FLORIDA GAS 24” PIPELINE SHALLOW COVER

Florida Gas Transmission Company, LLC

Alternatives Analysis

U.S. Army Corps of Engineers – Standard Permit Application

December 2020

Introduction

Florida Gas Transmission Company, LLC (FGT) is submitting the accompanying Clean Water Act Section 404 permit application requesting authorization to perform maintenance to restore cover to a pipeline asset in Galveston Bay. FGT operates a 24-inch diameter natural gas pipeline that crosses Galveston Bay from San Leon to Smith Point.

This alternatives analysis has been prepared to meet the Section 404 Standard Permit application requirements. Mitigation measures for impacts to resources that cannot be avoided are outlined in the enclosed Oyster Mitigation Plan.

Project Need and Purpose

The FGT pipeline system is an approximately 5,400-mile natural gas pipeline system with extensive access to diverse natural gas supply sources. The pipeline transports natural gas from producers in Texas to serve the rapidly growing Gulf Coast to the Florida peninsula. The Florida customer base includes electric utilities, independent power producers, industrials, and local distribution companies. Continuous natural gas flow is crucial so these customers can provide the public with natural gas to heat, power, and fuel the public's needs.

The pipeline was installed in 1958 under USACE permit W-N-243-41-PERMIT-4281. The pipeline was permitted and installed 3 feet below the bay bottom. FGT is required to periodically assess pipeline conditions and maintain the appropriate depth of cover per the U.S. Department of Transportation (DOT) / Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations (49 CFR 192.612). A depth of cover survey was conducted in August of 2018 that showed areas of the pipeline in Galveston Bay had less than 36 inches of cover. PHMSA regulations require the operator to either bury the pipeline so that the top of the pipe is 36 inches below the underwater natural bottom or to employ engineered alternatives to bury the pipe that meet or exceed the level of protection provided by burial. The purpose of this project is to bring the pipeline system back to approved depth of cover parameters to ensure continued safety and reliability of the system. The following sections discuss the alternatives considered to mitigate the depth of cover issue.

Alternatives Considered

1. Alternative 1 – No Action

The "No Action" alternative does not meet the PHMSA requirements to address shallow cover over the existing pipeline. FGT is required to inspect the pipeline, repair any defects, and correct any safety-related conditions. The pipeline needs to be covered adequately to function as it was originally designed, and shallow-covered areas must be addressed due to the increased potential for corrosion, flowing debris, and/or vessels striking the pipeline. This pipeline was designed so that the surrounding soil would provide restraining forces to counteract possible loads that could cause pipeline failure. Eroded areas along the pipeline, if left alone, would result in areas of unsupported pipe that would be subject to stress and subsequent failure. Areas of the pipeline with shallow cover are also vulnerable to strikes by vessels and debris. Failure of this high-pressure pipeline could potentially result in loss of life and damage to the surrounding environment. "No Action" also does not meet the requirements of PHMSA pipeline operation regulations; therefore, the "No Action" alternative is not a practical option.

2. Alternative 2 – Lowering the Pipelines (Open Cut Trenching / Jetting)

Pipelines can be lowered in place to increase the amount of cover atop the pipelines. In marine environments, this is accomplished by using high pressure water jetting to displace the soil under the pipeline. Creation of this void beneath the pipeline allows the pipeline to move lower in the newly created trench. A jetting barge would be towed along the pipeline in the shallow-covered areas. The jetting apparatus uses water pressure to suspend the soils around and below the pipeline in order to lower the existing pipeline to an adequate depth below the existing bay bottom. Because of the diameter of the pipeline and thickness of the concrete coating around the pipeline, significant jetting would be required to lower the pipeline so that the top of pipe is more than 3 feet below the mud line. The operation of lowering the pipeline would last approximately one month. Once the pipeline is lowered, FGT standard protocol requires that the pipeline be hydrotested and inspected to determine if any damage occurred during the lowering process. To accomplish the hydrotest, a portion of the pipeline would have to be excavated on either end of the bay. The pipeline would have to be cut, and a test header would be welded in to allow for testing. The pipeline would then be filled with water from Galveston Bay, with the addition of a biocide to prevent biofouling inside the pipeline. The pipeline's pressure would be raised to the test pressure and held at test pressure to confirm pipeline integrity. If leaks are encountered during the hydrotest, a biodegradable dye would be injected into the pipeline to locate the leak. The area in question would be shored with coffer dams, dewatered, and excavated for repair of the pipeline. After the pipeline is repaired, then the hydrotest would be conducted again. After the pressure test is satisfactorily completed, the pipeline is dewatered and dried. Dewatering and drying the pipeline consists of discharging the test water in a manner that meets applicable regulations and permits. The test water is pushed out of the pipeline with compressed air and a series of pipeline drying pigs until the dew point in the pipeline meets specification. After dewatering and drying the pipeline, an inline inspection tool will be sent through the pipeline to take measurements and examine the pipeline for potential anomalies. Once the hydrotest is complete and results of the measurements are analyzed by engineers, the pipeline can return to service. This process is anticipated to take an additional 70 days to complete.

