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September 28, 2015

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *Cameron LNG, LLC*, Application for Authorization Under Section 3 of the Natural Gas Act, Docket No. CP15- -000

Dear Ms. Bose:

Pursuant to Section 3(a) of the Natural Gas Act ("NGA"), as amended, 15 U.S.C. § 717b(a) (2013), and Parts 153 and 380 of the Rules and Regulations of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. Parts 153 & 380 (2015), Cameron LNG, LLC ("Cameron LNG") submits herewith an Application for Authorization Under Section 3 of the Natural Gas Act to site, construct, and operate facilities to provide additional natural gas processing, storage, and liquefaction capability at the site of the existing Cameron LNG liquefied natural gas terminal located in Cameron and Calcasieu Parishes, Louisiana ("Application").

In addition to this transmittal letter, this filing consists of the (i) the Application, (ii) the exhibits to the Application, including an environmental report at Exhibit F and an Applicant-Prepared Draft Environmental Assessment at Exhibit Z-1, (iii) a verification, and (iv) a form of notice suitable for publication in the *Federal Register*.

Cameron LNG respectfully requests that the Commission approve the application by May 2016.

Material in Exhibit F contains specific information about cultural resources, as well as proprietary and competitively sensitive commercial and engineering and design information. Therefore, portions of this submission consist of privileged materials, which are being submitted in separate volumes. In accordance with section 388.112 of the Commission's regulations, 18 C.F.R. § 388.112 (2015), Cameron LNG hereby requests privileged treatment for this material and states that these volumes contain material the Commission routinely treats as privileged and exempt from mandatory disclosure under the Freedom of Information Act. Cameron LNG has labeled this material accordingly.

In addition, portions of this submission consist of critical energy infrastructure information ("CEII"), which is being submitted in separate volumes. In accordance with section 388.112 of the Commission's regulations, Cameron LNG hereby requests that the Commission provide CEII treatment for this material and withhold it from public disclosure. Cameron LNG has labeled this material as "CRITICAL ENERGY INFRASTRUCTURE INFORMATION – DO NOT RELEASE."

Questions regarding this request for privileged and CEII treatment should be directed to the undersigned.

Please contact the undersigned with any questions regarding this submission.

Respectfully submitted,

/s/ Brett A. Snyder

Brett A. Snyder
Counsel to Cameron LNG, LLC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Cameron LNG, LLC	**)**	**Docket No. CP15-___-000**
	)	

APPLICATION OF CAMERON LNG, LLC FOR
AUTHORIZATION UNDER SECTION 3 OF THE NATURAL GAS ACT

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September 28, 2015

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cameron LNG, LLC	**)))**	**Docket No. CP15-___-000**

APPLICATION OF CAMERON LNG, LLC FOR
AUTHORIZATION UNDER SECTION 3 OF THE NATURAL GAS ACT

Pursuant to section 3(a) of the Natural Gas Act ("NGA"), as amended,[1] and Parts 153 and 380 of the Rules and Regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] Cameron LNG, LLC ("Cameron LNG") hereby submits this Application for authorization to site, construct, and operate facilities to provide additional natural gas processing, storage, and liquefaction capability ("Expansion Project") at the site of the existing Cameron LNG liquefied natural gas ("LNG") terminal located in Cameron and Calcasieu Parishes, Louisiana ("Cameron LNG Terminal"). On June 19, 2014, the Commission authorized Cameron LNG to site, construct, and operate liquefaction and export facilities having the maximum capacity of 14.95 million metric tonnes per annum (MTPA), equivalent to 772 billion cubic feet (Bcf) per year ("Liquefaction Project").[3] The Liquefaction Project is currently under construction. The Expansion Project proposed herein would increase the Cameron LNG

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1 15 U.S.C. § 717b(a) (2013).

2 18 C.F.R. Parts 153 & 380 (2015).

3 *Cameron LNG, LLC*, 147 FERC ¶ 61,230 ("Liquefaction Project Order"), *reh'g rejected*, 148 FERC ¶ 61,073, *reh'g denied*, 148 FERC ¶ 61,237 (2014), *pet. for review dismissed sub nom. Sierra Club v. FERC*, No. 14-1190, 2015 WL 1606900 (D.C. Cir. Mar. 16, 2015).

Terminal's maximum natural gas liquefaction and export capabilities by 9.97 MTPA, equivalent to 515 Bcf per year, to 24.92 MTPA.

In order to allow construction of the proposed Expansion Project to progress sequentially and uninterrupted with the construction of the previously approved Liquefaction Project, Cameron LNG respectfully requests that the Commission grant this Application no later than May 2016.

In support of its request, Cameron LNG states as follows:

I. INFORMATION REGARDING THE APPLICANT

The exact legal name of the applicant is Cameron LNG, LLC. Cameron LNG is a limited liability company organized under the laws of Delaware. Cameron LNG is an indirect subsidiary of Sempra Energy, Engie/GDF SUEZ S.A., Mitsui & Co., Ltd., Mitsubishi Corporation, and Nippon Yusen Kabushiki Kaisha.[4] Cameron LNG's executive offices are located at 2925 Briarpark Drive, Suite 1000, Houston, Texas 77042. Cameron LNG is currently engaged in the business of owning and operating the Cameron LNG Terminal in Cameron and Calcasieu Parishes, Louisiana.

II. COMMUNICATIONS

The persons to whom correspondence and communications concerning this Application should be directed and upon whom service is to be made are as follows:

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4 *See* Exhibit B.

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III. BACKGROUND

On September 11, 2003, the Commission issued to Cameron LNG (formerly Hackberry LNG, L.L.C.) authorization under section 3 of the NGA to construct and operate a new LNG import terminal in Cameron Parish, Louisiana, with facilities to receive, store, and re-gasify LNG, and send out natural gas for delivery to domestic markets at up to 1.5 Bcf per day (Bcf/d).[5]

On July 18, 2006, in Docket No. CP06-422-000, Cameron LNG filed an application under section 3 of the NGA to, among other things, expand the storage capacity of the LNG import terminal and increase the send-out rate of the Cameron LNG Terminal to 1.8 Bcf/d on an interim basis and, ultimately, to 2.65 Bcf/d. The Commission granted the requested authorizations on January 18, 2007.[6]

Cameron LNG completed construction and testing of the Cameron LNG Terminal and placed it in service in July 2009. The Cameron LNG Terminal has been providing import terminal services since that time.

On September 3, 2010, Cameron LNG filed an application under section 3 of the NGA for authorization to operate its import terminal for the additional purpose of exporting on behalf of its customers LNG that had previously been imported into the United States. The Commission granted the requested authorization on January 20, 2011.[7]

On December 7, 2012, Cameron LNG filed an application under section 3 of the NGA to expand the capabilities of the Cameron LNG Terminal to enable the export of domestically produced natural gas. The Commission granted the requested authorization on June 19, 2014,

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5 *Cameron LNG, LLC*, 104 FERC ¶ 61,269 (2003).

6 *Cameron LNG, LLC*, 118 FERC ¶ 61,019 (2007), *vacated in part*, 140 FERC ¶ 61,010 (2012).

7 *Cameron LNG, LLC*, 134 FERC ¶ 61,049 (2011).

permitting Cameron LNG to site, construct, and operate the Liquefaction Project.[8] These facilities included a fourth LNG storage tank and three liquefaction trains (Trains 1, 2, and 3), including the associated natural gas pre-treatment equipment, to produce up to 14.95 MTPA (772 Bcf per year) of LNG for export. The Liquefaction Project is currently under construction.

On February 23, 2015, Cameron LNG filed a request pursuant to section 157.21 of the Commission's rules[9] to commence the Commission's National Environmental Policy Act ("NEPA")[10] pre-filing process for the Expansion Project. These facilities include a fifth LNG storage tank and two liquefaction trains (Trains 4 and 5), including the associated natural gas pre-treatment equipment, to produce up to 9.97 MTPA (515 Bcf per year) of LNG for export. On March 2, 2015, the Director of the Office of Energy Projects issued a letter order in Docket No. PF15-13-000 granting Cameron LNG's request.[11] In the pre-filing process, Cameron LNG has engaged agency stakeholders to evaluate the Expansion Project. Additionally, on May 14, 2015, Cameron LNG conducted two open house meetings is Sulphur, Louisiana, for the Expansion Project. Cameron LNG has also filed drafts of the environmental resource reports required under section 380.12 of the Commission rules[12] for review and comment. Subsequently, on June 18, 2015, the Commission issued a notice announcing the commencement of the scoping process used to gather input on the Expansion Project from the public and

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8 *Cameron LNG, LLC*, 147 FERC ¶ 61,230, *reh'g rejected*, 148 FERC ¶ 61,073, *reh'g denied*, 148 FERC ¶ 61,237 (2014), *pet. for review dismissed sub nom. Sierra Club v. FERC*, No. 14-1190, 2015 WL 1606900 (D.C. Cir. Mar. 16, 2015).

9 18 C.F.R. § 157.21 (2015).

10 42 U.S.C. § 4321 (2013).

11 Letter Order, *Cameron LNG, LLC*, Docket No. PF15-13-000 (Mar. 2, 2015).

12 18 C.F.R. § 380.12 (2015).

interested agencies.[13] The Commission also explained that it will prepare an environmental assessment under NEPA that will review the environmental impacts of the Expansion Project.

As a result of its participation in the pre-filing process, Cameron LNG has been able to better tailor this Application to address stakeholder comments. Cameron LNG appreciates the input of the Commission Staff and other stakeholders in the pre-filing process.

IV. EXECUTIVE SUMMARY

With the Expansion Project, Cameron LNG proposes to increase its natural gas processing and liquefaction capability at the Cameron LNG Terminal by adding two additional liquefaction trains (Trains 4 and 5), one additional LNG storage tank (Tank 5), and appurtenant facilities. The Expansion Project will increase the Cameron LNG Terminal's maximum capabilities for liquefying domestic natural gas for export by 9.97 MTPA from the currently authorized capacity of 14.95 MTPA to 24.92 MTPA.

As discussed in greater detail below, the proposed Expansion Project will enable Cameron LNG to meet the demonstrated market demand for liquefaction and export of domestic natural gas. Additionally, the Expansion Project will offer other public benefits, all of which are consistent with the public interest, including creating positive impacts on the national, regional, and local economies, due in part to a sustained construction workforce, an increase in overall economic activity, and higher tax revenues. The Expansion Project will also have little or no adverse local environmental impacts.

V. DETAILED PROJECT DESCRIPTION

The Cameron LNG Terminal is located in Cameron and Calcasieu Parishes, Louisiana, approximately 2.25 miles north of the City of Hackberry, Louisiana, on the west side of the

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[13] Notice of Intent to Prepare an Environmental Assessment for the Planned Cameron LNG Expansion Project, and Request for Comments on Environmental Issues, *Cameron LNG, LLC,* Docket No. PF15-13-000 (June 18, 2015).

Calcasieu Ship Channel. The Expansion Project facilities will be located on land within the previously FERC-reviewed site of the existing Cameron LNG Terminal.

With this Application, Cameron LNG proposes to construct and operate the following facilities: two liquefaction trains (Trains 4 and 5), each with a maximum production capability of 4.985 MTPA, and each with its own feed gas pre-treatment facilities; a fifth 160,000-m^3 full containment LNG storage tank (Tank 5); a condensate product storage tank; and associated utilities and infrastructure related to the Expansion Project. The Expansion Project will utilize the same liquefaction train design and the same LNG tank design as those the Commission recently approved in Docket No. CP13-25-000. Therefore, nearly all of the initial engineering design is already complete.

Cameron LNG anticipates that construction for the Expansion Project will begin in June 2016, resulting in the Expansion Project being completed and in-service by the end of 2019. Natural gas will be delivered to the Cameron LNG Terminal via the existing Cameron Interstate Pipeline, LLC ("Cameron Interstate Pipeline"), which connects the Cameron LNG Terminal with numerous existing interstate pipeline systems, or via the Cameron Access Project, an expansion to the existing Columbia Gulf Transmission ("CGT") pipeline system that will provide for a new interconnect with the Cameron LNG Terminal,[14] or via other pipelines that might interconnect with the Cameron LNG Terminal. At the Cameron LNG Terminal, natural gas will be cooled to a liquid state and stored in full-containment LNG storage tanks. The Expansion Project will increase the Cameron LNG Terminal's LNG production capacity from 14.95 MTPA from Trains 1 to 3 to 24.92 MTPA from Trains 1 to 5.

A detailed description of these facilities is set forth in the resource reports found in Exhibit F.

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14 *See Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214 (2015).

A. Liquefaction Trains

The proposed Expansion Project will consist of two additional liquefaction trains (Trains 4 and 5), each composed of a feed gas treatment unit, a heavy hydrocarbon removal unit, and liquefaction unit. These trains will be identical to Trains 1–3 authorized by the Commission as part of the Liquefaction Project. The feed gas treatment and heavy hydrocarbon removal units will remove feed gas impurities and condensate product from the natural gas received from the pipeline, and the liquefaction unit will liquefy the natural gas.

Each feed gas treatment unit will include equipment to remove carbon dioxide, hydrogen sulfide, water, and mercury.

Each heavy hydrocarbon removal unit will contain heat exchanger and turbo expander equipment to condense natural gas liquids from the feed gas stream and will then use a de-ethanizer and de-butanizer to produce a stabilized condensate product. This condensate product will be stored and transported offsite for sale. Lighter natural gas liquids from the de-ethanizer and de-butanizer overhead will be used as fuel or re-injected back into the natural gas stream prior to liquefaction, respectively. No intermediate storage is required for these streams.

Finally, each liquefaction unit will contain equipment to cool the feed gas progressively with propane and mixed refrigerants until the natural gas is condensed to a liquid state.

The Expansion Project will be constructed and placed into service by the end of 2019.

B. LNG Storage Tank

The Commission has authorized four full-containment LNG storage tanks for the Cameron LNG Terminal, three of which have already been constructed pursuant to prior FERC orders.[15] Construction of the fourth LNG storage tank will be completed under existing Commission authorization as part of the Liquefaction Project. As part of the Expansion Project,

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15 *See* Part III, *supra*.

Cameron LNG proposes to construct a fifth full-containment LNG storage tank designed to store 160,000 m^3 (approximately 1,006,000 barrels) of LNG at a temperature of -260°F and a normal pressure of 1 to 4 psig.

This fifth LNG storage tank will utilize the same design as the LNG storage tank recently authorized by the Commission as part of the Liquefaction Project and the design utilized for the three existing LNG storage tanks at the Cameron LNG Terminal. The fifth LNG storage tank will be constructed so that both a primary container and a secondary container are capable of independently containing the stored LNG. The primary container will hold the LNG under normal operating conditions. The secondary container is capable of containing the LNG and controlling vapor resulting from product release from the inner container.

C. Refrigerant and Condensate Product Storage and Truck Loading/Unloading

No new refrigerant storage will be required for the Expansion Project. The proposed liquefaction trains will utilize the refrigerant storage previously authorized by the Commission that will be common to all of the liquefaction trains.

Cameron LNG intends to store stabilized condensate product from the heavy hydrocarbon units prior to it being delivered off the Cameron LNG terminal site by truck tanker or pipeline. Cameron LNG proposes to construct one new stabilized condensate product tank to supplement the two condensate tanks previously authorized by the Commission. This new tank would be identical in size and design to those previously authorized, with a capacity of 1,070,000 gallons and a working capacity of 993,600 gallons.

The Commission previously authorized the Liquefaction Project's truck loading and unloading facility for receipt of refrigerant brought to the site and to load condensate product for delivery offsite. This truck loading and unloading facility will also serve the Expansion Project, and other than the addition of a second loading arm for the stabilized condensate product, no modifications to these facilities will be made.

D. Other Infrastructure

Additional proposed infrastructure for the Expansion Project includes: two new boil-off gas compressors to be used during the liquefaction process, which would be located in the existing regasification plant; three 2.5 MW diesel engine backup generators and a diesel storage tank; a new demineralized water system; and other minor modifications to the existing terminal facilities.

VI. SUPPLY SOURCE FOR THE EXPANSION PROJECT

As a result of the Cameron LNG Terminal's access through its existing interconnection with Cameron Interstate Pipeline to five major interstate pipelines (Florida Gas Transmission Company, Transcontinental Gas Pipe Line Company, LLC, Texas Eastern Transmission Corporation, Tennessee Gas Pipeline Company, and Trunkline Gas Company), and indirect access to multiple interstate and intrastate natural gas pipeline systems, the Cameron LNG Terminal's liquefaction customers will have a variety of stable and economical natural gas supply options from which to choose. Additionally, CGT's Cameron Access Project[16] will provide for a new, additional delivery route for shippers to transport natural gas to the west end of CGT's system and will provide for a new interconnect with the Cameron LNG Terminal.

The Cameron LNG Terminal's liquefaction customers will not have to limit themselves to particular geographical supply areas when contracting for gas supply. The Cameron LNG Terminal is in close proximity to the Henry Hub, one of the most liquid and transparent natural gas market centers in the world and the pricing point for the natural gas futures contract. In

[16] *See Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214 (2015).

addition to the Henry Hub, there are 11 other market centers in Louisiana and Texas.[17] These market centers provide ample liquidity to accommodate a wide range of gas supply arrangements for each of the Cameron LNG Terminal's liquefaction customers.

VII. PUBLIC INTEREST ANALYSIS

Section 3(a) of the NGA provides that "[t]he Commission shall issue [an] order upon application, unless … it finds that the proposed exportation … will not be consistent with the public interest."[18] Section 153.7(c)(1) of the Commission's regulations, which implements section 3(a) of the NGA, requires a showing that the proposal is "not inconsistent with the public interest."[19] In making its public interest determination, the Commission has explained that its review is limited to "the proposals before the Commission, that is, the impacts associated with Cameron LNG's export facilities used to facilitate the exports."[20] The Commission has stated that it will not review the public interest effects of exporting the commodity of natural gas, but rather will only review economic and environmental impacts and safety considerations around the construction and operation of the proposed facilities.[21]

For the reasons set forth below and in the exhibits attached hereto, Cameron LNG submits that the proposed Expansion Project is not inconsistent with the public interest and complies with the requirements set forth at section 153.7(c)(1).[22]

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17 Energy Information Administration, *Natural Gas Market Centers: A 2008 Update* (Apr. 2009).

18 15 U.S.C. § 717b(a) (2013).

19 *See* 18 C.F.R. § 153.7(c)(1) (2015).

20 Liquefaction Project Order at P 26.

21 *See, e.g., id*. at PP 26–32; *Sabine Pass Liquefaction Expansion, LLC,* 151 FERC ¶ 61,012 at PP 27, 30, *reh'g denied*, 151 FERC ¶ 61,253 (2015).

22 Section 153.7(c)(1) of the Commission's regulations also requires an applicant to explain how, if applicable, the proposed project: "(i) Will improve access to supplies of natural gas, serve new market demand, enhance the reliability, security, and/or flexibility of the applicant's pipeline system, improve the dependability of international energy trade, or enhance competition within the United States for natural gas transportation or supply; (ii) Will not impair the ability of the applicant to render transportation service in the United States at reasonable rates to its existing customers; and, (iii) Will not involve any existing contract(s) between the applicant and a foreign government or person concerning the control of operations or rates for the delivery or receipt of natural gas which

A. Benefits to Local, Regional, and National Economies

The Expansion Project will have a positive impact on the local, regional, and national economies through indirect job creation, increased economic activity, and tax revenues. Under the proposed Expansion Project, additional construction would be phased in to the ongoing construction for Cameron LNG's Liquefaction Project. The design, engineering, and construction of the Liquefaction Project is expected to create approximately 2,300 on-site engineering and construction jobs on average over a 56-month period with many more off-site jobs being created to support these construction activities. Cameron LNG estimates a total economy-wide impact of 63,000 job years over the 56-month construction period with a total economic impact resulting from construction estimated to be $7.6 billion.[23] While the Expansion Project will not significantly increase the peak workforce currently envisioned for the ongoing Liquefaction Project (3,500 personnel), the construction plan for the Expansion Project will extend construction at the Cameron LNG Terminal site by approximately 18 months, or approximately 30%, thereby increasing the duration of peak and total construction jobs and increasing economic benefits proportionately.

Expenditures in the Expansion Project area are estimated to be approximately $430 million for goods and services during construction. Total wages during the entire construction period of the Expansion Project are expected to equal approximately $444 million. The

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may restrict or prevent other United States companies from extending their activities in the same general area, with copies of such contracts." 18 C.F.R. § 153.7(c)(1) (2015). With respect to section 153(c)(1)(ii), Cameron LNG and its existing customers with regasification service have previously agreed to terminate existing terminal service agreements prior to the commencement of the terminal services contemplated under agreements associated with the Liquefaction Project. The Expansion Project will not alter these arrangements, and Cameron LNG's existing customers will continue to have access to their regasification services pursuant to their existing agreements until the commercial operation of the Liquefaction Project commences. With respect to section 153.7(c)(1)(iii), Cameron LNG states that the proposed Expansion Project does not involve any existing contracts between Cameron LNG and a foreign government or person concerning the control of operations or rates for the delivery or receipt of natural gas which may restrict or prevent other U.S. companies from extending their activities in the same general area as the Liquefaction Project.

23 *See* Exh. F, Resource Report 1 at 1-4.

estimated annual economic impact resulting from the operational phase of the Expansion Project includes $16 million in annual regional expenditures on goods and services, approximately $6.9 million per year in salaries.[24]

Cameron LNG commissioned a report detailing the economic and employment impacts of the Expansion Project ("ICF Report") between the test years 2016 and 2038, provided at Exhibit Z-2. Among other things, the ICF Report examines the direct, indirect, and induced impacts on gross domestic product ("GDP"), taxes, and employment, demonstrating that additional LNG exports resulting from Expansion Project will substantially benefit national, regional, and local economies. Although some benefits result from increased exports, other benefits relate to the construction and operation of the proposed facilities.

The Expansion Project could add $12.7 billion to the U.S. economy annually ($292 billion over the forecast period), and $847.4 million annually in Louisiana ($19.5 billion cumulative).[25] The Expansion Project could also lead to additional tax revenues. Federal, state, and local governments could receive an additional $4.4 billion annually at the national level, and $131.4 million at the state-level in Louisiana, leading to cumulative government revenues of $101.2 billion throughout the U.S. and $3.0 billion within Louisiana between 2016 and 2038.[26] ICF estimates an increase in annual LNG plant operating costs of $124.93 million by 2038,[27] or an annual average of $102.1 million between 2016 and 2038.[28] These additional operating costs over the base case are due to such costs as increased port fees, insurance costs, and equipment replacements.

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[24] *See* Exh. F, Resource Report 5 at 5-3.

[25] *See* Exh. Z-2, ICF Report at 4.

[26] *See id.* at 49, 53.

[27] *See id.* at 33.

[28] *See id.* at 42.

Employment numbers are expected to increase as a result of the additional LNG export terminal capacity construction and operation, as well as the indirect and induced employment impacts. The Expansion Project is expected to drive average annual job growth between 2016 and 2038, with a total forecasted increase of nearly 35,500 jobs. Over the forecast period, the added LNG export terminals are expected to increase job-years by over 816,200 job-years, including over 35,000 annual jobs for the U.S. economy, close to 2,800 in Louisiana, or a cumulative impact through 2038 of over 800,000 U.S. and 64,000 Louisiana job-years between 2016 and 2038.[29]

B. Minimal Adverse Environmental Impacts

The environmental impacts associated with the construction and operation of the Expansion Project will be minimal. As set forth in the environmental resource reports at Exhibit F and in the applicant-prepared draft environmental assessment ("Draft EA") found at Exhibit Z-1, the Expansion Project will be constructed entirely within the Cameron LNG Terminal and authorized Liquefaction Project boundary as previously authorized by the Commission.

The Expansion Project does not include any marine infrastructure or dredging activities. No significant impacts to fish, wildlife or vegetation resources are anticipated as part of the Expansion Project.

For the same reason, the Expansion Project will also not disturb any cultural resources, as the Expansion Project does not require any new land or additional cultural surveys. All land disturbances will be in areas previously surveyed for cultural resources and for which Louisiana State Historic Preservation Officer ("SHPO") concurrence has been previously sought and

[29] *See id.* at 48, 52.

received. Accordingly, no direct impacts to cultural resources are anticipated as part of the Expansion Project.

Lastly, the Expansion Project is being constructed using similar construction methods as currently authorized and will include the same equipment as being installed for the Liquefaction Project. Cameron LNG will continue to take appropriate measures to minimize air quality effects during the construction phase of the Expansion Project, such as fugitive dust mitigation measures, and operational air emission will be subject to an air quality permit. Noise quality will be subject to Commission regulation. Ambient air quality modeling and noise studies have been completed for the Expansion Project facilities and no significant impacts to air quality or noise sensitive areas are anticipated as part of the proposed project.[30]

In sum, as fully discussed in the environmental resource reports in Exhibit F and in the Draft EA at Exhibit Z-1, the Expansion Project will have minimal adverse impacts on the environment.

C. Safety

LNG terminals are regulated by the Commission and by other agencies of the Federal, state, and local government. The Federal government also provides regulatory oversight and approval of the measures employed by LNG terminal operators to ensure adequate security. National Fire Protection Association (NFPA) 59A "Production, Storage, and Handling of Liquefied Natural Gas (LNG)" is incorporated into the safety regulations for LNG found in 49 C.F.R. Part 193, "Liquefied Natural Gas Facilities: Federal Safety Standards." These codes and regulations in conjunction with direct oversight by Federal, state, and local agencies guide the siting, design, construction and operation of land-based LNG facilities. The proposed Expansion

[30] *See* Exh. F, Resource Report 9 at 9-1.

Project facilities are being designed, and will be constructed and operated, in compliance with these codes.

The LNG industry, both in the United States and worldwide, has had an exceptionally good safety record. This safety record has been achieved by adherence to national and international LNG safety codes and regulations, facility siting and design, and operational standards and procedures to reduce both the probability and consequences of a potential release. These measures to protect the public, which are in place for the current terminal facilities, will be expanded to integrate the Expansion Project.[31] Resource Reports 11 and 13 discuss the safety measures Cameron LNG will employ.

D. Previous Determinations by the Commission and DOE/FE

Additionally, in granting Cameron LNG long-term authorization to export LNG and to site, construct, and operate the Liquefaction Project, DOE/FE and the Commission both reached a favorable public interest determination based on the extensive market analyses and other evidence submitted by Cameron LNG in the Liquefaction Project proceedings.[32] Cameron LNG submits that those findings are equally applicable to the Expansion Project.

E. Public Interest Conclusion

There is a demonstrated market demand and need for the Expansion Project. Presently, the United States has a substantial and sustainable surplus of natural gas reserves and productive capacity. Within the past several years, natural gas drilling productivity gains and technology

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31 *See* Exh. F, Resource Report 11 at 11-1 to 11-2.

32 *See* DOE/FE Order No. 3391 at 133, *Cameron LNG, LLC*, FE Docket No. 11-162-LNG (Feb. 11, 2014); DOE/FE Order No. 3391-A at 87, *Cameron LNG, LLC*, FE Docket No. 11-162-LNG (Sept. 10, 2014); Liquefaction Project Order at P 29 (2014) ("We recognize DOE's public interest findings in issuing our order. Among other things, DOE found that exports from Cameron LNG's facility would result in increased production that could be used for domestic requirements if market conditions warrant such use, which would tend to enhance U.S. domestic energy security. DOE also found several other tangible economic and public benefits that are likely to follow from the requested authorization, including increased economic activity and job creation, support for continued natural gas exploration, and increased tax revenues.").

enhancements have resulted in rapid growth in natural gas supplies in the United States. In addition, the prolific and efficient natural gas pipeline network in the United States provides market participants with numerous options for both securing and delivering natural gas. In light of these substantial resource additions and the comparatively minor increases in domestic natural gas demand, there are more than sufficient natural gas resources to accommodate both domestic demand and the natural gas exports proposed in connection with the Expansion Project. As U.S. natural gas resources and production have increased, U.S. natural gas prices have fallen significantly. Prices for natural gas in the United States market are now substantially below those of most other major gas-consuming countries. The result is that domestic gas can be liquefied and exported to foreign markets on a competitive basis. The Expansion Project can safely meet this need, while producing national, regional, local economic benefits and minimal adverse local environmental effects.[33]

In light of the foregoing, Cameron LNG submits that its Expansion Project is not inconsistent with the public interest and satisfies the requirements of section 3(a) of the NGA and section 153.7(c)(1) of the Commission rules.

VIII. NATIONAL ENVIRONMENTAL POLICY ACT

As contemplated by section 157.21(d)(9) of the Commission's rules,[34] for purposes of the Commission's review under NEPA, Cameron LNG has prepared an applicant-prepared draft environmental assessment for the Expansion Project. The Draft EA is located at Exhibit Z-1.

IX. STATEMENT UNDER SECTION 153.7(c)(2)

Pursuant to section 153.7(c)(2) of the Commission's rules,[35] Cameron LNG states that it will not provide open access terminal and transportation services under Part 284 of the

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[33] To the extent the Commission seeks additional evidence that the Expansion Project is consistent with the public interest, additional considerations are addressed in the ICF Report at Exh. Z-2.

[34] 18 C.F.R. § 157.21(d)(9) (2015).

Commission's rules,[36] but rather will provide LNG terminal services pursuant to negotiated commercial arrangements under the policy established in *Hackberry LNG Terminal, L.L.C.*, 101 FERC ¶ 61,294 (2002).

X. PRESIDENTIAL PERMIT

The Expansion Project will not involve any facilities at the border of the United States and either Canada or Mexico and will not otherwise involve any physical connection between the United States and a foreign country. Therefore, neither section 153.15(a) of the Commission's rules nor Executive Order 10485 requires Cameron LNG to apply for a Presidential Permit.[37]

XI. DEPARTMENT OF ENERGY OFFICE OF FOSSIL ENERGY

As required by section 153.6 of the Commission's rules,[38] Cameron LNG states that it filed an application with the Department of Energy, Office of Fossil Energy ("DOE/FE") on February 23, 2015 in FE Docket No. 15-36-LNG, for long-term, multi-contract authorization to export up to 515 Bcf/year (9.97 MTPA) of LNG to any nation that currently has, or develops, the capacity to import LNG and with which the United States currently has, or in the future enters into, a Free Trade Agreement ("FTA") requiring the national treatment for trade in natural gas and LNG. On July 10, 2015, DOE/FE granted Cameron LNG authorization to export domestically produced LNG to FTA Countries.[39]

On May 28, 2015, in FE Docket No. 15-90-LNG, Cameron LNG filed a corresponding application to export 515 Bcf/year (9.97 MTPA) of LNG to non-FTA countries. That application is pending.

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35 18 C.F.R. § 153.7(c)(2) (2015)

36 18 C.F.R. Part 284 (2015).

37 *See EcoElectrica, L.P.*, 75 FERC ¶ 61,157 at 61,158 n.13 (1996).

38 18 C.F.R. § 153.6 (2015).

39 *Cameron LNG, LLC,* FE Docket No. 15-36-LNG, Order No. 3680 (July 10, 2015).

XII. OTHER RELATED APPLICATIONS

As discussed above, the Commission approved the Liquefaction Project on June 19, 2014, in Docket No. CP13-25-000.[40] There are no other related or companion filings before the Commission.

XIII. REQUIRED EXHIBITS

Cameron LNG submits the following additional information as required by 18 C.F.R. § 153.8 in support of its Application. To the extent any exhibits have been omitted, Cameron LNG requests that the Commission treat the omitted material as inapplicable or otherwise unnecessary.

Exhibit A	A certificate of formation of Cameron LNG, LLC, etc. is included.
Exhibit B	An explanation of financial and corporate relationships is included.
Exhibit C	An Opinion of Counsel is included.
Exhibit D	Agreement for border interconnects. Omitted; not applicable.
Exhibit E	Evidence that an appropriate and qualified concern will properly and safely receive or deliver LNG, including a report containing detailed engineering and design information, is provided in **Exhibit F**, particularly Resource Report 13, filed as part of this Application.
Exhibit E-1	Report on earthquake hazards for LNG facilities is provided in **Exhibit F**, Resource Report 13, filed as part of this Application.
Exhibit F	An environmental report as specified in 18 C.F.R. §§ 380.3 and 380.12 (comprised of Resource Reports 1–13) is included in separate volumes.
Exhibit G	A geographic location map of the proposed Project is included.
Exhibit H	A list of Federal authorizations for the Expansion Project is included.

[40] 147 FERC ¶ 61,230 (2014).

Exhibit Z-1	Applicant-Prepared Draft Environmental Assessment
Exhibit Z-2	ICF Report

A Verification and a form of notice of this Application is also attached.

XIV. CONCLUSION

Cameron LNG respectfully requests that the Commission grant the instant Application for authorization to construct and operate the Expansion Project at the site of the current Cameron LNG Terminal for the purpose of liquefying and exporting domestic natural gas as LNG, as discussed herein. Cameron LNG respectfully requests that such authorization be granted by May 2016.

Respectfully submitted,

/s/ Brett A. Snyder

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Dated: September 28, 2015

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Cameron LNG, LLC	)	Docket No. CP15-_____-000

VERIFICATION

County of Harris)
)
State of Texas)

BEFORE ME, the undersigned authority, on this day personally appeared John O'Leary, who, having been by me first duly sworn, on oath says that he is Chief Operating Officer for Cameron LNG, LLC, and is duly authorized to make this Verification on behalf of such company, that he has read the foregoing instrument, and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

John O'Leary

SWORN TO AND SUBSCRIBED before me on the 28th day of September 2015.

Notary Public Signature

SEAL: ANN SHIRLEY WOHN
NOTARY PUBLIC
State of Texas
Comm. Exp. 11-30-2016

DB1/ 84429328.8

PROPOSED FORM OF NOTICE SUITABLE FOR PUBLICATION IN THE FEDERAL REGISTER

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cameron LNG, LLC) Docket No. CP15-___-000

NOTICE OF APPLICATION

(September ____, 2015)

Take notice that on September 28, 2015, Cameron LNG, LLC ("Cameron LNG"), filed an application pursuant to Section 3(a) of the Natural Gas Act ("NGA"), 15 U.S.C. §717b, and Part 153 of the regulations of the Federal Energy Regulatory Commission ("Commission"), 18 CFR Part 153, for authorization to site, construct, and operate facilities to provide additional natural gas processing and liquefaction capability at the site of the existing Cameron LNG liquefied natural gas terminal located in Cameron and Calcasieu Parishes, Louisiana.

Any questions regarding the application should be addressed to Blair Woodward, 2925 Briarpark Drive, Suite 1000, Houston, Texas 77042, (832) 783-5582, bwoodward@cameronlng.com.

Any person desiring to intervene or protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants partiers to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov using the Commission's "eLibrary" link and is available for review at the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the Commission's website that enables interested parties to subscribe and receive email notification when a document is added to the subscribed docket(s). For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or call toll-free at (866) 208-3676, or for TTY, contact (202) 502- 8659.

Comment Date: 5:00 pm Eastern Standard Time on [insert date]

Kimberly D. Bose
Secretary

Exhibit A

Certified Copy of the Certificate of Formation of Cameron LNG, LLC, as amended; Limited Liability Company Operating Agreement of Cameron LNG, LLC, as amended; and List of Officers of Cameron LNG, LLC.

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED ARE TRUE AND CORRECT COPIES OF ALL DOCUMENTS ON FILE OF "CAMERON LNG, LLC" AS RECEIVED AND FILED IN THIS OFFICE.

THE FOLLOWING DOCUMENTS HAVE BEEN CERTIFIED:

CERTIFICATE OF FORMATION, FILED THE TWELFTH DAY OF DECEMBER, A.D. 2001, AT 12:15 O'CLOCK P.M.

RESTATED CERTIFICATE, CHANGING ITS NAME FROM "HACKBERRY LNG TERMINAL, L.L.C." TO "CAMERON LNG, LLC", FILED THE FIRST DAY OF MAY, A.D. 2003, AT 4:26 O'CLOCK P.M.

CERTIFICATE OF CHANGE OF REGISTERED AGENT, FILED THE TWELFTH DAY OF NOVEMBER, A.D. 2014, AT 10:28 O'CLOCK A.M.

AND I DO HEREBY FURTHER CERTIFY THAT THE AFORESAID CERTIFICATES ARE THE ONLY CERTIFICATES ON RECORD OF THE AFORESAID LIMITED LIABILITY COMPANY, "CAMERON LNG, LLC".

SECRETARY OF STATE · 1776 · DELAWARE · 1970

Jeffrey W. Bullock, Secretary of State

3467637 8100H

AUTHENTICATION: 2604359

151115524

DATE: 07-30-15

You may verify this certificate online at corp.delaware.gov/authver.shtml

STATE OF DELAWARE
SECRETARY OF STATE
DIVISION OF CORPORATIONS
FILED 12:15 PM 12/12/2001
010635952 - 3467637

CERTIFICATE OF FORMATION

OF

HACKBERRY LNG TERMINAL, L.L.C.

1. The name of the limited liability company is Hackberry LNG Terminal, L.L.C.

2. The address of its registered office in the State of Delaware is Corporation Trust Center, 1209 Orange Street, in the City of Wilmington, County of New Castle. The name of its registered agent at such address is The Corporation Trust Company.

IN WITNESS WHEREOF, the undersigned has executed this Certificate of Formation of Hackberry LNG Terminal, L.L.C., this 12th day of December, 2001.

HACKBERRY LNG TERMINAL, L.L.C.

By: /s/: Michelle L. Raszka
Michelle L. Raszka
Organizer

C:\TEMP\CertForm-HackberryLNGTrmlLLC.doc

AMENDED AND RESTATED CERTIFICATE OF FORMATION

OF

HACKBERRY LNG TERMINAL, L.L.C.

The following Amended and Restated Certificate of Formation of Hackberry LNG Terminal, L.L.C. hereby amends and restates the provisions of the Certificate of Formation originally filed with the Secretary of State of the State of Delaware on December 12, 2001 and supersedes the original Certificate of Formation and all prior amendments and restatements thereto in their entirety:

1. The name of the limited liability company is: **CAMERON LNG, LLC**.

2. The address of its registered office in the State of Delaware is National Registered Agents, Inc., 9 East Loockerman Street, Suite 1B, City of Dover, County of Kent 19901. The name of its registered agent at such address is National Registered Agents, Inc.

IN WITNESS WHEREOF, the undersigned has executed this Amended and Restated Certificate of Formation of Hackberry LNG Terminal, L.L.C. this 1st day of May, 2003.

Randall L. Clark

Randall L. Clark, Authorized Person

124907

State of Delaware
Secretary of State
Division of Corporations
Delivered 04:26 PM 05/01/2003
FILED 04:26 PM 05/01/2003
SRV 030283887 – 3467637 FILE

State of Delaware
Secretary of State
Division of Corporations
Delivered 11:11 AM 11/12/2014
FILED 10:28 AM 11/12/2014
SRV 141397617 - 3467637 FILE

STATE OF DELAWARE
CERTIFICATE OF AMENDMENT CHANGING ONLY THE REGISTERED OFFICE OR REGISTERED AGENT OF A LIMITED LIABILITY COMPANY

The limited liability company organized and existing under the Limited Liability Company Act of the State of Delaware, hereby certifies as follows:

1. The name of the limited liability company is CAMERON LNG, LLC.

2. The Registered Office of the limited liability company in the State of Delaware is changed to 2711 Centerville Road, Suite 400 (street), in the City of Wilmington, Zip Code 19808. The name of the Registered Agent at such address upon whom process against this limited liability company may be served is Corporation Service Company.

By: /s/ Dona Priebe
Authorized Person

Name: Dona Priebe, Authorized Person
Print or Type

Execution Copy

THIRD AMENDED AND RESTATED

LIMITED LIABILITY COMPANY OPERATING AGREEMENT

OF

CAMERON LNG, LLC

A Delaware Limited Liability Company

Dated as of

October 1, 2014

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<u>THIRD AMENDED AND RESTATED</u>
<u>LIMITED LIABILITY COMPANY OPERATING AGREEMENT</u>
<u>OF</u>
<u>CAMERON LNG, LLC</u>

A Delaware Limited Liability Company

This Third Amended and Restated Limited Liability Company Operating Agreement ("**Agreement**") of CAMERON LNG, LLC, a Delaware limited liability company (the "**Company**"), executed as of October 1, 2014, is entered into by CAMERON LNG HOLDINGS, LLC, a Delaware limited liability company (the "**Member**"), as the sole member of the Company.

RECITALS

WHEREAS, pursuant to that certain Existing Facilities Contribution Agreement, dated as of May 16, 2013, between SEMPRA LNG HOLDINGS II, LLC and the Member, one hundred percent (100%) of the issued and outstanding membership interests of the Company has been contributed by SEMPRA LNG HOLDINGS II, LLC to the Member;

WHEREAS, the Member desires to amend and restate the Second Amended and Restated Limited Liability Company Operating Agreement of the Company, dated as of May 13, 2013 (the "**Prior Agreement**"), and to supersede any and all other limited liability company agreements (or other operating agreements) of the Company as provided in this Agreement;

WHEREAS, the Company has no current intention of admitting additional members; and

WHEREAS, if additional members are admitted, the Company and the Member will amend or replace this Agreement, as may be necessary or appropriate, to address any issues raised by joint or multiple ownership of the Company.

NOW, THEREFORE, in consideration of the foregoing, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the undersigned Member hereby agrees as follows:

ARTICLE 1

ORGANIZATION

Section 1.01 Formation.

The Company was formed as a Delaware limited liability company on December 12, 2001, by the filing of the certificate of formation of the Company (as amended, the "**Delaware Certificate**") with the Delaware Secretary of State.

Section 1.02 Name.

The name of the Company is Cameron LNG, LLC, and all Company business must be conducted in that name or such other names that comply with applicable law as the Member may select.

Section 1.03 Registered Agent; Registered Office; Other Offices.

The registered office of the Company required by the Delaware Limited Liability Company Act (the "**Act**") to be maintained in the State of Delaware shall be the office of the registered agent named in the Delaware Certificate, or such other office (which need not be a place of business of the Company) as the Member may designate in the manner provided by applicable law. The registered agent of the Company in the State of Delaware shall be the registered agent named in the Delaware Certificate, or such other person or persons as the Member may designate in the manner provided by applicable law. The principal office of the Company in the United States shall be at such place as the Member may designate, which need not be in the State of Delaware, and the Company shall maintain records there or such other place as the Member shall designate, and shall keep the street address of such principal office at the registered office of the Company in the State of Delaware. The Company may have such other offices as the Member may designate.

Section 1.04 Purpose.

The purpose of the Company shall be to engage in any lawful business, act or activity permitted by the Act. The Company shall possess and may exercise all of the powers and privileges granted by the Act, by any other applicable law or by this Agreement (if not prohibited by the Act), together with any powers incidental thereto, so far as such powers and privileges are necessary or convenient to the conduct, promotion or attainment of the business purposes or activities of the Company.

Section 1.05 Foreign Qualification.

Prior to the Company conducting business in any jurisdiction other than Delaware, the Company shall comply, to the extent procedures are available and those matters are reasonably within the control of the Company, with all requirements necessary to qualify the Company as a foreign limited liability company in such jurisdiction.

Section 1.06 Term.

The term of the Company (the "**Term**") commenced on the date of the filing of the Delaware Certificate with the Delaware Secretary of State, and shall continue until the date on which the Company is terminated pursuant to the provisions of this Agreement or as otherwise required by the Act.

Section 1.07 Organizational Matters.

The Member shall execute all such certificates and other documents, make such filings and recordings, and perform such other acts conforming hereto, from time to time as shall be required to comply with the Act and any other applicable law.

Section 1.08 Applicability of Article 8 of UCC; Membership Interest Certificates.

(a) Each membership interest in the Company shall constitute a "*security*" within the meaning of, and governed by, Article 8 of the Uniform Commercial Code of the State of Delaware and of any other applicable jurisdiction as in effect from time to time (as applicable in each such jurisdiction, the "**UCC**"). Notwithstanding any provision of this Agreement to the contrary, to the extent that any provision of this Agreement is inconsistent with any non-waivable provision of Article 8 of the UCC, such provision of Article 8 of the UCC shall control.

(b) Membership interests in the Company shall be evidenced by certificates in the form of Exhibit A attached hereto (the "**Membership Interest Certificates**"). Each Membership Interest Certificate shall indicate the membership interest evidenced by such Membership Interest Certificate and shall be signed by the Member on behalf of the Company. The membership interests in the Company shall (and hereby do) provide that they are securities governed by Article 8 of the UCC as in effect in each applicable jurisdiction (and shall be treated as such for all purposes, including, without limitation, perfection of a security interest therein under Article 9 of the UCC as in effect in any jurisdiction). If there shall be delivered to the Company evidence (satisfactory to the Company) of the ownership of, and the destruction, loss or theft of, any Membership Interest Certificate, together with such security or indemnity as may be reasonably required by the Company to hold the Company harmless against loss, cost, damage or expense resulting to the Company therefrom, the Company shall issue, in lieu of such destroyed, lost or stolen Membership Interest Certificate, one (1) or more new Membership Interest Certificates evidencing (in the aggregate) the same Membership Interests in the Company as were evidenced by such destroyed, lost or stolen Membership Interest Certificate.

Section 1.09 Pledgee's Rights.

Notwithstanding anything contained herein to the contrary, the Member shall be permitted to pledge or hypothecate any or all of its membership interests, including all Membership Interest Certificates, economic rights, control rights and status rights as a Member, to any lender to the Company or an affiliate of the Company or any agent acting on such lender's behalf, and any transfer of such membership interests pursuant to any such lender's (or agent's) exercise of remedies in connection with any such pledge or hypothecation shall be permitted under this Agreement with no further action or approval required hereunder. Notwithstanding anything contained herein to the contrary, and without complying with any other procedures set forth in this Agreement, upon the exercise of such lender's right to acquire the Company's membership interests in connection with enforcement of the applicable pledge or hypothecation in accordance with the Common Security and Account Agreement dated as of August 6, 2014 (as amended, amended and restated, restated, supplemented or otherwise modified from time to time), among the Company, the senior creditor group representatives listed on schedule C thereto, Société Générale, as intercreditor agent, HSBC Bank USA, National Association, as security trustee, and HSBC Bank USA, National Association, as account bank, (a) the lender (or agent) or transferee of such lender (or agent), as the case may be, shall become a Member under this Agreement and shall succeed to all of the rights and powers, including the right to participate in the management of the business and affairs of the Company, and shall be bound by all of the obligations, of a Member under this Agreement without taking any further action on the part of such lender (or agent) or transferee, as the case may be, and (b) following such exercise of remedies, the pledging Member shall cease to be a Member and shall have no further rights or powers under this Agreement. The execution and delivery of this Agreement by the Member shall constitute any necessary approval of such Member under the Act to the foregoing provisions of this Section 1.09. This Section 1.09 may not be amended or modified so long as any of the membership interests is subject to a pledge or hypothecation without the pledgee's (or the Transferee of such pledgee's) prior written consent. Each recipient of a pledge or hypothecation of the membership interests shall be a third party beneficiary of the provisions of this Section 1.09.

ARTICLE 2

TITLE TO THE PROPERTY OF THE COMPANY

Section 2.01 Title.

Title to any and all property, whether real, personal or mixed, that is owned by or leased to the Company shall be held in the name of the Company or in the name of any nominee that the Company designates.

ARTICLE 3

MANAGEMENT

Section 3.01 Management of the Company.

Except as otherwise required by applicable law, the business and affairs of the Company shall be managed by or under the direction of the Member in accordance with this Agreement.

Section 3.02 Authority of Member.

