2008	Revised results for SRV transit and approach	Isabelle Gaboury

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Table 12: 95th percentile radii for inshore construction scenarios, M-weighted for low- and mid-frequency cetaceans and for pinnipeds. See Table 9 for un-weighted radii. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics. Note that both cetacean and pinniped criteria are shown for the pinniped M-weighting, as manatees do not clearly belong to either group for the purposes of harassment criteria. 25

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Figure 3: Third-octave band source levels for non-vessel activities involved in construction-related modeling scenarios (see Table 1). Source depth for the impact hammer is half the local water depth; source depth for the dredge is 2.2 m. Broad-band source levels are (a) 216 dB re µPa (assuming a 10 dB SEL-to-RMS offset) and (b) 188 dB re µPa. 6

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Figure 15: Estimated received sound levels for inshore pipe burial (see Table 1, Section 2.2.4). B-7

Figure 16: Estimated received sound levels for SRV transit (see Table 1, Section 2.2.5). B-7

Figure 17: Estimated received sound levels for SRV approach (see Table 1, Section 2.2.5). B-8

Figure 18: Estimated received sound levels for SRV docking (see Table 1, Section 2.2.5). B-8

1 Project Description

Port Dolphin Energy LLC proposes to construct and operate a Liquefied Natural Gas (LNG) Deepwater Port (DWP) at a site approximately 45 km (28 mi) west of Tampa Bay, Florida. The project will consist of two submerged turret unloading and mooring buoys, located in approximately 30 m (98 ft) of water, connected to Port Manatee in Tampa Bay via a pipeline approximately 68 km (42 mi) in length. The buoys will serve LNG Shuttle and Regasification Vessels (SRV's), purpose-built ocean going LNG vessels capable of regasifying the LNG onboard and delivering natural gas to the sub-sea pipeline.

Underwater noise will be generated during both the construction and operational phases of the deepwater port. During construction, noise will be generated from construction vessels, pile driving, and plowing of the pipeline, and to a lesser extent from drilling and dredging operations. During operation of the port, underwater noise will be generated by the operation of the SRV's during transit and docking/undocking and by acoustic transponders on the unloading buoys. Both types of noise will be intermittent.

This report details the results of acoustical modeling carried out by JASCO Research, Ltd., in order to predict the sound fields likely to be generated by construction and operation activities associated with the Port Dolphin DWP project. The scenarios modeled, including the layout of equipment and source levels associated with various vessels and activities, are outlined in Section 2. Natural sources of ambient noise that are likely to occur within the study area are also discussed. Model methodology and environmental parameterization are discussed in Sections 3 and 4, respectively. Finally, the results of the modeling study are presented in Section 5.

2 Modeling Scenarios and Source Level Characterization

Levels of underwater sound were modeled using JASCO's Marine Operations Noise Model (described in Section 3) for a variety of locations and activities, representing different stages of construction and operation of the Port Dolphin facility. The sites, equipment, and levels of underwater noise associated with these scenarios are discussed in the following sub-sections. Third-octave band source levels are also tabulated in Appendix A.

2.1 Study Area

The region around the Port Dolphin DWP, inshore of the 50 m (164 ft) isobath, is shown in Figure 1. As discussed in the following section, modeling was carried out for activities occurring at a number of locations in the vicinity of the DWP, including along the SRV transit route, at the buoys, and along various portions of the pipeline connecting the unloading buoys to Port Manatee (Figure 1).

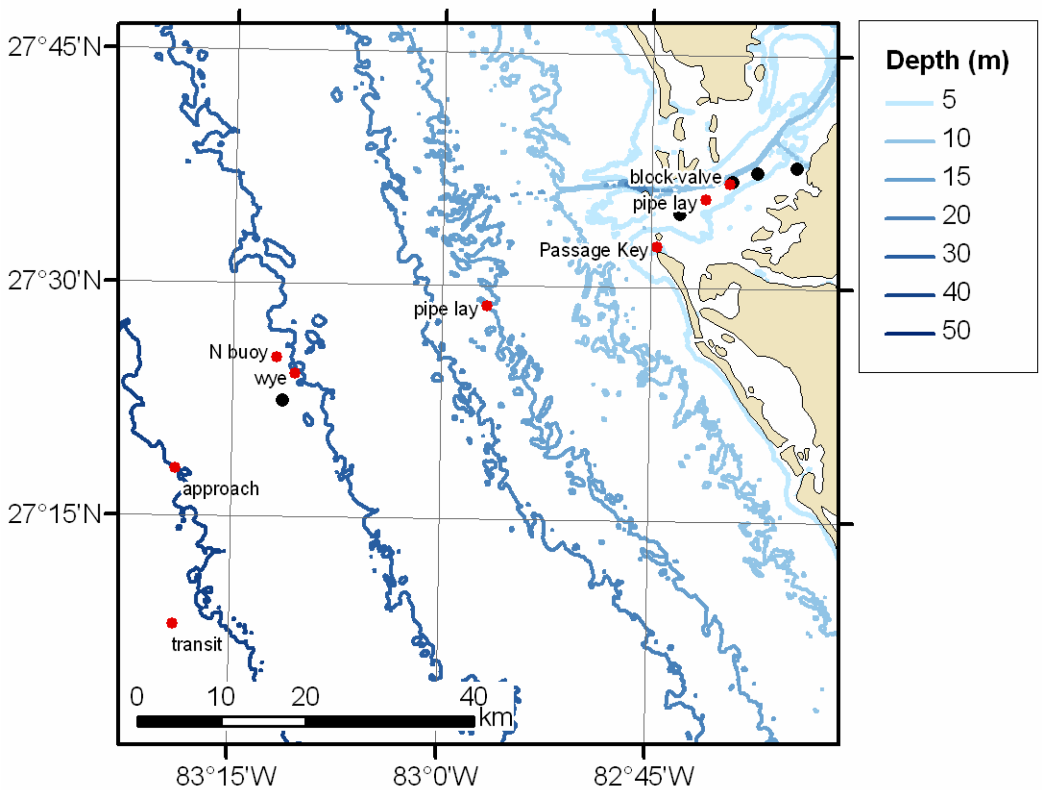

Figure 1: Overview of modeling sites. Dots mark key points along the carrier route and pipeline. The pipeline extends from the two buoys at the western-most end to the Port Manatee shore approach at the eastern-most end. Red dots represent model sites.

2.2 Model Scenarios and Source Levels

The scenarios that were modeled as part of this study are outlined in Table 1. Activities and locations were selected to represent key elements of the construction and operation of the DWP. The equipment list associated with each activity is based on current construction plans (Ocean Specialists, 2007). For each piece of equipment specified, proxy vessels were selected from JASCO Research's database of underwater noise measurements (right-most column of Table 1); this is discussed further in the following sub-sections.

Note that in many cases the scenarios involve multiple pieces of equipment. Although equipment spacing will vary during the course of operations, a single layout must be assumed for modeling purposes. As such, where multiple vessels were involved in the scenarios listed in Table 1 the following layout was assumed:

- The barge used for the main operation in each scenario (crane vessel, pipe laying barge, pipe burial barge) was set in the middle of the group of vessels.
- For four or fewer tugs (anchor handling and/or support), tugs were spaced at a range of 100 m (328 ft) from the center of the barge. Note that the pipe laying/burial barge itself is 122 m long by 30 m wide (400 ft x 100 ft).
- For pipe laying at Passage Key, the fifth standby tug was placed at a range of 200 m (656 ft) from the barge.

Table 1: Summary of model scenarios for the Port Dolphin LNG project. See also Figure 1. Proxy vessels and activities are discussed further in the sub-sections that follow.

Scenario		Location	Specified equipment	Proxy vessel/activity (for source levels)
Construction scenarios				
1	Installation of anchors, buoys, and anchor chains	North buoy	Crane vessel	Castoro II (barge), anchor operations
			Cargo barge	Assumed to be passive, hence negligible contribution
			Support vessel	Britoil 51 (tug), transiting
2	Impact pile driving (offshore)	Piggable wye site	Impact hammer	Menck MHU 3000
3	Impact pile driving (inshore)	Subsea block valve site	As for pile driving offshore	
4	Pipe laying (offshore)	15m isobath	Barge	Castoro II (barge), pipe laying
			2 anchor handling tugs	Britoil 51 (tug), anchor operations
			Support tug	Britoil 51 (tug), transiting
5	Pipe laying (inshore)	Tampa Bay	As for pipe laying offshore	

Scenario		Location	Specified equipment	Proxy vessel/activity (for source levels)
6	Pipe laying through Passage Key—live boat method	Passage Key	Barge	Castoro II (barge), pipe laying
			2 anchor handling tugs	Britoil 51 (tug), anchor operations
			2 live maneuvering tugs	Britoil 51 (tug), transiting
			Live tug on standby	Britoil 51 (tug), transiting
7	Pipeline burial—plowing (offshore)	15m isobath	Plow system	Aquarius dredge
			2 anchor handling tugs	Britoil 51 (tug), anchor operations
8	Pipeline burial—plowing (inshore)	Tampa Bay	As for pipe burial offshore	
Operational scenarios				
9	Offshore transit	34 km (18 nm) southwest of the unloading buoy	SRV, 36.1 km/h (19.5 kn) (90% propulsion)	Modeled SRV, full speed transit
10	Buoy approach	18 km (10 nm) southwest of the unloading buoy	SRV, <18.5 km/h (<10 kn) (half ahead)	Modeled SRV, half speed transit
11	Docking	Mooring buoy	SRV, dead slow, + bow and stern thrusters	Modeled SRV: main propulsion at dead slow, 2 bow thrusters and 1 stern thruster

2.2.1 Installation of anchors, buoys, and anchor chains

Proxies were selected for the crane and support vessels based on vessel specifications (Figure 2(a,d)). While a cargo barge may be present on-site for a portion of the operations, it was assumed that this barge would typically not be under power.

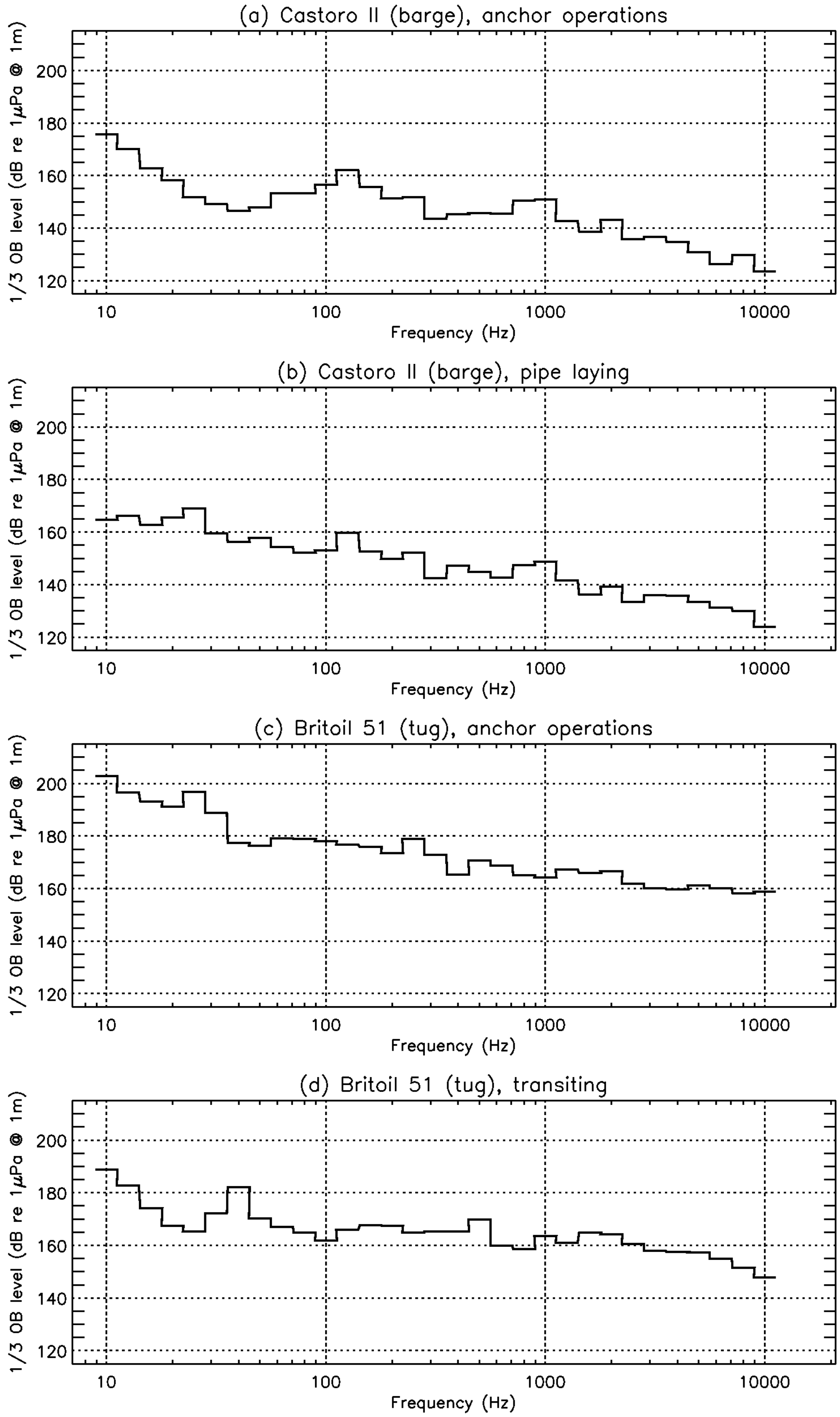

Figure 2: Third-octave band source levels for vessels involved in construction-related modeling scenarios (see Table 1). Source depths are 2.2 m and 3 m for the Castoro II and Britoil 51, respectively. Broad-band source levels are (a) 177 dB re μPa, (b) 174 dB re μPa, (c) 205 dB re μPa, and (d) 191 dB re μPa.

2.2.2 Impact Pile Driving

Piles may be driven as part of pipeline initiation at the piggable wye and subsea block valve sites (Figure 1, Table 1). The impact hammer involved is expected to be the same as that used for the Neptune LNG project (LGL and JASCO, 2005). As such, the same source levels were used (Figure 3(a)). For both the offshore and inshore scenarios, the source depth for pile driving was set to approximately half the local water depth (Figure 2(a)). In actuality, sound will radiate from all portions of the pilings; this mid-water column value is a precautionary estimate of the depth for an equivalent point source, as losses due to bottom and surface interactions will be less for a source at mid-depth than for one near the sea floor or surface.

Impact hammering operations will involve a pipe lay barge and tugs, similarly to pipe laying (Table 1). However, because the potential impact to marine mammals and turtles is different for impulsive and continuous sources, impact hammering noise (an impulsive source) is considered separately from vessel noise (continuous sources). Note that the source levels from impact hammering are much higher than those from the vessels that are likely to be on-site (Figure 2, Figure 3(a)).

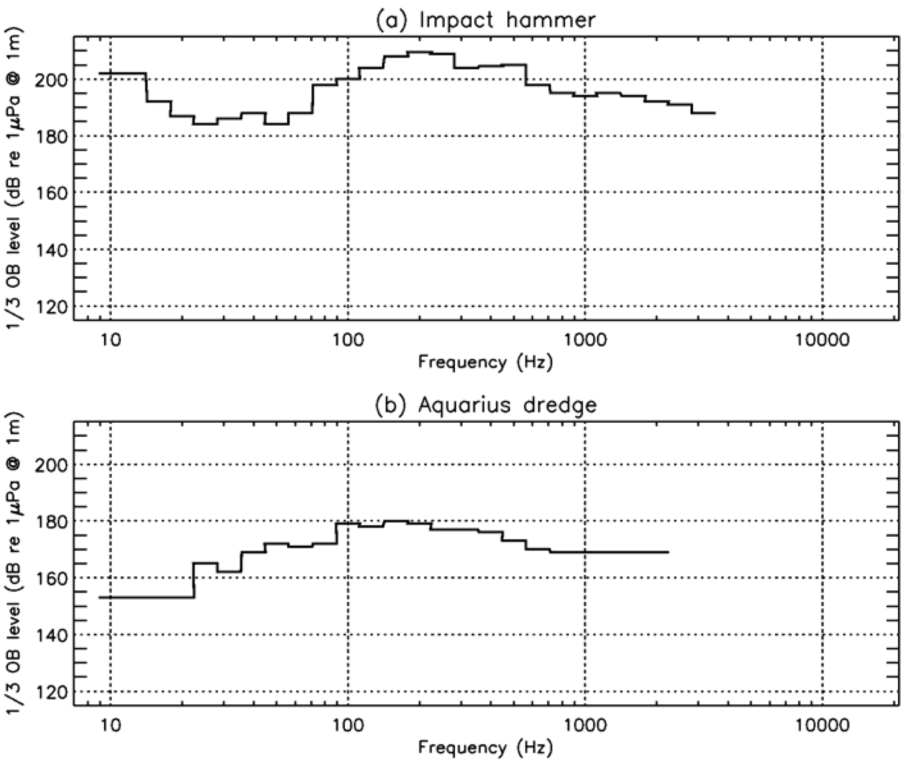

Figure 3: Third-octave band source levels for non-vessel activities involved in construction-related modeling scenarios (see Table 1). Source depth for the impact hammer is half the local water depth; source depth for the dredge is 2.2 m. Broad-band source levels are (a) 216 dB re μPa (assuming a 10 dB SEL-to-RMS offset) and (b) 188 dB re μPa.

2.2.3 Pipe Laying

A total of three sites were selected for pipe laying: one approximately mid-way along the offshore portion of the pipeline, another along the inshore portion, and a third at Passage Key (Figure 1, Table 1). Equipment lists for the offshore and inshore sites are identical: a pipe laying barge, two tugs involved in re-setting of anchors, and a third tug in transit (Table 1, Figure 2(b,c,d)). At Passage Key Inlet, shallow water and tidal currents are expected to require a modification of the pipe laying approach. The noisiest of the alternatives, referred to as the "live boat" method (Ocean Specialists, 2007), would require two additional tugs for live handling compared with the equipment setup used for most of the pipeline route (Table 1).

2.2.4 Pipe Burial

Similarly to pipe laying, pipe burial using a trenching plow system will consist of an anchored barge accompanied by two anchor handling tugs. In addition, noise will be generated by the plow used to bury the pipe line (Table 1). Detailed source level data were not available for plow operations. However, Aspen Environmental Group (2005) reported a broadband source level of 185 dB re 1 μPa at 1 m. Based on this information, source levels from the cutter-suction dredger Aquarius (Greene, 1987) were used for modeling purposes (Figure 3(b)). Note that the dredge source levels include the sound from the barge upon which the dredge is operated; consequently, a separate barge is not specified for plowing operations in Table 1. However, based on the observation from clamshell dredging that the highest levels of underwater sound are emitted from equipment on the barge rather than from the scraping sounds of the dredge itself (Richardson *et al.*, 1995), the source depth for plowing was taken to be that of the pipe laying/burial barge.

2.2.5 Operational Scenarios: SRV Transit and Docking

Operational procedures for the SRV's specify maximum allowable transit speeds during transit to the unloading buoys, as well as probable use of thrusters during approach and docking (Table 2). During offshore transit (i.e., over 34 km / 18 nm from the unloading buoys), SRV's travel at full service speed, which in calm weather can be up to 36.1 km/h (19.5 kn). Speed is gradually reduced as the SRV approaches the unloading buoys, until main propulsion is at dead slow (Table 2). Bow and stern thrusters are used during docking. Once moored, ship's propulsion is not required for positioning.

Based on these operational procedures, three sample situations were selected for modeling (see Table 1):

- Offshore transit at full service speed
- Approach at half speed to 10 nm distance from the unloading buoy
- Docking at the northern buoy, using both bow thrusters and one stern thruster

Table 2: Speed limits and thruster operation during approach of SRV's to the unloading buoys and subsequent docking. Point A is located 5.6 km (3 nm) from the unloading buoys.

Zone	Speed limit	Thrusters?
>28 km (15 nm) off point A	Full service speed (36 km/h, 19.5 kn)	No
20-28 km (11-15 nm) off point A	Full maneuver speed (<26 km/h, <14 kn)	No
11-20 km (6-11 nm) off point A	Half ahead (<19 km/h, <10 kn)	No
0-11 km (0-6 nm) off point A	Slow ahead (<11 km/h, <6 kn)	No
Point A to safety zone	Dead slow ahead (<8.3 km/h, <4.5 kn)	Bow and stern thrusters in operation
Inside safety zone	Dead slow ahead (<5.6 km/h, <3 kn)	Bow and stern thrusters in operation
Docking	Dead slow	2 bow thrusters and possibly 1-2 stern thrusters in operation

Very little information is available on the underwater noise levels radiated by LNG carriers. However, some data and empirical formulas have been developed for large tankers in general. At typical cruising speeds, source levels from such vessels are dominated by propeller cavitation (Sponagle, 1988; Seol *et al.*, 2002). As described by LGL and JASCO (2005), an empirical expression for the source spectrum level (1 Hz bandwidth) in the frequency range between 100 Hz and 10 kHz is

$$SL = 163 + 10 \log BD^4 N^3 f^{-2} \text{ dB re } 1\ \mu\text{Pa}$$

Here B is the number of blades, D is the propeller diameter in meters, N is the number of propeller revolutions per second, and f is the frequency in Hz. For frequencies less than 100 Hz, the source level is assumed to be constant at the 100 Hz level. In the case of ducted propellers (e.g., bow and stern thrusters), the constant is approximately 7 dB larger. The parameters used for modeling of a "typical" SRV are listed in Table 3. Specifications for the main propulsion system are based on a typical carrier, and are similar to those described by LGL and JASCO (2005). Bow and stern thrusters are expected to be single-speed, controllable-pitch devices, with power ratings of 2,000 kW each for the bow thrusters and 1,200 kW each for the stern thrusters. Based on these values, diameters and rates of revolution for the thrusters (Table 3) were based on specifications for the most common models currently available. Note that only a single set of parameters is shown for the thrusters, as rates of revolution do not change with power output for single-speed thrusters. The above model is not able to take into account the reduction in source levels that would result from a change in pitch at lower power outputs; hence, the modeled source levels are conservative (i.e., represent maximum expected levels of underwater noise).

The resulting estimated source levels for the SRV are shown in Figure 4.

Table 3: Parameters used to model cavitation noise from SRV main propulsion and thrusters.

Description	**Number of blades (*B*)**	**Diameter (*D*)**	**Propeller revolutions per minute**	**Propeller revolutions per second (*N*)**
Main propulsion, full speed	4	8.5	87	1.45
Main propulsion, half speed	4	8.5	45	0.75
Main propulsion, dead slow	4	8.5	10	0.17
Bow thruster	4	2.4	200	3.33
Stern thruster	4	2.0	245	4.08

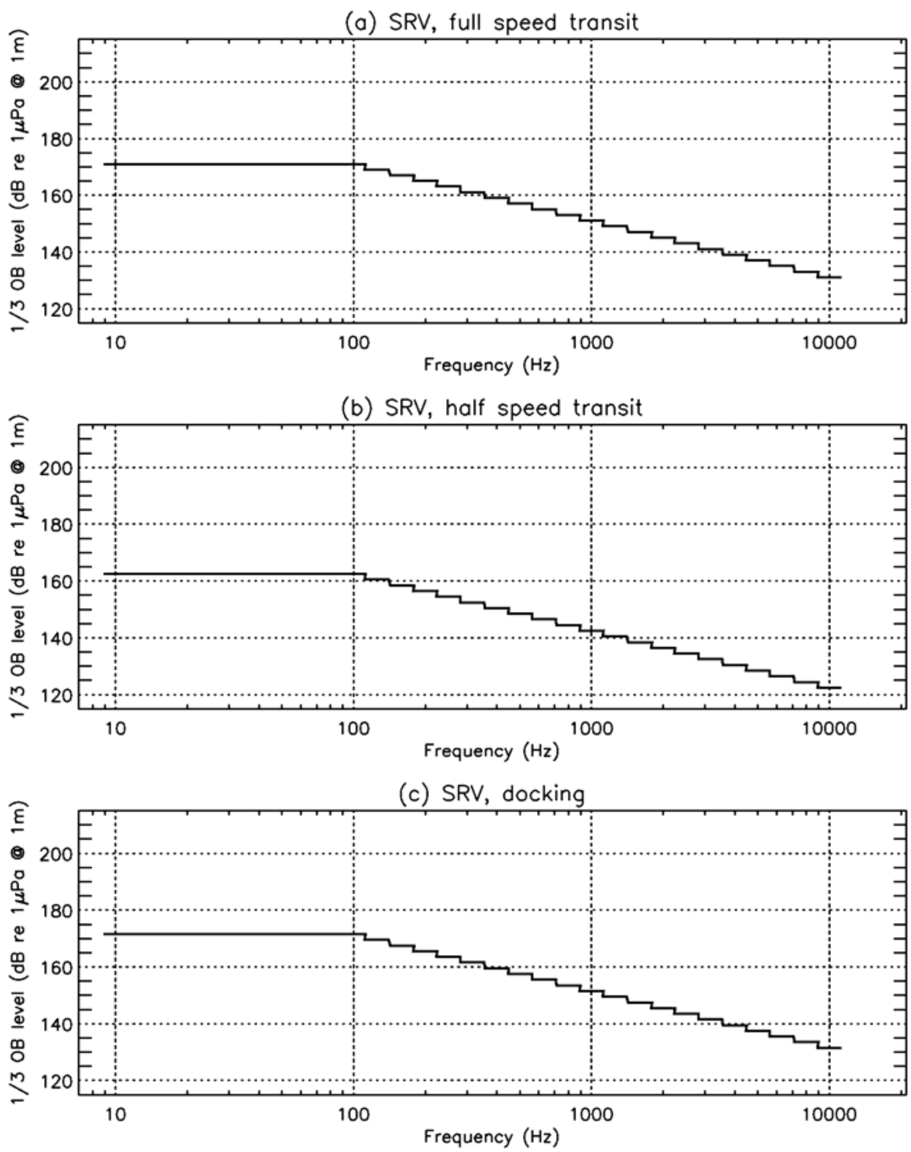

Figure 4: Third-octave band source levels for operational modeling scenarios (see Table 1). Source levels for docking (c) include main SRV propulsion at dead slow, two bow thrusters at half-power, and one stern thruster at half-power. Source depth is 6 m in all cases. Broad-band source levels are (a) 182 dB re μPa, (b) 174 dB re μPa, and (c) 183 dB re μPa.

2.3 Additional Sources of Noise

The following additional sources of underwater noise are expected to be present during construction of the Port Dolphin DWP, but were not modeled:

- Dredging: Dredging will be involved in a few stages of construction, including horizontal directional drilling (discussed below) and pipe laying at the Sunshine Bridge crossing (Ocean Specialists, 2007). This will involve a clamshell or bucket-style dredge, operated from a barge while one or more additional barges carry out other tasks nearby. Measurements taken by JASCO during operation of a clamshell dredge indicated source levels of approximately 150-155 dB re 1 uPa, i.e. roughly 20 dB lower than the source levels associated with the

Castoro II during pipe laying operations (Figure 2). As such, dredging may be considered an insignificant source of noise compared with operation of the barges that will also be present.

- Horizontal Directional Drilling (HDD): HDD will be employed for installation of the pipe line at a number of locations along the inshore portion of the route, including the Port Manatee shore approach and two crossings of the Gulfstream pipeline (Ocean Specialists, 2007). This will involve using progressively larger drill strings to eventually produce a drill bore 1.22 m (48") in diameter. Simultaneously, bucket dredging will be employed to produce an exit hole at the end of the bore. Very little information exists regarding source levels from horizontal directional drilling. However, measurements taken of drillships (Greene, 1987) suggest that the contribution to the underwater noise field from drilling is likely to be far less than that from the barges from which drilling and/or dredging will be taking place.

Once the port is operational, an additional source of underwater sound in the vicinity of the unloading buoys will be the acoustic transponders installed on the buoys. Information was not available on the specific transponders intended for use at the Port Dolphin DWP at the time of writing of this report. However, specifications from commercially available buoy positioning transponders indicate operating frequencies of a few tens of kHz, and source levels of approximately 190 dB re 1 µPa at 1 m. Given this estimated broadband source level, we may estimate ranges to various threshold values assuming simple spherical spreading, i.e.

$$RL = SL - 20\log_{10}(r)$$

Solving for r, we find that received levels will drop to 180 dB at a range of approximately 3 m, and to 160 dB at a range of approximately 32 m. As such, only marine mammals passing very near the unloading buoys would potentially be affected. It should also be noted that this will be a highly intermittent source of underwater noise, as the transponders will only transmit when interrogated by the SRV-based command unit.

2.4 Ambient Noise

Even in the absence of man-made sounds, the sea is typically a noisy environment. A number of natural sources of noise are likely to occur within Tampa Bay and the adjoining shelf, including the following (see Chapter 5 of Richardson *et al.* 1995):

- Wind and waves: The complex interactions between wind and water surface, including processes such as breaking waves and wave-induced bubble oscillations and cavitation, are a main source of naturally occurring ambient noise for frequencies between 200 Hz and 50 kHz (Mitson, 1995; Richardson *et al.*, 1995). In general, ambient noise levels tend to increase with increasing wind speed and wave height. Surf noise becomes important near shore, with measurements collected at a distance of 8.5 km (5.3 mi) from shore showing an increase of 10 dB in the 100 to 700 Hz band during heavy surf conditions (Richardson *et al.*, 1995).
- Precipitation noise: Noise from rain and hail impacting the water surface can become an important component of total noise at frequencies above 500 Hz, and possibly down to 100 Hz during quiet times (Richardson *et al.*, 1995).
- Biological noise: Marine mammals are the main contributors within this category, and can contribute significantly to ambient noise levels. In addition, some fish and shrimp may also make significant contributions (Richardson *et al.*, 1995). The frequency band for biological contributions is from approximately 12 Hz to over 100 kHz.

- Tidally generated noise: Where strong tidal currents occur, these flows may contribute to the ambient noise field via creation of turbulence, generation of surface waves, and transport of sediments along the sea floor (Thorne, 1990; Blackwell and Greene, 2002). The latter mechanism is particularly important where rapid tidal flows occur over loose, relatively large sediments such as gravel (e.g., Blackwell and Greene, 2002), and levels on the order of 70 dB in the 10 kHz region have been reported from measurements immediately above the sea bed (Thorne, 1990).

Sources of ambient noise related to human activity include transportation (surface vessels and aircraft), dredging and construction, oil and gas drilling and production, seismic surveys, sonars, explosions, and ocean acoustic studies (Richardson *et al.*, 1995). Shipping noise typically dominates the total ambient noise for frequencies between 20 and 300 Hz.

The sum of the various natural and anthropogenic noise sources at any given location and time depends not only on the source levels (as determined by current weather conditions and levels of biological and shipping activity) but also on the ability of sound to propagate through the environment. In turn, sound propagation is dependent on the spatially and temporally varying properties of the water column and sea floor (discussed further in Section 4), and is frequency-dependent. As a result of the dependence on a large number of varying factors, the ambient noise levels at a given frequency and location can vary by 10-20 dB from day to day (Richardson *et al.*, 1995).

Very few measurements of ambient noise from Tampa Bay and the adjoining shelf are available. Shooter *et al.* (1982) analyzed approximately 12 hours of data collected in deep (3280 m bottom depth) waters in the western Gulf of Mexico, and reported median ambient noise levels of 77-80 dB re. $\mu Pa^2/Hz$. These levels are likely to be somewhat lower than those occurring in the vicinity of Tampa Bay, due in large part to the reduced contribution from surf in deep water. Phillips *et al.* (2006) present measurements from manatee habitats in boating channels and rivers along the Florida coast, consisting of fairly flat or slightly sloping sea floors shallower than 5 m. Ambient noise measurements in these habitats range from 69 dB in Crystal River (away from the mouth of the river) to 105 dB near the mouths of the Crystal and Indian Rivers.

3 Modeling Methodology

Starting from source locations and levels for a given scenario (Section 2), the acoustic field at any range from the source(s) is estimated using an acoustic propagation model. Sound propagation modeling uses acoustic parameters appropriate for the specific geographic region of interest, including the expected water column sound speed profile, the bathymetry, and the bottom geoacoustic properties (see Section 4), to produce site specific estimates of the radiated noise field as a function of range and depth.

JASCO's Marine Operations Noise Model (MONM) is used to predict the directional transmission loss footprint from one or more source locations. MONM is an advanced modeling package whose algorithmic engine is a modified version of the widely-used the Range Dependent Acoustic Model (RAM) (Collins *et al.,* 1996). RAM is based on the parabolic equation method using the split-step Padé algorithm to efficiently solve range dependent acoustic problems. RAM assumes that outgoing energy dominates over scattered energy and computes the solution for the outgoing wave equation. An uncoupled azimuthal approximation is used to provide 2-D transmission loss values in range and depth. RAM has been enhanced by JASCO to approximately model shear wave conversion at the sea floor using the equivalent fluid complex density approach of Zhang and Tindle (1995).

Because the modeling takes place over radial planes in range and depth, volume coverage is achieved by creating a fan of radials that is sufficiently dense to provide the desired tangential resolution. This n × 2-D approach is modified in MONM to achieve greater computational efficiency by not over-sampling the region close to the source. The desired coverage is obtained through a process of tessellation, whereby the initial fan of radials has a fairly wide angular spacing (e.g., 5 degrees), but the arc length between adjacent radials is not allowed to increase beyond a preset limit (e.g., 1.5 km) before a new radial modeling segment is started, bisecting the existing ones. The new radial need not extend back to the source because its starting acoustic field at the bisection radius is "seeded" from the corresponding range step of its neighboring traverse.

The tessellation algorithm also allows the truncation of radials along the edges of a bounding quadrangle of arbitrary shape, further contributing to computational efficiency by enabling the modeling region to be more closely tailored to an area of relevance. MONM has the capability of modeling sound propagation from multiple directional sources at different locations and merging their acoustic fields into an overall received level at any given location and depth. The received sound levels at any location within the region of interest are computed from the ⅓-octave band source levels (see Section 2.2) by subtracting the numerically modeled transmission loss at each ⅓-octave band center frequency, and summing incoherently across all frequencies to obtain a broadband value.

3.1 Estimating 90% RMS SPL from SEL

For continuous noise sources (e.g., vessel noise), MONM predicts RMS sound pressure levels (SPL) upon which U.S. safety radius requirements are based. For impulsive noise sources (impact hammering) MONM predicts sound exposure level (SEL) over a nominal time window of 1 second. For *in situ* measurements of impulsive sound sources, SPL is related to SEL via a simple relation that depends only on the RMS integration period *T*:

$$SPL_{RMS90} = SEL - 10\log_{10}(T) - 0.458$$

Here the last term accounts for the fact that only 90% of the acoustic pulse energy is delivered over the standard integration period (Malme *et al.*, 1986; Greene, 1997; McCauley *et al.*, 1998). The pulse duration at any given point in the sound field is highly sensitive to the specific multi-path arrival pattern from an acoustic source. In the absence of *in situ* measurements, accurate direct forecasting of the pulse duration at any significant range from the source is computationally prohibitive at present. The best alternative is to use a heuristic value of *T*, based on field measurements in similar environments, to estimate an RMS level from the modeled SEL. Safety radii estimated in this way are approximate since the true time spreading of the pulse has not actually been modeled. For this study, the integration period *T* has been assumed equal to a pulse width of 0.1 s, resulting in the following approximate relationship between RMS SPL and SEL:

$$SPL_{RMS90} = SEL + 10$$

In various studies where the SPL_{RMS90}, SEL, and duration have been determined for individual airgun pulses, the average offset between SPL and SEL has been found to be 5 to 15 dB, with considerable variation dependent on water depth and geo-acoustic environment (Austin *et al.* 2003; MacGillivray *et al.* 2007).

3.2 Weighting for Hearing Capabilities of Marine Mammals and Turtles

In order to take into account the differential hearing capabilities of various groups of marine mammals, the M-weighting frequency weighting approach described by Miller *et al.* (2005) is commonly applied. The M-weighting filtering process is similar to the C-weighting method that is used for assessing impacts of loud impulsive sounds on humans. It accounts for sound frequencies extending above and below the most sensitive hearing range of marine mammals within each of five functional groups: low frequency cetaceans, mid-frequency cetaceans, high frequency cetaceans, pinnipeds in water and pinnipeds in air (Table 4). The filter weights Mw_i, for frequency band *i* with center frequency f_i, are defined by:

$$Mw_i = -20\log_{10}\left(\frac{f_i^2 f_{hi}^2}{\left(f_i^2 + f_{lo}^2\right)\left(f_i^2 + f_{hi}^2\right)}\right)$$

Here f_{lo} and f_{hi} are as listed in Table 4.

Table 4: Functional hearing groups and associated auditory bandwidths, as per Miller *et al.* (2005). Note that only the in-water bandwidth is shown for pinnipeds.

Functional hearing group	Members	Estimated auditory bandwidth (Hz)	
		f_{lo}	f_{hi}
Low-frequency cetaceans	Mysticetes	7 Hz	22 kHz
Mid-frequency cetaceans	Lower-frequency odontocetes	150 Hz	160 kHz
High-frequency cetaceans	Higher-frequency odontocetes	200 Hz	180 kHz
Pinnipeds	Pinnipeds	75 Hz	75 kHz

Three types of marine mammals have been identified as being of particular interest with respect to the proposed DWP, based on their frequency of occurrence and/or endangered status (Table 5). Bottlenose and Atlantic spotted dolphins are not endangered or threatened, but are common in the vicinity of the terminal; sperm whales and manatees are both endangered. The two dolphin species and sperm whales fall into Miller *et al.*'s (2005) mid-frequency cetacean grouping. The Florida manatee is not specifically referred to by Miller *et al.* (2005). However, measurements on captive manatees (Gerstein *et al.*, 1999; Gerstein, 2002) indicate a functional hearing range of 400 Hz to 46 kHz, within the bounds listed for pinnipeds (Table 4). As such, M-weightings for pinnipeds are used as a precautionary approximation for manatees in Section 5.

Although very little information exists on the hearing capabilities of sea turtles, available literature (primarily from loggerhead turtles) indicates that sea turtles hear low frequencies, with an effective hearing range of approximately 250 Hz – 750 Hz (Ridgway *et al.*, 1969; Moein, 1994; Bartol *et al.*, 1999). Given the limited data available, it is difficult to define specific upper and lower bounds as for marine mammal M-weightings. For the purposes of this project, low-frequency cetacean weightings were applied for turtles to provide some discounting of very high frequencies. However, this should be considered an extremely precautionary measure for sea turtles, whose effective hearing range appears to be much more limited than that of even low-frequency cetaceans.

Table 5: Key species of interest in the vicinity of the proposed Port Dolphin DWP and associated M-weightings (see Table 4). Note that the weightings applied for the Florida manatee and for sea turtles should be taken as precautionary approximations (see the text).

Species of interest	**Region**	**M-weighting**
Sperm whale	Offshore (shelf edge and continental slope)	Mid-frequency cetaceans
Dolphins: Bottlenose and Atlantic spotted	Coastal, shelf, and slope/deep	Mid-frequency cetaceans
Florida manatee	Coastal (Tampa Bay)	Pinnipeds
Sea turtles	Coastal, shelf, and slope	Low-frequency cetaceans

4 MONM Parameters

4.1 Source and Receiver Locations

Modeled source locations are shown in Table 6 below; see also Figure 1 in Section 2.1. These represent the center-points of the model field. Equipment was distributed around these center points as discussed in Section 2.2, with appropriate source depths based on the proxy vessels selected (see Figure 2 through Figure 4).

From each of the source location(s), the model generates a grid of acoustic levels over any desired area and for specified receiver depths. The following receiver depths were used in each case: 2 m intervals from surface to 10 m depth, then 5 m intervals to 20 m, then 10 m intervals to 100 m depth.

Table 6: Summary of modeling locations. See also Figure 1 in Section 2.1 and details of equipment layouts in Section 2.2.