In order to lower the pipeline while maintaining gradual slopes, the linear footage of pipeline that must be jetted is approximately 300 feet longer than the area of pipeline having less than 3 feet of cover (Example: An area of the pipeline measuring 500 linear feet has 3 feet or less of cover. This area of pipeline must be jetted for 800 feet.). This added length is required to maintain gradual slopes and to reduce the possibility of over-stressing the structure of the pipeline. Because of the inherent risk of pipeline stress during this operation, the pipeline must be shut down and brought to 0 pounds per square inch (psi) during this process.

Because this operation would require jetting approximately 5 feet into the bay bottom, significant side slope instability can be expected with disturbance occurring approximately 15 feet out on either side of the 6-foot-wide trench. Therefore, this operation would permanently impact 21.1 acres of the bay bottom. Silt curtains would be placed on either side of the jetting barge (40 feet wide) in order to reduce the amount of suspended sediment from leaving the area. However, the jetting impact area of 21.1 acres would create a significant amount of suspended sediment (~507,000 cubic yards) in the water column, which could adversely impact adjacent oyster populations. Because of the mobile nature of the jetting sled apparatus, the silt curtains are not expected to be effective at reducing sediment transport. This large disturbance area could have negative effects on the existing wildlife habitat and ecological system. Jetting would permanently impact 10.3 acres of public oyster reef. Combined permanent and environmental

impacts within the silt curtain area due to jetting and sedimentation would be unfavorable for this alternative compared to Alternative 4. (Table 2)

FGT is a Federal Energy Regulatory Commission (FERC) jurisdictional open access pipeline and provides natural gas transportation services as its core business. The FGT 24-inch Mainline - Galveston Bay crossing transports up to 500 million cubic feet of firm natural gas service on a daily basis (as defined within the FGT Tariff). Interrupting firm gas services on an extended basis to both receipts and deliveries to FGT's shippers in this area would have a major impact to FGT's long term Transportation Service Agreements across the Gulf Coast from South Texas to South Florida.

The combination of environmental impacts to oysters and other benthic organisms from jetting the pipeline lower and the major impact to customers and suppliers from the extended pipeline outage makes jetting the pipeline lower an impractical alternative.

3. Alternative 3 – Lowering the Pipeline (Horizontal Directional Drilling)

Horizontal directional drilling (HDD) is a trenchless method of pipe installation where a pipeline is installed in a directionally drilled and reamed hole using surface-mounted drilling equipment. The drilling process begins by directionally drilling a small diameter pilot hole between the entry and exit points. Upon completion of the pilot hole, the hole is enlarged to a diameter sufficient to accept the new pipeline using various diameter reaming tools. Once the hole is prepared, the new pipeline is pulled in from the exit side to the entry side.

Due to the length limitations associated with HDD installations, replacement of the pipeline across Galveston Bay would require nine separate shallow water marine-based HDD installations and one shore approach (land to water) HDD. Construction would begin with mobilizing barges, equipment, and personnel to the site. Using a dredge barge, a "false ditch" would be excavated using a dragline dredge to create a 10-foot-wide trench alongside the existing pipeline for much of the width of Galveston Bay (approximately 52,000 linear feet [LF]). The intent of the ditch is to protect the prefabricated pipe sections from boat traffic prior to installation. A lay barge would then lay a total of approximately 58,200 LF of new 24-inch pipeline in individual sections (one for each HDD) in this trench to be used during the installation of the HDDs and tie-ins between HDDs. Since the trench would traverse most of the bay, this operation would impact a significant area of oyster reefs both temporarily and permanently.