The Member shall have the full and complete discretion to manage, and the authority to take actions on behalf of and make decisions affecting the business affairs of, the Company to the maximum extent permitted by the Act, subject to any limitations or requirements expressly set forth in this Agreement. The Member is an agent of the Company's business and, except as otherwise expressly provided in this Agreement, the Member may bind the Company in accordance with the authority set forth in this Agreement.

Section 3.03 Liability for Debts of the Company.

The Company shall be responsible for all expenses, costs and liabilities arising from the management, organization or operation of the Company in accordance with this Agreement. The

Member shall not be personally liable for any debts or losses of the Company, except to the extent expressly required by the Act.

Section 3.04 Outside Interests.

The Member may engage, invest and participate in, and otherwise enter into, other business ventures of any kind, nature and description, individually and with others, irrespective of whether any such business venture competes with the business of the Company, and the Company shall not have any right in or to any such activities or the income or profits derived therefrom.

Section 3.05 Officers and Senior Managers.

The Member may elect officers and senior managers to supervise operations of the Company on a day to day basis. The Member shall determine the powers and authority of any such officers and senior managers and any other terms or conditions regarding the positions held by them. All officers and senior managers shall be subject to removal by the Member at any time, with or without cause. Any officer or senior manager of the Company may resign at any time by giving written notice to the Member. The resignation of an officer or senior manager shall take effect upon receipt of notice thereof or at such later time as shall be specified in such notice and, unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective. In the event of a resignation, the Member may nominate and elect such officer's or senior manager's successor.

ARTICLE 4

CAPITAL CONTRIBUTIONS

Section 4.01 Capital Contributions.

The Member has made or will make, as the case may be, an initial capital contribution to the Company. A capital account shall be established and maintained for the Member in accordance with the terms of the Internal Revenue Code of 1986, as amended (the "**Code**"), and the regulations promulgated thereunder.

Section 4.02 Additional Capital Contributions.

The Member shall have the right, but not the obligation, to make additional capital contributions in such additional amounts as the Member shall from time to time desire.

Section 4.03 Record of Contributions.

The amounts of the Member's contributions and the dates on which they were made shall be set forth in the records of the Company. In the event that the Member makes one (1) or more additional contributions pursuant to Section 4.02 above, the records of the Company and the Member's capital account shall be amended to reflect the amounts of such contributions and the dates on which they were made.

ARTICLE 5

DISTRIBUTIONS

Section 5.01 Distributions.

Except as otherwise provided in ARTICLE 7 hereof and subject to Section 18-607 of the Act, all distributions of cash or other property from the Company to the Member shall be made at such times, and in such amounts, as the Member deems appropriate.

ARTICLE 6

BOOKS AND RECORDS; FISCAL AND TAXABLE YEAR; BANK ACCOUNTS

Section 6.01 Records and Books of Account.

The Member shall keep the records required to be kept pursuant to, and shall abide by all limited liability company formalities required by, the Act, and shall keep any other books and records with respect to the Company as the Member in its sole discretion shall deem necessary or desirable. The Company's books and records shall at all times be maintained at the principal office of the Company and shall be open to the reasonable inspection and examination of the Member pursuant to Section 18-305 of the Act.

Section 6.02 Fiscal and Taxable Year.

The fiscal and taxable year of the Company shall commence on January 1 and end on December 31, unless the Member, in its sole and absolute discretion, designates a different fiscal or taxable year.

Section 6.03 Bank Accounts.

All funds received by the Company shall be deposited in the name of the Company in such bank account or accounts in the name of the Company as the Member may designate from time to time, and withdrawals therefrom shall be made upon the signature of an officer or other authorized person on behalf of the Company as the Member may designate from time to time.

ARTICLE 7

DISSOLUTION

Section 7.01 Events of Dissolution.

The Company shall be dissolved, liquidated and terminated upon the occurrence of any event specified in Section 18-801 of the Act.

Section 7.02 Winding Up Affairs.

Upon the dissolution of the Company, the Member shall be responsible for winding up the affairs of the Company. The Member shall have the authority to determine the time, place, manner and other terms of any sales involving the Company's assets, with due regard to the activity and the condition of the Company and the relevant market and economic conditions. Subject to the requirements of this Agreement and the Act, the Member shall have the authority to cause the Company to: (a) liquidate any of its assets and then distribute the liquidation proceeds; or (b) make in-kind distributions of any assets to the Member.

Section 7.03 Application of Proceeds.

Upon the dissolution of the Company and subject to the requirements of the Act, the Member shall distribute the assets of the Company in the following order of priority:

(a) first, to any creditors of the Company;

(b) second, to known and reasonably estimated costs of dissolution and winding up;

(c) third, to any reserves the Member may establish, in the Member's sole discretion, for contingent debts, liabilities or obligations of the Company; and

(d) fourth, to the Member.

Section 7.04 Certificate of Cancellation.

On completion of the distribution of Company assets as provided herein, the Member (or such other person or persons as the Act may require or permit) shall file a certificate of cancellation with the Delaware Secretary of State, cancel any other filings, and take such other actions as may be necessary to terminate the existence of the Company. Upon the filing of such certificate of cancellation, the existence of the Company shall terminate (and the Term shall end), except as may be otherwise provided by the Act or other applicable law.

ARTICLE 8

TAX MATTERS

Section 8.01 Tax Classification.

While the Company has only one (1) member, the Company shall be a disregarded entity for federal income tax purposes in accordance with the Code, and shall not be separate from the Member. In addition, the Company shall be a disregarded entity for all other tax purposes to the maximum extent permitted by applicable law, including (without limitation) state income tax, franchise tax, or similar entity income or value tax laws.

ARTICLE 9

INDEMNIFICATION

Section 9.01 Indemnification.

To the fullest extent permitted by applicable law, the Company shall indemnify the Member, its affiliates and their and the Company's, respective officers, representatives, employees and agents (each, an "**Indemnified Person**") on request by the Indemnified Person, and shall hold each of them harmless from and against all losses, costs, liabilities, damages and expenses (including reasonable costs of suit and attorney's fees) any of them may incur in performing their obligations hereunder, including any matter arising out of or resulting from the Indemnified Person's own simple, partial or concurrent negligence, except for any such loss, cost, liability, damage or expense primarily attributable to the Indemnified Person's gross negligence, willful misconduct, fraud or material breach of this Agreement. If an Indemnified Person becomes involved in any action, proceeding or investigation with respect to which indemnity may be available under this ARTICLE 9, the Company may reimburse the Indemnified Person for its reasonable legal and other expenses (including the cost of investigation and preparation) as they are incurred; provided, that the Indemnified Person shall promptly repay to the Company the amount of any such expense paid if it is ultimately determined that the Indemnified Person was not entitled to indemnification hereunder. Any amounts payable in respect of indemnification hereunder shall be recoverable only from the assets of the Company.

Section 9.02 Procedural Matters.

Promptly after receipt by an Indemnified Person of notice of any claim or the commencement of any action with respect to which indemnity may be available under this ARTICLE 9, the Indemnified Person shall, if a claim in respect thereof is to be made against the Company under this ARTICLE 9, notify the Company in writing of such claim or the commencement of such action; provided, that the failure to so notify the Company shall not relieve it from any liability which it may have to an Indemnified Person other than under this ARTICLE 9, except to the extent that the Company is prejudiced thereby. If any such claim or action shall be brought against an Indemnified Person, such Indemnified Person shall notify the Company thereof and the Company shall be entitled to (a) participate therein; and (b) to the extent that the Company wishes, and upon acknowledging in writing that it shall indemnify the Indemnified Person, assume the defense thereof with counsel reasonably satisfactory to such Indemnified Person. After notice from the Company to the Indemnified Person of its election to assume the defense of such claim or action, the Company shall not be liable to the Indemnified Person under this ARTICLE 9 for any legal or other expenses subsequently incurred by the Indemnified Person in connection with the defense thereof other than reasonable costs of investigation; provided, that all Indemnified Persons shall have the right to participate in (but not control) such proceeding and to employ counsel to represent them; and provided, further, that if, in the opinion of counsel to the Indemnified Persons, there are available to them defenses not available to the Company, the fees and expenses of such separate counsel shall be paid by the Company. In no event shall the Company be required to indemnify an Indemnified Person with respect to amounts paid in settlement of a claim unless such claim was settled with the consent of the Company.

Section 9.03 Outside Indemnitors.

In furtherance of this ARTICLE 9, the Company acknowledges that certain Indemnified Persons may have rights to indemnification, advancement of expenses and/or insurance provided by persons other than the Company (collectively, the "**Outside Indemnitors**"). The Company hereby agrees: (a) that it (and any of its insurers) is the indemnitor of first resort (i.e., its obligations to such Indemnified Persons are primary and any obligation of the Outside Indemnitors to advance expenses or to provide indemnification for the same expenses or liabilities incurred by such Indemnified Persons is secondary); (b) that it shall be required to advance the full amount of expenses incurred by such Indemnified Persons and shall be liable for the full amount of all expenses, judgments, penalties, fines and amounts paid in settlement to the extent legally permitted and as required by the terms of this Agreement (or any other agreement between the Company and such Indemnified Persons), without regard to any rights such Indemnified Persons may have against the respective Outside Indemnitors; and (c) that it irrevocably waives, relinquishes and releases the Outside Indemnitors from any and all claims against the Outside Indemnitors for contribution, subrogation or any other recovery of any kind in respect thereof. The Company further agrees that no advancement or payment by the Outside Indemnitors on behalf of any such Indemnified Person with respect to any claim for which such Indemnified Person has sought indemnification from the Company shall affect the foregoing, and the Outside Indemnitors shall have a right of contribution and/or be subrogated to the extent of any such advancement or payment to all of the rights of recovery of such Indemnified Person against the Company. The Company agrees that the Outside Indemnitors are express third party beneficiaries of the terms of this Section 9.03.

ARTICLE 10

NOTICES

Section 10.01 General Notices.

All notices and communications required or permitted to be given hereunder shall be sufficient in all respects if given in writing and delivered personally, or sent by courier, or mailed by U.S. Express Mail or by certified or registered United States Mail with all postage fully prepaid, or sent by facsimile transmission or other electronic transmission (provided that any such facsimile or other electronic transmission is confirmed either orally or by written or electronic confirmation), addressed to the Company or the Member at the address for the Member shown on Exhibit B or at such other address as the Member shall have designated by written notice delivered to the Company. Any notice, request or consent to the Company must be given to the Member. Whenever any notice is required to be given by applicable law, the Delaware Certificate or this Agreement, a written waiver thereof, signed by the person entitled to notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice.

Section 10.02 Deliveries of Notices; Revised Notice Information.

Unless otherwise provided herein, any notice given in accordance herewith shall be deemed to have been given (a) when delivered to the addressee in person or by courier; (b) when transmitted by facsimile transmission or other electronic transmission during normal business hours, or if not transmitted during normal business hours, at the commencement of normal business hours on the next business day; or (c) upon actual receipt by the addressee after such notice has either been delivered to an overnight courier or deposited in the United States Mail, as the case may be. The Member may change the address and facsimile or other electronic transmission numbers to which such communications are to be addressed by giving written notice to the Company in the manner provided in Section 10.01.

ARTICLE 11

MISCELLANEOUS

Section 11.01 Governing Law.

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without giving effect to its principles of conflicts of laws. In the event of a direct conflict between the provisions of this Agreement and any mandatory, non-waivable provision of the Act, such provision of the Act shall control. If any provision of the Act provides that it may be varied or superseded in a limited liability company agreement (or otherwise by agreement of the members or managers of a limited liability company), such provision shall be deemed superseded and waived in its entirety if this Agreement contains a provision addressing the same issue or subject matter. If any provision of this Agreement or the application thereof to the Member or circumstance is held invalid or unenforceable to any extent, (a) the remainder of this Agreement and the application of that provision to the Member or circumstances is not affected thereby; and (b) the Member shall replace that provision with a new provision that is valid and enforceable and that puts the Member in substantially the same economic, business and legal position as it would have been in if the original provision had been valid and enforceable.

Section 11.02 Amendments.

This Agreement or the Delaware Certificate may not be amended, modified, varied or supplemented except by an instrument in writing signed by the Member.

Section 11.03 No Third Party Beneficiaries.

This Agreement is entered into for the benefit of the Member only, and except as may be specifically set forth herein, no other person shall be entitled to enforce any provision hereof or otherwise be a third party beneficiary hereunder. Nothing in this Agreement shall otherwise be construed to create any duty to, or standard of care with reference to, or any liability to, any person other than the Member.

Section 11.04 Other Bankruptcy.

Should any creditor of the Member, or the Member's equityholders or their respective affiliates, make a claim against the Company in connection with the bankruptcy of the Member, or the Member's equityholders or their respective affiliates, the Member shall challenge any such claims to the extent permitted by applicable law.

Section 11.05 Waiver.

No delay or omission to exercise any right, power or remedy accruing to the Member as the result of any breach or default hereunder shall impair any such right, power or remedy, nor shall it be construed to be a waiver of any such breach or default, or an acquiescence therein, or of or in any similar breach or default thereafter occurring, nor shall any waiver of any single breach or default be deemed or otherwise constitute a waiver of any other breach or default theretofore or thereafter occurring.

Section 11.06 Binding Effect.

This Agreement is binding on and shall inure to the benefit of the Member and its successors and permitted assigns.

Section 11.07 Entire Agreement.

This Agreement sets forth all understandings and agreements of the Member with respect to the subject matter hereof and supersedes all prior agreements, negotiations, understandings and representations, whether written or oral, of the Member with respect to the subject matter hereof.

Section 11.08 Counterpart Execution.

This Agreement may be executed in any number of counterparts and each such counterpart shall be deemed an original Agreement for all purposes. A signature delivered by facsimile or other electronic means shall be deemed to be an original signature for purposes of this Agreement.

[*Remainder of page intentionally left blank*]

IN WITNESS WHEREOF, the undersigned Member has duly executed this Agreement as of the date first set forth above.

MEMBER:

CAMERON LNG HOLDINGS, LLC

By: F. Ahrabi
Name: Farhad Ahrabi
Title: Chief Executive Officer

EXHIBIT A

FORM OF MEMBERSHIP INTEREST CERTIFICATE

[See attached]

THESE MEMBERSHIP INTERESTS ARE SUBJECT TO CERTAIN RESTRICTIONS DESCRIBED ON THE REVERSE HEREOF

Organized Under the Laws of the State of Delaware on December 12, 2001

NUMBER ______

INTERESTS ______%

CAMERON LNG, LLC

MEMBERSHIP INTEREST CERTIFICATE

This certifies that ______________________ is the record holder of ______________ **Percent (______ %)** of the membership interests of **Cameron LNG, LLC** (the "Company"), transferable only on the books of the Company by the holder hereof, in person, or by a duly authorized attorney, upon surrender of this certificate properly endorsed or assigned. This certificate evidences a membership interest in the Company and shall be a security governed by Article 8 of the Uniform Commercial Code as in effect in the State of Delaware, and to the extent applicable, each other applicable jurisdiction.

A statement of all of the rights, preferences, privileges and restrictions granted to or imposed upon the membership interests of the Company and upon the holders thereof as established by the Certificate of Formation and the Third Amended and Restated Limited Liability Company Operating Agreement of the Company, as each may be amended from time to time, may be obtained by any holder of membership interests of the Company upon request and without charge at the principal office of the Company.

IN WITNESS WHEREOF, the Company has caused this Certificate to be signed by its duly authorized officers this ______ day of ____________, 20____.

____
[Name] [Title]

____
[Name] [Title]

THE SECURITIES REPRESENTED BY THIS CERTIFICATE HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (THE "ACT"), OR THE SECURITIES LAWS OF ANY STATE. THESE SECURITIES HAVE BEEN ACQUIRED FOR INVESTMENT AND NOT WITH A VIEW TO DISTRIBUTION OR RESALE, AND THEY MAY NOT BE TRANSFERRED WITHOUT AN EFFECTIVE REGISTRATION STATEMENT FOR SUCH SECURITIES UNDER THE ACT AND APPLICABLE STATE SECURITIES LAWS OR PURSUANT TO AN APPLICABLE EXEMPTION TO THE REGISTRATION REQUIREMENTS OF THE ACT AND SUCH LAWS.

EXHIBIT B

NOTICES

If to the Company:

CAMERON LNG, LLC
2925 Briarpark Dr., Suite 1000
Houston, TX 77042
Attn: Chief Financial Officer
Facsimile No.: +1.832.783.5503
Email: CameronLNGFinance@CameronLNG.com

If to the Member:

CAMERON LNG HOLDINGS, LLC
2925 Briarpark Dr., Suite 1000
Houston, TX 77042
Attn: Corporate Secretary
Facsimile No.: +1.832.783.5505
Email: CameronLNGHoldings@CameronLNG.com

DB1/ 79354924.6

Cameron LNG, LLC

The officers of Cameron LNG, LLC are as follows:

Name	Title	Nationality
Ahrabi, Farhad	Chief Executive Officer	United States
Bogani, Farid	Chief Engineering and Construction Officer	United States
Carla Mashinski	Chief Financial Officer	United States
O'Leary, John B.	Chief Operating Officer	United States
Lamar, Anne D.	Treasurer	United States
Woodward, Blair	Corporate Secretary	United States
Deloitte & Touche	Auditor	United States

Exhibit B

Detailed Organizational and Ownership Statement of Cameron LNG, LLC

Cameron LNG, LLC (formerly known as Hackberry LNG Terminal, LLC) is a limited liability company organized under the laws of Delaware, and its principal place of business is 2925 Briarpark Drive, Suite 1000, Houston, Texas 77042 (the "Company"). The Company's sole managing member, which holds 100% membership interest, is Cameron LNG Holdings, LLC. Cameron LNG Holdings, LLC does not have any subsidiaries.

The Company is currently engaged in the business of owning and operating a liquefied natural gas import facility located in Cameron Parish, Louisiana, constructed and operated by the Company as authorized by the Federal Regulatory Commission under Section 3 of the Natural Gas Act on September 11, 2003 (104 FERC P61, 269).

No officers of the Company own membership interests in Cameron LNG, LLC.

Exhibit C

Signed Opinion of Counsel

Cameron LNG

Blair Woodward
General Counsel

Cameron LNG
2925 Briarpark Drive
Suite 1000
Houston, TX 77042-3781

Tel.: 832-783-5582
Email: bwoodward@CameronLNG.com

September 11, 2015

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **Cameron LNG, LLC**
Docket No. CP15-_____-000
Application for Authorization Under Section 3 of the Natural Gas Act
Opinion of Counsel Furnished pursuant to 18 C.F.R. § 153.8(a)(3)

Dear Ms. Bose,

Cameron LNG, LLC ("Cameron LNG") is applying to the Federal Energy Regulatory Commission ("Commission") pursuant to Section 3(a) of the Natural Gas Act for Authorization to add additional liquefaction and export capabilities to the Cameron LNG Terminal in Cameron Parish, Louisiana.

I furnish this opinion pursuant to 18 C.F.R. § 153.8(a)(3) of the Commission's regulations which requires that Cameron LNG provide, as Exhibit C to its application, an opinion of counsel that the proposed project is within the authorized powers of Cameron LNG and that Cameron LNG has complied with the laws and regulations of the states in which it operates. For the purposes of this opinion, I have reviewed and examined all relevant documents and made examinations of law as I deemed necessary.

Based on the foregoing, I am of the opinion that Cameron LNG's proposal is within its authorized powers and that Cameron LNG is in compliance with the laws and regulations of this Commission and of the states in which it operates.

Respectfully Submitted,

Blair Woodward
General Counsel
Cameron LNG, LLC

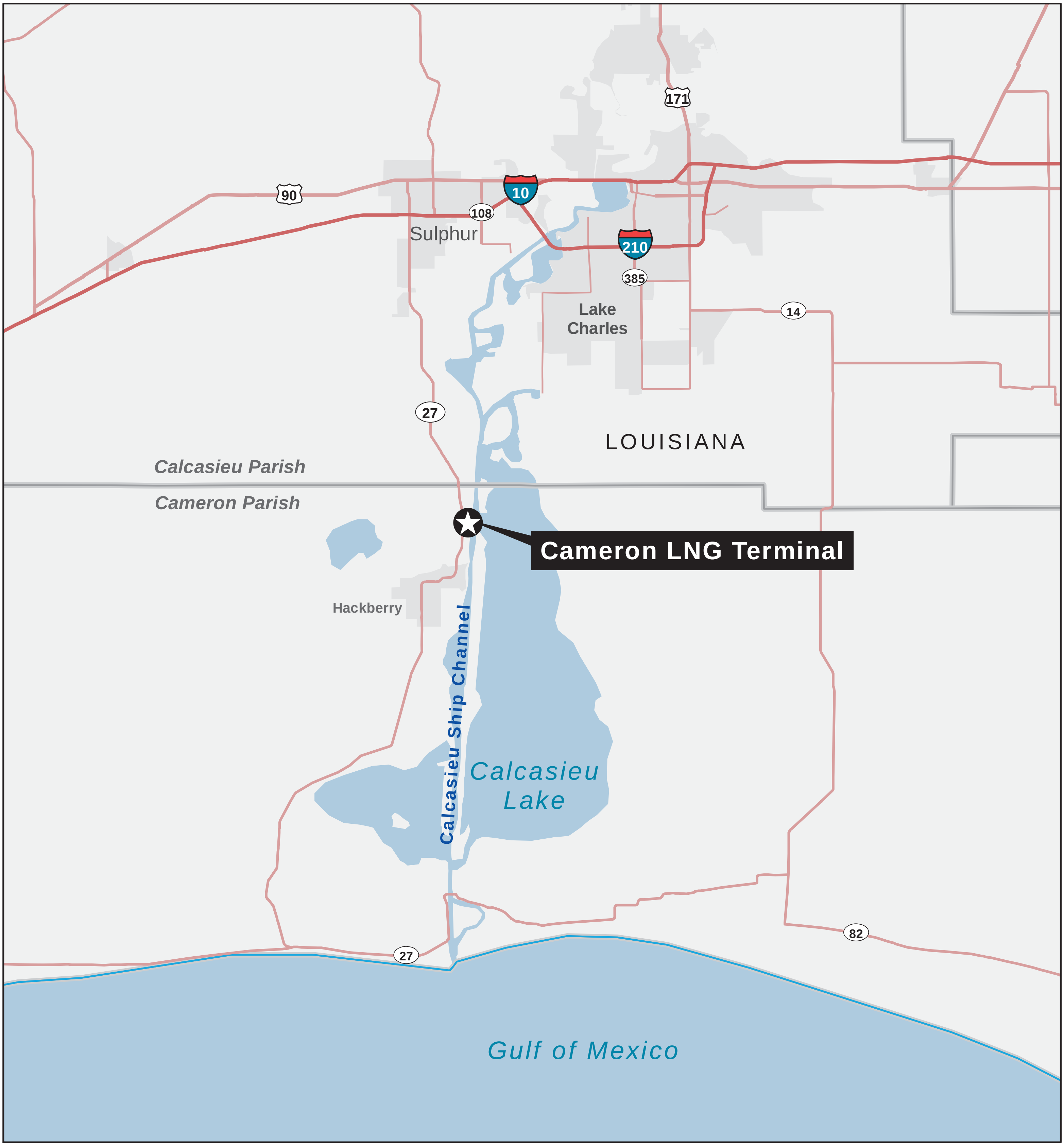
cc: Elizabeth Peters, Sempra

Exhibit F

Environmental Resource Reports 1 to 13 (Exhibit F) are provided in separate volumes, Volumes II to IX.

Exhibit G

A geographic location map of the Expansion Project is included in this exhibit.



0 3 6 Miles

Cameron LNG Terminal

Cameron LNG LLC

Cameron Expansion Project

Location Map

Exhibit G

Document Name: CLNG_Expansion_LocationMap
Date: 6/17/2015

Exhibit H

A list of Federal authorizations for the Expansion Project is included in this exhibit.

Exhibit H Federal Authorizations Cameron LNG Expansion Project			
Agency	**Permit/Approval**	**Contact**	**Status** *(Anticipated)*
Federal Energy Regulatory Commission	Section 3 of the Natural Gas Act	Danny Laffoon (202) 502-6257	*(Application Submission September 2015)*
U.S. Department of Energy	Application for Long Term, Multi-Contract Authorization to Export Natural Gas to Free Trade Agreement Countries Application for Long Term, Multi-Contract Authorization to Export Natural Gas to Non-Free Trade Agreement Countries	Larine A. Moore (202) 586-9478	**Application Completed** **February 23, 2015** **Authorization Received July 10, 2015** **Application Completed** **May 28, 2015**
U.S. Coast Guard (USCG)	LOR / WSA	Commander Monica Rochester (337) 774-7800	**Consultation Completed** **Feb 3, 2015**
U.S. Army Corps of Engineers (USACE)	Section 404 (CWA) Section 10 (Rivers and Harbors Act)	James W. Little Jr. (225) 342-3099	**Authorization Received** **June 22, 2015**
U.S. Fish and Wildlife Service (USFWS)	Section 7 of Endangered Species Act Consultation Migratory Bird Treaty Act	Jeff Weller (337) 291-3115	**Completed** **August 13, 2015**
National Marine Fisheries Service (NMFS)	Section 7 of Endangered Species Act Consultation Marine Mammal Protection Act Consultation	Kelly Shots	**Consultation Letter** **July, 2015**
	Magnuson-Stevens Fishery Management and Conservation Act Essential Fish Habitat (EFH) Consultation	Rick Hartman (225) 389-0508	*Anticipated Complete* *October, 2015*
Federal Aviation Administration (FAA)	Notice of Proposed Construction Possible Affecting Navigable Air Space	Vivian Vilaro (847) 294-7575	*April 2016*

Exhibit Z-1

Applicant Prepared Draft Environmental Assessment

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Abbreviations and Technical Acronyms

amsl	above mean seal level
AQCRs	Air Quality Control Regions
BACT	Best Available Control Technology
Bcf/d	Billion cubic feet per day
BHP	brake horsepower
BOG	boil-off gas
CAA	Clean Air Act
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CH_4	methane
CLNG	Cameron LNG, LLC
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	of carbon dioxide equivalents
COE	United States Army Corps of Engineers
Commission or FERC	Federal Energy Regulatory Commission
dB	decibels
dBA	A-weighted scale decibels
DOE	Department of Energy
DOT	U.S. Department of Transportation
EA	environmental assessment
EFH	Essential fish habitat
EO	Executive Order
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
ESD	emergency shutdown

FEED	front-end engineering design
FSP	Facility Security Plan
FWS	United States Fish and Wildlife Service
GHGs	greenhouse gases
GIS	Geographic Information System
gpm	gallons per minute
GWP	global warming potential
HAP	Hazardous Air Pollutant
HFCs	hydrofluorocarbons
ICE	internal combustion engines
LNG	liquefied natural gas
LDNR	Louisiana Department of Natural Resources
LNHP	Louisiana Natural Heritage Program
LPDES	Louisiana Pollutant Discharge Elimination System
L_{eq}	sound level
MBTA	Migratory Bird Treaty Act
Mtpy	million metric tonnes per year
MW	megawatt
m^3	cubic meters
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center’s
NEPA	National Environmental Policy Act
NESHAP	National Emission Standard for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NGA	Natural Gas Act of 1938
NNSR	Nonattainment New Source Review
NOI	notice of intent
NO_2	nitrogen dioxide

NRCS	Natural Resources Conservation Service
NNSR	Nonattainment New Source Review
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NSA	noise-sensitive areas
NSPS	New Source Performance Standards
N_2O	nitrous oxide
O_3	ozone
Pb	lead
PFCs	perfluorocarbons
PHMSA	Pipeline Hazardous Materials Safety Administration
PM	particulate matter
$PM_{2.5}$	PM less than 2.5 microns in aerodynamic diameter
PM_{10}	PM less than 10 microns in aerodynamic diameter
PSD	Prevention of Significant Deterioration
RICE	reciprocating internal combustion engines
RCW	red-cockaded woodpecker
ROI	region of influence
SF_6	sulfur hexafluoride
SHPO	State Historic Preservation Officer
SONRIS	Strategic Online Natural Resources Information System
SO_2	sulfur dioxide
tpy	tons per year
Secretary	Secretary of the Commission
USCG	U.S. Coast Guard
U.S.C.	Unites States Code
VOC	volatile organic compound
WSA	Water Suitability Assessment

1. PROPOSED ACTION

1.1 Introduction

On June 19, 2014, the Commission authorized Cameron LNG's Liquefaction Project (CLNG Liquefaction Project or Liquefaction Project) under Section 3 of the NGA (Docket No. 13-25-000). This authorization included natural gas processing, liquefaction, and storage facilities at Cameron LNG's LNG Terminal. These facilities included a fourth LNG storage tank (T-204) and three liquefaction trains (Trains 1, 2, and 3) including the associated natural gas pre-treatment equipment, to produce up to 14.95 million metric tonnes per year (Mtpy) of LNG for export. The CLNG Liquefaction Project is currently under construction.

The staff of the Federal Energy Regulatory Commission (Commission or FERC) has prepared this environmental assessment (EA) to address the potential environmental impacts of the Cameron LNG, LLC (referred to herein as CLNG) Expansion Project in compliance with National Environmental Policy Act of 1969 (NEPA) requirements and regulations issued by the Council on Environmental Quality (CEQ) at Title 40 of the Code of Federal Regulations (CFR) Parts 1500-1508 (49 CFR 1500-1508), and the Commission's regulation at 18 CFR 380. The FERC is the federal agency responsible for siting LNG facilities under the NGA, and is the lead federal agency for the preparation of this EA in compliance with the requirements of NEPA. Cooperating agencies have jurisdiction by law or special expertise with respect to environmental impacts involved with a proposal. The roles of the FERC and U.S. Department of Energy (DOE) in the Project review process are described in section 1.2. Our[1] EA is an integral part of the Commission's decision on whether to issue CLNG authorization to construct and operate the facilities described in section 1.5 below.

On September 28, 2015, Cameron LNG, LLC (referred to herein as CLNG) filed an application in Docket No. CP15-__-000 with the Federal Energy Regulatory Commission (Commission or FERC) pursuant to Section 3(a) of the Natural Gas Act of 1938 (NGA) and Part 157 of the Commission's regulations. CLNG requests authorization to expand its existing liquefied natural gas (LNG) Terminal[2] (CLNG Terminal or LNG Terminal) in Cameron and Calcasieu Parishes, Louisiana by siting, constructing, and operating additional LNG facilities within the LNG Terminal property. The CLNG Expansion

---

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

2 The CLNG Terminal, was previously evaluated and assessed by FERC for various project components in FERC Docket Nos. CP02-374-000 (CLNG Terminal and Cameron Interstate Pipeline), CP06-422-001 (CLNG Terminal Expansion), and CP13-25-000 (CLNG Liquefaction and Cameron Interstate Pipeline Expansion Project).

Project (Expansion Project) would increase the terminal's capability to liquefy natural gas for export by 515 billion cubic feet per year, equivalent to 9.97 Mtpy, (257.5 billion cubic feet per year or 4.985 Mtpy per liquefaction train).

Our principal purposes in preparing this EA are to:

- identify and assess potential impacts on the natural and human environment that would result from implementation of the proposed action;
- assess reasonable alternatives to the proposed action that would avoid or minimize adverse effects to the environment; and
- identify and recommend specific mitigation measures, as necessary, to minimize environmental impacts.

1.2 Scope of This Environmental Assessment

The topics addressed in this EA include alternatives; geology; groundwater; surface waters; wildlife and aquatic resources; migratory birds; land use and visual resources; socioeconomics (including transportation and traffic); cultural resources; air quality and noise; reliability and safety; and cumulative impacts. This EA describes the affected environment as it currently exists, discusses the environmental consequences of the CLNG Expansion Project, and compares the Expansion Project's potential impact with that of various alternatives. This EA also presents our recommended mitigation measures. The following resources will not be impacted by the Expansion Project and therefore, will not be discussed further in this EA:

- soils;
- essential fish habitat (EFH);
- vegetation;
- wetlands;
- mineral resources;
- oil and gas resources;
- paleontological resources;
- agriculture; and
- residential and business.

When considering the environmental consequences of constructing and operating the Expansion Project, the duration and significance of any potential impacts are described according to the following four levels:

- Temporary impacts generally occur during construction, with the resources returning to preconstruction conditions almost immediately;
- Short-term impacts could continue for approximately three years following construction;
- Long-term impacts would require more than three years to recover, but eventually would recover to pre-construction conditions; and
- Permanent impacts could occur as a result of activities that modify resources to the extent that they may not return to pre-construction conditions during the life of the project, such as with the construction of an aboveground facility.

An impact would be considered significant if it would result in a substantial adverse change in the physical environment.

1.2.1 Cooperating Agencies

U.S. Department of Energy

February 23, 2015 and May 28, 2015, CLNG filed applications with the DOE Office of Fossil Energy (FE) [3] for authorization to export up to 9.97 Mtpy of domestically produced LNG from the CLNG Terminal. CLNG requested authorization for a 20-year term, commencing the earlier of either the date of first export or 7 years from the date of issuance of the requested authorization. FE Docket No. 15-36-LNG seeks to export LNG from the CLNG Terminal to any country with which the United States (U.S.) has, or in the future may have, a free trade agreement requiring national treatment for trade in natural gas and that has, or in the future develops, the capacity to import LNG. While, FE Docket No. 15-90-LNG seeks to export LNG from the CLNG Terminal to any country (1) with which the United States does not have a free trade agreement requiring the national treatment for trade in natural gas and LNG; (2) with which trade is not prohibited by United States law or policy; and (3) that has, or in the future develops, the capacity to import LNG. The DOE's authority to regulate exports of natural gas, including LNG, is explained by DOE. This authority has been delegated to the Assistant Secretary for the FE in Redelegation Order No. 00-002.04F, issued July 11,

3 FE Docket Nos. 15-36-LNG and 15-90-LNG

2013. FE Docket No. 15-36-LNG was approved and Order No. 3680 was issued by the U.S. DOE on July 10, 2015. FE Docket No. 15-90-LNG is still under DOE review.

The DOE's FE must meet its obligation under Section 3 of the NGA to authorize the import and export of natural gas, including LNG, unless it finds that the import or export is not consistent with the public interest. The purpose and need of DOE action is to respond to the February 23, 2015 and May 28, 2015 applications for authority to export LNG from the CLNG Terminal filed by CLNG with the FE (FE Docket Nos. 15-36-LNG and 15-90-LNG, respectively).

As previously stated, the DOE/FE has approved FE Docket 15-36-LNG (Order No. 3680) and is still reviewing FE Docket No. 15-90-LNG submitted by CLNG for long-term, multi-contract authorization to export up to 9.97 Mtpy of domestic natural gas as LNG produced from domestic sources.

U.S. Department of Transportation

The U.S. Department of Transportation (DOT) has prescribed the minimum federal safety standard for onshore LNG facilities in compliance with 49 Unites States Code (U.S.C.) 60101. Those standards are codified in 49 CFR 193 and apply to siting, construction, operation, and maintenance of onshore LNG facilities. The National Fire Protection Association (NFPA) Standard 59A, *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*, is incorporated into these requirements by reference, with regulatory preemption in the event of conflict. The DOT is a cooperating agency with the FERC, serving as a subject matter expert on its federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities codified in 49 CFR 193. The DOT does not issue a permit or license but, as a cooperating agency, assists FERC staff in evaluating whether an applicant's proposed design would meet the DOT siting requirements.

1.3 Purpose and Need

Applicant's Stated Purpose and Need: CLNG states that the proposed liquefaction facilities expansion would increase the liquefaction capacity of the CLNG Terminal to efficiently export LNG to a global market place in a cost competitive manner with the least amount of environmental impacts. The Expansion Project is needed to give U.S. producers of natural gas (where natural gas production is projected to exceed demand in 2040) access to global markets where there is greater demand for natural gas. CLNG indicated that the Expansion Project would result in the benefits to public interest listed below:

- stimulation of the local, state, regional, and national economies through job creation;

- improve the United States' balance of trade; and
- reduce global greenhouse gas emissions by providing low carbon natural gas to foreign markets.

Section 3 of the NGA, as amended, requires that authorization be obtained from the DOE prior to importing or exporting natural gas, including LNG, from or to a foreign country. For applicants that have, or intend to have, a signed gas purchase or sales agreement/contract for a period of time longer than two (2) years, long-term authorization is required. Under Section 3 of the NGA, the FERC considers, as part of its decision to authorize natural gas facilities, all factors bearing on the public interest. Specifically, regarding whether to authorize natural gas facilities for importation or exportation, the FERC shall authorize the proposal unless it finds that the proposed facilities would not be consistent with the public interest.

1.4 Public Review and Comment

On March 2, 2015, we granted CLNG's request to use the pre-filing process and assigned Docket No. PF15-13-000 to activities involved with the Expansion Project.

CLNG hosted an open house information session for landowners, agencies, and other interested stakeholders on May 14, 2015, in Sulphur, Louisiana. The open house provided stakeholders an opportunity to learn about the CLNG Expansion Project and ask questions in an informal setting. Notifications of the open house were mailed by CLNG to stakeholders and published in local newspapers. CLNG also established a webpage and a telephone hotline for the Expansion Project.

On June 18, 2015, we issued a *Notice of Intent to Prepare an Environmental Assessment for the Planned CLNG Expansion Project and Request for Comments on Environmental Issues*, (NOI). This NOI, which identified a 30-day public comment period and instructed interested parties on how to comment on the Expansion Project, was mailed to federal, state, and local government representatives and agencies; elected officials; Native American tribes; and other interested individuals and groups.

During the review process we received no comments about the Expansion Project from the public. One letter was received from the Louisiana Department of Wildlife and Fisheries (LDWF) stating no objection to the Expansion Project. Another letter was received from the EPA that included comments and recommendations pertaining to the information to be provided in the EA. Table 1.4-1 lists the concerns identified during the public comment process that are within the scope of the environmental analysis, and identifies the applicable sections of this EA that address each issue.

TABLE 1.4-1

Issues Identified During Scoping

Issue	EA Section Where Addressed
GENERAL	
Purpose and Need	1.2
Indirect Impacts and Cumulative Impacts	2.8
Fugitive Dust, Mobility and Stationary Source and Administrative Control Measures	2.6.1 and appendix 2
WATER RESOURCES	
Surface Water Quality	2.2.1
Water Supply Quality and Reliability	2.2.1.1
Ground Water Quality and Quantity and Mitigation Measures to Prevent Adverse Impacts	2.2.1.1 and appendix 2
Stormwater Pollution Prevention and Mitigation Measures	2.2.1.2, 2.2.1.3 and appendix 2
AIR RESOURCES	
Air Quality	2.6.1 and appendix 2
GHG and Methane Leakage	2.6.1
SOCIOECONOMICS	
Effects on Environmental Justice Populations	2.4.6
Effects on Land Use Plans in the Local Area	2.4
WILDLIFE AND VEGETATION	
Impacts and Avoidance of Covered Species and Mitigation Efforts	2.2.1, 2.2.2, and 2.2.3
CULTURAL RESOURCES	
Tribal Government Coordination	2.5
Cultural and Historic Sites	2.5
ALTERNATIVES	
Description of Alternatives and Analysis	3.0

1.5 Proposed Facilities

The CLNG Expansion Project facilities are described in this section. Figure 1 is a general location map. Figure 2 is an aerial view of the liquefaction expansion facilities. A detailed U.S. Geological Survey (USGS) map is provided in appendix 1.

CLNG Expansion Project

The CLNG Expansion Project has been designed to process a total of approximately 9.97 Mtpy of pipeline-quality gas that would be delivered to the LNG Terminal through the interconnecting pipeline system. Natural gas would be liquefied and stored in the LNG Terminal's three existing storage tanks, and authorized fourth storage tank, and proposed fifth storage tank. The new storage tank (T-205) would be the same size and design as the existing and authorized tanks and would have a primary and a secondary container capable of independently containing the stored LNG. LNG would be exported from the terminal by LNG carriers that would arrive at the terminal via the Calcasieu Ship Channel. The proposed liquefaction facilities consist of two new liquefaction trains (Trains 4 and 5). Each liquefaction train will have a maximum liquefaction production capacity of approximately 4.985 Mtpy (26,986 million metric tons per day). The Expansion Project facilities would be constructed and operated on about 60 acres entirely within the previously authorized CLNG Terminal site, as shown on figure 2. The Expansion Project includes the following key facilities:

- two liquefaction trains (Trains 4 and 5), including the pre-treatment and liquefaction facilities described below;
    - two hydrogen sulfide removal units for acid removal, one in each of the two liquefaction trains;
    - two amine units for removal of carbon dioxide (CO_2) concentrations, one in each of the two liquefaction trains;
    - two mercury removal units for the removal of mercury, one in each of the two liquefaction trains;
    - two dehydration units for the removal of water vapor, one in each of the two liquefaction trains;
    - two heavy hydrocarbon removal units, one in each of the two liquefaction trains (Trains 4 and 5);
- one 160,000 cubic meters (m^3) full containment LNG storage tank (T-205);

- one new low pressure elevated flare, associated with the LNG storage tank (T-205);
- two new boil-off gas (BOG) compressor units, for delivery into the fuel system;
- one 1,070,000 gallon capacity low pressure condensate storage tank;
- one demineralized water system, capable of 20 gallons per minute (gpm) per liquefaction train;
- three 2.5 megawatt (MW) capacity diesel powered standby generators;
- one 54,100 gallon capacity diesel storage tank with a secondary concrete containment;
- interconnections to existing facilities; and
- modifications and additions to existing utilities and infrastructure to accommodate the two additional liquefaction trains.

No additional marine facilities would be required for the Expansion Project. No modifications would be required for the LNG loading arms, berthing equipment, basin, or other portions of the marine terminal. The number and size of ships using the LNG Terminal would not increase from the number of ships previously authorized by the U.S. Coast Guard (USCG) Water Suitability Assessment (WSA) for the LNG Terminal. Because the loading rates proposed for the Expansion Project would be the same as the unloading rates for the LNG Terminal, no increase in the previously analyzed ship traffic is expected.

CLNG anticipates beginning construction of the Expansion Project in June 2016 and expects liquefaction Trains 4 and 5 to be in operation by year’s end 2019.

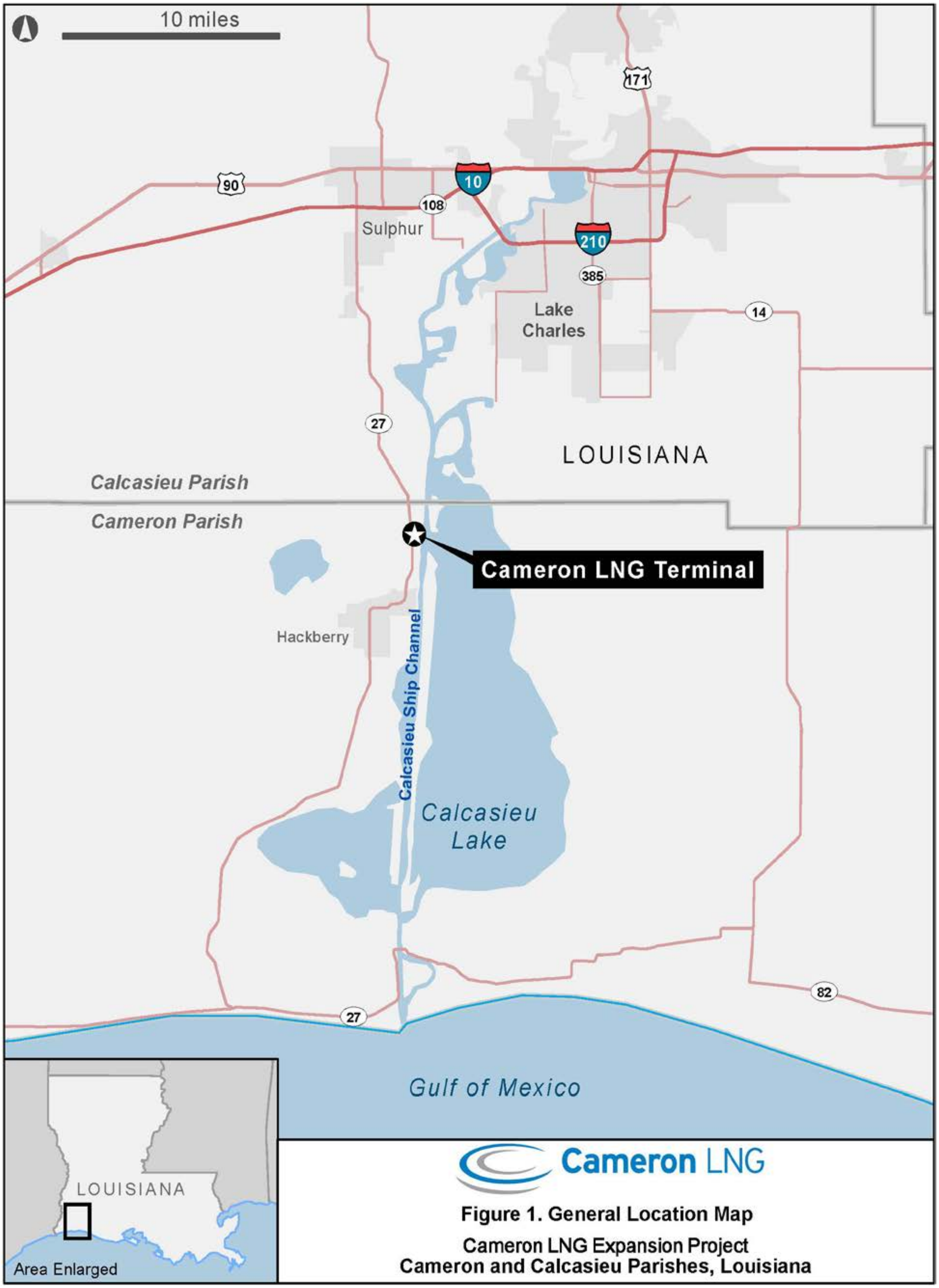
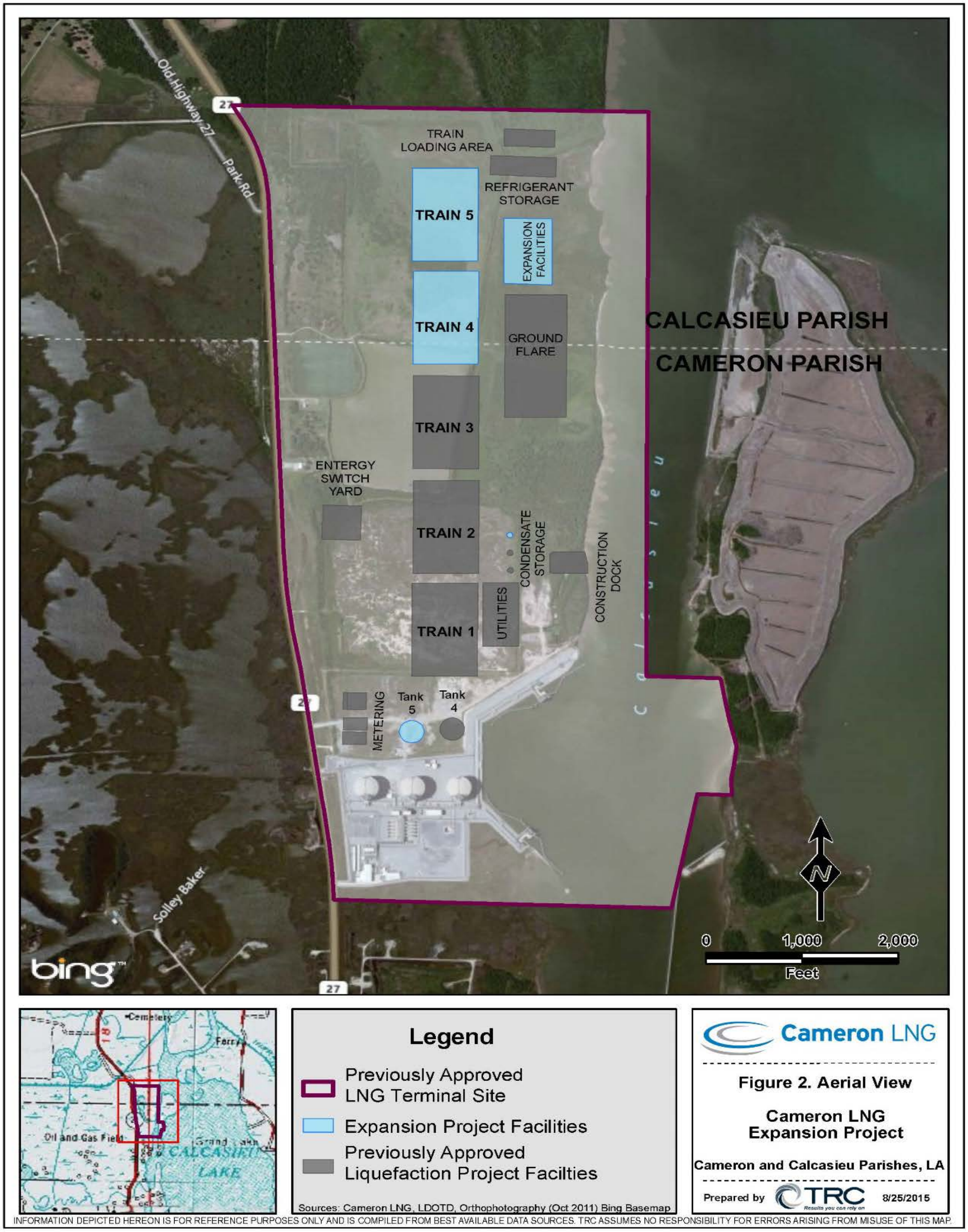


Figure 1. General Location Map
Cameron LNG Expansion Project
Cameron and Calcasieu Parishes, Louisiana


Old Highway 27
Park Rd
27
TRAIN LOADING AREA
REFRIGERANT STORAGE
TRAIN 5
EXPANSION FACILITIES
TRAIN 4
GROUND FLARE
CALCASIEU PARISH
CAMERON PARISH
TRAIN 3
ENTERGY SWITCH YARD
TRAIN 2
CONDENSATE STORAGE
CONSTRUCTION DOCK
TRAIN 1
UTILITIES
METERING
Tank 5
Tank 4
Calcasieu
Solley Baker
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0 1,000 2,000
Feet
N
Legend
Previously Approved LNG Terminal Site
Expansion Project Facilities
Previously Approved Liquefaction Project Facilties
Sources: Cameron LNG, LDOTD, Orthophotography (Oct 2011) Bing Basemap
Cameron LNG
Figure 2. Aerial View
Cameron LNG Expansion Project
Cameron and Calcasieu Parishes, LA
Prepared by TRC 8/25/2015
INFORMATION DEPICTED HEREON IS FOR REFERENCE PURPOSES ONLY AND IS COMPILED FROM BEST AVAILABLE DATA SOURCES. TRC ASSUMES NO RESPONSIBILITY FOR ERRORS ARISING FROM MISUSE OF THIS MAP.