Scenario		Location	Latitude (°N)	Longitude (°W)
Construction scenarios				
1	Installation of anchors, buoys, and anchor chains	North buoy	27° 25'12.14"	83° 11' 50.11"
2	Impact pile driving (offshore)	Piggable wye site	27° 24' 13.06"	83° 10' 27.72"
3	Impact pile driving (inshore)	Subsea block valve site	27° 36' 45.87"	82° 39' 17.98"
4	Pipe laying (offshore)	15m isobath	27° 28' 43.32"	82° 56' 41.64"
5	Pipe laying (inshore)	Tampa Bay	27° 35' 42.70"	82° 41' 0.97"
6	Pipe laying through Passage Key—live boat method	Passage Key	27° 32' 39.18"	82° 44' 30.95"
7	Pipeline burial—plowing (offshore)	15m isobath	27° 28' 43.32"	82° 56' 41.64"
8	Pipeline burial—plowing (inshore)	Tampa Bay	27° 35' 42.70"	82° 41' 0.97"
Operational scenarios				
9	Offshore transit	37 km (20 nm) west of the unloading buoy	27° 08' 00"	83° 19' 00"
10	Buoy approach	18.5 km (10 nm) west of the unloading buoy	27° 18' 00"	83° 19' 00"
11	Docking	North buoy	27° 25'12.14"	83° 11' 50.11"

4.2 Frequency Range

As discussed in Section 3, MONM computes transmission loss, and hence received sound levels, for individual third-octave bands. As there is a trade-off between the number of frequencies computed and computation time, it is desirable to use the minimum frequency range that will capture most of the energy from the sources present and provide good overlap with the hearing capabilities of the species of interest in the region.

For this study, a frequency range of 10 Hz to 2 kHz was used. While this upper limit is less than the upper limit of cetacean hearing (Section 3.2), the frequency characteristics of the sound sources involved in construction and terminal operations (Section 2.2) are such that this frequency range captures almost all of the sound energy emitted by the vessels and equipment, even when applying the relatively high-frequency cutoffs associated with M-weighting for mid-frequency cetaceans.

4.3 Bathymetry

The relief of the sea floor is one of the most crucial parameters affecting the propagation of underwater sound, and detailed bathymetric data are therefore essential to accurate modeling. For each of the sites, bathymetric data were extracted from the NGDC US Coastal Relief model (Divins and Metzger 2007) with a horizontal resolution of 3 arc-seconds (approximately 92 m in the N-S direction and 82 m in the E-S direction for the study area). Bathymetric contours are shown in Figure 1 of Section 2.1.

4.4 Geoacoustic Properties

Tampa Bay is located on the southwestern flank of the Ocala Platform (Brooks and Doyle, 1998). This section of consolidated sediments, which is represented by limestones of different formations, is covered by a thin layer of unconsolidated sediments. The top of the bedrock section consists of soft Miocene-Oligocene limestones with a thickness of 80-190 m, which is underlain by hard dolomite and limestone (Crandall, 2007).

Surface sediments in the region are dominated by the Tampa Bay ebb-tidal delta, which is responsible for continuous late-Holocene sediment cover extending to approximately 15 km offshore (Locker *et al.*, 1999; Hine *et al.*, 2001). These sediments consist of fine quartz sand, as well as some coarse sand and gravel size carbonates. While the sediment layer is variable, sediment thicknesses of 4-5 m are common near shore. Beyond the near-shore region, the sediment cover thins to expose occasional hard-bottom (Locker *et al.*, 1999). Similarly, sediments between the mouth of Tampa Bay and Port Manatee are primarily sandy (USGS, 2007). Sediment thicknesses here are typically less than 6 m, although this increases to a depth of 16-17 m within the deepest depressions (Brooks and Doyle, 1998; Edgar, 2002).

Taking into account the information presented above, the geoacoustic profile was constructed based on values suggested by Hamilton (1980), assuming an average profile consisting of 5 m of fine sand overlying two limestone layers (Table 7).

Table 7: Tampa Bay geoacoustic profile

Depth (m)	Description	Density (g/cm^3)	P-wave		S-wave	
			Velocity (m/s)	Attenuation	Velocity (m/s)	Attenuation
0–5	unconsolidated sandy sediment	1.8-1.85	1700–1750	0.8	200	0.1
5–125	soft limestone	2.5	2500	0.25		
>125	hard limestone	2.7	3500	0.13		

4.4.1 Alternative Profiles for Sensitivity Testing

Particularly in shallow water, where opportunities exist for multiple bottom interactions, model predictions are very sensitive to the bottom parameters used. As a result, uncertainty in the geoacoustic profile translates to uncertainty in the model results. For example, in the case of Tampa Bay and the adjoining continental shelf, there is considerable spatial variability in the thickness of the near-surface sand layer. In addition, there is some uncertainty in the thicknesses and geoacoustic properties of the underlying limestone layers.

In order to quantify these sources of variability, additional model runs were carried out with a series of modified geoacoustic profiles, based on the main profile in Table 7. The following variations were considered:

- The thickness of the sand layer was varied, from no sand at all to a maximum thickness of 10 m.
- The properties of the soft limestone layer were modified to simulate a slightly harder, higher-velocity rock: density was increased by 0.1 g/cm^3, and p-wave velocity was increased by 500 m/s.
- The depth of the interface between the soft and hard limestones was varied from 80 m to 190 m, bracketing the range of interface depths reported by Crandall (2007).

4.5 Sound Speed Profiles

Sound speed profiles in the ocean for each modeling location were derived from the US Naval Oceanographic Office's Generalized Digital Environmental Model (GDEM) database (Teague *et al.,* 1990). The latest release of the GDEM database (version 3.0) provides average monthly profiles of temperature and salinity for the world's oceans on a latitude/longitude grid with 0.25 degree resolution. Profiles in GDEM are provided at 78 fixed depth points up to a maximum depth of 6,800 m. The profiles in GDEM are based on historical observations of global temperature and salinity from the US Navy's Master Oceanographic Observational Data Set (MOODS).

For each acoustic model scenario, a single temperature/salinity profile was extracted from the GDEM database for the appropriate season and source location and converted to speed of sound in seawater using the equations of Coppens (1981):

$$
\begin{aligned}
c(z,T,S) &= 1449.05 + 45.7T - 5.21t^2 - 0.23t^3 \\
&\quad + (1.333 - 0.126t + 0.009t^2)(S - 35) + \Delta \\
\Delta &= 16.3Z + 0.18Z^2 \\
Z &= (z/1000)(1 - 0.0026\cos(2\phi)) \\
t &= T/10
\end{aligned}
$$

Here z is depth in meters, T is temperature in degrees Celsius, S is salinity in psu and φ is latitude (in radians).

The resulting sound speed profiles for the study area are shown in Figure 5, for the month of January. Note that the sound speed profile will vary seasonally. As terminal operations will occur year-round, and construction activities will cover several months, this has the potential to produce seasonal variations in the impacts from underwater noise associated with the DWP. January was selected as a "worst-case" month for offshore operations, as the cooler temperatures and decreased stratification will produce a sound speed profile which will tend to reduce refraction of sound into the bottom and thus reduce transmission loss. In contrast, the July profile for the offshore region is more downward-refracting

(Figure 6). In order to test the effect of these seasonal variations on received sound levels, selected model scenarios were run for both January and July sound speed profiles.

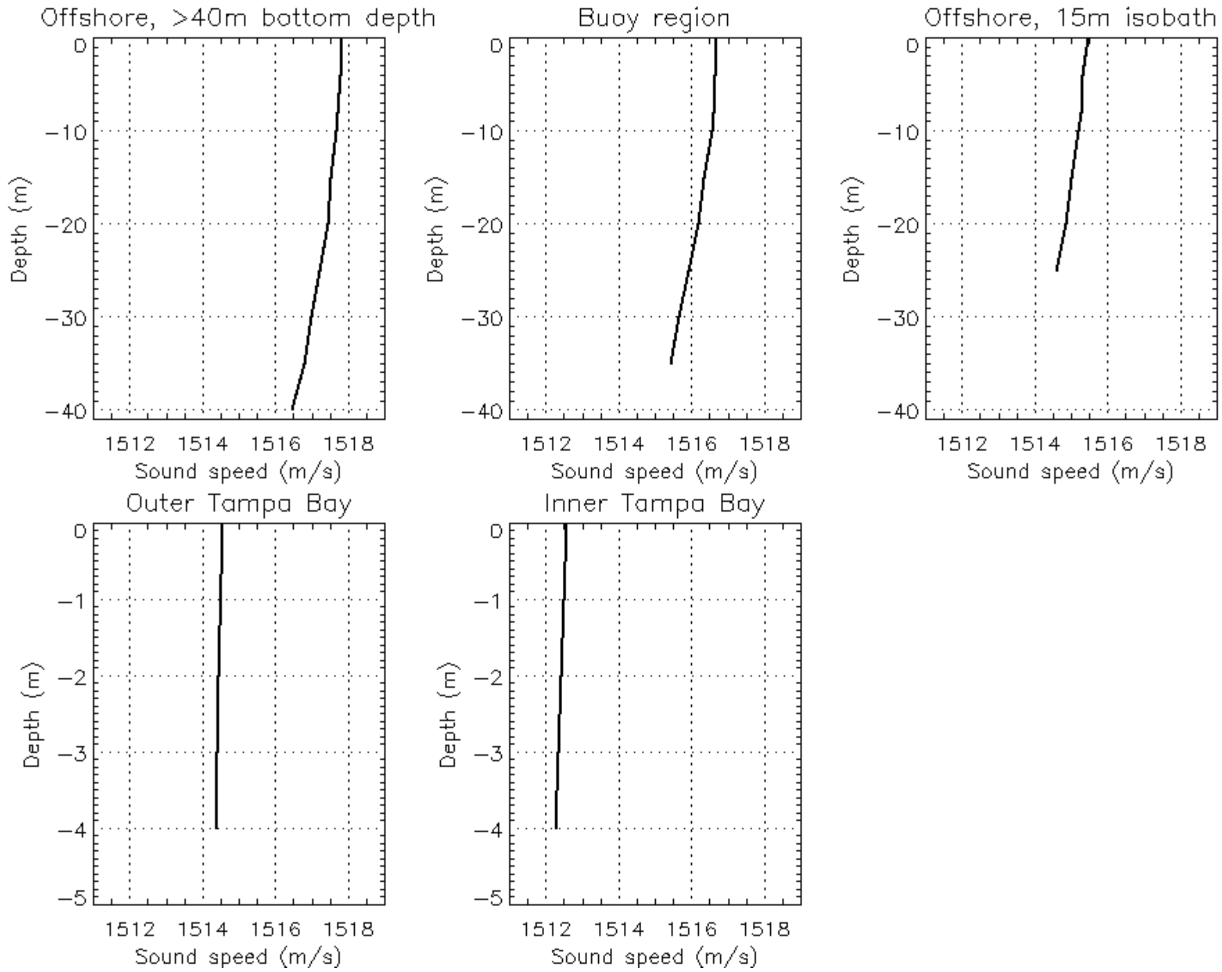

Figure 5: Predicted sound speed profiles for the month of January, from GDEM version 3.0 (Teague *et al.,* 1990).

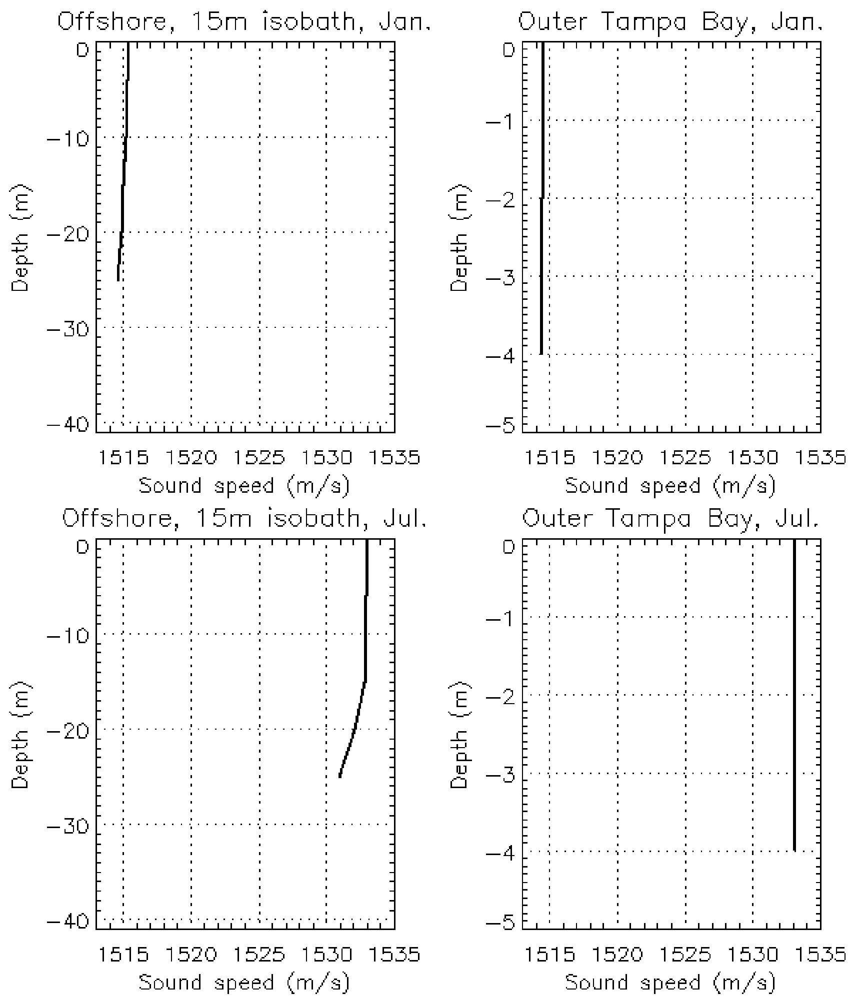

Figure 6: Predicted sound speed profiles for the months of January and July, from GDEM version 3.0 (Teague *et al.,* 1990).

5 Model Results

The MONM propagation model was run in the full n × 2-D sense as described in Section 3. Geographically rendered maps of the estimated received sound levels are shown in Appendix B for each of the scenarios described in Section 2. The tables in the following sub-sections summarize the results of the acoustic modeling in terms of radii to threshold values of 120 dB to 190 dB RMS. In addition, the threshold levels relevant to NMFS criteria for Level A and Level B harassment are highlighted. Note that the radial resolution of the model runs was 10 m.

For an impulsive source such as impact hammering, the acoustic level values in the model output represent the SEL metric, a suitable measure of the impact of an impulsive sound because it reflects the total acoustic energy delivered over the duration of the event at a receiver location. In order to determine the RMS SPL, a pulse duration of 0.1 s was assumed, resulting in a conversion factor of +10 dB (Section 3.1). Thus, RMS levels (in dB re 1μPa) were taken to be 10 dB higher than SEL values (in dB re $1\mu Pa^2 \cdot s$). This conversion is not required for continuous noise sources (vessel noise, plowing), for which the model outputs RMS values.

For each sound level threshold, the tables below list the 95% radius. Given a regularly gridded spatial distribution of modeled received levels, the 95% radius is defined as the radius of a circle that encompasses 95% of the grid points whose value is equal to or greater than the threshold value. This definition is meaningful in terms of potential impact to an animal because, regardless of the geometrical shape of the noise footprint for a given threshold level, it always provides a range beyond which no more than 5% of a uniformly distributed population would be exposed to sound at or above that level. Modeled sound levels were sampled at several depths at each site, up to the seafloor depth. The tables list radii based on maximum received levels over these ranges of depths.

Note that for some scenarios, higher threshold values only occur in the vicinity of individual pieces of equipment, with relatively little overlap of the sound fields from neighboring vessels. In these cases the overall radius depends primarily on the spacing between the vessels, and a single scenario-specific radius cannot sensibly be defined. For example, in the case of pipe laying in Passage Key (Figure 7 below), contour levels greater than 160 dB only occur in the immediate vicinity of the barge and tugs. In the tables that follow, such a situation is indicated by an entry such as “<0.2 km”.

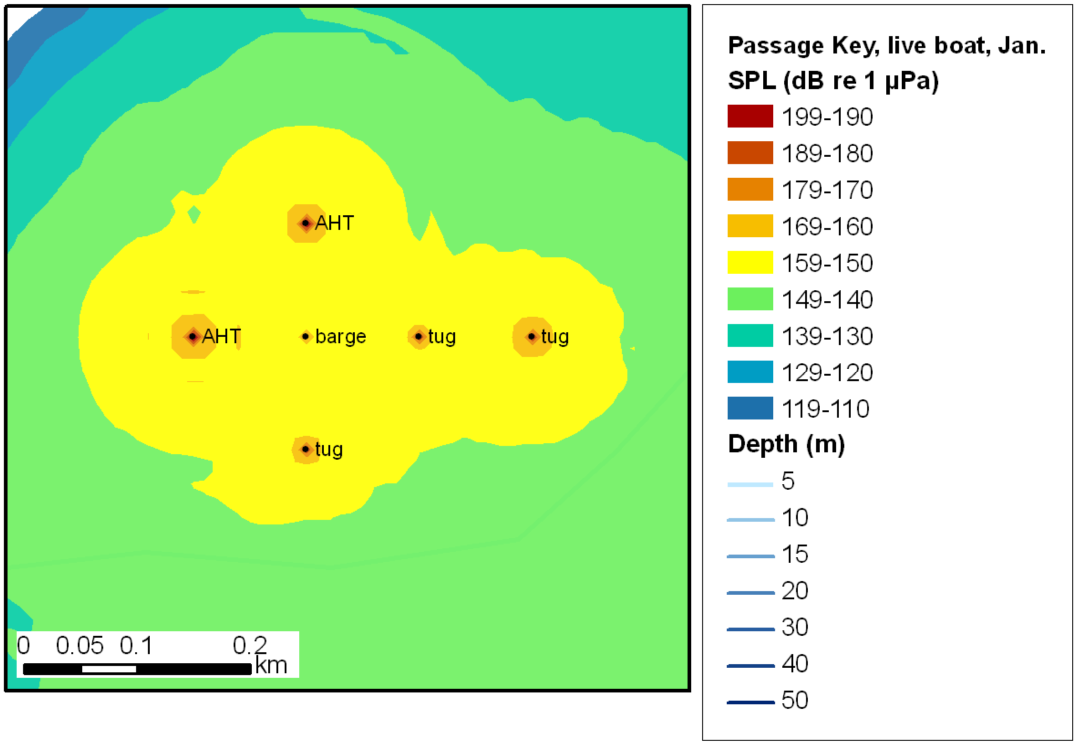

Figure 7: Estimated received sound levels near the sources, for pipe laying in Passage Key (see also Figure 12 in Appendix B). Note that "AHT" refers to an anchor-handling tug, while "tug" refers to a tug whose propulsion system is active but which is not actively pushing or pulling.

5.1 Un-Weighted Model Results

Raw model results, i.e. without application of M-weightings (see Section 3.2), are presented in the following two sub-sections.

5.1.1 Construction Scenarios

Radii to various threshold values are shown below for construction activities occurring in the offshore (Table 8) and inshore (Table 9) regions. See also Figure 8 through Figure 15 in Appendix B. Impact hammering is by far the loudest of the activities. However, it will likely occur only during relatively brief periods of time. Radii for pipe laying and burial are similar to one another, on the order of 6-8 km for the 120 dB contour and less than the equipment spacing for the 180 dB contour (Table 8, Table 9). Note that radii for a given activity vary with water depth; for example, the radius to the 120 dB contour during pipe laying varies from 7.5 km offshore (water depth of 15 m) to a mere 1.6 km in Passage Key (water depth less than 5 m). This is primarily due to the dramatically reduced transmission of lower-frequency sounds in shallower waters. For example, in the region of the Passage Key site the water depths are less than a single wavelength for frequencies up to at least a few hundred Hz ($f=c/\lambda$). Considering Figure 2 in Section 2.2, we see that most of the energy from the vessels associated with pipe laying occurs at these low frequencies, and so will propagate poorly.

Table 8: 95th percentile radii for offshore construction scenarios. See Figure 1 for site locations. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics. Note that radii for threshold values up to 140 dB exceeded the model bounds for impact hammering.

SPL (dB re 1 μPa)	95th percentile radius (km)			
	Buoy installation	Impact hammering	Pipe laying	Pipe burial
120	***3.9***	>20	***7.5***	***8.4***
130	1.4	>20	3.8	3.9
140	0.35	>20	2.0	2.0
150	<0.20	14.4	0.52	0.59
160	<0.20	***4.5***	<0.20	<0.20
170	<0.20	1.1	<0.20	<0.20
180	***<0.20***	***0.18***	***<0.20***	***<0.20***
190	***<0.20***	***0.03***	***<0.20***	***<0.20***

Table 9: 95th percentile radii for inshore construction scenarios. See Figure 1 for site locations. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics.

SPL (dB re 1 μPa)	95th percentile radius (km)			
	Impact hammering	Pipe laying: Passage Key	Pipe laying: Tampa Bay	Pipe burial: Tampa Bay
120	18.3	***1.6***	***6.0***	***6.7***
130	12.3	0.95	2.1	2.4
140	8.0	0.49	0.89	0.98
150	3.7	0.24	0.39	0.44
160	***1.9***	<0.21	<0.20	<0.20
170	0.85	<0.20	<0.20	<0.20
180	***0.30***	***<0.20***	***<0.20***	***<0.20***
190	***0.07***	***<0.20***	***<0.20***	***<0.20***

5.1.2 Operational Scenarios

Radii to various threshold values are shown in Table 10 below for transit, buoy approach, and docking of an SRV. See also Figure 16 through Figure 18 in Appendix B. Radii are similar for the transit and docking scenarios, i.e. 3.6-3.8 km for the 120 dB contour. As might be expected given the relative source levels (Figure 4 in Section 2.2.5), radii are considerably less for the approach scenario, during which main propulsion is at half speed and thrusters are not yet in operation.

Table 10: 95th percentile radii for operational scenarios. See Figure 1 for site locations. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics. Note that values are not shown for threshold values higher than the source level.

SPL (dB re 1 μPa)	**95th percentile radius (km)**		
	SRV transit	**SRV buoy approach**	**SRV docking**
120	***3.8***	***1.7***	***3.6***
130	1.5	0.43	1.5
140	0.32	0.09	0.37
150	0.05	0.01	0.09
160	0.01	<0.01	0.01
170	<0.01	<0.01	<0.01
180	***<0.01***	***------***	***<0.01***
190	***------***	***------***	***------***

5.2 Weighting for Hearing Capabilities of Marine Mammals and Turtles

As discussed in Section 3.2, model results may be weighted to reflect the hearing capabilities of various marine species. Ninety-fifth percentile radii are shown in Table 8 through Table 13 below for various combinations of model scenarios and functional hearing groups, based on the study sites listed in Table 1 of Section 2.2 and the species distributions listed in Table 5 of Section 3.2.

Comparing the radii in the following tables with the un-weighted radii in the previous section, we see relatively little reduction after weighting for low-frequency cetaceans and pinnipeds, as might be expected given their relatively low values for f_{lo} (see Table 4 of Section 3.2). Note, however, that the actual hearing capabilities of sea turtles and manatees, for which these M-weightings are applied as precautionary approximations, are likely to be less. As a result, these radii likely represent over-estimates for these species. A greater reduction in 95th percentile radii is seen when weighting for mid-frequency cetaceans (which includes sperm whales and dolphins).

Table 11: 95th percentile radii for offshore construction scenarios, M-weighted for low- and mid-frequency cetaceans. See Table 8 for un-weighted radii. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics.

SPL (dB re 1 μPa)	95th percentile radius (km)			
	Buoy installation	**Impact hammering**	**Pipe laying**	**Pipe burial**
Low-frequency cetaceans				
120	***3.8***	>20	***7.4***	***8.3***
130	1.4	>20	3.6	3.8
140	0.35	>20	1.8	1.9
150	<0.20	14.3	0.51	0.55
160	<0.20	***4.5***	<0.20	<0.20
170	<0.20	1.1	<0.20	<0.20
180	***<0.20***	***0.18***	***<0.20***	***<0.20***
190	<0.01	0.03	<0.20	<0.20
Mid-frequency cetaceans				
120	***2.9***	>20	***6.8***	***7.9***
130	0.90	>20	2.2	2.7
140	0.22	>20	0.76	0.91
150	<0.20	11.1	0.24	0.28
160	<0.20	***3.1***	<0.20	<0.20
170	<0.20	0.72	<0.20	<0.20
180	***<0.01***	***0.10***	***<0.20***	***<0.20***
190	<0.01	0.01	<0.01	<0.01

Table 12: 95th percentile radii for inshore construction scenarios, M-weighted for low- and mid-frequency cetaceans and for pinnipeds. See Table 9 for un-weighted radii. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics. Note that both cetacean and pinniped criteria are shown for the pinniped M-weighting, as manatees do not clearly belong to either group for the purposes of harassment criteria.

SPL (dB re 1 μPa)	95th percentile radius (km)			
	Impact hammering	**Pipe laying: Passage Key**	**Pipe laying: Tampa Bay**	**Pipe burial: Tampa Bay**
Low-frequency cetaceans				
120	18.3	***1.6***	***6.0***	***6.7***
130	12.2	0.95	2.1	2.4
140	7.9	0.49	0.88	0.98
150	3.7	0.24	0.39	0.44
160	***1.9***	<0.21	<0.20	<0.20
170	0.85	<0.20	<0.20	<0.20
180	***0.30***	***<0.20***	***<0.20***	***<0.20***
190	0.07	<0.20	<0.20	<0.20
Mid-frequency cetaceans				
120	18.3	***1.5***	***5.9***	***6.6***
130	12.2	0.92	2.0	2.3
140	7.8	0.40	0.77	0.88
150	3.6	0.22	0.28	0.32
160	***1.7***	<0.21	<0.20	<0.20
170	0.70	<0.20	<0.20	<0.20
180	***0.20***	***<0.20***	***<0.20***	***<0.20***
190	0.04	<0.01	<0.01	<0.01
Pinnipeds (in water)				
120	18.3	***1.5***	***6.0***	***6.7***
130	12.3	0.94	2.1	2.4
140	7.9	0.45	0.84	0.94
150	3.7	0.23	0.34	0.39
160	***1.8***	<0.21	<0.20	<0.20
170	0.80	<0.20	<0.20	<0.20
180	***0.26***	***<0.20***	***<0.20***	***<0.20***
190	***0.06***	***<0.01***	***<0.01***	***<0.01***

Table 13: 95th percentile radii for operational scenarios, M-weighted for low- and mid-frequency cetaceans. See Table 10 for un-weighted radii. Radii corresponding to Level A and Level B harassment criteria are shown in bold italics. Note that values are not shown for threshold values higher than the un-weighted source level.

SPL (dB re 1 μPa)	95th percentile radius (km)		
	SRV transit	SRV buoy approach	SRV docking
Low-frequency cetaceans			
120	***3.8***	***1.6***	***3.5***
130	1.5	0.40	1.5
140	0.31	0.09	0.34
150	0.04	0.01	0.08
160	0.01	<0.01	0.01
170	<0.01	<0.01	<0.01
180	***<0.01***	***------***	***<0.01***
190	------	------	------
Mid-frequency cetaceans			
120	***1.7***	***0.5***	***1.7***
130	0.37	0.11	0.41
140	0.05	0.01	0.10
150	0.01	<0.01	0.01
160	<0.01	<0.01	<0.01
170	<0.01	<0.01	<0.01
180	***<0.01***	***------***	***<0.01***
190	------	------	------

5.3 Sensitivity of Model Results to Environmental Parameters

As discussed in Sections 4.4 and 4.5, model results are sensitive to uncertainties and variations in the environmental parameters that are input to the model, including water column sound speed profiles and geoacoustic properties of the sea floor. In order to quantify the effects of these sources of uncertainty, MONM was run for a number of variations on the main setup described in the previous sections, using pipe laying as an example scenario (effects will be similar for other scenarios).

As expected given the seasonal variation in the water column sound speed profile (see Figure 6 in Section 4.5), radii to various thresholds are less in July than they are in January (Table 14). As a result, the assumption presented in Section 4.5 that January values would represent a seasonal "worst-case" appears to be valid.

Table 14: 95th percentile radii for inshore and offshore pipe laying, modeled using water column sound speed profiles from two different times of year (see Figure 6 in Section 4.5). Radii corresponding to Level A and Level B harassment criteria are shown in bold italics.

SPL (dB re 1 μPa)	95th percentile radius (km): Pipe laying			
	Offshore, January	Offshore, July	Inshore, January	Inshore, July
120	***7.5***	***6.9***	***6.0***	***5.5***
130	3.8	3.3	2.1	2.0
140	2.0	1.8	0.89	0.83
150	0.52	0.50	0.39	0.37
160	<0.20	<0.20	<0.20	<0.20
170	<0.20	<0.20	<0.20	<0.20
180	***<0.20***	***<0.20***	***<0.20***	***<0.20***
190	***<0.20***	***<0.20***	***<0.20***	***<0.20***

The model results were found to be sensitive to the presence or absence of an unconsolidated sand layer overlying the limestone basement (Table 15; see also Section 4.4.1). The effect is slightly more pronounced at the inshore site, where shallower water favors greater interaction with the bottom, hence magnifying the effect of changing the bottom characteristics. While adding even a thin sand layer significantly reduces the radii, particularly at the inshore site, the change produced by increasing the depth of the sand layer from 2.5 m to 5 m is relatively small (Table 15). Similarly, increasing the thickness of the sand layer even further to 10 m has no significant effect on the estimated radii. Varying the geoacoustic properties of the soft limestone layer and the depth of the interface between the two limestone layers (as discussed in Section 4.4.1) also fails to produce any significant changes in the modeled radii.

Table 15: 95th percentile radii for inshore and offshore pipe laying, modeled using a sand layer of varying thickness (see Section 4.4.1). Radii corresponding to Level A and Level B harassment criteria are shown in bold italics.

SPL (dB re 1 μPa)	95th percentile radius (km): Pipe laying					
	Offshore, no sand	Offshore, 2.5 m sand layer	Offshore, 5 m sand layer	Inshore, no sand	Inshore, 2.5m sand layer	Inshore, 5 m sand layer
120	***11.8***	***7.8***	***7.5***	***9.1***	***6.0***	***6.0***
130	4.8	4.0	3.8	3.6	2.2	2.1
140	2.0	2.0	2.0	1.5	0.96	0.89
150	0.72	0.62	0.52	0.67	0.45	0.39
160	<0.20	<0.20	<0.20	0.22	<0.20	<0.20
170	<0.20	<0.20	<0.20	<0.20	<0.20	<0.20
180	***<0.20***	***<0.20***	***<0.20***	***<0.20***	***<0.20***	***<0.20***
190	***<0.20***	***<0.20***	***<0.20***	***<0.20***	***<0.20***	***<0.20***

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Appendix A: Source Levels

SOURCE LEVELS

The third-octave band source levels input to the acoustic propagation model for various pieces of equipment are listed in Table 16 through Table 18 below. Their use is discussed further in Section 2.

Table 16: Third-octave band source levels for vessels involved in construction-related modeling scenarios (see Section 2.2). Source depths are 2.2 m and 3 m for the Castoro II and Britoil 51, respectively.

Frequency (Hz)	Castoro II (barge), anchor operations	Castoro II (barge), pipe laying	Britoil 51 (tug), anchor operations	Britoil 51 (tug), transiting
10	175.6	164.7	202.8	188.7
12.5	170.0	166.2	196.5	182.7
16	162.7	162.7	193.1	174.1
20	158.3	165.5	191.1	167.5
25	151.8	169.0	196.7	165.2
31.5	149.1	159.6	188.8	172.2
40	146.6	156.2	177.3	182.2
50	147.9	157.7	176.4	170.2
63	153.3	154.3	179.2	167.1
80	153.2	152.2	178.8	164.9
100	156.4	153.0	178.1	161.8
125	162.2	159.8	176.7	166.0
160	155.6	152.5	175.9	167.6
200	151.4	149.8	173.5	167.5
250	151.7	152.2	178.8	164.8
315	143.6	142.4	172.8	165.2
400	145.2	147.2	165.4	165.2
500	145.8	144.8	170.7	169.8
630	145.5	142.7	168.8	159.9
800	150.5	147.5	165.1	158.6
1000	150.8	148.7	164.2	163.6
1250	142.7	141.7	167.3	161.0
1600	138.6	136.1	165.9	164.9
2000	143.2	139.3	166.5	164.2
Broadband	**177.2**	**173.9**	**205.2**	**190.8**

Table 17: Third-octave band source levels for non-vessel activities involved in construction-related modeling scenarios (see Section 2.2). Source depth for the impact hammer is half the local water depth; source depth for the dredge is 2.2 m.

Frequency (Hz)	Impact hammer	Aquarius dredge
10	202.0	153.0
12.5	202.0	153.0
16	192.0	153.0
20	187.0	153.0
25	184.0	165.0
31.5	186.0	162.0
40	188.0	169.0
50	184.0	172.0
63	188.0	171.0
80	198.0	172.0
100	200.0	179.0
125	204.0	178.0
160	208.0	180.0
200	209.5	179.0
250	209.0	177.0
315	204.0	177.0
400	204.5	176.0
500	205.0	173.0
630	198.0	170.0
800	195.0	169.0
1000	194.0	169.0
1250	195.0	169.0
1600	194.0	169.0
2000	192.0	169.0
Broadband	**216.2**	**187.7**

Table 18: Third-octave band source levels for operational modeling scenarios (see Section 2.2). Source levels for docking include main SRV propulsion at dead slow, two bow thrusters, and one stern thruster. Source depth is 6 m in all cases.

Frequency (Hz)	SRV, full speed transit	SRV, half speed transit	SRV, docking
10	171.0	162.4	171.5
12.5	171.0	162.4	171.5
16	171.0	162.4	171.5
20	171.0	162.4	171.5
25	171.0	162.4	171.5
31.5	171.0	162.4	171.5
40	171.0	162.4	171.5
50	171.0	162.4	171.5
63	171.0	162.4	171.5
80	171.0	162.4	171.5
100	171.0	162.4	171.5
125	169.1	160.5	169.6
160	167.0	158.4	167.4
200	165.0	156.4	165.5
250	163.1	154.5	163.6
315	161.1	152.5	161.6
400	159.0	150.4	159.5
500	157.1	148.5	157.5
630	155.1	146.5	155.5
800	153.0	144.4	153.5
1000	151.0	142.4	151.5
1250	149.1	140.5	149.6
1600	147.0	138.4	147.4
2000	145.0	136.4	145.5
Broadband	**182.1**	**173.5**	**182.6**

Appendix B: Sound Maps

SOUND MAPS

Sound field maps are shown below for each of the scenarios described in Section 2 (see summaries in Table 1 and Figure 1). At each point within the sound field, maximum sound levels are selected over all modeled depths, down to the local bottom depth. In the case of the impact hammer, which is an impulsive source, SPL_{RMS} values were estimated from the SEL values output by the model by the addition of 10 dB (see Section 3.1). Model results are discussed further in Section 5.

Buoy Installation

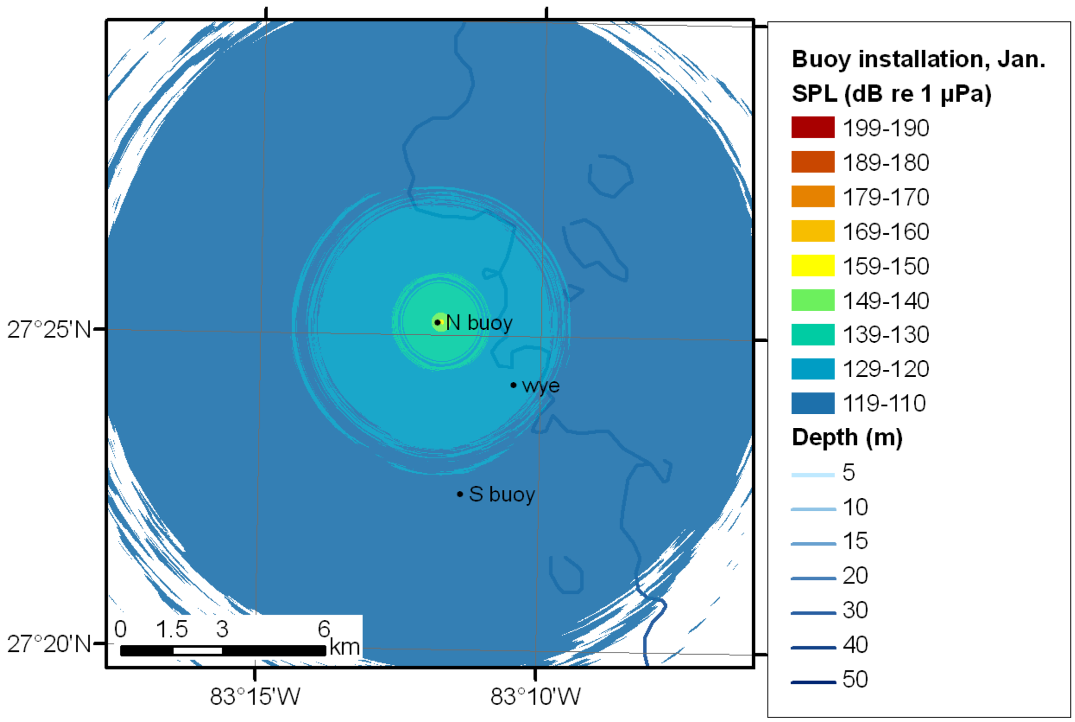

Figure 8: Estimated received sound levels for activities related to installation of the north anchor buoy (see Table 1, Section 2.2.1).

Impact Hammering

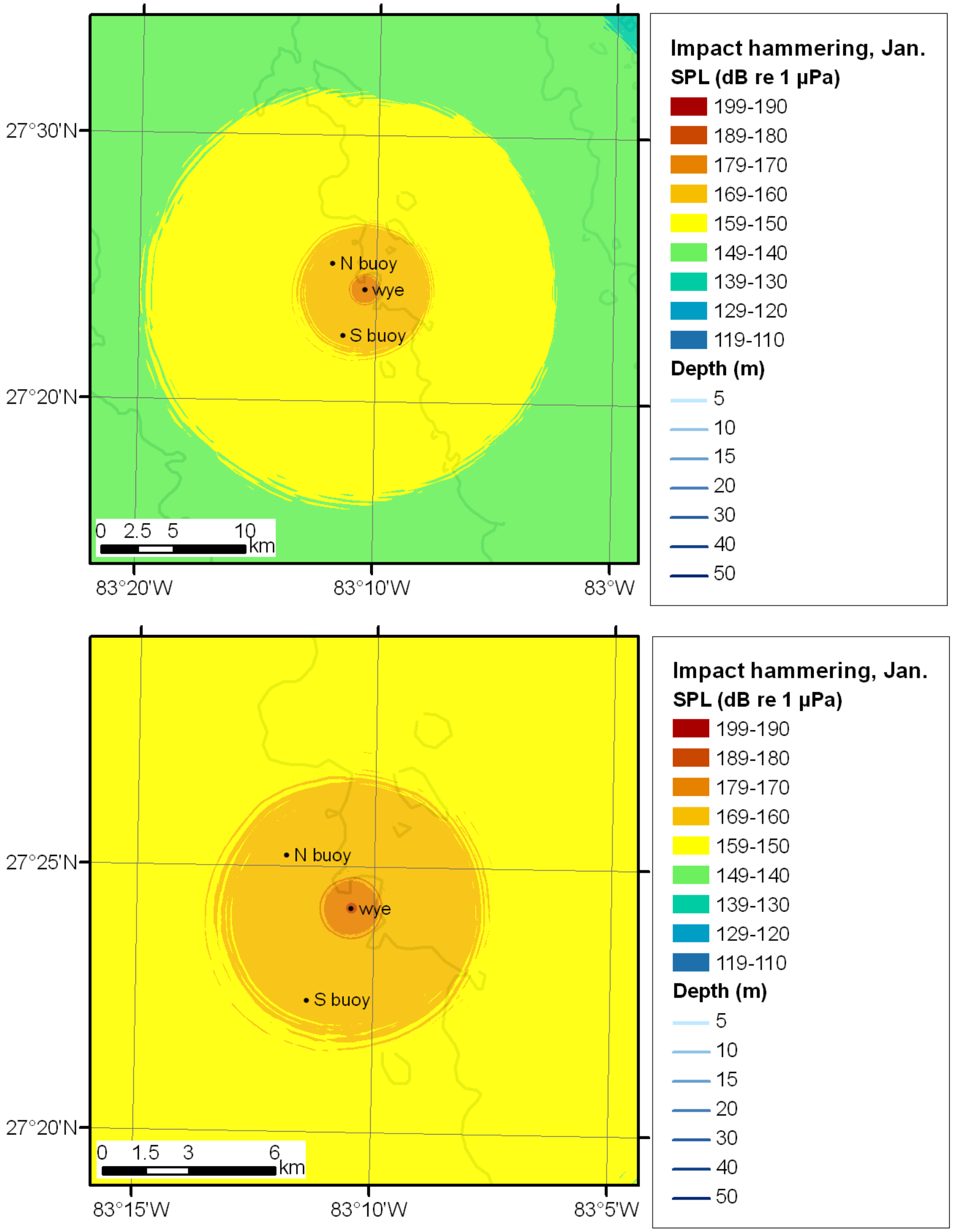

Figure 9: Estimated received sound levels for impact hammering at the piggable wye (see Table 1, Section 2.2.2). The lower panel is a zoomed-in (2x) version of the upper panel.