A second option of storing the pipe in preparation for installation would be to fabricate and store the new pipe sections in a dredged ditch that is outside of mapped oyster reef areas. This option presents two main obstacles: The first obstacle is that because the HDD would require new pipe for the entire width of the bay and because of the vast and sporadic distribution of oyster reef (Figure 1), the pipe trench would impact oysters essentially anywhere it is proposed, which would be relatively close to the project site. The second obstacle is that while a remote trench in less densely populated oyster reefs may reduce some impact to oysters, significant equipment would be required to move long sections of pipe to the HDD locations. This would prevent boat traffic from traversing the bay during installation in this area and increases the risk for collisions during transportation of the long strings of pipe.

A third option would be to fabricate the new pipe on land and to tow the string through the bay to the HDD locations. This method would face the same equipment and safety issues as the previously discussed method.

A fourth option would be to fabricate the new pipe sections approximately 3,000 feet in length to reduce the length of trenches needed. Ideally, these trenches would be dredged beyond the HDD exit point and in alignment with the HDD alignment but could be dredged some distance away outside of oyster reef areas. Because the HDD installations are in excess of 3,000 feet in length, the HDD contractor will need to temporarily halt pipe installation operations to make a tie-in weld between individual pipe sections. This is somewhat common for land-based HDD installations when adequate workspace to fabricate the pipeline in one continuous section is not available, however; it complicates and extends the duration of the installation process. For marine based installations, this is an uncommon practice that substantially complicates the process and needlessly increases the risk of a failed installation. Depending on where the trenches are dredged, this option could also pose some of the same risks as those outlined in option 2 above.

The HDD would then continue by having the drilling equipment set up at each of the 9 entry/exit workspaces. Each workspace would be approximately 300 feet wide by 500 feet long. In total, approximately 28 acres of workspace would be required for the HDD option. Permanent impacts and impact within areas of the silt curtains are detailed in Table 2. Due to the depth of Galveston Bay in this area and the size of equipment required for HDD, dredging would be required for access routes to and at some of the installation locations.

During the course of HDD evaluation and the development of this analysis, a number of potential risks associated with construction of the HDDs were considered, including but not limited to the following: mobilizing and employing HDD equipment within marine workspaces; protecting commercial mariners and public boaters within and adjacent to the proposed workspaces; protecting existing utilities and infrastructure; installing large and small diameter casing; conducting marine-based HDD operations; and/or experiencing hydraulic fracture, inadvertent drilling fluid returns, drilled hole instability, and/or damage to the product pipe during pullback. Hydraulic fracture and inadvertent drilling fluid returns are events in which the downhole drilling fluid pressure exceeds the shear strength of the earth above a drill path. This allows drilling fluid to flow through a path of least resistance into the bay rather than through the bore hole, where it can be captured at the drilling rig. These events have the potential to release large volumes of drilling fluid into the bay in locations along the drill path. Once this occurs, it can be difficult to prevent fluid from continuing to release through the hydraulic fracture point during continuation of the HDD.

During the HDD process, a 42-inch casing can be installed in an effort to mitigate hole instabilities, drilling fluid loss, and drilling fluid release. Without large-diameter casing, the drilling fluid returns that are typically collected and recycled for reuse during land-based installations would be released to the bay, increasing turbidity. These casings are typically installed at the same angle as the HDD entry and exit angles at the bay bottom surface. Casing would be installed with a pneumatic hammer system, which is a lengthy process. Once the HDD process is completed, the casing is removed using a pneumatic hammer system as well. This process can cause significant noise pollution and impacts to nearby aquatic resources due to the vibrations caused during installation and removal. Occasionally, the friction of the soils around the casing is too great, and the casing cannot be extracted with the hammer. If this occurs, the casing would then have to be cut and removed at the bay bottom.

The HDD operation is estimated to take approximately 1 year. Similar to the open cut trenching option, HDD would require the shutdown of pipeline operations for tying into the existing pipeline. The time of

shutdown would be shorter than the lowering via the jetting option, but interruption of service would still occur for approximately 20 days.