1.6 Non-jurisdictional Facilities

Occasionally, proposed projects have associated facilities that do not come under the jurisdiction of the FERC. These non-jurisdictional facilities may be integral to the project (e.g., an electrical switch yard for an LNG terminal) or they may be minor, non-integral components of the jurisdictional facilities that would be constructed and operated as a result of the project.

1.6.1 Entergy Electrical Transmission Line

In its application, CLNG identified plans for Entergy Louisiana, LLC (Entergy) to build a new transmission line in Calcasieu and Cameron Parishes as well as a new switch yard on the west side of the LNG Terminal. The new transmission line would include a 15.9-mile-long 230 kilovolt (kV) transmission line. Entergy would consult with the appropriate state and federal resource agencies to obtain the required permits or authorizations, including: United States Army Corps of Engineers (COE) (Section 10/404 Permit); Louisiana Department of Natural Resources (LDNR) Office of Coastal Management (OCM) (Coastal Use Permit); and LDWF (Habitat Evaluation). We have included this non-jurisdictional facility in our cumulative impacts analysis (refer to section 2.8).

1.7 Construction, Operation, and Maintenance Procedures

The Expansion Project facilities would be designed, constructed, operated, and maintained to conform to or exceed federal standards that are intended to adequately protect the public by preventing or mitigating LNG failures or accidents and ensure safe operation of the facilities. The liquefaction facilities would be constructed according to the standards outlined by the DOT's *Federal Safety Standards for Liquefied Natural Gas Facilities* in 49 CFR 193 and the NFPA's *Standards for the Production, Storage, and Handling of LNG* (NFPA 59A).

CLNG has adopted, in whole without changes, the FERC's *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan [FERC 2013a]) and the FERC's *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures [FERC 2013b])[4] into its Environmental Plan (appendix 2). We previously reviewed and approved use of CLNG's Environmental Plan for the Liquefaction Project, which is currently under construction. CLNG is not proposing to modify its Environmental Plan for the Expansion Project.

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[4] Copies of the FERC's Plan and Procedures may be accessed on our website at http://www.ferc.gov/industries/gas/enviro/guidelines.asp.

1.7.1 Construction Procedures

For purposes of quality assurance and compliance with mitigation measures, other applicable regulatory requirements, and other project specifications, CLNG would be represented on-site by one or more environmental inspectors. CLNG would require their contractors to observe and comply with all federal, state, and local laws, ordinances, and regulations that apply to the conduct of their work and would provide environmental training to all construction personnel. The level of training would be appropriate for the duties performed. Training would be provided before the start of construction and throughout the construction process, as needed. The environmental training program would cover the measures outlined in CLNG's Environmental Plan, job-specific permit conditions, company policies, and any other project requirements.

Site Preparation

The Expansion Project would involve modifications to the existing LNG Terminal facilities and the construction of new infrastructure. The construction area for the new facilities would be entirely located within the previously authorized CLNG Terminal property and would not require any new construction infrastructure (i.e., roads or docks) or modifications. No wetlands would be impacted by the construction of the Expansion Project. However, CLNG has modified its existing COE Section 404 of the Clean Water Act (CWA) Permit (MVN-2002-03266-WII) and LDNR OCM Coastal Use Permit (P20121194) to incorporate the Expansion Project facilities.

Site Grade and Fill

The Expansion Project process area would be located north of existing liquefaction Trains 1, 2 and 3. The process area would not require additional clearing or grubbing. Onsite material would be used as structural backfill material when applicable. If onsite material is determined to be insufficient or unsuitable for the intended application, clean structural backfill material would be imported from existing local borrow areas.

The Expansion Project process area would be at a minimum grade elevation of +11.5 mean sea level (MSL) (+12.6 feet North American Vertical Datum of 1988 (NAVD88)) and the new LNG storage tank (T-205) minimum grade elevation would be +5 feet MSL (+6.1 feet NAVD88). Foundations for the associated structures would consist of pile supports and spread footings. Critical equipment and infrastructure such as process equipment and pipe racks would have their foundations supported by piles. The foundations would be constructed of reinforced concrete and designed according to standard engineering practices. Concrete would be delivered to the Expansion Project site either from an existing Gulf Intracoastal Coastal Waterway (GIWW) batch plant located near the Expansion Project site or the Engineering, Procurement, and

Construction contractor may utilize an onsite concrete batch plant. If the GIWW batch plant is used, an existing GIWW barge dock and lay down area, located adjacent to the batch plant, would be used for delivery of aggregate and concrete pile during construction. No improvements to the GIWW dock would be required for its use.

Materials and Equipment Delivery

Construction traffic would access the site from Louisiana State Highway (LA) 27 and use the same entrances already approved for the CLNG Terminal. Material delivery would be by barge through the Material Offloading Facility to the maximum extent practical. There would still be some material delivery by truck by using LA 27. Bulk materials and equipment would be delivered via LA 27 or by barge. The construction barge dock constructed as part of the CLNG Liquefaction Project at the LNG Terminal would accommodate barge deliveries.

1.7.2 Operating Procedures

Natural gas would be delivered to the existing CLNG Terminal via the Cameron Interstate Pipeline and the Cameron Access Project Pipeline. The gas would be metered and enter the gas pre-treatment section of the liquefaction facilities to remove components in the gas stream in preparation for liquefaction. The removed components include solids, carbon dioxide, hydrogen, sulfur, water, and mercury.

The dry gas would be fed to the heavy hydrocarbon removal unit to remove pentane and heavier hydrocarbon (stabilized condensate product) to prevent freeze-out in the liquefaction unit and meet the LNG product specification.

The purified natural gas would be pre-cooled using propane before entering the liquefaction systems where it would be put in contact with progressively cooler refrigerants, consisting of mixed refrigerants (MR) which consist of nitrogen, methane, ethylene, and propane. The LNG would then be pumped to the LNG storage system.

Additional operating procedures would be developed for the new liquefaction facilities and included in the LNG Terminal's Operations Manual. Training in accordance with the DOT minimum federal safety standards specified in 49 CFR Parts 192 and 193 would be required for the additional 90 operational personnel needed for the Expansion Project. The control and monitoring system for the Expansion Project would interconnect with the existing LNG Terminal distributed control system for transferring critical data and would interface for total plant monitoring and control. An independent safety instrumented system would be installed to allow the safe, sequential shutdown and isolation of the liquefaction facilities.

The existing hazard detection and fire protection systems provide alarm-signaling and notification when a hazardous condition or fire is present. The fire and gas detection system for the existing LNG Terminal would be expanded to protect the new liquefaction facilities and would perform as a continuous monitoring system. The Expansion Project would tie into and expand the existing fire protection for the existing LNG Terminal.

The emergency shutdown (ESD) system for the new facilities would consist of shutdown and control devices designed to leave the facilities in a safe state. The ESD system would be capable of either shutting down the entire facility, individual processes, and/or individual pieces of equipment.

The CLNG Facility Security Plan would be modified in coordination with the USCG and the Pipeline Hazardous Materials Safety Administration for the Expansion Project. The plan would provide for risk-based levels of security carried out by trained personnel during all operational shifts and, if necessary, by government law enforcement officers for response to serious threats. The Expansion Project facilities would be located within the LNG Terminal security fence.

1.7.3 Maintenance Procedures

Facility maintenance would be conducted in accordance with 49 CFR 193, Subpart G. CLNG would update all current manuals as necessary to include the expanded terminal operations and submit amendments to the agencies prior to commissioning the Expansion Project facilities. CLNG would train all operations and maintenance personnel to safely perform their jobs prior to commissioning the proposed facility. Operators would meet all the training requirements of USCG, DOT, local fire departments, and other regulatory entities.

1.8 Land Requirements

No additional land would be required for construction or operation of the proposed Expansion Project. The Expansion Project would affect about 141 acres within the previously authorized CLNG Terminal site during construction. A total of 60 acres would be permanently affected by the Expansion Project. All facility access and egress would be through existing highway access locations. No wetlands would be affected by the construction or operation of the Expansion Project.

1.9 Required Consultation, Approvals, and Permits

Table 1.9-1 lists the federal, state, and local regulatory agencies that have permit or approval authority or consultation requirements and the status of that review for the Expansion Project. CLNG would be responsible for obtaining all necessary permits, licenses, and approvals for the Expansion Project, regardless of whether or not they are listed in table 1.9-1.

TABLE 1.9-1

Permits and Consultations for the Expansion Project

Agency	Permit/Consultation	Status
Federal		
Federal Energy Regulatory Commission	Section 3 of the Natural Gas Act	Application Filed September 28, 2015
U.S. Department of Energy	Application for Long Term, Multi-Contract Authorization to Export Natural Gas to Free Trade Agreement Countries	Order Received July 10, 2015
	Application for Long Term, Multi-Contract Authorization to Export Natural Gas to Non-Free Trade Agreement Countries	Application Filed May 28, 2015
U.S. Coast Guard (USCG)	Letter of Intent and Update/Preliminary Waterway Suitability Assessment Waiver	Concurrence Letter Received February 3, 2015
United States Army Corps of Engineers (COE)	Section 404 (CWA) Section 10 (Rivers and Harbors Act)	Approval of Permit (MVN-2012-03266-WII) Modification Received June 22, 2015
U.S. Fish and Wildlife Service (FWS)	Section 7 of Endangered Species Act Consultation Migratory Bird Treaty Act	Concurrence Letter Received August 8, 2015
National Marine Fisheries Service (NMFS)	Section 7 of Endangered Species Act Consultation Magnuson-Stevens Fishery Management and Conservation Act Essential Fish Habitat (EFH) Consultation Marine Mammal Protection Act Consultation	Concurrence Letter Filed May 19, 2015
State		

TABLE 1.9-1

Permits and Consultations for the Expansion Project

Agency	Permit/Consultation	Status
Louisiana Department of Natural Resources (LDNR) Coastal Management Division	Coastal Use Consistency Determination	Amended Coastal Use Permit (P20121194) Authorization Received June 21, 2015
Louisiana Department of Environmental Quality (LDEQ) Air Quality Division	Prevention of Significant Deterioration (PSD) and Title V Air Permits (modify existing permits)	Application to Modify Existing Permits (0560-00184-V6 and PSD-LA-766(M1)) Filed May 14, 2015
Louisiana Department of Environmental Quality (LDEQ) Water Quality Division	Hydrostatic Test Water Discharge General Permit Water Quality Certification	Permit Received September 17, 2014 Certification (020809-08) Received October 24, 2012
LDWF	Threatened and Endangered Species Consultation	Concurrence Letter Filed May 19, 2015
Louisiana State Historic Preservation Office (SHPO)	Section 106 Consultation	Concurrence Received July 17, 2015
Local		
Cameron Parish Police Jury	Building Permit	Application Anticipated to be Filed April 2016; as needed
Cameron Parish Coastal Use Consistency	Letter of No Objection	Approval Received July 20, 2015
Calcasieu Parish Police Jury	Building Permit	Application Anticipated to be Filed April 2016; as needed
Calcasieu Parish Coastal Use Consistency	Letter of No Objection	Approval Received July 22, 2015

2. ENVIRONMENTAL ANALYSIS

2.1 Geology, Foundations, and Natural Hazards

2.1.1 Geology

The Expansion Project is located within the West Gulf Coastal Plain geomorphic province (Hunt, 1974), in southwestern Louisiana just west of Calcasieu Lake on the Calcasieu Ship Channel. The surface of Louisiana is underlain by geologically young sedimentary sequences that were deposited in or adjacent to rivers and deltas in a coastal plain setting. These deposits and those in other states in the West Gulf Coastal Plain are underlain by southward-dipping sedimentary rocks which were deposited in mostly shallow marine water.

The Expansion Project site lies within Tertiary-aged terraces of Louisiana which consist of sand, gravel, and mud. These surfaces are remnants of pre-existing flood plains.

The sediments at the site are of late Pleistocene to Holocene (Recent) age and are underlain by Tertiary rocks to a depth of thousands of feet. Much of the site is covered with dredged soil from the maintenance dredging of the Calcasieu Ship Channel conducted by the COE.

Blasting

The geotechnical studies conducted to date by CLNG, and recent work at the CLNG Terminal indicate that there is no bedrock near the surface of the LNG Terminal site that would require blasting for removal. Should blasting be required for the construction of the Expansion Project, a blasting plan would be prepared and filed with the commission.

2.1.2 Foundation Conditions

CLNG's geotechnical investigation of the Liquefaction Project site indicated that the surficial conditions at the Expansion Project site primarily consist of recently deposited very soft to firm, high plasticity cohesive soils to depths ranging from about 20 to 30 feet below grade. However, at several locations the surficial conditions consisted of existing fill materials or cohesionless/granular soils. These surficial soils were underlain by alternating strata of firm to stiff, cohesive soils and loose to medium-dense cohesionless soils to a depth of about 40 feet below grade. Below depths of 40 feet, very stiff Pleistocene aged cohesive deposits along with occasional stratums of medium-dense to very dense cohesionless soil were encountered.

The results of the geotechnical investigation (Fugro, 2015a) indicate that subsurface conditions at the site are generally suitable for the Expansion Project facilities, provided that adequate site preparation and foundation design and construction methods are implemented. CLNG would support all settlement sensitive structures on deep foundations. Lightly loaded structures or equipment insensitive to settlement may be supported on concrete pads.

Due to raising the site grade up to 11.5 feet above mean sea level (amsl), settlement of the soft soils would continue for a long time and create downdrag on piles. Therefore, piles would be designed for downdrag loads. The foundations would be supported on 14- or 18-inch-square prestressed or auger cast concrete piles designed for downdrag.

Cameron LNG's Terminal Expansion would be constructed to satisfy the design requirements of 49 CFR 193, NFPA 59A-2001, 2006 International Building Code, and American Society of Civil Engineer (ASCE) 7-05. For seismic design, the facility would also be designed to satisfy the requirements of NFPA 59A-2006 and ASCE 7-05.

No significant impacts to site topography would occur during construction of the Expansion Project facilities. The proposed facilities would be constructed within areas of the ongoing Liquefaction Project that have been previously cleared, grubbed, filled and brought to grade. In addition, primary surface drainage features would have already been constructed for the Liquefaction Project site, therefore only minor topography changes are anticipated for the Expansion Project facilities.

Construction and operation of the Expansion Project would not materially alter the geologic conditions of the site and the Expansion would not affect mining resources during construction or operation. Blasting is not anticipated. The Expansion Project would not be affected by any significant geologic hazards, including areas of seismic activity or subsidence. Based on CLNG's proposal, including implementation of its Environmental Plan (appendix 2), we conclude that impacts on geologic resources would be adequately minimized and would not be significant, and that the potential for impacts on the Expansion Project from geologic hazards would also be minimized.

The design of the facility is currently at the front-end engineering design (FEED) level of completion. Cameron LNG has proposed a feasible design, and it has committed to conducting a significant amount of detailed design work if the Expansion Project is authorized by the Commission. Information regarding the development of the final design would need to be reviewed by FERC staff in order to ensure that the final design addresses the requirements identified in the FEED. Therefore, **we recommend that:**

- CLNG file the following information, stamped and sealed by the professional engineer-of-record licensed in the state where the Expansion

Project is being constructed, with the Secretary of the Commission (Secretary):

a. LNG tank and foundation design based on the seismic design ground motions in Cameron LNG's Resource Report 13, Appendix I dated February 2013, early in the design phase and prior to construction;

b. site preparation drawings and specifications prior to construction;

c. structure and foundation design drawings and calculations of the liquefaction facilities prior to their construction;

d. seismic specifications used in conjunction with the procuring equipment prior to the issuing of requests for quotations;

e. quality control procedures that will be used for design and construction early in the design phase.

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

2.1.3 Natural Hazards

Geologic hazards that could potentially affect the Expansion Project site include earthquake ground motions and faulting, soil liquefaction, landslides, and subsidence. Other natural hazards of concern include hurricane winds as well as storm surge-related flooding.

Earthquake Ground Motions and Liquefaction

The proposed Expansion Project is in an area of low seismicity. Earthquakes have occurred in Louisiana, but their occurrence has been infrequent, with most having a magnitude too low to be felt by people or to have caused serious damage to property or structures (USGS 2001).

The expected peak ground acceleration in the Expansion Project area on a soft rock site, expressed as a percentage of the acceleration of gravity, is 4 percent for a 10 percent probability of exceedance in 50 years and 4 percent for a 2 percent probability of exceedance in 50 years (USGS, 2008). These peak ground accelerations can be amplified by factors of two or more on soft soil sites, which are typical of those in the vicinity of the Expansion Project.

The Seismic Design of the Expansion Project's Category I items, including the new LNG tank, are to be based on site-specific Safe Shutdown Earthquake (SSE) and

Operating Basis Earthquake (OBE) ground motions developed by Fugro (2012c). The site specific SSE is a ground motion which has a 2 percent probability of exceedance in 50 years while the OBE has a 10 percent probability of exceedance in 50 years. The site-specific peak ground and spectral acceleration values of the SSE and OBE are provided in table 2.1-1.

TABLE 2.1-1

Probability of Seismic Hazards at the Terminal Expansion [a]

Probability/Return Period	Peak Ground Acceleration (g)	Spectral Acceleration at 0.2 Second (g)	Spectral Acceleration at 1 Second (g)
10 percent in 50/475 years	0.041	0.107	0.075
2 percent in 50 /2475 years	0.121	0.292	0.230

[a] From Tables 7.2-1 and 7.2-2 of Fugro (2012c) Maximum Rotated Component.

The facility structures and systems, other than the LNG tank and associated safety systems, are being designed to the seismic design ground motion as specified in ASCE 7-05.

Fugro (2012c) performed a site-specific Probabilistic Seismic Hazard Analysis for the Terminal Expansion to determine the ". . . location, size, and resulting shaking intensity of future earthquakes . . ." and ". . . [a] description of the distribution of future shaking that may occur at a site" based on Baker (2008). The results of the analysis are presented in table 2.1-1. The predicted ground accelerations are relatively low compared to other locations in the United States.

While some soils and surficial sediments within the Expansion Project are susceptible to liquefaction, the low peak ground acceleration indicates a low liquefaction potential. Therefore, earthquakes and liquefaction are not likely to affect construction or operation of the Expansion Project.

Faulting

A detailed geologic fault detection study (Fugro, 2015c) was submitted by CLNG to document the presence/absence of surface faulting at the site. Based on the study, it was concluded that there are no surface faults present at the terminal site, even though areas in close proximity of the Hackberry Salt Dome have a higher risk for surface faulting (i.e., radial faults extending from the dome) and the proximity to the coast (i.e., regional faults trending approximately parallel to the coast). Faulting is not likely to affect construction or operation of the Expansion Project.

Ground Subsidence

Subsidence is downward movement of near-surface material as a result of geologic or manmade-induced processes. Typical causes of localized subsidence include karst-related voids or sinkholes, underground mines, groundwater or other subsurface gas or fluid withdrawal, and dewatering and resettlement of recent deposits. There are no karst features within the Expansion Project site. All key Expansion Project facilities would be installed on piles at depths such that the facilities would not be susceptible to subsidence, as described in section 2.1.2, Foundation Conditions, of this EA. Additionally, foundations and other critical facilities would be monitored to ensure that they remain within acceptable limits. Subsidence is not likely to affect construction or operation of the Expansion Project.

Landslides

The ground surface in this part of the gulf coast regions is relatively flat with very little grade change. Therefore, landslides are not expected on or in the area of the Expansion Project.

Wind

The Expansion Project would be designed to satisfy the design wind speed requirements in 49 CFR 193.2067; therefore, we do not consider that construction or operation of the Expansion Project would be significantly impacted by wind speed.

Flooding

CLNG considered the potential threat of storm surge associated with hurricane winds in its facility design. The Expansion Project's Storm Surge Study (Moffat and Nichol 2012) indicated that the 500 year still water level with sea level rise for the Expansion Project site is 12.4 feet amsl. Sea level rise includes subsidence and global sea level rise of 0.5 foot over the 20 year design life of the facility. Based on this, the minimum point of support elevation for equipment would be set at 12.5 feet amsl.

The proposed Expansion Project site is subject to flooding from hurricanes, tropical storms, and other weather systems. CLNG's design considers a hurricane storm surge with a 500-year return period. When subsidence and the rise in sea level are considered, the resulting design elevation to be resisted is several feet greater than the 100-year base flood map elevations provided in the FEMA Flood Risk Insurance Maps.

We conclude that construction and operation of the Expansion Project would not likely be adversely affected by flooding.

2.2 Water Resources, Fisheries, and Wildlife

2.2.1 Water Resources

2.2.1.1 Groundwater

Geographic Information System (GIS) electronic records obtained from the LDNR Strategic Online Natural Resources Information System (SONRIS) and review of the Louisiana Groundwater Law indicated that the previously authorized CLNG Terminal site was not within an "Area of Groundwater Concern" or "Critical Area of Groundwater Concern" (LDNR, 2012). The Expansion Project would be wholly within the limits of the LNG Terminal site and utilize the same groundwater sources.

Local surficial groundwater sources consist of discontinuous beds of sand near the surface, which provide small quantities of groundwater for domestic use. Depth to groundwater within the Cameron and Calcasieu Parish surficial water bearing zones typically ranges from two to 10 feet with water-bearing zones being present at roughly 10, 20, and 50 feet, depending on local geology. Permeability within the surficial geology varies, but is less than that of the Chicot Aquifer (USGS, 1998). There are no springs within 150 feet of the proposed construction area.

During construction of the Expansion Project, water would be supplied from the existing on-site water well. Approximate water use would be as follows; hydrostatic testing of the LNG storage tank would require about 30 million gallons, hydrostatic testing of the piping would require about 10 million gallons, dust control would require about 28 million gallons, and concrete batch plant operations would require about 560 thousand gallons.

Water supply to the existing CLNG Terminal is through an existing 10-inch-diameter line from the City of Hackberry. This water supply is also being utilized for the Liquefaction Project. The same water supply would be utilized for operations of the Expansion Project. Approximately 68.5 million gallons of water would be used during construction of the Expansion Project.

There are a total of three water wells (1 active, 1 inactive, 1 abandoned) on the CLNG Terminal site and would be within 150 feet of the Expansion Project (LDNR, 2012). Two of these wells were drilled for use during the construction of the original LNG Terminal. One well is active and would be utilized during construction of the Expansion Project, the other has been plugged and abandoned. The third well (number 019-51042) within the LNG Terminal site is an inactive domestic water supply well as described in the LDEQ records previously drawing water from the 200-foot sand of the Lake Charles Area.

There are a total of two water wells (1 active, 1 abandoned) on properties adjacent to the existing LNG Terminal. These wells (numbers 023-216 and 023-217) are part of a rural public water supply system operated by Cameron Parish Waterworks, Water Supply District 10. Well 023-217 is an active well drawing water from the 500-foot sand of the Lake Charles Area. Well 023-216 is an abandoned well installed by the Water Supply District as a test hole for well number 023-217. Both wells are in a small fenced parcel of property owned by Cameron Parish Waterworks that is bound on three sides by the existing CLNG Terminal property. These wells are not within 150 feet of Expansion Project construction activities.

No significant impacts are expected to occur on groundwater resources from construction or operation of the Expansion Project. Potential impacts on groundwater resources would be avoided or minimized by the use of both standard and specialized construction techniques. Specifically with regard to the Cameron Parish Waterworks well, CLNG would not conduct construction activities within 150 feet of this well. In addition, no refueling activities would be allowed within 400 feet of the well.

Some groundwater withdrawals (such as dewatering for foundation construction) would be required, but these withdrawals would only potentially affect the surficial aquifer and not the deeper aquifers that are used for potable water supply. No significant withdrawals from the surficial aquifer would be required for the operation or maintenance of the Expansion Project. Therefore, we do not anticipate the Expansion Project to permanently affect the surficial aquifer.

No adverse effects on groundwater resources are anticipated from the placement of foundations for the Expansion Project facilities. The deepest structures for the Expansion Project would be the piles used for the LNG storage tank (T-205). The outer piles would be driven to a depth of approximately 110 feet and the inner piles to a depth of 95 feet. These piles and all other foundations and piles would be well above the water table of the shallowest aquifer, the 200-foot sand aquifer.

If contaminated groundwater is encountered, CLNG would immediately discontinue any activities that may be using such water and any activities which could potentially be causing contamination. CLNG would investigate the situation to determine that construction activities are not the cause of the contamination and would properly dispose of any water collected.

No significant groundwater drawdowns from the deeper aquifers (200-foot and 500-foot sand aquifers) are anticipated due to the use of the on-site well for the hydrostatic test of the LNG storage tank (T-205), as none were observed during the hydrostatic testing of the three previously constructed LNG storage tanks.

No blasting activities are anticipate during construction, therefore no adverse effects due to blasting on water wells, springs, and wetlands are expected and accordingly, no measures would be required to detect and remedy such effects.

CLNG's SPC Plan would be utilized during construction and operation of the Expansion Project to prevent spills, leaks, or other releases of hazardous materials that could adversely impact groundwater quality from entering groundwater. We conclude that CLNG's proposed mitigation, and use of the CLNG SPC Plan would minimize effects on groundwater within the Expansion Project site. CLNG's SPC Plan is contained within the Environmental Plan in appendix 2.

2.2.1.2 Surface Water

The Expansion Project facilities would be constructed completely within the existing LNG Terminal site. No surface waterbodies are within the Expansion Project area. However, the Calcasieu River lies directly east of the LNG Terminal site.

The proposed Expansion Project would be constructed within the existing LNG Terminal site but away from the perimeter edges, therefore construction activities would not directly affect the Calcasieu River-Calcasieu Ship Channel.

Land disturbing activities required for the construction of the Expansion Project would be confined to the existing graded portions of the existing CLNG Terminal site. Land disturbance would be minimal with no grubbing or clearing and minimal grading and soil disturbance required. To minimize the impacts of erosion and sedimentation on surface waters, land disturbing and construction activities would be conducted in compliance with the CLNG Environmental Plan. Accordingly, CLNG would install erosion and sedimentation control structures as needed and specified in its Environmental Plan.

CLNG would implement its SPC Plan during construction to prevent spills, leaks, or other releases of hazardous materials that could adversely impact water quality. The SPC Plan is included in the CLNG Environmental Plan (appendix 2) described above.

Because the Expansion Project would be constructed wholly within the existing LNG Terminal site's graded footprint, no additional stormwater or stormwater outfalls would be required. Stormwater and other discharges from operation of the LNG Terminal would be in accordance with the existing CLNG Terminal's Louisiana Pollutant Discharge Elimination System (LPDES) permit for stormwater and industrial wastewater.

No additional work would be conducted to maintain the marine basin or the construction dock at the LNG Terminal site.

The number of ships traveling to and from the existing LNG Terminal would not increase beyond the number of vessels previously approved by the USCG for the existing terminal. No increase in ballast water discharge is expected. There would also be no increase in the amount of cooling water used while the ships are at the terminal because there would be no change in ship traffic above the number previously analyzed.

A temporary increase in barge traffic to and from the construction dock would be associated with the transportation of construction equipment and supplies. Barge traffic would occur primarily during the construction period and would have only temporary effects, which may include suspension of sediment from tug propeller wash or unintentional groundings in the dock area.

We do not anticipate significant impacts on or modifications of surface water quality due to ship or temporary barge traffic.

2.2.1.3 Hydrostatic Testing

The Expansion Project would require hydrostatic testing of the LNG storage tank (T-205). Piping would be tested using hydrostatic or pneumatic testing. In general, cryogenic piping will be pneumatically tested with dry air or nitrogen at 1.1 times design pressure. Non-cryogenic piping will be hydrostatically tested using clean water at 1.5 times design pressure. Hydrostatic test water would be withdrawn from the on-site water well. No chemicals would be added to the hydrostatic test water before or after testing. All hydrostatic test water would be sampled, tested, and discharged in accordance with Louisiana General Permit LAG67000 for discharge of hydrostatic test wastewater discharges. As allowed by permit, discharges would be either through internal or external outfalls. All test water discharges would be conducted in accordance with the CLNG Environmental Plan. We conclude that effects from hydrostatic testing at the LNG Terminal would be negligible and temporary.

2.2.1.4 Floodplain Management

Executive Order (EO) 11988: Floodplain Management, issued on May 24, 1977, requires federal agencies to avoid adverse effects on the 100-year floodplain, when possible.

The Expansion Project would be constructed outside of the 100-year floodplain. During construction, CLNG would use and maintain appropriate erosion and sedimentation measures to prevent the movement of disturbed materials off construction workspaces. The design of the facilities includes stormwater management measures to control runoff, erosion, and sedimentation during operation. These measures would minimize impacts on adjacent floodplains. We conclude that construction and operation of the Expansion Project would comply with EO 11988.

2.2.2 Fisheries

There are no waterbodies within the existing CLNG Terminal, although the terminal is adjacent to the Calcasieu River/Ship Channel. It is classified as a warm water marine or estuarine waterbody.

There would be no direct in-water impacts associated with the Expansion Project. A temporary increase in barge traffic to and from the construction dock would be associated with the transportation of construction equipment and supplies. While barge traffic may temporarily increase disturbance to the water column and disturb sediment in the vicinity of the construction dock, these impacts are consistent with the active shipping areas.

No additional work would be conducted to maintain the marine basin at the existing CLNG Terminal as a result of construction and operation of the Expansion Project, and routine maintenance dredging would continue.

The number of LNG ships traveling to and from the existing CLNG Terminal would not increase beyond what is currently authorized. No increase in ballast water discharge is expected. There would also be no increase in the amount of cooling water used while the ships are at the terminal beyond the amount currently evaluated. There would be no impacts on fisheries from construction and operation of the new facilities.

As described in section 2.2.1.3, the non-cryogenic piping and the new LNG storage tank (T-205) at the CLNG Terminal would be tested to ensure structural integrity before the facility is placed into service. Hydrostatic test water would be withdrawn from the existing onsite well. After testing, hydrostatic test water would be discharged in accordance with LDEQ permit conditions and CLNG's Environmental Plan. Impacts associated with hydrostatic testing are expected to be temporary and negligible.

Based on the characteristics of the identified fisheries, our review of hydrostatic test water withdrawal and discharge methods, and implementation of impact minimization methods, we have determined that constructing and operating the Expansion Project would not significantly affect fisheries.

2.2.3 Wildlife

Impacts on wildlife from construction of the Expansion Project would be temporary and considered not significant because construction would occur within the disturbed LNG Terminal site. The Expansion Project would add additional light and noise to the LNG Terminal, but the amounts would not be appreciable. Mobile wildlife species would be temporarily displaced from the construction workspace to surrounding habitats nearby. Further, there is an abundance of suitable habitat for wildlife species adjacent to the construction and operational areas. We conclude that the Expansion Project would not significantly affect wildlife.

2.2.3.1 Migratory Birds

Migratory birds are protected under the Migratory Bird Treaty Act of 1918 ([MBTA] -16 U.S. C.703-711) and Bald and Golden Eagles are additionally protected under the Bald and Golden Eagle Protection Act (16 U.S.C. 668-668d). EO 13186 (66 Federal Register 3853) directs federal agencies to identify where unintentional take is likely to have a measurable negative effect on migratory bird populations and to avoid or minimize adverse impacts on migratory birds through enhanced collaboration with the FWS. EO 13186 states that emphasis should be placed on special species of concern, priority habitats, and key risk factors, and that particular focus should be given to addressing population-level impacts.

On March 30, 2011, the FWS and the Commission entered into a Memorandum of Understanding that focuses on avoiding or minimizing adverse impacts on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the Commission and the FWS by identifying areas of cooperation. This voluntary Memorandum does not waive legal requirements under the MBTA, Bald and Golden Eagle Protection Act, the Endangered Species Act of 1973 (ESA), the Federal Power Act, the NGA, or any other statutes and does not authorize the take of migratory birds.

CLNG received concurrence from FWS for the Expansion Project that no mitigation for migratory birds was required for the Project. Construction and operation of the Expansion Project would be entirely within previously disturbed and improved areas of the LNG Terminal and site. We agree with the FWS.

2.2.4 Special Status Species

Federal agencies are required by Section 7 of the ESA to consult with the FWS to ensure that any action they authorize, fund, or carry out would not jeopardize the continued existence of a federally listed threatened or endangered species or species proposed for listing. As the lead federal agency, the FERC is responsible for the Section 7 consultation with the FWS. In accordance with Section 380.13(b) of FERC's Order 603, however, the Project sponsor is designated as FERC's non-federal representative for purposes of initial coordination and informal consultation with the FWS. In compliance with ESA, CLNG has been assisting the FERC in meeting its Section 7 obligations by conducting informal consultations with the FWS and, NMFS about species under their jurisdictions that would be potentially affected by the Expansion Project. In addition, CLNG also consulted with the LDWF.

We identified 10 federally listed species as potentially occurring in the Expansion Project area through consultation with the FWS, Lafayette Office, and the LDWF. They determined the possible presence of five federally listed endangered species, red-cockaded woodpecker (RCW), West Indian manatee, hawksbill sea turtle, leatherback turtle, Kemp's ridley sea turtle; four federally listed threatened species, gulf sturgeon, piping plover, green sea turtle, loggerhead sea turtle; and one federal candidate species, Sprague's pipit. Candidate species do not receive protection under the ESA; however, the FWS (2013) encourages avoidance of activities that would negatively impact Sprague's pipit. As such, we are evaluating potential impacts on this species in this EA. Table 2.2-1 lists the special status wildlife species that may occur in the Expansion Project area and the potential effects the Expansion Project poses to each species.

TABLE 2.2-1

Federal and State-Listed Species Potentially Occurring in the Project Area

Common Name	Federal Status	State Status	Suitable Habitat	Effects
Fish				
Gulf Sturgeon	Threatened	Threatened	No Suitable Habitat	No Effect
Birds				
Piping Plover	Threatened	Threatened/ Endangered	No Suitable Habitat	No Effect
Red-cockaded Woodpecker	Endangered	Endangered	No Suitable Habitat	No Effect
Sprague's Pipit	Candidate	Not Listed	No Suitable Habitat	No Effect
Mammal				
West Indian Manatee	Endangered	Endangered	No Suitable Habitat	No Effect
Reptiles				
Hawksbill Sea Turtle	Endangered	Endangered	No Suitable Habitat	No Effect
Green Sea Turtle	Threatened	Threatened	No Suitable Habitat	No Effect
Leatherback Turtle	Endangered	Endangered	No Suitable Habitat	No Effect
Kemps' Ridley Sea Turtle	Endangered	Endangered	No Suitable Habitat	No Effect

TABLE 2.2-1 Federal and State-Listed Species Potentially Occurring in the Project Area				
Loggerhead Turtle	Threatened	Threatened	No Suitable Habitat	No Effect

The Expansion Project would be constructed entirely within the CLNG Terminal site. The Louisiana Natural Heritage Program (LNHP) provided concurrence, on September 25, 2012, indicating that based on review of their database, no impacts to rare, threatened, or endangered species or critical habitats are anticipated for the Liquefaction Project. On October 9, 2012, a response of "is not likely to adversely affect these resources," was received from the FWS regarding the development of the Liquefaction Project. Based on the proposed location of the Expansion Project activities and previous determinations, we conclude that the Expansion Project is not likely to adversely affect any federally listed species. However, on May 19, 2015, CLNG initiated correspondence with the FWS, the NMFS, and the LNHP to confirm the Expansion Project "is not likely to adversely affect," federal or state listed species.

2.3 Land Use, Recreation, and Visual Resources

2.3.1 Land Use

No new land would be required for the Expansion Project. The Expansion Project would be constructed on 60 acres located entirely within CLNG Terminal site. No other land use impacts would occur due to construction. The land use within the CLNG Terminal site is classified as Industrial, High Intensity. CLNG's previously developed Traffic Management Plan[5] includes the busing of workers to offset traffic impacts from the Liquefaction Project. This Traffic Management Plan is sufficient for the Expansion Project. Material delivery to the site would also be mitigated by the use of barges to the proposed construction dock and by minimizing delivery during peak traffic periods.

Coastal Zone Management

Section 307(c) (3) of the Coastal Zone Management Act requires that all federally licensed and permitted activities be consistent with approved state Coastal Zone Management Programs. The LDNR's OCM, administers the state's Coastal Zone Management Program and is the lead state agency that performs federal consistency reviews. The Expansion Project is within the coastal zone boundary, which is defined by

5 CLNG filed the Traffic Management Plan for the CLNG Terminal Liquefaction Project under FERC Docket No. CP13-25-000.

the area south of the Gulf Intracoastal Waterway with exception of areas above the five foot contour.

The Expansion Project facilities would be constructed completely within the CLNG Terminal site which is currently authorized by the OCM. Although the Expansion Project facilities would be constructed in areas well above the five foot contour, the Expansion Project would be designed and developed in consultation with LDNR and in compliance with Louisiana Coastal Zone consistency guidelines. Given the Expansion Project facilities would be constructed wholly within the disturbed land authorized under the Liquefaction Project Coastal Use Permit, the permit has been revised to reflect the new facilities.

On June 21, 2015, the LDNR, OCM, Permits/Mitigation Division, issued an Amended Coastal Use Permit/Consistency Determination (P20121194) for the Expansion Project. Subsequently, the COE issued an amended Section 404 of the CWA Permit (MVN-2002-3266-WII) for the Expansion Project. By accepting the permits, CLNG would agree to comply with permit conditions in accordance with the rules and regulations of the Louisiana Coastal Resources Program and Louisiana R. S. 49 Sections 214.21 and 214.41, the State and Local Coastal Resources Management Act of 1978, as amended. The permit authorizes the initiation of the permitted coastal use within two years from the date of its initial issuance.

2.3.2 Recreation and Public Interest Areas

The Expansion Project would be within the footprint of the existing CLNG Terminal site and would not cross public or conservation lands. The Creole Nature Trail, which is designated an All American Road and a Louisiana State Scenic Byway, includes the portion of LA 27 that passes along the west side of the existing CLNG Terminal where the Expansion Project would be located. LA 27 would be the primary road access for workers and material transport, and construction activities may delay or temporary affect vehicular traffic during peak hours. CLNG would implement their Traffic Management Plan to alleviate congestion on LA 27.

Designated natural and recreational areas in the vicinity of the Expansion Project include the Sabine National Wildlife Refuge (located about eight miles south of Hackberry, Louisiana) and Cameron Prairie National Wildlife Refuge (located about 25 miles southeast of Lake Charles, Louisiana). The nearest marina is located about two miles to the south of the Liquefaction Project site, near Hackberry. We conclude that construction and operation of the Expansion Project would not affect these recreational resources.

2.3.3 Visual Resources

The majority of the construction activities for the Expansion Project would take place concurrently with the activities for the Liquefaction Project. Construction of all facilities associated with the Expansion Project would result in temporary visual impacts on the immediate area consistent with that of the LNG Liquefaction Project. Therefore, the level of temporary visual impacts on the immediate area would remain essentially unchanged, but the duration of those visual impacts would be lengthened by approximately 12 – 18 months.

The construction of the Expansion Project's liquefaction Trains 4 and 5 and the new LNG storage tank (T-205) would result in a permanent change in the visual resources. These impacts would be relatively minimal because construction would occur in an industrial area within the CLNG Terminal site and construction is already under way at the site for liquefaction Trains 1 through 3.

The construction of liquefaction Trains 4 and 5, the new LNG storage tank (T-205) and associated facilities would be within the CLNG Terminal site that is already part of the visual environment. Liquefaction Trains 4 and 5 would be installed next to liquefaction Trains 1 through 3, which are already under construction at the CLNG Terminal, and would be constructed and lit in the same manner. The Expansion Project would constructed within a previously disturbed area of the CLNG Terminal site. No changes in land use would result for the construction and operation of the Expansion Project. Intermittent views of the facility would be available to boaters in the Calcasieu River/Calcasieu Ship Channel and motorists using LA 27. The visual impact of the construction and operation of the Expansion Project would be relatively minor because it located within an existing, similar industrial facility and construction of liquefaction Trains 4 and 5 and the new LNG storage tank (T-205) would be consistent with the existing viewshed. Therefore, we do not believe there would be a significant cumulative visual resources impact.

2.4 Socioeconomics

Socioeconomics is an evaluation of the basic conditions (attributes and resources) associated with the human environment, particularly the population and economic activity within a region. Economic activity generally encompasses regional employment, personal income, and revenues and expenditures. Impacts on these fundamental socioeconomic components can influence other issues such as regional housing availability and provision of community services.

This section addresses several different factors that could affect the quality of life and economy in the area surrounding the Expansion Project where employees might live, shop, and use public resources. These factors include public services such as fire, police, and medical facilities; educational facilities; and environmental justice.

For the purpose of this analysis the region of influence (ROI) includes all geographic areas within reasonable commuting distance for local hires (15 to 16 miles from the Expansion Project location). This area includes portions of Cameron and Calcasieu parishes where construction would take place.

2.4.1 Population and Demographics

Table 2.4-1 provides a summary of selected population and demographic information for the area in and around the Expansion Project area.

TABLE 2.4-1

Existing Population and Demographics

State/ Parish	Population			Population Density (per square mile)	
	1990[(a)]	2000[(a)]	2014 (est.) [(a)]	2000 [(a) (b)]	2014 [(a) (b)]
Louisiana	4,219,976	4,468,976	4,649,676	103.4	107.6
Cameron	9,260	9,991	6,679	7.8	5.2
Calcasieu	168,134	183,577	197,204	172.5	185.4

(a) U.S. Census Bureau, State and County *Quick Facts*

(b) Persons per square mile, based on population and area size: Louisiana (43,203.9 sq. mi.), Calcasieu Parish (1063.7 sq. mi.), Cameron Parish (1,284.9 sq. mi).

2.4.2 Employment and Income

Table 2.4-2 provides a summary of selected employment and income statistics for the area in and around the Expansion Project site.

TABLE 2.4-2

Existing Socioeconomic Conditions

State/ Parish	Per Capita Income	Labor Force	Unemployment Rate (percent)	Top Major Industries
	2014 [(a)]	2014[(c)]	2014 [(c)]	2013 [(b)]

TABLE 2.4-2

Existing Socioeconomic Conditions

State/ Parish	Per Capita Income 2014 [(a)]	Labor Force 2014[(c)]	Unemployment Rate (percent) 2014 [(c)]	Top Major Industries 2013 [(b)]
Louisiana	$24,442	2,159,000	6.4	1. Manufacturing 2. Construction
Cameron	$29,559	3,510	4.8	1. Sales & Office 2. Production & Transportation 3. Management & Professional
Calcasieu	$24,355	94,601	5.9	1. Management & Professional 2. Sales & Office Service

(a) U.S. Census Bureau, State and County *Quick Facts*
(b) Louisiana Works Department of Labor, *Louisiana Workforce at a Glance*
(c) U.S. Department of Labor, Bureau of Labor Statistics, *Local Unemployment Statistics, Labor Force Data by County 2014.*

2.4.3 Housing

With an increase in non-local workers during both construction and operation, housing within the ROI becomes an important socioeconomic factor. Table 2.4-3 provides summary of the housing characteristics for the area in and around the Expansion Project site.

TABLE 2.4-3

2013 Housing Characteristics in Affected Parishes[(a)]

State/Parish	Owner Occupied (percent)	Renter Occupied (percent)	Owner Vacancy Rate (percent)	Rental Vacancy Rate (percent)
Louisiana	67.0	33.0	1.9	8.2
Cameron	90.0	10.0	3.6	10.3
Calcasieu	70.6	29.4	1.9	9.9

(a)	U.S. Census Bureau; 2009-2013 American Community Survey 5-year Estimates, Selected Housing Characteristics, Table DP04; American Fact Finder; <http://factfinder2.census.gov>; (26 May 2015).

The Expansion Project would utilize the construction workforce hired for the ongoing Liquefaction Project. CLNG anticipates adding approximately 90 additional permanent staff positions to operate the Expansion Project facilities.

Due to the adequate availability of housing in the ROI for both the construction and operation workforce and the fact that construction at the site would not be significantly increased from what is required for the ongoing Liquefaction Project, we conclude that no negative impacts on housing resources are anticipated during the construction and operation of the Expansion Project.

2.4.4 Public Services

This section describes the community and public services available within the ROI, including schools, emergency response protocol and medical facilities, and fire and police protection.