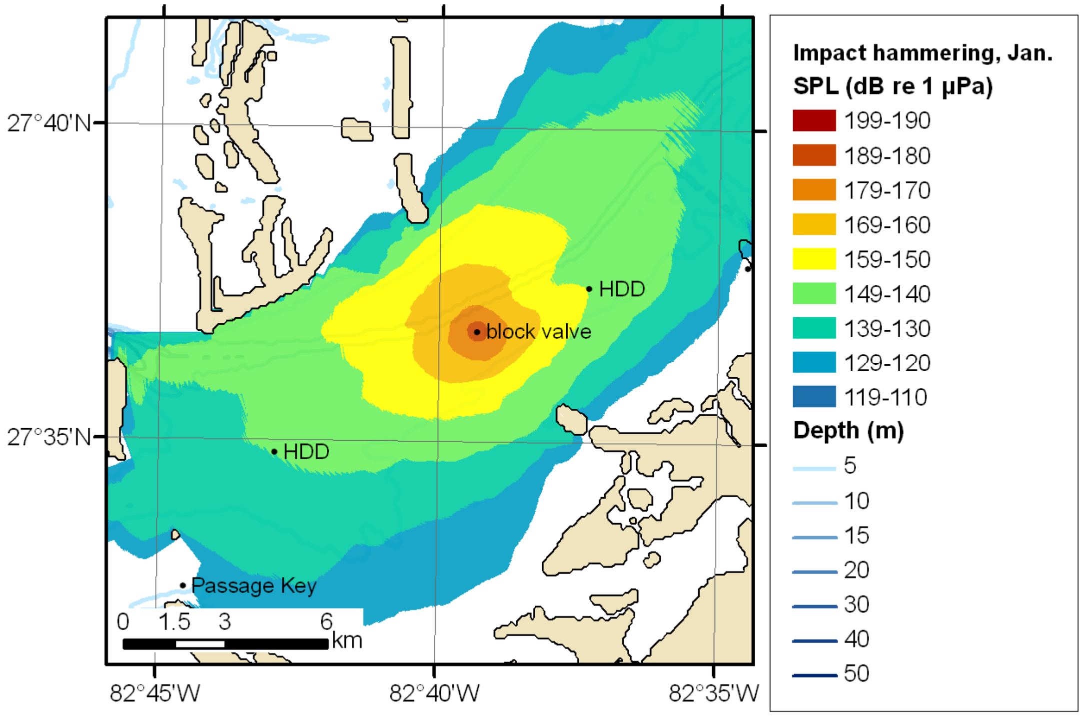

Figure 10: Estimated received sound levels for impact hammering at the subsea block valve (see Table 1, Section 2.2.2).

Pipe Laying

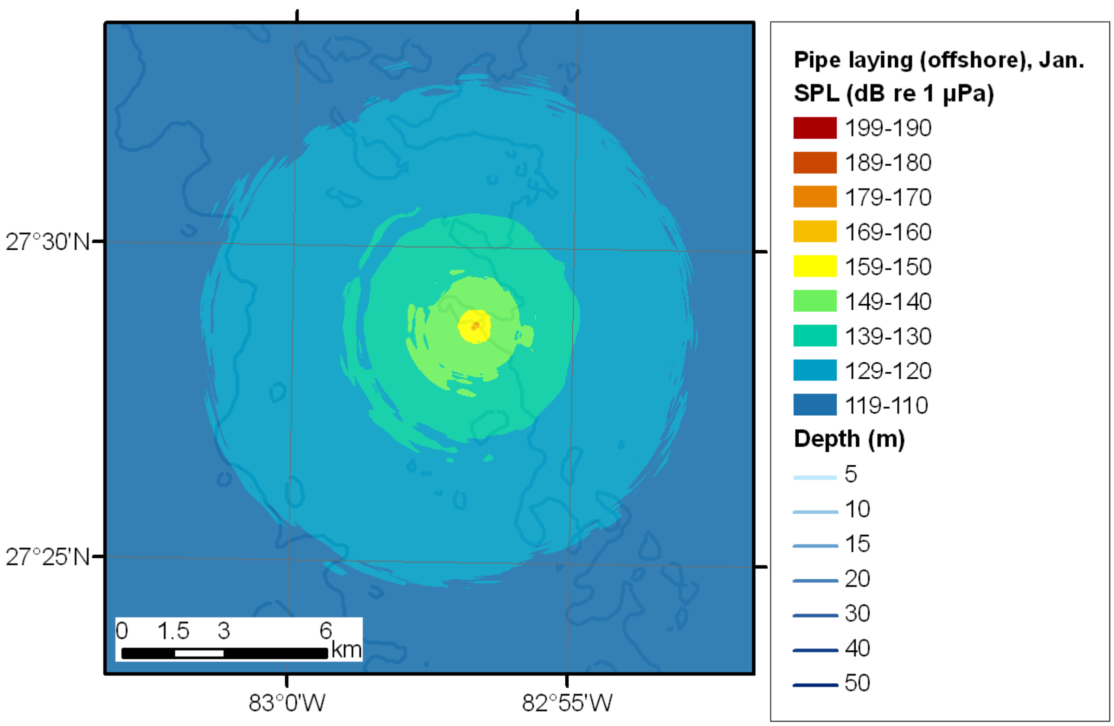

Figure 11: Estimated received sound levels for offshore pipe laying (see Table 1, Section 2.2.3).

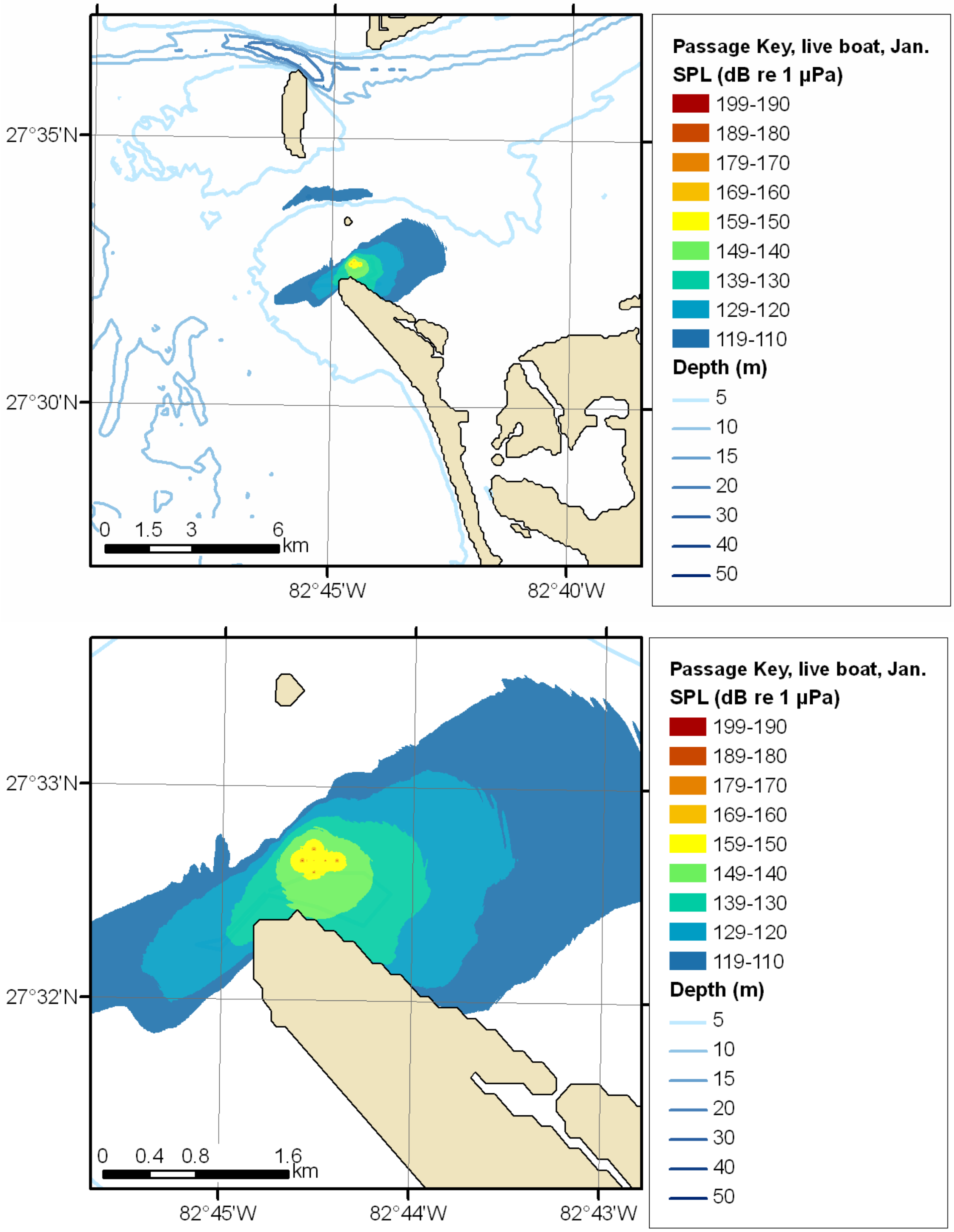

Figure 12: Estimated received sound levels for pipe laying in Passage Key (see Table 1, Section 2.2.3). The lower panel is a zoomed-in version of the upper panel.

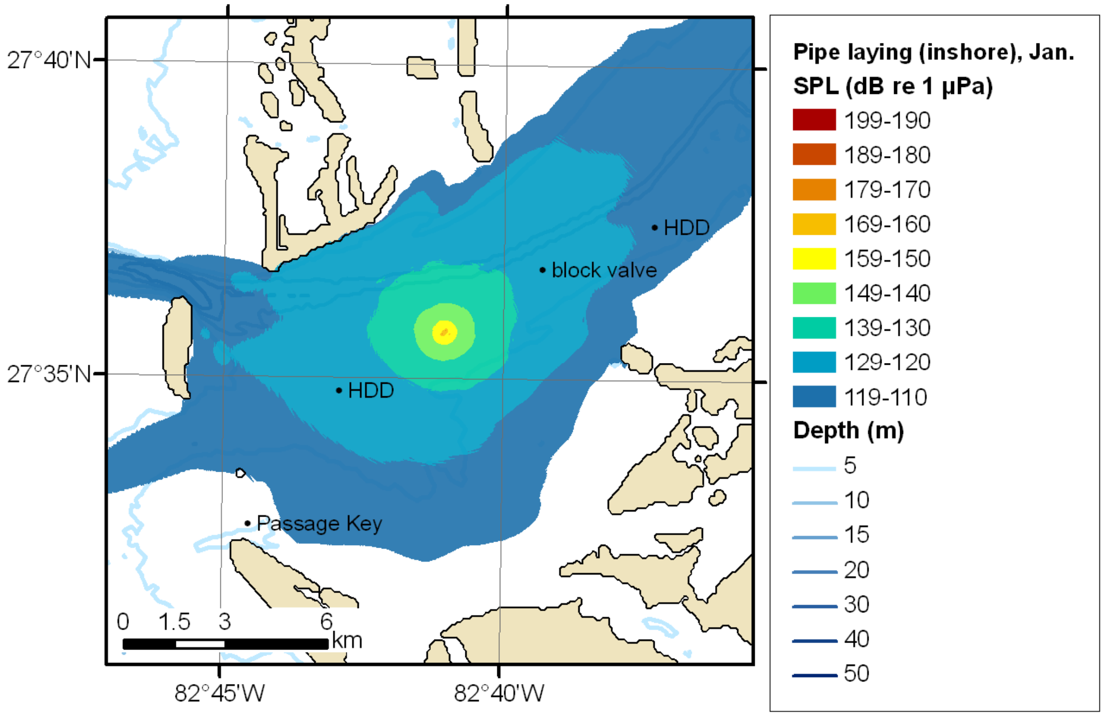

Figure 13: Estimated received sound levels for inshore pipe laying (see Table 1, Section 2.2.3).

Pipe Burial

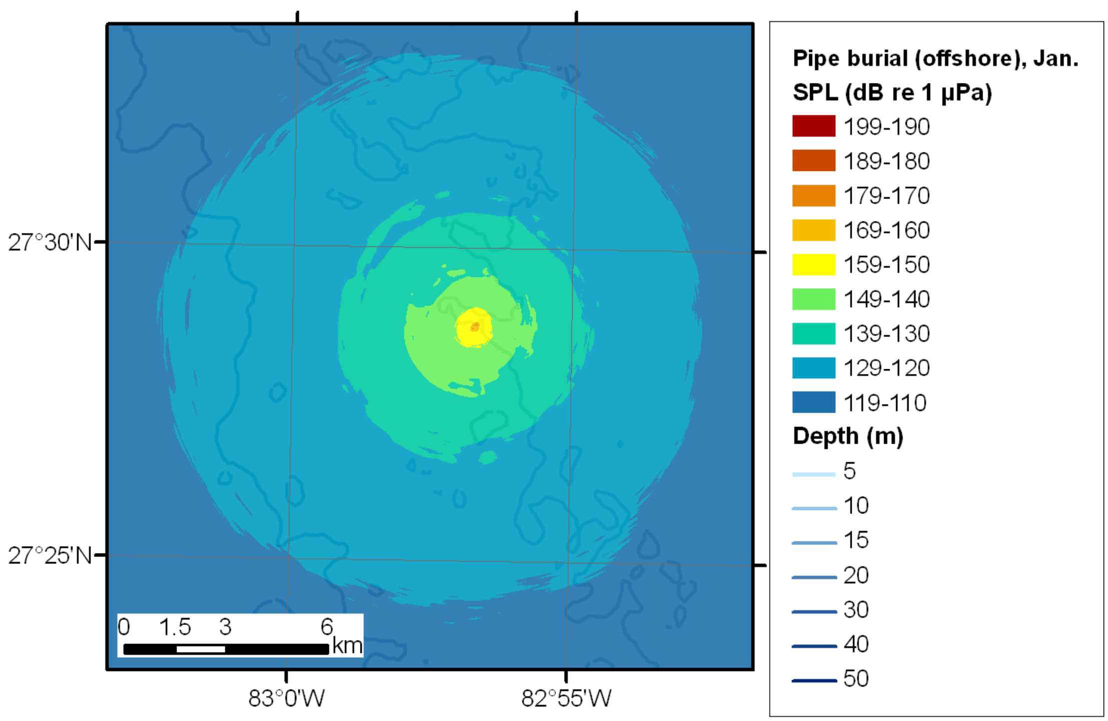

Figure 14: Estimated received sound levels for offshore pipe burial (see Table 1, Section 2.2.4).

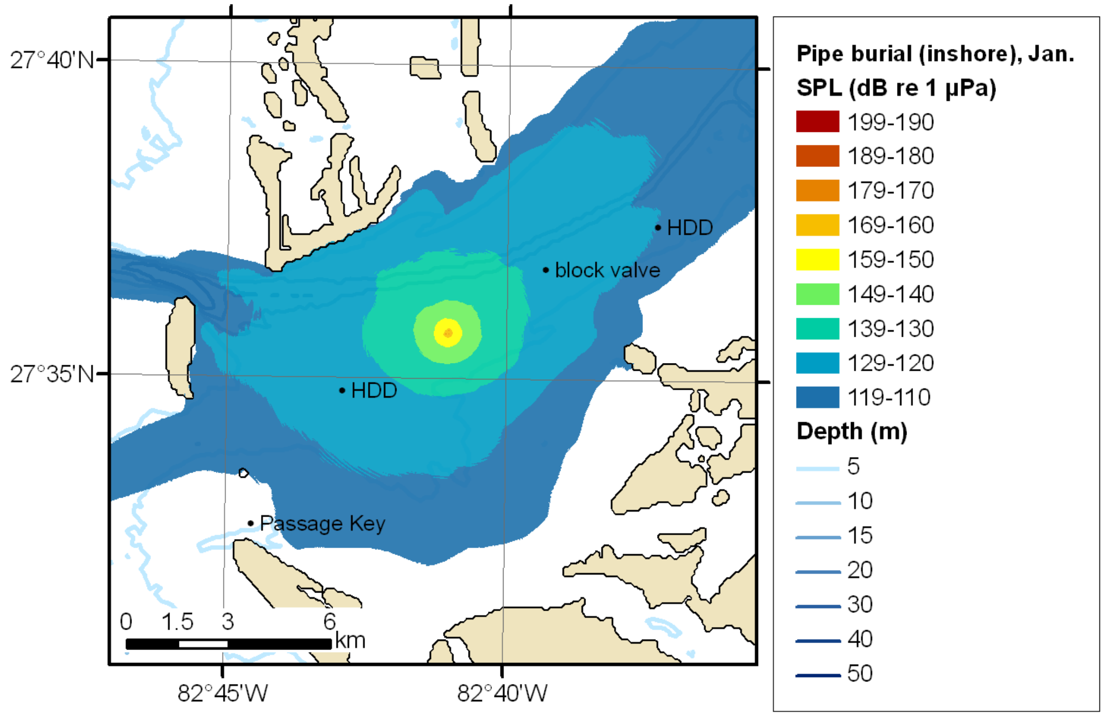

Figure 15: Estimated received sound levels for inshore pipe burial (see Table 1, Section 2.2.4).

Operational Scenarios

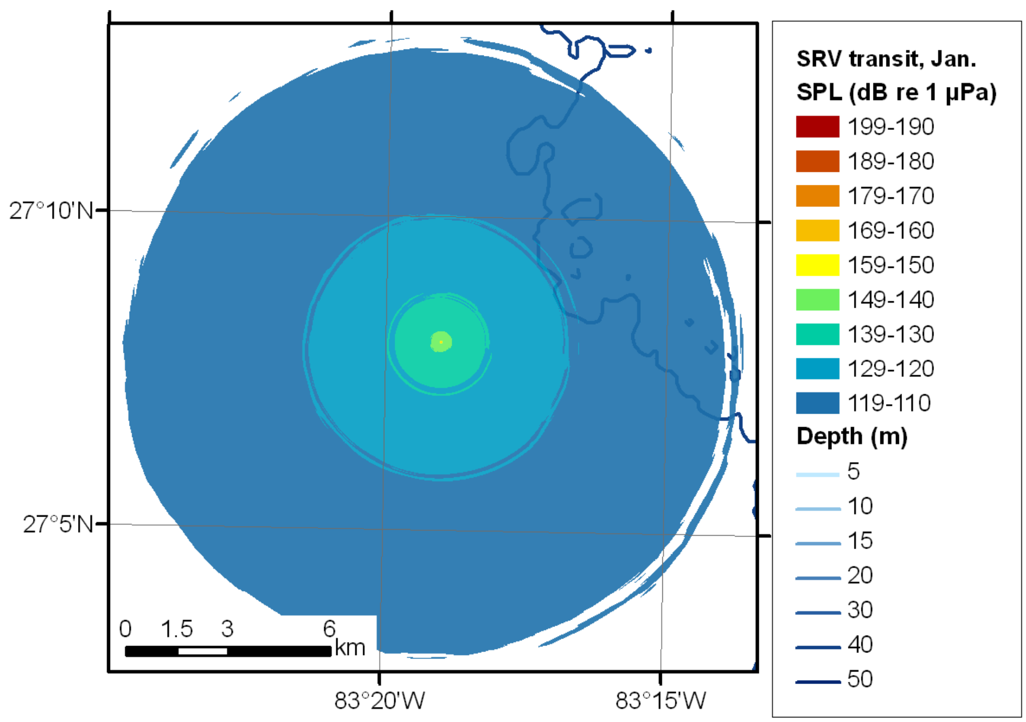

Figure 16: Estimated received sound levels for SRV transit (see Table 1, Section 2.2.5).

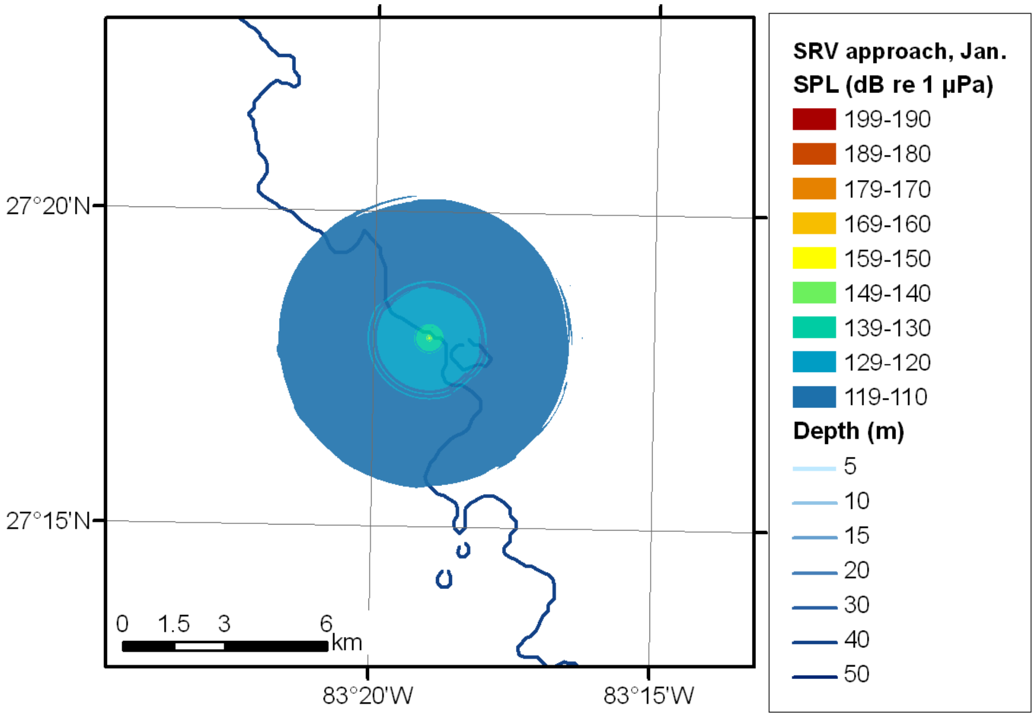

Figure 17: Estimated received sound levels for SRV approach (see Table 1, Section 2.2.5).

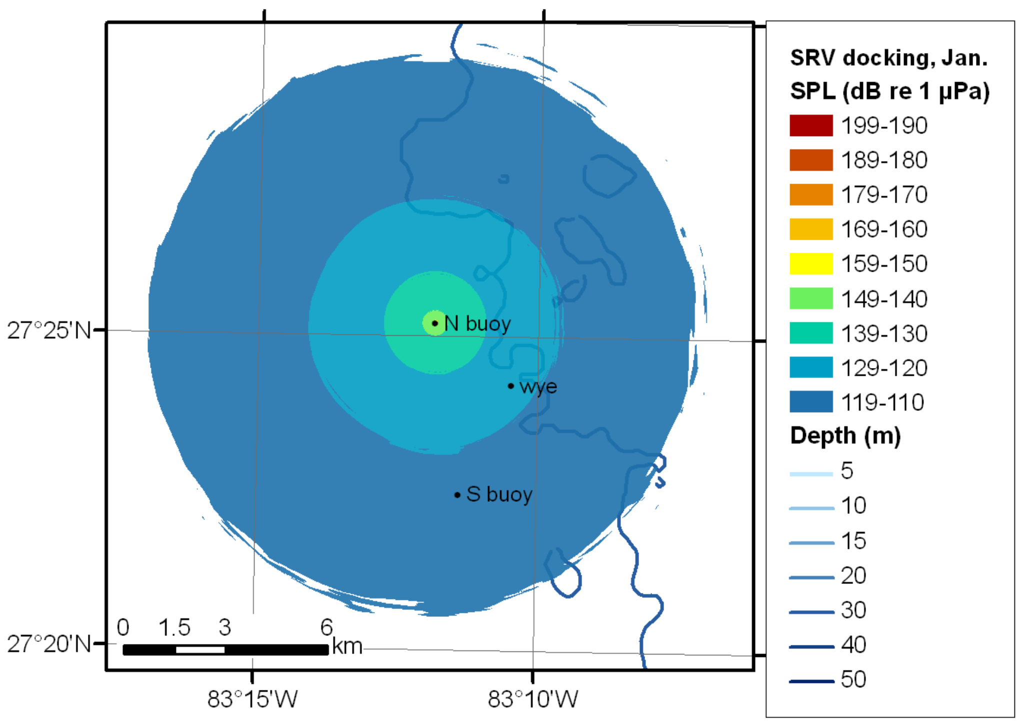

Figure 18: Estimated received sound levels for SRV docking (see Table 1, Section 2.2.5).

Noise	
106	Please provide possible mitigation measures for noise abatement for the construction of pilings and any other underwater construction that would occur due to the Proposed Action.
Response	Volume II, Appendix F Construction and Operational Mitigation Measures provides sections on Marine Mammal Acoustic Disturbance Mitigation and Air Quality and Noise Impact Mitigation that discuss the mitigation measures for noise abatement.

Project Description and Alternatives	
107	Please provide expected noise levels of the facility when the pumps are operational.
Response	The expected noise levels to be generated by SRVs during regasification were originally estimated by JASCO and included in the Underwater Acoustics Modeling Report included in Neptune DWP Application's Volume II – Appendix H. Each SRV consists of one LNG pump, one glycol circulation pump, one seawater pump, one cargo pump, and a turbine generator. The broadband source level of an SRV during regasification (when pumps are operational) is 164.6 dB re 1 µPa at 1 m. Source levels of one-octave bands range between 131.8 and 151.2 dB re 1 µPa at 1 m. Estimates of one-octave band source levels in water are given below. **Estimate of 1-Octave Band Levels for Regasification on One SRV**

Center Frequency (Hz)	Source Level (dB re 1 µPa-1m)
31.5	131.8
63	135.5
125	139.2
250	143.0
500	146.5
1000	148.9
2000	151.2
Broadband	164.6

Due to its understanding of and familiarity with the SRV technology, Port Dolphin has recently engaged JASCO Research Limited to complete underwater acoustics modeling for this project.

REFERENCE:

LGL LIMITED and JASCO RESEARCH LIMITED, 2005. *Assessment of the Effects of Underwater Noise From the Proposed Neptune LNG Project*. Appendix H: Deepwater Port License Application, Neptune Project, Massachusetts Bay. Volume II: Environmental Evaluation (Public). Submitted to the U.S. Coast Guard by Neptune LNG LLC.

Map/Graphics	
108	Confirm Map Projection: NAD_1927_Florida_West_FIPS_0902
Response	This information was confirmed in the e-mail sent July 11, 2007.

Map/Graphics	
109	Please provide the GIS Data layers for: Preferred and Alternative Pipeline Routes, Buoys, Anchors and Anchor Chain Mooring Existing Natural Gas Transmission Pipelines in GOM/FL Shipping Lanes for Tampa Bay Offshore Disposal Sites Fisheries Management Areas affected by restrictions, if any. Water Quality Sampling Stations Surficial Sediments and Sediment Sampling Locations Class 1 Air Resources Areas (known Parks, Wilderness Areas, etc) Aquatic Preserve Areas, Critical Habitat Areas, Ocean Sanctuaries Air Quality Monitoring Stations Vessel Position Data for Fishing Activity or Fishing Tracts in Tampa Bay and the project area, if available Current and Proposed Projects in Tampa Bay
Response	This information was placed on an FTP for download with instruction provided for access in the e-mail sent July 11, 2007.

Supplemental	
110	Please provide the 'CORMIX Session Report' and the 'CORMIX Prediction File' for each CORMIX run described in the Application.
Response	This information was included on CD in the EPA completeness response documents.

Water Quality	
111	Would glycol or another similar agent be used to dry the pipeline after hydrostatic testing? If so, how would the disposal of glycol (or another agent) be handled?
Response	Port Dolphin does not intend to use glycol to dry the pipeline after hydrostatic testing. Port Dolphin proposes to utilize the “dry air” process for drying the pipeline, which produces no agents, solvents or other similar byproducts that require disposal.

Water Quality	
112	In addition to the turbidity modeling already requested, please provide: 1) an estimate of the concentration of sediments in the turbidity plume in mg/L; 2) quantification (total area and depth) of impacts on hardbottom, seagrass beds, aquatic preserves, and manatee critical habitat as a result of redeposited sediment in the area of the pipeline and unloading buoys; . 3) estimate of potential turbidity plume impacts on hardbottom, seagrass beds, aquatic preserves, and manatee critical habitat.
Response	The response is included below.

Response to e²M Request for Clarification and References (Data Gaps and Scoping)

COMMENT #112

"In addition to the turbidity modeling already requested, please provide: 1) an estimate of the concentration of sediments in the turbidity plume in mg/L; 2) quantification (total area and depth) of impacts on hardbottom, seagrass beds, aquatic preserves, and manatee critical habitat as a result of redeposited sediment in the area of the pipeline and unloading buoys; 3) estimate of potential turbidity plume impacts on hardbottom, seagrass beds, aquatic preserves, and manatee critical habitat."

RESPONSE

1) Suspended Sediment Concentrations

Suspended sediment concentration in the turbidity plume are presented in the attached report by ASA International (2008) entitled, "Results of Sediment Dispersion Modeling for Proposed Pipeline Construction Activities."

2) Total Area and Depth of Impact

Hard/Live Bottom Areas

The extent of hard/live bottom exposed to turbidity from plowing/jetting can be roughly estimated by assuming that the plume typically would extend about 150 m (492 ft) to each side of the pipeline (based on Table 12 in the modeling report). Using a plume width of 300 m (984 ft) and a total length of 35,193 m (115,468 ft) for the plowable segments of the pipeline, the total plume area would be 10,557,900 m^2 (113,620,512 square feet) or 1,056 hectares (2,609 acres). Habitats along the plowable portion of the route are 12.64% hard/live bottom (Types A, B, and D) and 87.36% soft bottom. Multiplying the total plume area by the percentage of hard/live bottom habitats yields an impact area of 133.5 hectares (330 acres).

Seagrass Beds

Seagrasses are not present along the pipeline corridor, except for the area near the HDD exit point for the pipeline landfall. As noted in the **Addendum**, a diver survey showed the nearest seagrasses were 23 m (75 ft) to the southwest and greater than 59 m (194 ft) to the northeast of the HDD exit point.

Three sources of sedimentation near seagrass beds are addressed in the ASA modeling report: (1) plowing along segment 1; (2) resuspended sediment from excavation of HDD pit #1; and (3) drilling fluid from HDD punch-through at HDD pit #1.

As shown in **Figures 1 and 2**, the modeling predicts that sediment resuspended by plowing along segment 1 would not reach seagrass beds near the landfall.

As shown in **Figures 3 and 4**, the modeling predicts that resuspended sediment from HDD pit #1 excavation would reach seagrass beds south of the HDD pit. The seagrass beds would be exposed to suspended sediment levels of 0 to 5 mg/L and the total area of seagrasses affected would be 1.93 acres (0.78 hectares). However, no measurable sediment accumulation on seagrasses is predicted.

Figure 1. Suspended sediment, pipeline segment 1, plowing, mead tide & wind.

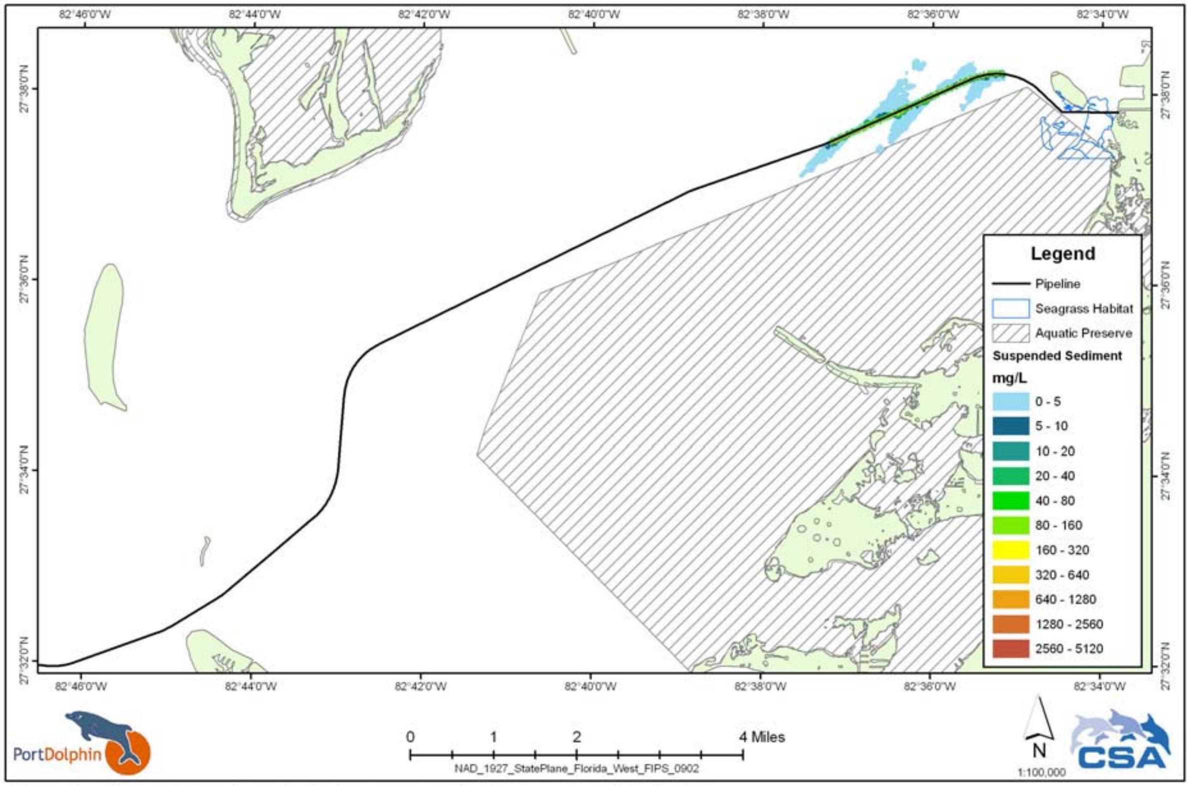

Figure 1. Suspended sediment, pipeline segment 1, plowing, mean tide & wind.

Figure 2. Sediment thickness, pipeline segment 1, plowing, mean tide & wind.

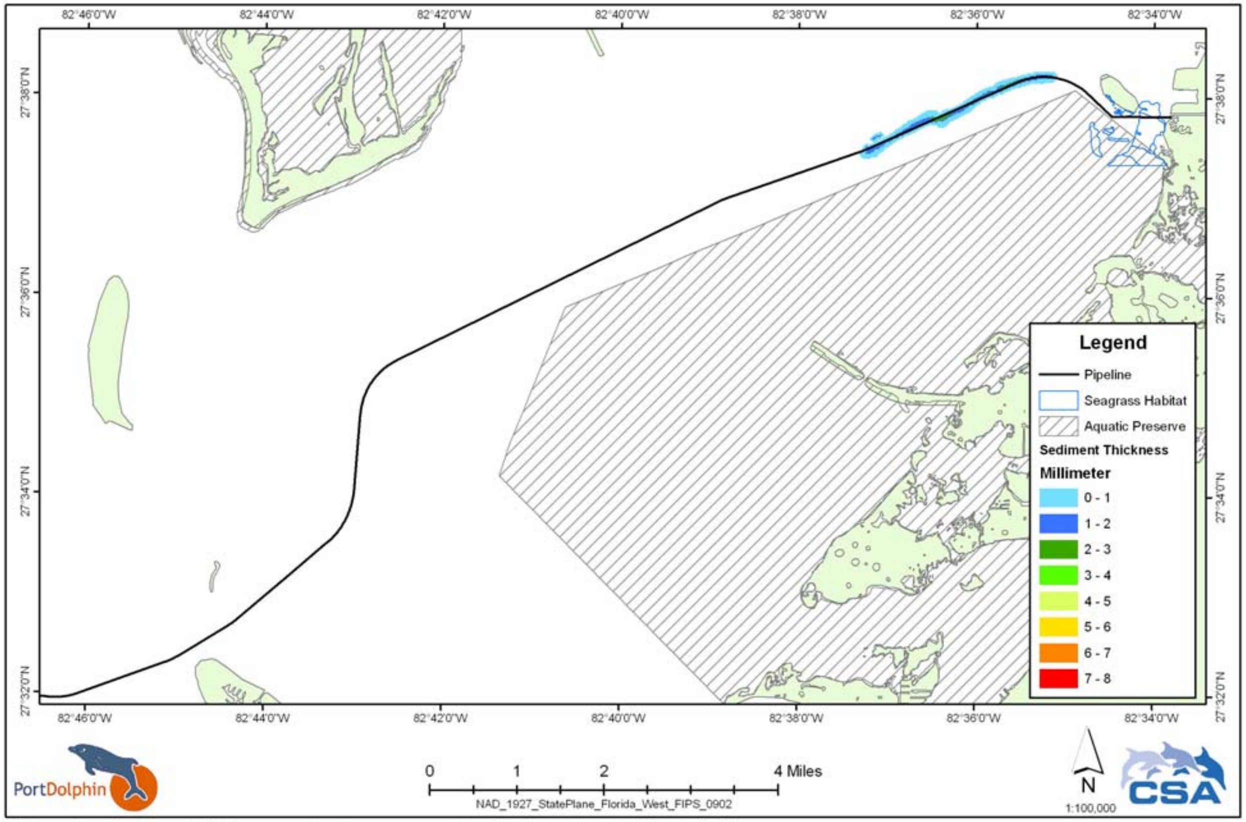

Figure 2. Sediment thickness, pipeline segment 1, plowing, mean tide & wind.

Figure 3. Suspended sediment, excavation HDD pit #1, mean tide & wind.

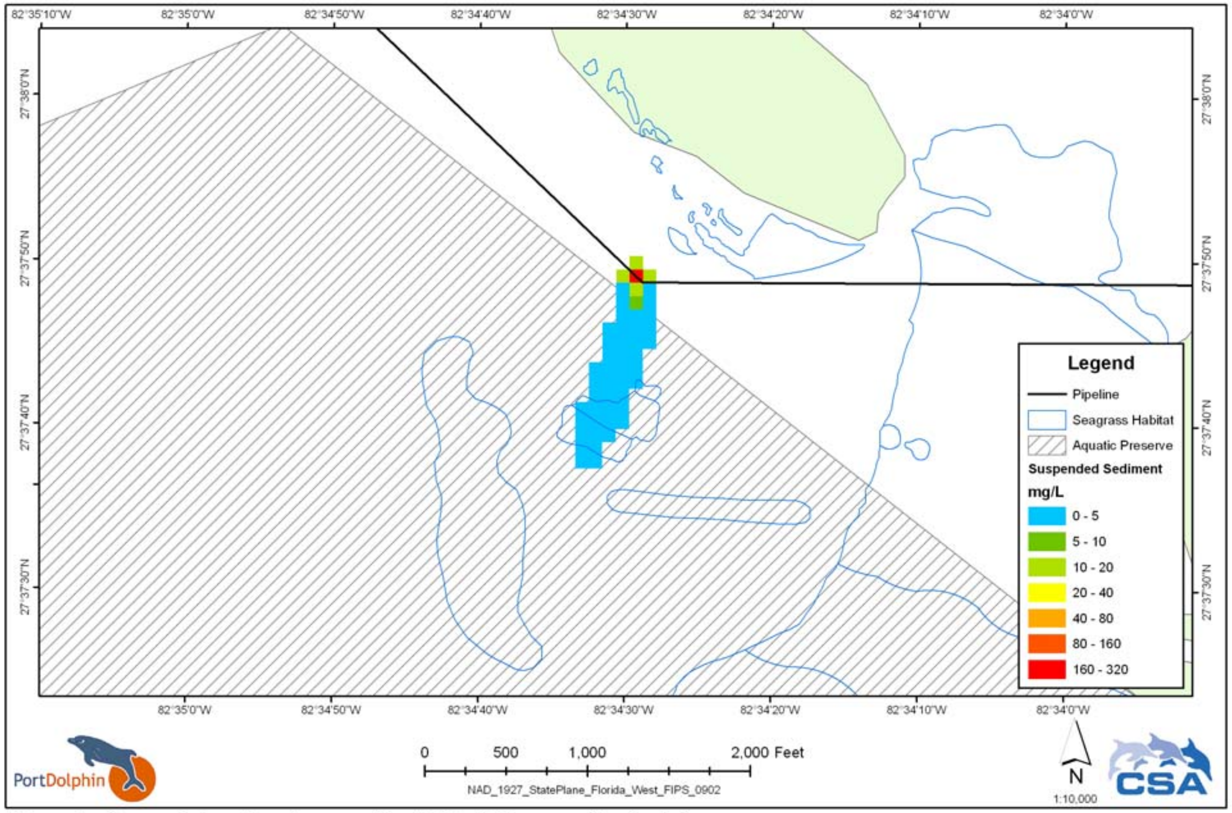

Figure 3. Suspended sediment, excavation HDD pit #1, mean tide & wind.