If HDD is used to install new, deeper piping, the old pipe would need to be removed per TGLO guidelines so it would no longer be a hazard to navigation. The old pipeline would be removed by excavating around the pipeline and cutting and removing the pipeline. Removal of the old pipeline via excavation would have similar disturbance areas as Alternative 2 but would disturb the bay bottom across the entire approximate 11-mile pipeline reach in Galveston Bay. Therefore, the total cost of an HDD implemented to satisfy the goal of this project would include far more cost and environmental impact than that of a similar new install of a new pipeline via HDD.

The cost of the HDD option is roughly twenty times that of the next most expensive option, which is the lowering via the jetting option. Due to the length of shallow-covered pipeline in this reach, complexity of operations, and removal of old pipe, HDD would be unreasonable in terms of time required for repair and the total cost. The HDD option, due to removal of the old pipe and creation of the false ditch, would also be most unfavorable in terms of environmental impact. Therefore, HDD is not practical for FGT and is not the preferred alternative.

Off-site 1 (South):

FGT analyzed potential offsite solutions, both north and south of the current pipeline alignment, to remedy the pipeline cover issue. The only conceivable offsite alternative that would satisfy the purpose of this project would be to HDD a new pipeline along a different route. Two individual routes were researched; both routes were planned to avoid concentrated areas of oyster reefs. Construction and installation of the new pipeline would be similar to the aforementioned HDD discussion. Project work areas and impacts would be larger due to the extended length of pipeline required to traverse an extended route in the bay while tying into the same points on land as the existing pipeline. However, because FGT does not possess any right-of-way (ROW) or easements in these areas, significant land acquisition would be required. Realty negotiations would have to take place with the U.S. Army Corps of Engineers Real Estate Group, Texas General Land Office, Galveston Drainage District, Chambers Drainage District, Candy Abshier Wildlife Management Area, and The Nature Conservancy, among others. This process adds substantial time and cost to the overall project.

Due to the complexity, the marine environment of this HDD installation, and the extended length due to the proposed route of the pipeline, this alternative is not practical.

Off-site 2 (North):

FGT analyzed potential routes of installing a new pipeline via HDD north of the current alignment. Areas north of the current pipeline alignment contain a dense network of oil and gas wells, gathering and transmission pipelines, and other structures. This area also contains dense areas of oyster reefs. (Figure 1) Because of these new pipeline path conflicts, this off-site alternative is not suitable to meet the needs of this project.

All of the HDD options exceed the cost limit of the FERC Blanket Certificate, which is currently $35.2 million. Therefore, FGT would be required to submit a 7(c) application for the project to FERC. The time frame for the 7(c) process for a project of this size would be approximately eighteen months. The

remediation of the shallow cover on this pipeline has already been delayed past the PHMSA deadline, and a 7(c) filing would delay it even further.

In addition, FGT analyzed potential routes of installing a new pipeline primarily along a land route north of the current alignment. Areas north of the current pipeline alignment include the cities of Bacliff, Kemah, Seabrook, Laporte, Pasadena, and Baytown (Figure 2). These cities are densely populated, and the land is heavily developed for residential, commercial, and industrial use. New and additional ROW of 100 feet and a permanent easement of 50 feet would have to be negotiated and acquired for each landowner that the new pipeline would cross. This process would involve hundreds of contracts and take several years to accomplish. Also, a new pipeline along a land route would still have to cross the Houston Ship Channel at some point and may impact other environmentally sensitive areas on land. It is not practical to install the new pipeline in existing electrical power line ROWs due to cathodic protection and corrosion prevention issues. The estimated cost of this alternative is approximately $250 million and would exceed the cost limit of the FERC Blanket Certificate, which is currently $35.2 million. Therefore, FGT would be required to submit a 7(c) application for the project to FERC. The time frame for the 7(c) process for a project of this size would be approximately eighteen months. Due to the population in these cities and development, a viable route for a new high-pressure natural gas pipeline is not practical along a land route. Because a practical alternative on land is not available, this project is water dependent.