Education and School System

Cameron Parish has five public schools with a 2013 enrollment of 1,279 (LDE, 2014). There are 58 primary and secondary public schools in Calcasieu Parish, with a 2013 enrollment of 32,271 students (LDE, 2014). Based on the analysis completed for the CLNG Liquefaction Project (Docket No. CP13-25-000), the Liquefaction Project will result in a 0.08-percent increase in school enrollment in these parishes. The Expansion Project would utilize the same construction workforce, so there would be no new impact on school enrollment during construction. Based on current census data, the average family size in Calcasieu Parish is 2.57, and in Cameron Parish is 2.67 (U.S. Census Bureau, 2015a). Using a very conservative estimate that each of the additional 90 permanent operational employees for the Expansion Project do not currently live in the area and will have to relocate and that each family has 2 children; the result would be an additional 180 children to be accommodated by the parish school systems or a 0.5 percent increase in enrollment

We conclude that impacts from the addition of 90 full-time workers on the local school system are expected to be negligible.

Health Care

There is one hospital in Cameron Parish with a combined total of 33 beds (LDHH, 2007) and ten hospitals located in Calcasieu Parish with a combined total of 1,540 beds (LDHH, 2007).

Health care demands during the construction phase are expected to include emergency medical services to treat injuries resulting from construction accidents. Medical facilities within the ROI are sufficient to absorb any increase in demand by the temporary construction workforce, with minimal cost to the local governments. Ultimately, we conclude that impacts on the local hospitals are expected to be negligible. The addition of about 90 full-time permanent workers at the CLNG Terminal would have a negligible effect on hospitals.

Police and Fire Services

Cameron Parish has a sheriff's department and nine volunteer fire protection districts (Cameron Parish Police Jury, 2012). Calcasieu Parish has a sheriff's office, six police departments, and nine fire protection districts (Calcasieu Parish, 2012).

Construction-related demands on local agencies could include increased enforcement activities associated with issuing permits for vehicle load and width limits, local police assistance during construction at road crossings to facilitate traffic flow, and emergency medical services to treat injuries resulting from construction accidents. Police and fire departments within the ROI can absorb any increase in demand by the temporary construction workforce with minimal cost to the local governments. Further, the existing CLNG Terminal has 24-hour on-site security, which would minimize reliance on local law enforcement. The existing LNG Terminal also has an on-site firewater pond and pumps with sufficient capacity to respond to fires. We conclude that construction of the Expansion Project would have only minor and temporary negative impacts on the local police and fire services. The addition of about 90 full-time permanent workers at the CLNG Terminal would have a negligible effect on police and fire services.

2.4.5 Transportation

Existing public road, LA 27, would be used to transport construction equipment, materials, and workers to the Expansion Project site. LA 27 runs north-south adjacent to the west side of the Expansion Project site. The Expansion Project would utilize the entrances located on LA 27 already approved for the existing CLNG Terminal. Parking for construction workforce would be provided both at on-site and at off-site locations with bus transportation. Material deliveries to the site will occur throughout the construction phase.

Traffic impacts associated with the Expansion Project would be the same as those analyzed for the Liquefaction Project. Neel-Schaffer, Inc. conducted a traffic study of LA

27 adjacent to the Liquefaction Project site for the Liquefaction Project in April 24, 2013. That study was filed with the Commission (Docket No. CP13-25-000) on April 26, 2013. A Traffic Management Plan was subsequently developed by CLNG and submitted to the Commission on October 30, 2014 (Docket No. CP13-25-000). In the Final Environmental Impact Statement (FEIS) prepared for the Liquefaction Project, we concluded that, with the implementation of the Traffic Management Plan, there would be no significant impacts to existing traffic conditions during construction or operation of the Liquefaction Project. The plan is currently in use for the Liquefaction Project and would be utilized for the Expansion Project.

Barges would deliver the majority of large equipment and materials, such as soil and rock fill, to the work dock during construction. This would reduce the number of truck trips to and from the Expansion Project site as well as the potential for damage to local roadways and traffic congestion. The Expansion Project would not significantly increase the barge traffic currently planned for the Liquefaction Project.

2.4.6 Environmental Justice

In 1994, EO 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, was issued to focus the attention of federal agencies on human health and environmental conditions in minority and low-income communities (The White House, 1994). In 1997, EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, expanded the focus to include children populations. The EOs require that impacts on minority or low-income populations and children be taken into account when preparing environmental and socioeconomic analysis of projects or programs that are proposed, funded, or licensed by federal agencies. EOs 12898 and 13045 are described in more detail below.

- *EO 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (February 1994)* requires federal agencies to identify and take necessary measures to address disproportionately high and adverse human health or environmental effects of its actions on these populations to the greatest extent practicable permitted by law and also involve representatives of these populations in the community participation and public involvement process (The White House, 1994).

- *EO 13045, Protection of Children from Environmental Health Risks and Safety Risks (April 1997)* requires a similar analysis for children, where federal agencies are required to identify and address the potential environmental health risks and safety risks of its actions that may disproportionately affect children (The White House, 1997).

The Expansion Project would be located within CLNG Terminal site and not near any low-income or minority population areas. Therefore, there would not be any disproportionately high or adverse environmental and human health impacts to low-income and minority populations. During operation, the Expansion Project would have positive socioeconomic effects on minority and economically disadvantaged populations as well as the general population in the ROI through job creation, economic activity, and continuing tax payments. Construction and operation of the Expansion Project would not generate significant levels of air quality emissions (either nuisance or human health hazards) off-site. Additionally, no significant impacts on water quality or noise are expected to affect the health or welfare of the population living in the ROI. The minor impacts that would occur would be temporary or would be about the same as existing noise conditions in the area (see section 2.6.2).

We conclude that construction and operation of the Expansion Project would not disproportionately affect any population group, and no environmental justice or protection of children issues are anticipated as a result of construction or operation of the Expansion Project.

2.5 Cultural Resources

All construction activities would take place in areas previously approved under Docket No. CP13-25-000. Cultural resources/Section 106 review and tribal consultation completed under that docket concluded that no historic properties would be affected. CLNG would implement the Unanticipated Discoveries Plan approved under Docket No. CP13-25-000. In addition, CLNG re-contacted the Louisiana State Historic Preservation Office (SHPO) regarding the current Expansion Project activities. On July 17, 2015, the SHPO indicated that "no known historic properties will be affected by this undertaking." We agree.

2.6 Air Quality and Noise

2.6.1 Air Quality

Air quality would be affected by construction and operation of the Expansion Project. Although air emissions would be generated by equipment operations during construction of the Expansion Project, most air emissions associated with the Expansion Project would result from the long-term operation of liquefaction Trains 4 and 5 and associated facilities proposed by CLNG.

2.6.1.1 Existing Environment

The general area in the vicinity of the Expansion Project has a modified marine climate which can be influenced by a predominant onshore flow of tropical marine air from the Gulf of Mexico. During onshore flow events, the area experiences a subtropical humid climate. In summer, sea breezes help decrease temperatures. Based on data from the National Climatic Data Center's (NCDC) Climatology of the United States No. 20 (NCDC 2010), which provides data from 1971 to 2000, maximum and minimum temperatures at the Port Arthur Airport in Beaumont, Texas (the data collection point that is closest to the proposed Expansion Project) usually occur in July and January, respectively.

Mean annual precipitation falling at the Port Arthur Airport is 59.9 inches, while monthly average precipitation is from 3.35 inches in February to 6.58 inches in June. Thunderstorms occur in the area approximately 60 days per year and the average annual snowfall is 0.3 inch.

Winds in the area are generally from the south, with average wind speeds around 9 miles per hour. Winds from the southwest through north-northwest are quite rare. Wind direction can vary by season; spring winds are from the south through southeast, summer winds are from the south and west-southwest; fall winds are from the north clockwise through south; and in winter, winds are from the north.

2.6.1.2 Ambient Air Quality

Ambient air quality is protected by federal and state regulations. The Clean Air Act (CAA) and its amendments designate six pollutants as criteria pollutants for which National Ambient Air Quality Standards (NAAQS) are promulgated. The NAAQS for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter (PM), including PM less than 10 microns in aerodynamic diameter (PM10) and PM less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$), carbon monoxide (CO), ozone (O_3), and lead (Pb) were set by the EPA to protect human health (primary standards) and public welfare (secondary standards). Individual states are allowed to establish their own air quality standards, however these standards cannot be less stringent than the NAAQS. The current NAAQS and LDEQ standards for these criteria pollutants are summarized in table 2.6-1.

TABLE 2.6-1

National Ambient Air Quality Standards

Air Contaminant	NAAQS		LDEQ	Averaging Time
	Primary	Secondary	Primary	
CO	35 ppm	NA	35 ppm	1-hour
	9 ppm	NA	9 ppm	8-hour

TABLE 2.6-1

National Ambient Air Quality Standards

Air Contaminant	NAAQS		LDEQ	Averaging Time
	Primary	Secondary	Primary	
Pb	0.15 µg/m^3	0.15 µg/m^3	1.5 µg/m3	3-month (NAAQS) Calendar Quarter (LDEQ)
NO_2	100 ppb	NA	NA	1-hour
	53 ppm	53 ppb	0.05 ppm	Annual
O_3	0.075 ppm	0.075 ppm	0.08 ppm	8-hour
$PM_{2.5}$	35 µg/m^3	35 µg/m^3	35 µg/m^3	24-hour
	12 µg/m^3	15 µg/m^3	15 µg/m^3	Annual
PM_{10}	150 µg/m^3	150 µg/m^3	150 µg/m^3	24-hour
SO_2	75 ppb	NA	NA	1-hour
	NA	0.5 ppm	NA	3-hour
	NA	NA	0.14 ppm	24-hour
	NA	NA	0.03 ppm	Annual

Source: EPA 2014, LDEQ Title 33, Part III, Chapter 7, §711 (July 2014)
Abbreviations:
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide
CO = carbon monoxide
NO_2 = nitrogen dioxide
O_3 = ozone
Pb = lead

NA = not applicable

mg = milligram(s)
µg = microgram(s)
m^3 = cubic meter(s)
ppm = part(s) per million
ppb = part(s) per billion

On December 7, 2009, the EPA defined air pollution to include six greenhouse gases (GHGs), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), finding that the presence of these GHGs in at the atmosphere endangers public health and public welfare through climate change.

As with any fossil-fuel fired project or activity, the Expansion Project would contribute GHG emissions. The principal GHGs that would be produced are CH_4, CO_2, and N_2O. No fluorinated gases would be emitted. Emissions of GHGs are typically quantified and regulated in units of carbon dioxide equivalents (CO_2e).

The CO_2e takes into account the global warming potential (GWP) of each GHG. The GWP is a ratio relative to CO_2 that is based on the properties of a GHG's ability to absorb solar radiation as well as its residence time in the atmosphere. Thus, CO_2 has a GWP of 1, CH_4 has a GWP of 25, and N_2O has a GWP of 298.[6] In compliance with EPA's definition of air pollution to include GHGs, we have provided estimates of GHG emissions for construction and operation, as discussed throughout this section. Impacts from GHG emissions (climate change) are described in more detail in section 2.6.1.4.

Air Quality Control Regions (AQCRs) were established in accordance with Section 107 of the CAA as a way to implement the CAA and to comply with the NAAQS through state implementation plans. The AQCRs are intra- and interstate regions such as large metropolitan areas where the improvement of the air quality in one portion of the AQCR requires emission reductions throughout the AQCR. Each AQCR, or portion thereof, is designated as attainment, unclassifiable, maintenance, or nonattainment for each of the six criteria pollutants. Areas where an ambient air pollutant concentration is determined to be below the applicable NAAQS are designated attainment. Areas where no data are available are designated unclassifiable and are treated as attainment areas for the purpose of permitting a stationary source of pollution. Areas where the ambient air concentration is greater than the applicable NAAQS are designated nonattainment. Areas that previously were designated nonattainment that are now meeting the NAAQS are designated maintenance for that pollutant. The following counties potentially affected by emissions from the Expansion Project are classified as attainment for all six of the NAAQS criteria pollutants: Cameron, Calcasieu, Beauregard, Allen, and Evangeline.

2.6.1.3 Regulatory Requirements

The CAA, as amended, is the basic federal statute governing air pollution. The provisions of the CAA that are potentially relevant to the Expansion Project include the following:

- PSD/Nonattainment New Source Review (NNSR);
- Title V Operating Permits;
- New Source Performance Standards (NSPS);

[6] U.S. EPA, 40 CFR 98, Subpart A, 79 FR 73779, Dec 11, 2014.

- National Emission Standard for Hazardous Air Pollutants for Source Categories (NESHAP);
- Chemical Accident Prevention Provisions;
- General Conformity; and
- GHG Reporting Rule.

Prevention of Significant Deterioration/Nonattainment New Source Review

Separate procedures have been established for federal pre-construction review of certain large proposed projects located in attainment areas versus nonattainment areas. Federal pre-construction review for affected sources located in nonattainment areas is commonly referred to as Nonattainment New Source Review (NNSR). This process is intended to keep new or modified major air emission sources from causing existing air quality to deteriorate beyond acceptable levels. Federal pre-construction review for affected sources located in attainment areas is formally called PSD. The CLNG Terminal is located in attainment areas and is, therefore, potentially subject to PSD regulations.

The PSD regulations under 40 CFR 52.21 define a major source as any source type belonging to a list of 28 sources categories which emits or has the potential to emit 100 tons per year (tpy) or more of any pollutant regulated under the CAA, or any other source type which emits or has the potential to emit regulated pollutants in amounts greater than 250 tpy [40 CFR 52.21(b)]. The Expansion Project does not fall under a listed source category, but it is considered a major source because it has the potential to emit more than 250 tpy of a pollutant regulated under the CAA. Major source emission thresholds are included in table 2.6-2. Table 2.6-3 provides a summary of the potential-to-emit as a result of the new equipment associated with the Expansion Project. Table 2.6-4 provides a summary of the total emissions for the existing CLNG Terminal including the ongoing Liquefaction Project.

On May 13, 2010, the EPA issued the PSD GHG Tailoring Rule. After July 1, 2011, the PSD major source threshold of 100,000 tpy of CO_2-eq became effective for new sources. For existing PSD major sources, the threshold for a modification is 75,000 tpy CO_2-eq.

The CLNG Terminal is an existing PSD major source, and the Expansion Project would be a major modification. As shown in table 2.6-2, the net emissions increase requires a PSD review for PM_{10}, $PM_{2.5}$.

NO_2, CO, and volatile organic compounds (VOCs). CLNG filed its revised air permit application with the LDEQ in May 2015.

The May 2015 permit application addresses emissions associated with the two additional liquefaction trains and the new LNG storage tank (T-205) associated with the Expansion Project and updated permitted equipment for liquefaction Trains 1 through 3. Changes to liquefaction Trains 1 through 3 reflect updates to the engineering design basis for those units.

The sum of the changes from the revised application are reflected in the emission totals shown in this section.

TABLE 2.6-2

Major Stationary Source/Major Modification Emission Thresholds for NAAQS Attainment Areas

Pollutant	**Major Stationary Source Threshold Level (tons/year)**	**Major Modification Significant Net Increase (tons/year)**
Ozone (as VOC or NO_x)	250	40
CO	250	100
SO_2	250	40
PM	250	25
PM_{10}	250	15
$PM_{2.5}$	250	10
Lead	250	0.6
GHG	100,000 tons/yr of CO_2e and 250 tons/yr of GHGs[a]	75,000 tons/yr of CO_2e and >0 tons/yr of GHGs [b]

[a] A facility is considered a major stationary source if the potential-to-emit is greater than 100,000 tons/year (tpy) of CO_2e and greater than 250 tpy of GHG (sum of six GHGs on a mass basis).
[b] A major modification must meet both conditions of greater than 75,000 tpy of CO_2e and exceed 0 tpy of GHG (sum of six GHGs on a mass basis).

TABLE 2.6-3

Potential to Emit Summary
(Expansion Project)

Emission Unit	Pollutant Emissions (tpy)						
	Nitrogen Oxides (NO_x)	**CO**	**SO_2**	**PM_{10}**	**VOC**	**VOC TAPs**	**CO_2e**
Refrigeration Compressor Turbines (4)	1023.82	623.28	3.24	146.08	35.02	19.53	2,178,200
Thermal Oxidizer CAP (Trains 4 & 5)	29.99	24.59	5.72	2.26	22.77	3.06	999,370
Low Pressure Flare	8.17	44.43	0.07	0.89	0.65	0.01	14,163
Ground Flare	10.84	58.99	0.10	1.19	4.45	0.34	19,652
Emergency Generators (3)	5.28	2.88	0.03	0.18	5.28	0.12	576
Emergency Fire Water Pumps (3)	0.45	0.39	0.03	0.03	0.45	0.12	78
Condensate Loading	-	-	-	-	0.89	-	-
Diesel Storage Tanks (2)	-	-	-	-	0.02	-	-
Fugitives	-	-	-	-	0.96	0.96	96
SSM Emissions	121.50	538.50	0.44	14.05	11.55	-	234,672
Total Facility	**1,200.05**	**1293.06**	**9.63**	**164.68**	**82.04**	**24.14**	**3,446,807**

TABLE 2.6-4

Currently Authorized Facilities Emissions Summary
(Existing CLNG Terminal and Liquefaction Project Facilities)

Emission Unit	Pollutant Emissions (tpy)						
	NO_x	CO	SO_2	PM_{10}	VOC	VOC TAPs	CO_2e
Submerged Combustion Vaporizer CAP	230.0	182.65	3.16	33.60	24.32	0.37	527,665
Fuel Gas Heater	1.40	0.88	0.01	0.12	0.09	0.04	1,947
Emergency Generators (2)	3.08	1.68	0.02	0.10	3.08	0.08	334
Emergency Fire Water Pumps (3)	0.75	0.24	0.03	0.03	0.75	0.12	48
Emergency River Water Pumps (2)	0.26	0.12	0.02	0.02	0.26	0.08	18
Diesel Storage Tank	-	-	-	-	0.01	-	-
Fugitives	-	-	-	-	1.11	0.02	164
Flare	12.19	66.31	0.11	1.34	0.97	0.01	21,279
Refrigeration Compressor Turbines (6)	1,535.73	934.92	4.86	219.12	52.53	29.30	3,267,300
Thermal Oxidizer CAP	44.98	36.89	8.59	3.37	34.15	4.58	1,499,055
Ground Flare	16.26	88.48	0.14	1.78	6.67	0.52	29,478
Emergency Generators (3)	5.28	2.88	.03	0.18	5.28	0.12	576
Emergency Fire Water Pumps (3)	0.45	0.39	0.03	0.03	0.45	0.12	78
Emergency River Water Pumps (2)	0.30	0.26	0.02	0.02	0.30	0.08	52
Condensate Loading	-	-	-	-	1.33	-	-
Fugitives (Trains 1-3)	-	-	-	-	1.44	1.43	144
SSM Emissions	121.50	538.50	0.44	14.05	11.55	-	234,672
Total Facility	**1,972.18**	**1,854.20**	**17.46**	**273.76**	**144.29**	**36.88**	**5,582,810**

Facilities can trigger additional review by the EPA if emissions exceed the PSD major source thresholds and if project-associated emissions exceed the PSD significant emission rate for existing facilities defined as a PSD major source. The revised air permit application and addendum is still under LDEQ's review. CLNG would be subject to the emissions limitations, monitoring requirements, and other conditions set forth in the permit.

On June 23, 2014 the U.S. Supreme Court issued a decision addressing the application of stationary source permitting requirements to GHG. The Supreme Court stated that the EPA may not treat GHG as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Supreme Court also stated that the EPA could continue to require PSD permits, otherwise required based on emissions of other criteria pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). The EPA in its memorandum dated July 24, 2014, states that it intends to continue applying the PSD BACT requirement to GHG emissions if the source emits or has the potential to emit 75,000 tpy or more of GHG on a CO_2e basis[7]. Projected CO_2e emissions for the Expansion Project are above the 75,000 tpy CO_2e threshold; thus it is subject to the GHG BACT requirements that may be contained in its PSD permit.

Title V Operating Permit

The Title V Operating Permit program requires major stationary sources of air emissions to obtain an operating permit within one year of initial facility startup. The major source threshold levels for determining the need for a Title V Operating Permit are a potential to emit 100 tpy or more of any criteria pollutant, 10 tpy of any individual Hazardous Air Pollutant (HAP), or 25 tpy of any combination of HAPs.

On May 13, 2010, the EPA issued the GHG Tailoring Rule to address the inclusion of GHG emission into the PSD and Title V permitting programs. The EPA currently believes it is still appropriate for a Title V permit to incorporate and assure compliance with GHG BACT limits that remain applicable requirements under a PSD permit issued to a facility.

The CLNG Terminal is considered an existing Title V major source and currently operates under Title V permit number 0560-00184-V6 issued by the LDEQ on June 26, 2014. The permit includes provisions allowing operation as both an export and import facility, with no restrictions on simultaneous operation of export and import equipment

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7 U.S. EPA, "Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme' Court's Decision in the *Utility Air Regulatory Group v. Environmental Protection Agency"*, July 24, 2014.

(i.e., bi-directional operation). CLNG applied to the LDEQ to modify its existing Title V permit to include the facilities associated with the Expansion Project and submitted a Major Modification Application in May 2014.

New Source Performance Standards

The NSPS include emission limits, monitoring, reporting, and record keeping for new or significantly modified sources. The following NSPS requirements were identified as potentially applicable to the Expansion Project.

Condensate Storage Tanks - NSPS Subpart Kb, "Standards of Performance for Volatile Organic Liquid Storage Vessels, (Including Petroleum Liquid Storage Vessels)" applies to storage vessels that are constructed, reconstructed, or modified after July 23, 1984, with a capacity more than 75 cubic meters (19,800 gallons) that store volatile organic liquids. Therefore, the condensate storage tanks are required to comply with NSPS Subpart Kb. CLNG states that it would comply with NSPS Subpart Kb.

Emergency Generators, Emergency Fire Water Pumps, and Emergency River Water Pumps - NSPS Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines", applies to certain stationary compression ignition internal combustion engines (ICE). The Expansion Project includes three standby generator diesel engines and three emergency fire water pumps which would be subject to Subpart IIII. These engines must meet the applicable emission standards in effect for the model year and type of engine installed. CLNG states it would comply with the emission and monitoring limitations of Subpart IIII. Additionally, Subpart IIII limits operation of emergency stationary ICE for the purpose of maintenance checks and readiness testing to 100 hours per year unless operation beyond 100 hours per year is required by other federal, state, or local standards. NSPS Subpart JJJJ, "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (ICEs)," does not apply to the Expansion Project because no spark ignition engines would be installed.

Refrigeration Compression Turbines - NSPS Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," applies to manufacturers and owner/operators of gas turbines manufactured after the applicability date stated in the rule for the particular type and size gas turbine. Subpart KKKK regulates emissions of NO_X and SO_2. The Expansion Project's proposed gas turbines to drive refrigeration compressors and electrical generators would be subject to NSPS Subpart KKKK. The turbines at both locations must meet the applicable emission limits and operational requirements, as well as the record-keeping and reporting requirements of this subpart.

All NSPS requirements would be defined in the PSD and Title V air permits issued by LDEQ to CLNG for the CLNG Terminal.

National Emission Standards for Hazardous Air Pollutants

NESHAPS, codified in 40 CFR Parts 61 and 63, regulate the emissions of HAPs from existing and new sources. Part 61 was promulgated prior to the 1990 CAA Amendments and regulates eight types of hazardous substances: asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride. The Expansion Project will not operate processes that are regulated by Part 61.

The 1990 CAA Amendments established a list of 189 HAPs, resulting in the promulgation of Part 63. Part 63, also known as the Maximum Achievable Control Technology standards, regulates HAP emissions from major sources of HAP emissions, and specific source categories that emit HAPs. Some NESHAPS standards may apply to non-major sources (area sources) of HAPs. The major source thresholds for the purpose of NESHAP applicability are 10 tpy of any single HAP or 25 tpy of all HAPs in aggregate. The existing CLNG Terminal (export facilities and liquefaction Trains 1 through 3) are major HAP emitters. The existing LNG Terminal would continue to be a major source of HAP emissions after completion of the Expansion Project.

NESHAPS standards for marine tank vessel-loading operations were promulgated under Subpart Y and apply to marine vessel loading operations at facilities that are considered major sources of HAPs. Although the Expansion Project would be considered a major source of HAPs, this subpart does not apply to emissions resulting from marine tank vessel-loading operations of commodities with vapor pressures less than 10.3 kilopascals at standard conditions. Therefore, this subpart does not apply to the Expansion Project.

NESHAPS standards for stationary combustion turbines (such as refrigeration compression turbines) were promulgated under Subpart YYYY. The natural gas-fired refrigeration compressor turbines proposed for the Expansion Project qualify as new stationary combustion turbines under Subpart YYYY. The EPA issued a stay of standards for natural gas-fired units, therefore the units are only required to comply with the initial notification requirements set forth in §63.6145.

NESHAPS for reciprocating internal combustion engines (RICE) were promulgated under subpart ZZZZ. Subpart ZZZZ exempts new emergency stationary RICE that are subject to NSPS Subpart IIII, as long as the RICE has a site rating of less than or equal to 500 brake horsepower (BHP). NSPS subpart IIII is applicable to the three fire water pumps and as their ratings of 460 BHP each are less than 500 BHP, they are exempt from the requirements of subpart ZZZZ, including initial notification. The Expansion Project would have emergency generators, emergency fire water pumps, and emergency river water pumps, all of which are classified as RICE. The three emergency generators are also subject to NSPS subpart IIII, but with ratings of 3,353 BHP each, cannot take the exemption and must meet the requirements of subpart ZZZZ.

Chemical Accident Prevention Provisions

The chemical accident prevention provisions, codified in 40 CFR 68, are federal regulations designed to prevent the release of hazardous materials in the event of an accident and minimize potential impacts if a release does occur. The regulations contain a list of substances and threshold quantities for determining applicability to stationary sources, including methane, propane, and ethylene in amounts greater than 10,000 pounds (lbs). If a stationary source stores, handles, or processes one or more substances on this list in a quantity equal to or greater than that specified in the regulation, the facility must prepare and submit a risk management plan. A risk management plan is not required to be submitted to the EPA until the chemicals are stored on-site at the facility.

If a facility does not have a listed substance onsite, or the quantity of a listed substance is below the applicability threshold, the facility does not have to prepare a risk management plan. In the latter case, the facility still must comply with the requirements of the general duty provisions in Section 112(r)(1) of the 1990 CAA Amendments if there is any regulated substance or other extremely hazardous substance on-site. The general duty provision is as follows:

> "The owners and operators of stationary sources producing, processing, handling and storing such substances have a general duty to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility, taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."

Stationary sources are defined in 40 CFR 68 as any buildings, structures, equipment, installations, or substance-emitting stationary activities that belong to the same industrial group, that are located on one or more contiguous properties, are under control of the same person (or persons under common control), and are from which an accidental release may occur. The Expansion Project would use propane and mixed refrigerants (nitrogen and light hydrocarbons) as refrigerants in the overall process for liquefying the natural gas at the CLNG Terminal. No new refrigerant storage would be required for the Expansion Project.

The definition of a stationary source does not apply however to transportation of any regulated substance or any other extremely hazardous substance. When the EPA issued the final rule for chemical accident prevention provisions (*Federal Register*, January 6, 1998 [Vol. 63, pp 639-645]), it clarified that the transportation exemption applies to LNG facilities and natural gas transmission facilities subject to oversight or regulation under 49 CFR Part 193. These exempt facilities include natural gas pipeline and compressor stations, those used to liquefy natural gas or those used to transfer, store, or vaporize LNG in conjunction with pipeline transportation. We have included a compliance analysis of the design of the Expansion Project with Part 193, including overpressure modeling, in section 2.7.2.5 of this EA.

General Conformity

The General Conformity Rule was designed to require federal agencies to ensure that federally-funded or federally-approved projects conform to the applicable State Implementation Plan (SIP). Section 176(c) of the CAA prohibits federal actions in nonattainment or PSD maintenance areas that do not conform to the SIP for the attainment and maintenance of NAAQS. General Conformity regulations apply to project-wide emissions of pollutants for which the project areas are designated as nonattainment (or, for ozone, its regulated precursor emission NO_X and VOC) that are not subject to NSR and that are greater than the significance thresholds established in the General Conformity regulations, or 10 percent of the total emissions budget for the entire nonattainment area. Federal agencies are able to make a positive conformity determination for a proposed project if any of several criteria in the General Conformity Rule are met. These criteria include:

- emissions from the project that are specifically identified and accounted for in the SIP attainment or maintenance demonstration; or
- emissions from the action that are fully offset within the same area through a revision to the SIP, or a similarly enforceable measure that creates emissions reductions so there is no net increase in emissions of that pollutant.

As noted earlier, the Expansion Project site would be located within an attainment area; however, CLNG stated that some tug vessel and barge transport used to deliver equipment and materials during construction would originate at the Port of Houston, which is in Houston-Galveston-Brazoria, Texas, 8-hour severe attainment area. Operating emission from the CLNG Terminal would be entirely within an attainment area and would be subject to PSD permitting and therefore, are not subject to General Conformity Regulations. Construction emissions, including barge/vessel transport, would be subject to be subject to General Conformity Regulations for any emissions that occur in the Beaumont-Port Arthur ozone maintenance area or the Houston-Galveston-Brazoria non-attainment area. Vessels would impact the Beaumont-Port Arthur area when traveling through Jefferson and Orange Counties, Texas when traveling to and from the Port of Houston. Vessels/Barges traveling along the Gulf Intracoastal Waterway in Louisiana would remain outside of the Baton Rouge nonattainment area (i.e., the parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge). CLNG's vessel/barge emissions estimates within the nonattainment and maintenance areas are provided in table 2.6-9 in section 2.6.1.4.

The maximum annual emission rates due to barge/vessel transport in the Houston-Galveston-Brazoria Area are below the *de minimis* emission rates for NOX and VOCs of 25 tpy for severe ozone nonattainment areas. Similarly, the maximum annual emission rates due to construction in the Beaumont-Port Arthur Area are also below the *de minimis* emission rate for NOX and VOCs of 100 tpy for moderate ozone maintenance areas. Therefore, the Expansion Project's construction emissions would be below the General Conformity Applicability threshold, and a General Conformity Determination is not required for the Expansion Project.

Greenhouse Gas Reporting Rule

In September 2009, EPA issued the final Mandatory Reporting of Greenhouse Gases Rule, requiring reporting of GHG emissions from suppliers of fossil fuels and facilities that emit greater than or equal to 25,000 metric tpy of GHG (reported as CO_2e). In November 2010, EPA signed a rule finalizing GHG reporting requirements for the petroleum and natural gas industry in 40 CFR Part 98, Subpart W. The industry separates LNG storage facilities from LNG import and export equipment because the former are considered part of the source category regulated by Subpart W. The rule does not apply to construction emissions.

The new LNG facilities associated with the Expansion Project would potentially be subject to the GHG Mandatory Reporting Rule. The rule establishes reporting requirements based on actual emissions; however it does not require emission controls. CLNG would monitor emissions in accordance with the reporting rule. If actual emissions exceed the 25,000 tpy CO_2e reporting threshold, CLNG would be required to report its GHG emissions to EPA.

Applicable State Air Quality Requirements

The LDEQ is the lead air permitting authority for the CLNG Terminal. The Expansion Project would be required to obtain an air quality permit prior to initiating construction. The Terminal Expansion facilities would be subject to state standards, codified in LAC Title 33, Part III. Facilities also trigger review by other states if the project location is within 50 miles of an adjacent state's border. The CLNG Terminal is within 25 miles of the Texas state line; therefore, the TCEQ will have the opportunity to review and comment on the application and subsequent permits.

In addition to the federal regulations identified above, the state requirements potentially applicable to the Expansion Project are listed below.

- Chapter 5 – Permit Procedures applies to any operation which emits or has the potential to emit any air contaminant in the state of Louisiana.

- Chapter 9 – General Regulations on Control of Emissions and Emission Standards. This Chapter contains requirements to submit an air emissions inventory and report unauthorized discharges.

- Chapter 11 – Control of Air Pollution from Smoke establishes opacity limits for combustion units, prohibits open burning and impairment of visibility on public roads.

- Chapter 13 – Emission Standards for Particulate Matter apply to any operation, process, or activity from which PM is emitted and requires that all reasonable precautions be taken to minimize PM emissions from fugitive sources. Fuel burning equipment is limited to 0.6 lbs per 1 million British thermal units of PM emissions.

- Chapter 21 – Control of Emission of Organic Compounds, subchapter A, section 2111 requires that pumps and compressors handling VOCs with a true vapor pressure greater than 1.5 pounds per square inch absolute (psia) at handling conditions to be equipped with mechanical seals or other equivalent equipment approved by the administrative authority. Section 2113 requires best practical housekeeping and maintenance practices must be maintained at highest possible standards to minimize the quantity of organic compound emissions.

- Chapter 29 – Odor Regulations require that a facility be operated such that off-site odors do not cause a nuisance.

- Chapter 51 – The Comprehensive Toxic Air Pollutant Emission Control Program applies to major sources of toxic air pollutants. Operations at major sources subject to a Federal Maximum Achievable Control Technology standard are exempt; however, all other operations are included.

- Chapter 56 – Prevention of Air Pollution Emergency Episodes requires any person responsible for operation of a listed source to prepare a standby plan for the reduction of emissions, and activate the plan when LDEQ declares an Air Pollution Alert, Air Pollution Warning and Air Pollution Emergency.

2.6.1.4 Impacts and Mitigation

The Expansion Project would produce air pollutant emissions during construction and operation. Although many construction activities for the projects would be considered temporary, construction at the CLNG Terminal would occur over a 4-year period (2016 to 2019) in one location. The construction of the Expansion Project facilities would extended the temporary construction period at the CLNG Terminal site for an additional 12 – 18 months. Therefore, the impacts are considered to be short-term. In addition, following construction, air quality near the CLNG Terminal would not revert to previous conditions but would transition to operational-phase emissions after commissioning and initial startup of liquefaction Trains 4 and 5.

Construction Emissions

Air emissions during the construction of the Expansion Project would consist of tailpipe emissions (due to fossil fuel combustion from equipment, vehicles, and vessels) and fugitive dust (ground and roadway dust).

The quantity of fugitive dust generated by construction-related activities depends on several factors, including the size of area disturbed, the nature and intensity of construction activity, surface properties (such as the silt and moisture content of the soil), wind speed, and the speed, weight, and volume of vehicular traffic. CLNG would limit or mitigate fugitive dust emissions if necessary, by spraying water to dampen the surfaces of dry work areas and/or by the application of calcium chloride or other dust suppressants as needed. Table 2.6-5 provides estimates of fugitive dust emissions associated with construction activities and assumes a dust suppressant control efficiency of 50 percent.

TABLE 2.6-5

Construction Fugitive Dust Emissions From Expansion Project

Year	Land Affected (acres)	Duration (months)	PM_{10} (tons)	$PM_{2.5}$ (tons)
2016	141	6	34.95	3.59
2017	141	12	69.90	7.18
2018	141	12	69.90	7.18
2019	141	10	58.25	5.99

Note:
Emission factors used are most applicable to a semi-arid climate. The Expansion Project site is in a wetter marine climate; therefore, actual emissions are expected to be less than the calculated emissions.

Emissions of NO_X, CO, PM_{10}/$PM_{2.5}$, SO_2, VOCs, and GHGs from nonroad equipment engines, on-road vehicles, and tugs were estimated for the Expansion Project construction activities. The estimates are based on the vehicles and equipment expected to be used. Emission factors for nonroad construction equipment were obtained from the EPA NONROAD 2008 program. Tug vessels and barges used to deliver equipment and material during construction would originate from the Ports of New Orleans, Houston, and Lake Charles. Therefore, emissions from tug vessel and barge activity are included in the construction emission estimates. Emissions were estimated using the methods described in the EPA publication *Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories* (ICF International, April 2009) and travel distances obtained from the National Oceanic and Atmospheric Administration (NOAA) publication *Distances Between United States Ports, 12th Edition*.

Tables 2.6-6, 2.6-7, and 2.6-8 summarize the nonroad construction equipment emissions, the on-road vehicle construction equipment, and the tug vessel emissions estimates by year for construction.

TABLE 2.6-6

Construction Emissions of Nonroad Construction Equipment

Year	Annual Emissions (tons)						
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2e
2016	32.16	59.77	0.07	5.35	3.43	3.43	10,510
2017	72.27	124.06	0.23	14.08	7.00	7.00	34,494
2018	56.05	92.08	0.21	12.41	4.85	4.85	32,652
2019	31.93	58.29	0.24	8.80	2.96	2.96	24,646

TABLE 2.6-7

Construction Worker and Materials Transport On-Road Vehicle Emissions

Year	Annual Emissions (tons)						
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2e
2016	21.42	12.87	0.06	0.95	0.56	0.54	5,994
2017	42.37	27.94	0.14	2.00	1.25	1.21	13,256
2018	38.89	21.41	0.13	1.56	0.90	0.87	12,254
2019	16.18	4.55	0.05	0.41	0.17	0.16	3,845

TABLE 2.6-8

Tug Vessel Construction Equipment and Material Transport Emissions

Year	Annual Emissions (tons)						
	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	CO_2e
Attainment / Unclassifiable Areas							
2016	18.37	96.66	9.96	2.07	2.40	2.40	5,350
2017	19.70	103.46	10.61	2.20	2.53	2.53	5,696
2018	3.32	17.40	1.77	0.37	0.42	0.42	951
2019	2.07	10.85	1.10	0.23	0.26	0.26	592
Houston-Galveston-Brazoria, TX 1-Hr O_3 Severe 17 / 8-Hr O_3 Standard Severe 15 Nonattainment Area							
2016	0.63	3.28	0.33	0.07	0.08	0.08	178
2017	1.15	6.01	0.61	0.13	0.14	0.14	326
2018	0.94	4.92	0.50	0.10	0.12	0.12	266
2019	0.58	3.01	0.30	0.06	0.07	0.07	163
Beaumont - Port Arthur, TX 1-Hr O_3 Serious / 8-Hr O_3 Moderate Nonattainment							
2016	0.29	1.50	0.15	0.03	0.04	0.04	81
2017	0.53	2.75	0.28	0.06	0.06	0.06	149
2018	0.43	2.25	0.23	0.05	0.05	0.05	122
2019	0.26	1.38	0.14	0.03	0.03	0.03	75

Construction activities would result in temporary emissions of air pollutants that would be restricted to the construction period. Construction equipment would be operated primarily on an as-needed basis during daylight hours. The emissions from gasoline and diesel engines would be minimized because the engines must be built to meet the standards for mobile sources established by the EPA mobile source emission regulations. The construction equipment would be powered by fossil fuel engines and would be equipped with typical control equipment. Once construction activities are completed, fugitive dust and construction equipment emissions would subside. Conditions after construction would transition to operational-phase emissions after commissioning and initial startup of liquefaction Trains 4 and 5.

Operational Emissions

The Expansion Project includes the following stationary point sources of air pollutants for liquefaction Trains 4 and 5:

- four refrigeration turbines;
- two amine units controlled by a thermal oxidizer;
- three emergency generators;
- three emergency firewater pumps;
- one low pressure flare;
- one diesel storage tank;
- one condensate storage tank;
- condensate loading; and
- fugitive emission sources (valves, flanges, connectors, and pump seals).

Potential emissions for the Expansion Project are contained in table 2.6-3 and for the existing CLNG Terminal (excluding the Expansion Project) in table 2.6-4. The existing CLNG terminal consists of the original import terminal and liquefaction Trains 1 through 3. The emission data are based on the *Title V Major Modification/PSD Application* submitted by CK Associates to the LDEQ on May 14, 2015.

As part of the air permit application process for the Expansion Project, a BACT analysis was prepared for the stationary gas turbine and emergency engine emission sources. Methods for reducing emissions of NO_X, CO, $PM_{10}/PM_{2.5}$, and VOCs for each of these emission sources were evaluated based on technical feasibility.

Through this process and review by the LDEQ, CLNG would reduce emissions of NO_X for the turbines by using dry-low NO_X combustion. CO and VOC emission rates would be maintained by using good combustion practices. CLNG is proposing a $PM_{10}/PM_{2.5}$ BACT emission limitation of 7.6×10^{-3} lbs/million British terminal units (MMBtu's) based on manufacturer provided data for each proposed gas driven refrigeration compressor.

For the internal combustion engines, CNLG is proposing the use of ultra-low sulfur fuel, good combustion practices, and compliance with NSPS subpart IIII as BACT for reducing NO_x, CO, and VOC emissions.

Air Modeling

A thorough examination of the potential impacts on air quality is necessary to evaluate the Expansion Project. An air quality modeling analyses that quantifies the impacts of the Expansion Project is required as part of the air quality permit application process and has been submitted. Therefore, we have used those analyses for our evaluation of the Expansion Project's stationary source impacts. The analyses included the following:

- Preconstruction monitoring and significant impact analyses
- Cumulative impact analysis
- Additional impacts analysis
- Class I area analysis

Dispersion Modeling

Dispersion modeling of operational emissions followed USEPA PSD modeling requirements to evaluate potential air quality impacts within an area extending out to at least 50 kilometers from the facility. Dispersion modeling was performed using AERMOD version 14134 and various AERMOD system processors. Data sets input to this model include emission source parameter values (stack height and diameter, stack exhaust temperature and gas flow, and emission rate), building dimensions, receptor locations, terrain elevation data, and meteorological data.

Preconstruction Monitoring and Significant Impact Analyses

According to PSD rules, if a modeled result (i.e., maximum predicted ambient impact) does not exceed the applicable significant impact level (SIL), no additional modeling is required. If a modeled result exceed the applicable SIL, a full impact analysis, including the Expansion Project other nearby sources, is required.

For the preconstruction monitoring analysis, modeled results are compared to monitoring *de minimis* levels specified in the PSD regulation. If the modeled result exceeds the applicable monitoring *de minimis* level, then one year of preconstruction ambient air pollutant monitoring must be conducted for the applicable pollutant. If the modeled result does not exceed the *de minimis* level, preconstruction monitoring is not required.

The emissions of each pollutant proposed to be emitted above the significant emission rate defined in the PSD regulation (NO_x, CO, PM_{10}, and $PM_{2.5}$), were modeled to determine whether any of the predicted maximum ambient impacts were greater than the applicable SIL or monitoring *de minimis* concentration. Five years (2010 through 2014) of surface and upper air meteorological data from the Lake Charles, Louisiana station (National Weather Service Facility 03937) were used. The meteorological data was processed using the AERMET, AERMINUTE, and AERSURFACE programs. Boundary layer parameters required as input to AERMET using AERSURFACE were calculated based on the albedo, Bowen ratio, and surface roughness parameters. The rural dispersion coefficients were employed, and the Regulatory Default option was chosen (except for the 1-hour NO_2 analysis).

The results are summarized in table 2.6-9, and show that only the 1-hour NO_2 predicted impact exceeds its associated SIL, and none of the predicted impacts exceed their associated monitoring *de minimis* levels. Therefore, a cumulative impacts analysis was required only for the 1-hour NO_2 NAAQS, and preconstruction monitoring of the ambient air quality was not required.

TABLE 2.6-9

Expansion Project Significant Impact Analysis Summary

Pollutant	Averaging Period	Year[1]	Predicted Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Monitoring *De Minimis* Level ($\mu g/m^3$)
CO	1-hour	2014	176	2,000	575
CO	8-hour	2010	70	500	NA
NO_2	1-hour	2010 - 2014	19.2	7.5	NA
NO_2	Annual	2011	0.65	1	14
PM_{10}	24-hour	2012	1.38	5	10
PM_{10}	Annual	2011	0.11	1	NA
$PM_{2.5}$	24-hour	2010 - 2014	1.07[2]	1.2	NA
$PM_{2.5}$	Annual	2011	0.11	0.3	NA

- Meteorological data year when the maximum impact was predicted to occur
- Includes primary and secondary $PM_{2.5}$

Cumulative Impact Analysis

A cumulative impact analysis was performed for the 1-hour NO_2 NAAQS because the predicted 1-hour NO_2 impact exceeded its associated SIL. The key analysis assumptions were as follows:

- The plume volume molar ratio method (PVMRM) was used to model atmospheric chemistry (i.e., the oxidation of NO to NO_2 during plume expansion) as an exhaust plume travels downwind. Five years (2010 through 2014) of ozone concentration data from the Carlyss, Louisiana and Vinton, Louisiana monitoring station were input to the model.

- For the refrigeration turbines, an NO_2/NO_x in-stack ratio (ISR) of 0.15 was used based on data provided by the manufacturer, GE.

- Data for off-site sources were obtained from the LDEQ permit inventory.

- Background NO_2 concentration data from the Westlake, Louisiana monitoring station (located 23 kilometers from the Expansion Project) were added to the modeled NO_2 impacts in accordance with EPA guidance[8]. Based on this guidance, background data was input to the modeling runs by season and hour-of-day using the 3rd highest value for each season and hour-of-day combination.

Data for off-site sources were obtained from the LDEQ permit inventory, and adjusted as follows:

- Any source located more than 10 kilometers from CLNG with emission rate less than 0.10 lb/hr was considered insignificant and omitted from the inventory.

- Emergency equipment and sources permitted to operate less than 500 hours per year were considered to be intermittent sources per EPA guidance[9] and modeled with the permitted annual emission rates averaged over 8,760 hours.

[8] http://www.epa.gov/region07/air/nsr/nsrmemos/appwno2_2.pdf accessed September 2, 2015.
[9] Ibid.

- Per EPA guidance[10], an ISR of 0.2 was used for off-site sources located more than 1 kilometer from CLNG.

- Stack heights were adjusted to a maximum of 65 meters.

- Sources located within 6 kilometers of the Westlake monitor (from which the background NO_2 concentration were obtained) were omitted from the inventory because the contributions of these sources to the ambient 1-hour NO_2 impacts are accounted for in the background NO_2 data.

The results of the cumulative impacts analysis were as follows:

- The maximum predicted 1-hour NO_2 concentration (the 8th highest of the daily maximum 1-hour values over a year, a surrogate for the 98th percentile) predicted by AERMOD was 705 $\mu g/m^3$, exceeded the NAAQS of 188 $\mu g/m^3$. However, CLNG's contribution to this total was only 0.00004 $\mu g/m^3$.

- The maximum contribution by CLNG to any predicted violation of the 1-hour NO_2 was 5.05 $\mu g/m^3$, which is less than the SIL of 7.5 $\mu g/m^3$.

These results indicate that the Expansion Project would not significantly contribute to any NAAQS violation.

<u>Additional Impacts Analysis</u>

To obtain a PSD permit, CLNG was required to conduct analyses demonstrating that:

- The industrial, commercial, and residential source growth associated with the Expansion Project will not cause or contribute to a violation of any applicable NAAQS or PSD increment. Excluded from consideration as associated sources are mobile and temporary sources.

- The proposed emissions increases associated with the Expansion Project will not adversely affect soils or vegetation.

- The proposed emissions increases associated with the Expansion Project will not impair visibility.

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[10] Ibid.

The growth analysis indicated that no significant commercial, residential, or industrial growth is expected as a result of construction of the facility due to a combination of factors, including only modest job growth (approximately 50 new permanent employees).

Secondary ambient air quality standards are set under the CAA for the protection of soils, water, vegetation, animals, and other public welfare impacts. CLNG's air quality analysis demonstrated that no secondary ambient air quality standards would be violated. Therefore, any impacts on soils, vegetation, animals, and other public welfare concerns would not be significant.

Visibility impacts were evaluated using the visibility screening model (VISCREEN). Visibility impacts were assessed using a Level I screening analysis, followed by a refined analysis. The refined analysis was necessary because the visibility impacts determined via the Level I screening analysis were found to be above critical screening criteria. The refined analysis is more rigorous because it includes the use of regional meteorological data, annual PM and NO_x emission rates, a background ozone concentration value, geometric data defining the orientation of a hypothetical plume relative to the Class II area and a hypothetical observer. The results of the refined analysis show that the Expansion Project would not result in adverse visibility impacts in the Class II area.