Figure 4. Thickness, excavation HDD pit #1, mean tide & wind.

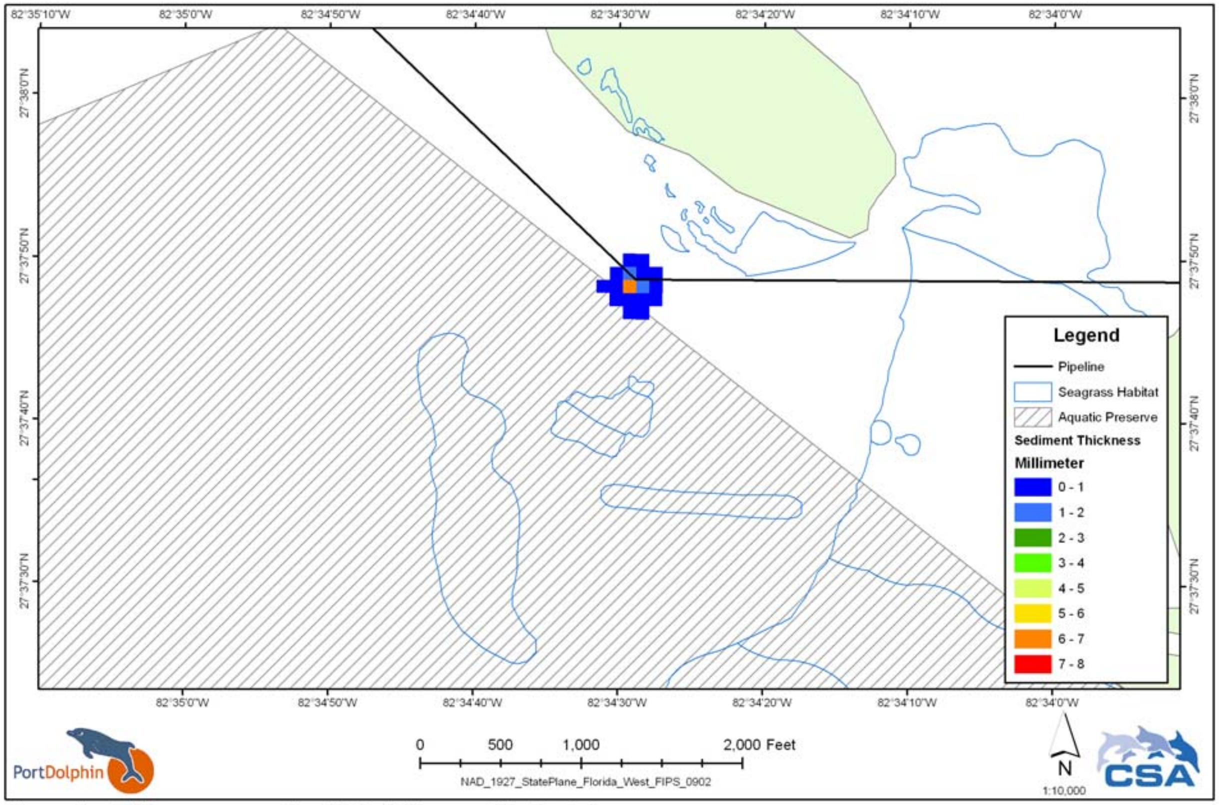

Figure 4. Thickness, excavation HDD pit #1, mean tide & wind.

As shown in **Figures 5 and 6**, the modeling predicts that drilling fluid from HDD punch-through would reach seagrass beds south of HDD pit #1. The seagrass beds would be exposed to suspended sediment levels between 0 and 20 mg/L but virtually no sediment accumulations (0.006 to 0.034 mm thickness). The total area of seagrasses exposed to elevated suspended solids would be 5.12 acres (2.07 hectares). The area of sediment deposition would be 0.69 acres (0.28 hectares).

Aquatic Preserves

Several sources of turbidity and sedimentation near the Terra Ceia Aquatic Preserve are addressed in the ASA modeling report, including plowing along pipeline segment 1; plowing and jetting along segment 2; clamshell dredging of the section beneath the Skyway bridge; and HDD pit excavation and drilling fluid releases from HDD exit holes 1, 2, and 3. The modeling indicates that resuspended sediments from pipeline burial along segments 4, 5, 6, and 7 and from HDD pits #4 and #5 would have no contact with the Aquatic Preserve and these are not discussed further..

Modeling of plowing along the northern and northwestern edge of the Aquatic Preserve (segment 2 in the modeling report) predicts that the plume would not produce turbidity or sediment accumulation in the Aquatic Preserve (**Figures 7 and 8**). However, if jetting is used for pipeline burial along segment 2, suspended solids concentrations of 1 to 10 mg/L are predicted to occur in 32.87 acres (13.30 hectares) of the adjacent Aquatic Preserve (**Figure 9**). No measurable sediment thickness is predicted (**Figure 10**).

The modeling predicts that other pipeline installation activities north of the Aquatic Preserve, such as clamshell dredging of the section beneath the Skyway bridge, excavation of HDD pits #2 and 3, and releases of drilling fluid from HDD pits #2 and #3 would not affect suspended solids concentrations or result in measurable sediment thickness in the Aquatic Preserve.

Modeling of plowing along segment 1 predicts suspended sediment concentrations of about 0 to 5 mg/L in the nearest portions of the Aquatic Preserve (**Figure 1**). The total area of the Aquatic Preserve affected would be 1.83 acres (0.74 hectares). No measurable sediment thickness is predicted (**Figure 2**).

HDD pit #1 excavation near the landfall is predicted to result in suspended sediment concentrations of 0 to 10 mg/L in an area of 6.38 acres (2.58 hectares) within the Aquatic Preserve (**Figure 3**). Sediment deposition in the Aquatic Preserve is predicted to be 0 to 1 mm (**Figure 4**), affecting an area of 0.66 acres (0.27 hectares). Releases of drilling fluid from the HDD punch-through could result in briefly elevated suspended solids concentrations ranging from 0 to 640 mg/L but virtually no sediment accumulations (thicknesses 0 to 0.034 mm) (**Figures 5 and 6**). The total area of the Aquatic Preserve affected by elevated suspended solids concentrations would be 27.12 acres (10.98 hectares). The area of sediment deposition would be 2.87 acres (1.16 hectares).

Manatee Critical Habitat

Plumes from construction activities are not expected to result in turbidity or sedimentation in areas of manatee critical habitat. The nearest designated critical habitat areas for manatees are (1) the Manatee River, which is approximately 5 km (3.1 miles) from the nearest point on the pipeline route; and (2) the Little Manatee River, which is approximately 13 km (8.1 miles) away. Based on the turbidity modeling (ASA International, 2008), the plume is not expected to reach these areas.

Figure 5. Suspended sediment, drilling mud, HDD pit #1, mean tide & wind.

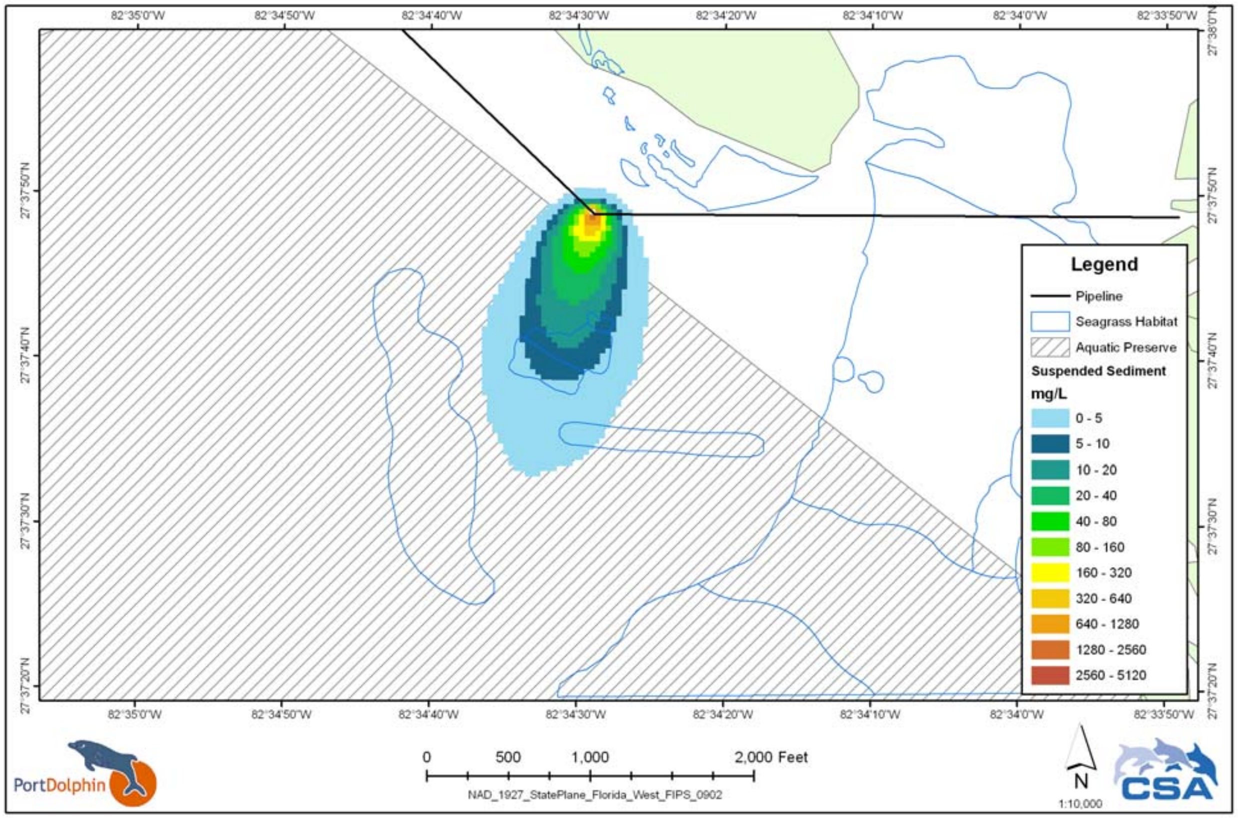

Figure 5. Suspended sediment, drilling mud, HDD pit #1, mean tide & wind.

Figure 6. Thickness, drilling mud, HDD pit #1, mean tide & wind.

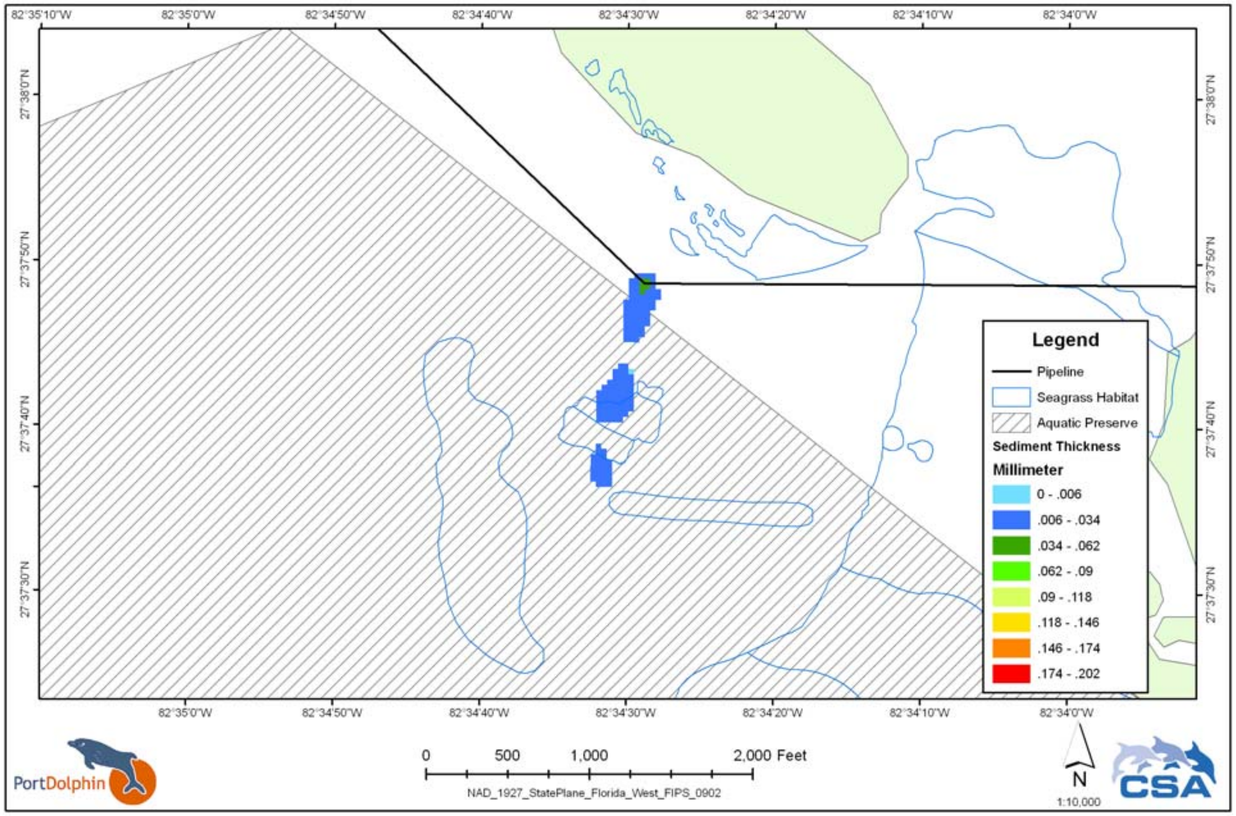

Figure 6. Thickness, drilling mud, HDD pit #1, mean tide & wind.

Figure 7. Suspended sediment, pipeline segment 2, plowing, mean tide & wind.

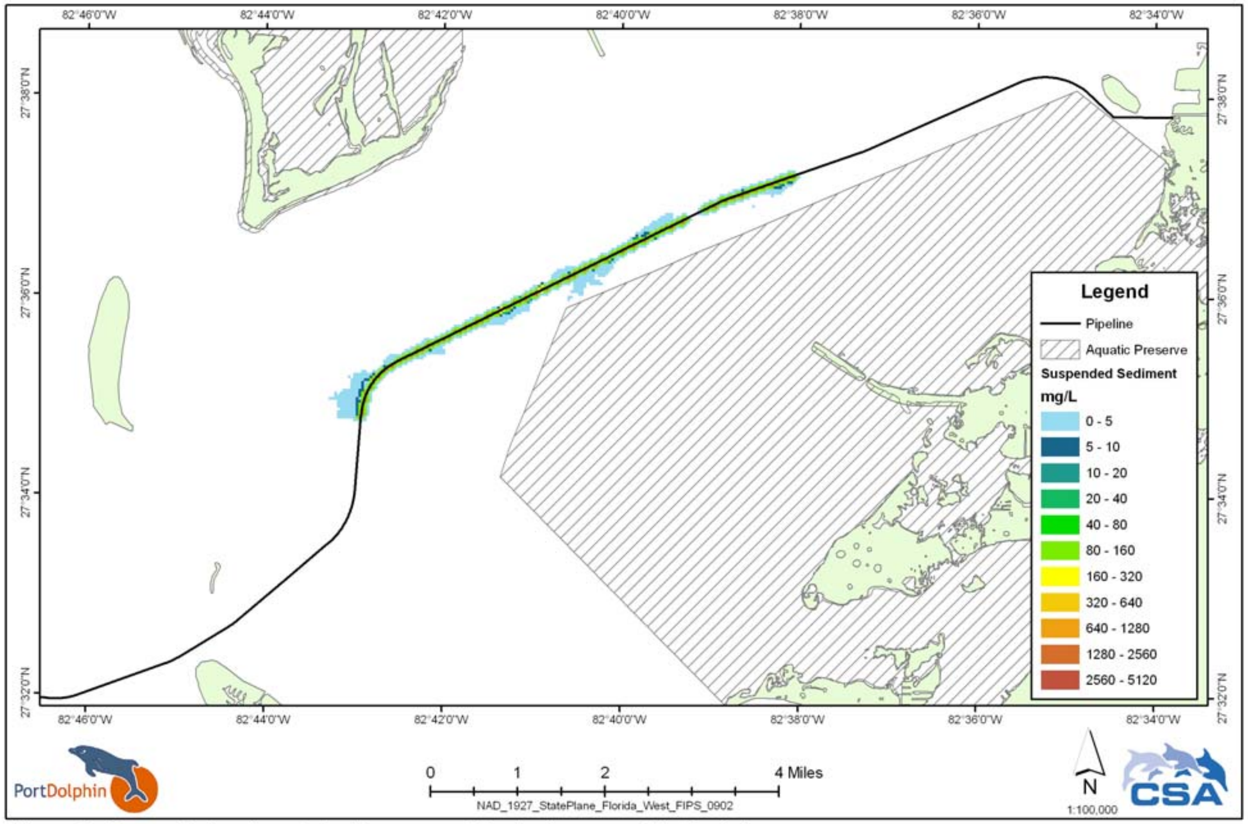

Figure 7. Suspended sediment, pipeline segment 2, plowing, mean tide & wind.

Figure 8. Thickness, pipeline segment 2, plowing, mean tide & wind.

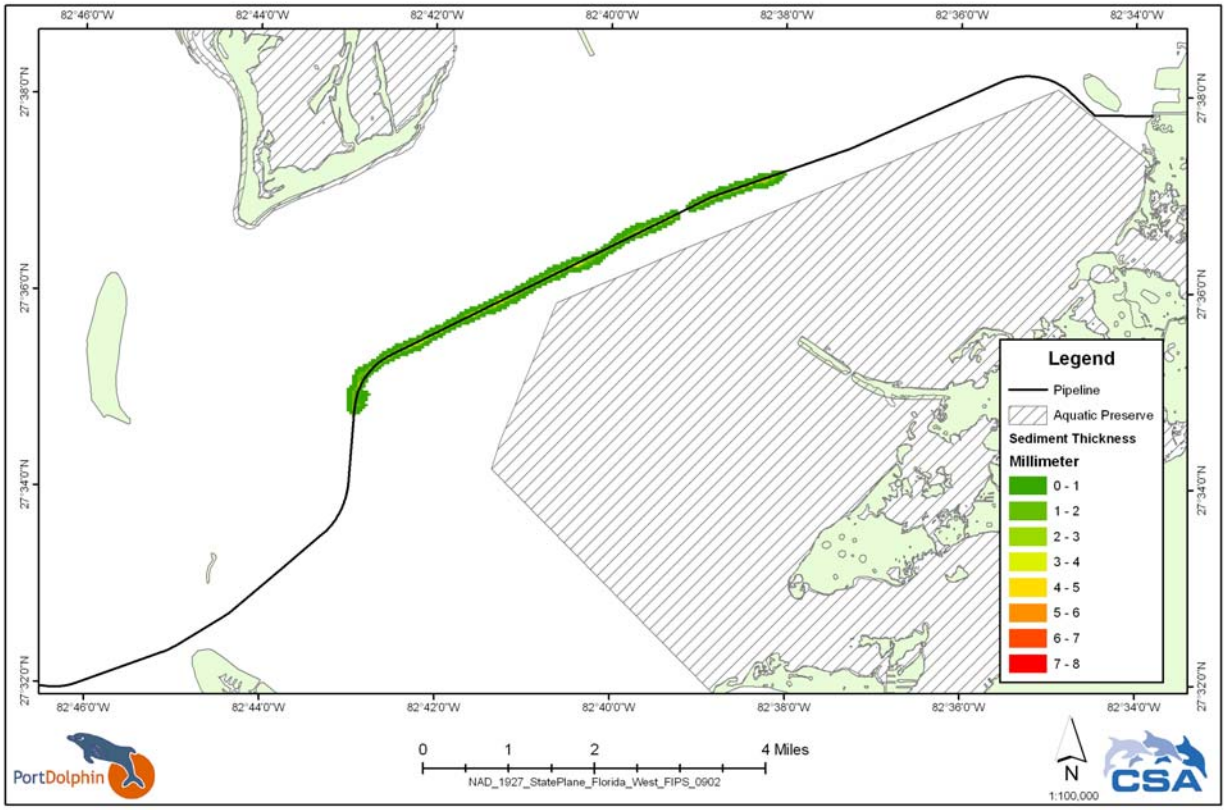

Figure 8. Thickness, pipeline segment 2, plowing, mean tide & wind.

Figure 9. Suspended sediment, pipeline segment 2, jetting, mean tide & wind.

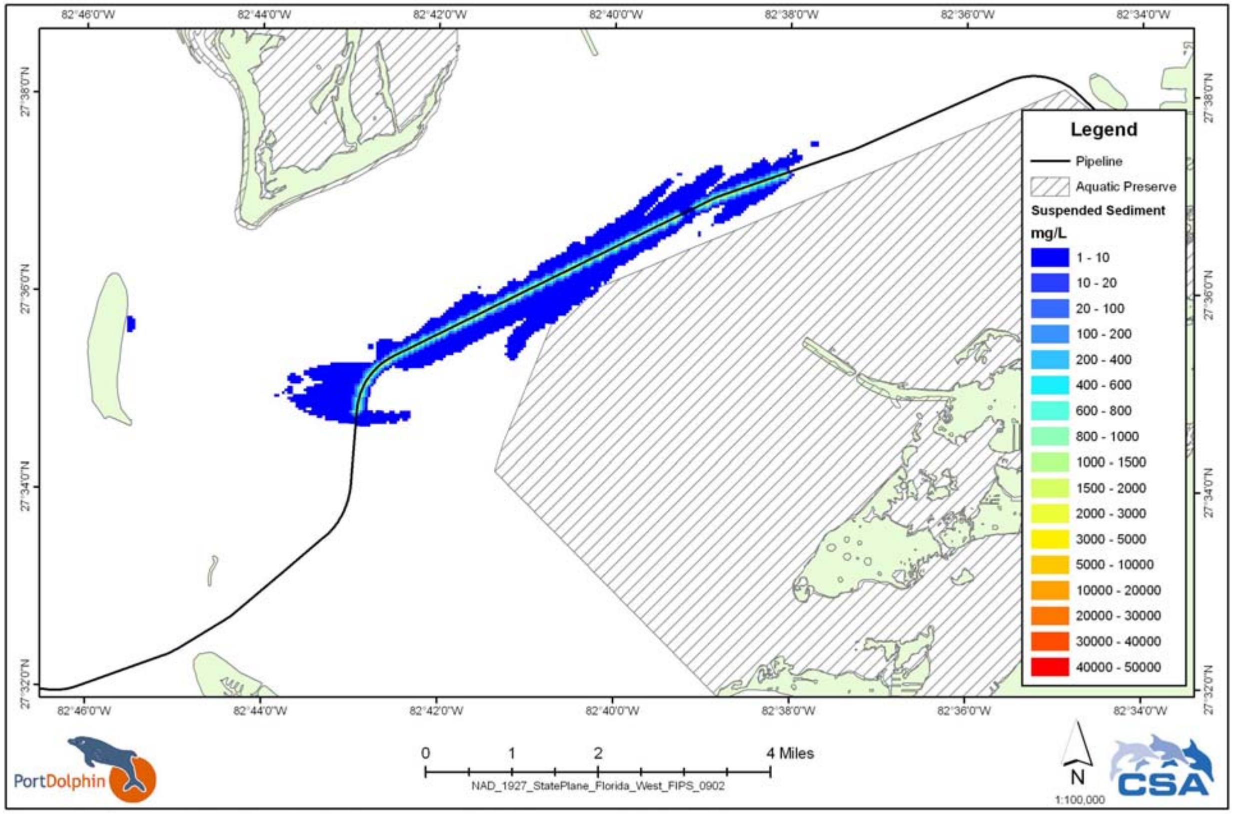

Figure 9. Suspended sediment, pipeline segment 2, jetting, mean tide & wind.

Figure 10. Sediment thickness, pipeline segment 2, jetting, mean tide & wind.

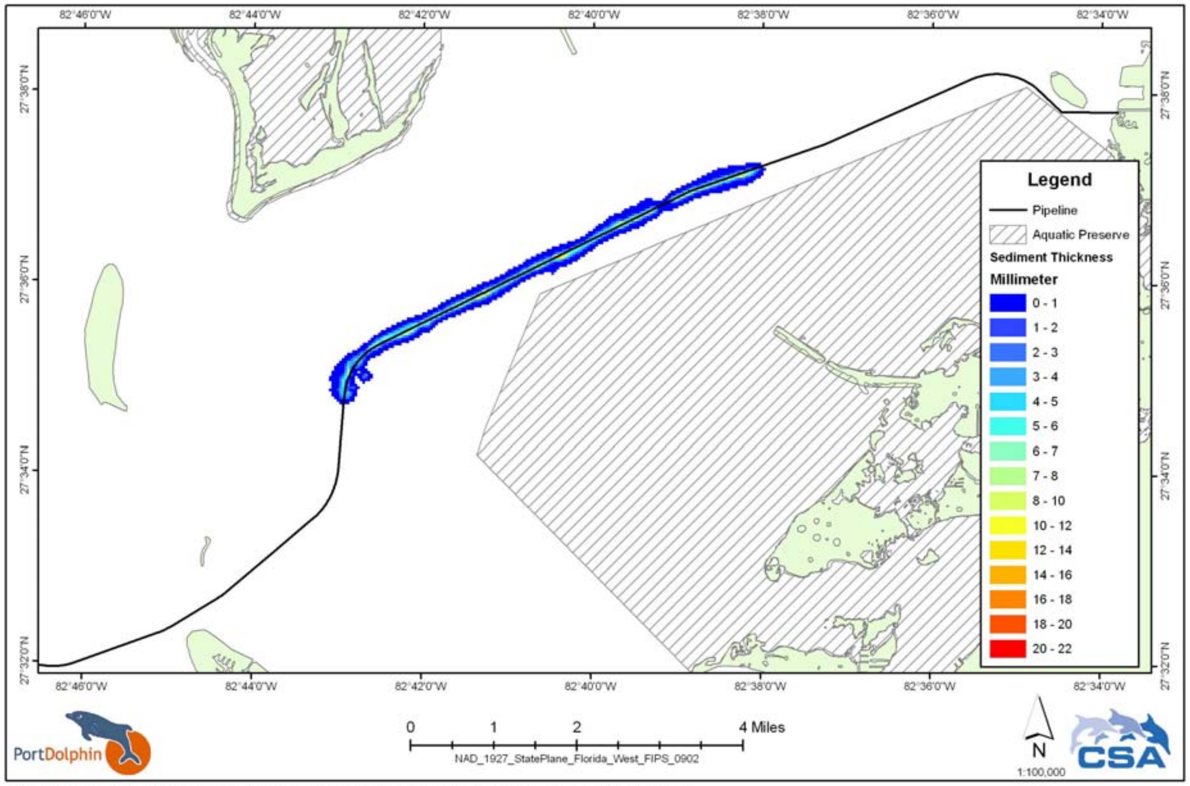

Figure 10. Sediment thickness, pipeline segment 2, jetting, mean tide & wind.

3) Turbidity plume impacts:

Hard/Live Bottom Areas

The small and short-term levels of sediment deposition resulting from pipeline construction are not expected to have significant impacts on hard bottom communities. Sediment thickness tapers off to less than 2 mm within about 50 to 200 m (164 to 656 ft) from the source for most of the seafloor deposits. While the total area receiving sediment deposits of 2 mm thickness could be several times greater than the area directly affected by trenching as noted above, the areas receiving the thickest accumulations would be close to the trench – essentially the same areas directly affected by the plowing or jetting *per se*. These are predominantly soft-bottom areas since such areas are amenable to plowing or jetting.

Sediment trap studies and visual monitoring during MMS-sponsored studies have demonstrated that the west Florida shelf is a dynamic environment with frequent episodes of sediment movement and resuspension (Danek and Lewbel, 1986; Environmental Science and Engineering, Inc., LGL Ecological Research Associates, Inc., and Continental Shelf Associates, Inc., 1987; Continental Shelf Associates, Inc., 1987; Thompson et al., 1989). For example, during the Southwest Florida Shelf Ecosystems study, sedimentation rates in traps located 1 m above the bottom ranged as high as 848 grams/m^2/day. Time-lapse cameras revealed periods of several days or more during which benthic visibility was reduced to near zero by sediment resuspended by storms. Fish seen in time-lapse camera frames prior to turbidity storms were sometimes observed at the same locations immediately afterward, without apparent ill effects. To some extent, nearshore benthic communities of the continental shelf in this region are adapted to intermittent sedimentation and turbidity (Rice and Hunter, 1992). The small and short-term levels of sediment deposition resulting from pipeline construction are not expected to have significant impacts on hard bottom communities. The impacts are expected to be <u>minor</u>.

Seagrass Beds

The modeling predicts that seagrass beds near the approach to Port Manatee may be exposed to brief periods of turbidity from plowing, HDD pit excavation, and drilling fluid from HDD punch-through. While the suspended solid levels will typically be low, because of the ecological importance of seagrass beds, it will be necessary to use turbidity curtains and/or other mitigation measures to minimize suspended solids during construction in this area. Taking mitigation into account, turbidity and sedimentation impacts on seagrasses near the approach to Port Manatee are expected to be <u>minor</u>.

Aquatic Preserves

The modeling predicts that the Terra Ceia Aquatic Preserve may be exposed to brief periods of turbidity from plowing, jetting, HDD pit excavation, and drilling fluid from HDD punch-through. While the suspended solid levels will typically be low, because of the OFW status of the Aquatic Preserve, it will be necessary to use turbidity curtains and/or other mitigation measures to minimize suspended solids during construction. In addition, a temporary variance will be applied for to ensure that there is no violation of OFW standards. Taking mitigation into account, the impacts were rated as <u>minor</u> in the **Addendum**.

Manatee Critical Habitat

<u>No impact</u> on manatee critical habitat is expected. Because of the distance from the pipeline, turbidity plumes are not expected to reach these areas.

LITERATURE CITED

ASA International. 2008. Results of Sediment Dispersion Modeling for Proposed Pipeline Construction Activities. Report for CSA International, Inc. ASA Project No. 2007-195. January 2008.

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Danek, L.J. and G.S. Lewbel, eds. 1986. Southwest Florida shelf benthic communities study, Year 5 final report. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 86-0076.

Environmental Science and Engineering, Inc., LGL Ecological Research Associates, Inc., and Continental Shelf Associates, Inc., 1987. Southwest Florida Shelf Ecosystems Study, Volume II: Data Synthesis Report. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 87-0023.

Rice, S.A. and C.L. Hunter. 1992. Effects of suspended sediment and burial on scleractinian corals from west central Florida patch reefs. Bulletin of Marine Science 51(3): 429-442.

Thompson, M.J., A.D. Hart, and C.W. Kerlin. 1989. Exposure of deep seagrass beds off the west coast of Florida to discharged drilling effluents. In: F.R. Engelhardt, J.P. Ray, and A.H. Gillam, eds., Drilling Wastes. Proceedings of the 1988 International Conference on Drilling Waste, Calgary, Alberta, Canada, 5-8 April 1988. Elsevier Applied Science Publishers, Ltd., London.

Biological Resources and Water Quality	
113	Please provide the volume of dye, biocides, and oxygen scavengers to be used for pipeline hydrostatic testing.
Response	The volume of biocides and Oxygen Scavengers is 154,640.2 gallons of a product called HydroHib-P which is both an oxygen scavenger and biocide. The volume of Dye required is 1,310.78 gallons of a product named Hydrotag by Edelweiss Enterprises.

Biology and Water Quality	
114	In addition to the temperature of the hydrostatic test water requested, please provide dilution modeling for the temperature, dye, and biocides in the hydrostatic test water.
Response	Based on the additional engineering analysis performed and the revised construction plan included in the Deepwater Port Application Addendum, Project Design Changes and Corresponding Impacts submitted December 7, 2007, the scenario for hydrostatic testing has changed. The main changes proposed for the hydrostatic testing procedure are as follows: 1) The volume of hydrostatic test water would be roughly twice the original estimate (12.3 to 23.9 million gallons) due to a slight increase in pipeline length of the nearshore portion of the Revised Preferred Route, and the fact that the pipeline would be filled twice (i.e., one for gauging and another for hydrostatic pressure testing). 2) The hydrotest discharge location has been changed to an offshore location from a marine vessel at one of the STL buoy locations rather than at Port Manatee. 3) Originally, the hydrotest water was expected to contain biocides, oxygen scavenger, and a fluorescent dye. The water was to be treated with industrial grade hydrogen peroxide to render the effluent non-toxic prior to discharge. The revised plan includes an "environmentally benign" treatment chemical (HydroHib P) that is not expected to require any treatment prior to discharge. When HydroHib P is mixed with seawater its characteristic becomes benign and is able to be released back into the environment as a benign substance. There are hundreds of applications worldwide very similar to Port Dolphin's proposed use that has used HydroHib P, and none have required treatment prior to release back into the environment. The discharge would comply with NPDES permit requirements and is expected to be non-toxic upon discharge. The MSDS and supporting information of the treatment chemical is attached below. 4) The line fill (water) used for the lay and burial operations will be in the pipeline for many weeks and therefore its temperature will be essentially the same as the surrounding subsea water when it is time to discharge it. Port Dolphin will also ensure the discharge temperature of the hydrostatic test water has stabilized (temperature and surge) prior to conducting the test and discharging it, as these variables can have an effect on the final acceptance of the test. The stabilization period will be a minimum of 24-hours. The project design changes would not affect the conclusion of the impact analysis. Although the discharge volume is greater, it is also expected to disperse more rapidly offshore than in Tampa Bay because of stronger ocean currents and the larger volume of receiving waters. The discharge is expected to be non-toxic, and any impacts on fish and water quality would be negligible. Therefore, dilution modeling is no longer necessary.

Edelweiss Enterprises, Inc.

Emergency
Phone No.

(800) 255-3924

P.O. Box 124
St. Martinville, Louisiana 70582-0124
Company Phone No. 337-394-8898

IDENTIFICATION:

Product Name:	HydroHib P
Chemical Name and/or Family:	Amine
C.A.S. Number:	Blend
Formula:	Proprietary
M.S.D.S. Effective Date:	April 28, 1999

COMPOSITION and INFORMATION on INGREDIENTS:

Component	C.A.S. #	%	Exposure Limits
ETHANOL, 2,2'-OXYBIS-, reaction products with ammonia, morpholine derivative residues	68909-77-3	Conf.	No Data
METHYL ALCOHOL	67-56-1	15%	OSHA, TWA PEL 200 ppm ACGIH, TWA 200 ppm ACGIH, STEL 250 ppm

HAZARD IDENTIFICATION:

Health Hazard: Acute, Inhalation of vapors may be narcotic and can be fatal. Ingestion of liquid will cause gastrointestinal distress, irritation, possibly nausea, and can be fatal. Liquid or vapors may be irritating to skin and eyes.

Primary Routes of Entry:
- **Inhalation**.................. Irritant
- **Skin**........................... Irritant
- **Ingestion**................... Irritant

Over Exposure Effects: Skin irritation develops slowly after contact. Eye irritation develops immediately upon contact.
Symptoms of overexposure: Headache, Fatigue, Nausea, Visual Impairment, Acidosis, Convulsions, Circulatory Collapse, Respiratory Failure, Death. Ingestion may cause blindness or be fatal.

Carcinogenicity:

NTP .... No
IARC.......................... No
OSHA .... No

Hazardous Materials Identification System Rating:

Health........................ 1
Flammability............. 2
Reactivity.................. 0
Personal Protection. C

FIRST AID MEASURES:

First Aid Procedures: **EYE CONTACT:** Flush immediately with plenty of water for at least 15 minutes and get medical attention.
SKIN CONTACT: Wash thoroughly with large amounts of soap and water.
INHALATION: Remove victim to fresh air and, if needed, immediately begin artificial respiration. Give Oxygen if breathing is labored. Get emergency medical help. Contact physician immediately.
INGESTION: Seek emergency medical instructions before inducing vomiting.

FIRE FIGHTING MEASURES:

Flash Point: 101°F.
Flammable Limits:
Lower........................ ND
Upper........................ ND
Extinguishing Media: Water fog or spray, Foam, Dry Chemical, Carbon Dioxide (CO_2).
Unusual Fire Hazard: Containers may explode from internal pressure if confined to fire. Cool with water. Keep unnecessary people away.

ACCIDENTAL RELEASE MEASURES:

Spill or Leak: In case of spillage, absorb with inert material and dispose of in accordance with applicable federal, state, and local regulations.

HANDLING and STORAGE PROCEDURES:

Precautionary Handling: Keep away from heat, sparks and flame.
Storage: Store in a cool place away from ignition sources.
Store away from oxidizers or materials bearing a yellow “DOT” label.

EXPOSURE CONTROLS and PERSONAL PROTECTION:

Ventilation:

Mechanical	Desired in closed places
Local	Recommended
Respiratory Protection:	NIOSH approved organic vapor mask
Eye Protection:	Use goggles and/or face shield if splashing is likely
Protective Gloves:	Wear impervious gloves
HMIS Personal Protective Code:	C: Safety Glasses, Gloves, Apron
Threshold Limit Value:	200 ppm based on Methyl Alcohol in blend

PHYSICAL and CHEMICAL PROPERTIES:

Appearance and Odor:	Dark Brown Liquid, Ammonical Odor
Boiling Point:	212°F.
Freezing Point:	< 20°F.
Vapor Pressure (mmHg):	NA
Vapor Density (Air = 1):	NA
pH Value:	8.2 - 8.8
Solubility in Water:	Infinite
Specific Gravity (Water = 1):	1.005 - 1.010

STABILITY and REACTIVITY:

Chemical Stability:	Stable
Conditions to Avoid:	Keep away from heat, sparks and flame.
Incompatible Materials:	Oxidizers or Oxidizing Materials.
Decomposition Products:	From Fire; Smoke, Carbon Dioxide, Carbon Monoxide, Oxides of Sulfur, and Oxides of Nitrogen.
Hazardous Polymerization:	Will Not Occur
Polymerization Avoid:	None

DISPOSAL CONSIDERATIONS:

Waste Disposal Method:	Hazardous Waste. Follow Federal and State and Local Regulations for Hazardous Waste Disposal.
EPA Hazard Waste Codes:	DOO1 - Characteristic of Ignitability U154 - Methyl Alcohol

TRANSPORTATION INFORMATION:

Hazard Class:	3
DOT Proper Shipping Name:	FLAMMABLE LIQUID, n.o.s., (Contains Methyl Alcohol and Amine), 3, UN 1993, PG III
Reportable Quantity:	33,000 lbs. based on Methyl Alcohol in blend

REGULATORY INFORMATION:

Notice The following information is presented in good faith and is believed to be accurate, as of the revised date shown above. No warranty is therefore, expressed or implied. Regulatory information requirements are subject to change as governmental regulations change.

TSCA: Toxic Substances Control Act: All chemical substances contained in this product are listed in the TSCA Inventory List. (This, however, does not imply that all products are "toxic".)