4. Alternative 4 – Articulating Concrete Mattresses (ACMs)

An ACM system is an effective pipeline protection and erosion control technique when correctly installed. Divers and equipment aboard work barges would first be mobilized to the site. Equipment aboard the work barges would lower the mats to the bay bottom using an ACM handling frame. Divers would operate the release mechanism on the frame to set the ACM and would then use a small jetting apparatus to bury the edges of the ACMs into the bay bottom. The jetting apparatus uses water pressure to suspend the soils around and below the pipeline in order to lower the mat edges to an adequate depth below the existing bay bottom. Burying the edges of the ACMs would help to anchor the mats to the bay bottom and help to prevent oystermen and trawlers from snagging the mat system.

Mechanically trenching with an excavator is another alternative used to burying the mat edges. However, this option is not practical at this location due to the depth of the bay and low visibility of the work area. Digging with machinery in a marine environment with limited visibility in close proximity to a pipeline presents major safety concerns and is not an activity FGT would allow.

No adverse effects to water flows or impoundments are expected due to the low hydraulic profile of the 4.5-inch-thick ACMs. Additionally, the voids in the ACMs would allow suspended sediment to settle, re-establishing the native habitat function of the bay bottom. Case studies have shown that the ACMs provide a valuable habitat for aquatic resources, including oysters. Some disruption to the local habitat can be expected during construction, but construction duration is estimated to be short relative to Alternative 3, Off-site 1, and Off-site 2. Construction could also begin immediately once the Section 404 and TPWD Sand and Gravel Permits are acquired.

The ACMs would be placed on 4.2 acres of the bay bottom. The barge would need to spud alongside the pipeline during installation, which would potentially disturb oyster habitats. It is estimated that the construction barge would need to spud approximately 200 times along the pipeline to complete the project. The spuds at each location would disturb approximately 5 square feet; therefore, spudding

activities would impact approximately 0.02 acres of the bay bottom in addition to the placement of the ACMs. This impact is considered minimal overall to the project but is accounted for in the oyster mitigation plan. Total permanent impact to oyster reef for this alternative would be 2.3 acres, while temporary impacts to oysters via jetting would be 6.0 acres. This option would create substantially less sedimentation in the water column than Alternative 2. Jetting for this alternative would suspend sediment in the water column but only approximately 1% of that of Alternative 2. This option also does not require shut down of the pipeline, an action which would have major operational impacts on FGT and downstream customers that rely on natural gas for fuel, heating, etc.

ACMs have previously been authorized by the USACE – Galveston District for placement in and around Galveston Bay. In 2009, USACE and TPWD authorized (USACE Permit No. SWG-2009-00496) the installation of thirty-eight 9-inch-thick ACMs in Galveston Bay along the same FGT pipeline referenced in this application. There have been no reported adverse impacts or issues with the placement of ACMs. ACMs have been used extensively in marine environments in coastal Louisiana with no reported adverse impacts to the oyster fishery according to representatives with the Louisiana Department of Wildlife and Fisheries. PHMSA has also approved the use of ACMs as an acceptable form of an engineered alternative that meets or exceeds the required level of protection to the pipeline cover where 3 feet of soil cover cannot be maintained. Therefore, this alternative achieves the purpose of this project.

PHMSA requires FGT to remedy shallow-covered pipeline areas within 6 months of discovery. FGT has updated PHMSA on the permitting process for this project, and FGT is obligated to complete this project in a timely manner. The ACM option, although requiring an extensive permitting process, can begin construction immediately once permits are obtained and can be completed timely without disrupting pipeline operations. The ACM option also contains the smallest combined permanent and temporary impacts. Because of these factors, installation of ACMs is the preferred option.

Table 1. Alternative Comparison Matrix for Practicability

Practicability Category	Factor	Alt. 1: No Action	Alt. 2: Jetting / Open Cut Trenching	Alt. 3: HDD (On-site)	Alt. 3: HDD (Off-site North)	Alt. 3: HDD (Off-site South)	Alternative 4: ACM
Availability	Land Available for Acquisition	Yes	Yes	Yes	Unknown	Unknown	Yes
Logistics	Pipeline Shutdown Required	No	Yes	Yes	Yes	Yes	No
Logistics	Acceptable Timeline (PHMSA)	N/A	No	No	No	No	Yes
Costs	Reasonable Construction Costs (non-exorbitant)	Yes	No	No	No	No	Yes
Costs	Reasonable Land Acquisition Costs (non-exorbitant)	Yes	Yes	Yes	No	No	Yes
Practical Overall		**No**	**No**	**No**	**No**	**No**	**Yes**