Class I Area Analysis

If a proposed major source or major modification is located within 100 kilometers of Class I area, the Federal PSD regulations require that the reviewing authority provide written notification of any such proposed source to the Federal Land Manager (FLM) with jurisdiction for that area. The permitting authority should also notify FLM of "very large sources" with the potential to impact a Class I area within their jurisdiction, even if the facility is beyond 100 kilometers from the Class I area. In practice, all sources within 200 (and sometimes 300) kilometers are included in the review because the term "very large sources" is not defined in the Clean Air Act. The nearest Class I area, Breton National Wildlife Refuge, is located 415 kilometers east of CLNG. Therefore, no Class I modeling analysis was necessary.

Photochemical Modeling

The Expansion Project location would be in Calcasieu and Cameron Parishes, which are designated as attainment areas for the 2008 8-hour ozone (O_3) National Ambient Air Quality Standard (NAAQS). However, it is located near the Baton Rouge area (Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge

Parishes), which EPA has proposed to re-designate as attainment for the 2008 8-hour O_3 NAAQS[11], and the Houston - Galveston - Brazoria (HGB) area, which is designated as marginal non-attainment for the 2008 8-hour O_3 NAAQS. Due to the Expansion Project's potential emissions of O_3 precursor pollutants, photochemical grid modeling was performed to assess its potential impacts on ambient O_3 concentrations in the Calcasieu – Cameron, Baton Rouge and HGB areas. Photochemical grid modeling was performed to evaluate the impacts of the Expansion Project on regional ambient air quality with respect to the 8-hour average O_3 concentration.

EPA has not issued formal guidance for conducting photochemical grid ozone modeling or interpreting the results. Therefore, this evaluation was performed in accordance with EPA guidance on the use of photochemical models[12] and the suggestions of EPA Region 6 and the attainment demonstration performed in support of the Louisiana State Implementation Plan for the 2008 8-hour O_3[13]. This analysis does not supersede air dispersion modeling performed for Prevention of Significant Deterioration (PSD) permitting, and was not performed in lieu of modeling that may be required in the future for other reasons.

The Comprehensive Air Quality Model with Extensions (CAMx)[14] was used for the analysis. Two benchmarking cases, a 2010 base case and a 2017 future case were run to check that the model duplicated previous LDEQ CAMx results. The benchmarking cases reproduced the results of the previous analyses to within O_3 concentrations of 1×10^{-6} parts per billion (ppb). This confirmed that transfer of the CAMx modeling platform from one computer cluster to another would not affect the analyses described herein.

The modeling concept to evaluate the CLNG Facility (i.e., the combined Liquefaction Project and Expansion Project) was to re-model a previous attainment demonstration based on a known ozone episode (August 17 to October 31, 2010) with the CLNG Facility NO_x and VOC emissions from Trains 1 through 5 added to the projected emission inventory. The inventory included the following:

- Ten refrigeration compressor turbines
- Four thermal oxidizers

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[11] 80 FR 51992 - 52002, August 17, 2015.

[12] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, EPA-454/B-07-002, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC. April 2007.

[13] Technical Support Document Photochemical Modeling for the Louisiana 8-Hour Ozone State Implementation Plan, ENVIRON International Corporation and Eastern Research Group, Inc., April 2013 http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/Engineering/Ozone/LDEQ_TSD_4Oct13.pdf (accessed 09/19/2015)

[14] http://www.camx.com/files/camxusersguide_v6-10.pdf (accessed 09/19/2015)

- Eight flares
- Six emergency generators
- Eight emergency water pumps
- Two diesel storage tanks
- LNG loading operations
- Fugitive sources

This is an unlikely operating scenario because it assumes the simultaneous operation of normal operating, spare, and emergency equipment, which would not normally occur. The results from the modeling likely overestimate the impacts on ambient O_3 from the CLNG Facility. NO_x and VOC emission were processed using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system[15] based on a 90% NO and 10% NO_2 speciation.

The impact of the CLNG Facility was evaluated using the Relative Response Factor (RRF) and absolute model predicted impact methods. An RRF is the ratio of the O_3 design concentration in a future year (or a project impact case) to the current or baseline year concentrations near a monitor site. Future O_3 concentrations are estimated at existing monitoring sites by multiplying a RRF at locations near each monitor by the observation-based, monitor-specific, "baseline" design value. The resulting predicted future concentrations are compared to the NAAQS. In the absolute model predicted impact method, the O_3 impacts predicted by the model are compared directly to the NAAQS. In general, EPA recommends the RRF method rather than the absolute model predicted impact method because the latter does not account for model biases.[16] The results of both analysis methods are summarized for completeness.

Over 90 monitor locations in Texas, Louisiana, Mississippi, and Florida were evaluated using the RRF method. The predicted peak O_3 impact for the CLNG Facility was 0.4 ppb greater than the baseline at a single monitor in Calcasieu Parish in Louisiana, and at two monitors in Orange County in Texas. At approximately 90% of these monitor locations, the predicted peak O_3 impact exceeds the baseline by 0.1 ppb or less. At areas removed from the monitors, the predicted peak O_3 impact exceeds the baseline by 0.7 ppb or less[17].

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[15] https://cmascenter.org/smoke/ (accessed 09/20/15)

[16] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, EPA-454/B-07-002, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC. April 2007. See Section 2.

[17] As a point of reference, the O_3 NAAQS is 75 ppb, based on the annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years. The modeling results are conservatively presented as the highest maximum 8-hour impact, which overstates their effect relative to the NAAQS

Using the EPA Region 6 absolute basis metrics at monitors, the CLNG Facility is estimated to impact the maximum 8-hour average O_3 concentrations at locations estimated to be over 70 ppb by a maximum of 1.73 ppb.

We conclude that the emissions from the Project as simulated by the photochemical modeling are not expected to cause or contribute to any violation of the 2008 8-hour O_3 NAAQS.

2.6.2 Noise

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

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

In 1974, the EPA published its *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*. This document provides information for state and local governments to use in developing their own ambient noise standards. The EPA has indicated that an L_{dn} of 55 dBA protects the public from indoor and outdoor activity interference. We have adopted this criterion and use it to evaluate the potential noise impacts from the Expansion Project at noise-sensitive areas (NSAs) such as residences, schools, or hospitals. Because of the 10 dBA nighttime penalty added before calculating the L_{dn}, for a facility to meet the L_{dn} 55 dBA limit, it must be designed such that actual constant noise levels on a 24-hour basis do not exceed 48.6 dBA L_{eq} at any NSA. Also, in general, a person's threshold of perception for a perceivable change in loudness on the A- weighted sound level is about 3 dBA, whereas a 5 dBA change is clearly noticeable, and a 10 dBA change is perceived as either twice or half as loud.

The State of Louisiana and Cameron Parish do not have noise regulations or ordinances applicable to the Expansion Project.

2.6.2.1 Existing Noise Conditions

The Expansion Project facilities would be located within the CLNG Terminal site. CLNG identified two NSAs in the vicinity of the site. The nearest NSA is a rural residence located approximately 5,200 feet northwest of the approximate acoustic center of the Expansion Project. The next nearest NSA (NSA 2) to the proposed Expansion Project is located just northwest of NSA 1, approximately 6,000 feet northwest of the approximate acoustic center of the facility.

Existing ambient noise levels in the vicinity of NSA 1 and NSA 2 were based on the previous noise survey conducted by CLNG for the previously authorized CLNG Terminal Project (FERC Docket CP13-25-000). All of the NSAs are in similar land use areas, and are therefore anticipated to experience similar ambient noise levels.

2.6.2.2 Construction Noise Impacts and Mitigation

Construction activity and associated noise levels would vary depending on the construction phase in progress at any given time. Generally, construction would take place during daylight hours (7:00 a.m. to 7:00 p.m.) and would include the following major phases: site preparation, excavation, installation of pipeline and/or aboveground facilities, and site cleanup and restoration. The construction equipment would differ from phase to phase but would include dozers, cranes, cement mixers, dump trucks, and loaders. Noise generated during construction is primarily from the diesel engines that power the equipment. Exhaust noise is usually the predominant source of diesel engine noise. Equipment used is not generally operated continuously, nor is the equipment always operated simultaneously. Typically, the highest site average sound levels (89 dBA at 50 feet) are associated with excavation and finishing activities.

Measures to mitigate construction noise include complying with federal regulations limiting noise from trucks and ensuring that equipment and sound-muffling devices provided by the manufacturer are kept in good working condition.

CLNG's analysis indicated that given the large distance to the nearest NSA (5,200 feet), maximum construction related noise levels would be very low (about 38 dBA). Pile driving for the new tank foundation would produce peak levels of about 95 dBA at 50 feet. Estimated pile driving noise levels at the nearest NSA would be approximately 46 dBA. CLNG indicated that if pile driving is required at night, mitigation measures would be developed to minimize nighttime noise impacts.

CLNG noted that the current Expansion Project schedule reflects construction activities occurring during daylight hours. However, in some cases to avoid delays, some activities such as unloading/staging materials, barge unloading, welding and NDE activities, may require working during non-daylight hours. Construction noise levels for these activities were stated to be minimal. CLNG further noted that should the noise levels be greater than anticipated at the noise sensitive areas and the residents are inconvenienced, CLNG would provide alternative accommodations for the residents during that activity.

2.6.2.3 Operation Noise Impacts and Mitigation

The proposed Expansion Project will include two liquefaction Trains (Trains 4 and 5). Liquefaction Trains 1 through 3, previously authorized under FERC Docket CP 13-25-00, are currently under construction. CLNG used the commercially available CadnaA model developed by DataKustik GmBH to conduct a noise analysis for the Expansion Project. The software has the ability to take into account spreading losses, ground and atmospheric effects, shielding from barriers and buildings, and reflections from surfaces. The software is standards based. CLNG's noise analysis included an evaluation of noise from the proposed Expansion Project, noise from the previously authorized CLNG Liquefaction Project, and expected noise levels for the liquefaction Trains 1 through 5. Their analysis also included a comparison to measured ambient noise levels.

The major noise producing equipment associated with the proposed Expansion Project for liquefaction Trains 4 and 5 combined include:

- two air compressors;
- two boil off gas compressors;
- two residue gas compressors;
- two drier regeneration gas compressors;
- two EFG compressors;
- two expander compressors;
- one hundred eighty fin fan gas coolers;
- four GE 7EA combustion turbines;

- four GE 7EA cooling water modules;
- two HP MR compressors;
- two LP MR compressors;
- two MP MR compressors;
- two propane compressors;
- miscellaneous pumps; and
- above ground piping.

Each liquefaction Train is identical and will contain the same noise generating components, with the exception that all of the BOG compressors will be at the south end of the previously authorized Liquefaction Project, and the two air compressors for liquefaction Trains 4 and 5 will be located immediately to the west of and in between liquefaction Trains 4 and 5.

CLNG's noise analysis conducted for the previously authorized CLNG Terminal liquefaction Trains 1 through 3 revealed that operational noise levels from the Liquefaction Project would be 53.8 dBA as an L_{dn} at NSA 1. The analysis utilized estimated source noise level data and a conceptual design. CLNG indicated that since that analysis was conducted, they were able to obtain vendor specific data for all of the proposed fans and for the BOG compressors. CLNG noted that the vendor supplied data revealed that these source noise levels are significantly lower than the estimated source noise levels utilized in that the previous noise analysis. Additionally, fewer fans would be present than was assumed in the original noise analysis. CLNG therefore revisited the noise modeling analysis for liquefaction Trains 1 through 3, revised the number of fans and their associated sound levels, and the sound levels for the BOG compressors. CLNG's noise analysis for the proposed Expansion Project therefore, contains the results of the revised noise modeling for the previously authorized CLNG Liquefaction Project (Trains 1 through 3), the results for the proposed Expansion Project (Trains 4 and 5), and the total modeled sound level for the liquefaction Trains 1 through 5.

These levels were evaluated against the existing baseline L_{dn} noise levels and our impact criterion to determine potential impacts at the nearby NSAs. The calculated noise levels, as well as the existing ambient sound level and the future sound levels for the nearest NSAs are presented in table 2.6-10.

The noise analysis for the proposed Expansion Project incorporated specific noise mitigation measures to reduce potential impacts. CLNG indicated that these measures were incorporated to their analysis in order to achieve the levels presented. These mitigation measures included the following:

- Enclosures or buildings providing a nominal transmission loss of 15 dBA for the following sources:
- Boil off gas compressors;
- Residue gas compressors;
- Drier regeneration compressors;
- EFG compressors;
- Expander compressors;
- GE 7EA combustion turbines.
- Enclosures or buildings providing a nominal transmission loss of 20 dBA for the following sources:
- HP MR compressors;
- LP MR compressors;
- MP MR compressors; and
- Propane compressors.
- Exhaust stack silencers for the GE Frame 7EA combustion turbine exhausts, providing a nominal insertion loss of 30 dBA; and
- Standard eight foot combustion air intake silencers for the GE Frame 7EA combustion turbines.

TABLE 2.6-10

Operational Noise Impacts Results (dBA)

NSA	Cameron LNG Terminal Project L_{dn} (1)	Liquefaction Expansion Project L_{dn} (2)	Full Project L_{dn} (3)	Existing L_{dn} with no Project	Future L_{dn} (Existing Plus Full Project)	Expected Increase Over Ambient
NSA 1 – Nearest Residence	48.7	51.0	53.2	50.9	55.2	4.3
NSA 2	47.2	49.2	51.5	50.9	54.2	3.3

(1) Trains 1 through 3
(2) Trains 4 and 5
(3) Trains 1 through 5 (full Project)

The results of the acoustical analysis for the full CLNG Project are shown to be below our criterion of 55 dBA L_{dn} at all NSAs. Increases of 3 dBA or less are considered to be barely perceptible. The increase in noise levels at the NSAs would be approximately at the threshold of a perceptible change. Therefore, noise impacts from operation of the CLNG Project are not projected to be significant. **However, we recommend that:**

- CLNG file a full load noise survey of the Full Project with the Secretary no later than 60 days after placing the Expansion Project (Trains 4 and 5) in service. If a full load condition noise survey is not possible, CLNG should provide an interim survey at the maximum possible operation within 60 days of placing each liquefaction train in service and file the full load operational survey within 6 months. If the noise attributable to operation of all the equipment at the CLNG Facility, under interim or full load conditions, exceeds an L_{dn} of 55 dBA at any nearby NSA, CLNG should file a report on the changes that are needed and should install the additional noise controls to meet the level within one year of the service date. CLNG should confirm compliance with the above requirement by filing a second noise survey with the Secretary no later than 60 days after it installs additional noise controls.

2.7 Reliability and Safety

2.7.1 LNG Facility Regulatory Oversight

Three federal agencies share regulatory authority over the siting, design, construction and operation of LNG import terminals: the USCG, the DOT, and FERC. The USCG has authority over the safety of an LNG facility's marine transfer area and LNG marine traffic as well as over security plans for the entire LNG terminal facility and LNG marine traffic. Those standards are codified in 33 CFR Parts 105 and 127. The DOT establishes federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities, as well as for the siting of marine cargo transfer systems at waterfront LNG plants. Those standards are codified in 49 CFR 193. Under the NGA and delegated authority from the DOE, FERC authorizes the siting and construction of LNG import and export facilities.

In 1985, FERC and the DOT entered into a Memorandum of Understanding regarding the execution of each agency's respective statutory responsibilities to ensure the safe siting and operation of LNG facilities. In addition to FERC's existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the Memorandum specified that FERC may, with appropriate consultation with the DOT, impose more stringent safety requirements than those in Part 193.

In February 2004, the USCG, DOT, and FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals, including terminal facilities and tanker operations, and maximizing the exchange of information related to the safety and security aspects of the LNG facilities and related marine operations. Under the Interagency Agreement, the FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with terminal construction and operation. The DOT and USCG participate as cooperating agencies. All three agencies have some oversight and responsibility for inspection and compliance during the facility's operation.

As part of the review required for a FERC authorization, we must ensure that all proposed LNG facilities would operate safely and securely. The design information that must be filed in the application to the Commission is specified by 18 CFR 380.12 (m) and (o). The level of detail necessary for this submittal requires the project sponsor to perform substantial front-end engineering of the complete facility. The design information is required to be site-specific and developed to the extent that further detailed design would not result in changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs which we considered during our review process.

The FERC's filing regulations also require an applicant to identify how its proposed design would comply with DOT's siting requirements of 49 CFR 193, Subpart B. As part of our NEPA review, we use the applicant's information, developed to comply with DOT's regulations, to assess whether or not the facility would have a public safety impact. As a cooperating agency, DOT assists the FERC in evaluating whether an applicant's proposed siting meets the DOT requirements. If a facility is constructed and becomes operational, the facility would be subject to DOT's inspection program. Final determination of whether a facility is in compliance with the requirements of 49 CFR 193 would be made by DOT staff.

The existing CLNG Terminal is currently operated and maintained in accordance with the DOT's Federal Safety Standards for LNG Facilities 49 CFR Part 193 and NFPA 59A (2001 Edition) Standard for the Production, Storage, and Handling of LNG and the existing marine facilities are operated and maintained in accordance with the USCG regulations for LNG Waterfront Facilities 33 CFR 127. The previously approved LNG Liquefaction Project facilities and the proposed Expansion Project facilities would be operated in accordance with these same standards.

[Section to Be Completed by FERC LNG Engineering Staff]

2.7.2 LNG Facility Hazards

With the exception of the October 20, 1944 failure at an LNG facility in Cleveland, Ohio, the operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people.[18] The failure of the LNG storage tank was due to the use of materials inadequately suited for cryogenic temperatures. LNG migrating through streets and into underground sewers due to the lack of adequate spill impoundments at the site was also a contributing factor. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used and that spill impoundments are designed and constructed properly to contain a spill at the site.

An operational accident occurred in 1979 at the Cove Point LNG facility in Lusby, Maryland. A pump seal failure resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to ensure that the situation would not occur again.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction facility, which killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced to the high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981.

On March 31, 2014, an explosion and fire occurred at Northwest Pipeline Corporation's LNG peak-shaving facility in Plymouth, Washington. The facility was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No members of the public were injured. The accident investigation is still in progress. Once developed, measures to address any causal factors which led to this incident would be applied to all facilities under the Commission's jurisdiction.

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

[To Be Completed by FERC LNG Engineering Staff]

2.7.2.1 Hazards Associated with the Proposed Equipment

[To Be Completed by FERC LNG Engineering Staff]

2.7.2.2 Loss of Containment

[To Be Completed by FERC LNG Engineering Staff]

2.7.2.3 Vapor Dispersion

[To Be Completed by FERC LNG Engineering Staff]

2.7.2.4 Flammable Vapor Ignition

[To Be Completed by FERC LNG Engineering Staff]

2.7.2.5 Overpressures

[To Be Completed by FERC LNG Engineering Staff]

2.7.3 Technical Review of the Facility Preliminary Engineering Design

[To Be Completed by FERC LNG Engineering Staff]

2.7.4 LNG Facility Siting Requirements

[To Be Completed by FERC LNG Engineering Staff]

2.7.5 LNG Facility Siting Analysis

[To Be Completed by FERC LNG Engineering Staff]

2.7.5.1 Impoundment Systems

[To Be Completed by FERC LNG Engineering Staff]

2.7.5.2 Design Spills

[To Be Completed by FERC LNG Engineering Staff]

2.7.5.3 Vapor Dispersion Analysis

[To Be Completed by FERC LNG Engineering Staff]

2.7.5.4 Overpressure Analysis

[To Be Completed by FERC LNG Engineering Staff]

2.7.5.5 Thermal Radiation Analysis

[To Be Completed by FERC LNG Engineering Staff]

2.7.6 LNG Facility Emergency Response

[To Be Completed by FERC LNG Engineering Staff]

2.7.7 Conclusions on Facility Reliability and Safety

[To Be Completed by FERC LNG Engineering Staff]

2.8 Cumulative Impacts

In accordance with NEPA and FERC policy, we considered the cumulative impacts of the Expansion Project and other projects in the general area. Cumulative impacts represent the incremental effects of the proposed action when added to other past, present, or reasonably foreseeable future actions, regardless of what agency or person undertakes such other actions. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over a given period. The direct and indirect impacts of the Expansion Project are addressed in other sections of this EA.

This cumulative impact analysis generally follows generally follows the methodology set forth in relevant guidance (CEQ, 1997). Under these guidelines, we based our selection of other projects in the analysis by identifying commonalities of impacts. The actions considered in the cumulative analysis may vary from the Expansion Project in nature, magnitude, and duration; however, an action must meet the following three criteria to be included in the cumulative impacts analysis:

- impacts a resource potentially affected by the Project;
- causes this impact within all, or part of, the project areas; and
- causes this impact within all, or part of, the time span for the potential impact from the Project.

For the purposes of this cumulative impact analysis, only projects directly in the vicinity of the Expansion Project are considered. The effects of more distant projects are not assessed because their impacts would be localized to their project areas and would not contribute significantly to the cumulative impacts in the Expansion Project area.

Project impacts would be primarily additive to the existing CLNG Terminal. The Expansion Project would be within the existing CLNG Terminal site, thereby minimizing additional temporary, permanent, and cumulative impacts. Potential cumulative impacts associated with current, proposed, or reasonably foreseeable future projects or activities in the ROI (e.g., same parishes) were identified and are listed in table 2.8-1. Some of these projects do not fit all three criteria that determine the potential for cumulative impacts; however, they were large enough to mention in the analysis to ensure a more complete picture of the types of project occurring in the same region as the Expansion Project. Although we were able to find the acreage affected by the majority of the projects listed in table 2.8-1, we were unable to gather resource-specific impacts for all the projects. Where appropriate, we have included conservative assumptions regarding the scope of these projects.

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
Liquefaction and LNG Export Projects at Existing LNG Terminals		
Lake Charles Liquefaction Project Industrial Canal, Calcasieu Parish	Addition of three liquefaction trains at existing terminal.	2014 to 2018
Cameron Liquefaction Expansion Project Calcasieu Ship Channel, Cameron and Calcasieu Parishes	Expansion at the existing CLNG Terminal to export 12 million tons of LNG per year.	2014 to 2018
Sabine Pass Liquefaction Projects Cameron Parish	Addition of liquefaction facilities at existing terminal. (Located about 38 miles south-southwest of the Expansion Project.)	2013 to 2019

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
New Liquefaction and LNG Export Projects		
Magnolia LNG Project Industrial Canal, Calcasieu Parish	Construction/operation of a new LNG terminal including four liquefaction trains, two LNG storage tanks, liquefaction and refrigerant units, safety and control systems, and associated infrastructure.	2015 to 2018
Live Oak LNG Project Calcasieu Ship Channel, Calcasieu Parish	Potential project that would include the construction/operation of a liquefaction and LNG export facility including eight liquefaction units capable of producing a nominal capacity of 5.2 Mtpy of LNG, two 130,000-m3 LNG storage tanks, a marine berth and an interconnection with nearby pipeline systems. (Located about 5 miles north of the Expansion Project.)	Unknown to 2019
Venture Global LNG Calcasieu Pass Project Calcasieu Ship Channel, Cameron Parish	Construction/operation of a LNG export plant with the capacity to export up to 10 million metric tons of LNG each year. (Located about 18 miles south of the Expansion Project near the Gulf of Mexico.)	2016 to 2019
Waller Point Marine LNG Terminal Calcasieu Ship Channel, Cameron Parish	Potential project that would include the use of small-scale liquefaction technology and installation of nominal 500,000 gallon per day LNG trains in phases to meet market and demands for marine LNG fuels. (Located about 18 miles south of the Expansion Project on Monkey Island.)	Unknown
Pipeline Projects		
Cameron Pipeline Expansion Project Cameron and Beauregard Parishes	Addition to existing pipeline system of 21 miles of 42-inch diameter pipeline and 1 new compressor station for bi-directional flow capability.	2014 to 2017

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
Cameron Access Project Cameron, Calcasieu, and Jefferson Davis Parishes	Construction/operation of approximately 27 miles of new pipeline, 10 miles of loop pipeline, and a new compressor station. (Located about 2 miles north of the Expansion Project.)	2016 to 2017
Other Industrial Projects		
G2X Energy's Natural Gas to Gasoline Facility Industrial Canal, Calcasieu Parish	Construction/operation of a facility that will use natural gas to produce methanol, then convert methanol to final gasoline for 90 percent of its production. About 10 percent of the output will be liquefied petroleum gas or propane. (Located about 5 miles north-northeast of the Expansion Project.)	2015 to 2017
IFG Port Holdings/New Export Grain Terminal Project Port of Lake Charles, Calcasieu Parish	Construction/operation of a state-of-the-art export grain terminal to handle agricultural products such as Louisiana rice, wheat, corn, soybeans and dried distillers' grain for shipment to other countries. (Located about 14 miles north-northeast of the Expansion Project.)	2014 to 2015
Juniper GTL Project Port of Lake Charles, Calcasieu Parish	Renovate a dormant steam methane reformer in the Westlake area and convert it to a natural gas-to-liquids facility to produce about 1,100 barrels a day of diesels, waxes and naphtha. (Located about 15 miles north-northeast of the Expansion Project.)	2014 to 2015

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
LA Gas Storage Expansion Project Calcasieu and Cameron Parishes	Construction/operation of one new compressor station, one new salt dome natural gas storage cavern, conversion of three existing salt dome brine storage caverns to natural gas storage caverns, 5.1-mile-long pipeline, one new meter station to interconnect with Cameron Interstate Pipeline, 4.0-mile-long brine disposal pipeline, and four salt water disposal wells. (Located about 8 miles southwest of the Expansion Project.)	2015 to 2017
Matheson Tri-Gas Sasol Supply Gas Project Calcasieu Parish	Industrial gas supply to Sasol's ethane cracker facility. Matheson Tri-Gas will supply Sasol with tonnage oxygen and nitrogen via a new Air Separation Unit, which will be part of a relocated facility set to be built on Evergreen Road. (Located about 16 miles north of the Expansion Project.)	2015 to 2016
Port of Lake Charles City Dock Project Port of Lake Charles, Calcasieu Parish	Major renovations to facilities at the City Docks off Sallier and improvements at the Bulk Terminal 1 consisting of addition of two docks that will triple vessel accommodations and improvements to the port's former administration building. (Located about 13 miles north-northeast of the Expansion Project.)	Unknown
Sasol's Ethane Cracker and Derivatives Complex Calcasieu Parish	Construction/operation of a facility to produce 1.5 million tons/year of ethylene and derivatives, which are used to make synthetic fibers, detergents, paints and fragrances. The facility will also include six chemical manufacturing plants. (Located about 15.5 miles north of the Expansion Project.)	2014 to 2018

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
Sasol's Gas-to-Liquids Complex Calcasieu Parish	Construction/operation of a gas-to-liquids complex that will provide a new source of demand for the Haynesville Shale and other natural gas plants in Louisiana. The complex would produce more than 96,000 barrels of diesel fuels and chemicals per day and would also house Sasol's second linear alkyl benzene unit, which will increase the company's production of detergent alkylates. (Located about 15 miles north of the Expansion Project.)	2016 to Unknown
Westlake Chemical Corporation Calcasieu Parish	Expand its ethylene, styrene and polyethylene capacity to increase ethane-based ethylene capacity by approximately 250 million pounds annually. (Located about 10 miles north of the Expansion Project.)	2014 to 2015/2016
Utility Projects		
Calcasieu Point Development Project	Improvements in three intersection locations (Tank Farm and Big Lake Roads, Big Lake and Lincoln Roads, and Lincoln Road and Gulf Highway) to reduce impacts on local users of the roadways during construction of the G2X Energy natural gas-to-gasoline, facility, Lake Charles Liquefaction Project, and Magnolia LNG Project. (Located about 6 miles north-northeast of the Expansion Project.)	2015 to 2016
Entergy's Lake Charles Transmission Project	Construction/operation of approximately 25 miles of new transmission lines (including 500-kV and 230-kV lines), two new substations, and the expansion of one existing substation. (Located about 6 miles north-northeast of the Expansion Project.)	2016 to 2018

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
Entergy's Transmission Line and Substation for the Lake Charles Liquefaction Project	Construction/operation a 19-mile-long 230 kV electric transmission line and a new substation to provide incremental power for the Lake Charles Liquefaction Project.	Dependent on LNG Project
Entergy's Transmission Line for the Cameron Liquefaction Project	Construction/operation of a 12-mile-long electrical transmission line to provide power for the CLNG Liquefaction Project.	Dependent on LNG Project
Entergy's Transmission Line for the Cameron Expansion Project	Construction/operation of a 14-mile-long 230 KV electrical transmission line to provide power for the Expansion Project.	Dependent on LNG Project
Residential Development Projects		
Audubon Trace Subdivision Calcasieu Parish	Construction of a 182 single-family residential development, square footage of homes is 1600-2000 with each lot being 7,500 square feet. (Located about 20 miles north-northeast of the Expansion Project.)	2015 to Unknown
Belle Savanne Development Calcasieu Parish	Construction of a development that includes over 12 acres of commercial and 15 acres of multifamily product. Phase one include about 100 lots (238 homes total with 80 in Phase 1 – completion in April 2014). The remainder of the lots will be built out in additional phases with future plans for development over time accessing about 300 acres comprised of about 1,000 lots. (Located about 10 miles north-northwest of the Expansion Project.)	2013 to Unknown

TABLE 2.8-1

Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion

Project/Location	Project Description (Distance/Direction)	Estimated Timeframe Construction to Operation
Moss Lake Worker Village Calcasieu Parish	Construction of a development that will provide housing for workers participating in several large projects in the region. About 100 acres of airport property will be leased. The planned community is designed to scale up and down, based on demand, and to accommodate up to 2,500 people at peak occupancy. To address traffic concerns, the transportation services incorporated into Moss Lake Village are expected to significantly reduce the number of vehicles traveling on Highway 27. (Located about 7 miles north-northwest of the Expansion Project.)	2015 to Unknown
Pelican Lodge Industrial Housing Facility Calcasieu Parish	Construction of a temporary industrial employee housing facility to be built near the Chennault International Airport on 250 acres owned by the Port of Lake Charles. It will hold up to 4,000 workers and include recreational facilities, a baseball field, basketball courts and several different dining options. To address traffic concerns, Pelican Lodge's transportation plan will reduce impacts by offering bus service for workers to and from their work sites. (Located about 19 miles northeast of the Expansion Project.)	2014 to Unknown
Walnut Grove Development Calcasieu Parish	Development of 60 acres down from the Port of Lake Charles of a mixed-use community with residential and commercial properties. (Located about 13 miles north-northeast of the Expansion Project.)	2013 to 2020

TABLE 2.8-1 **Authorized and Planned Major Projects in the Vicinity of the CLNG Expansion**		
Project/Location	**Project Description (Distance/Direction)**	**Estimated Timeframe Construction to Operation**
Federal and State Projects		
U.S. Army Corps of Engineers and Lake Charles Harbor and Terminal District's Maintenance Dredging of the Calcasieu Ship Channel Cameron and Calcasieu Parishes	Maintenance dredging along the 68-mile-long Calcasieu River navigation channel.	Ongoing

2.8.1 Potential Cumulative Impacts of the Proposed Action

Potential impacts most likely to be cumulative with the Expansion Project's impacts are related to water resources, socioeconomics, air quality, and noise.

2.8.1.1 Water Resources and Wetlands

The Expansion Project facilities would not permanently affect any perennial, intermittent, ephemeral streams, or drainages. Temporary impacts associated with construction include runoff from construction areas that could temporarily increase turbidity and sedimentation in adjacent waterbodies and wetlands. Surface water withdrawals and discharges related to hydrostatic testing could also temporarily impact surface water quality. Proponents of projects under the jurisdiction of the FERC would be required to comply with the FERC Procedures to minimize impacts on waterbodies and wetlands to the maximum extent practicable. Projects solely under the jurisdiction of the COE will be required to implement BMPs.

Each project noted in table 2.8-1 may include the permanent loss of wetlands or conversion of forested wetlands to emergent or scrub-shrub wetlands. However, these impacts would be offset by compensatory mitigation either through the purchase of credits from established mitigation banks or in-lieu mitigation.

2.8.1.2 Socioeconomics

All the projects listed in table 2.8-1 have or would generate temporary construction jobs. While many of the construction workers may reside locally, a number of non-local construction workers with specialized training for the specific project would be needed. Non-local laborers typically reside in hotels, motels, rental units, or mobile home parks in local communities near the Expansion Project. Positive cumulative economic benefits from these projects would be local sales taxes on goods and services during construction and increased property taxes on the completed projects when operating. The projects would also add permanent jobs in facility operations to the region.

2.8.1.3 Land Use and Aesthetics

The Expansion Project facilities would be constructed within the existing approved footprint of the LNG Terminal site. The adjacent area consists of open land dominated by industrial uses or property owned by CLNG. The new LNG storage tank and the associated Expansion Project facilities would have an effect on visual resources, however the effect would not be considered a critical impact because of the existing surrounding heavy industrial uses.

2.8.1.4 Air Quality and Noise

Construction activities have the potential to produce a temporary decrease in air quality and an increase in local noise levels. Temporary impacts would occur associated with each project due to fugitive dust from land clearing, grading, excavation, concrete work, and operation of fossil-fueled construction equipment and vehicles. However, with the exception of the current construction and proposed expansion at the CLNG Terminal and at the Sabine Pass LNG Terminal, these projects are geographically separated and would not result in cumulative impacts in any one specific area. The CLNG Terminal and the Sabine Pass LNG Terminal are located in the same parish (Cameron Parish). As currently proposed, both expansion projects at the LNG terminals began construction in 2015. The CLNG and Sabine Pass LNG terminals are about 37 miles apart, so cumulative impacts from fugitive dust would not occur. Emissions from construction equipment would be primarily restricted to daylight hours and would be minimalized through typical control equipment. The construction equipment emissions would result in short-term emissions that would be highly localized. In addition, fugitive dust emissions would be controlled by implementing fugitive dust controls as needed.

Permanent impacts on air quality and noise would be largely associated with the operation of aboveground facilities associated with the liquefaction trains, the LNG storage tanks, or the other industrial facilities. CLNG is proposing to update permitted equipment for the approved liquefaction Trains 1 through 3 to reflect the changes to permitted equipment. Air emissions from operation of the Expansion Project would be additive because it would discharge into a shared air basin. However, Cameron Parish in which the Expansion Project would be constructed is in attainment for all NAAQS criteria pollutants. Furthermore, each project would be required to meet all applicable federal and state air quality standards. As discussed in section 2.6.1, detailed ambient air quality impact modeling was performed to quantitatively evaluate the impacts from operation of the existing LNG Terminal. The modeling also included other existing sources of air emissions in the Expansion Project area and the updated permitted equipment for liquefaction Trains 1 through 3. The results of the modeling analysis concluded that there would be no significant impact on air quality from operation of the Expansion Project in the region.

2.8.1.5 Climate Change

Climate change is the change in the climate over time, whether due to natural variability or as a result of human activity, and cannot be represented by single annual events or individual anomalies. For example, a single large flood event or particularly hot summer is not an indication of climate change, while a series of floods or warm years that statistically change the average precipitation or temperature over years or decades may indicate climate change.

The Intergovernmental Panel on Climate Change (IPCC) is the leading international, multi- governmental scientific body for the assessment of climate change. The United States is a member of the IPCC and participates in the IPCC working groups to develop reports. The leading U.S. scientific body on climate change is the United States Global Change Research Program (USGCRP). Thirteen federal departments and agencies[19] participate in the USGCRP, which began as a presidential initiative in 1989 and was mandated by Congress in the Global Change Research Act of 1990.

The IPCC and USGCRP have recognized that:

- globally, GHGs[20] have been accumulating in the atmosphere since the beginning of the industrial era (circa 1750);
- combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture and clearing of forests is primarily responsible for the accumulation of GHG;
- anthropogenic GHG emissions are the primary contributing factor to climate change; and

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19 The following departments comprise the USGCRP: EPA, DOE, Department of Commerce, Department of Defense, Department of Agriculture, Department of the Interior, Department of State, DOT, Department of Health and Human Services, National Aeronautics and Space Administration, National Science Foundation, Smithsonian Institution, and Agency for International Development.

20 See Section 2.6.1.2

- impacts extend beyond atmospheric climate change alone and include changes to water resources, transportation, agriculture, ecosystems, and human health.

The USGCRP issued a report, *Global Climate Change Impacts in the Unites States*[21], in June 2009 summarizing the impacts climate change has already had on the United States and what projected impacts climate change may have in the future. The report categorizes overall impacts by resource and impacts for various regions of the United States. Although climate change is a global concern, for this cumulative analysis, we would focus on the cumulative impacts of climate change in the Expansion Project area.

The USGCRP's report notes the following continental Southeast and Coastal regional impacts:

- average temperatures have risen about 2°F since 1970 and are projected to increase another 4.5 to 9°F during this century;
- increases in illness and death due to greater summer heat stress;
- destructive potential of Atlantic hurricanes has increased since 1970 and the intensity (with higher peak wind speeds, rainfall intensity, and storm surge height and strength) is likely to increase during this century;
- in the United States, within the past century, relative sea level changes ranged from falling several inches to rising about 2 feet and are projected to increase another 3 to 4 feet this century;
- sea level rise and human alterations have caused 1,900 square miles of coastal wetland loss in Louisiana during the past century, reducing their capacity to protect against storm surge, and projected sea level rise is anticipated to result in the loss of a large portion of the nation's remaining coastal wetlands;
- declines in dissolved oxygen in streams and lakes have caused fish kills and loss of aquatic species diversity;

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21 U.S. Global Change Research Program. 2009. *Global Climate Change Impacts in the United States*. Thomas R. Karl, Jerry M. Melillo, and Thomas C. Peterson (eds.). Cambridge University Press.

- moderate to severe spring and summer drought areas have increased 12 percent to 14 percent (with frequency, duration, and intensity also increasing also projected to increase);

- longer periods of time between rainfall events may lead to declines in recharge of groundwater and decreased water availability;

- responses to decreased water availability, such as increased groundwater pumping, may lead to stress or depletion of aquifers and strain on surface water sources;

- increases in evaporation and plant water loss rates may alter the balance of runoff and groundwater recharge, which would likely to lead to saltwater intrusion into shallow aquifers;

- coastal waters have risen about 2°F in several regions and are likely to continue to warm as much as 4 to 8°F this century; and

- coastal water warming may lead to the transport of invasive species through ballast water exchange during ship transit.

The GHG emissions associated with construction and operation of the CLNG Terminal, identified in section 2.6.1.4, would not have any direct impacts on the environment in the Expansion Project area.

Climate change in the region would have two effects that may cause increased storm surges, increase temperatures of Gulf waters, which would increase storm intensity, and a rising sea level. In Louisiana, relative sea level changes have been estimated by the NOAA to be about 14 inches by 2050. This is greater than the global average because of regional ground subsidence. The CLNG Terminal is designed for a 500-year storm surge elevation level of 12.4 feet amsl. Given that the Expansion Project's process equipment minimum elevation point of support would be 12.5 feet amsl and the LNG storage tank (T-205) would be 14.0 amsl at top of the elevated pile cap, climate change-enhanced sea level rise and subsidence are considered adequately addressed in the Expansion Project design.

Currently there is no standard methodology to determine how the Expansion Project's incremental contribution to GHGs would translate into physical effects on the global environment. However, the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change that produces the impacts previously described. Because we cannot determine the Expansion Project's incremental physical impacts due to climate change on the environment, we cannot determine whether the Expansion Project would result in significant impacts related to climate change.

2.8.2 Conclusions

A thorough determination about the significance of cumulative impacts for specific environmental resources is difficult because of the lack of access to details about impacts on resources for the some of the projects listed in table 2.8-1. Some of the project sponsors would not file applications with the FERC because they are not under its jurisdiction. Some of the projects under FERC jurisdiction are early in their development and data about their impacts has not yet been assessed (projects that are in pre-filing and which have a "PF" docket number). The most significant cumulative impacts would occur if all of these projects were constructed at the same time as the Expansion Project; however, this is not anticipated. It can be assumed that construction and operation of the listed projects is likely to have impacts on a wide variety of environmental resources. However, construction of the Expansion Project would not cumulatively contribute to these impacts since most of the Expansion Project's impacts are minor and temporary and would be located within the previously disturbed existing CLNG Terminal site.

Air quality impacts could be cumulatively significant without mitigation, but each of the project proponents would be required to meet all applicable federal and state air quality standards, thereby lessening the cumulative impact.

Cumulative benefits would include enhancing the local economy through taxes, jobs, wages, and purchasing of goods and materials.

3. ALTERNATIVES

As required by NEPA and Commission policy, we identified and evaluated alternatives to the proposed Expansion Project. These alternatives were considered to determine whether they would be reasonable and environmentally preferable to the proposed action. These alternatives include the no-action alternative, energy alternatives, system alternatives, and alternative site configurations. The evaluation criteria for selecting potentially reasonable and environmentally preferable alternatives include the following:

- technical feasibility and practicality;
- significant environmental advantage over the Expansion Project; and
- ability to meet the Expansion Project objectives.

Our alternative assessment is based on project-specific information provided by CLNG, our expertise regarding the siting, construction, and operation of LNG export facilities and the potential effects on the environment, and takes into consideration the comments provided to the Commission about the Expansion Project.

3.1 No-Action Alternative

Under the no-action alternative CLNG would not construct the Expansion Project. If the Expansion Project is not constructed, then neither the adverse nor beneficial potential impacts described in this EA would occur. Implementing the no-action alternative would not allow CLNG to meet the purpose and need as described in section 1.3. Further, we have concluded that the impacts associated with the Expansion Project would not be significant; therefore, we do not recommend the no action alternative.

3.2 Alternative Energy Sources

The purpose of the Expansion Projects is to export natural gas to global markets and provide competitively priced LNG to other major gas consuming countries. CLNG indicated that the Expansion Project would result in benefits to public interest including: stimulation of the local, state, regional, and national economies through job creation; improve the United States' balance of trade; and reduce global greenhouse provide by providing low carbon natural gas to foreign markets. As part of the alternative selection process, it is important to consider and evaluate other alternative energy sources, including other fossil fuels such as coal and oil as well as renewable sources such as wind and solar.

Studies have shown that when natural gas is used to fire a power plant it emits about half the CO_2 emissions as compared with conventional plants that use other fossil fuels. It has been termed a "bridge fuel" between the dominant fossil fuels used today and renewable energy sources because it is clean burning and can reliably serve as a backup fuel to renewable energy facilities, which often provide power intermittently.

Renewable energy sources such as wind and solar are considered a cleaner alternative to fossil fuels because the amount of GHG emissions and other pollutants are less than energy produced by coal, oil, or natural gas. The United States and other countries around the world are using and exploring expanded use of these resources. The drawback to selecting these types of sources is that the resources are not consistently available, nor are they available at a quantity to be able to meet the energy demands of the global market.

Currently, these alternatives cannot provide energy sources that are economically, environmentally, and technically more feasible or practical than the natural gas that would be provided by the Expansion Project. Therefore, we do not recommend them.

3.3 System Alternatives

System alternatives to the proposed action would use existing or other proposed natural gas export facilities, natural gas transmission facilities, or other methods of transporting natural gas to meet the purpose of the Expansion Project. Implementing a system alternative would make it unnecessary to construct all or part of the Expansion Project, although some modifications or additions to an existing transmission system or other proposed system may be necessary.

In addition the CLNG's LNG Terminal, there are currently five operating LNG import terminals in the Gulf of Mexico, Gulf LNG in Pascagoula, Mississippi; Trunkline LNG Terminal in Lake Charles, Louisiana, Freeport LNG on Quintana Island, Texas, Sabine Pass LNG in Cameron Parish, Louisiana, and Golden Pass LNG in Sabine Pass, Texas. Three liquefaction expansion projects have been approved by the Commission and are currently under construction in the Gulf area of Louisiana and Texas: Sabine Pass LNG in Sabine Pass, Louisiana; Freeport LNG Expansion/FLNG Liquefaction in Freeport, Texas; and Corpus Christi LNG in Corpus Christi, Texas.

Several companies are seeking authorizations to construct and operate LNG liquefaction facilities and to export LNG. Table 3.3-1 lists the proposed projects, their location, anticipated in-service date, capacity, and whether the project would be co-located with existing LNG facilities. Twenty-one such projects have been identified within the vicinity of the Expansion Project area: eleven at existing LNG terminals, and 10 at new or greenfield LNG liquefaction facilities. The projects, assuming all are built, would liquefy 25.87 billion cubic feet per day (Bcf/d) of natural gas. Of this total, about

XX.XX Bcf/d is already subscribed for export. Natural gas for all the projects would come from the interstate pipeline system, allowing gas to be supplied from any location. But the supply of gas to the liquefaction facilities may be limited by pipeline capacity in a given area.

Sufficient liquefaction capacity may be available in the region if all projects are built as proposed; however, unlike common carrier natural gas, LNG cannot be accessed with an off-take connection and traded readily. Currently each project has its own load out facility designed to complement plant output, and has or would have natural gas pipeline infrastructure connected to it. No currently proposed projects report available capacity that would meet the applicant's need for 1.96 Bcf/d of supply, other things being equal. Therefore, CLNG's proposed expansion cannot be accomplished at the other existing facilities as no available capacity is reported.

The cost of a project is such that most, if not all, of the available capacity is subscribed to before construction is begun. As a result, we determined that these other projects would not be economically or practically feasible alternatives to the Expansion Project. Therefore, we do not recommend them as system alternatives.

TABLE 3.3-1

Gulf Coast System Alternatives

Project	**Liquefaction Plant Location (Parish or County, State)**	**Liquefaction Plant In-Service Date**	**Plant Capacity a/ (Bcf/d)**	**Co-Location with Existing LNG Regasification Unit**
Cameron LNG Expansion (Trains 4 and 5)	Cameron and Calcasieu Parishes, LA	2019	1.4	Yes
Existing LNG Regasification Facility, Proposing or Approved to add LNG Liquefaction b/				
Sabine Pass LNG	Cameron Parish, LA	2015	1.4	Yes
Trunkline LNG	Calcasieu Parish, LA	2019	2.4	Yes
Freeport LNG	Brazoria County, TX	2018	1.8	Yes
Golden Pass	Jefferson County, TX	2020	2.1	Yes
Cameron LNG (Liquefaction Project)	Cameron Parish, LA	2017	1.7	Yes

TABLE 3.3-1

Gulf Coast System Alternatives

Project	Liquefaction Plant Location (Parish or County, State)	Liquefaction Plant In-Service Date	Plant Capacity a/ (Bcf/d)	Co-Location with Existing LNG Regasification Unit
Gulf LNG Liquefaction Co., LLC	Jackson County, MS	2019	1.5	Yes
Proposed LNG Liquefaction Projects c/				
Southern Union-Trunkline LNG [CP14-120]	Lake Charles, LA	2019	2.2	Yes
Excelerate Liquefaction [CP14-71,72]	Lavaca Bay, TX	2018	1.38	No
Magnolia LNG [CP14-347]	Lake Charles, LA	2018	1.07	No
CE-FLNG PF13-11]	Plaquemines Parish, LA	2018	1.07	No
ExxonMobil-Golden Pass [CP14-517]	Sabine Pass, TX	2019	2.1	Yes
Gulf LNG Liquefaction [PF13-4]	Pascagoula, MS	2019/2020	1.5	Yes
Louisiana LNG [PF14-17]	Plaquemines, LA	2017/2018	0.30	No
Venture Global LNG, LLC [PF15-2]	Cameron Parish, LA	2018	1.34	No.
Texas LNG [PF15-14]	Brownsville, TX	2018	0.27	No
Annova LNG [PF15-15]	Brownsville, TX	2017 d/	0.94	No
Port Arthur LNG [PF15-18]	Port Arthur, TX	2021	1.4	No
Rio Grande LNG [PF15-20]	Brownsville, TX	2020	3.6	No
Freeport LNG Development [PF15-25]	Freeport, TX	2020	0.72	Yes
Cheniere-Corpus Christi	Corpus Christi, TX	2018/2019	1.4	No

TABLE 3.3-1

Gulf Coast System Alternatives

Project	Liquefaction Plant Location (Parish or County, State)	Liquefaction Plant In-Service Date	Plant Capacity a/ (Bcf/d)	Co-Location with Existing LNG Regasification Unit
LNG [PF15-26]				
Freeport LNG Development [CP15-518]	Freeport, TX	2018	0.34	Yes

a/ FERC North American LNG Export Terminals for Design Capacity – Bcf/d.
b/ Existing LNG regasification plant with plans for expansion. Liquefaction trains operating or under construction.
c/ Proposed Gulf of Mexico sites identified by project sponsors and shown on FERC's *June 18, 2015 North America LNG Export Terminal – Proposed*.
d/ Estimated based upon owner's press release contents.