EPA: Environmental Protection Agency:

SARA: Superfund Amendments and Reauthorization Act
Title III, Section 313 (Toxic Chemicals): Yes - Methyl Alcohol
Reportable Quantity (RQ): 33,000 lbs. based on Methyl Alcohol in blend
Threshold Planning Quantity (TPQ): None
Title III, Section 311 (Hazard Categories):
Acute........................ .... Yes
Chronic..................... .... Yes
Ignitable.................... .... Yes
Reactive.................... .... No
Sudden Release of Pressure ... No

CERCLA: The Comprehensive Environmental Response, Compensation, and Liability Act of 1980:

Reportable Quantity (RQ):............ .... 33,000 lbs. based on Methyl Alcohol in blend

Clean Air Act:

Sections:....................................... .... Section 111

Clean Water Act:

Sections:....................................... .... NA

MISCELLANEOUS OTHER INFORMATION:

Product Packaging: Various

Footnotes:
ND - No Data Available
NA - Not Applicable
< = Less Than
> = Greater Than

This product's safety information is provided to assist our customers in assessing compliance with health, safety and environmental regulations. The information contained herein, is based on data available to us and is believed to be accurate, although no guarantee or warranty is provided by this company in this respect. Since the use of this product is within the exclusive control of the user, it is the user's obligation to determine the conditions of safe use of this product. Such conditions should comply with all Federal regulations concerning the product. *All materials in this product are produced in compliance with Public Law 94-469 (also known as the "Toxic Substances Control Act" of 1976).*

Prepared By:
TechniKos
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Date Revised: .... April 28, 1999

Packer Fluid Inhibitors

Edelweiss

Enterprises, Inc.

Packer Fluid Inhibitors

Corrosion Problems in Packer Fluids

Introduction

The primary purpose of a packer fluid is to provide a hydrostatic head above the packer to reduce the force necessary to hold the packer in place when the drilling fluid column in the tubing is removed and well fluids are produced.

In addition to providing a hydrostatic head, the fluid should provide a non-corrosive environment to preserve the casing and tubing. The packer fluid should not contain dissolved solids that could promote scale or allow suspended solids to settle and impair the removal of the packer should it become necessary to pull the tubing.

In order to properly design the most trouble-free packer fluid, first examine the most important factors involved in the corrosion process, then examine the various packer fluids in relationship to the factors affecting corrosion.

Corrosion Theory

Corrosion is an electrochemical reaction in which there is an anode, an electrolyte, a cathode and an electrical conductor between the cathode and the anode. The electrochemical behavior that must occur in a cell or battery is as follows:

At the anode, a metal ion (cation) dissolves into the electrolyte leaving free electrons (negative charges).

In the electrical connector, the electrons travel to the cathode giving it a negative charge.

At the cathode, the electrons attach themselves to cations in the electrolyte.

In the electrolyte, excess ions transport the electrons through the electrolyte back to the anode.

The factors influencing the electrochemical behavior in batteries are also the important factors in the corrosion cell. These factors are:

1. Area of anode and cathode
2. Resistance of electrical connector
3. Resistance of the electrolyte
4. Potential of the cell

With this brief and simplified background, examine some of the corrosion reactions possible in packer fluids. First, consider the relative areas of anode and cathode. Clean, bare metal is generally anodic to older, passive metal. Clean, bright scratches, such as tool marks, will be anodic to the area surrounding them. Movement of tubing against casing wall will expose bright metal to the packer fluid. Freshly exposed areas will be anodic to older, passive metal. The current that flows in a corrosion cell will flow from small anodes at a higher current density whereas on a large cathode the current density may be very low. This will create high rates of metal loss over a small area, causing the surface to be pitted. Scratches or bright metal also tend to reduce overall cell resistance by affording better electrical contact with the electrolyte.

The second factor is the metal conductor. Generally, the pipe is relatively quite thick and its resistance is low. Tightly adhering mill scale, which is also an electrical conductor, will provide a good cathode but is a poorer electrical conductor that is bare, passive metal. Being a conductor, poorly adherent mill scale can act as a cathode to the metal under it if an electrolyte can get between the metal and the mill scale.

Thirdly, the resistance of the electrolyte will vary considerably depending upon the dissolved solids content. A brine containing 50,000 ppm of sodium chloride will have less resistance than fresh water. Only a few parts per million sodium chloride increase will decrease the resistance by tenfold.

The fourth factor is the cell potential. The corrosion cells can become very complicated if one attempts to work out all of the little factors; just examine the more important ones. Normally the corrosion cell is an iron half cell and a hydrogen half cell where iron is the anode creating ferrous ions and the hydrogen half cell creates hydrogen from hydrogen ions in the electrolyte.

Therefore, reducing the hydrogen ions will reduce the cell potential. Increasing the resistance of some portion of the cell will reduce the corrosion current regardless of the cell potential. These two methods are most often used to control corrosion in the annulus protected by a packer fluid.

Packer Fluids and Corrosion Processes

The most common initiator of corrosion in any aqueous-base packer fluid, whether it be low solids mud, ordinary brine or sea water, is oxygen. Oxygen acts readily with bare metal at the metal-electrolyte of oxygen, thus setting up an oxygen concentration cell which increases in cell potential as the oxygen concentration near the surface becomes exhausted. This cell potential then decreases as the total oxygen is used up. This action causes a high concentration of iron ions near the anodic areas. Precipitation of iron hydroxide leads to a decrease in pH or an increase in hydrogen ions and allows corrosion to continue in the form of the normal Fe and hydrogen corrosion cell.

Fortunately this occurrence usually creates a deposit of a thin iron oxide film uniformly over the anodic areas and hydrogen forms over the cathodic areas stifling the corrosion by creating a high resistance barrier in the area of both anodes and cathodes. If no other contaminants change this condition, it may exist static for years.

In view of what has just been discussed, it is apparent that the reactions that initiate corrosion can be stifled by simply scavenging the oxygen out ot the packer fluid. It takes only about 10 pounds of catalyzed sulfite, or its equivalent, to scavenge the oxygen in 100 barrels of water, brine or mud. Generally, muds properly treated will have a high pH which also discourages the corrosion reaction by having an abundance of hydroxyl ions.

Changes which occur in a packer fluid after it is in the well may come from gas leaking by the packer from the producing zone. Gases which are most harmful are carbon dioxide and hydrogen sulfide. Both of these gases dissolve in water to increase hydrogen ions; in the case of hydrogen sulfide this causes the protective oxide film discussed previously to be converted to iron sulfide usually in such a manner that it is no longer protective.

Also, a disaster can be caused by acid from an acid stimulation leaking by a packer into the annulus. This can cause rapid penetration of the tubing or casing. The tubing may become sufficiently thin that it may twist off when attempts are made to unseat the packer or it may part from normal stresses or movement.

Another source for the formation of hydrogen sulfide in the packer fluid may be from sulfate-reducing bacteria. These bacteria are quite common in the air and in surface waters. They thrive in warm, static conditions utilizing sulfates in water and will consume hydrogen which keeps the corrosion cell polarized or from becoming active.

These bacteria are anaerobic, meaning that they require no oxygen for life. Their byproducts tend to form scale or tubercles on steel which upsets the status quo condition at electrical neutral areas and, in fact, can cause normally anodic areas to become cathodic to the bacteria formed deposits. This logically creates high current density at the newly formed anodes and hastens penetration. Corrosion from bacterial growth can be avoided by treating the packer fluid with a good biocide.

Organic inhibitors that are brine soluble have been developed for use in sour brines or in brines which may become sour from a packer leak or from bacteria growth. These inhibitors should be used at about one 55-gallon drum per 100 barrels of brine or mud. Sour brine rarely contains any appreciable oxygen and chromates cannot be used; therefore, the organic inhibitors are the best protection against corrosion.

Related Problems

Inhibitors can be used in the drilling mud which will leave the casing clean and hydrophobic in nature so that clean crude oil can be used in many instances without serious corrosion damage. Dead fluid areas, such as the space between a packer and perforations above a packer, will become filled with brine or be filled with the completion fluid. This space is susceptible to corrosion from bacteria or normal corrosion and it is difficult to inhibit; however heavy liquid inhibitors have been developed which can be used effectively in inhibiting corrosion in these dead spaces. Dead fluid areas are often found between a packer and a set of gas lift valves. This space will experience the same type of corrosion cell as has been described and should be protected in the same general manner as packer fluids.

Conclusions

Corrosion controlling materials are available for most any type of packer fluid; however the best protection against corrosion will result from properly designed programs before the well is drilled or completed.

References:

"Corrosion Problems in Packer Fluids" by B. F. Davis, Jr.
Presented at:
Southwestern Petroleum Short Course
Department of Petroleum Engineering
Texas Tech University
Lubbock, TX
April 15-16, 1971

HydroHib P
Corrosion Inhibitor

Product Information:

HydroHib P is a combination surfactant, cationic, filming amine corrosion inhibitor and oxygen scavenger for use in fresh waters and brines. **HydroHib P** will control corrosion from salt water due to CO_2, inorganic salts, dissolved oxygen and H_2S contamination from sour fluids or bacterial action.

HydroHib P forms a clear solution with all natural and synthetic oilfield brines.

Typical Physical Properties:

Appearance and Odor	Brown solution, Ammonia Like Odor
Density @ 77°F.	8.39 lbs/gal.
Specific Gravity @ 77°F.	1.005 - 1.010
Flash Point	101°F.
Pour Point	-6°F.
pH	8.2 - 8.8

Application:

HydroHib P is recommended for use in salt water packer fluids, salt water drilling fluids and other waters that will come in contact with the hydrocarbon producing formations. A treatment rate of 55 gallons per 100 to 150 bbls of fluid is recommended.

HydroHib P is recommended as a hydrostatic corrosion inhibitor at treatment rates of 500 to 2000 ppm.

Handling Precautions:

Avoid contact with the skin, eyes and clothing. In case of contact, flush immediately with plenty of water for 15 minutes. Contact with the eyes will require medical attention.

HydroHib P (Methanol Free)

Corrosion Inhibitor

Product Information:

HydroHib P is a combination surfactant, cationic, filming amine corrosion inhibitor and oxygen scavenger for use in fresh waters and brines. **HydroHib P** will control corrosion from salt water due to CO_2, inorganic salts, dissolved oxygen and H_2S contamination from sour fluids or bacterial action.

HydroHib P forms a clear solution with all natural and synthetic oilfield brines.

Typical Physical Properties:

Appearance and Odor	Brown solution, Ammonia Like Odor
Density @ 77°F.	8.39 lbs/gal.
Specific Gravity @ 77°F.	1.005 - 1.010
Flash Point	> 200° F.
Pour Point	-6°F.
pH	8.2 - 8.8

Application:

HydroHib P is recommended for use in salt water packer fluids, salt water drilling fluids and other waters that will come in contact with the hydrocarbon producing formations. A treatment rate of 55 gallons per 100 to 150 bbls of fluid is recommended.

HydroHib P is recommended as a hydrostatic corrosion inhibitor at treatment rates of 500 to 2000 ppm.

Handling Precautions:

Avoid contact with the skin, eyes and clothing. In case of contact, flush immediately with plenty of water for 15 minutes. Contact with the eyes will require medical attention.

FAQ: Has HydroHib-P been used anywhere before?

The answer is a resounding **YES**. Hydrohib-P has been privately labeled for over 30 years by large, medium and small chemical and service companies with sales in excess of one million gallons. Under private label, HydroHib-P was the product of choice for Marathon, Pennzoil, Union Oil, Chevron, Texaco, Brown and Root, McDermott and Transco. HydroHib-P has been utilized on hundreds of pipeline hydrostatic test projects around the world. One customer delayed the commissioning of a pipeline while they air-lifted 80 drums of product to Brazil. Another company compiled the following sales chart for HydroHib-P, under private label, for the one-year period from 12/96 through 12/97.

Company	Project Name/Pipeline	Gallons Used	Date
Shell Transportation	Amberjack	4,670	12/96
Leviathan	S.S. Blk 332	750	3/97
Leviathan	S.S. Blk 207	165	3/97
Leviathan	S.S. Blk 332	255	9/97
Leviathan		430	3/97
Marathon Pipeline	Nautilus	220	5/97
Marathon Pipeline	Nautilus	4,000	8/97
Bridgeline	Discovery	535	9/97
Bridgeline	Discovery	40	
Bridgeline	Discovery	440	11/97
Shell	Genesis	2,300	12/97
Texaco	Poseidon	40	12/97
Shell	MantaRay	1,426	8/97
Shell	Ram Powell	650	
Shell	Enchilada	110	
	TOTAL	**16,031**	

FAQ: How long will treatment last?

HydroHib P applied at 500 ppm in Fresh or Salt water will be effective for one to two years. In theory once the oxygen has been scavenged and the corrosive bacterial effects and acids have been neutralized and metal surfaces filmed then the treatment could last indefinitely. This would require that the dynamics of the treated system not change.

FAQ: Is HydroHib-P a Biocide?

Edelweiss Enterprises Inc. makes no claim for HydroHib-P as a biocide, therefore, this product requires no registration.

To further explain, one of the key components described as a surfactant in our literature, it is a benzyl quaternary ammonium chloride. This product has several functions:

1. As a surfactant, it increases the dispersing of the filming amine portion of the product and aids in metal surface wetting and penetration.
2. As a corrosion inhibitor, it aids in the neutralization of corrosive acids present in hydrostatic or completion fluids.
3. In other applications it has been used as a bactericide, algaecide and microbiocide in everything from cooling towers, production fluids, completion fluids and mouthwash. All of these applications require registration with EPA or USDA.

In additional literature we have available, a very brief history of the HydroHib-P usage over a one year period, by one of our clients, shows the pipelines it has been successfully used on. It has been the product of choice for nearly 30 years for both Hydrostatic testing and completion fluids. Edelweiss has been private labeling this product for more than 40 service companies over that time period.

Corrosion Inhibition Tests HydroHib P

Conditions of Testing

1. Test Procedures

Solutions – Synthetic Seawater was prepared by adding 41.953 g/l sea salt to 100 g/l sodium chloride to deionized water and adjusting pH to 7.3. The calcium bromide, calcium chloride and zinc bromide/calcium bromide solutions were obtained from Dow Chemical U.S.A.

2. Fluid Concentration	dr/bbl	ppm
1/200	6,500	
	1/150	8,700
	1/100	13,100

Corrosion Test – The waters were purged with carbon dioxide for one hour prior to beginning the test. The desired amount of chemical was added to seven one-ounce bottles and a mild steel shimstock corrosion coupon was placed in the bottles. Two hundred ml. (200 ml.) of the test solution was added to the bottles and the bottles were placed in a forced-draft oven at 160^{o} F. for four days. After four days, the bottles were removed from the oven, cooled, coupons cleaned, re-weighed and percent protection calculated. pH measurements and observations of solubility were made before and at the conclusion of the test period.

Test Results

S – Soluble
D – Dispersible
NS – Not Dispersible

SLD – Slightly Dispersible

HydroHib P
Corrosion Test
February 1982

Fluid	**Concentration**	**AV% Protection**	Solubility **Initial**	**Final**
Synthetic Sea-Water + 100 g/l Sodium Chloride Solution	6500	89.1	S	S
	8700	91.8	S	S
	13100	93.5	S	S
Calcium Chloride	6500	99.5	S	S
	8700	88.4	S	S
	13100	25.4	S	S
Calcium Bromide	6500	84.1	S	S
	8700	91.3	S	S
	13100	96.5	S	S

Chevron U.S.A. Protocol

The results of the products and the control sample are as follows. Each inhibitor was tested under the conditions described below:

Brine:	12.2#/gl. $CaCl_2/CaBr_2$
Temperature:	295^{O} F
Pressure:	1500 psig
Inhibitor Concentration:	1.5% by volume
Test Duration:	72 hours

Solubility under these conditions and ambient conditions were noted. A 10% inhibitor solution was observed for 72 hours under ambient conditions. Mild steel corrosion coupons were used to generate a corrosion rate.

HydroHib P
Corrosion Test
September 1991

Product	**MPY**	**295^{O} F, 1500 psig 12.2#/gl. $CaCl_2/CaBr_2$ 1.5% inhibitor, 72 hr**	**Solubility @75^{O} F 10% inhibitor, 72 hr.**
Blank	8.6	Rust solution/corrosion Products on coupon	blank, clear
HydroHib P	5.4	Slight white ppt/ Splotchy deposits	Slight white ppt, some foam with agitation

Mobil Protocol

Weight loss coupons made of C-95, L-80, 9% chrome and 13% chrome materials were used in evaluating the performance of the inhibitor. Electro-Chemical probes made of C-95 and L-80 materials were also used but had to be limited to low temperatures (220^o F. to 270^o F.)

HydroHib P
Corrosion Rate MPY

December 27, 1990

Test Period 28-30 days

Test	Coupon	Blank		Concentration	HydroHib P	
		Electro Chemical	Weight Loss		Electro Chemical	Weight Loss
2% KCl	C-95	10.7	15.4	0.87%	1.3	1.7*
200^o F	L-80	8.5	12.4		1.1	1.8
0.01 psi H_2S	9Cr		4.3*			3.2
10 psi CO_2	13Cr		0.5			0.5
2% KCl	C-95	15.8	12.5	1.05%	27.6	17.5*
270^o F	L-80	10.5	13.4		13.3	13.0
0.45 psi H_2S	9Cr		3.2*			2.4
2500 psi CO_2	13Cr		1.8			1.6
4% KCl	C-95	12.8		0.87%		5.9
400^o F	L-80	9.5				7.9
20 psi H_2S	9Cr	9.6				9.4
400 psi CO_2	13Cr	10.7				9.6
12 lb C_aCl2	C-95	17.2*		0.87%		9.2*
400^o F	L-80	8.0*				8.2*
20 psi H_2S	9Cr	8.1				7.7*
400 psi CO_2	13Cr	8.8*				7.2*
14.5 $CaBr_2/Cl_2$	C-95	4.6*		0.87%		5.5*
400^o F	L-80	4.0				6.3
20 psi H_2S	9Cr	2.7				4.1
400 psi CO_2	13Cr	5.0				7.8
2% KCl	C-95	4.7	50.1	0.87%	2.8	25.2
200^o F	L-80	8.3	35.4		0.1	10.6
0.00 psi H_2S	9Cr		1.2			2.1
2500 psi CO_2	13Cr		1.2			1.0
2% KCl	C-95	2.1	3.0	0.87%	.3	1.8*
200^o F	L-80	1.6	18.2*		.3	10.3*
32 psi H_2S	9Cr		2.2			1.2
140 psi CO_2	13Cr		1.4			2.2*

*Pitting/Crevice/Localized corrosion was observed

Evaluation of Corrosion Inhibitors
For Workover Fluid Applications
January, 1990

Conditions of Testing

Test Procedures

TechniKos, Inc. was requested to perform static corrosion tests on Edelweiss Enterprises, Inc.'s product HydroHib P. The objective of the testing was to provide a comparison of the inhibitors performance in 10.0 lb/gal sodium chloride brine as well as 11.7 lb/gal calcium chloride brine. The test series also considered the effect of either oxygen or carbon dioxide on the corrosion protection provided by the inhibitor.

The test was conducted using 1018 carbon steel coupons cut from flat shim stock and measuring 3" x 0.5" x 0.01". The tests were performed at atmospheric pressure and a temperature of 180^{o} F. for an exposure period of 74 hours. Following exposure, the coupons were cleaned and weighed to determine the corrosion rate. The inhibitor was tested at 1% by volume concentration in the workover fluids.

Test Results

S – Soluble
D – Dispersible
NS – Not Dispersible

SLD – Slightly Dispersible

Corrosion Test
Average Percent Protection
January 1990

	0_2		$C0_2$		Solubility	
Identification	**NaCl**	**$CaCl_2$**	**NaCl**	**$CaCl_2$**	**NaCl**	**$CaCl_2$**
HydroHib PHT	61.02	85.16	79.74	50.66	S	S
HydroHib P, 11/22/88, 15 drums	70.27	70.75	89.79	30.37	S	S
HydroHib P, 12/18/88, 15 drums	75.68	90.57	89.18	34.55	S	S
HydroHib P, 01/06/89, 20 drums	91.89	93.40	92.68	36.13	S	S
HydroHib P, 03/15/89	61.16	35.85	83.54	18.85	S	S
HydroHib P, 05/25/89	67.57	82.08	88.72	51.31	S	S

Toxological Data

Analytical Method Used:

U.S. Environmental Protection Agency toxicity testing procedure contained in the Federal Register Volume 50, No. 165, Monday, August 26, 1985 (34627-34636)

Packer Fluid Test

Chemical: **HydroHib P (10,000 ppm Solution)**

Sample Date: 09/09/91 **Dates of Rangefinder test:** 09/09/91 to 09/13/91

Test Summary:

Mysid shrimp (*Mysidopsis Bahia*) were exposed to a 1:9 SPP of a 10,000 ppm solution of "HydroHib P". The 10,000 ppm solution was made by blending 2 ml. of HydroHib P and 198 ml. of seawater.

Test concentrations were set 1%, 5%, 10%, 25%, 50%, and 100% of the 1:9 SPP

At the end of the 96 hour test, an LC-50 value was calculated utilizing the latest revised method furnished by the USEPA Environmental Monitoring and Support Laboratory (EMSL).

THE CALCULATED LC-50 FOR THIS FLUID IS 172,891 PPM SPP WITH A 95% CONFIDENCE INTERVAL OF 123,414 PPM AND 237,009 PPM.

Chemical: **HydroHib P (500 ppm Solution)**

Sample Date: 05/16/96 **Dates of Rangefinder test:** 05/20/96 to 05/24/96

Analytical Method Used:

U.S. Environmental Protection Agency toxicity testing procedure contained in the Federal Register Volume 58, No. 41, Thursday, March 4, 1993 (12507 – 12512).

Test Summary:

Mysid shrimp (*Mysidopsis Bahia*) were exposed to a 1:9 SPP of a 500 ppm solution of "HydroHib P". The 500 ppm solution was made by blending 1 ml. of HydroHib P and 1999 ml. of seawater.

Test concentrations were set 1%, 5%, 10%, 25%, 50%, and 100% of the 1:9 SPP

At the end of the 96 hour test, an LC-50 value was calculated utilizing the latest revised method furnished by the USEPA Environmental Monitoring and Support Laboratory (EMSL).

THE CALCULATED LC-50 FOR THIS FLUID IS 1,000,000+ ppm

Toxicity Bioassay Data

For: *Miscellaneous Discharges of Seawater which have been chemically treated*

Analytical Method(s) Used:

U.S. Environmental Protection Agency protocol used to determine the "safe" or "no effect" concentration was in accordance with the acute toxicity test method found in 40 CFR part 136, and EPA/600/4-90-027F. This method estimates the toxicity of whole effluents to inland silverside minnows (Menidia beryllina) 7 to 14 day-old fry and mysid shrimp (Mysidopsis bahia) using 7 day-old organisms in two day static renewal tests.

Chemical Tested: ***HydroHib P*** *at 500 ppm*

Test Started: *May 10, 2002*
Test Terminated: *May 12, 2002*

Test Results:
All test data were analyzed statistically using parametric and/or non-parametric procedures which identify the NOEC (no observable effect concentration) and the LOEC (lowest observable effect concentration). The NOEC and LOEC can be used to calculate the chronic value, an estimate of the concentration which is chronically toxic.

Critical dilution: *24.6%* ***(taken from table 2-A, page 19173 of the NPDES GMG 290000 General Permit issued for OCS-G leases)***

Menidia beryllina

	SURVIVAL
NOEC	***24.6% by Volume***
LOEC	***49.2% by Volume***
Chronic Value	***7.01% by Volume***

Sample passes toxicity limit

Mysidopsis bahia

	SURVIVAL
NOEC	***49.2% by Volume***
LOEC	***98.4% by Volume***
Chronic Value	***9.92% by Volume***

Sample passes toxicity limit

Note: To convert to parts per million (ppm): multiply value times 10,000.

Biodegradability Data

Biodegradability study

40 CFR Ch. 1 Section 796.3200

Date started: 12/30/96 **Time started**: 9:58

Date completed: 01/27/97

Inoculum	**Percent Degradation after x days**		
	5	**15**	**28**
Polyseed	15.2%	40.0%	43.2%
Topsoil	24.6%	94.1%	99.0%

HydroHib PHT

CORROSION INHIBITOR

Product Information:

HydroHib PHT is a corrosion inhibitor designed specifically to mitigate corrosion in heavy brines such as corrosion due to CO_2, inorganic salts, dissolved oxygen and H_2S contamination from sour fluids or bacterial action.

HydroHib PHT forms a clear solution with all natural and synthetic oilfield brines.

HydroHib PHT has been tested at temperatures greater than 300°F. with excellent results.

HydroHib PHT is recommended for use in heavy brine packer fluids where high temperatures and pressures are expected to be encountered. A treatment rate of 55 gallons per 100 to 130 bbls of fluid is recommended.

Typical Physical Properties:

Physical State	Clear Liquid
Density @ 77°F.	10.58 - 10.75 lbs/gal.
Specific Gravity @ 77°F.	1.27 - 1.29
Flash Point	> 200°F.
Pour Point	(-) 6°F.
pH	5.6 - 5.9
Freeze Point	-6°F.

Handling Precautions:

Avoid contact with skin, eyes, and clothing. In case of contact, flush immediately with plenty of water for 15 minutes. Contact with the eyes will require medical attention. KEEP OUT OF REACH OF CHILDREN. DO NOT TAKE INTERNALLY. FOR INDUSTRIAL USE ONLY.

Corrosion Test HydroHib PHT

Conditions of Testing

Test Procedures

HydroHib PHT submitted for Corrosion Test in $CaBr_2$ (14.1 ppm) Brine at 300°F.

Type Test	-	Continuous Treatment Static Test
Acid Gas	-	Oxygen plus 50 psig Applied Carbon Dioxide
Test Temperature	-	300°F
Liquid Volume	-	50 ml
Liquid Composition	-	100% $CaBr_2$ Brine
Exposure Time	-	24 Hours
Type Coupon	-	1/4" x 3" Sandblasted Mild Steel Shimstock
Test Date	-	August 1990

Test Results

Chemical	Concentration ppm	Weight Loss, mg	Corrosion Rate, MPY	Percent Protection
None	0	18.4	34.0	Blank
None	0	18.7	34.6	Blank
None	0	19.0	35.1	Blank
HydroHib PHT	1,000	12.6	23.3	32.6
HydroHib PHT	1,000	12.5	23.1	33.2
HydroHib PHT	1,000	10.3	19.0	44.9
HydroHib PHT	5,000	8.4	15.5	55.1
HydroHib PHT	5,000	8.3	15.3	55.6
HydroHib PHT	5,000	7.0	12.9	62.6
HydroHib PHT	10,000	5.6	10.4	70.1
HydroHib PHT	10,000	5.9	10.9	68.4
HydroHib PHT	10,000	5.0	9.2	73.3

HydroHib PC

CORROSION INHIBITOR CONCENTRATE

Product Information:

HydroHib PC is a combination surfactant, cationic, filming amine corrosion inhibitor and oxygen scavenger for use in drilling and mud, fresh waters and brines. **HydroHib PC** will control corrosion from salt water due to CO2, inorganic salts, dissolved oxygen and H_2S contamination from sour fluids or bacterial action.

HydroHib PC forms a clear solution with all natural and synthetic oilfield brines.

Typical Physical Properties:

Physical State	Dark Brown Liquid, Ammonia Odor
Density	8.96 lbs/gal.
Specific Gravity	1.07 - 1.08
Flash Point	145^{o} F.
Pour Point	< 20^{o} F.
pH	8.0 - 9.0

Application:

HydroHib PC is recommended for use in salt water packer fluids, salt water drilling fluids and other waters that will come in contact with the hydrocarbon producing formations. **HydroHib PC** can be formulated to a 30 to 35% active product to give treatment rates of one drum per 100 to 200 bbls.

Formulations:

To make a 55 gallon drum of ready to use product.

HydroHib PC	18.5 gallons	33.6% by volume	or	**HydroHib PC**	18.5 gallons	33.6% by volume
Methanol	5.0 gallon	9.1% by volume		Water	36.5 gallons	66.4% by volume
Water	31.5 gallons	57.3% by volume				

Handling Precautions:

HydroHib PC is a COMBUSTIBLE LIQUID. Avoid contact with the skin, eyes, and clothing. In case of contact, flush immediately with plenty of water for 15 minutes. Contact with the eyes will require medical attention.

Biological Resources	
115	Please provide the following references: Myers and Ewel 1990. Ecosystems of Florida, Edited by Ronald L. Myers and John J Ewel, Chapter 15 Mangroves, Odum, William E. and Carole C. McIvor, pp. 517-546, University of Central Florida Press, 1990. Rogers et al 1996. Rare and endangered Biota of Florida, Volume V. Birds, Edited by James A. Rogers, Jr., Herbert W. Kale II, and Henry T. Smith, University Press of Florida, 1996. Ashton and Ashton 1981. Ashton, Jr., Ray E., Patricia Sawyer Ashton. Handbook of Reptiles and Amphibians of Florida, The Snakes, Windward Publishing, 1981.
Response	The above references are books that have been ordered. Port Dolphin will send these books to the USCG as soon as they are received, which is anticipated to be the week of November 12.

Land Use	
116	Please provide additional information on where the remaining 0.34 acres of additional workspace (referenced in Resource Report 3 on page 3-9 in the first paragraph) would be located along the onshore portion of the pipeline route.
Response	The additional 0.34 acres is the extra work space for the drill exit on the east side of Hwy 41, which was an HDD (drill) planned by Port Dolphin as described in the original filing documents. Due to the re-route of the terrestrial portion of the Port Dolphin pipeline, this HDD crossing of Hwy. 41 is no longer necessary. Port Dolphin's current pipeline alignment (as reflected in the addendum filing documents) will cross Hwy. 41 further south and is proposed to be an uncased slick bore design, therefore the 0.34 acres of additional workspace identified in this question is no longer applicable.

Cultural Resources	
117	Please provide a statement that identifies and describes the configuration and dimensions (horizontal and vertical) of the offshore Project APE (e.g., the Port/Buoy Area, Pipeline Corridor [trench and spoil area], and Anchor Spread) and provide supporting correspondence confirming that the agency consulted with the SHPO/THPO "to determine and document the area of potential effects," as part of the scoping of the identification efforts outlined in CFR 800.4(a) of the Section 106 process.
Response	Identification and descriptions of the configuration and dimensions of the offshore Project APE are provided in the attached. The Florida SHPO has been consulted for all appropriate permits and report review. The permit(s) have been applied for and are currently being processed. Currently, only telephone communications and email exist, rather than any formal letters. Supporting correspondence confirming consultation with the Florida SHPO/THPO will be provided when received.

Impacts to cultural resources are discussed in **Volume II, Section 5** of the **Deepwater Port Application**. Impacts discussed here are those resulting from direct physical disturbance to the seafloor during plowing of the seafloor, placement of concrete mattresses, and anchoring of barges during construction activities. Other impact sources relevant to the project design changes include installation of the STL subsea system and sweeping of the seafloor due to movement of STL mooring lines during routine operations. These impacts are changed slightly due to optimization of the mooring system. There are no project design changes relevant to decommissioning or accidents or upsets, and so potential impacts from these sources are unchanged from the original analysis.

Construction

Seafloor Disturbance – Pipeline Installation. The areal extent of seafloor disturbance during pipeline installation has increased due to re-routing of the pipeline around the Aquatic Preserve. Also, the specific location of some impacts within Tampa Bay has changed due to the re-routing.

Plowing and Mattress Placement – **Table 5-1** summarizes the area affected by plowing, mattress placement, and anchoring for the original and revised corridors. (Further details of the anchoring calculations are provided later in this section.) The original corridor values are from **Volume II**, **Section 4.3.2** of the **Deepwater Port Application**. The revised numbers reflect (1) the re-routing of the pipeline around the Terra Ceia Aquatic Preserve; (2) corrections to the original spreadsheet for "plowability" of various pipeline segments; and (3) the use of GIS to calculate more accurately the extent of impacts.[1]

For plowing impacts, a width of 67 feet (20.4 meters) was used. Mattress placement was assumed to affect a width of 13 feet (4.0 meters). Diagrams illustrating the impact width are included in the **Deepwater Port Application**. In one location in Tampa Bay where a combination of dragline burial and concrete mattresses is planned, an effect width of 60 feet (18.3 meters) was assumed. This impact is related to the Sunshine Skyway Bridge crossings and was not included in the original analysis.

[1] In the original analysis, the pipeline route was divided into about 90 segments that were rated as plowable or not plowable, and the habitat within each segment was rated as A, B, D, or soft bottom. In the revised analysis, the same approach was used for plowability, but the linear extent of plowing and mattressing impacts were measured directly using the GIS on mapped habitats.

Table 5-1
Areal Extent of Seafloor Impacts from Pipeline Installation in Original and Revised Preferred Corridors (Entire Route)

Activity	Area Affected Acres (Hectares)	
	Original Preferred Corridor[a]	**Revised Preferred Corridor**
Plowing	153.43 (62.09)	176.1 (71.27)
Mattress Placement	40.85 (16.54)	35.74 (14.46)
Dragline /mattress	--	1.38 (0.56)
Anchoring	19.19 (7.77)	20.27 (8.20)
Total	213.47 (86.40)	233.49 (94.49)

[a] As estimated in **Volume II, Section 4.3.2** of the **Deepwater Port Application**.

The revised analysis predicts that a total of 176.10 acres (71.27 hectares) would be affected by plowing.

The revised analysis also predicts that 35.74 acres (14.46 hectares) would be affected by concrete mattresses.

A small area of 1.38 acres (0.56 hectares) would be affected by dragline burial and concrete mattresses at one location in Tampa Bay. All of the area would be soft bottom.

Overall, the areal extent of seafloor impacts during pipeline installation is estimated to be about 9% larger than originally estimated in **Volume II, Section 4.3.2** of the **Deepwater Port Application**.

Anchoring – **Table 5-2** summarizes impacts of anchoring for the entire Revised Preferred Route. The following assumptions were made to calculate the extent of anchoring impacts:

- The barge will make four passes along the route, for pipelaying, plowing, backfilling, and mattress placement.
- During the first three passes, the barge will use 10 anchors, which will be reset every 2,000 feet (610 meters). Each anchor contact with the seafloor will directly affect an area of 360 square feet (33.4 meters^2).
- The fourth pass (mattress placement) will be done by a smaller barge with four smaller anchors, which will be reset every 1,000 feet (305 meters). The anchors would affect a smaller area of 90 square feet (8.4 meters^2).

Table 5-2
Areal Extent of Impacts from Anchoring During Pipeline Installation
(Entire Revised Preferred Route)

Pass[a]	Activity	Length (feet)	No. of Anchor Resets	No. of Anchor Impacts	Direct Impact Area
1st	Pipelaying	235,549	117	1,170	9.68 (3.91)
2nd	Plowing	115,468	58	580	4.79 (1.94)
3rd	Backfilling	115,468	58	580	4.79 (1.94)
4th	Mattress placement	120,081	121	484	1.0 (0.40)
				Total	20.26 (8.19)

[a] For first three passes, assumed a barge would use 10 anchors that would be reset every 2,000 feet (610 meters) and each would affect an area of 360 square feet (33.4 meters^2). For the fourth pass, assumed four smaller anchors would be reset every 1,000 feet (305 meters) and each would affect an area of 90 square feet (8.4 meters^2).

The actual sequence of events involved in pipelaying is more complicated than indicated by these assumptions, particularly in Tampa Bay where three HDD operations will be conducted. However, the assumptions are considered a reasonable basis for estimating the number and extent of anchor impacts.

The revised analysis predicts that 20.27 acres (8.19 hectares) would be affected by anchoring.

In addition to the direct impacts, each anchor cable will also contact (sweep) the seafloor. The areal extent of anchor sweep impacts has not been estimated. During detailed design, an anchoring plan will be developed that will provide specific procedures to minimize anchor sweep impacts on hard/live bottom habitat.

Seafloor Disturbance – STL Subsea System Installation. Another construction activity that will disturb the seafloor is installation of the STL subsea system, which consists of the STL buoy and pipeline end manifold (PLEM), as well as associated moorings, risers, and umbilicals. Installation will disturb sediments due to placement of components on the seabed, as well as anchoring of construction vessels. Although specific mooring locations around the STL buoys have been changed due to optimization of the mooring configuration (see **Section 3.3**), the number of moorings is unchanged. Therefore, the total area of seafloor impacts during construction is the same as in the original analysis in **Volume II**, **Section 4.3.2** of the **Deepwater Port Application**, which was 0.59 acres (0.23 hectares). **Table 5-3** summarizes impact calculations.

Table 5-3
Area Affected by Installation of the STL Subsea System

Impact Source	North Buoy	South Buoy	Total
Placement of STL landing pad	0.13 (0.05)	0.13 (0.05)	0.26 (0.10)
Placement of PLEM	0.02 (0.01)	0.02 (0.01)	0.04 (0.02)
Placement of anchors/piles (8 anchors total)[a]	0.07 (0.027)	0.06 (0.027)	0.13 (0.054)
Barge anchoring (10 anchors total)[b]	0.082 (0.033)	0.083 (0.033)	0.170 (0.066)
Total	0.298 (0.12)	0.298 (0.12)	0.67 (0.23)

[a] Each mooring assumed to affect 360 square feet (33.4 meters^2).

[b] Each barge anchor assumed to affect 360 square feet (33.4 meters^2).

The landing pad and PLEM will be fixed to the seafloor, either by means of a skirted mud mat or with a suction pile. The area affected would be 0.02 acres (0.01 hectares) for the PLEM and 0.13 acres (0.05 hectares) for the STL landing pad.

The STL subsea system includes eight anchors or suction piles in both the North Buoy and South Buoy areas. Each anchor or suction pile is assumed to affect an area of 360 square feet (33.4 meters^2). The total area affected at both buoy areas would be 0.193acres (0.054 hectares).

Installation of the STL subsea system is assumed to be conducted by a barge with 10 anchors, each affecting an area of 360 square feet (33.4 meters^2). The area affected would be 0.17 acres (0.05 hectares).

The total impact area for STL subsea system installation is estimated to be 0.67 acres (0.23 hectares).

Operations

During operations, the anchor chains/cables from the STL buoys will chafe bottom sediments. The two unloading buoys will each have eight mooring lines consisting of wire rope and chain connecting to anchors or driven piles on the seabed. When not connected to an SRV, the unloading buoy would be submerged below the sea surface. When an SRV arrives, the unloading buoy would be retrieved from its submerged position by means of a winch and recovery line. As the STL buoy moves up and down, some lateral movement of the mooring lines will occur, contacting the seabed. **Table 5-3** summarizes the estimated areas that would be contacted by anchor sweep.

Table 5-3
Area Estimated to be Affected by
Anchor Sweep During Routine Operations[a]

Impact Source	North Buoy	South Buoy	Total
Anchor sweep (STL buoy)	11.05 (4.47)	11.05 (4.47)	22.1 (8.94)

In **Volume II, Section 4.3.2** of the **Deepwater Port Application**, the total seafloor area affected by anchor sweep at both North and South buoys combined was estimated to be about 30 acres (12.14 hectares). The revised estimate is approximately 22.1 acres (8.94 hectares). The area of seafloor disturbance is about 25% less than the original estimate and represents less than 1% of the seafloor within each buoy area.