Table 2. Impact Table (figures in acres)

Options	Area within Silt Curtains	Permanent Impact	Area within Silt Curtains: Public Oyster Reef	Permanent Impact: Public Oyster Reef	Area within Silt Curtains: Private Oyster Lease	Permanent Impact: Private Oyster Lease
Alternative 1: No Action	0	0	0	0	0	0
Alternative 2: Line Lowering - Jetting	23.5	21.1	11.4	10.3	1.9	1.7
Alternative 3: HDD	116.9	63	45	26	7.5	4.5
Alternative 3: HDD Offsite-South	121.8	72.2	24.5	20.9	7.5	4.5
Alternative 3: HDD Offsite-North	N/A	N/A	N/A	N/A	N/A	N/A
Alternative 4: ACMs	11.5	4.2	6.0	2.3	1.4	0.4

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Logistics	Pipeline Shutdown Required	No	Yes	Yes	Yes	Yes	No
Logistics	Acceptable Timeline (PHMSA)	N/A	No	No	No	No	Yes
Costs	Reasonable Construction Costs (non-exorbitant)	Yes	No	No	No	No	Yes
Costs	Reasonable Land Acquisition Costs (non-exorbitant)	Yes	Yes	Yes	No	No	Yes
Practical Overall		**No**	**No**	**No**	**No**	**No**	**Yes**

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SURVEY NOTES:

1. SURVEY INFORMATION SHOWN PROVIDED BY T. BAKER SMITH DRAWING: "DEPTH OF COVER SURVEY" FOR FLORIDA GAS TRANSMISSION DATED 07/31/2018 & 02/26/2019. WATER DEPTHS DETERMINED FROM SURVEY DATED 07/31/2018. THIS SURVEY INFORMATION ONLY APPLIES FOR THE FLORIDA GAS TRANSMISSION PIPELINE. ALL WELL & PIPELINE DATA ACQUIRED FROM WWW.RRC.STATE.TX.US.
2. PUBLIC OYSTER LEASE DATA TAKEN FROM: POWELL E.N., SONG J., ELLIS M., AND CHOI K. (1997). GALVESTON BAY OYSTER REEF SURVEY, TECHNICAL REPORTS, VOLUME 1. TEXAS A&M UNIVERSITY AT GALVESTON (TAMUG) PUBLICATION GBNEP 50-05. TAMUG, DEPARTMENT OF OCENOGRAPHY, GALVESTON, TEXAS.
3. ALL LOCATIONS OF UNDERGROUND UTILITIES SHOWN ARE APPROXIMATE.

TRINITY BAY

CL OF HOUSTON SHIP CHANNEL

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EXISTING PIPELINE ALIGNMENT

ALTERNATE PIPELINE ROUTE

GALVESTON BAY

0' 5000' 10000' 15000'

SCALE: 1"=5,000'

FOR PERMITTING ONLY

LEGEND:

- PUBLIC OYSTER REEF
- WELL DATA
- PIPELINES

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NO.	REVISION DESCRIPTION	DATE

DATE: 07/03/2020 DWN: KJD CHK: JMF

PROJECT No: 15693

Florida Gas Transmission Company
An Energy Transfer/Kinder Morgan Affiliate

FLORIDA GAS
24" PIPELINE
SHALLOW COVER
GALVESTON COUNTY
GALVESTON, TX

SHEET TITLE:

FIGURE 1

N:\15600S\15693 ETC FGT, TX\DRAWINGS\CAD\EXHIBITS\15693_FGT_GALVESTON TX_FIGURE 1

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ALTERNATE PIPELINE ROUTE

CL OF HOUSTON SHIP CHANNEL

3300+00
3350+00
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3950+00

TRINITY BAY

EXISTING PIPELINE ALIGNMENT

GALVESTON BAY

0' 15000' 30000' 45000'

SCALE: 1"=15,000'

LEGEND:

- PUBLIC OYSTER REEF
- WELL DATA
- PIPELINES

FOR PERMITTING ONLY

N:\15600S\15693 ETC FGT, TX\DRAWINGS\CAD\EXHIBITS\15693_FGT_GALVESTON TX_FIGURE 2

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FLORIDA GAS
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FIGURE 2