3.4 Alternative Configurations and Designs

CLNG considered alternative configurations and designs for the Expansion Project site. However, the number of possible alternatives was limited by the siting requirements of NFPA-59A and other industry or engineering standards. Regulatory requirements stipulate that potential thermal exclusion and vapor dispersion zones remain on site and as such dictate the locations of specific pieces of equipment for the liquefaction facilities. Likewise, thermal radiation zones associated with flares require specific distances from other pieces of equipment and property lines which require specific placement of the flare facilities. The selected location of each of the Expansion Project facility components was accomplished with these guidelines and requirements as well as minimizing the areas of land to be disturbed during the construction and operation of the Expansion Project. We have reviewed CLNG's filings and believe this is a reasonable conclusion.

3.4.1 LNG Terminal Site Alternatives

The CLNG Terminal site is bounded on the east by the Calcasieu Ship Channel, which would restrict development in that direction and bordered to the south by broken marsh and areas occupied by active oil and gas production facilities. LA 27 runs directly adjacent to the LNG Terminal site and the area to the west of LA 27 is comprised of open water and broken marsh with portions of the area used for active oil and gas production. The area in the northern section of the CLNG Terminal site has sufficient area to accommodate the Expansion Project.

Portions of this area had been previously disturbed by the deposition of material dredged from the channel and construction activities associated with the existing CLNG Terminal. As stated in section 1.1 of this EA, the entire tract was previously surveyed and approved by the Commission for construction-related activities associated with the Liquefaction Project. Because this tract was of sufficient size, in close proximity to the existing CLNG Terminal and had been previously approved for Liquefaction Project facilities, it was selected for development of the Expansion Project.

In addition, this tract is composed of upland as opposed to other property adjacent to the existing CLNG Terminal, which is composed primarily of marsh wetlands. Close proximity allows the Expansion Project to use existing infrastructure including storage tanks, LNG carrier berth and LNG cargo loading/unloading facilities, and associated facilities. Because the use of another site to develop the Expansion Project facilities, as well as the associated storage and LNG carrier and cargo facilities, would require a greater potential environmental impact than the Expansion Project as proposed, we conclude that no other site alternatives would be an environmentally preferable alternative.

4. CONCLUSIONS AND RECOMMENDATIONS

We conclude that the approval of the Expansion Project would not constitute a major federal action significantly affecting the quality of the human environment. This finding is based on our environmental analysis as described above; information provided in Expansion Project application and supplemental filings; and their implementation of our recommended mitigation measures. We recommend that the Commission order include the mitigation measures listed below as conditions to any Section 3 Authorization the Commission may issue.

1. CLNG shall follow the construction procedures and mitigation measures described in their application and supplements, including responses to staff data requests and as identified in the EA, unless modified by the Order. CLNG must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;

    b. justify each modification relative to site-specific conditions;

    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

    d. receive approval in writing from the Director of the OEP **before using that modification**.

2. For LNG facilities, the Director of OEP has delegated authority to take all steps necessary to ensure the protection of life, health, property, and the environment during Expansion Project construction and operation. This authority shall allow:

    a. stop-work authority and authority to cease operation; and

    b. the design and implementation of any additional measures deemed necessary to ensure compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from Expansion Project construction and operation.

3. **Prior to any construction,** CLNG shall file affirmative statements with the Secretary, certified by senior company officials, that all company personnel, EIs, and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the

environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. The authorized facility locations shall be as shown in the EA, as supplemented by filed alignment sheets. **As soon as they are available, and before the start of construction,** CLNG shall file with the Secretary any revised detailed survey maps or sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must specify locations designated on these alignment maps or sheets.

5. CLNG shall file with the Secretary detailed maps or aerial photographs at a scale not smaller than 1:6,000 identifying all facility relocations, staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed that have not been previously identified in filings with the Secretary. Approval for use of each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use or cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps, or aerial photographs. Use of each area must be approved in writing by the Director of OEP **before construction in or near that area**.

This requirement does not apply to route variations required herein or extra workspace allowed by FERC's Plan. Examples of alterations requiring approval include all facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern mitigation measures

c. recommendations by state regulatory authorities; and

[FERC staff to list additional conditions]

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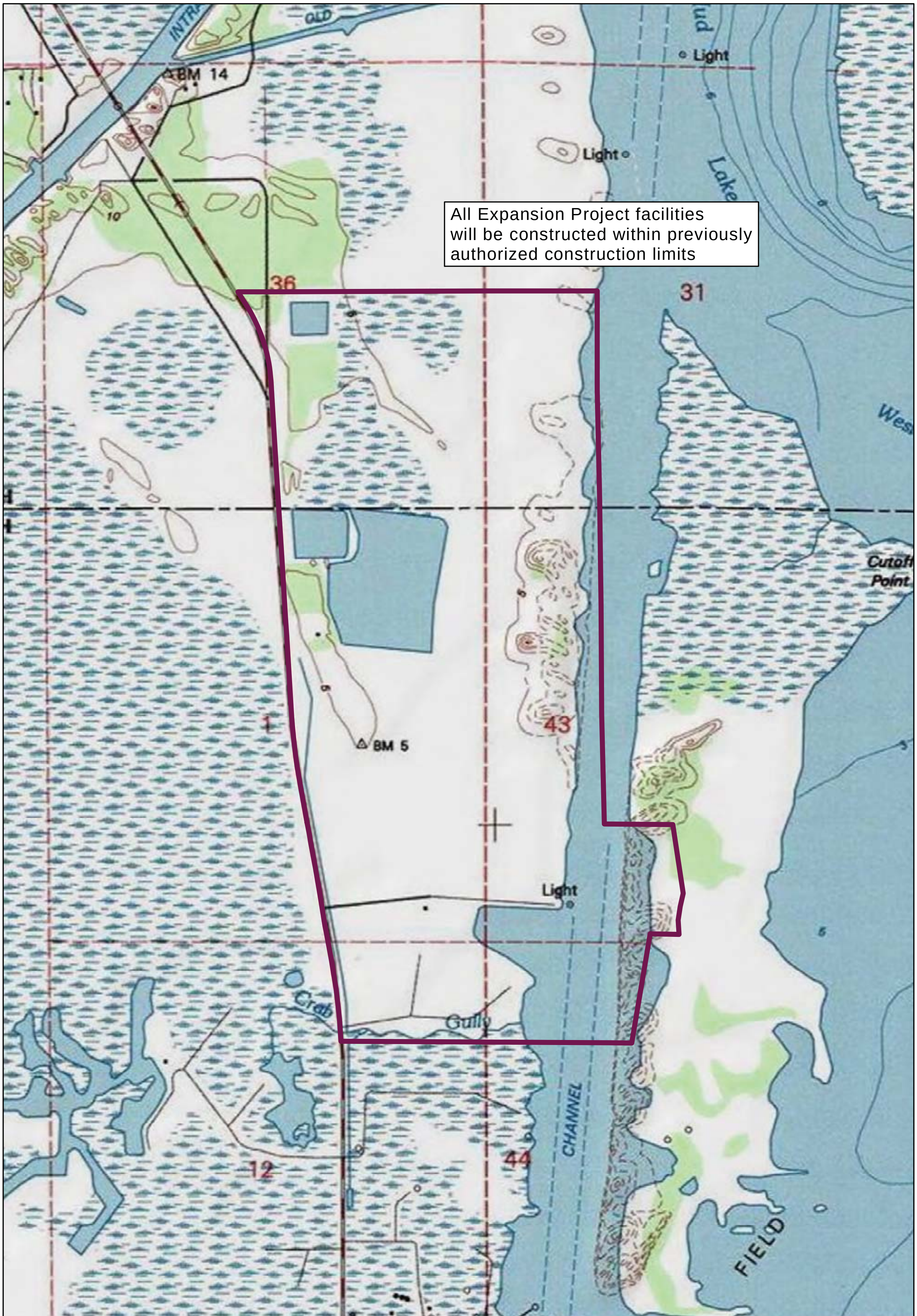
APPENDIX 1 – DETAILED USGS PROJECT MAP



1 inch = 1,250 feet

LNG Terminal Project Area

USGS Topographic Map of the Liquefaction Project Site
Cameron LNG Expansion

APPENDIX 2 – CAMERON LNG ENVIRONMENTAL PLAN

ENVIRONMENTAL PLAN

Cameron LNG Liquefaction &
Expansion Project

Note: This Environmental Plan is currently in use at the CLNG Liquefaction Project. The same plan will be utilized for the proposed Expansion Project. If modifications to the plan are required as part of the approval process for the Expansion Project, the modifications will be made and the revised plan will be submitted in the Implementation Plan for the Expansion Project.

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Appendix 1: Spill Notification & Agency Contacts

Appendix 2: Unanticipated Hazardous Waste Discovery Plan

Appendix 3: Unanticipated Discovery Plan

Appendix 4: Invasive Aquatic Weeds and Animals Plan

Appendix 5: FERC Upland Erosion Control, Revegetation & Maintenance Plan

Appendix 6: FERC Wetland & Waterbody Construction & Mitigation Procedures

1. ENVIRONMENTAL PLAN APPLICABILITY

The intent of this Environmental Plan (Plan) is to provide the Contractor with detailed instructions for maintaining compliance with applicable Local, State and Federal Regulatory Officials' (Agency) regulations governing construction activities on the Project. Project specific information is provided in Appendix A.

Significant changes to the implementation or design of this plan must be approved by the applicable Agency and Cameron LNG, LLC (Company). Significant changes shall be considered if the alternate measures:

a. provide equal or better environmental protection;
b. are necessary because a portion of this Plan is not feasible or is unworkable based on Project-specific conditions; and/or
c. are specifically required in writing by another Agency for the portion of the Project on its land or under its jurisdiction.

Environmental permits will be acquired by Company unless otherwise specified in the Appendices or in the contract document. Please note permits issued by the appropriate Agency shall be appended to this document immediately upon receipt by Company.

2. GENERAL CONDITIONS

2.1 Environmental Training

Prior to entering the construction right-of-way, all individuals working on the project shall attend the environmental training session. All individuals working on the project shall sign an acknowledgement of having attended the appropriate level of training and shall display a hard hat sticker acknowledging attendance at environmental training. In order to insure successful compliance, personnel shall attend repeat or supplemental training, if compliance is not satisfactory or as new, significant issues arise.

2.2 Environmental Inspection

Environmental Inspectors shall have the authority to stop activities that violate the environmental conditions of the Certificate, State and/or Federal environmental permit conditions, or landowner requirements; and to order appropriate corrective action.

The Company's Environmental Inspector(s) shall be responsible for the following:

a. ensuring compliance with the requirements of this Environmental Plan, the environmental conditions of applicable permits and authorizations, the mitigation measures proposed by the applicant (as approved and/or modified), other environmental permits and approvals, and environmental requirements in landowner easement agreements;
b. identifying, documenting, and overseeing corrective actions, as necessary to bring an activity back into compliance;.
c. verifying that the limits of authorized construction work areas and locations of access roads are properly marked before clearing;

d. verifying the location of signs and highly visible flagging marking the boundaries of sensitive resource areas, water bodies, wetlands, or areas with special requirements along the construction work area;
e. ensuring that protective measures are in place and well maintained to prevent impacts to sensitive resource areas, such as identified endangered species;
f. identifying erosion/sediment control and soil stabilization needs in all areas;
g. ensuring that the location of dewatering structures and slope breakers shall not direct water into known cultural resources sites or locations of sensitive species;
h. verifying that trench dewatering activities do not result in the deposition of sand, silt, and/or sediment near the point of discharge into a wetland or waterbody. If such deposition does occur, the dewatering activity shall be stopped and the design of the discharge shall be changed to prevent recurrence;
i. advising the Chief Construction Inspector when conditions (such as wet weather) make it advisable to restrict construction activities to avoid excessive rutting;
j. verifying the pre-construction and post-construction elevation surveys of impacted wetlands and the restoration of contours and topsoil as outlined in special conditions of the USACE permit;
k. verifying that the soils imported for agricultural or residential use have been certified as free of noxious weeds and soil pests, unless otherwise approved by the landowner;
l. determining the need for and ensuring that erosion controls are properly installed, as necessary to prevent sediment flow into wetlands, water bodies, sensitive areas, and onto roads;
m. perform inspections as required by the applicable regulatory agency. See Appendix A for site specific requirements.
n. ensuring the repair of all ineffective temporary erosion control measures within twenty-four (24) hours of identification;
o. keeping records of compliance with the environmental conditions of applicable permits and authorizations, and the mitigation measures proposed by Company in the application submitted to Federal or State environmental agencies during active construction and restoration; and
p. identifying areas that should be given special attention to ensure stabilization and restoration after the construction phase.

2.3 Access

All construction vehicles and equipment shall be confined to Company approved access roads and the construction right-of-way. If temporary alternative private roads for access are constructed they shall be designed to provide and allow proper drainage and shall be built to minimize soil erosion. Sufficiently sized gaps shall be left in all spoil and topsoil wind right-of-ways at all temporary private access roads and obvious livestock or wildlife trails unless agreed with the Landowner prior to construction that these access points can be blocked during construction. All construction related private roads and access points to the right-of-way shall be marked with signs. Private roads not approved for construction shall also be marked.

2.4 Appearance of Worksite

The construction right-of-way shall be maintained in a clean neat condition at all times. At no time shall litter be allowed to accumulate at any location on the construction right-of-way. The contractor shall provide a daily garbage detail with each major construction crew to keep the construction right-of-way clear of trash, pipe banding and spacers, waste from coating products, welding rods, timber skids, defective material and all construction and other debris immediately behind construction operations unless otherwise approved by Company. Paper from wrapping, coating products or lightweight items shall not be permitted to be scattered around by the wind.

2.5 Non-Hazardous Waste Disposal

Non-hazardous construction wastes include but are not limited to human waste, trash, pipe banding and spacers, waste from coating products, welding rods, timber skids, cleared vegetation, stumps, rock and all other construction debris.

All waste which contains (or at any time contained) oil, grease, solvents, or other petroleum products falls within the scope of the oil and hazardous substances control, clean up and disposal procedures. This material shall be segregated for handling and proper disposal by the Contractor in accordance with Section 2.7.

The Contractor shall be responsible for human wastes to be handled and disposed of exclusively by means of portable self-contained toilets during all construction operations. Wastes from these units shall be collected by a licensed Contractor for disposal only at licensed and approved facilities.

The Contractor shall dispose of all drill cuttings and drilling mud at a Company approved location. Disposal options may include spreading over the construction right-of-way in an upland location approved by Company, hauling to an approved licensed landfill, or other site approved by Company.

The Contractor shall remove all extraneous vegetative, rock and other natural debris from the construction right-of-way by the completion of clean-up. The Contractor shall remove all trash and waste from temporary Contractor's yards, pipe yards and staging areas when work is completed at each location. The Contractor shall dispose of all waste materials at licensed waste disposal facilities. Wastes shall not be disposed of in any other fashion such as un-permitted burying or burning.

2.6 Concrete Waste Management

The contractor shall dispose of all concrete waste at a designated concrete disposal station approved by Company. Concrete wash water should not be discharged into waterways, wetlands, storm drains or ground water. The concrete washout area should be located at least 100 feet from storm drains, open ditches, wetlands or waterbodies. The washout area can be constructed below or above grade depending on the location of the structure and must be approved by Company personnel prior to construction. Concrete washout facilities should be constructed with a minimum width and length of ten (10) feet with sufficient quantity and volume to contain all liquid and concrete waste generated by washout operations. The concrete washout structure can be constructed with straw bales, wood stakes and sandbags, earthen pit or other materials approved by the Environmental Inspector.

When the temporary concrete washout facilities are no longer required the hardened concrete shall be removed and disposed of properly. The materials used to construct the washout facility shall be removed from the site and disposed of properly.

Washout facilities must be cleaned, or new facilities must be constructed and ready for use once the washout is seventy-five percent (75%) full.

2.7 Hazardous Materials

If hazardous materials or containers are encountered during construction, the Contractor shall stop work immediately and notify Company. The Contractor shall not restart work until clearance is granted by Company. The Contractor shall ensure that all hazardous and potentially hazardous materials are transported, stored and handled in accordance with all applicable regulations. Workers exposed to or required to handle hazardous materials shall also be trained in accordance with the applicable regulations and the manufacturer's recommendations. The Contractor shall dispose of all hazardous materials at licensed waste disposal facilities. Hazardous materials shall not be disposed of in any other fashion such as un-permitted burying or burning. A unanticipated hazardous materials discovery plan is provided as Appendix 1.

All transporters of oil, hazardous substances, and hazardous waste shall be licensed and certified according to the applicable state vehicle code. Incidents on public highways shall be reported to the appropriate agencies. All hazardous wastes being transported off-site shall be manifested. The manifest shall conform to DOT requirements and the appropriate state agency. The vehicles as well as the drivers must conform to all applicable vehicle codes for transporting hazardous wastes.

2.8 Noise

The Contractor shall minimize noise during non-daylight hours and within one (1) mile of residences or other noise-sensitive areas such as hospitals, motels or campgrounds. Contractor shall abide by municipal bylaws regarding noise near residential and commercial/industrial areas. The Contractor shall provide notice to Company if noise levels are expected to exceed bylaws for a short duration. The Contractor shall minimize noise in the immediate vicinity of herds of livestock or poultry operations, which are particularly sensitive to noise. If any project specific noise requirements are required they will be included attached to this environmental plan or included in the contract document prior to commencement of construction activities.

2.9 Weed Control

There are no project specific weed control requirements at this time however, if determined necessary they will be included in this plan prior to commencement of construction activities.

2.10 Dust Control

The Contractor shall at all times control airborne dust levels during construction activities to levels acceptable by Company. The Contractor shall employ water trucks, sprinklers or calcium chloride as necessary to reduce dust to acceptable levels. Utilization of calcium chloride would be limited to roads. Dust shall be strictly controlled where the work approaches dwellings, farm buildings and other areas occupied by people and when the pipeline parallels an existing road or highway. This shall also apply to access roads where dust raised by construction vehicles may irritate or inconvenience local residents. The speed of the Contractor vehicles shall be controlled while in these areas. The Contractor shall take appropriate precautions to prevent fugitive emissions caused by sand blasting operations from reaching any residence or public building. The Contractor shall place curtains of suitable material, as necessary, to prevent windblown particles from sand blasting operations from reaching any residence or public building.

2.11 Fire Prevention and Control

The Contractor shall comply with all Federal, State, County and Local fire regulations pertaining to burning permits and prevention of uncontrolled fires. The following mitigative measures shall be implemented to prevent fire hazards and control of fires:

- A list of relevant Authorities and their designated representative to contact shall be maintained on the construction site by construction personnel.
- Adequate firefighting equipment in accordance with the regulatory requirements shall be available on site.
- The level of forest fire hazard shall be posted at the construction office (where visible for all workers) and make them aware of it and related implications.
- The Contractor shall provide equipment to handle any possible fire emergency. This shall include, although not be limited to, water trucks, portable water pumps, chemical fire extinguishers, hand tools such as shovels, axes, chain saws, etc. and heavy equipment adequate for the construction of fire breaks when required.
- Specifically, the Contractor shall supply and maintain in working order an adequate supply of fire extinguishers for each crew that is engaged in work such as welding, cutting, grinding, burning of brush or vegetative debris, etc.
- In the event of a fire, the Contractor shall notify local emergency response personnel.
- All tree clearing activities are to be carried out in accordance with local rules and regulations for the prevention of forest fires.
- Burning shall be done in compliance with state and/or county regulations and in the center of the right-of-way and in small piles to avoid overheating or damage to trees or other structures along the right-of-way.
- Flammable wastes shall be removed from the construction site on a regular basis.
- Flammable materials kept on the construction site must be stored in approved containers away from ignition sources.
- Smoking shall be prohibited around areas with flammable products.
- Smoking shall be prohibited on the construction site when the fire hazard is high.

2.12 Adverse Weather

The Contractor shall restrict certain construction activities and work in cultivated agricultural areas in excessively wet soil conditions to minimize rutting and soil compaction. In determining when or where construction activities should be restricted or suspended during wet conditions, the Contractor shall consider the following factors:

- The extent that rutting may cause mixing of topsoil with subsoil layers or damage to tile drains
- Excessive buildup of mud on tires and cleats
- Excessive ponding of water at the soil surface
- The potential for excessive soil compaction

The Contractor shall implement mitigative measures to minimize rutting and soil compaction in excessively wet soil conditions which may include:

- Restricting work to areas on the spread where conditions are not prohibitive;
- Using low ground weight or wide-track equipment or other low impact construction techniques;

- Limiting work to areas that have adequately drained soils or have a cover of vegetation such as sod, crops or crop residues sufficient to prevent mixing of topsoil with subsoil layers or damage to drain tiles; or
- Installing geotextile material or construction mats in problem areas.

2.13 Wetland and Waterbody Identification

Wetland and waterbody delineation was conducted using the current federal methodology (Interim Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Atlantic and Gulf Coastal Plain Region, October 2008). A wetland permit has been applied for and will be attached to the environmental plan or included in the contract document prior to commencement of construction activities. Construction methodology to be used in wetlands and waterbodies is located in Sections 5 through 8.

2.14 Threatened and Endangered Species

A threatened and endangered species survey was conducted within the Project boundary. Any conditions or considerations for federal or state listed species will be attached to this environmental plan or included in the contract document prior to commencement of construction activities.

2.15 Cultural Resource Assessment

A Cultural Resource Assessment was conducted within the Project boundary. Any conditions or considerations from any federal or state agency will be attached to this environmental plan or included in the contract document prior to commencement of construction activities. An Unanticipated Discovery Plan for the project is included in Appendix 3.

2.16 Invasive Aquatic Weeds & Animals

In accordance with regulatory requirements set forth by the Louisiana Department of Wildlife and Fisheries (LDWF) the following requirements must be adhered to. Water extracted from water bodies, as well as equipment, must be inspected for presence of invasive aquatic weeds, including but not limited to giant salvinia (Salvinia molesta), water hyacinth (Eichhornia spp), and Esthwaite Waterweed (Hydrilla verticallata), or aquatic animals, such as apple snails (Family Ampulariidae), before being brought to the site and before being moved from the site to prevent the transport and spread of such species. An Invasive Aquatic Weed and Animal Plan is included in Appendix 4.

3. UPLAND CONSTRUCTION

3.1 Approved Areas of Disturbance

The Contractor shall abide by the Project Specific FERC Upland Erosion Control, Revegetation, and Maintenance Plan as well any other local, state and federal permit guidelines set forth for the project. The Project Specific FERC Upland Erosion Control, Revegetation and Maintenance Plan is included as Appendix 5. Project-related ground disturbance shall be limited to the construction rights-of-way, extra work space areas, pipe storage yards, right-of-way and disposal areas, access roads and other areas as indicated on the approved alignment sheets. Any Project-related ground disturbing activities outside these approved areas, except those needed to comply with the erosion and sediment control practices specified in this Plan (e.g., slope breakers, energy-dissipating devices, dewatering structures, drain tile system repairs) will require notification and approval of appropriate local, state and federal agencies. All construction or restoration activities outside of the approved areas are subject to all applicable survey and mitigation requirements.

3.1.1. Road Crossings and Access Points

Install and maintain safe and accessible conditions at all road crossings and access points during construction.

The use of crushed stone access pads is required where access points are located along paved roadways to reduce tracking of soils onto paved roads. Placement of the crushed stone onto geotextile fabric shall facilitate maintenance and removal.

Road crossings shall be monitored when in use and after rain events. Roadways shall be swept as needed to ensure paved roadways are clear of accumulated soils.

Construction materials placed on paved roadways shall be removed immediately following use.

Reference Figures 2 - 4 for construction and placement details.

3.1.2. Clearing

The objective of clearing is to provide a clear and unobstructed right-of-way for efficient construction of the pipeline. The following mitigative measures shall be implemented:

- Construction traffic shall be restricted to the construction right-of-way and approved access roads.
- Construction right-of-way boundaries including pre-approved temporary workspace shall be clearly staked to prevent disturbance to unauthorized areas.
- If crops are present, they shall be mowed or disked to ground level unless an agreement is made for the Landowner to remove for personal use.
- Burning is prohibited on cultivated land.
- Construction right-of-way at timber shelterbelts in agricultural areas shall be reduced to the minimum necessary to construct the pipeline.
- Chipping in wetland is prohibited.

3.1.3. Topsoil Segregation Within Uplands

Unless the landowner or land management agency specifically approves otherwise, prevent the mixing of topsoil with subsoil by stripping topsoil from the full work area or from the trench and subsoil storage area (ditch plus spoil side method) in the following areas:

- Areas specified in the contract by Company
- residential areas;
- hayfields;
- other areas at the landowner's or land managing agency's request; and
- actively cultivated or rotated croplands and pastures.

In residential areas importation of topsoil is an acceptable alternative to topsoil segregation.

In deep soils (more than twelve (12) inches of topsoil), segregate at least twelve (12) inches of topsoil.

In soils with less than twelve (12) inches of topsoil make every effort to segregate the entire topsoil layer. Where topsoil segregation is required, maintain separation of salvaged topsoil and subsoil throughout all construction activities.

Segregated topsoil may not be used for padding the pipe.

Tree stumps and root wads should be segregated from topsoil and should not be used as backfill. Tree stumps should be considered construction debris and should be removed from the construction right-of-way.

3.1.4. Grading

The objective of grading is to develop a right-of-way that allows the safe passage of equipment and meets the bending limitations of the pipe. The following mitigative measures shall be implemented during grading unless otherwise approved or directed by Company based on site specific conditions or circumstances. However, work shall be conducted in accordance with applicable permits.

- All grading shall be undertaken with the understanding that original contours and drainage patterns shall be re-established during clean up.
- Agricultural areas that have been land formed with terraces shall be surveyed to establish pre-construction contours to be utilized for restoration of the terraces after construction.
- On steep slopes, or wherever erosion potential is high, temporary erosion control measures shall be implemented.
- Bar ditches adjacent to existing roadways that shall be crossed during construction shall be adequately ramped with grade or ditch spoil to prevent damage to the road shoulder and ditch.
- Where the construction surface remains inadequate to support equipment travel, timber mats, timber riprap or other method shall be used to stabilize surface conditions.

The Contractor shall limit the interruption of the surface drain network in the vicinity of the right of way, using the appropriate methods:

- Providing gaps in the right-of-ways of subsoil and topsoil in order to prevent any accumulation of water on the land
- Preventing obstructions in right-of-ways, right-of-way drains and ditches
- Installing flumes and ramps in right-of-ways, and right-of-way drains and ditches to facilitate water flow across the construction right-of-way and allow for construction equipment traffic
- Installing flumes over the trench for any watercourse where flow is continuous during construction

3.1.5. Drain Tiles

In the event that drain tiles are discovered during the course of construction Company and the Environmental Inspector shall be notified immediately and the following procedures shall be taken:

- Mark locations of drain tiles damaged during construction.
- Probe all drainage tile systems within the area of disturbance to check for damage.
- Repair damaged drain tiles to their original or better condition. Do not use filter-covered drain tiles unless the local soil conservation authorities and the landowner agree. Use qualified specialists for testing and repairs. For new pipelines in areas where drain tiles exist or are planned, ensure that the depth of cover over the pipeline is sufficient to avoid interference with drain tile systems. For adjacent pipeline loops in agricultural areas, install the new pipeline with at least the same depth of cover as the existing pipeline(s).

3.2 Temporary Erosion Control (Uplands)

Temporary erosion controls are crucial in maintaining compliance with the local, state and federal water quality regulations. Temporary erosion controls include, but are not limited to, temporary seed and mulch cover, silt fencing, staked hay or straw bales, straw wattles, erosion eels, temporary sediment traps, and temporary diversion berms. Temporary erosion controls shall be installed immediately prior to initial disturbance of the soil where practical. Where dense existing vegetation is present, install temporary erosion controls immediately following initial disturbance. Temporary erosion controls must be properly maintained throughout construction (on a daily basis)
and reinstalled as necessary (such as after backfilling of the trench) until replaced by permanent erosion controls or restoration is complete.

3.2.1. Temporary Slope Breakers (Uplands)

Temporary slope breakers are intended to reduce runoff velocity and divert water off the construction right-of-way. Temporary slope breakers may be constructed of materials such as soil, silt fence, staked hay or straw bales, or sand bags.

Install temporary slope breakers on all disturbed areas as necessary to avoid excessive erosion. Temporary slope breakers must be installed on slopes greater than 5 percent where the base of the slope is less than 50 feet from waterbody, wetland, and road crossings at the following spacing (closer spacing should be used if necessary):

Percent Slope	Spacing Distance (ft)
5% – 15%	300
> 15% – 30%	200
> 30%	100

Direct the outfall of each temporary slope breaker to a stable, well vegetated area. Where space allows, construct a small sediment trap at the base of slope breakers; otherwise construct or install an energy-dissipating device at the end of the slope breaker and off the construction right-of-way.

Position the outfall of each temporary slope breaker to prevent sediment discharge into wetlands, water bodies, or other sensitive resources.

Slope breakers may extend slightly (about four [4] feet) beyond the edge of the construction right-of-way to effectively drain water off the disturbed area.

Reference Figure 5 for placement and construction details.

3.2.2. Sediment Barriers (Uplands)

Sediment barriers are intended to stop the flow of sediments and to prevent the deposition of sediments into sensitive resources. They may be constructed of materials such as silt fence, staked hay or straw bales, compacted earth (e.g., drivable berms across travel ways), sandbags, or other appropriate materials suitable for site conditions.

At a minimum, install and maintain temporary sediment barriers across the entire construction right-of-way at the base of slopes greater than five percent (5%) where the base of the slope is less than fifty (50) feet from a waterbody, wetland, or road crossing until revegetation is successful as defined in this Environmental Plan.

Leave adequate room between the base of the slope and the sediment barrier to accommodate ponding of water and sediment deposition.

Proper installation and regular maintenance of barriers is essential to ensure proper performance of devices. Sediment that has accumulated beyond one-half (½) the capacity of the device should be removed immediately. Undermining and bypassing must be repaired as needed to provide for adequate performance of devices.

Where wetlands or water bodies are adjacent to and down-slope of construction work areas, install sediment barriers along the edge of these areas as necessary to prevent sediment flow into the wetland or waterbody.

Reference Figures 6 and 7 for sediment barrier details.

3.2.3. Silt Fence

Silt fence shall be installed to control sheet and rill erosion along the boundary of the construction right-of-way to contain limited areas of disturbed soils. Silt fence is an effective measure to intercept runoff from upslope to form ponds that temporarily store runoff and allow sediment to settle out of the water and stay on the construction site. Silt fence can also prevent sheet erosion by decreasing the velocity of the runoff.

Silt fences should be installed on the contour so that flow does not concentrate and cause bypassing, overtopping and/or failure.

A silt fence is specifically designed to retain sediment transported by sheet flow from disturbed areas, while allowing water to pass through the fence. Silt fences should be installed to be stable under the flows expected from the site.

Silt fences should not be installed across streams, ditches, waterways, or other concentrated flow areas.

Silt fences are composed of geotextile fabric supported between steel or wooden posts. Silt fences are commercially available with geotextile fabric attached to the post and can be rolled out and installed by driving the post into the ground.

Silt fences must be trenched in a minimum of six (6) inches at the bottom to prevent runoff from undermining the fence and developing rills under the fence.

Silt fences are normally limited to situations in which only sheet or overland flow is expected. Silt fences normally cannot filter the volumes of water generated by channel flow. The following is a table of minimum requirements for silt fence materials:

Specifications	Type A
Tensile Strength (Lbs. Min.[1] ASTM D-4632)	Warp – 260 Fill – 100
Elongation (% Max.) (ASTM D-4632)	40
AOS (Apparent Opening Size) (Max. Sieve Size) (ASTM D-4751)	no.30
Flow Rate (Gal/Min/Sq. Ft.) (GDT-87)	70
Ultraviolet Stability[2] (ASTM D-4632 after 300 hours weathering in accordance with ASTM D-4355)	80
Bursting Strength (PSI Min.) (ASTM D-3786 Diaphragm Bursting Strength Tester)	175
Minimum Fabric Width (Inches)	36

1 Minimum roll average of 5 specimens.
2 Percent of required initial minimum tensile strength.

The drainage area up gradient to the silt fence should not exceed one-quarter (¼) acre per one hundred (100) linear feet of silt fence for non-reinforced fence and one-half (½) acre per one hundred (100) linear feet of reinforced fence. When all runoff from the drainage area is to be stored up gradient to the fence (i.e. there is no stormwater disposal system in place) the maximum slope length up gradient to the fence should not exceed those shown in the following table:

Percent Slope	Maximum Slope Length above Fence (ft)
< 2%	100
2% – 5%	75
5% – 10%	50
10% – 20%	25
> 20%	15

In areas where the slope is greater than ten percent (10%), a flat area length of ten (10) feet between the top of the slope to the fence shall be provided.

Contractor shall install silt fences at the base of disturbed slopes across or adjacent to roadways, streams, wetlands, and anywhere else vegetative cover has been disturbed. When a construction right-of-way parallels a lake, stream, impoundment, or wetland, Contractor shall install a silt fence at the edge of the construction right-of-way to isolate and protect that feature from siltation. Contractor shall also employ these methods for paved roads and roadside trenches to minimize the flow of sediment onto or into these structures.

Contractor shall install silt fences whenever disturbed slopes are of such degree, and features requiring erosion and sediment control protection are in such horizontal proximity to those slopes, as specified in the following table:

Percent Slope	Proximity Distance (ft)
< 5%	25
5% – 15%	50
16% – 30%	75
> 30%	100

Contractor shall install silt fence in all instances when vegetation is sparse within 150 ft. of a body of water that parallels or is adjacent to the construction right-of-way, and the disturbed slope is toward the water.

Reference Figure 6 for construction details and diagrams.

3.2.4. Temporary Trench Breakers (Uplands)

Trench breakers are intended to slow the flow of subsurface water along the trench. Trench breakers may be constructed of materials such as sand bags or polyurethane foam. Do not use topsoil in trench breakers.

An engineer or similarly qualified professional shall determine the need for and spacing of trench breakers. Otherwise, trench breakers shall be installed at the same spacing as an upslope of permanent slope breakers.

In agricultural fields and residential areas where slope breakers are not typically required, install trench breakers at the same spacing as if permanent slope breakers were required.

At a minimum, install a trench breaker at the base of slopes greater than 5 percent where the base of the slope is less than 50 feet from a waterbody or wetland and where needed to avoid draining a waterbody or wetland.

Reference Figure 8 for placement details.

3.3. Mulching

The Contractor shall apply mulch on all areas with high erosion potential and on slopes greater than 8 percent (8%) unless otherwise approved by Company based on site specific conditions or circumstances. The Contractor shall spread mulch uniformly over the area to cover at least 75 percent (75%) of the ground surface at an approximate rate of two (2) tons/acre of straw, unless otherwise specified in Appendix A. Mulch application includes straw mulch or hydro mulch and tackifier. The Contractor shall not apply mulch in cultivated areas unless requested by the Landowner. The Contractor shall use mulch that is free of noxious weeds. The Contractor shall apply mulch immediately following seeding. The Contractor shall not apply mulch in wetlands unless otherwise specified in Appendix A. If a mulch blower is used, the majority of strands of the mulching material shall not be shredded to less than eight (8) inches in length to allow anchoring.

The Contractor shall anchor mulch immediately after application to minimize loss by wind and water. When anchoring (straw crimping) by mechanical means, the Contractor shall use a tool specifically designed for mulch anchoring with flat, notched disks to properly crimp the mulch to a depth of approximately two (2) to three (3) inches. A regular farm disk shall not be used to crimp mulch. In soils possessing high erosion potential, the Contractor may be required to make two passes of the mulch-crimping tool; passes must be as perpendicular to the others as possible.

When anchoring with liquid mulch binders (tackifiers), the Contractor shall use a biodegradable tackifier derived from a vegetable-based, organic source. The Contractor shall apply mulch binders at rates recommended by the manufacturer. The Contractor shall limit the use of liquid mulch binders (tackifiers) for anchoring straw and the use of hydro mulch and tackifier to areas that are too steep or rocky to safely or effectively operate mechanical mulch-anchoring tools.

3.4. Stringing (Uplands)

The objective of stringing is to place the line pipe along the construction right-of-way for bending and welding in an expedient and efficient manner. The Contractor shall utilize one or more of the following mitigation measures as applicable and when necessary to reduce compaction on the working side of the right-of-way or as directed by Company. However, all work shall be conducted in accordance with applicable permits.

- Prohibiting access by certain vehicles
- Using only machinery possessing low ground pressure (tracks or extra-wide tires)
- Control access thus minimizing the frequency of all vehicle traffic
- Hastening drainage through digging drainage ditch to re-establish surface drainage as required
- Using timber riprap, matting, or geotextile fabric overlain with soil
- Stopping construction entirely for a period of time

3.5. Trenching (Uplands)

The objective of trenching is to provide a ditch of sufficient depth and width with a bottom to continuously support the pipeline. During trenching operations, the following mitigative measures shall be implemented unless otherwise approved or directed by Company based on site specific conditions or circumstances. However, all work shall be conducted in accordance with applicable permits.

- Segregate subsoil materials from topsoil in separate, distinct right-of-ways with a separation that shall limit any mixing of topsoil and subsoil during handling of these materials.
- Gaps must be left in the spoil piles that coincide with breaks in the strung pipe to facilitate natural drainage patterns and to allow the passage of livestock or wildlife.
- Trenching operation shall be followed as closely as practicable by lower-in and backfill operations to minimize the length of time the ditch is open.
- Construction debris (e.g., welding debris) and other garbage shall not be deposited in the ditch. Should blasting be necessary for removal of rock, the following mitigation measures shall be implemented:

    i. Where blasting is required, operations shall be done accordingly to laws and regulations governing explosives.
    ii. Prior to using explosives the Contractor shall advise residents of the immediate area in order to prevent any risk of accidents or undue disturbances.
    iii. Blasting mats or subsoil shall be piled over the trench line to prevent any rocks from being blown outside the construction right-of-way.
    iv. Each blasting location shall be cleared and cleaned up before and after all blasting operations.
    v. Blasting shall be carried out during regular daylight working hours.

3.6. Trench Dewatering/Well Points

The Contractor shall make all reasonable efforts to discharge trench water in a manner that avoids damage to adjacent agricultural land, crops and pasture. Damage includes, but is not limited to the inundation of crops for more than twenty-four (24) hours, deposition of sediment in ditches, and the deposition of gravel in fields or pastures. If trench dewatering is necessary in an area where salt damage to adjacent crops is evident, the Company Inspector shall conduct a field conductivity test on the trench water before it is discharged. If the conductivity of the trench water is determined to potentially affect soil quality, it shall not be discharged to areas where salt damage to crops is evident, but shall be directed as feasible so that water flows over a well vegetated, non-cropland area or through an energy dissipater and sediment barrier, then directed to nearby ditches or brackish wetlands or waterbodies. When pumping water from the trench for any reason the Contractor shall ensure that adequate pumping capacity and sufficient hose is available to permit dewatering as follows:

- Water shall be diverted through a well vegetated area, a geotextile filter bag or a permeable berm (straw bale or Company approved equivalent);
- trench water shall not be disposed of in a manner which could damage crops or interfere with the functioning of underground drainage systems; and
- the Contractor shall screen the intake hose and keep the hose either one (1) foot off the bottom of the trench or in a container to minimize entrainment of sediment.

3.7. Welding, Field Joint Coating, and Lower-In

The objectives of welding, field joint coating and lower-in are to provide continuous segments of pipeline, to provide corrosion protection to the weld areas of the pipeline, and to place the pipeline in the center of the trench, without stress, at the required depth of cover. The following mitigative measures shall be followed during pipe welding, field joint coating, and lower-in, unless otherwise specified by Company in response to site specific conditions or circumstances. However, all work shall be conducted in accordance with applicable permits.

- Shavings produced during beveling of the line pipe are to be removed immediately following this operation to ensure that livestock and wildlife do not ingest this material. When welding operations have created a continuous line of pipe that may be left on the right-of-way for an extended period of time due to construction or weather constraints, a gap in the welded pipe shall be provided to allow for access at farm road crossings and also for passage of livestock and/or wildlife.
- Prior to the application of epoxy powder, urethane epoxy or other approved pipe coatings, a tarp shall be placed underneath the pipe to collect any overspray of epoxy powder and/or liquid drippings. Excess powder and/or liquid or other hazardous materials (e.g. brushes, rollers, gloves, etc.) shall be continuously collected and removed from the construction right-of-way.

3.8. Padding and Backfilling

The objective of padding (when required) and backfilling is to cover the pipe with material that is not detrimental to the pipeline and pipeline coating. The following mitigative measures shall be utilized during backfilling, unless otherwise approved or directed by Company based on site specific conditions or circumstances. All work shall be conducted in accordance with applicable permits.

- Excessive water accumulated in the trench shall be eliminated prior to backfilling.

- In the event it becomes necessary to pump water from open trenches, the Contractor shall pump the water and discharge it in accordance with Section 3.6.
- Prior to backfilling, all drain tile shall be permanently repaired, inspected and the repair documented as described in Section 5.5.
- Prior to backfilling, trench breakers shall be installed on slopes where required to minimize the potential for water movement down the ditch and potential subsequent erosion.
- In backfilling the trench, the stockpiled subsoil shall be placed back into the trench before replacing the topsoil.
- Topsoil shall not be utilized for padding the pipe.
- Backfilling shall be done without mixing spoil with topsoil.
- Backfill shall be compacted to a minimum of ninety percent (90%) of pre-existing conditions where the trench line crosses tracks of wheel irrigation systems (pivots).
- To reduce the potential for ditch line subsidence, spoil shall be replaced and compacted by backhoe bucket and/or by the wheels or tracks of equipment traversing down the trench.
- The top four (4) feet or the actual depth of top cover, whichever is less, within the pipeline trench, bore pits, or other excavations shall not be backfilled with soil containing rocks of any greater concentration or size than existed prior to the pipeline's construction.

4. RESTORATION AND CLEAN-UP (UPLANDS)

Commence clean-up, final grading, topsoil replacement, and installation of permanent erosion control structures operations immediately following backfill operations.

Grade the construction right-of-way to restore pre-construction contours and leave the soil in the proper condition for planting. Post-construction contours should match the adjacent properties.

Tree stumps and forestry slash should be considered construction debris and should be removed from the construction right-of-way.

Vegetative mulch created by forestry clearing activities may be utilized as mulch and may not remain stockpiled.

Where adjacent to wetland crossings the Environmental Inspector shall be consulted to ensure upland restoration does not encroach on wetland areas.

A travel lane may be left open temporarily to allow access by construction traffic if the temporary erosion control structures are installed, inspected and maintained. When access is no longer required, the travel lane must be removed and the right-of-way restored.

Rock excavated from the trench may be used to backfill the trench only to the top of the existing bedrock profile. Rock that is not returned to the trench should be considered construction debris, unless approved for use as mulch or for some other use on the construction work areas by the land owner or land managing agency.

Remove excess rock from at least the top twelve (12) inches of soil in all actively cultivated or rotated cropland and pastures, hayfields, and residential areas, as well as other areas at the landowner's request. The size, density, and distribution of rock on the construction work area should be similar to adjacent areas not disturbed by construction. The landowner may approve other provisions in writing.

Remove construction debris from all construction work areas unless the landowner or land managing agency approves otherwise.

Remove temporary sediment barriers when replaced by permanent erosion control measures or when revegetation is successful.

4.1. Permanent Erosion Control Devices (Uplands)

4.1.1. Permanent Trench Breakers

Trench breakers are intended to slow the flow of subsurface water along the trench. Trench breakers may be constructed of materials such as sand bags or polyurethane foam. Do not use topsoil in trench breakers.

An engineer or similarly qualified professional shall determine the need for and spacing of trench breakers. Otherwise, trench breakers shall be installed at the same spacing as and upslope of permanent slope breakers.

In agricultural fields and residential areas where slope breakers are not typically required, install trench breakers at the same spacing as if permanent slope breakers were required.

At a minimum, install a trench breaker at the base of slopes greater than five percent (5%) where the base of the slope is less than fifty (50) feet from a waterbody or wetland and where needed to avoid draining a waterbody or wetland.

Reference Figures 9 and 10 for construction and placement details.

4.1.2. Permanent Slope Breakers

Permanent slope breakers are intended to reduce runoff velocity, divert water off the construction right-of-way, and prevent sediment deposition into sensitive resources. Permanent slope breakers may be constructed of materials such as well vegetated earthen berms or functional equivalent.

Construct and maintain permanent slope breakers in all areas, except cultivated areas and lawns, using spacing recommendations obtained from the local soil conservation authority or land managing agency. In the absence of written recommendations, use the following spacing unless closer spacing is necessary to avoid excessive erosion on the construction right-of-way:

Percent Slope	**Spacing Distance (ft)**
5% – 15%	300
> 15% – 30%	200
> 30%	100

Construct slope breakers to divert surface flow to a stable area without causing water to pool or erode behind the breaker. In the absence of a stable area, construct appropriate energy-dissipating devices at the end of the breaker.

Slope breakers may extend slightly (about four [4] feet) beyond the edge of the construction right-of-way to effectively drain water off the disturbed area. Where slope breakers extend beyond the edge of the construction right-of-way, they are subject to compliance with all applicable survey requirements.

Where there is an existing right-of-way adjacent to the site, slope breakers should tie into existing breakers on an adjacent right-of-way, wherever practical.

Reference Figure 5 for construction and placement details.

4.2. Soil Compaction Mitigation

Test topsoil and subsoil for compaction at regular intervals in agricultural and residential areas disturbed by construction activities. Conduct tests on the same soil type under similar moisture conditions in undisturbed areas to determine preconstruction conditions. Use penetrometers or other appropriate devices to conduct tests.

Mitigate severely compacted soils in agricultural areas with deep tillage implements or other methods approved by the Company.

Perform appropriate soil compaction mitigation in severely compacted residential areas.

4.3. Revegetation

4.3.1. General

Contractor shall be responsible for ensuring successful revegetation of soils disturbed by Project-related activities. Revegetation is considered successful when permanent vegetation density is at least seventy-five percent (75%) coverage throughout one hundred percent (100%) of the disturbed area (as compared to adjacent undisturbed vegetation), per the local, state and federal requirements. Additional measures may need to be taken to provide successful permanent revegetation.

In residential areas, restore all ornamental shrubs and specialized landscaping in accordance with the construction line list. Restoration work must be performed by personnel familiar with local horticultural and turf establishment practices.