Cultural Resources	
118	Please provide a description of the potential impacts to historic resources (e.g., shipwrecks) that are anticipated during construction of the preferred location and route. Only potential impacts to prehistoric resources within the Port's buoy area are included in Volume II, Section 5.3.1 (page 5-12) of the Deepwater Port License Application. Please include in the description potential impacts within the Pipeline area as well for both prehistoric and historic resources.
Response	***Construction*** The primary potential impacts to cultural resources associated with construction activities would be potential impacts to prehistoric and historic sites. Construction of the terminal and pipeline would involve derrick/lay barges, anchor handling tug support vessels, and other support vessels. Potential disturbance of historic and prehistoric sites could occur from anchors used by these vessels if used near or within the designated avoidance zones. If historic or prehistoric sites were encountered during construction, the impacts could be significant and irreversible. Proposed construction activities would be modified to avoid such areas, thus minimizing the degree of impact and subsequent significance of the impact. Phase I geophysical surveys in and around the terminal revealed the presence of buried fluvial channels in St. Petersburg Area Blocks 545 and 589 that retain geomorphic features representing high probability areas for prehistoric archaeological sites. Although specific locations of prehistoric sites associated with these features are not known, the potential exists for undisturbed channel margins to retain these resources. Avoidance areas of 250 feet within and outside of one area of relict channels have been designated. Project installation activities, specifically Anchor 10 of the proposed south buoy, are located about 5,300 feet southeast of the prehistoric cultural resources avoidance area. Three unidentified side scan sonar contacts and 16 unidentified magnetic anomalies within the pipeline area may represent possible historic shipwreck remains. Avoidance zones of 300-foot radii have been established around Sonar Contacts 1a, 1b, and 1c, 6, and 9. Magnetic Anomaly Nos. 18, 28, 29, 50, 53, 105, 185, 186, 196, 197, 200, 208, 212, 213, 283, and 287 should all be avoided by a distance of 200 feet. Prior to commencing construction, any features that cannot be avoided will be investigated to assess their potential historic significance. ***Operations*** Once the port components and marine pipeline are installed, there would be no further contact with the seafloor other than the periodic scouring of mooring anchor chains/cables in the port component. Since no potentially significant prehistoric or historic resources would be located within 1,000 feet of any port components or the pipeline, there would be no impacts on cultural resources by routine operations. Potential disturbance of historic or prehistoric sites could occur from anchors used by support vessels if used

	near or within the designated avoidance zones. ***Decommissioning*** The proposed decommissioning procedure for the buoy is to remove the buoy, riser, umbilical, and mooring lines. The landing pad would be removed as well. In the case of pile anchors, the anchors would be cut subsurface, with the top portion being removed and the lower portion remaining in place. In the case of suction anchors, the anchors would either be left on the seabed (with some rock to cover the top of the top of the anchor), or an attempt could be made to remove the anchors by injecting seawater (reverse installation process) and removing them completely from the seafloor. Subject to negotiated land lease conditions, the pipeline would be decommissioned by filling with seawater and leaving in place. Impacts on historic and prehistoric sites from decommissioning activities are not anticipated because terminal components would be more than 1,000 feet from any potential significant targets, and disturbance to the seabottom from decommissioning activities would be minimal. Potential disturbance of prehistoric sites could occur from anchors used by support vessels if used near or within the designated avoidance zones. Pipeline decommisioning procedures should have no impact on prehistoric or historic cultural resources. ***Accidents and Upsets*** It is not anticipated that releases of LNG, natural gas, or other petroleum products would impact the seafloor. Therefore, cultural resources are not expected to be impacted by upsets or accidents.

Cultural Resources	
119	The series of magnetometer and side scan sonar anomaly maps depict the following side scan sonar contacts and magnetic anomalies within the three mapped avoidance areas: - Side Scan Sonar Contacts: 1 (consisting of 1a, 1b, & 1c), 6 and 9 - Magnetic Anomaly Nos.: 18, 28, 29, 50, 53, 105, 185, 186, 196, 197, 200, 208, 212, 213, 283, and 287 (n=16); however, the report only lists: - Side Scan Sonar Contacts: 1, 6 and 9 - Magnetic Anomaly Nos.: 15, 28, 29, 50, 53, 100, 185, 186, 196, 197, 200, 212, 213, 283, and 287 (n=15). If the maps of the anomalies are correct, then it appears that: 1) the report's listing of Magnetic Anomaly No. 15 may be a typo and was, instead, meant to 18 2) the report's listing of Magnetic Anomaly No. 100 may also be a typo and was supposed to be 105 3) that Magnetic Anomaly No. 208 plotted on the map may have been left off the list of magnetic anomalies in the report accidentally. The question is which is accurate – the maps or the lists in the text of the report?
Response	The **Conclusions and Recommendations** section of the archaeological report should also include all components of Side Scan Sonar Contact 1: 1a, 1b, and 1c. Under the section **Magnetometer and Side Scan sonar Analysis**, this feature is described as being "comprised of several individual targets." All three components of this contact are described in the **Table of Side Scan Sonar Contacts** in this section. The archaeological report's listing of Magnetic Anomaly No. 15 should be No. 18, and the listing of Magnetic Anomaly No. 100 should be No. 105. These are typographic errors in the **Conclusions and Recommendations** section of the archaeological report. Magnetic Anomaly No. 208 is included in the **Table of Magnetic Anomalies Associated with Side Scan Sonar Contacts Recommended for Avoidance by 200-foot Radius**, as is No. 200. Magnetic Anomaly No. 208 should be included in the discussion of magnetic anomalies to be avoided in the **Conclusions and Recommendations** section of the archaeological report.

Project Description and Alternatives	
120	Please provide an explanation for the rationale behind designating 250 ft avoidance areas within and outside only *one* of several relict channels identified in the survey area and described in Volume II, Section 5.3.1 (page 5-12) of the Deepwater Port License Application as retaining "geomorphic features representing high probability areas for prehistoric archaeological sites." Why weren't all the archaeologically sensitive relict channels designated as areas to be avoided?
Response	Most of these features recorded are fragmented, discontinuous from line to line, and the tops of these features appear truncated, probably during the Holocene marine transgression. A minimal possibility exists that cultural features could be incorporated into the infill sediments, if any were present to begin with. However, because the upper fill deposits and outer margins appear truncated by erosion, the probability of encountering cultural remains in association with the upper margins of the infill sediments and the outer margins of the channels is extremely low. It is unlikely that any archaeological features would remain in these marginal areas, therefore no avoidance criteria were established for these features. In the west central portion of the mooring area the buried fluvial channels do *not* appear truncated (Archaeological and Hazard Report Map 2, Sheet 2 and Figure 23). Because the profiles indicate that overbank deposition is present, not affected by erosion, the possibility exists that any cultural features that could be associated with the channels are protected by the overbank deposits, and therefore remain minimally undisturbed. These were the criteria used for assigning an avoidance area to these particular features.

Transportation	
121	How many vessels (and what types) currently utilize Port Manatee annually?
Response	Vessel data for Port Manatee is discussed in Volume II, Section 11.9.5.3. In addition, attached are additional data available for number and type of vessels that call on Port Manatee.

U.S. Port Calls by Port and Vessel Type

Year	Port/State	State	Coastal Region	All Types		Tanker*		Product Tanker		Crude Tanker		Container			Dry Bulk	
				Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Capacity (TEU)	Calls	Capacity
2002	Port Manatee	FL	USG	44	839,836	1	72,910	0	0	1	72,910	0	0	0	4	205,126
	Tampa	FL	USG	879	29,346,252	171	5,607,737	170	5,500,476	1	107,261	8	183,004	6,500	413	16,626,663
2003	Port Manatee	FL	USG	122	3,863,275	10	390,483	10	390,483	0	0	0	0	0	64	2,673,348
	Tampa	FL	USG	769	25,851,435	179	6,187,155	176	5,962,291	3	224,864	17	337,355	23,417	348	13,531,889
2004	Port Manatee	FL	USG	137	4,411,605	8	302,947	7	232,520	1	70,427	1	22,778	450	57	2,355,210
	Tampa	FL	USG	859	30,410,513	297	10,973,470	295	10,761,189	2	212,281	32	535,246	34,524	370	14,056,007
2004	Port Manatee	FL	USG	159	5,544,357	21	873,999	16	515,481	5	358,518	0	0	0	76	3,150,968
	Tampa	FL	USG	1,003	36,366,002	401	14,912,990	398	14,637,575	3	275,415	38	586,624	38,413	396	15,884,888

* Tanker includes Product Tanker and Crude Tanker
** Ro-Ro includes Vechicle Carriers

Source: http://www.lloydsmiu.com/mtmarlin/marlin/system/render.jsp?MarlinViewType=MARKT_EFFORT&siteid=20001000683&marketingid=20001147162&forcedBounce=true&code

U.S. Port Calls by Port and Vessel Type

Year	Port/State	State	Coastal Region	Ro-Ro*		Vehicle		Gas Carrier		Combination		General Cargo	
				Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity	Calls	Capacity
2002	Port Manatee	FL	USG	0	0	0	0	0	0	0	0	39	561,800
	Tampa	FL	USG	26	349,481	25	331,631	140	3,994,238	2	111,955	119	2,473,174
2003	Port Manatee	FL	USG	2	23,700	0	0	0	0	0	0	46	775,744
	Tampa	FL	USG	25	357,874	19	244,875	106	3,419,402	1	48,062	93	1,969,698
2004	Port Manatee	FL	USG	3	36,870	0	0	0	0	0	0	68	1,693,800
	Tampa	FL	USG	21	304,154	15	199,614	89	3,138,744	2	124,154	48	1,278,738
2004	Port Manatee	FL	USG	0	0	0	0	0	0	0	0	62	1,519,390
	Tampa	FL	USG	26	388,184	24	358,870	94	3,382,907	1	45,727	47	1,164,682

* Tanker includes Product Tanker
** Ro-Ro includes Vechicle Carrie

Source: http://www.lloydsmiu.com/

Transportation	
122	When the pipeline (both on and offshore) is decommissioned at the end of it's use, what is the timeline expected for removal of all parts of the pipeline, and what decommissioning equipment will be necessary?
Response	The decommissioning phase would include removal of all fixed components (excluding the pipelines), both offshore and onshore, and is expected to take approximately 1 to 2 months to remove the offshore components and approximately 1 month~~s~~ to remove the onshore components. Equipment to be used for decommissioning the offshore components: 1. 1 each, 4-point DSV barge with a 30 ton crane 2. 2 each, tugs to support the DSV barges 3. 1 each, crew/supply boats Equipment to be used for decommissioning the onshore components: 1. 1 each, 50 ton crane~~s~~ 2. 2 each, eighteen wheeler trucks 3. 2 each, welding rig trucks 4. 3 each pickup/crew trucks

Transportation	
123	Will the Seaboard Coast Line Railroad (CSX) be used in regard to Port Dolphin, and if so, in what capacity (such as to bring materials or labor)?
Response	During construction planning, Port Dolphin will certainly consider the CSX railroad as a means to transport material and equipment for the Port Dolphin project. However, since no contracts have been yet entered to supply materials then it is premature to determine whether using CSX would meet the project needs. If the CSX railroad is used, Port Dolphin sees the most viable components to be transported would be large, permanent gas handling equipment such as vessels, skids and line pipe. Port Dolphin does not see a need for the CSX railroad to transport personnel.

Transportation	
124	If the offshore construction will run 24 hours a day as expected, when are the shift changes?
Response	Shift changes are normally twice per day and occur at 12:00 noon and midnight.

Transportation	
125	How many semi-trucks are expected to be required to bring onshore equipment and materials to Port Manatee, and on what timeframe?
Response	Port Dolphin's base case construction plan anticipates that as many as 680 semi-truck trips would be needed to bring supplies and equipment for the construction of the onshore and offshore pipelines as well as the Interconnection Station facilities. Approximately 620 of those trips would be associated with transporting pipe and other components for the offshore portion of the project and 60 of those trips would be associated with the onshore pipeline and the Interconnection Station. Approximately 30 of those trips would be for the work required inside Port Manatee. The actual number of semi-trucks to be used for the project will be dependent on the roundtrip distance and travel time for each trip (which is dependent upon the location of the pipe manufacturer and other suppliers who are awarded contracts), so the actual number of semi-trucks to be used will be substantially less than the number of truck-trips needed. Alternatively, Port Dolphin may also use barges to bring the pipe to Port Manatee (if the selected pipe mill and coating yard is strategically located next to port facilities). The final selection of the applicable materials/equipment transportation alternative will be made during the procurement stage of this project. If transportation by sea is possible then the number of truck-trips would be reduced to approximately 100.

Air Quality	
126	What port (Port of Tampa, Port Manatee, or similar) will the support vessel and dedicated crew boat operate out of?
Response	The support vessels and dedicated crew boat are anticipated to operate out of Port Manatee.

Air Quality	
127	We are requesting meteorological files (extracted from the very large "Item1" files) for two specific periods: 1) 1996 Julian days 70 and 71 (48 hour period) 2) 1992 Julian days 45-49 (5 days, or 120 hours)
Response	The requested files have been copied to an external hard drive which has been sent to USCG/e^{2}M. The paths for these meteorological files on the drive are: Comment 127\1992\large\1992-1.met Comment 127\1992\small\1992-1.met Comment 127\1996\large\1996-3.met Comment 127\1996\small\1996-3.met

Air Quality	
128	It appears that the averaging-time adjustments were applied incorrectly in calculating the maximum 24-hour concentrations in the SCREEN3 analysis (Response to EPA Comments received on 6/14/2007, Attachment C, SCREEN3 Air Modeling Results). The stated operating limit for the generators is up to two hours per week. From the information presented, it is unclear whether these sources could operate for two hours in one day. Assuming that the emergency generators would be allowed to operate up to 2 hours per day, the correct adjustment to determine the maximum 3-hour average concentration for each generator from the maximum one-hour value should be 2/3 (two of 3 hours). Similarly, the maximum 24-hour average value should be 1/12 of the maximum one-hour value (2 of 24 hours). If the generators can only operate for one hour in a given day, the correct adjustments should be 1/3 and 1/24, respectively. Since the impacts will occur within a period of one or two hours, adjustments based on varying dispersion conditions over a longer time period (during hours when the source is not operating) are not applicable. The adjustment factors used to produce the values presented in Attachment C are not documented, but the maximum 24-hour average values are too low, compared to the maximum 3-hour values at the same receptors. The maximum 24-hour value should never be less than 1/8 of the maximum 3-hour value, since that is the 24-hour average value obtained if there is zero impact during the remaining 21 hours. If EPA has approved the averaging-time adjustments, please provide documentation of their approval. If not, please provide amended analyses.
Response	The SCREEN3 modeling results for onshore generators were submitted to EPA and the USCG on August 9, 2007. However, EPA has not commented on utilizing the emission rate averaging adjustment technique together with the EPA SCREEN3 adjustment factors for different averaging periods. Once EPA comments on this approach, we will either provide the approval from EPA or make modifications based on EPA's response.

Air Quality	
129	The "offshore" impacts listed for SO_2 are also problematic. The maximum 24-hour impact is greater than the maximum 3-hour impact.
Response	From the SCREEN3 results, we did not find that maximum 24-hour impact is greater than the maximum 3-hour impact. Further discussions with the USCG indicated that upon further review, they also did not find that the maximum 24-hour impact is greater than the maximum 3-hour impact.

Air Quality	
130	It would also be useful for future documentation to indicate what emission rates were used to obtain the listed "modeled impacts" (which are the same for SO_2 and PM).
Response	The SCREEN3 modeling runs were based on 1 lb/hr for all pollutants. The model output concentrations were then scaled based on actual emission rates to calculate actual model output concentrations.

	Air Quality
131	Please provide additional files related to CALMET and CALPUFF (to verify model results, replicate Applicant runs, and run alternative cases if necessary). Files in Item 1 are meteorological input files required to run CALMET (in order to run CALPUFF). The files listed in items 2 and 3 provide documentation of model predictions, including time and location of critical events and receptors, and the post-processor settings used for calculating deposition and visibility impacts. 1) MM4/MM5 model ready files (as identified in CALMET input files) MM4DAT=D:\EXTMM5\1990\1990H1.DAT MM4DAT=D:\ExtMM5\1990\1990H2.DAT MM4DAT=Z:\ExtMM5\1992\1992H1.DAT MM4DAT=Z:\ExtMM5\1992\1992H2.DAT MM4DAT=Z:\ExtMM5\1996\9609.MM5 MM4DAT=Z:\ExtMM5\1996\9608.MM5 MM4DAT=Z:\ExtMM5\1996\9607.MM5 MM4DAT=Z:\ExtMM5\1996\9606.MM5 MM4DAT=Z:\ExtMM5\1996\9605.MM5 MM4DAT=Z:\ExtMM5\1996\9604.MM5 MM4DAT=Z:\ExtMM5\1996\9603.MM5 MM4DAT=Z:\ExtMM5\1996\9602.MM5 MM4DAT=Z:\ExtMM5\1996\9612.MM5 MM4DAT=Z:\ExtMM5\1996\9611.MM5 MM4DAT=Z:\ExtMM5\1996\9610.MM5 MM4DAT=Z:\ExtMM5\1996\9601.MM5 2) output files for deposition and visibility DFDAT=DOLDW_CONF.DRY WFDAT=DOLDW_CONF.WET VISDAT=DOLDW_CONF.VIS 3) CALPUFF post-process files CALPOST (input and output) - Processes receptor statistics such as averages, time series and maximums from CALPUFF CALSUM (input and output) - Scales, sums, and combines concentration or flux files from CALPUFF POSTUTIL (input and output) - Processes deposition fluxes from CALPUFF

Response	The requested files have been copied to an external hard drive which has been sent to USCG/e^{2}M. For Item #1, The paths are: Comment 131_Item1\1990H1.dat Comment 131_Item1\1990H2.dat Comment 131_Item1\1992H1.dat Comment 131_Item1\1992H2.dat Comment 131_Item1\1990H1.dat Comment 131_Item1\9601.mm5 to Comment 131_Item1\9612.mm5 For Item #2, The paths are: Comment 131_Item2\PSD-F\DOLDWPyy_PSDF.ext yy: 90, 92 or 96 ext: DRY, VIS or WET For Item #3, The paths are: Comment 131_Item3\PSD-F\APPEND Comment 131_Item3\PSD-F\CALPOST Comment 131_Item3\PSD-F\CALPUFF Comment 131_Item3\PSD-F\POSTUTIL Comment 131_Item3\PSD-N\CALPOST Comment 131_Item3\PSD-N\CALPUFF Comment 131_Item3\PSD-N\POSTUTIL

Air	
132	We have not found Greenhouse Gas (GHG) emission estimates for the Project (Construction, Operations and Decommission phases) in the Application materials submitted to date. Please provide GHG emissions estimates (or identify where we can find them) for Project emissions, including SRV emissions within the proposed Safety Zone and vessel emissions during construction and decommissioning. If the impacts of GHG emitted by the Project have been evaluated (including cumulative impacts), please provide descriptions of the analyses and results.
Response	The attached modeling report provides the requested information.

PORT DOLPHIN GHG IMPACT ANALYSIS

PORT DOLPHIN ENERGY LLC.

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Port Dolphin LNG Deepwater Facility GHG Impact Analysis

1.0 Project Summary

Port Dolphin Energy LLC (Applicant) is filing for a license pursuant to the Deepwater Port Act of 1974, as amended (DWPA), and the United States Coast Guard's (USCG) regulations, 33 C.F.R. Part 148 (2006), to construct, own and operate a deepwater port. The unloading portion of the deepwater port, named *Port Dolphin*, would be located in federal waters approximately 28 miles (45-kilometers) offshore of the Tampa Bay area of Florida in approximately 100-feet (30-meters) of water. This area lies within the St. Petersburg block of the Outer Continental Shelf.

The third party EIS contractor to the U.S Coast Guard, e^{2}M, has made the following request for clarification of the initial Deepwater Port License Application as part of a September 2007 Data Gaps and Scoping review;

"We have not found Greenhouse Gas (GHG) emission estimates for the Project (Construction, Operations and Decommission phases) in the Application materials submitted to date. Please provide GHG emissions estimates (or identify where we can find them) for Project emissions, including SRV emissions within the proposed Safety Zone and vessel emissions during construction and decommissioning. If the impacts of GHG emitted by the Project have been evaluated (including cumulative impacts), please provide descriptions of the analyses and results."

This analysis has been done in response to this request.

1.1 No –Action Project Specific GHG Baseline

The United States currently receives about 3% of its natural gas from overseas via liquefied natural gas tankers. Another 17% is imported from Canada through pipelines. The remaining 80% is produced domestically and is currently declining in overall production. It is anticipated that natural gas imports will rise to 30% of overall United States consumption by 2030. The Project no-action Baseline case for no additional imports of an average of 800 mmscfd of natural gas is assumed to be the consumption of fuels in the Florida/Tampa area of an equivalent heating value at the same proportion of existing coal, fuel oil, and natural gas use as determined by U.S. DOE Energy Information Administration. Without the project implementation the fuel use mix for electricity consumption would change with increased imports of fuel oil from international sources and natural gas from Canada if available in the future. Overall, this is a conservative assumption because limiting imports of natural gas would also result in incrementally increased cost of natural gas which would encourage utility fuel switching to coal and fuel oil which means that future use would probably be at ratios that include more coal and fuel oil on a percentage basis than in present use. The U.S. Department of Energy (DOE) Energy Information Administration indicates that the average electricity emission factor for the period 1999 through 2002 for Florida was 0.678 metric tonnes of Carbon Dioxide per MWh. The equivalent factor for use of natural gas only for power generation is 0.403 metric tonnes of Carbon Dioxide per MWh. This represents a **net reduction of approximately 40%** in the GHG intensity of emissions from fuel use for electricity generation.

Consistent with a discussion held with the US Coast Guard on September 28, 2007 the project GHG assessment boundary does not include a comparison of supply side production emissions between the no-action base case and the project preferred option; supply side emissions are assumed to be at least equivalent and therefore net out. This is a conservation assumption because coal mining and fuel oil refining are both much more energy intensive than natural gas production and supply side GHG emissions are likely to actually be greater for the no-action base case. Natural gas is a preferred option for power generation when considering GHG and other pollutant emissions. Table 1 below compares fossil fuel emissions in pounds per billion BTUs of Energy Input for natural gas, oil and coal.

Table 1
Emission Levels for Selected Fossil Fuels
(Pounds/billion BTU of Energy Input)

Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457

Port Dolphin, when fully operational will deliver an average of 800 mmscfd of natural gas to Manatee County, Florida. Assuming an average heat content of 1020 Btu/scf for delivered natural gas and 7600 Btu/KWh for electricity generation by natural gas this is enough gas to generate approximately 39.2 million MWh per year. Table 2 summarizes the carbon dioxide emissions from the no action baseline and shows the 10.8 million metric tonnes per year that will occur if the project is implemented by the displacement of coal and fuel oil generated power with natural gas as the primary fuel source.

Table 2
Carbon Dioxide Emission Comparison to No-Action Base Case

Scenario	Carbon Dioxide (Metric Tonnes/MWh)	Carbon Dioxide (Million Metric Tonnes/year)
Base Case No-Action 39.2MMWh	**0.678**	**26.6**
Port Dolphin 39.2MMWh	**0.403**	**15.8**
Project GHG Reduction		**10.8**

2.0 Project GHG Air Emissions Inventory

Both US EPA and US DOE have emission factors for carbon dioxide and methane. EPA's factors are documented in different chapters of AP-42. DOE's factors are presented in "Technical Guidelines Voluntary Reporting Of Greenhouse Gases (1605(b)) Program, January 2007". For the purpose of comparison, calculations for all activities (e.g., construction, operation, decommission) have been performed using both sets of factors. However, the final report only demonstrates results based on the DOE factors. The carbon dioxide emissions based on EPA and DOE factors are very close (within 10% difference). However, the methane emissions are quite different between these two sets of factors. The main reason is that DOE factors are more specific and it considers different fuel types and industries. Therefore, DOE factors are more representative. Furthermore, some of the DOE factors are cross-referenced to data published by Intergovernmental Panel on Climate Change (IPCC). This indicates that DOE has also adopted a global approach for the greenhouse gas issue. Based on these considerations, DOE factors have been chosen for the report but the analysis by both methods is documented in the emissions calculation spreadsheets attached in Appendix A.

2.1 Construction

Construction emission sources come from the following construction equipment: a pipelay/derrick barge, anchor-handling tug supply (AHTS) vessel, crew boat, and supply boat. During the construction of the proposed *Port Dolphin* deepwater facility and pipeline, different tasks would require the use of a variety of vessels and each vessel would contribute to the total air emissions. The main sources of emissions during construction would be the diesel engines used onboard each vessel for propulsion and electricity generation.

<u>Pipeline Construction</u>

Emission factors for the construction equipment, including a pipelay/derrick barge, anchor handling support vessels , survey boat, diving barges, jack-up barge, pipe burial barge, dragline, and pipe pull barge, are obtained from Department of Energy (DOE) Guidelines[1], Tables 1.C.6 and 1.C.11. The table below presents these emission factors as well as a summary of activities on these vessels.

[1] Based on DOE "Technical Guidelines Voluntary Reporting of Greenhouse Gases (1605(b)) Program", January 2007.

Table 3 Offshore Pipeline Construction –Engine Characteristics and Emission Factors					
Source	**Number of Barges**	**Number of Engines per Barge**	**HP per engine**	**Carbon Dioxide (tonnes/1E9 BTU)[1]**	**Methane (tonnes/1E9 BTU)[1]**
Survey Boat	1	1	2,000	78.8	0.018
Pipe-Lay Barge	1	1	4,000	78.8	0.018
Anchor Handling Support Vessel	2	2	7,500	78.8	0.018
Burial Barge Anchor Tug	2	2	7,500	78.8	0.018
Burial/Backfill Barge	1	1	4,000	78.8	0.018
Diving Barge	4	1	3,000	78.8	0.018
Jack-up Barge	2	1	2,000	78.8	0.018
Dragline	1	1	1,500	78.8	0.018
Pipeline Pull Barge	1	1	1,000	78.8	0.018
Note: DOE Tables 1.C.6 and 1.C.11 factors are used.					

Pipeline construction emissions were estimated for normal operation, downtime operation, and direct drill operation modes. Greenhouse gas emissions for each of operation modes are detailed in Tables 4 – 6.

Table 4 Offshore Pipeline Construction Normal Operation – Greenhouse Gas (GHG) Emissions				
Source	**Op. Hours hr/yr**	**Engine Load %**	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**
Survey Boat	1,440	50	764.9	0.17
Pipe-Lay Barge	2,520	75	3,330.3	0.76
Anchor Handling Support Vessel	2,520	75	24,977.3	5.71
Burial Barge Anchor Tug	1,584	75	15,700	3.59
Burial/Backfill Barge	1,584	75	2,093.3	0.48
Diving Barge	3,960	75	15,700	3.59
Jack-up Barge	600	50	637.5	0.15
Dragline	1,800	50	717.1	0.16
Pipeline Pull Barge	336	75	133.9	0.031
Notes: Since engines are not fully loaded, a correction factor of 1.1 is applied to DOE factors. Fuel type is Bunker C. Fuel consumption is 205 g/kW-h (for engine rates less than 2,000 HP and 170 g/kW-h for engine rates higher than 2,000 HP and less than 8,000 HP. Fuel heating value is 1E9 Btu/tonne[1].				

Sample calculation for the survey boat:

$$CO_2\,(\text{lb/hr}) = 205\,\frac{\text{g}}{\text{kW}-\text{hr}} \times 0.75\,\frac{\text{kW}}{\text{HP}} \times 2{,}000\ \text{HP} \times 1\ \text{barge} \times 1\,\frac{\text{engine}}{\text{barge}} \times 1\text{E9}\,\frac{\text{Btu}}{\text{tonne}} \times 78.8\,\frac{\text{tonnes}}{1\text{E9 Btu}}$$

$$\times \frac{1}{453.59}\,\frac{\text{lb}}{\text{g}} \times 50\%\ \text{engine load} \times 1.1\ (\text{safety factor}) = 1{,}170\ (\text{lb/hr}).$$

$$CO_2\ (\text{tonnes/yr}) = CO_2\,(\text{lb/hr}) \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6}\,\frac{\text{tonne}}{\text{lb}} = 764.9\ (\text{tonnes/yr}).$$

Table 5
Offshore Pipeline Construction Downtime Operation – Greenhouse Gas(GHG) Emissions

Source	Op. Hours hr/yr	Engine Load %	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)
Survey Boat	0	0	0	0
Pipe-Lay Barge	360	25	191.2	0.044
Anchor Handling Support Vessel	360	15	860.6	0.20
Burial Barge Anchor Tug	360	15	860.6	0.20
Burial/Backfill Barge	360	20	153.0	0.035
Diving Barge	360	15	344.2	0.079
Jack-up Barge	0	0	0	
Dragline	360	25	71.7	0.016
Pipeline Pull Barge	0	0	0	0

Notes:
Since engines are not fully loaded, a correction factor of 1.1 is applied to DOE factors.
Fuel type is Bunker C.
Fuel consumption assumed to be 205 g/kW-h (for engine rates less than 2,000 HP and 170 g/kW-h for engine rates higher than 2,000 HP and less than 8,000 HP.
Fuel heating value is 10E9 Btu/tonne[1].

Table 6 Offshore Pipeline Construction Direct Drilling Operation – Greenhouse Gas (GHG) Emissions					
Source	**HP per engine**	**Carbon Dioxide (tonnes/1E9 BTU)[1]**	**Methane (tonnes/1E9 BTU)[1]**	**Carbon Dioxide (tonnes/yr)**	**CH_4 (tonnes/yr)**
Construction Barge	8,000	78.8	0.018	3,229	0.74
Attending Boat	671	78.8	0.018	271	0.062
Diving Barge	2,000	78.8	0.018	807	0.18
Tug	800	78.8	0.018	323	0.074
Drilling Engine	2,600	78.8	0.018	1,050	0.24
Notes: Engine loading for drilling operations is 100%. Annual operation is 1,008 hours per year. Fuel heating value is 10E9 Btu/tonne[1].					

Sample calculation for the construction barge:

$$CO_2\,(\text{lb/hr}) = 170\ \frac{\text{g}}{\text{kW}-\text{hr}} \times 0.75\ \frac{\text{kW}}{\text{HP}} \times 8{,}000\ \text{HP} \times 1\text{E}9\,\frac{\text{Btu}}{\text{tonne}} \times 78.8\,\frac{\text{tonnes}}{1\text{E}9\ \text{Btu}} \times \frac{1}{453.59}\ \frac{\text{lb}}{\text{g}} \times$$

$$100\%\ \text{engine load} \times 1.1\ (\text{safety factor}) = 7{,}057\ (\text{lb/hr}).$$

$$CO_2\ (\text{tonnes/yr}) = CO_2\,(\text{lb/hr}) \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6}\ \frac{\text{tonne}}{\text{lb}} = 3{,}229\ (\text{tonnes/yr}).$$

Table 7 presents the total greenhouse gas emissions from the pipeline construction activities. Since different greenhouse gases have varying global warming impacts, global warming potential factors are used to standardize greenhouse gas emissions into “Carbon Dioxide Equivalents”. Carbon Dioxide is assigned a global warming potential factor of one (1) and Methane is estimated to have a global warming potential factor of 23[1]. Therefore, the total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the pipeline construction are estimated at 72,595 tonnes per year.

Table 7 Summary of Pipeline Construction – Greenhouse Gas Emissions				
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**	**Carbon Dioxide Equivalent (tones/yr)**	**Total Greenhouse Gases Emission Rate (tones/yr)**
Pipeline Construction Preferred Route	72,215	16.5	379.4	72,595

Deep Water Port (DWP) STL Buoy Construction

During the construction phase of DWP, anchor handling support vessels, supply boat, crew boat and tug will be used. The table below summarizes the activities during DWP construction, as well as Carbon Dioxide and Methane emission factors used for emission calculations.

Table 8 DWP STL Buoy Construction – Engine Characteristics and Emission Factors					
Source	**Number of Barges**	**Number of Engines per Barge**	**HP per engine**	**Carbon Dioxide (tonnes/1E9 BTU)[1]**	**Methane (tonnes/1E9 BTU)[1]**
Anchor Handling Support Vessel	2	1	3,750	78.8	0.018
Supply Boat	1	1	671	78.8	0.018
Crew Transfer Boat	1	1	671	78.8	0.018
Tug	1	1	800	78.8	0.018
Note: DOE Tables 1.C.6 and 1.C.11 factors are used.					

GHG emissions for the DWP construction are summarized in the table below.

Table 9 DWP STL Buoy Construction – Greenhouse Gas Emissions				
Source	**Op. Hours hr/yr**	**Engine Load %**	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**
Anchor Handling Support Vessel	2,520	100	7,569	1.73
Supply Boat	672	100	218	0.05
Crew Transfer Boat	420	100	136	0.03
Tug	420	100	162	0.04
Notes: Fuel type is Bunker C. Fuel consumption is 205 g/kW-h (for engine rates less than 2,000 HP and 170 g/kW-h for engine rates higher than 2,000 HP and less than 8,000 HP. Fuel heating value is 1E9 Btu/tonne[1].				

Sample calculation for the Anchor Handling and Support Vessel:

$$CO_2\ (\text{lb/hr}) = 78.8\frac{\text{tonnes}}{\text{1E9 Btu}} \times \frac{3{,}750\ \text{HP}}{\text{engine}} \times \frac{1\ \text{engine}}{\text{barge}} \times 2\ (\text{number of barges}) \times$$

$$100\ \text{load\%} \times 0.75\frac{\text{kW}}{\text{HP}} \times 1\text{E}9\frac{\text{Btu}}{\text{tonne}} \times 170\frac{\text{g}}{\text{kW - hr}} \times \frac{1}{453.59\ \text{g/lb}} = 6{,}616\ (\text{lb/hr}).$$

$$CO_2\ (\text{tonnes/yr}) = CO_2\,(\text{lb/hr}) \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6}\ \frac{\text{tonne}}{\text{lb}} = 7{,}569\ (\text{tonnes/yr}).$$

Table 10 presents the total greenhouse gas emissions from the DWP construction activities. As explained earlier, global warming potential factors are used to standardize greenhouse gas emissions into "Carbon Dioxide Equivalent". The total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the DWP construction are estimated at 8,127 tonnes per year.

Table 10 DWP Construction – Greenhouse Gas Emissions				
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**	**Carbon Dioxide Equivalent (tones/yr)**	**Total Greenhouse Gases Emission Rate (tones/yr)**
DWP Construction	8,085	1.8	42.5	8,127

<u>Onshore Construction</u>

During the onshore facility construction, a heavy lift crane, pipe bending machine, welding generator, and air compressor will be used. Table 11 below summarizes the activities during onshore facility construction, as well as Carbon Dioxide and Methane emission factors used for emission calculations.

Table 11 Onshore Construction – Engine Characteristics and Emission Factors					
Source	**Fuel**	**Operating Hours per Year**	**HP per engine**	**Carbon Dioxide (kg/MMBtu)[1]**	**Methane (kg/MMBtu)[1]**
Heavy Lift Crane	Diesel	480	500	72.32	0.018
Pipe Bending Machine	Diesel	180	100	72.32	0.018
Welding Generator	Gasoline	720	50	72.32	0.018
Air Compressor	Gasoline	720	50	72.32	0.018
Note: DOE Tables 1.C.6 and 1.C.11 factors are used.					

Table 11 and 12 do not include GHG emissions from mobile construction vehicle sources since these emissions are minimal in comparison to the project overall and occur during a short period of several months only.

GHG emissions for the onshore construction activities are summarized in the table below:

Table 12 Onshore Construction – Greenhouse Gas Emissions		
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**
Heavy Lift Crane	115.7	63.4
Pipe Bending Machine	8.7	4.8
Welding Generator	16.8	9.2
Air Compressor	16.8	9.2
Notes: Fuel consumption is 205 g/kW-h (for engine rates less than 2,000 HP and 170 g/kW-h for engine rates higher than 2,000 HP and less than 8,000 HP. Diesel heating value is 0.043 MBtu/kg (DOE Table 1.C.6). Gasoline heating value is 0.04 MBtu/kg (NIST Chemistry WebBook).		

Sample calculation for the heavy lift crane:

$$CO_2\,(\text{lb/hr}) = 72.32\,\frac{\text{kg}}{\text{MMBtu}} \times 500\ \text{HP} \times 0.75\,\frac{\text{kW}}{\text{HP}} \times 0.043338\,\frac{\text{MMBtu}}{\text{kg}} \times 205\,\frac{\text{g}}{\text{kW - hr}} \times \frac{1\ \text{lb}}{0.453\ \text{kg}} = 531\,(\text{lb/hr}).$$

$$CO_2\,(\text{tonnes/yr}) = CO_2\,(\text{lb/hr}) \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6}\,\frac{\text{tonne}}{\text{lb}} = 115.7\,(\text{tonnes/yr}).$$

Table 13 presents the total GHG emissions from the onshore construction activities. The total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the onshore construction are estimated at 2,150.1 tonnes per year.

Table 13 Onshore Construction – Greenhouse Gas Emissions				
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**	**Carbon Dioxide Equivalent (tones/yr)**	**Total Greenhouse Gases Emission Rate (tones/yr)**
Onshore Construction	158	86.6	1992.1	2,150.1

In summary, during the construction phase, *Port Dolphin* stationary sources, Project vessels, and onshore equipment would generate annual Carbon Dioxide and Methane emissions of 80,458 and 105 tonnes per year, respectively. Total annual greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the *Port Dolphin* Project construction phase are estimated at 82,872.4 tonnes per year, as summarized in the table below.

Table 14 Construction Activities – Greenhouse Gas Emissions			
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**	**Total Greenhouse Gases Emission Rate (tones/yr)**
Construction Activities Preferred Route	80,458	105	82,872.4

2.2 Yearly Operational Emissions

The *Port Dolphin* DWP will consist of one unloading system (located within an safety zone) comprised of two unloading buoys; each buoy capable of mooring one (1) Shuttle and Regasification Vessel (SRV) with an Liquefied Natural Gas (LNG) storage capacity close to 217,000 m^3. All SRV emission sources have been sized to accommodate the maximum capacity of the buoy unloading system; and all emission sources located on each SRV calling at the port will be equipped with emission controls specified in the air quality permit; and will operate at or below proposed permit limits.

<u>DWP Operational Activities</u>
Routine operation for the *Port Dolphin* DWP includes two (2) SRVs at two (2) buoys for LNG unloading, crew boat, and supply boat. Each vessel contains several engines and boilers. To be conservative, a 10% safety factor is applied to all emission units.

The table below summarizes the emission rates during DWP routine operation, as well as Carbon Dioxide and Methane emission factors used for emission calculations.

Table 15
DWP Operation – Engine Characteristics and Emission Factors

Source	Carbon Dioxide (kg/1E6 Btu)	Methane (kg/1E6 Btu	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr
Boilers	52.65	0.043	564,157	460.8
Engines (Natural Gas)	52.65	0.043	152,400	124.5
Engines (Diesel)	72.32	0.018	2,085	0.52

Notes:
Annual operation is 8,760 hours per year.
Heat input per boiler is 278 MMBtu/hr.
Since engines are not fully loaded, a correction factor of 1.1 is applied to DOE factors.
Heating value of natural gas is 1,025 Btu/scf.
Total engine rate is 45,600 kW.
Distillate fuel oil consumption is 170 g/kW-hr.
Distillate fuel oil in operation is 87.6 hours/yr.
Natural gas in operation is 8,672.4 hours/yr.
Natural gas energy input is 5,510 Btu/hp-hr.
Diesel heating value is 19,300 Btu/lb.

Sample calculation for boiler:

$$CO_2\ (\text{lb/hr}) = 52.65 \frac{\text{kg}}{\text{1E6 Btu}} \times 4\ (\text{number of boilers}) \times 278 \frac{\text{MMBtu}}{\text{hr}} \times 2.2 \frac{\text{lb}}{\text{kg}} \times \text{safety factor}$$

$$= 141{,}853\ (\text{lb/hr}).$$

$$CO_2\ (\text{tonnes/yr}) = CO_2\,(\text{lb/hr}) \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6}\ \frac{\text{tonne}}{\text{lb}} = 564{,}157\ (\text{tonnes/yr}).$$

Table 16 presents the total greenhouse gas emissions from the DWP operation activities. The total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the DWP operation activities are estimated at 732,114 tonnes per year. Detailed calculations are presented in Appendix A.

Table 16
DWP Operation – Greenhouse Gas Emissions

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Carbon Dioxide Equivalent (tones/yr)	Total Greenhouse Gases Emission Rate (tones/yr)
DWP Operation	718,642	586	13,472	732,114

Onshore Operational Activities

The *Port Dolphin* DWP pipeline will extend 44.12 miles from the DWP, traversing federal and state waters, through Passage Key Inlet into Tampa Bay; and, landing near Port Manatee, Florida at a proposed onshore valve station (the Port Manatee valve station). Additional onshore pipeline facilities include the Gulfstream and TECO interconnections station at O'Neil Road. The interconnection stations are located approximately 3.8 miles from the landing point.

The onshore operational emissions will include fugitive emissions, tank emissions, and engine emissions.

Table 17 presents the total greenhouse gas emissions from the onshore operation activities. The total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the onshore operation activities are estimated at 24.8 tonnes per year. Detailed calculations are presented in Appendix A.