4.3.2. Soil Additives and Seeding Requirements

Contractor shall be required to revegetate all soil disturbed by construction except inundated wetlands. Contractor shall protect all new seeding from vehicular traffic during establishment. Contractor shall install permanent diversion dikes to channel runoff away from the seeded areas on slopes and to prevent erosion while vegetation is being established.

If mulch was applied prior to seeding for temporary erosion control, the Contractor shall remove and dispose of the excess mulch prior to seedbed preparation to ensure that seedbed preparation equipment and seed drills do not become plugged with excess mulch; to ensure that seed can adequately contact the soil surface; and to ensure that seed incorporation or soil packing equipment can operate without becoming plugged with mulch.

Contractor shall use a disk, field cultivator, drag, rake, or similar implement to prepare a smooth, firm, debris-free seedbed to a depth of six (6) inches. The soil shall not be worked when it is too wet. If soil conditions do not permit an adequate seedbed to be prepared, Contractor shall increase seeding rates by fifty percent (50%).

Contractor shall supply and apply agricultural or pelletized lime at a minimum rate of two (2) tons/acre, unless otherwise specified in the contract or by the Company, on all disturbed areas of the construction right-of-way, except wetlands. Lime shall be worked into the soil during application, or immediately thereafter, to prevent the possibility of exposure to storm water runoff. Suitable liming material includes dolomitic or calcitic materials. Liquid application is acceptable.

Contractor shall supply and apply fertilizer as specified in contract or as advised by the Company to meet the nutrient requirements of the site conditions. The fertilizer shall be incorporated into the upper two (2) inches of the soil where conditions permit. Fertilizer shall not be applied to wetlands or waterbodies.

Contractor shall supply and apply a seed mixture on all disturbed areas of the construction right-of-way, except wetlands, based on site specific seeding requirements identified in the contract or as specified by the Company. All seed must be used within twelve months of testing and incorporated by Contractor into the upper soil surface using a roller/packer.

Seed shall be broadcast utilizing a cyclone seeder or with a drill seeder. The Contactor shall operate the cyclone seeder or drill seeder such that the specified seed rate is planted. Seeds shall be incorporated by a cultipacker to ensure good ground contact.

In locations of extreme slope or very rocky ground conditions, Contractor shall hydro seed specific areas of the construction right-of-way as directed by Company. Hydro seeding shall apply seed at the rates specified by manufacturer for site conditions. Fertilizer shall be included with the seed, organic fiber, tackifier and water mixture. Organic fiber content shall be applied at the rate of three thousand (3,000) lbs/acres on an air-dry weight basis. The required tackifier shall consist of biodegradable, vegetable-based material and shall be applied at the rate recommended by the manufacturer. The seed, mulch and tackifier slurry shall be applied so that it forms a uniform, mat-like covering of the ground.

Additional measures may be needed, such as soil testing, re-application of soil additives, re-application of seed and mulch, to ensure permanent vegetation.

4.3.3. Erosion Control Blankets

Erosion control blankets (ECBs) shall be applied where shown on the Construction Drawings or as directed by a Company representative. The Contractor shall anchor the ECBs with staples or approved devices. The Contractor shall use ECBs specified in Appendix A or otherwise directed by EI, however if no ECB is specified in Appendix A the Contractor should use a mat that is made of 100% biodegradable, double net, natural fiber such as straw or coir (coconut fiber). The Contractor shall prepare the soil surface and install the erosion control matting to ensure it is stable and the matting makes uniform contact with the soil of the slope face or stream bank underneath with no bridging of rills, gullies or other low areas.

Reference Figure 11.

5. WATERBODY CROSSINGS

In the event that additional jurisdictional waterbodies are discovered during the course of construction Company and the Environmental Inspector shall be notified immediately and the following procedures shall be taken. FERC Wetland & Waterbody Construction & Mitigation Procedures are included in Appendix 6.

5.1 Notification Procedures and Permits

Prior to construction activities, Contractor will provide a schedule detailing the dates of all waterbody and wetland crossing. Contractor will update the schedule at least weekly. Company will notify Agency, if required.

5.2 Installation

The following procedures shall be followed for waterbodies within the construction right-of-way.

Reference Figures 12 through 15 for placement, construction and maintenance details of Waterbody and Crossing practices.

5.2.1. Extra Work Areas

Extra Work Areas are identified on the construction alignments.

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

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

5.2.2. General Waterbody Crossing Procedures

Comply with the local, state and federal permit terms and conditions.

Removal of vegetation within wetlands shall be limited to the approved construction right-of-way. Existing contours shall not be altered. Rutting of soils (greater than twelve (12) inches) shall be repaired immediately. Stump removal shall occur only within the trench line.

Mulching shall not occur within wetland or waterbody area. All vegetation cleared from wetland areas shall be moved to an upland area immediately following logging and clearing activities.

Storage of construction related materials, such as river weights, shall not occur within wetlands.

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

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

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

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

Wetland or 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.

Reference Figures 12 -15 for crossing details.

5.2.3. Equipment Bridges for Waterbodies

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.

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

a. equipment pads and culvert(s)
b. equipment pads or railroad car bridges without culverts
c. clean rock fill and culvert(s)
d. 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.

Design and maintain each equipment bridge to withstand and pass the highest flow expected to occur while the bridge is in place. Field adjustments must be made to ensure adequate flow of stormwater below bridges.

Align culverts to prevent bank erosion or streambed scour. If necessary, install energy dissipating devices downstream of the culverts.

Design and maintain equipment bridges to prevent soil from entering the waterbody. Use geo-textile fabric under equipment pads where needed to prevent soil from moving up to surface of equipment pads or to prevent soil from falling into waterbody below.

Construct and remove equipment pads in such a way to reduce disturbance of wetland soils beyond the limits of the equipment bridges. Avoid rutting of soils by the pads or the equipment outside of the bridge area. Rutting of soils (greater than twelve [12] inches) should be repaired immediately.

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

If there shall be more than one month between final clean-up 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 clean-up.

Reference Figures 12 through 15 for placement of controls.

5.2.4. Spoil Pile Placement and Control

All spoil from wetland or minor and intermediate waterbody crossings, and upland spoil from major waterbody crossings, must be placed in the construction right-of-way at least ten (10) feet from the water's edge or in additional extra work areas as needed.

Use sediment barriers to prevent the flow of spoil or heavily silt-laden water into any wetland or waterbody. Should sediment migrate beyond sediment barriers steps shall be taken immediately to repair breaches in the barrier and to retrieve lost sediment. Should heavily silt-laden water seep from the barriers, immediate steps shall be taken to reduce flow and provide for adequate settling or filtration. Flocculants shall be utilized where additional filtration or settling is not practical due to space limitations.

5.2.5. Dewatering Activities

Trench dewatering shall occur as needed to prevent sediment laden water from entering wetlands, waterbodies or drainage channels that are beyond the immediate construction area.

Trench water shall not be allowed to enter wetlands, waterbodies or drainage channels in such as way as to cause or contribute to scouring or sedimentation.

Dewatering structures shall be limited by the following conditions:

a. constructed within well vegetated uplands areas where engineering and routing conditions permit
b. placed at the farthest location above wetlands, waterbodies or drainage channels as is practical
c. located above natural sediment barriers such as existing well vegetated earthen berms or above sediment barriers constructed with appropriate materials
d. within wetlands shall be removed immediately after use
e. constructed and maintained to ensure discharge water quality meets the applicable regulatory standards

Contractor shall supply adequate pumping equipment, hoses and supplies to each dewatering location for appropriate placement and maintenance of dewatering activities. Dewatering intake hoses shall be floated near the surface of trench water to reduce uptake of concentrated sediments within the trench water. This shall increase efficiency of pumps and filtration bags and increase discharge water quality.

Discharge water clarity shall be visually monitored during dewatering activities. Should discharge water appears to be more cloudy than the receiving water or the water immediately upstream of dewatering location or fail to meet the water quality requirements for any reason, such as improper materials, placement, construction or maintenance of dewatering structures, dewatering activities shall cease immediately. Structures shall be moved, repaired, or replaced as requested by the Environmental Inspector. Flocculants shall be utilized where additional filtration or settling is not practical due to space limitations.

Reference Figures 16 – 18 for dewatering details.

5.2.6. Filter Bags for Dewatering

Contractor shall supply and utilize filter bags, for purposes of dewatering, of the minimum specification as follows in the following table:

Parameter	Minimum Specification
Grab Strength	> 200 lbs.
Grab Elongation @ Break	100% (max)
Puncture Resistance	> 100 lbs.
Trapezoid Tear Strength	> 75 lbs.
Burst Strength	> 350 psi
Apparent Opening Size (AOS)	70 – 100
(U.S. sieve no. equivalent)	
Water Flow Rate	> 105 gpm/sq. ft.

Contractor shall have the option to procure pre-fabricated filter bags or to construct them on-site with the above specified geotextile fabric. If on-site construction is utilized, Contractor shall construct the filter bag to provide efficient sediment removal and resist seam failure. Dewatering rates shall be followed as described below for on-site constructed bags:

Minimum Filter Dimensions		Approximate Pumping Rate Gallons per Minute
"X" (ft.)	"Y" (ft.)	
10	20	300
15	20	350
20	20	400
20	25	450
25	25	500
25	30	550
30	30	600

Contractor shall monitor the condition of the filter bags throughout the dewatering activities and shall ensure appropriate pumping levels shall be used in accordance with manufacturers recommended filter bag capacity. The table above shall be used in the absence of manufacturer's recommendations.
Contractor shall remove used filter bags from the construction right-of-way immediately following dewatering activities.

Reference Figures 16 and 18 for filter bag diagram and details.

5.2.7. Waterbody Crossing Methods

Construction methods pertinent to waterbody crossings are presented below. Selection of the most appropriate method at each crossing shall be depicted on the construction drawings but may be amended or changed based on site-specific conditions (i.e., environmental sensitivity of the waterbody, depth, and rate of flow, subsurface soil conditions, and the expected time and duration of construction) at the time of crossing. In general the dry-ditch crossing technique should be utilized at all waterbody crossings less than 30' wide with a perceivable flow at the time of the crossing. The open-cut (wet-ditch) method should be utilized at ephemeral streams and ditches when there is no perceivable flow at the time of crossing. Equipment to complete dry-ditch crossing will be onsite as a contingency in case that flow should begin during construction. Where required, horizontal directional drilling (HDD) will be used at designated major and or sensitive waterbody crossings.

5.2.8. Open-Cut Crossing Method (wet-ditch)

An open-cut waterbody crossing will use methods similar to conventional upland open-cut trenching. This crossing method is typically used to cross waterbodies that are non state-designated as well as intermediate and major waterbodies with substantial flows that cannot be effectively culverted or pumped around the construction zone using the dry-ditch crossing techniques. Non-state designated waterbodies typically include perennial warmwater streams not considered significant by the state, intermittent drainage ditches and stream and ephemeral stream or ditches. The open-cut construction method will evolve excavation of the pipeline trench across the waterbody, installation of a prefabricated segment of pipe, and backilling of the trench with native material. The construction zone is not isolated from the stream flow and the objective of this method is to complete the waterbody crossing as quickly as practical in order to minimize the duration of impacts to aquatic resources. There are two types of open-cut crossing methods: non-flowing open-cut method and the flowing open-cut method.

The contractor shall utilize the non-flowing open cut crossing method (Figure 12) for all non-state designated waterbody crossings (ephemeral, ditches, gullies, drains, swales, ect.) with no perceptible flow at the time of construction. Should site conditions change and the waterbody is flowing at the time of construction, the contractor shall utilize a dry-ditch crossing method unless otherwise approved by the Company.

The flowing open-cut method is typically utilized on waterbodies 30’ or greater where dry-ditch crossing methods cannot be effectively utilized where dry-ditch crossing methods cannot be effectively utilized. Reference to Figure 13 for construction details.

The open-cut crossing method shall be installed as follows:

1. For minor waterbodies:

   a. Equipment bridges are not required at non state-designated fisheries (e.g. agricultural or intermittent drainage ditches). However, if an equipment bridge is used, it must be constructed in accordance with Section 5.2.2;

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

   c. Complete trenching and backfilling in the waterbody (not including blasting and other rock breaking measures) within 24 continuous hours; and

   d. If a flume is installed within the waterbody during mainline activities, it can be removed just prior to lowering in the pipeline. The 24-hour timeframe starts as soon as the flume is removed.

2. For intermediate waterbodies:

   a. Limit use of equipment operating in the waterbody to that needed to construct the crossing. All other construction equipment must cross on an equipment bridge.

   b. Attempt to complete trenching and backfill work within the waterbody (not including blasting and other rock breaking measures) within 48 continuous hours, unless site specific conditions make completion within 48 hours infeasible.

3. For major waterbodies:

   a. Company will develop site-specific crossing plans to be submitted for approval by the FERC and the appropriate permitting agency; and

   b. Construct the crossing in accordance with the measures contained in this Plan to the maximum extent practical.

5.2.9. Dry-Ditch Open-Cut Crossing Method

The dry-ditch crossing method is divided into a flumed crossing method and a dam and pump crossing method. These methods are designed to maintain downstream flow at all times and to isolate the construction zone form the stream by channeling the water flow through a flume pipe or by damming the flow and pumping the water around the construction area. The overall objective is to minimize siltation of the waterbody and to facilitate trench excavation of saturated spoil. Unless approved otherwise by the appropriate state agency, pipeline construction and installation must occur using one of the two "dry" crossing methods for waterbodies state-designated as either coldwater or significant coolwater or warmwater fisheries. The flumed and dam and pump crossing methods are applicable to waterbodies up to 30 feet wide at the water's edge at the time of construction.

5.2.10. Dam and Pump Method (dry-ditch)

The dam-and-pump method may be used for crossings of waterbodies where pumps can adequately transfer stream flow volumes around the work area, and there are no concerns about sensitive species passage.

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

a. use sufficient pumps, including on-site backup pumps, to maintain downstream flows;
b. construct dams with materials that prevent sediment and other pollutants from entering the waterbody (e.g., sandbags or clean gravel with plastic liner);
c. screen and float pump intakes;
d. prevent streambed scour at pump discharge; and
e. monitor the dam and pumps to ensure proper operation for the duration of the waterbody crossing.

Reference Figure 14 for construction diagram.

5.2.11. Flume Crossing Method (dry-ditch)

The flume crossing method requires implementation of the following steps:

a. install flume pipe after blasting (if necessary), but before any trenching;
b. 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 (minor modifications to the stream bottom may be required in order to achieve an effective seal);
c. properly align flume pipe(s) to prevent bank erosion and streambed scour;
d. do not remove flume pipe during trenching, pipe laying, or backfilling activities, or initial streambed restoration efforts; and
e. remove all flume pipes and dams that are not also part of the equipment bridge as soon as final clean-up of the stream bed and bank is complete.

Reference Figure 15 for construction diagram.

5.2.12. Horizontal Directional Drill (HDD)

To the extent they were not provided as part of the planning process, for each waterbody or wetland that would be crossed using the HDD method, the Contractor shall provide a site specific plan to address each crossing.

Unless otherwise specified in a site specific HDD plan, the procedures that the Contractor shall implement in the event of an inadvertent drilling mud release ("frac-out") into any waters of the

United States or Wetland areas within or adjacent to the construction right-of-way include containment of the inadvertent release and subsequent clean up, as necessary.

In the event that an inadvertent release is identified during the operation of a HDD, the Contractor shall immediately notify Company. Response options and actions shall be mutually evaluated and implemented, as necessary, to stop the release and prevent further inadvertent releases. Actions by the Contractor may include decreasing the drilling mud pressure and/or increasing the viscosity of the drilling mud. Company shall notify all applicable agencies as to the status of any release and subsequent clean-up.

Company and the Contractor shall evaluate the frac-out to determine the need for clean-up and removal of the drilling mud. In general, typical, minor frac-outs within the construction right-of-way or adjacent wetland areas shall be contained and cleaned-up, unless such activity would cause further detrimental impacts to those areas.

Upon identification of a frac-out, the Contractor shall take immediate measures to contain the release, depending on its location. If a frac-out occurs within the construction right-of-way, the Contractor shall immediately install silt fence to contain the release within an area adequate to facilitate potential clean-up procedures and protect adjacent wetland areas. The Contractor shall make every effort to contain frac-outs and releases within the construction right-of-way.

In the event a frac-out occurs in a water body or watercourse, the Contractor shall, as approved by Company, install turbidity curtains within safely accessible open water areas to contain the release and decrease turbidity levels, thus allowing the drilling mud to settle to the bottom of the waterbody. During containment procedures, care shall be taken to minimize and limit impacts to adjacent areas.

In the event a frac-out occurs in a water body or area outside the construction right-of-way, the Contractor shall notify Company immediately and shall not be permitted access to the spill without Company approval.

Wetlands that are not part of the permitted construction right-of-way but are disturbed as a result of Contractor frac-out and a Contractor response effort to a major drilling mud release (as directed by the permitting agencies) shall be restored to their pre-project elevations and conditions, including replanting. In the event that replanting is required, Company shall contact the appropriate regulatory agency(s) to determine revegetation requirements. Revegetation shall be conducted by the Contractor in accordance with requirements set forth by the regulatory agency(s).

5.2.13. Crossings of Major Waterbodies, Scenic Rivers or Other

Before construction, the project sponsor shall file with the FERC from 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. 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 EI may adjust the final placement of the erosion and sediment control structures in the field to maximize effectiveness.

5.3. Clearing (Waterbody)

Except where rock is encountered and at non-flowing open cut crossings, all necessary equipment and materials for pipe installation must be on-site and assembled prior to commencing trenching in a waterbody. All staging areas for materials and equipment shall be located at least fifty (50) feet from the waterbody edge unless otherwise approved by Company. The Contractor shall preserve as much vegetation as possible along the waterbody banks while allowing for safe equipment operation. Clearing and grubbing for temporary vehicle access and equipment crossings shall be carefully controlled to minimize sediment entering the waterbody from the construction right-of-way. Clearing and grading shall be performed on both sides of the waterbody prior to initiating any trenching work. All trees shall be felled away from watercourses. Plant debris or soil inadvertently deposited within the high water mark of waterbodies shall be promptly removed in a manner that minimizes disturbance of the waterbody bed and bank. Excess floatable debris shall be removed above the high water mark from areas immediately above crossings. Vegetation adjacent to waterbodies which are to be installed by horizontal directional drill or boring methods shall not be disturbed except by hand clearing as necessary for drilling operations.

5.4. Grading (Waterbody)

The construction right-of-way adjacent to the waterbody shall be graded so that soil is pushed away from the waterbody rather than towards it when possible. In order to minimize disturbance to woody riparian vegetation within extra workspaces adjacent to the construction right-of-way at waterbody crossings, the Contractor shall maintain at a minimum a ten (10) foot vegetative buffer of waterbody banks. Grubbing shall be limited to the ditch line plus an appropriate width to accommodate the safe installation of vehicle access and the crossing to the extent practicable.

5.5. Temporary Erosion and Sediment Control (Waterbody)

Install sediment barriers immediately following the 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. 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 drivable 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 anticipated;
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.

5.6. Trenching (Waterbody)

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

a. All equipment and materials shall be on site before trenching in the active channel of all minor waterbodies containing state designated fisheries, and in intermediate and major waterbodies.
b. All activities shall proceed in an orderly manner without delays until the trench is backfilled and the stream banks stabilized.
c. The Contractor shall not begin in-stream activity until the in-stream pipe section is complete and ready to be installed in the waterbody.
d. The Contractor shall use trench plugs at the end of the excavated trench to prevent the diversion of water into upland portions of the pipeline trench and to keep any accumulated upland trench water out of the waterbody.
e. Trench plugs must be of sufficient size to withstand upslope water pressure. The Contractor shall conduct as many in-stream activities as possible from the banks of the waterbodies.
f. The Contractor shall limit the use of equipment operating in waterbodies to that needed to construct each crossing.
g. The Contractor shall place all spoil from minor and intermediate waterbody crossings, and upland spoil from major waterbody crossings in the construction right-of-way at least fifty (50) feet from the water's edge, in additional extra work areas or as otherwise directed by Company.
h. No trench spoil, including spoil from the portion of the trench across the stream channel, shall be stored within a waterbody unless the crossing cannot be reasonably completed without doing so.
i. The Contractor shall install and maintain sediment barriers around spoil piles to prevent the flow of spoil into the waterbody. Spoil removed during ditching shall be used to backfill the trench usually with a backhoe, clamshell or a dragline working from the waterbody bank. Sand, gravel, rockshield, or fill padding shall be placed around the pipe where rock is present in the channel bottom.

5.7. Pipe Installation (Waterbody)

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

a. The trench shall be closely inspected to confirm that the specified cover and that adequate bottom support can be achieved, and shall require Company approval prior to the pipe being installed.
b. Such inspections shall be performed by visual inspection and/or measurement by a Company Representative.
c. In rock trench, the ditch shall be adequately padded with clean granular material to provide continuous support for the pipe.
d. The pipe shall be lowered into the trench and shall, where necessary, be held down by weights, as-built recorded and backfilled immediately to prevent the pipe from floating.
e. The Contractor shall provide sufficient approved lifting equipment to perform the pipe installation in a safe and efficient manner.
f. As the coated pipe is lowered in, it shall be prevented from swinging or rubbing against the sides of the trench.
g. Only properly manufactured slings, belts and cradles suitable for handling coated pipe shall be used.
h. All pipes shall be inspected for coating flaws and/or damage as it is being lowered into the trench.
i. Any damage to the pipe and/or coating shall be repaired.

5.8. Backfilling (Waterbody)

The following requirements apply to all waterbody crossings except those being installed by the non-flowing open cut crossing method.

a. Trench spoil excavated from waterbodies shall be used to backfill the trench across waterbodies.
b. After lowering-in has been completed, but before backfilling, the line shall be reinspected to ensure that no skids, brush, stumps, trees, boulders or other debris is in the trench.
c. If discovered, such materials or debris shall be removed from the trench prior to backfilling.
d. For each major waterbody crossed, the Contractor shall install a trench breaker at the base of slopes near the waterbody unless otherwise directed by Company based on site specific conditions.
e. The base of slopes at intermittent waterbodies shall be assessed on-site and trench breakers installed only where necessary.
f. Slurred muck or debris shall not be used for backfill.
g. At locations where the excavated native material is not acceptable for backfill or must be supplemented, the Contractor shall provide granular material approved by Company.
h. If specified in the Construction Drawings, the top of the backfill in the stream shall be armored with rock riprap or bio-stabilization materials as appropriate.

5.9. Stabilization and Restoration of Stream Banks and Slopes (Waterbody)

The stream bank contour shall be re-established. All debris shall be removed from the streambed and banks. Stream banks shall be stabilized and temporary sediment barriers shall be installed within twenty-four (24) hours of completing the crossing if practicable. Approach slopes shall be graded to an acceptable slope for the particular soil type and surface run off controlled by installation of permanent slope breakers. Where considered necessary, the integrity of the slope breakers shall be ensured by lining with erosion control blankets. Immediately following reconstruction of the stream banks, the Contractor shall install seed and flexible channel liners on waterbody. If the original stream bank is excessively steep and unstable and/or flow conditions are severe or if specified on the Construction Drawings, the banks shall be stabilized with rock riprap, gabions, stabilizing cribs, or bio-stabilization measures to protect backfill prior to reestablishing vegetation. Stream bank riprap structures shall consist of a layer of stone, underlain with approved filter fabric or a gravel filter blanket. Riprap shall extend from the stabilized streambed to the top of the stream bank, where practicable, native rock shall be utilized. Bio-stabilization techniques may be considered for specific crossings. The Contractor shall remove equipment bridges as soon as possible after final clean up.

6. RESTORATION (WATERBODY)

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

For open-cut crossings, stabilize waterbody banks and install temporary sediment barriers within twenty-four (24) hours of completing in-stream construction activities.

For dry-ditch crossings, complete streambed and bank stabilization before returning flow to the waterbody channel.

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

Application of riprap for bank stabilization must comply with USACE or any other Agency permit terms and conditions.

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

Revegetate disturbed waterbody areas with conservation grasses and legumes or native plant species.

Install a permanent slope breaker across the construction right-of-way at the base of slopes greater than five percent (5%) that are less than fifty (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.

Above-mentioned restoration requirements also apply to those perennial or intermittent streams not flowing at the time of construction.

7. POST- CONSTRUCTION MAINTENANCE (WATERBODY)

Limit vegetation maintenance adjacent to waterbodies to allow a riparian strip at least twenty-five (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 ten (10) feet wide may be maintained in an herbaceous state.

In addition, trees that are located within fifteen (15) feet of the pipeline that are greater than fifteen (15) feet in height may be cut and removed from the permanent right-of-way.

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

8. WETLAND CROSSINGS

8.1. General

Where applicable, procedures for waterbody crossings should also be considered for wetland crossings. FERC Wetland & Waterbody Construction & Mitigation Procedures are located in Appendix 6.

8.1.1. Field Markings

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. Wetland boundaries marking shall be maintained as needed to ensure visibility throughout the Project.

8.1.2. Alternative Crossing Plan

Implement the measures of FERC’s Wetland and Waterbody Construction And Mitigation Procedures in the event a waterbody crossing is located within or adjacent to a wetland crossing. If all measures of FERC's Wetland and Waterbody Construction and Mitigation Procedures cannot be met, Company must file with the applicable local, state and federal agencies a site-specific crossing plan for review and written approval 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
f. size and location of all extra work areas

8.2. Installation (Wetlands)

8.2.1. Extra Work Areas and Access Roads (Wetlands)

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

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 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.

Company & Agency only approved 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.

8.2.2. General Wetland Crossing Procedures

Comply with FERC Wetland and Waterbody Construction and Mitigation Procedures (Appendix 6) as well as USACE or any other permit terms and conditions.

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

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

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

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

Wetland or 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.

Removal of vegetation within wetlands shall be limited to the approved construction right-of-way. Existing contours shall not be altered. Rutting of soils (greater than twelve [12] inches) shall be repaired immediately.

Mulching shall not occur within wetland or waterbody area. All vegetation cleared from wetland areas shall be moved to an upland area immediately following logging and clearing activities.

Storage of construction related materials, such as river weights, shall not occur within wetlands.

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

Trench operations shall be limited to periods of time when significant precipitation is not anticipated during the crossing procedures.

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.

Limit the length of time that topsoil is segregated and the trench is open to less than twenty-four (24) hours. If backfill operations cannot be completed within twenty-four (24) hours due to site conditions beyond the control of Contractor, the Environmental Inspector shall be notified in advance.

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

Limit pulling of tree stumps and grading activities to directly over the trench line. 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 beneath the working side of the construction right-of-way.

Segregate the top one (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.

Restore disturbed areas to pre-construction contours as recorded in pre-construction wetland survey.

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

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.

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

Attempt to use no more than two (2) layers of timber riprap to support equipment on the construction right-of-way.

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

Reference Figure 19-22 for wetland crossing details.

8.2.3. "Dry" Wetland Crossing Method

Topsoil shall be segregated. Pipe stringing and fabrication may occur within the wetland adjacent to the trench line or adjacent to the wetland in a designated extra workspace. The "dry" wetland crossing procedure depicted in Figure 19 shall be used where this type of wetland is identified on the Construction Drawings. The following are exceptions to "standard" wetland crossing methods:

- The width of the construction right-of-way for upland construction is maintained through the wetland.
- Sediment barriers are not required across or along the edges of the construction right-of-way.
- If the wetland is cultivated, the topsoil shall be stripped using the trench and spoil side method at the same depth as the adjacent upland areas.
- Seeding requirements for agricultural lands shall be applied to farmed wetlands.

8.2.4. "Standard" Wetland Crossing Method

Topsoil stripping is impracticable due to the saturated nature of the soil. Pipe stringing and fabrication may occur within the wetland adjacent to the trench line or adjacent to the wetland in a designated extra workspace. Based upon the length of a standard wetland crossing and presence of sufficient water to float the pipe, the Contractor may elect to install a standard wetland crossing utilizing the “push/pull” method. The standard wetland crossing procedure depicted in Figure 20 shall be used where this type of wetland is identified on the Construction Drawings.

Procedures unique to standard wetlands include:

- Limiting construction right-of-way width to a maximum of seventy-five (75) feet unless site conditions warrant a wider width or as specified in Appendix A.
- Utilizing low ground pressure construction equipment or support equipment on timber rip rap or timber mats.
- Installing sediment barriers across the entire right-of-way where the right-of-way enters and exits the wetland.

8.2.5. Flooded "Push/Pull" Wetland Crossing Method

In these wetlands, standing surface water or high groundwater levels are present. Difficult trenching conditions may exist, and trench widths of up to thirty-five (35) feet are common. Topsoil stripping is impossible due to the flooded conditions. Pipe stringing and fabrication is required adjacent to the wetland in a designated extra workspace. And the pipe pushed and/or pulled with flotation into place. The "Push/Pull" Wetland crossing procedure as depicted in Figure 21 shall be used where water is sufficient to float the pipeline in the trench and other site conditions allow. Clean metal barrels or Styrofoam floats may be used to assist in the flotation of the pipe. Metal banding shall be used to secure the barrels or floats to the pipe. All barrels, floats and banding shall be recovered and removed upon completion of lower-in. Backfill shall not be allowed before recovery of barrels, floats and banding.

8.2.6. Spoil Pile Placement and Control (Wetlands)

All spoil from wetland or minor and intermediate waterbody crossings, and upland spoil from major waterbody crossings, must be placed in the construction right-of-way at least ten (10) feet from the water's edge or in additional extra work areas as needed.

Use sediment barriers to prevent the flow of spoil or heavily silt-laden water into any wetland, waterbody or drainage feature. Should sediment migrate beyond sediment barriers steps shall be taken immediately to repair breaches in the barrier and to retrieve lost sediment. Should heavily silt-laden water seep from the barriers, immediate steps shall be taken to reduce flow and provide for adequate settling or filtration.

Reference Figures 19-22 for placement of controls.

8.2.7. Dewatering Activities (Wetlands)

Trench dewatering shall occur as needed to prevent sediment laden water from entering wetlands, waterbodies or drainage channels that are beyond the immediate construction area.

Trench water shall not be allowed to enter wetlands, waterbodies or drainage channels in such as way as to cause or contribute to scouring or sedimentation.

Dewatering structures shall be limited by the following conditions:

a. Constructed within well vegetated uplands areas where engineering and routing conditions permit.
b. Placed at the farthest location above wetlands, waterbodies or drainage channels as is practical.
c. Located above natural sediment barriers such as existing well vegetated earthen berms or above sediment barriers constructed with appropriate materials.
d. Within wetlands shall be removed immediately after use.
e. Constructed and maintained to ensure discharge water quality meets the applicable regulatory standards.

Contractor shall supply adequate pumping equipment, hoses and supplies to each dewatering location for appropriate placement and maintenance of dewatering activities. Dewatering intake hoses shall be floated near the surface of trench water to reduce uptake of concentrated sediments within the trench water. This shall increase efficiency of pumps and filtration bags and increase discharge water quality.

Discharge water clarity shall be visually monitored during dewatering activities. Should discharge water appear to be cloudier than the receiving water or the water immediately upstream of dewatering location, or fail to meet the water quality requirements for any reason such as improper materials, placement, construction or maintenance of dewatering structures, dewatering activities shall cease immediately. Structures shall be moved, repaired, or replaced as requested by the Environmental Inspector.

Reference Figures 16-18 for dewatering details.

8.2.8. Filter Bags for Dewatering (Wetlands)

Contractor shall supply and utilize filter bags, for purposes of dewatering, of the minimum specification as follows in the following table:

Parameter	Minimum Specification
Grab Elongation @ Break	100% (max)
Puncture Resistance	> 100 lbs.
Trapezoid Tear Strength	> 75 lbs.
Burst Strength	> 350 psi
Apparent Opening Size (AOS)	70 – 100
(U.S. sieve no. equivalent)	
Water Flow Rate	> 105 gpm/sq. ft.

Contractor shall have the option to procure pre-fabricated filter bags or to construct them on-site with the above specified geotextile fabric. If on-site construction is utilized, Contractor shall construct the filter bag to provide efficient sediment removal and resist seam failure.

Contractor shall monitor the condition of the filter bags throughout the dewatering activities and shall ensure appropriate pumping levels shall be used in accordance with manufacturers recommended filter bag capacity.

Contractor shall remove used filter bags from the construction right-of-way immediately following dewatering activities.

Reference Figures 16 and 18 for filter bag diagram and details.

8.2.9. Temporary Erosion and Sediment Control (Wetlands)

Install sediment barriers prior to 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. 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 drivable 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 anticipated;
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.

Install temporary erosion controls immediately before initial disturbance of the soil where practical. Where dense existing vegetation is present, install temporary erosion controls immediately following initial disturbance. Maintain sediment barriers until replaced by permanent erosion controls or restoration of adjacent upland areas are complete.

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 drivable 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 anticipated.

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.

Install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil and sediment within the wetland construction right-of-way. Remove these sediment barriers during initial right-of-way clean-up immediately following backfill operations.

Reference Figures 6 and 7 for barrier details.

8.3. Restoration (Wetlands)

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.

Contractor shall ensure the appropriate replacement of subsoil and topsoil within the trench.

Contractor shall ensure pre-construction contours are met following restoration activities. No right-of-way of the trench shall be permitted within wetlands.

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 slope greater than five percent (5%) where the base of the slope is less than fifty (50) feet from the wetland, or as needed to prevent sediment transport into the wetland. In addition, install sediment barriers as outlined. In some areas, with the approval of the Environmental Inspector, an earthen berm may be suitable as a sediment barrier adjacent to the wetland.

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

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.

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

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

Remove temporary sediment barriers located at the boundary between wetland and adjacent upland areas after upland revegetation and stabilization of adjacent upland areas are verified by the Environmental Inspector to be successful as specified.

Reference Figure 22 for backfill details.

8.4. Post-Construction Maintenance (Wetland)

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 ten (10) feet wide may be maintained in an herbaceous state. In addition, trees within fifteen (15) feet of the pipeline, which are greater than fifteen (15) feet in height, may be selectively cut and removed from the permanent right-of-way.

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

Wetland revegetation shall be considered successful if the cover of herbaceous and/or woody species is at least eighty percent (80%) of the type, density, and distribution of the vegetation in adjacent wetland areas that were not disturbed by construction.

9. HYDROSTATIC TESTING

9.1. Testing Equipment Location

The Contractor shall provide for the safety of all pipeline construction personnel and the general public during hydrostatic test operations by placing warning signs in populated areas. The Contractor shall locate hydrostatic test manifolds one hundred (100) feet outside wetlands and riparian areas to the maximum extent practicable.

9.2. Test Water Source and Discharge Locations

Company is responsible for acquiring all permits required by federal, state and local agencies for procurement of water and for the discharge of water used in the hydrostatic testing operation. Company shall provide the Contractor with a copy of the appropriate withdrawal/discharge permit for hydrostatic test water. The Contractor shall keep the water withdrawal/discharge permit on site at all times during testing operations.

Any water obtained or discharged shall be in compliance with permit notice requirements and with sufficient notice for Company's Testing Inspector to make water sample arrangements prior to obtaining or discharging water. In some instances sufficient quantities of water may not be available from the permitted water sources at the time of testing. Withdrawal rates may be limited as stated by the permit. Under no circumstances shall an alternate water source be used without prior authorization from Company. The Contractor shall be responsible for obtaining any required water analyses from each source to be used in sufficient time to have a lab analysis performed prior to any filling operations. The sample bottle shall be sterilized prior to filling with the water sample. The analysis shall determine as specified in Appendix A. Each bottle shall be marked with:

- Source of water with pipeline station number
- Date taken
- Laboratory order number
- Name of person taking sample

Staging/work areas for filling the pipeline with water shall be located a minimum of fifty (50) feet from the waterbody or a wetland boundary if topographic conditions permit. The Contractor shall install temporary sediment filter devices adjacent to all streams that runoff may enter. The Contractor shall screen the intake hose to prevent the entrainment of fish or debris. The hose shall be kept off the bottom of the waterbody. Refueling of construction equipment shall be conducted a minimum distance of one hundred (100) feet from the stream or a wetland. Pumps used for hydrostatic testing within one hundred (100) feet of any waterbody or wetland shall be operated and refueled in accordance with Section 3. The Contractor shall maintain adequate flow rates in the waterbody to protect aquatic life, provide for all waterbody uses, and provide for downstream withdrawals of water by existing users. The Contractor shall not use chemicals in the test water. The Contractor shall not discharge any water containing oil or other substances that are in sufficient amounts as to create a visible color film or sheen on the surface of the receiving water. Selected road, railroad, and river crossing pipe sections may be specified to be pre-tested for a minimum of four (4) hours. The water for pre-testing of any road and railroad crossings shall be hauled by a tanker truck from an approved water source. Water for pre-testing of a river crossing may be hauled or taken from the respective river if it is an approved water source. Since the volume of water utilized in these pretests shall be relatively small, the water shall be discharged overland along the construction right-of-way and allowed to soak into the ground utilizing erosion and sediment control mitigative measures. Selection of final test water sources will be determined based on site conditions at the time of construction and applicable permits.

9.3. Dewatering the Pipeline

The Contractor shall comply with state-issued NPDES permits for discharging test water. The Contractor shall not discharge any water containing oil or other substances that are in sufficient amounts as to create a visible color film on the surface of the receiving water. The Contractor shall 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.

The Contractor shall calculate, record and provide to Company the day, date, time, location, total volume, maximum rate and methods of all water discharged to the ground or to surface water in association with hydrostatic testing. The Contractor shall regulate the pig velocity discharge rate, use an energy dissipation device(s), and install sediment barriers, as necessary, to prevent erosion, streambed scour, suspension of sediments, or excessive stream flow. Water must be disposed of using good engineering judgment so that all federal, state, and local environmental standards are met. Dewatering lines shall be sufficient strength and be securely supported and tied down at the discharge end to prevent whipping during this operation.

To reduce the velocity of the discharge, The Contractor shall utilize an energy dissipating device described as follows:

9.3.1. Splash Pup

A splash pup consists of a piece of large diameter pipe (usually over twenty inches (20") O.D.) of variable length with both ends partially blocked that is welded perpendicularly to the discharge pipe. As the discharge hits against the inside wall of the pup, the velocity is rapidly reduced and the water is allowed to flow out either end. A variation of the splash pup concept, commonly called a diffuser, incorporates the same design, but with capped ends and numerous holes punched in the pup to diffuse the energy.

9.3.2. Splash Plate

The splash plate is a quarter section of thirty-six (36) inch pipe welded to a flat plate and attached to the end of a six (6) inch discharge pipe. The velocity is reduced by directing the discharge stream into the air as it exits the pipe. This device is also effective for most overland type discharge.

9.3.3. Plastic Liner

In areas where highly erodible soils exist or in any low flow drainage channel, it is a common practice to use layers of visqueen (or any of the new construction fabrics currently available) to line the receiving channel for a short distance. One anchoring method may consist of a small load of rocks to keep the fabric in place during the discharge.

9.3.4. Straw Bale Dewatering Structure

Straw bale dewatering structures are designed to dissipate and remove sediment from the water being discharged. Straw bale structures are used for on-land discharge of wash water and hydrostatic test water and in combination with other energy dissipating devices for high volume discharges. A straw bale dewatering structure is shown In Figure 23.

10. OFF-ROAD VEHICLE CONTROL

Company shall offer to each owner or manager of forested lands to install and maintain measures to control unauthorized vehicle access to the right-of-way. These measures may include:

- signs
- fences with locking gates
- slash and timber barriers, pipe barriers, or a line of boulders across the right-of-way
- conifers or other appropriate trees or shrubs across the right-of-way

11. SPILL PREVENTION AND CONTAINMENT

Spill prevention and containment applies to the use and management of hazardous materials on the construction right-of-way and all ancillary areas during construction. This includes the refueling or servicing of all equipment with diesel fuel, gasoline, lubricating oils, grease, hydraulic and other fluids during normal upland applications and special applications within one hundred (100) feet of perennial streams or wetlands. **All Vehicles and Equipment Must have a Spill Kit On Board**.

11.1. Spill Prevention

11.1.1. Staging Areas

Staging areas (including Contractor yards and pipe stockpile sites) shall be set up for each construction spread. Hazardous materials at staging areas shall be stored in compliance with federal and state laws. The following spill prevention measures shall be implemented by the Contractor:

- Contractor fuel trucks shall be loaded at existing bulk fuel dealerships or from bulk tanks set up for that purpose at the staging area. In the former case, the bulk dealer is responsible for preventing and controlling spills;
- Fuels and lubricants shall be stored only at designated staging areas. Storage of fuel and lubricants in the staging area shall be at least one hundred (100) feet away from the water's edge.
- Refueling and lubrication of equipment shall be restricted to upland areas at least one hundred (100) feet away from stream channels and wetlands;
- Contractors shall be required to perform all routine equipment maintenance at the staging area and recover and dispose of wastes in an appropriate manner;
- Temporary liners and berms and/or dikes (secondary containment) shall be constructed around the above-ground bulk tanks, so that potential spill materials shall be contained

and collected in specified areas isolated from any waterbodies. Tanks shall not be placed in areas subject to periodic flooding or washout;

- Drivers of tank trucks are responsible for safety and spill prevention during tank truck unloading. Procedures for loading and unloading tank trucks shall meet the minimum requirements established by the Department of Transportation;
- Warning signs requiring drivers to set brakes and chock wheels shall be displayed at all tanks. Proper grounding of equipment shall be undertaken during fuel transfer operations. Drivers shall observe and control the fueling operations at all times to prevent over-filling the temporary tank;
- Prior to departure of any tank truck, all vehicle outlets shall be closely examined by the driver for leakage and tightened, adjusted or replaced to prevent liquid leakage while in transit;
- A supply of sorbent and barrier materials sufficient to allow the rapid containment and recovery of any spill shall be maintained at the construction staging areas. Sorbent and barrier materials shall also be utilized to contain runoff from contaminated areas;
- Shovels and drums shall be kept at each of the individual staging areas. In the event that small quantities of soil become contaminated, shovels shall be utilized to collect the soil and the material shall be stored in fifty-five (55) gallon drums. Large quantities of contaminated soil may be bio-remediated on-site, subject to government approval, or collected utilizing heavy equipment, and stored in drums or other suitable containers prior to disposal. Should contamination occur adjacent to staging areas as a result of runoff, shovels and/or heavy equipment shall be utilized to collect the contaminated material. Contaminated soil shall be disposed of in accordance with state and federal regulations;
- Temporary above-ground tanks shall be subject to visual inspection on a monthly basis and when the tank is refilled. Inspection records shall be maintained. Operators shall routinely keep tanks under close surveillance and potential leaks or spills shall be quickly detected;
- Visible fuel leaks shall be reported to the Contractors' designated representative and corrected as soon as conditions warrant. Company's designated representative shall also be informed;
- Drain valves on temporary tanks shall be locked to prevent accidental or unauthorized discharges from the tank. Company may allow modification of the above specifications as necessary to accommodate specific situations or procedures. Any modifications must comply with all applicable regulations and permits.

11.1.2. Construction Right-of-way

Rubber-tired vehicles (pick-up trucks, buses) shall normally refuel at the construction staging areas or commercial gas stations. Tracked machinery (backhoes, bulldozers) shall be refueled and lubricated on the construction right-of-way. Equipment maintenance shall be conducted in staging areas when practical. When impractical, repairs to equipment can be made on the construction right-of-way when approved by Company’s representative. The following preventive measures apply to refueling and lubricating activities on the construction right-of-way:

- Construction activities shall be conducted to allow for prompt and effective clean up of spills of fuel and other hazardous materials. Each construction crew, including clean-up crews shall have on hand sufficient tools and material to stop leaks and supplies of absorbent and barrier materials to allow rapid containment and recovery of spilled materials and must know and follow the procedure for reporting spills;
- Refueling and lubrication of construction equipment shall be restricted to upland areas at least one hundred (100) feet away from stream channels and wetlands. Where this is not

possible (e.g., trench dewatering pumps), the equipment shall be fueled by designated personnel with special training in refueling and spill containment and clean up. The Environmental Inspector shall ensure that signs are installed identifying restricted areas;
- Spent oils, lubricants, filters, etc. shall be collected and disposed of at an approved location in accordance with state and federal regulations;
- Equipment shall not be washed in streams. Company may allow modification of the above specifications as necessary to accommodate specific situations or procedures. Any modifications must still comply with all applicable regulations and permits.

11.2. Contingency Plans

The Contractor shall develop emergency response procedures for all incidents (e.g., spills, leaks, fires) involving hazardous materials which could pose a threat to human health and/or the environment. The procedures shall address activities in all work areas, as well as during transport to and from the construction right-of-way and to any disposal or recycling facility.

11.3. Equipment

The Contractor shall retain emergency response equipment that shall be available at all areas where hazardous materials are handled or stored. This equipment shall be readily available to respond to a hazardous material emergency. Such equipment shall include, but not be limited to, the following:

- first aid kit/supplies
- phone or communications radio
- protective clothing (Tyvek suit, gloves, goggles, boots)
- hand held fire equipment
- absorbent material and storage containers
- non-sparking bung wrench and shovel
- brooms and dust pan

Hazardous material emergency equipment shall be carried in all mechanic and supervisor vehicles. This equipment shall include, at a minimum:

- first aid kit/supplies
- phone or communications radio
- two (2) sets of protective clothing (tyvek suit, gloves, goggles, boots)
- one (1) non-sparking shovel
- six (6) plastic garbage bags (twenty [20] gallon)
- ten (10) absorbent socks and spill pads
- hand held fire extinguisher
- barrier tape
- two (2) orange reflector cones

Fuel and service trucks shall carry a minimum of twenty (20) pounds of suitable commercial sorbent material. The Contractor shall inspect emergency equipment weekly, and service and maintain equipment regularly. Records shall be kept of all inspections and services.

11.4. Emergency Notification

Emergency notification procedures between the Contractor and Company shall be established in the preplanning stages of construction, and the Company representative shall be identified to serve as contact in the event of a spill during construction activities. In the event of a spill which meets government reporting criteria, the Contractor shall notify the Company representative immediately who, in turn, shall notify the appropriate regulatory agencies as documented in Appendix 1.

11.5. Spill Containment and Countermeasures

In the event of a spill of hazardous material, Contractor personnel shall:

- notify the appointed Company representative;
- identify the product hazards related to the spilled material and implement appropriate safety procedures, based on the nature of the hazard;
- control danger to the public and personnel at the site;
- implement spill contingency plans and mobilize appropriate resources and manpower;
- isolate or shutdown the source of the spill;
- block manholes or culverts to limit spill travel;
- initiate containment procedures to limit the spill to as small an area as possible, to prevent damage to property or areas of environment concern (e.g., watercourses); and
- Commence recovery of the spill and clean-up operations.

When notified of a spill, the Company representative shall immediately ensure that:

- action is taken to control danger to the public and personnel at the site;
- spill contingency plans are implemented and that necessary equipment and manpower are mobilized;
- measures are taken to isolate or shutdown the source of the spill;
- all resources necessary to contain, recover and clean up the spill are available;
- any resources requested by the Contractor from Company are provided; and
- The appropriate agencies are notified. For spills which occur on public lands, into surface waters or into sensitive areas the appropriate federal or state managing office shall also be notified and involved in the incident. On a land spill, berms shall be constructed with available equipment to physically contain the spill. Personnel entry and travel on contaminated soils shall be minimized. Sorbent materials shall be applied or, if necessary, heavily contaminated soils shall be removed to an approved facility. Contaminated sorbent materials and vegetation shall also be disposed of at an approved facility. On a spill threatening a water body, berms and/or trenches shall be constructed to contain the spill prior to entry into a water body. Deployment of booms, skimmers and sorbent materials shall be necessary if the spill reaches the water. The spilled product shall be recovered and the contaminated area shall be cleaned up with in consultation with spill response specialists and appropriate government agencies.