Table 17
Onshore Operation – Greenhouse Gas Emissions

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Carbon Dioxide Equivalent (tonnes/yr)	Total Greenhouse Gases Emission Rate (tonnes/yr)
Onshore Operation	25	0.0061	0.14	24.8

Arrival Operational Activities

The Applicant anticipates that one (1) fully loaded SRV may be waiting (hoteling) outside the safety zone (in the arrival zone); or, may be transiting the arrival zone in route to the safety zone; while up to two (2) SRV are in operation at each buoy within the safety zone.

Table 18 below summarizes the emission rates during the arrival phase, as well as Carbon Dioxide and Methane emission factors used for emission calculations.

Table 18 Arrival Operation – Engine Characteristics and Emission Factors				
Source	**Carbon Dioxide (kg/MMBtu)**	**Methane (kg/MMBtu**	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**
Boilers	52.65	0.043	4,947	4.0
Engines (Natural Gas)	52.65	0.043	11,037	9.01
Engines (Diesel)	72.32	0.018	151	0.038
Notes: Economic zone is 200 miles. DWP is 28 miles. SRV travel distance is 172 miles. Number of annual trips is 47. Round trip time is 12 hours/trip. Power output from engines is 51,295 kW. Distillate fuel oil consumption is 170 g/kW-hr. Diesel heating value is 19,300 Btu/lb. Natural gas in operation is 11.88 hours/trip. Natural gas energy input is 5,510 Btu/hp-hr. For Boilers warm up: Total Boiler heat input is 166.8 MBtu/hr. Heating value of natural gas is 1,025 Btu/scf. NG usage from all boilers is 162,732 scf/hr.				

Sample calculation for boiler:

$$CO_2 \text{ (lb/hr)} = 52.65 \frac{\text{kg}}{\text{1E6 Btu}} \times 166.8 \frac{\text{MMBtu}}{\text{hr}} \times 2.2 \frac{\text{lb}}{\text{kg}} = 19{,}320 \text{ (lb/hr)}.$$

$$CO_2 \left(\text{tonnes/yr}\right) = CO_2 \text{(lb/hr)} \times \frac{\text{Operating hours}}{\text{year}} \times \frac{1}{2{,}204.6} \frac{\text{tonne}}{\text{lb}} = 4{,}947 \text{ (tonnes/yr)}.$$

In summary, during normal operations, *Port Dolphin* stationary sources, Project vessels, and onshore equipment would generate annual Carbon Dioxide and Methane emissions of 734,802 and 599 tonnes per year, respectively. The annual greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the *Port Dolphin* operation sources are 748,576 tonnes per year. Detailed calculations are presented in Appendix A.

Table 19 Operational Activities – Greenhouse Gas Emissions			
Source	**Carbon Dioxide (tonnes/yr)**	**Methane (tonnes/yr)**	**Total Greenhouse Gases Emission Rate (tones/yr)**
Operational Activities	734,802	599	748,576

2.3 Decommissioning Emissions

DWP Decommissioning

Decommissioning of the DWP will create two (2) types of emission sources. One is the LNG blow down from the pipeline; the other is the vessels associated with this event.

The table below summarizes the activities during DWP decommissioning, as well as Carbon Dioxide and Methane emission factors used for emission calculations.

Table 20
DWP Decommissioning – Engine Characteristics and Emission Factors

Source	Number of Barges	Number of Engines per Barge	HP per engine	Carbon Dioxide (tonnes/1E9 BTU)	Methane (tonnes/1E9 BTU)
Anchor Handling Support Vessels	2	1	3750	78.8	0.018
Supply Boat	1	1	671	78.8	0.018
Tug	1	1	800	78.8	0.018

Table 21 presents the total greenhouse gas emissions from the DWP decommissioning activities. The total greenhouse gas emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the decommissioning activities are estimated at 2,551 tonnes per year. Detailed calculations are presented in Appendix A.

Table 21
DWP Decommissioning – Greenhouse Gas Emissions

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Carbon Dioxide Equivalent (tones/yr)	Total Greenhouse Gases Emission Rate (tones/yr)
DWP Decommissioning	2,538	0.6	13.3	2,551

Onshore Decommissioning

During the onshore decommissioning activities, all pipeline pressure will be reduced from 1200 psi to 600 psi.

The parameters associated with the pipeline are:

CH_4 weight fraction is 0.7068.
CO_2 weight fraction is 0.0114.
LNG density at 600 psi, 68 F is 2.34 lb/ft^3.
Operation hours are 480 hours/yr.
Pipe diameter is 3 ft.
Onshore pipe length is 27,456 ft.

Table 22 presents the total GHG emissions from the onshore decommissioning activities. The total GHG emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the decommissioning activities are estimated at 29,913 tonnes per year. Detailed calculations are presented in Appendix A.

Table 22
Onshore Decommissioning – Greenhouse Gas Emissions

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Carbon Dioxide Equivalent (tones/yr)	Total Greenhouse Gases Emission Rate (tones/yr)
Onshore Decommissioning Preferred Route	21	1,299.7	29,892.4	29,913.3

In summary, during the decommissioning activities, *Port Dolphin* stationary sources, Project vessels, and onshore equipment would generate annual Carbon Dioxide and Methane emissions of 2,559 and 1,300 tonnes per year, respectively. The annual GHG emissions (Carbon Dioxide and Carbon Dioxide Equivalent) for the *Port Dolphin* decommissioning sources are 32,465 tonnes per year. Detailed calculations are presented in Appendix A.

Table 23
Decommissioning Activities – Greenhouse Gas Emissions

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Total Greenhouse Gases Emission Rate (tones/yr)
Decommissioning Activities	2,559	1,300	32,465

2.4 Summary of GHG Emissions

The table below presents the total GHG emissions (Carbon Dioxide and Carbon Dioxide Equivalent) associated with *Port Dolphin* construction (preferred route), operation, and decommissioning (preferred route) activities. Detailed calculations are presented in Appendix A.

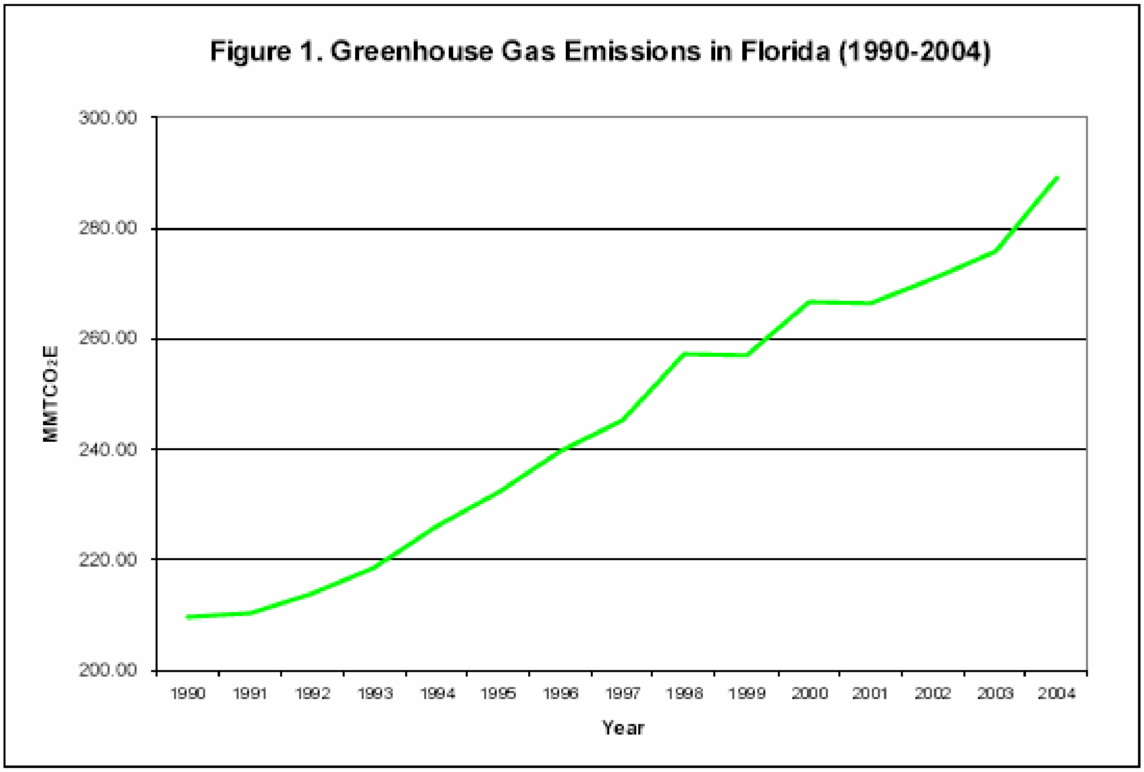
Table 24
***Port Dolphin* Activities – Greenhouse Gas Emissions**

Source	Carbon Dioxide (tonnes/yr)	Methane (tonnes/yr)	Total Greenhouse Gases Emission Rate (tones/yr)
Construction, preferred	80,458	105	82,872.4
Operation	734,802	599	748,575.6
Decommissioning, Preferred	2,559	1,300	32,464.6

2.5 Comparison to Florida GHG Emissions

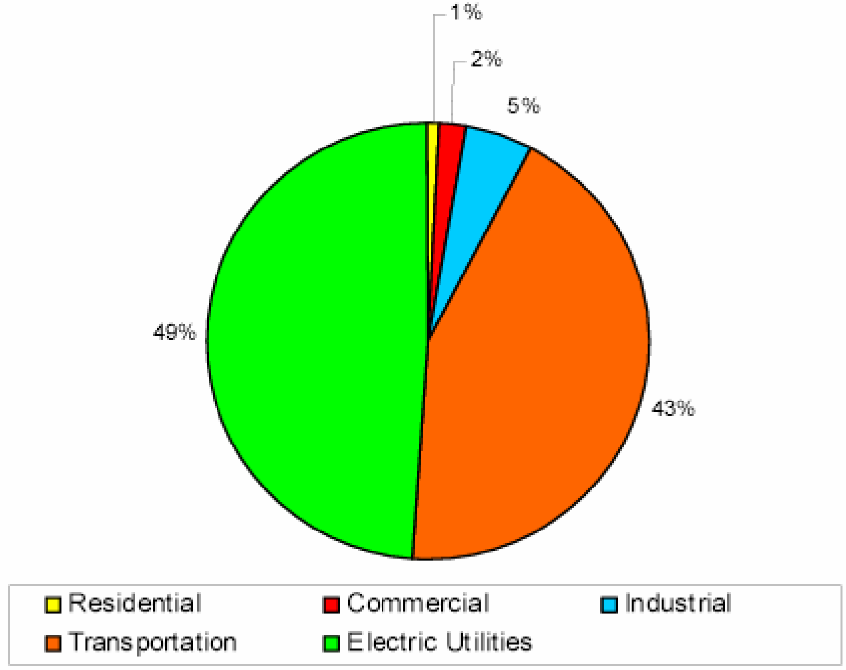
The Florida Department of Environmental Protection (FDEP) has estimated the state's greenhouse gas emissions in a September 2007 report entitled "Preliminary Inventory of Florida Greenhouse Gas Emissions: 1990-2004". The results of the inventory are expressed in million metric tones of CO_2 equivalent ($MMTCO_2E$) for a number of economic sectors including the Energy sector. Total Florida GHG emissions in 2004 were 289 $MMTCO_2E$. The project in comparison will have the benefit when fully operational of a net reduction of 10.07 $MMTCO_2E$ per year.

Florida GHG emissions are increasing at a rate of 2.5% or approximately 7.2 $MMTCO_2E$ per year. The project will have the significant impact of offsetting the increase in GHG emissions increases for at least 1 year for the entire state of Florida. Figure 1 indicates the general trend of Florida's overall GHG emissions from 1990 – 2004.



Energy sector emissions from fossil fuel combustion are responsible for the majority of GHG emissions in Florida. Energy sector emissions were 256 $MMTCO_2E$ in 2004 which is approximately 89% of total state emissions. Electric utilities and transportation are where the majority of fossil fuel combustion occurs as indicated in Figure 2.

Figure 2. CO_2 Emissions by Energy Sub-sector in Florida-2004



2.6 Comparison of Alternatives – GHG Emissions

2.6.1 Preferred Location and Route

The unloading portion of the deepwater port would be located in federal waters approximately 28 miles (45-kilometers) offshore of the Tampa Bay area of Florida in approximately 100-feet (30-meters) of water. This area lies within the St. Petersburg block of the Outer Continental Shelf. Please refer to Figure 9-1, General Site Location, and Figure 9-2, Preferred and Alternative Pipeline Routes, located in Volume II, Section 9.

The total Carbon Dioxide and Methane emissions for the construction, operation, and decommissioning activities for the preferred route are 817,820 and 2,004 tonnes per year, respectively. Therefore, the annual greenhouse gas emissions are 863,913 tonnes (0.864 $MMTCO_2E$) per year of Carbon Dioxide equivalents.

2.6.2 Southern Location and Route

The Southern Route would be approximately five (5) miles longer than the Preferred Route. Certain emissions associated with the pipeline installation are typically dependent on the length of the pipeline. These include emissions from vessels associated with trenching, installing the pipeline, backfilling, and installing mats. Please refer to Figure 9-2, Preferred and Alternative Pipeline Routes, located in Volume II, Section 9.

The total Carbon Dioxide and Methane emissions for the construction, operation, and decommissioning activities for the Southern Route are 826,526 and 2,136 tonnes per year, respectively. Therefore, the annual greenhouse gas emissions are 875,644 tonnes (0.876 $MMTCO_2E$) per year of Carbon Dioxide equivalents.

2.6.3 Northern Location and Route

The Northern Route would be 18 miles longer than the Preferred Route. Certain emissions associated with the pipeline installation are typically dependent on the length of the pipeline. These include emissions from vessels associated with trenching, installing the pipeline, backfilling, and installing mats. Please refer to Figure 9-2, Preferred and Alternative Pipeline Routes, located in Volume II, Section 9.

The total Carbon Dioxide and Methane emissions for the construction, operation, and decommissioning activities for the Northern Route are 836,445 and 2,519 tonnes per year, respectively. Therefore, the annual greenhouse gas emissions are 894,372 tonnes (0.894 $MMTCO_2E$) per year of Carbon Dioxide equivalents.

Appendix A

Port Dolphin Project
Greenhouse Gas Emissions
Calculation Spreadsheets

CSA
Port Dolphin Project
Greenhouse Gas Emissions

Pipeline Construction

	Based on EPA Factor				Based on DOE Factor			
Route	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. Tonnes/yr	Total as CO2 equi. tonnes/yr	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. tonnes/yr	Total as CO2 equi. tonnes/yr
Preferred	93904	57.1	1312.6	95217.1	72215	16.5	379.4	72594.9
North	118117	71.8	1651.1	119768.1	90833	20.7	477.2	91310.2
South	105170	63.9	1470.1	106639.7	80919	18.5	425.1	81344.5

DWP

	Based on EPA Factor				Based on DOE Factor			
	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. Tonnes/yr	Total as CO2 equi. tonnes/yr	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. tonnes/yr	Total as CO2 equi. tonnes/yr
Construction	10516	6.4	147.0	10663.3	8085	1.8	42.5	8127.5
Operation	714257	800.3	18408.0	732664.8	718642	585.7	13472.0	732114.0
Decommissioning	3253	2.0	45.5	3298.7	2538	0.6	13.3	2551.2

Onshore

	Based on EPA Factor				Based on DOE Factor			
	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. Tonnes/yr	Total as CO2 equi. tonnes/yr	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. tonnes/yr	Total as CO2 equi. tonnes/yr
Construction	170	0.0	0.0	170.0	158	86.6	1992.1	2150.1
Operation	27	0.0	0.0	26.8	25	0.0061	0.14	24.8
Decommission, preferred	21	1299.7	29892.4	29913.3	21	1299.7	29892.4	29913.3
Decommission, North	29	1809.9	41628.6	41657.8	29	1809.9	41628.6	41657.8
Decommission, South	23	1429.2	32872.1	32895.1	23	1429.2	32872.1	32895.1

Arrival

	Based on EPA Factor				Based on DOE Factor			
	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. Tonnes/yr	Total as CO2 equi. tonnes/yr	CO2 tonnes/yr	CH4 tonnes/yr	CO2 equi. tonnes/yr	Total as CO2 equi. tonnes/yr
SRV	15588	57.8	1330.5	16918.5	16136	13.1	301.1	16436.7

Total CO2 from all sources
construction = all construction activities
operation = DWP operation + onshore operation + arrival
decommissioning = all decommissioning

Total as CO2 Equiv. tonnes/yr

Activity	Based on EPA	Based on DOE
Construction, preferred	106050.4	82872.4
Construction, North	130601.5	101587.8
Construction, South	117473.0	91622.1
Operation	749610.0	748575.6
Decommissioning. Preferred	33212.0	32464.6
Decommissioning. North	44956.5	44209.0
Decommissioning. South	36193.8	35446.3

Basic Information

Safety Factor	1.1
Fuel Type	Bunker C
Fuel heating value, 1E9 btu/tonne*	0.03986
lb to tonnes	0.000454
CH4 to CO2 equivalent potential*	23

Fuel Consumption

HP	Avg. g/kW-h
< 2000	205
2000 to 8000	170

*Based on DOE "TECHNICAL GUIDELINES VOLUNTARY REPORTING OF GREENHOUSE GASES (1605(b)) PROGRAM", January 2007

Source	Num. of Barges	Num. of Eng per barge	HP per engine	CO_2 lb/hp-hr[1]	CH_4 lb/hp-hr[1]	CO_2 tonnes/10e9 BTU[2]	CH_4 tonnes/10e9 BTU[2]
Survey Boat	1	1	2000	1.16	7.05E-04	78.8	0.018
Pipe-Lay Barge	1	1	4000	1.16	7.05E-04	78.8	0.018
Anchor Handling Support Vessel	2	2	7500	1.16	7.05E-04	78.8	0.018
Burial Barge Anchor Tug	2	2	7500	1.16	7.05E-04	78.8	0.018
Burial/Backfill Barge	1	1	4000	1.16	7.05E-04	78.8	0.018
Diving Barge	4	1	3000	1.16	7.05E-04	78.8	0.018
Jack-up Barge	2	1	2000	1.16	7.05E-04	78.8	0.018
Dragline	1	1	1500	1.16	7.05E-04	78.8	0.018
Pipeline Pull Barge	1	1	1000	1.16	7.05E-04	78.8	0.018

1. AP-42 Table 3.4-1
2 DOE Technical Guidelines Table 1.C.6 and 1.C.11.

lb/hr =AP42 Factor lb/hp-hr x Safety factor x Load% x HP/engine x Num. of Engines x Num of Barges
tonnes/yr = lb/hr x Op. hours/year x 0.000454 tonnes/lb
lb/hr =g/KWh x 0.75 KW/HP x HP/engine x load% x num of engine x num of barges x tonnes/1e6 g x heating value 1e9 BTU/tonne
x DOE factor tonne/1e9 BTU x 1 lb/0.000454 tonne x safety factor

Option **Preferred Route**

Normal Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	1440	50	1276	834.2	0.78	0.51	1170	764.9	0.27	0.17
Pipe-Lay Barge	2520	75	3828	4379.5	2.33	2.66	2911	3330.3	0.66	0.76
Anchor Handling Support Vessel	2520	75	28710	32846.5	17.45	19.96	21832	24977.3	4.99	5.71
Burial Barge Anchor Tug	1584	75	28710	20646.39	17.45	12.55	21832	15700.0	4.99	3.59
Burial/Backfill Barge	1584	75	3828	2752.9	2.33	1.67	2911	2093.3	0.66	0.48
Diving Barge	3960	75	11484	20646.4	6.98	12.55	8733	15700.0	1.99	3.59
Jack-up Barge	600	50	2552	695.2	1.55	0.42	2340	637.5	0.53	0.15
Dragline	1800	50	957	782.1	0.58	0.48	878	717.1	0.20	0.16
Pipeline Pull Barge	336	75	957	146.0	0.58	0.089	878	133.9	0.20	0.031

Downtime Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	0	0								
Pipe-Lay Barge	360	25	1276	208.5	0.78	0.13	1170	191.2	0.27	0.044
Anchor Handling Support Vessel	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.20
Burial Barge Anchor Tug	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.20
Burial/Backfill Barge	360	20	1021	166.8	0.62	0.10	936	153.0	0.21	0.035
Diving Barge	360	15	2297	375.4	1.40	0.23	2106	344.2	0.48	0.079
Jack-up Barge	0	0								
Dragline	360	25	479	78.2	0.29	0.048	439	71.7	0.10	0.016
Pipeline Pull Barge	0	0								

Option **North Route**

Normal Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	1800	50	1276	1042.7	0.78	0.63	1170	956.2	0.27	0.22
Pipe-Lay Barge	3240	75	3828	5630.8	2.33	3.42	2911	4281.8	0.66	0.98
Anchor Handling Support Vessel	3240	75	28710	42231.3	17.45	25.67	21832	32113.6	4.99	7.34
Burial Barge Anchor Tug	2160	75	28710	28154.2	17.45	17.11	21832	21409.1	4.99	4.89
Burial/Backfill Barge	2160	75	3828	3753.9	2.33	2.28	2911	2854.5	0.66	0.65
Diving Barge	4680	75	11484	24400.3	6.98	14.83	8733	18554.5	1.99	4.24
Jack-up Barge	960	50	2552	1112.3	1.55	0.68	2340	1019.9	0.53	0.23
Dragline	2520	50	957	1094.9	0.58	0.67	878	1004.0	0.20	0.23
Pipeline Pull Barge	336	75	957	146.0	0.58	0.089	878	133.9	0.20	0.031

Downtime Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	0	0								
Pipe-Lay Barge	360	25	1276	208.5	0.78	0.13	1170	191.2	0.27	0.044
Anchor Handling Support Vessel	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.20
Burial Barge Anchor Tug	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.20
Burial/Backfill Barge	360	20	1021	166.8	0.62	0.10	936	153.0	0.21	0.035
Diving Barge	720	15	2297	750.8	1.40	0.46	2106	688.4	0.48	0.16
Jack-up Barge	0	0								
Dragline	360	25	479	78.2	0.29	0.048	439	71.7	0.10	0.016
Pipeline Pull Barge	0	0								

Option **South Route**

Normal Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	1800	50	1276	1042.7	0.78	0.63	1170	956.2	0.27	0.22
Pipe-Lay Barge	2880	75	3828	5005.2	2.33	3.04	2911	3806.1	0.66	0.87
Anchor Handling Support Vessel	2880	75	28710	37538.9	17.45	22.81	21832	28545.4	4.99	6.52
Burial Barge Anchor Tug	1800	75	28710	23461.8	17.45	14.26	21832	17840.9	4.99	4.08
Burial/Backfill Barge	1800	75	3828	3128.2	2.33	1.90	2911	2378.8	0.66	0.54
Diving Barge	4320	75	11484	22523.3	6.98	13.69	8733	17127.3	1.99	3.91
Jack-up Barge	720	50	2552	834.2	1.55	0.51	2340	764.9	0.53	0.17
Dragline	2160	50	957	938.5	0.58	0.57	878	860.6	0.20	0.20
Pipeline Pull Barge	336	75	957	146.0	0.58	0.089	878	133.9	0.20	0.031

Downtime Operation

			AP-42 Factor				DOE Factor			
Source	**Op. Hours hr/yr**	**Engine Load %**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Survey Boat	0	0								
Pipe-Lay Barge	360	25	1276	208.5	0.78	0.13	1170	191.2	0.27	0.044
Anchor Handling Support Vessel	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.197
Burial Barge Anchor Tug	360	15	5742	938.5	3.49	0.57	5265	860.6	1.20	0.197
Burial/Backfill Barge	360	20	1021	166.8	0.62	0.10	936	153.0	0.21	0.035
Diving Barge	720	15	2297	750.8	1.40	0.46	2106	688.4	0.48	0.157
Jack-up Barge	0	0								
Dragline	360	25	479	78.2	0.29	0.048	439	71.7	0.10	0.016
Pipeline Pull Barge	0	0								

Activity **Direct Drilling**
The emission is the same regardless of route selection.
Operation hours 1008 hours/year
Engine Load 100 %

		EPA Factor		DOE Factor	
Source	**HP**	**CO2 lb/hp-hr**	**CH4 lb/hp-hr**	**CO2 tonnes/1e 9 Btu**	**CH4 tonnes/1e 9 Btu**
Construction Barge	8000	1.16	7.05E-04	78.8	0.018
Attending Boat	671	1.16	7.05E-04	78.8	0.018
Diving Barge	2000	1.16	7.05E-04	78.8	0.018
Tug	800	1.16	7.05E-04	78.8	0.018
Drilling Engine	2600	1.16	7.05E-04	78.8	0.018

lb/hr = AP42 factor lb/hp-hr x HP x load%
lb/hr = DOE factor tonnes/1e9 Btu x HP x load% x 0.75 KW/hp x heating value 1e9 Btu/tonnes x g/KWh x lb/454g

	EPA Factor				DOE Factor			
Source	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Construction Barge	9280	4247	5.64	2.58	7057	3229	1.61	0.74
Attending Boat	778	356	0.47	0.22	591	271	0.14	0.062
Diving Barge	2320	1062	1.41	0.65	1764	807	0.40	0.18
Tug	928	425	0.56	0.26	706	323	0.16	0.074
Drilling Engine	3016	1380	1.83	0.84	2293	1050	0.52	0.24

Activity **DWP Construction**

Engine Load 100 %

					EPA Factor		DOE Factor	
Source	**hours/yr**	**Num. of Barges**	**Num. of Eng per barge**	**HP per engine**	**CO2 lb/hp-hr**	**CH4 lb/hp-hr**	**CO2 tonnes/1e9 Btu**	**CH4 tonnes/1e9 Btu**
Anchor Handling Support Vessels	2520	2	1	3750	1.16	0.000705	78.8	0.018
Supply Boat	672	1	1	671	1.16	0.000705	78.8	0.018
Crew Transfer Boat	420	1	1	671	1.16	0.000705	78.8	0.018
Tug	420	1	1	800	1.16	0.000705	78.8	0.018

lb/hr = AP42 factor lb/hp-hr x HP/engine x num engine/boat x num. of boat x load%
lb/hr = DOE factor tonnes/1e9 Btu x HP/eng x num of eng/boat x num of boat x load% x 0.75 KW/hp
x heating value 1e9 BTU/tonnes x g/KWh x lb/454g

	EPA Factor				DOE Factor			
Source	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Anchor Handling Support Vessels	8700	9953	5.29	6.05	6616	7569	1.51	1.73
Supply Boat	778.36	237	0.47	0.14	714	218	0.16	0.05
Crew Transfer Boat	778.36	148	0.47	0.09	714	136	0.16	0.03
Tug	928	177	0.56	0.11	851	162	0.19	0.04

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Port Dolphin Project
Greenhouse Gas Emissions

Activity **DWP Operation**

Number of SRV	2	
Operation hours	8760	hours/yr
heat input per boiler	278	MMBTU/hr
Total heat input from all boilers	1112	1e6 Btu/hr
Fuel for boilers	Natural gas	
Safety factor	1.1	
Heating value of natural gas	1025	Btu/scf
NG usage from all boilers	1084878	scf/hr
Dual fuel engines for all SRVs	45600	KW
Distillate fuel oil consumption	170	g/KW-h
Distillate fuel oil in operation	87.6	hours/yr
Natural gas in operation	8672.4	hours/yr
Natural gas energy input	5510	Btu/hp-hr
Diesel heating value	19300	Btu/lb

Boiler
lb/hr = AP 42 lb/M scf x natural gas scf/hr x safety factor
lb/hr = DOE factor kg/1e6 Btu x boiler 1e6 Btu/hr x 2.2 lb/kg x safety factor
Engines
lb/hr =AP 42 lb/1e6 Btu x NG energy Btu/hp-hr x engines KW x 1.33 hp/KW
lb/hr = DOE factor kg/1e6 Btu x 2.2 lb/kg x engines KW x 1.33 HP/KW x energy input Btu/hp-hr
lb/hr = DOE factor kg/1e6 Btu x diesel heating value Btu/lb x fuel consumption g/KW-h x engine KW x 1 lb/454 g x 2.2 lb/kg

	AP 42 Factor[1]			**DOE/IPCC[2]**		**Based on AP 42**				**Based on DOE/IPCC**			
Source	**CO2**	**CH4**	**Unit**	**CO2 kg/1e6 Btu**	**CH4 kg/1e6 Btu**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Boilers	120000	2.3	lb/10e6 scf	52.65	0.043	143204	569528	2.74	10.9	141853	564157	115.9	460.8
Engines[3]	110	0.6	lb/MMBtu	52.65	0.043	36759	144729	200.50	789.4	38707	152400	31.6	124.5
Engines[4]				72.32	0.018					52432	2085	13.0	0.52

1 AP 42, Table 1.4-2 (for boilers), Table 3.4-1 (dual fuel engines)
2 DOE "TECHNICAL GUIDELINES VOLUNTARY REPORTING OF GREENHOUSE GASES (1605(b)) PROGRAM", 1/07, Table 1.c.5, 1.c.6 and 1.c.11
3 AP 42 for dual fuel engine assumes 95% NG and 5% diesel. DOE factor for natural gas.
4 DOE factors are for diesel

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Greenhouse Gas Emissions

Activity **DWP Decommisioning**

Engine Load 100 %

					EPA Factor		DOE Factor	
Source	**hours/yr**	**Num. of Barges**	**Num. of Eng per barge**	**HP per engine**	**CO2 lb/hp-hr**	**CH4 lb/hp-hr**	**CO2 tonnes/1e9 Btu**	**CH4 tonnes/1e9 Btu**
Anchor Handling Support Vessels	720	2	1	3750	1.16	0.000705	78.8	0.018
Supply Boat	300	1	1	671	1.16	0.000705	78.8	0.018
Tug	720	1	1	800	1.16	0.000705	78.8	0.018

lb/hr = AP42 factor lb/hp-hr x HP/engine x num engine/boat x num. of boat x load%
lb/hr = DOE factor tonnes/1e9 Btu x HP/eng x num of eng/boat x num of boat x load% x 0.75 KW/hp
x heating value 1e9 Btu/tonnes x g/KWh x lb/454g

	EPA Factor				DOE Factor			
Source	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Anchor Handling Support Vessels	8700	2844	5.29	1.73	6616	2163	1.51	0.49
Supply Boat	778.36	106	0.47	0.06	714	97	0.16	0.02
Tug	928	303	0.56	0.18	851	278	0.19	0.06

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Activity **Onshore Construction**

Fuel consumption	205	g/KW-hr	
Diesel heating value	0.043338	1e6 Btu/kg	(DOE document Table 1.c.6)
Gasoline heating value	0.042051	1e6 Btu/kg	(NIST Chemistry WebBook)

Source	HP	Fuel	Op hrs/yr
Heavy Lift Crane	500	Diesel	480
Pipe Bending Machine	100	Diesel	180
Welding Generator	50	Gasoline	720
Air Compressor	50	Gasoline	720

	AP-42		DOE/IPCC	
Source	**CO2 lb/hp-hr**	**CH4 lb/hp-hr[1]**	**CO2 kg/1e6Btu**	**CH4 kg/1e6Btu**
Heavy Lift Crane	1.15	0	72.32	0.018
Pipe Bending Machine	1.15	0	72.32	0.018
Welding Generator	1.08	0	72.32	0.018
Air Compressor	1.08	0	72.32	0.018

1 No matching emission factor is listed in AP-42 for CH_4

lb/hr = AP-42 lb/hp-hr x HP

lb/hr = DOE factor kg/1e6 Btu x HP x 0.75 KW/HP x heating value 1e6 Btu/kg x fuel consumption kg/KW-h x lb/0.454kg

	AP-42				DOE/IPCC			
Source	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**	**CO2 lb/hr**	**CO2 tonnes/yr**	**CH4 lb/hr**	**CH4 tonnes/yr**
Heavy Lift Crane	575	125.3	0	0	531	115.7	0.132	63.4
Pipe Bending Machine	115	9.4	0	0	106	8.7	0.026	4.8
Welding Generator	54	17.7	0	0	51	16.8	0.013	9.2
Air Compressor	54	17.7	0	0	51	16.8	0.013	9.2

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Greenhouse Gas Emissions

Activity **Onshore Operation**

CH4 weight fraction 0.7068
CO2 weight fraction 0.0114

Fugitive Emissions

Source	lb/hr	tpy	CO2 lb/hr	CO2 tonnes/yr	CH4 lb/hr	CH4 tonnes/yr
TECO	3.31	14.59	0.038	0.15	2.34	9.35
Gulfstream	3.31	14.59	0.038	0.15	2.34	9.35
Valve station	3.31	14.59	0.038	0.15	2.34	9.35

Tank Emissions

Source	CO2 lb/hr	CO2 tpy	CH4 lb/hr	CH4 tpy	CO2 tonnes/yr	CH4 tonnes/yr
TECO	0	0	0.051	0.223	0	0.20
Gulfstream	0	0	0.051	0.223	0	0.20

Engine Emissions

Fuel Diesel
Operation hours 104 hours/yr
Fuel consumption 205 g/KW-h
Diesel heating value 0.043338 1e6 Btu/kg (DOE document Table 1.c.6)

Source	HP	CO2 lb/hp-hr[1]	CH4 lb/hp-hr[1]	CO2 kg/1e6Btu[2]	CH4 kg/1e6Btu[2]
Caterpillar D75-4S	91	1.15	0	72.32	0.018
Caterpillar C9 ATAAC	402	1.15	0	72.32	0.018

engine
lb/hr = DOE factor kg/1e6 Btu x HP x 0.75 KW/HP x diesel heating value 1e6 Btu/kg
x fuel consumption kg/KW-h x lb/0.454kg

	Based on AP-42				Based on DOE/IPCC			
Source	CO2 lb/hr	CO2 tonnes/yr	CH4 lb/hr	CH4 tonnes/yr	CO2 lb/hr	CO2 tonnes/yr	CH4 lb/hr	CH4 tonnes/yr
Caterpillar D75-4S	104.7	4.94	0	0	96.59	4.56	0.024	0.0011
Caterpillar C9 ATAAC	462.3	21.83	0	0	426.69	20.15	0.11	0.0050

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Activity **Onshore Decommissioning**

During the decommissioning, all pipeline pressure will be reduced from 1200 psi to 600 psi.

CH_4 weight fraction	0.7068		
CO_2 weight fraction	0.0114		
LNG density at 600 psi, 68 F	2.34	lb/ft3	(see LNG density calc)
Operation hours	480	hours/yr	
Pipe diameter	3	ft	
Onshore pipe length	27456	ft	

Route	Pipe length ft	Total Vol, ft3	CO_2 lb/hr	CH_4 lb/hr	CO_2 tonnes/yr	CH_4 tonnes/yr
Preferred	217536	1730868	96.2	5964.0	21.0	1299.7
North	313724	2410437	134.0	8305.5	29.2	1809.9
South	241957	1903403	105.8	6558.5	23.1	1429.2

Activity **SRV travels in Economic Zone**

Ecomonic zone	200	miles
DWP	28	miles
SRV travel distance	172	miles
Trips	47	trips/yr
Round trip time	12	hours/trip
Power output from engines	51295	KW
Distillate fuel oil consumption	170	g/KW-h
Distillate fuel oil	0.12	hours/trip
Diesel heating value	19300	btu/lb
Natural gas in operation	11.88	hours/trip
Natural gas energy input	5510	Btu/hp-hr

Boilers warm up

Total Boiler heat input	166.8	1e6 Btu/hr
Heating value of natural gas	1025	Btu/scf
NG usage from all boilers	162732	scf/hr

Boiler
lb/hr = AP 42 lb/1e6 scf x natural gas scf/hr x safety factor
lb/hr = DOE factor kg/1e6 Btu x boiler 1e6 Btu/hr x 2.2 lb/kg
Engines
lb/hr =AP 42 lb/1e6 Btu x NG energy Btu/hp-hr x engines KW x 1.33 hp/KW
lb/hr = DOE factor for natural gas kg/1e6 Btu x 2.2 lb/kg x engines KW x 1.33 HP/KW x energy input Btu/hp-hr
lb/hr = DOE factor kg/1e6 Btu x diesel heating value Btu/lb x fuel consumption g/KW-h x engine KW x 1 lb/454 g x 2.2 lb/kg

	AP 42 Factor[1]			DOE/IPCC[2]		Based on AP 42				Based on DOE/IPCC			
Source	CO2	CH4	Unit	CO2 kg/1e6 Btu	CH4 kg/1e6 Btu	CO2 lb/hr	CO2 tonnes/yr	CH4 lb/hr	CH4 tonnes/yr	CO2 lb/hr	CO2 tonnes/yr	CH4 lb/hr	CH4 tonnes/yr
Boilers	120000	2.3	lb/1e6 scf	52.65	0.043	19528	5000	0.37	0.10	19320	4947	15.8	4.0
Engines[3]	110	0.6	lb/1e6 Btu	52.65	0.043	41350	10588	225.54	57.8	43541	11037	35.6	9.01
Engines[4]				72.32	0.018					58980	151	14.7	0.038

1 AP 42, Table 1.4-2 (for boilers), Table 3.4-1 (dual fuel engines)
2 DOE "TECHNICAL GUIDELINES VOLUNTARY REPORTING OF GREENHOUSE GASES (1605(b)) PROGRAM", 1/07, Table 1.c.5, 1.c.6 and 1.c.11
3 AP 42 for dual fuel engine assumes 95% NG and 5% diesel. DOE factor for natural gas.
4 DOE factors are for diesel

Typical LNG Pipeline Operates at 600 psi and 68 F

LNG Samp	Mole Fractio	Molecular Weight (lb/lb-mole)	Weight Fraction	ω[1]	Critical Pressure (atm)	Critical Temperature (K)	Ambient Pressure (atm)	Ambient Temperature (K)	P_r	T_r	B_0	B_1	Z	Density (kg/m^3)
Methane	0.8000	16.04	0.7961	0.0120	46	190.7	40.8	293.15	0.9	1.5	-0.13	0.11	0.93	29.41
Ethane	0.1000	30.07	0.1865	0.1000	49	305.4	40.8	293.15	0.8	1.0	-0.37	-0.07	0.67	75.67
N2	0.0100	28.01	0.0174								**LNG Density**			**37.53**
											LNG Density, lb/ft^3		**2.34**	

[1] Introduction to Chemical Engineering Thermodynamics, Hendrick C. Van Ness. J. M. (Joseph Mauk), Smith, Michael M. Abbott, 2004.

Appendix B

Preliminary Inventory of Florida Greenhouse Gas Emissions: 1990- 2004

Preliminary Inventory of Florida Greenhouse Gas Emissions: 1990-2004

Division of Air Resource Management
Florida Department of Environmental Protection

September 2007

Version 1.1

Version History

Version	Date	Description
1.0	6/28/2007	First report.
1.1	10/8/2007	Updated the inventory to 2004. Removed international bunker fuels from Table 2, as this is not included in the inventory (in version 1.0 for information purpose).

Introduction

The Department of Environmental Protection (DEP) has prepared this preliminary inventory of Florida greenhouse gas (GHG) emissions to help guide planning efforts in the state. The GHG emission levels shown here are gross estimates. While more refined estimates may be obtainable over time, DEP believes this preliminary inventory can be relied upon to identify the major categories of GHG emission sources and the general trend of emissions in those categories since 1990. Over the next several months, DEP, with the help of other experts in the field, will identify potential improvements to the inventory and make refinements as needed.

Methodology

This inventory was developed using the U.S. Environmental Protection Agency's (EPA's) State Inventory Tool (SIT). To aid states in the effort of compiling GHG inventories, EPA developed the ten-module SIT software according to methodologies outlined in the agency's emissions inventory guidance documents. This tool estimates GHG emissions from 14 sectors:

- Energy sector (CO_2 emissions from fossil fuel combustion);
- Industrial processes;
- Natural gas and oil systems;
- Coal mining;
- Solid waste disposal;
- Domesticated animals;
- Manure management;
- Flooded rice fields;
- Agricultural soils;
- Forest management;
- Burning of agricultural crop wastes;
- Municipal wastewater;
- Methane and N_2O emissions from mobile source combustion; and
- Methane and N_2O emissions from stationary source combustion.

To calculate GHG emissions, the SIT relies on "activity" data for each source sector. Some of the activity data, such as fossil fuel use in the electric power industry as reported to the U.S. Energy Information Administration, are readily available. Other data are more difficult to obtain and subject to greater uncertainty. For purposes of this preliminary inventory, DEP has relied on "default" activity data built into the SIT and updated through 2004. As DEP seeks to refine this inventory, it will explore the possibility of developing more accurate, Florida-specific data for certain source categories. Also, it should be noted that the SIT does not account for "carbon-neutral" GHG emissions resulting from the combustion of renewable fuels.

The greenhouse gases covered by this inventory are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and the ozone-depleting substance (ODS) substitutes -

hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The Intergovernmental Panel on Climate Change (IPCC) has assigned each of these gases a Global Warming Potential (GWP) that accounts for the relative effectiveness of each gas at absorbing terrestrial radiation and its average lifetime in the atmosphere. For example, taking the GWP of CO_2 as “1,” the GWP of methane is “21.” This means that one ton of methane emissions has the same effect on global warming as 21 tons of CO_2 emissions. To make this inventory more meaningful, all GHG emissions are adjusted by their GWPs and reported in units of “million metric tons of CO_2 equivalent.” A million metric tons of CO_2 equivalent represents the global warming potential of a million metric tons of CO_2. A metric ton is 1000 kilograms, or 2205 pounds.

Results

The results of the inventory are summarized in the following tables and graphs. All numbers are expressed in million metric tons of CO_2 equivalent ($MMTCO_2E$).

Total GHG Emissions

Figure 1 shows the trend of total GHG emissions in Florida during the period from 1990 through 2004. The emissions have increased at an average rate of 2.5 percent per year. The total GHG emissions in 2004 were 289 $MMTCO_2E$.

Figure 1. Greenhouse Gas Emissions in Florida (1990-2004)

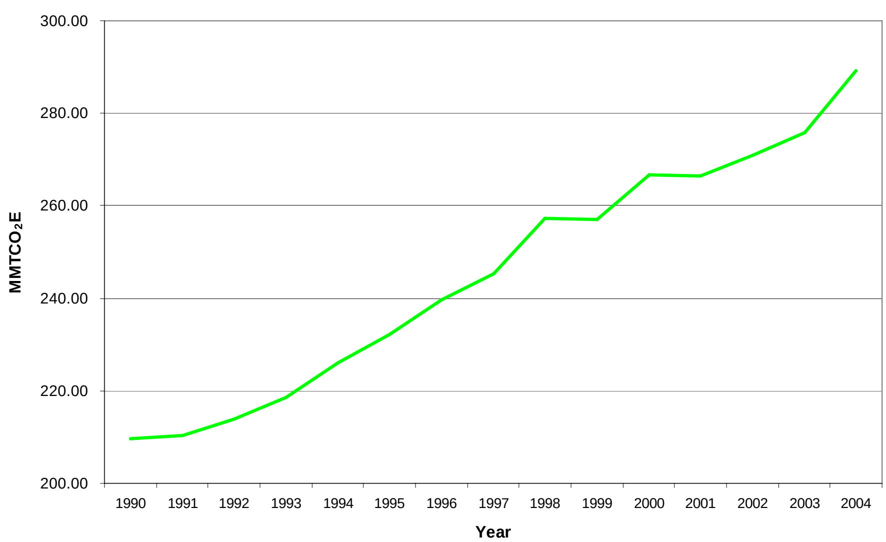


Figure 2 shows the total GHG emissions, vehicle miles traveled (VMT), and population in Florida, normalized to the 1990 values, over the same 15-year time period. Over this period, total GHG emissions increased by 38 percent, while the state’s population increased by 33 percent and the total VMT increased by 79 percent.

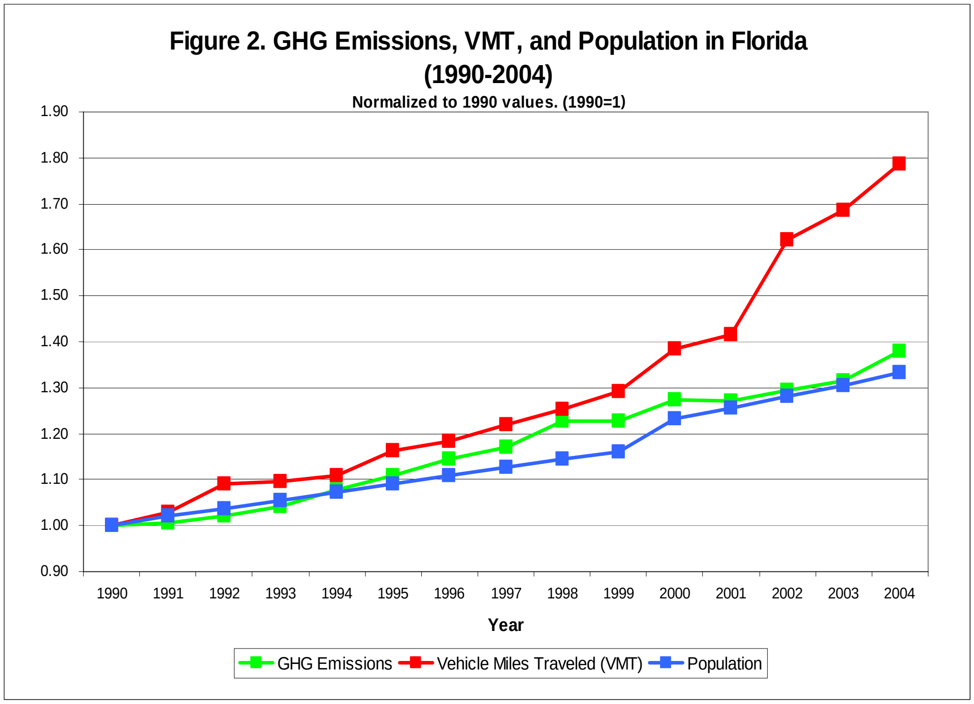
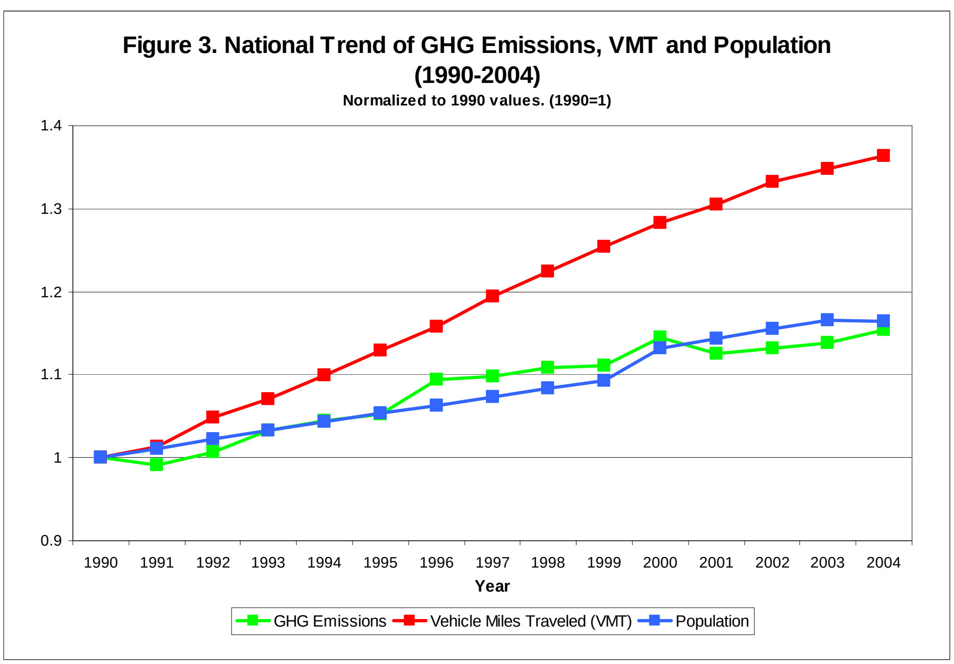


Figure 3 shows the national total GHG emissions, VMT, and population in the U.S., normalized to the 1990 values. From 1990 to 2004, U.S. GHG emissions increased by 15 percent, while the population increased by 18 percent and the total VMT increased by 38 percent. Florida's GHG emissions in 2004 represent 4 percent of total U.S. GHG emissions.



GHG Emissions by Gas

Table 1 shows Florida GHG emissions by gas and source sector during the period from 1990 through 2004. Figure 4 shows the percentage of emissions by each GHG. The data shown here represent gross emissions; that is, no adjustments are made for year-to-year changes in the amount of carbon stored, or sequestered, in biomass and soils.

The most prevalent GHG is carbon dioxide (CO_2). Florida's CO_2 emissions increased from 191 $MMTCO_2E$ in 1990 to 265 $MMTCO_2E$ in 2004 and currently account for approximately 92 percent of the state's gross GHG emissions. Annual methane (CH_4) emissions in 2004 were 9.9 $MMTCO_2E$, representing approximately 3.4 percent of gross emissions. Nitrous oxide (N_2O) emissions in 2004 were 6.2 $MMTCO_2E$ - approximately 2.1 percent of gross emissions. Emissions of the ODS substitutes, HFCs, PFCs and SF_6 as a group, increased from about 1.5 $MMTCO_2E$ in 1990 to 7.8 $MMTCO_2E$ in 2004 and account for about 2.7 percent of the state's gross GHG emissions.

Figure 4. GHG Emissions by Gas in Florida-2004

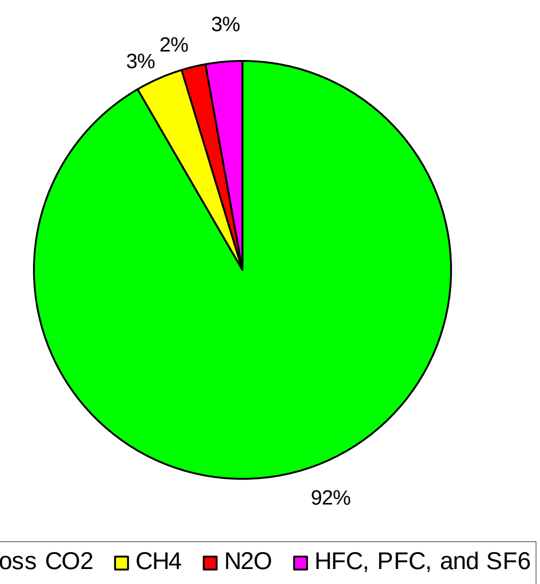


Table 1. Summary of GHG Emissions by Gas and Sector in Florida ($MMTCO_2E$)

Emissions (MMTCO2E)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gross CO_2	191.02	191.65	194.60	198.83	206.98	211.79	218.58	224.57	237.24	236.60	245.09	243.78	248.08	252.33	265.28
CO_2 from Fossil Fuel Combustion	188.16	188.92	191.26	195.08	202.59	207.29	213.77	219.38	231.99	231.16	239.37	236.95	240.14	244.16	256.34
Other	2.86	2.74	3.34	3.76	4.39	4.50	4.81	5.20	5.26	5.44	5.71	6.83	7.94	8.17	8.95
CH_4	10.40	10.65	10.71	10.47	10.26	10.43	10.31	9.63	8.53	8.74	9.14	9.64	9.55	9.64	9.88
Stationary Combustion	0.31	0.32	0.33	0.22	0.21	0.21	0.22	0.19	0.18	0.18	0.18	0.17	0.17	0.18	0.18
Mobile Combustion	0.23	0.22	0.23	0.22	0.21	0.21	0.20	0.19	0.18	0.17	0.18	0.16	0.17	0.16	0.14
Enteric Fermentation	2.51	2.53	2.54	2.54	2.59	2.67	2.49	2.45	2.35	2.29	2.30	2.26	2.24	2.20	2.21
Manure Management	0.62	0.62	0.61	0.63	0.66	0.64	0.61	0.65	0.68	0.64	0.64	0.64	0.62	0.61	0.59
Waste	5.70	5.85	5.87	5.73	5.41	5.53	5.61	4.96	3.94	4.25	4.60	5.16	5.10	5.25	5.48
Wastewater	0.88	0.90	0.92	0.93	0.95	0.97	0.98	1.00	1.01	1.02	1.09	1.11	1.13	1.15	1.17
Other	0.16	0.20	0.21	0.21	0.22	0.21	0.20	0.19	0.19	0.19	0.16	0.13	0.12	0.10	0.11
N_2O	6.62	6.71	6.89	7.41	6.64	6.98	7.26	6.94	6.93	6.69	6.97	6.91	6.78	6.63	6.21
Stationary Combustion	0.56	0.58	0.60	0.60	0.60	0.60	0.65	0.64	0.64	0.62	0.63	0.61	0.62	0.65	0.65
Mobile Combustion	2.17	2.27	2.46	2.53	2.56	2.65	2.66	2.69	2.69	2.59	2.67	2.49	2.61	2.45	2.20
Manure Management	0.14	0.13	0.13	0.13	0.13	0.14	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.10	0.09
Agricultural Soil Management	3.01	2.95	2.90	3.33	2.48	2.72	2.94	2.59	2.57	2.43	2.57	2.69	2.39	2.36	2.17
Wastewater	0.70	0.73	0.75	0.76	0.80	0.80	0.81	0.83	0.85	0.88	0.93	0.95	0.96	0.98	1.01
Other	0.05	0.04	0.06	0.06	0.07	0.07	0.07	0.05	0.05	0.05	0.05	0.07	0.09	0.09	0.09
HFC, PFC, and SF_6	1.48	1.43	1.55	1.77	2.13	2.99	3.59	4.22	4.57	5.02	5.58	6.08	6.59	7.16	7.77
Industrial Processes	1.48	1.43	1.55	1.77	2.13	2.99	3.59	4.22	4.57	5.02	5.58	6.08	6.59	7.16	7.77
Gross Emissions	**209.52**	**210.44**	**213.75**	**218.49**	**226.01**	**232.19**	**239.74**	**245.36**	**257.27**	**257.06**	**266.78**	**266.41**	**271.00**	**275.77**	**289.14**

GHG Emissions by Source Sector

Energy Sector (Fossil Fuel Combustion Carbon Dioxide (CO_2))

Fossil fuel combustion, otherwise referred to as the energy sector, is responsible for the majority of GHG emissions in Florida. Table 2 shows the CO_2 emissions from fossil fuel combustion by sub-sector and fuel type. GHG emissions from this sector increased from 188 $MMTCO_2E$ in 1990 to 256 $MMTCO_2E$ in 2004, and account for roughly 89 percent of Florida's GHG emissions. Emissions in this sector increased at an average annual rate of 2.4 percent from 1990 to 2004. Overall, the CO_2 emissions from fossil fuel combustion increased by 36 percent over the 15-year period.

GHG emissions from fossil-fuel combustion are primarily attributable to the utility and transportation sub-sectors, which comprise 49 and 43 percent of emissions from the energy sector, respectively. The industrial sub-sector accounts for 5 percent of these emissions, with minor emissions from the commercial sub-sector (less than 2 percent) and the residential sub-sector (less than 1 percent). The emissions by sub-sector are presented graphically in Figures 5 and 6.

Figure 5. CO_2 Emissions by Energy Sub-sector in Florida-2004

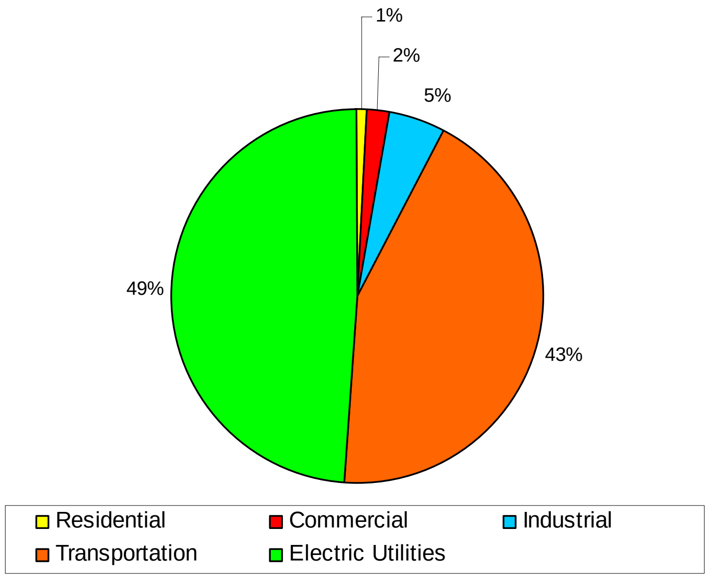
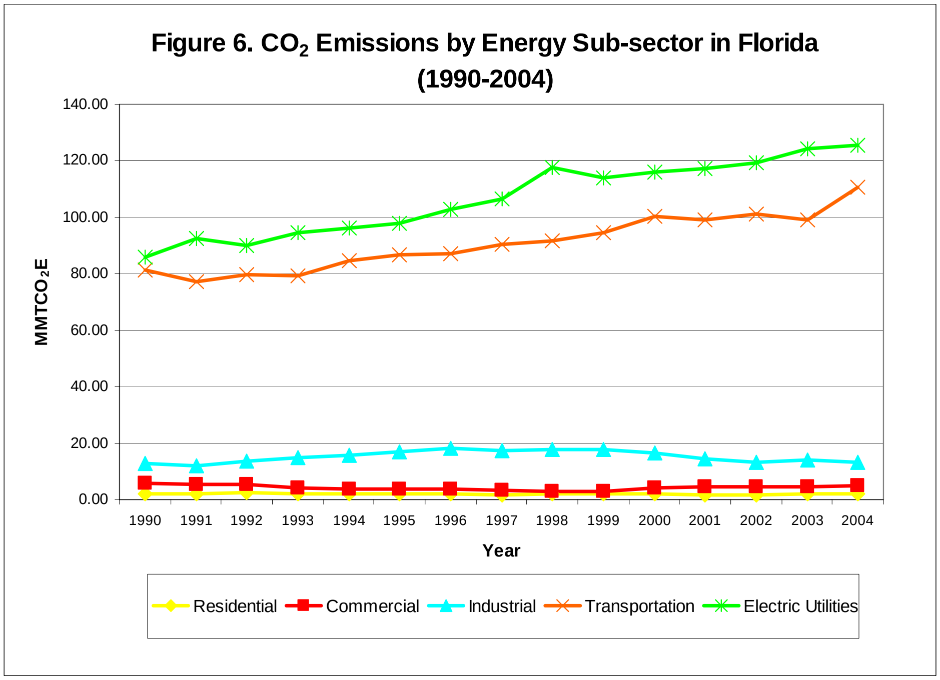
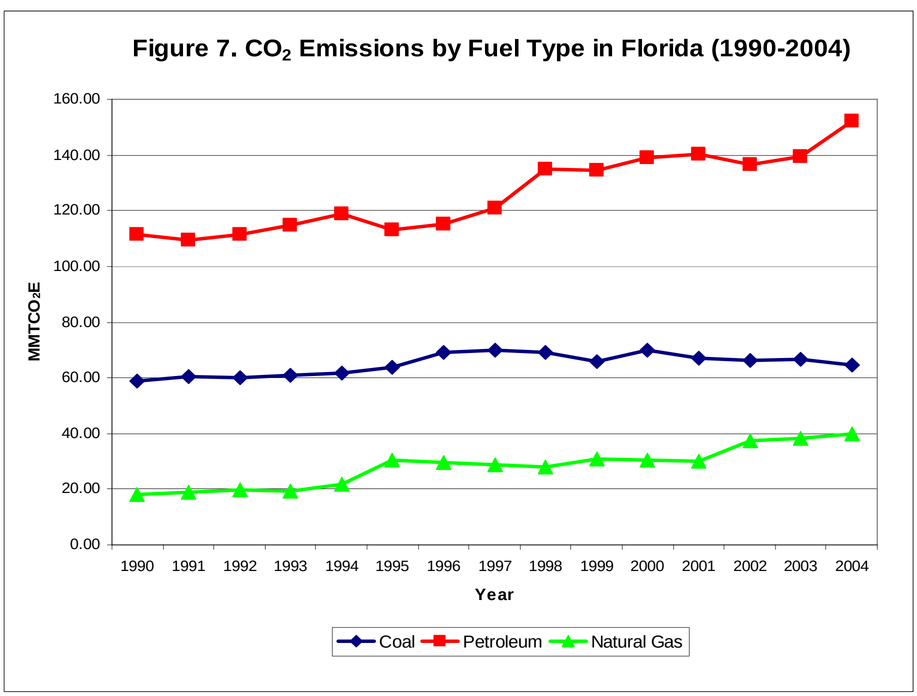


Table 2. Summary of CO_2 Emissions from Fossil Fuel Combustion in Florida ($MMTCO_2E$)

$MMTCO_2E$	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	2.07	2.13	2.30	2.20	2.07	1.91	2.08	1.79	1.92	1.89	1.98	1.82	1.79	1.88	2.11
Coal	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
Petroleum	1.32	1.37	1.45	1.38	1.23	1.08	1.12	1.05	1.13	1.12	1.09	0.92	0.97	0.97	1.28
Natural Gas	0.75	0.75	0.84	0.81	0.83	0.82	0.96	0.74	0.79	0.77	0.89	0.88	0.82	0.91	0.83
Commercial	5.69	5.39	5.36	4.16	3.79	3.85	3.67	3.15	3.01	3.09	4.27	4.45	4.48	4.52	5.02
Coal	0.01	0.00	0.03	0.03	0.04	0.00	0.00	0.00	0.01	0.01	0.02	0.12	0.02	0.02	0.00
Petroleum	3.59	3.10	2.90	1.73	1.36	1.56	1.19	1.09	0.90	1.07	1.43	1.55	1.44	1.40	2.07
Natural Gas	2.09	2.29	2.43	2.40	2.39	2.29	2.47	2.06	2.10	2.01	2.81	2.79	3.02	3.10	2.95
Industrial	12.80	11.97	13.65	14.89	15.69	16.89	18.03	17.25	17.58	17.61	16.59	14.55	13.13	14.17	13.11
Coal	2.81	2.65	3.11	3.03	3.02	3.10	2.97	3.14	2.97	2.76	2.98	2.80	2.85	2.63	2.51
Petroleum	5.11	4.34	5.39	6.03	5.63	6.64	7.35	7.12	7.84	7.49	7.50	6.43	5.83	7.39	7.31
Natural Gas	4.88	4.97	5.15	5.83	7.04	7.15	7.70	6.99	6.76	7.36	6.11	5.32	4.46	4.14	3.30
Transportation	81.52	77.12	79.78	79.26	84.76	86.69	87.28	90.44	91.77	94.67	100.39	98.91	101.21	99.23	110.72
Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Petroleum	81.36	76.91	79.52	79.00	84.44	86.26	86.93	90.11	91.54	94.28	99.94	98.52	100.58	98.65	110.13
Natural Gas	0.16	0.20	0.26	0.26	0.32	0.43	0.35	0.33	0.23	0.40	0.44	0.40	0.63	0.58	0.59
Electric Utilities	86.08	92.32	90.18	94.57	96.29	97.95	102.71	106.74	117.70	113.89	116.15	117.22	119.53	124.36	125.38
Coal	55.94	57.65	57.08	57.66	58.50	60.63	66.25	66.65	66.28	63.19	67.03	63.92	63.41	64.01	61.87
Petroleum	19.98	23.85	22.20	26.82	26.39	17.47	18.38	21.36	33.42	30.53	29.11	32.65	27.75	31.01	31.23
Natural Gas	10.16	10.82	10.90	10.09	11.40	19.85	18.08	18.73	18.01	20.18	20.01	20.65	28.37	29.34	32.28
TOTAL	**188.16**	**188.92**	**191.26**	**195.08**	**202.59**	**207.29**	**213.77**	**219.38**	**231.99**	**231.16**	**239.37**	**236.95**	**240.14**	**244.16**	**256.34**
Coal	58.77	60.30	60.22	60.72	61.57	63.73	69.23	69.80	69.27	65.96	70.03	66.85	66.28	66.66	64.38
Petroleum	111.37	109.58	111.46	114.96	119.04	113.01	114.97	120.74	134.83	134.49	139.08	140.07	136.57	139.43	152.02
Natural Gas	18.03	19.03	19.58	19.40	21.98	30.55	29.57	28.84	27.89	30.71	30.27	30.03	37.29	38.07	39.94



Fossil fuel combustion emissions by fuel type are shown graphically in Figure 7. In 2004, petroleum use accounted for roughly 152 $MMTCO_2E$ (approximately 59 percent) of the state's fossil energy emissions. Coal and natural gas follow in order of importance, accounting for roughly 25 and 16 percent of energy-related GHG emissions, respectively. Most petroleum is consumed in the transportation sub-sector, while the vast majority of coal is used by electric utilities. Natural gas is consumed largely in the electric utility, industrial and commercial sub-sectors.



Solid Waste Disposal

Table 3 shows GHG emissions from solid waste disposal activities in Florida. Figure 8 shows the emissions trend by gas for the period from 1990 to 2004. As noted previously, the SIT does not account for emissions of CO_2 from the burning of biogenic waste material. The year-to-year variability in landfill methane (CH_4) emissions as estimated by the SIT bears further investigation.

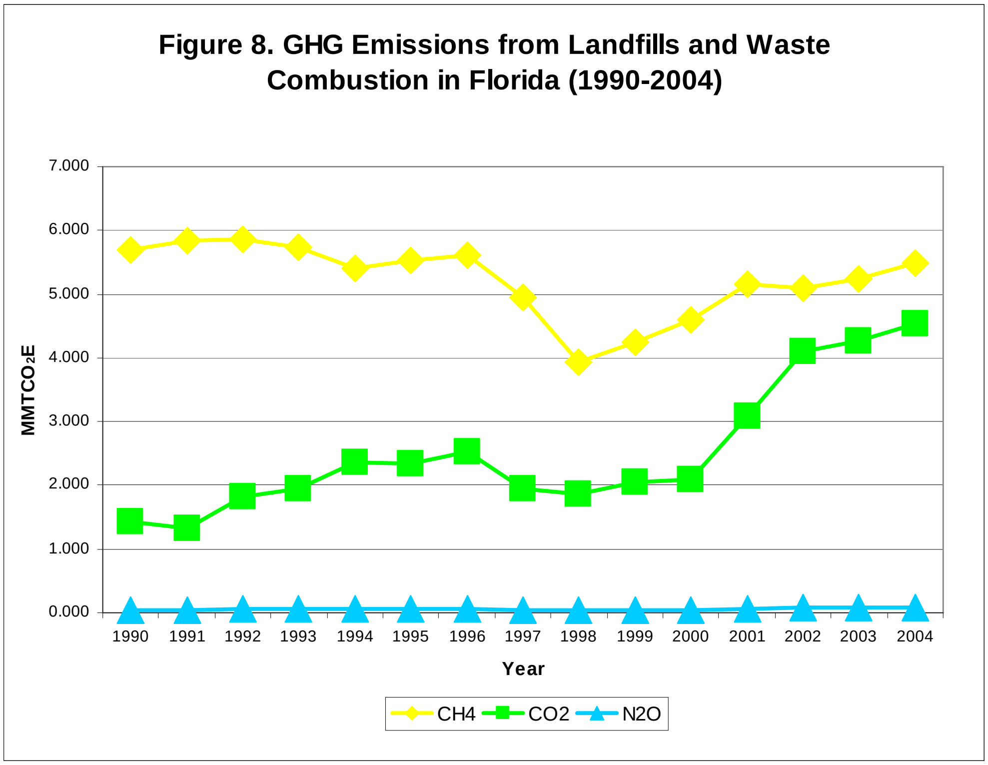


Table 3. Summary of GHG Emissions from Solid Waste in Florida ($MMTCO_2E$)

CH_4 Emissions from Landfills ($MMTCO_2E$)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Potential CH_4	7.319	7.669	7.998	8.201	8.375	8.572	8.738	8.898	9.101	9.325	9.716	10.090	10.407	10.668	10.984
MSW Generation	6.840	7.167	7.475	7.665	7.827	8.011	8.167	8.316	8.505	8.715	9.081	9.430	9.727	9.970	10.266
Industrial Generation	0.479	0.502	0.523	0.537	0.548	0.561	0.572	0.582	0.595	0.610	0.636	0.660	0.681	0.698	0.719
CH_4 Avoided	-0.988	-1.173	-1.478	-1.837	-2.365	-2.425	-2.508	-3.389	-4.723	-4.604	-4.604	-4.353	-4.736	-4.837	-4.893
Flare	-0.480	-0.665	-0.970	-1.329	-1.857	-1.917	-2.000	-2.577	-2.990	-2.871	-2.871	-2.620	-2.932	-2.930	-2.930
Landfill Gas-to-Energy	-0.508	-0.508	-0.508	-0.508	-0.508	-0.508	-0.508	-0.812	-1.733	-1.733	-1.733	-1.733	-1.804	-1.907	-1.963
Oxidation at MSW Landfills	-0.585	-0.599	-0.600	-0.583	-0.546	-0.559	-0.566	-0.493	-0.378	-0.411	-0.448	-0.508	-0.499	-0.513	-0.537
Oxidation at Industrial Landfills	-0.048	-0.050	-0.052	-0.054	-0.055	-0.056	-0.057	-0.058	-0.060	-0.061	-0.064	-0.066	-0.068	-0.070	-0.072
Total CH_4 Emissions	**5.698**	**5.846**	**5.868**	**5.728**	**5.410**	**5.532**	**5.608**	**4.958**	**3.940**	**4.249**	**4.601**	**5.163**	**5.105**	**5.247**	**5.482**
CO_2 and N_2O Emissions from Waste Combustion ($MMTCO_2E$)															
Gas/Waste Product	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
CO_2	**1.433**	**1.316**	**1.812**	**1.947**	**2.351**	**2.344**	**2.521**	**1.937**	**1.870**	**2.041**	**2.095**	**3.096**	**4.102**	**4.263**	**4.536**
Plastics	0.961	0.884	1.211	1.305	1.557	1.563	1.681	1.307	1.263	1.398	1.425	2.097	2.777	2.868	2.994
Synthetic Rubber	0.209	0.187	0.248	0.260	0.310	0.279	0.296	0.219	0.208	0.215	0.225	0.340	0.445	0.465	0.632
Synthetic Fibers	0.263	0.244	0.353	0.382	0.483	0.502	0.544	0.412	0.400	0.428	0.445	0.659	0.880	0.929	0.909
N_2O	**0.048**	**0.039**	**0.055**	**0.055**	**0.067**	**0.066**	**0.066**	**0.050**	**0.047**	**0.049**	**0.049**	**0.069**	**0.090**	**0.091**	**0.092**
Total CO_2 and N_2O Emissions	**1.480**	**1.355**	**1.867**	**2.002**	**2.418**	**2.410**	**2.587**	**1.987**	**1.917**	**2.090**	**2.144**	**3.165**	**4.191**	**4.354**	**4.628**

Agricultural Activities

Table 4 and Figure 9 show the GHG emissions from agriculture-related sectors, which include methane (CH_4) emissions from enteric fermentation and nitrous oxide (N_2O) emissions from soil management practices.

On average, CH_4 produced through the process of enteric fermentation accounts for less than 1 percent of the gross GHG emissions in Florida, with emissions of 2.5 $MMTCO_2E$ in 1990 and 2.2 $MMTCO_2E$ in 2004. The majority of emissions from enteric fermentation are attributable to beef and dairy cattle.

N_2O from agricultural soil management activities accounted for nearly 3.0 $MMTCO_2E$ in 1990 and 2.2 $MMTCO_2E$ in 2004, representing roughly 1 percent of the gross GHG emissions in Florida. Direct and indirect emissions from agricultural soils decreased by 24 and 35 percent, respectively, resulting in an overall decrease of 28 percent. The major sources of the direct emissions are fertilizers and livestock, while leaching/runoff of fertilizers and animal waste is the dominant source of the indirect emissions.

Figure 9. GHG Emissions from Agriculture in Florida (1990-2004)

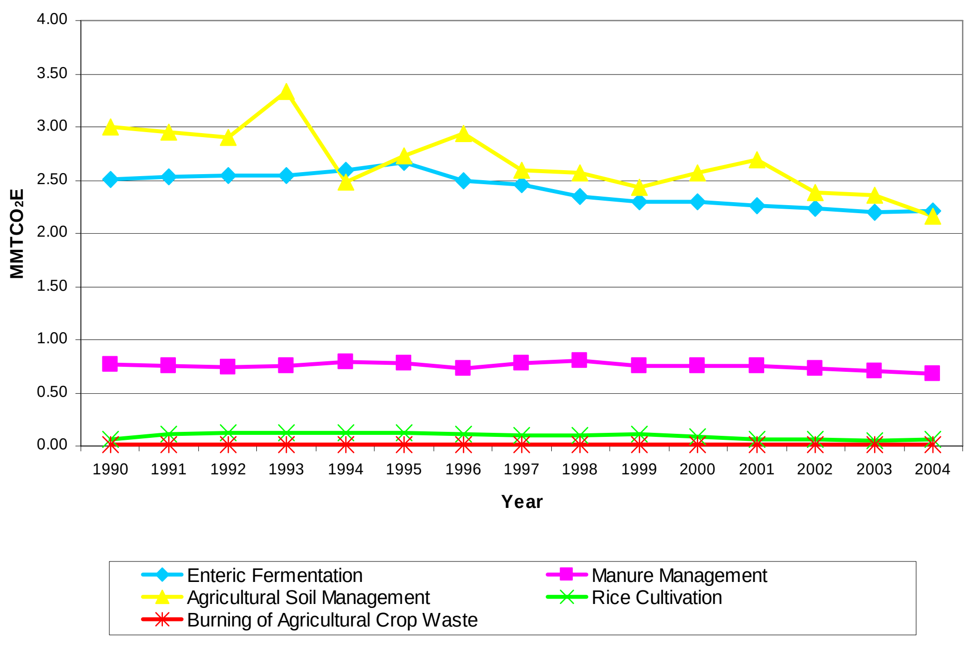


Table 4. Summary of GHG Emissions from Agriculture in Florida ($MMTCO_2E$)

Emissions ($MMTCO_2E$)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Enteric Fermentation	2.51	2.53	2.54	2.54	2.59	2.67	2.49	2.45	2.35	2.29	2.30	2.26	2.24	2.20	2.21
Manure Management	0.76	0.75	0.74	0.76	0.79	0.78	0.73	0.78	0.81	0.76	0.76	0.76	0.73	0.70	0.68
Agricultural Soil Management	3.01	2.95	2.90	3.33	2.48	2.72	2.94	2.59	2.57	2.43	2.57	2.69	2.39	2.36	2.17
Rice Cultivation	0.06	0.11	0.12	0.12	0.12	0.12	0.11	0.10	0.10	0.11	0.09	0.07	0.07	0.05	0.06
Burning of Agricultural Crop Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
TOTAL	6.35	6.35	6.31	6.76	6.00	6.30	6.29	5.94	5.84	5.60	5.73	5.78	5.43	5.33	5.13

Carbon Flux from Land-Use Change and Forestry

The SIT includes the sector, "carbon flux from land-use change and forestry operations." This sector is intended to reflect year-to-year changes in the amount of carbon stored in aboveground biomass, belowground biomass, dead wood, leaf litter, and soil organic carbon. The carbon in forest products (wood and paper) and long-term storage of carbon from disposed forest products in landfills are also included. The SIT-computed emissions for this sector for the 1990-2004 period show values on the order of ± 30 $MMTCO_2E$, where negative values represent net sequestration of carbon as a result of land-use changes and forestry operations in a given year.

While potentially significant, the results for this sector are based on very limited data and are not considered usable for analyzing trends. Therefore, the department has not included the GHG emissions, or sinks, from this sector in this report.

Alternatives	
133	In Volume II, Section 2.8.4 of the Application, you conclude, 'The Northern Location and Route Alternative is not a feasible or practicable alternative because it would involve the pipeline's crossing major shipping fairways and the Gulfstream Pipeline offshore.' Two offshore crossings of the Gulfstream Pipeline are proposed with the new pipeline modifications. Please provide information on whether this changes your assessment of the feasibility of the Northern Location and Route Alternative since the modifications to the Tampa Bay approach would require only one crossing of the Gulfstream Pipeline. What technical considerations were included in determining if multiple crossings of the Gulfstream Pipeline or a single crossing of the pipeline and a single crossing of the Fairway would be more or less feasible?
Response	Installation of the Port Dolphin main gas transmission pipeline across the Tampa Bay shipping fairway is feasible but presents logistical issues, including interference with ship traffic and dredging activities during pipeline installation. In addition, it's relative location to existing National Wildlife Refuges and State Parks also plays a role in Port Dolphin's analysis and decision-making process. ***<u>Shipping Fairway HDD Crossing</u>*** Due to safety considerations, the pipeline would have to be buried deeper than current and future dredging depths in order to properly protect and avoid potential impacts to it. For achieving the targeted depth and clear the required 1,000 ft width of channel, the corresponding HDD crossing would need to be 100 ft below the existing channel bottom creating a total depth of a minimum of 140 ft, and approximately 3,200 ft long. The construction of this HDD would approximately last 30days. The construction spread that would be required for installing the HDD across the shipping fairway would consist of four jack-up barges in the 200-class range (which are typically self-propelled, with spuds 60 meters long, 288 square meters of deck space, and up to 181 tonnes of deck loading capacity); three hopper barges moored to one jack-up barge at each crossing location to collect slurry and cuttings, along with water barges to provide fresh water for slurry make-up; two tugs (1,200 HP each) for barge towing; and crew boats for personnel transport and logistics. During construction of this HDD, a Clearance Zone will be established and enforced around the construction spread. According to offshore construction practices, this Clearance Zone is expected to at least be a 500 m radius circle around the HDD entrance/exit points. Therefore, it is anticipated that this construction spread would temporarily interfere with regular ship traffic and dredging activities within Tampa Bay's shipping fairway. ***<u>Pipeline Plowing/Burial in the Shipping Fairway Area</u>*** The pipeline plow/burial construction spread would run along the southern portion of the safety fairway for approximately 15 miles. Construction of this pipeline segment would approximately take 25 days. The pipeline construction spread would consist of a pipelay barge, approximately 400-feet long by 100-feet wide, which would likely require 10 anchors weighing up to 20,000 pounds each, and two anchor handling support vessels to deploy and recover these anchors. During pipeline construction, a Moving Exclusion Zone will be established and enforced around the construction spread. Port Dolphin's proposed Moving Exclusion Zone dimensions would be 3,000 ft wide by 2,500 ft long (refer to Response to Question No. 97). Therefore, it is anticipated that this

	Zone would temporarily impact the regular flow of vessel traffic into and out of Tampa Bay via the major shipping fairway. ***Environmental Considerations*** During early consultation implemented by Port Dolphin with the Florida Department of Environmental Protection (FDEP), it was strongly urged that Port Dolphin's pipeline route should be designed for avoiding and/or minimizing potential impacts to Egmont Key. Therefore, one criterion in Port Dolphin's analysis has been to locate the pipeline route as far as reasonably practicable from this National Wildlife Refuge and Florida State Park (including bird sanctuaries, a lighthouse, historic fort, and other tourist attractions), which is visited frequently by recreational boaters and other tourists. Pipeline installation during the construction phase would produce noise, air emissions, additional vessel traffic, and visual/aesthetic impacts. The Preferred Route and Southern Route are farthest from Egmont Key, at a distance of >2.4 miles. The Northern Route would be located closer (1.15 miles). Likewise, another criterion in Port Dolphin's analysis has been to locate the pipeline route as far as reasonably practicable from Passage Key, which is a NWR. Again, pipeline installation during the construction phase would produce noise, air emissions, additional vessel traffic, and visual/aesthetic impacts. The Preferred Route and Southern Route are farthest from Passage Key, at a distance of 0.39 miles. The Northern Route would be closer (0.19 miles). ***Conclusion*** The Northern Route is the longest (55.7 miles) and presents several significant disadvantages over the other alternatives considered. The Northern Route would cross a shipping fairway and then travel parallel to the southern edge of the shipping fairway for about 15 miles likely disrupting vessel traffic and dredging activities. The Northern Route would be located closer to Egmont Key (1.15 miles) and Passage Key (0.19 miles) than either of the other alternatives. In conclusion, Port Dolphin has chosen a Preferred Alternative which not only eliminates and/or minimizes the above-mentioned issues, but (including its most recent revision) also avoids the Terra Ceia Aquatic Preserve. In order to realize these benefits and/or enhancements, Port Dolphin has decided to include in its plans two water-to-water HDDs, which are relatively short and shallow (1,335 ft - 2,947 ft long and 27 ft below the existing seafloor).