FIGURES

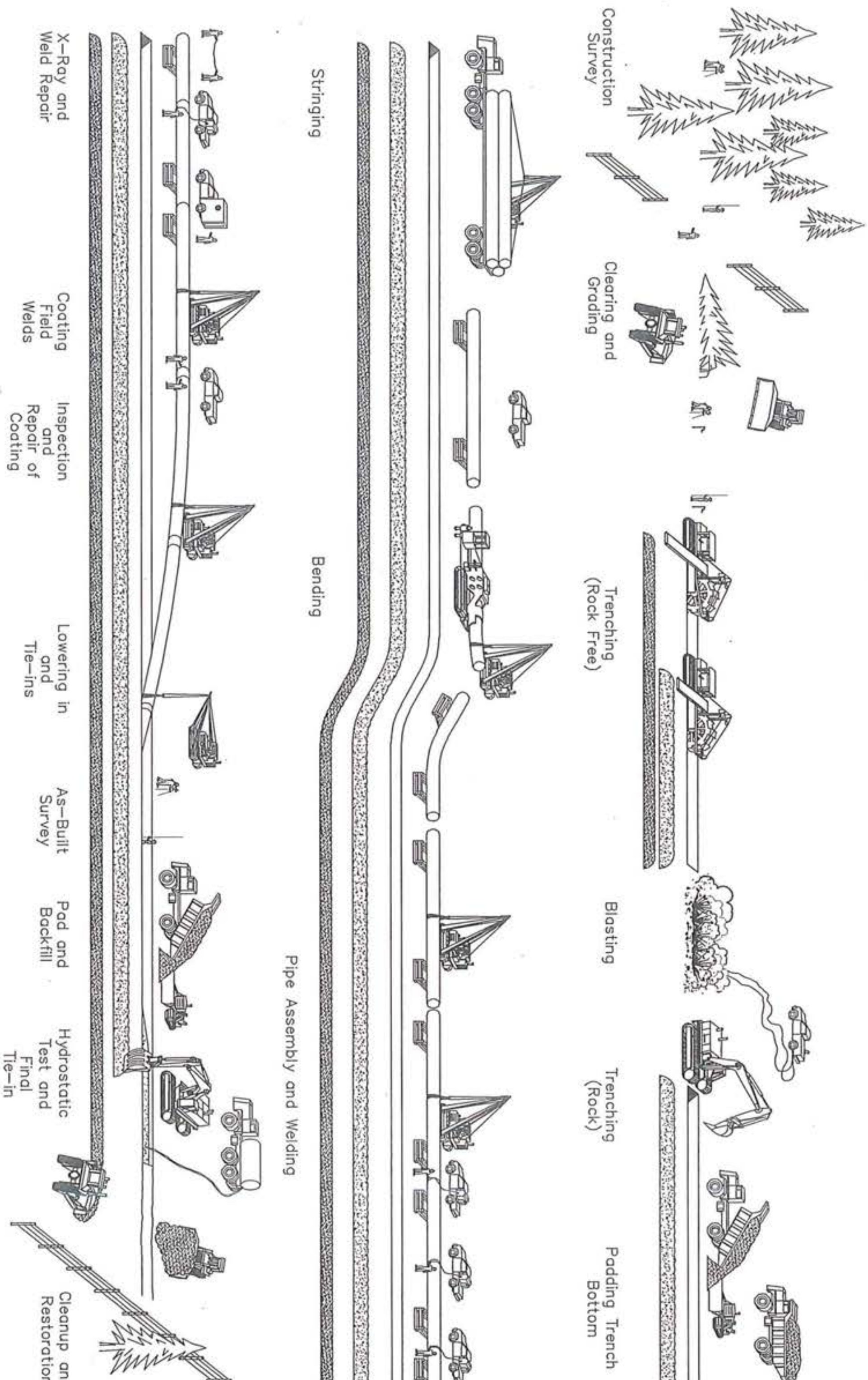

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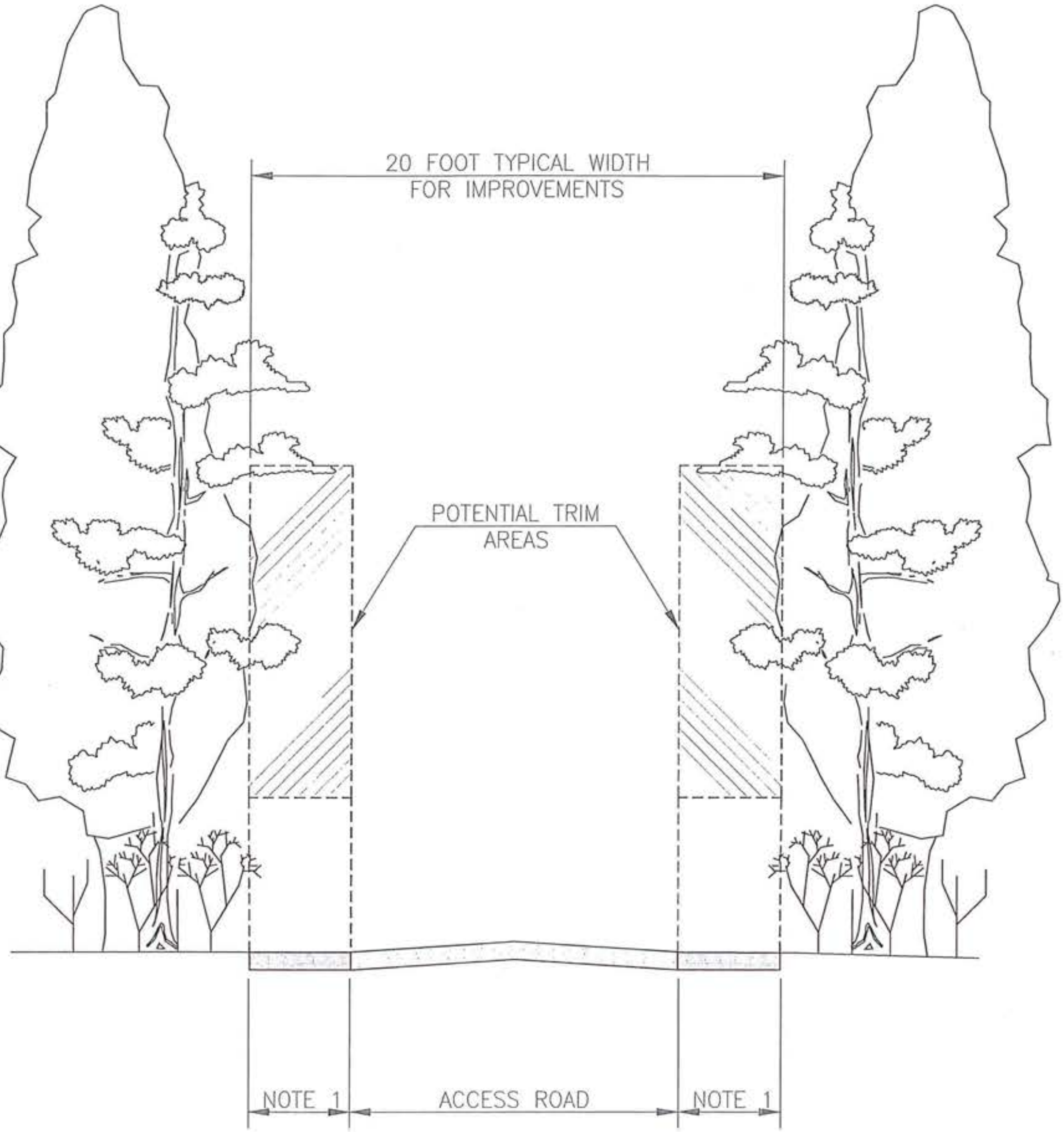
FIGURE: 1

Typical Pipeline Construction Sequence

Cameron LNG, LLC



NOTES:

- Access roads will be maintained in passable condition for the duration of the project.
- Diversion berms within roadways will direct flow into well vegetated upland location.

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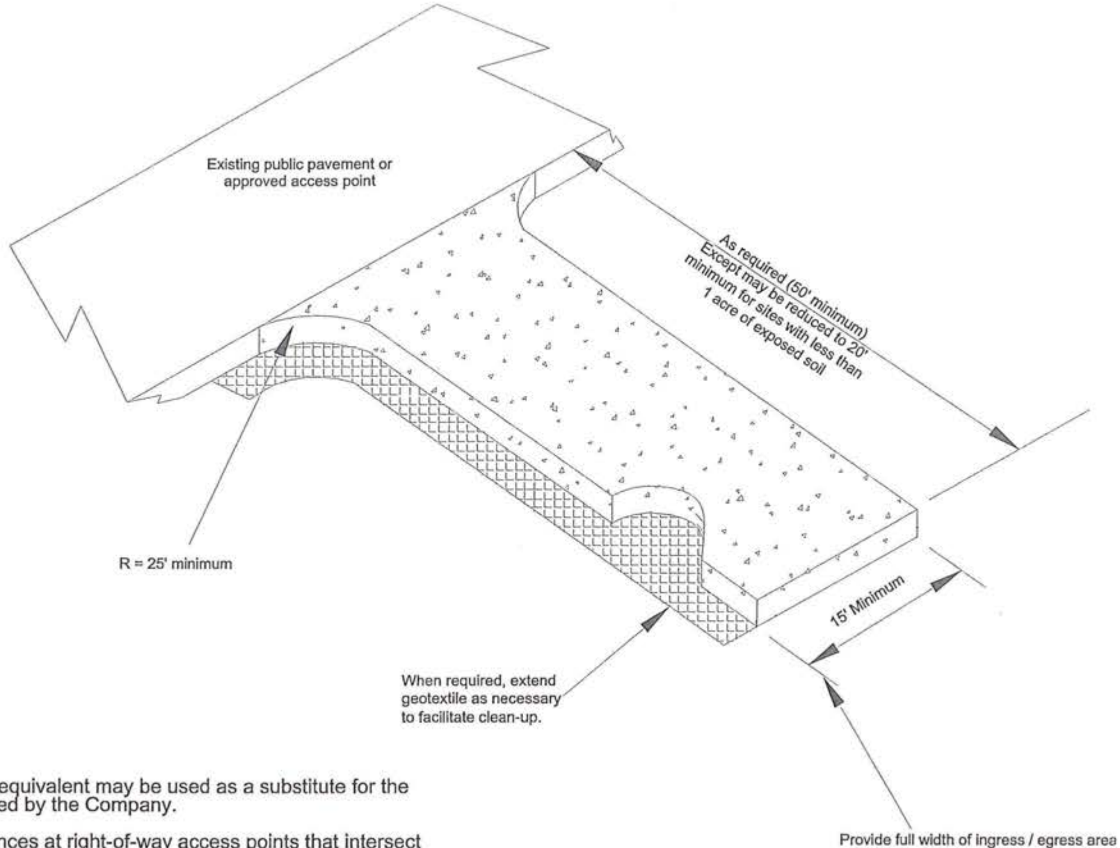
FIGURE: 2

Access Roadways

Cameron LNG, LLC



Notes:

Equipment mats or their equivalent may be used as a substitute for the graveled apron if approved by the Company.

Install construction entrances at right-of-way access points that intersect paved roads to reduce sediment transport onto roadway.

Install culverts in road ditches as necessary.

Crushed stone access pads shall be placed on synthetic fabric in residential or active agricultural areas to facilitate stone removal. Use Synthetic Industries style 22TEX, Light Stabilization Fabric, or equivalent (3 oz/yd woven geotextile).

INSTALLATION: The area of the entrance should be cleared of all vegetation, roots and other objectionable material. The gravel shall be placed to the specified dimensions. Any drainage facilities required because of washing should be constructed according to specifications in the plan. If wash racks are used, they should be installed accoriding to manufacturer's specifications.

AGGREGATE: 2" to 6" crushed Ballast Rock.

ENTRANCE DIMENSIONS: The aggregate layer must be at least 6 inches thick. It must extend the full width of the vehicular ingress and egress area. The length of the entrance must be at least 50 feet.

MAINTENANCE: The entrance shall be maintained in a condition which will prevent tracking or flow of mud onto public rights-of-way. This may require periodic top dressing with 2-inch stone, as conditions demand, and repair and/or clean out any structures used to trap sediment. All materials spilled, dropped, washed or tracked from vehicles onto roadway or into storm drains must be removed immediately.

RESTORATION: Access pads will be removed as soon as possible following construction activities and the area restored to pre-construction conditions.

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FIGURE: 3

Typical Construction Entrance Pad

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ROAD CROSSING – SPOIL AREAS

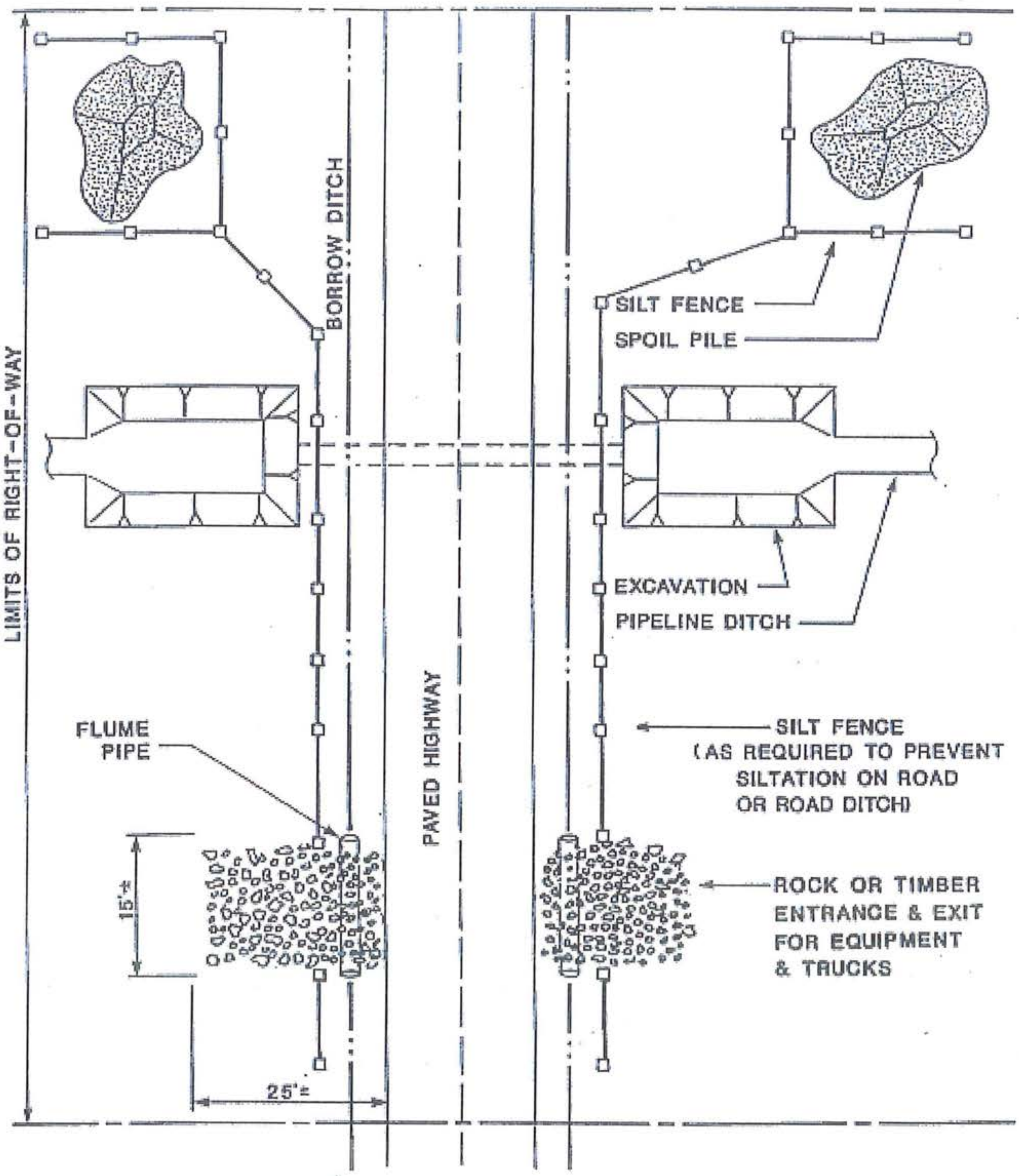

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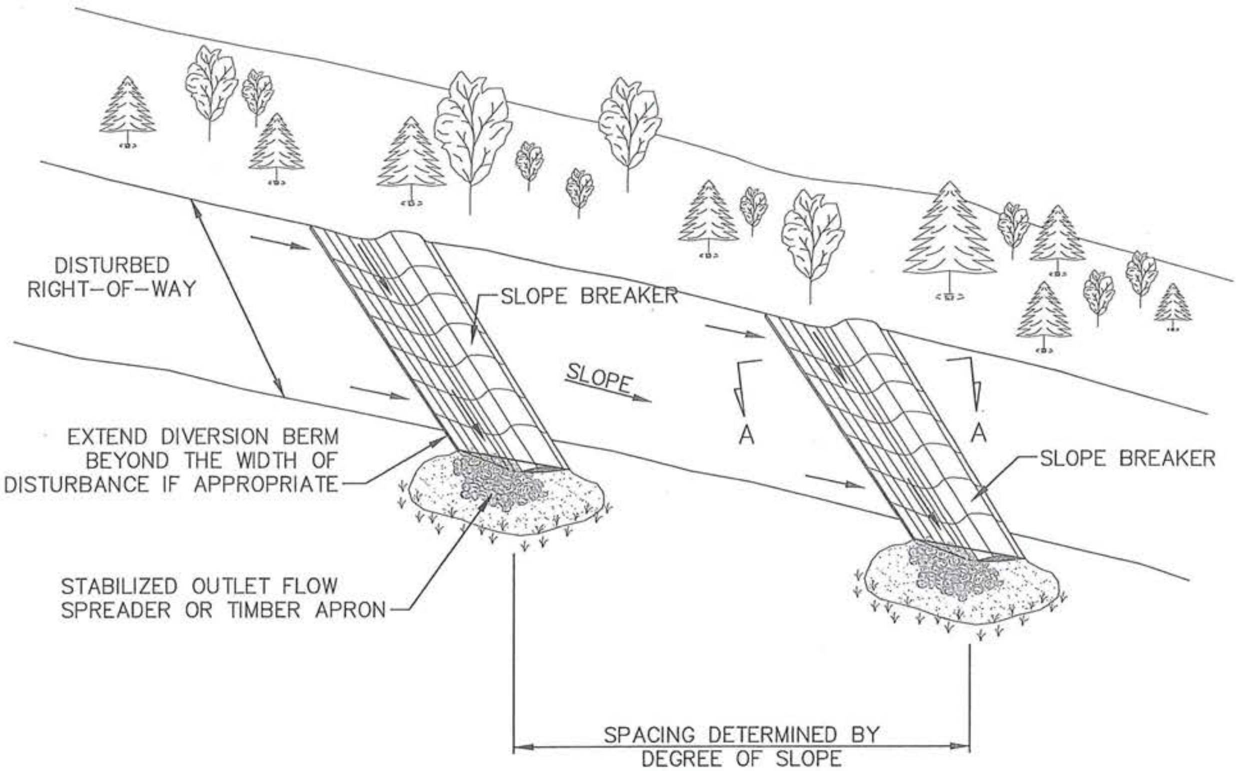
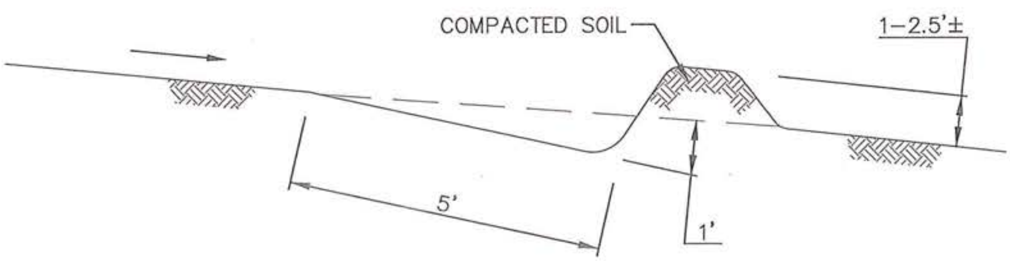
FIGURE: 4
Road Crossing – Spoil Areas
Cameron LNG, LLC



PLAN



NOTES:

1. PERMANENT SLOPE BREAKERS TO PROVIDE POSITIVE DRAINAGE TO A STABILIZED OUTLET.
2. INSTALLATION SPECIFICATIONS TO BE MODIFIED BY THE PROJECT AS NECESSARY TO SUIT ACTUAL SITE CONDITIONS.
3. THE CONTRACTOR SHALL INSTALL TEMPORARY AND PERMANENT SLOPE BREAKERS ON SLOPES GREATER THAN APPROXIMATELY 5% ON ALL DISTURVED LANDS AT THE FOLLOWING RECOMMENDED SPACING:

SLOPE (%)	SPACING (FEET)
5–15	300
>15–30	200
>30	100

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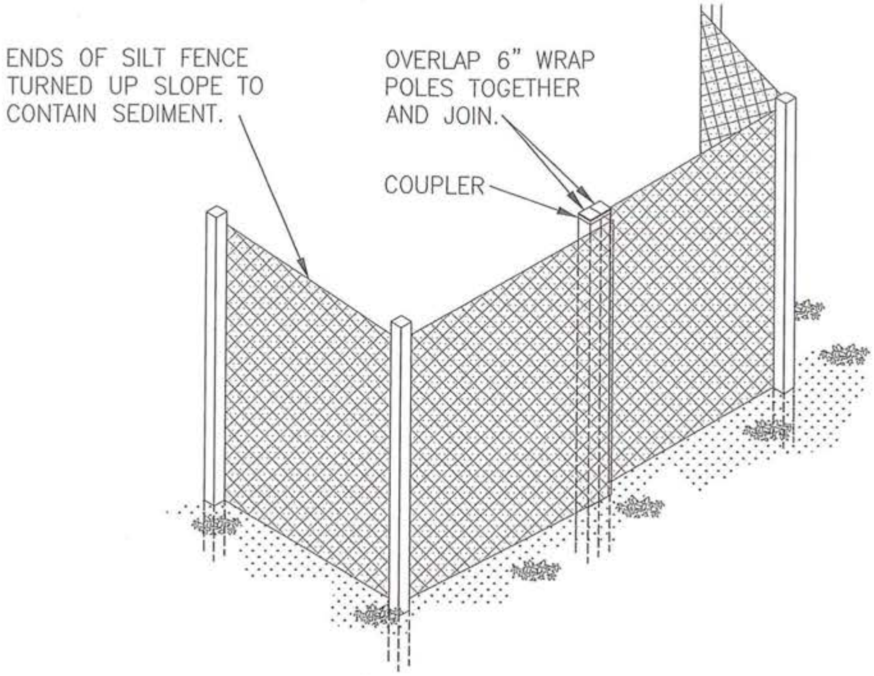
FIGURE: 5

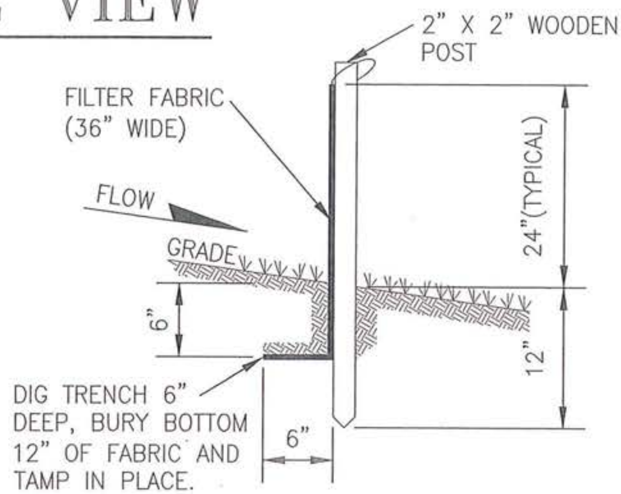
Temporary/Permanent Slope Breaker Detail

Cameron LNG, LLC



PERSPECTIVE VIEW

NOT TO SCALE



INSTALLATION:

Placement:

- Place along base of disturbed slopes or spoil piles where adjacent to environmental resource areas, wetlands, waterbodies or road crossings.
- Allow 6 feet spacing from toe of slope to for sediment collection.
- DO NOT INSTALL WITHIN AREAS OF HIGHLY CONCENTRATED FLOW.

Anchoring:

- Trench wherever possible.
- Use sandbag or backfill with compacted soils where trenching is not possible due to large roots or rocky soils.

MAINTENANCE:

Inspection:

- Daily in areas of active construction.
- Weekly in areas with no construction.
- Within 24 hours following rainfall event of greater than 0.75 inches.

Repair or replace fence as needed to ensure sediment is not bypassing or undercutting fence.

Remove accumulated sediment, to an upland area, when it reaches greater than ½ the height of the fence.

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FIGURE: 6

Silt Fence Detail

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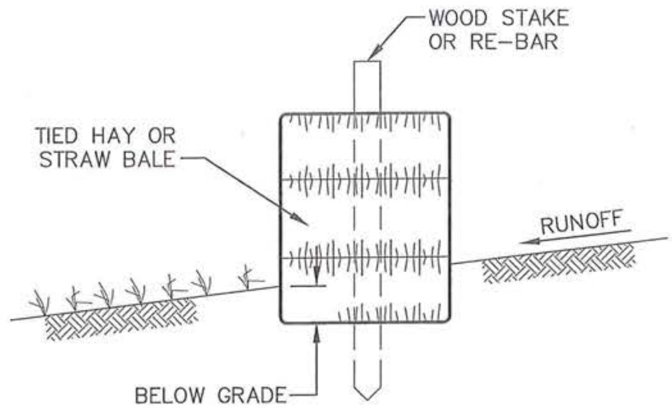
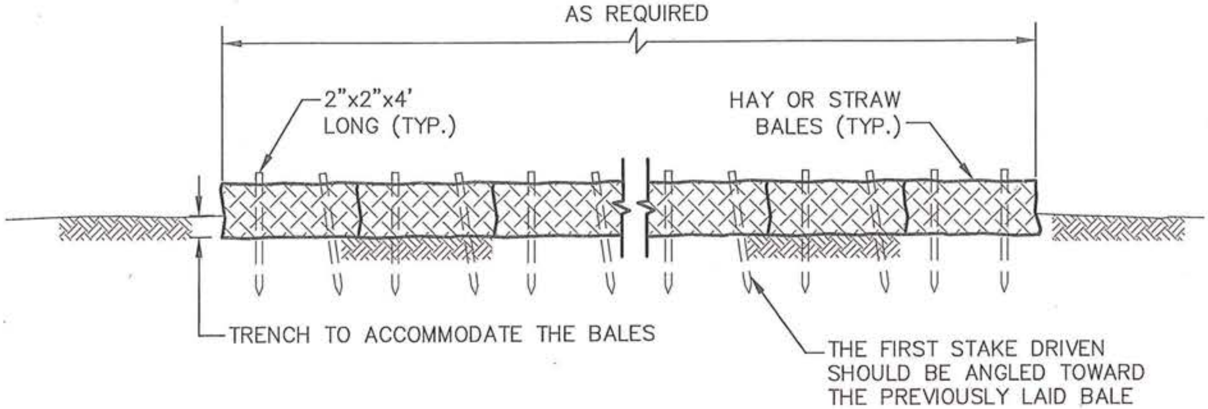


SECTION



INSTALLATION:

Placement:

- Bales should be embedded in the soil 4 to 6 inches and ends should be tightly abutted
- Place along base of disturbed slopes or spoil piles where adjacent to environmental resource areas, wetlands, waterbodies or road crossings.
- Allow 6 feet spacing from toe of slope to for sediment collection.
- DO NOT INSTALL WITHIN AREAS OF HIGHLY CONCENTRATED FLOW.

Anchoring:

- Use native soils as backfill on up-slope side of bales to key in the bottom of bales.
- Use two stakes per bale to anchor into ground
- When used with silt fence, bales should be placed upslope of fence and do not need to be embedded.

MAINTENANCE:

Inspection:

- Daily in areas of active construction.
- Weekly in areas with no construction.
- Within 24 hours following rainfall event of greater than 0.75 inches.

Replace bales as needed to ensure sediment is not bypassing or undercutting fence.

Remove accumulated sediment, to an upland area, when it reaches greater than ½ the height of the bales.

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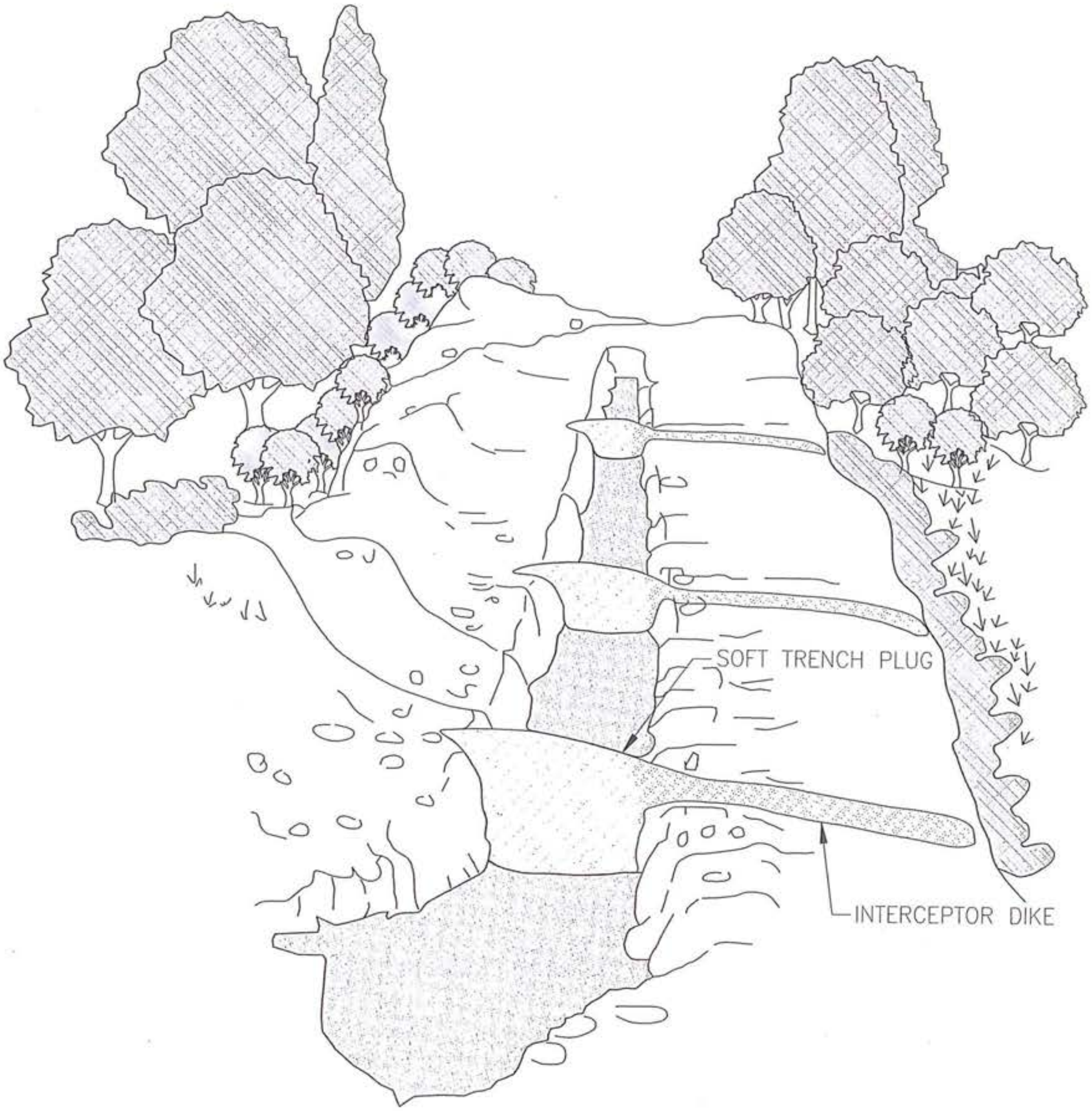
FIGURE: 7

Hay Bale Detail

Cameron LNG, LLC



NOTES:

- Temporary trench plugs may be used in conjunction with diversion dikes to prevent water from overflowing into sensitive areas.
- Divert trench overflow to a well vegetated location off the right-of-way or install appropriate energy dissipating device.

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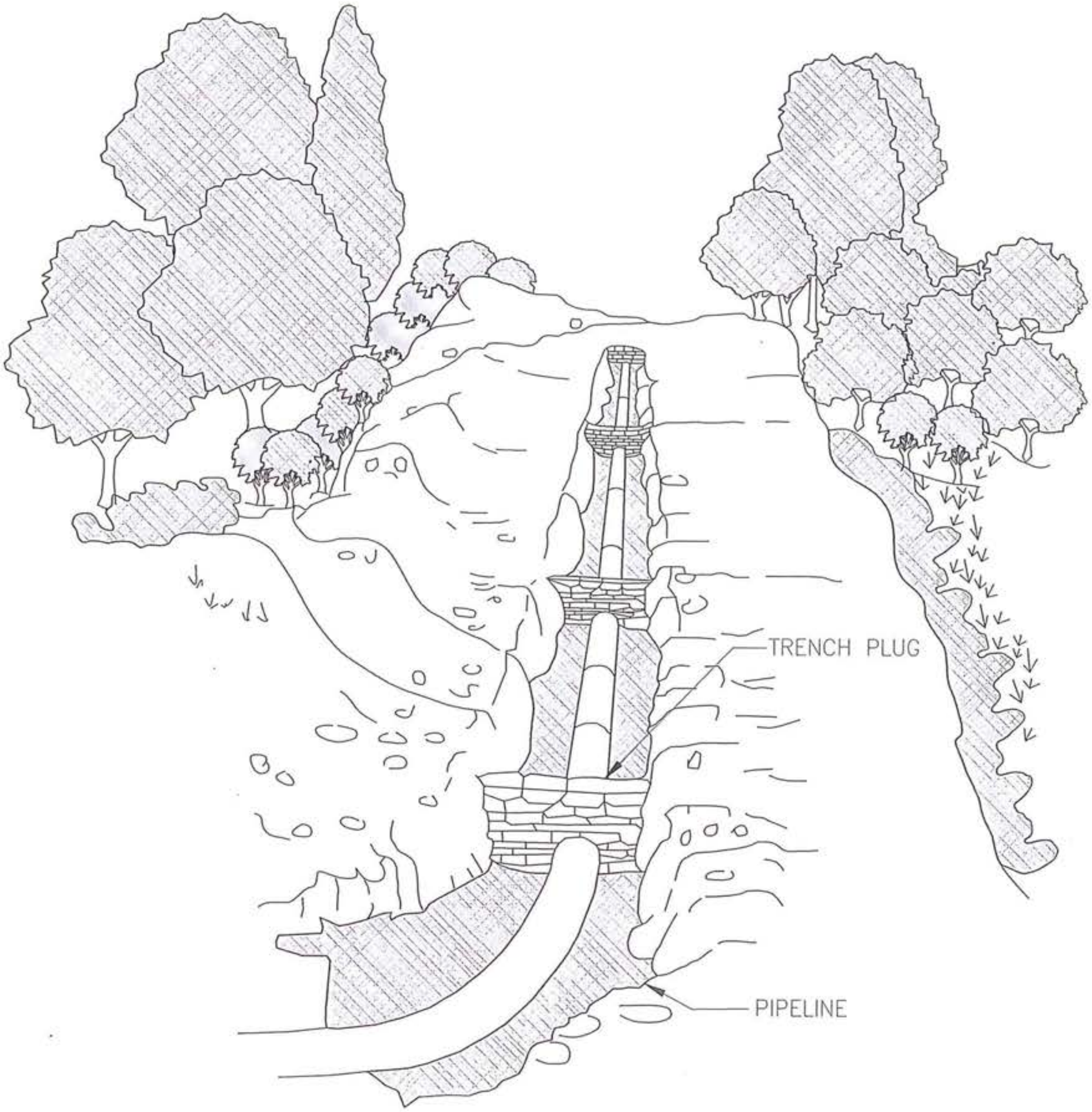
FIGURE: 8

Temporary Trench Breaker

Cameron LNG, LLC



NOTES:

SLOPE (%)	SPACING (FT)
5–15	300
>15–30	200
>30	100

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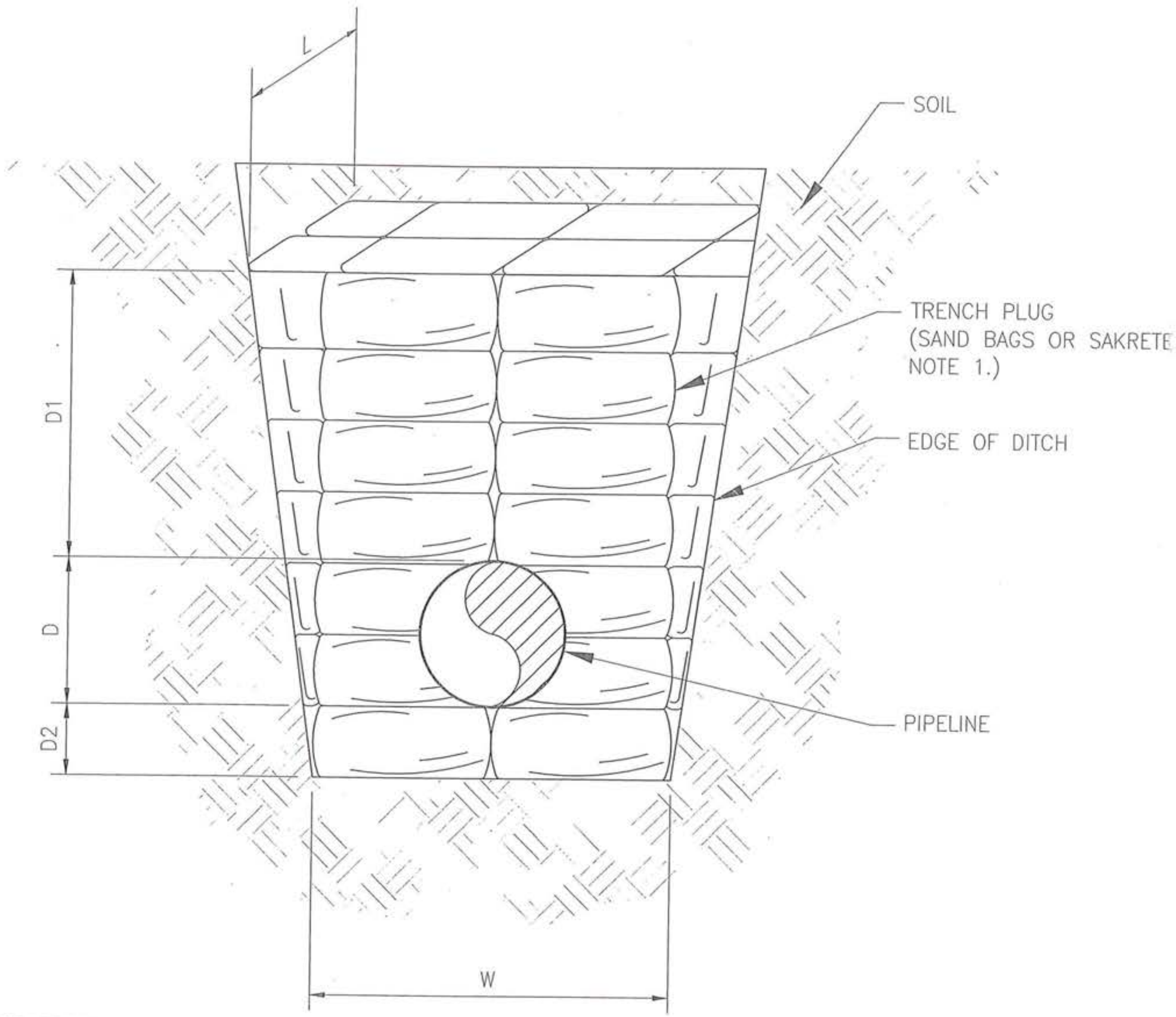
FIGURE: 9

Permanent Trench Breaker

Cameron LNG, LLC



LEGEND:

D	=	PIPE DIAMETER
D1	=	APPROXIMATELY 24"
D2	=	APPROXIMATELY 6" (8" MIN. IN ROCK)
D3	=	APPROXIMATELY 12"
W	=	D + 2 TO 4 FEET
L	=	APPROXIMATELY 18" – 24"
D1+D3	=	36" MINIMUM

NOTES:

1. USE OF SAKRETE SHALL REQUIRE PRIOR COMPANY APPROVAL.

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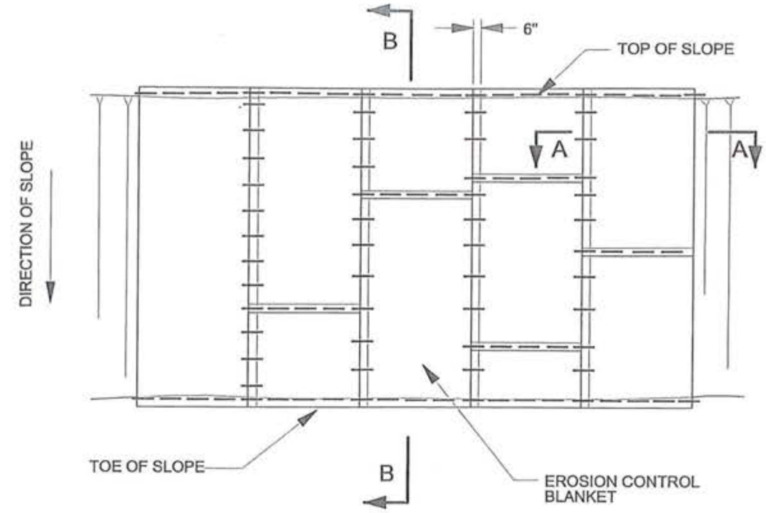
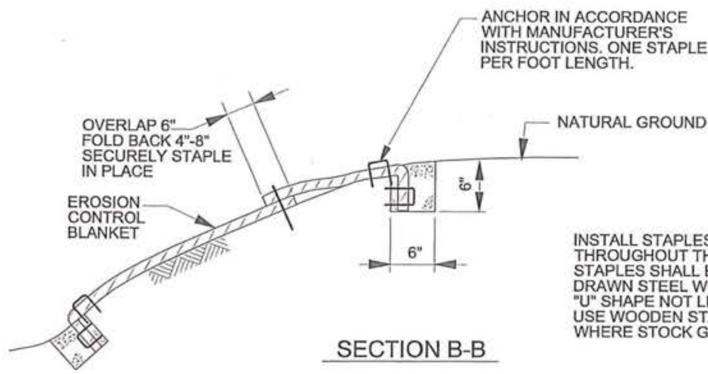
FIGURE: 10
Trench Plug Detail
Cameron LNG, LLC

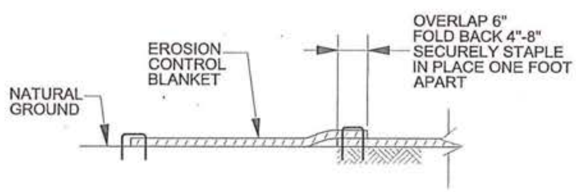


PLAN



SECTION B-B

INSTALL STAPLES 18" TO 24" APART THROUGHOUT THE BLANKET/MAT. STAPLES SHALL BE 14-GAUGE COLD DRAWN STEEL WIRE FORMED IN A "U" SHAPE NOT LESS THAN 12" LENGTH. USE WOODEN STAKES AS AN ALTERNATIVE WHERE STOCK GRAZING IS ANTICIPATED.



SECTION A-A

EMBANKMENT INSTALLATION

EROSION CONTROL MATTING

PERMANENT EROSION CONTROL MEASURE

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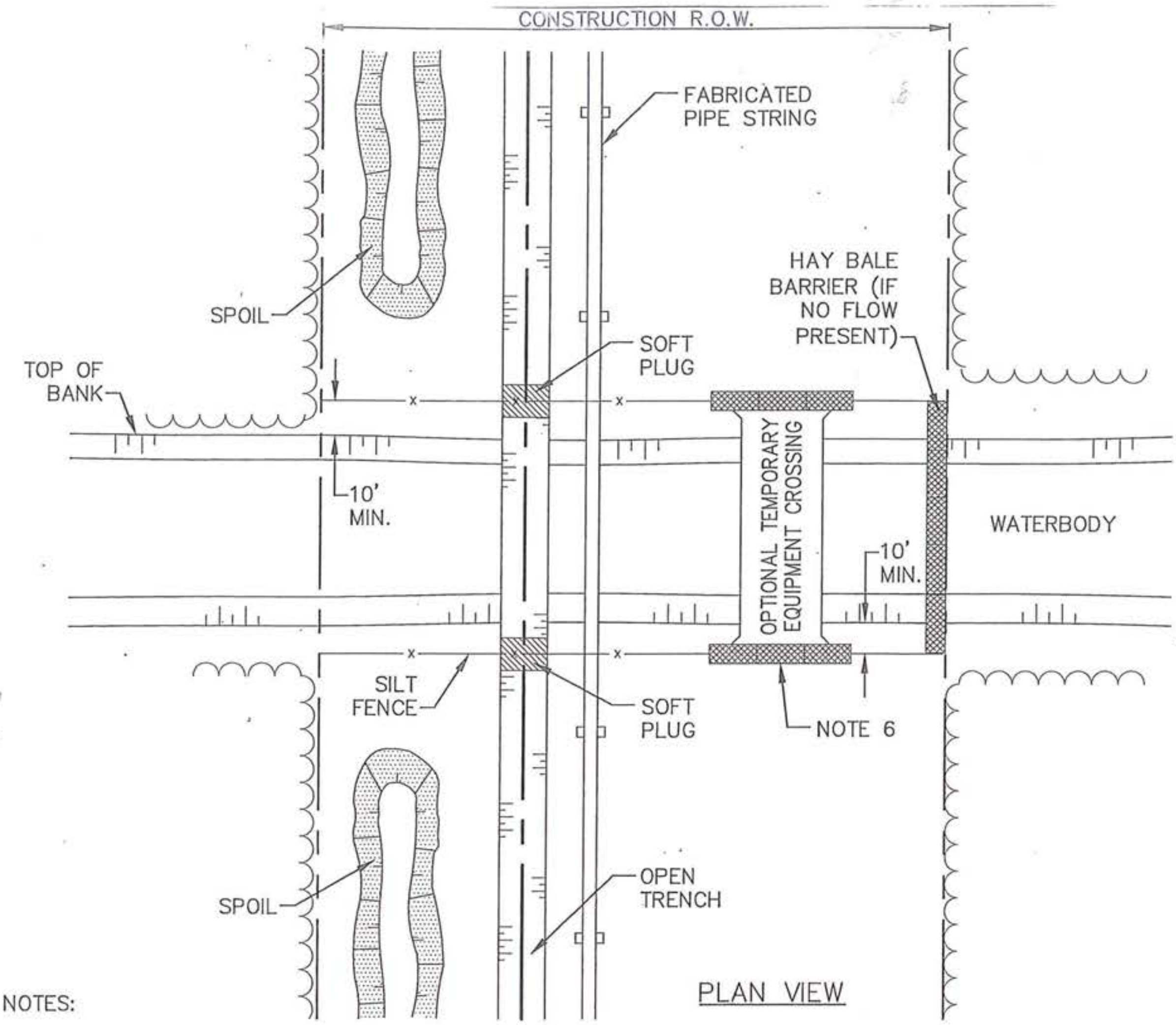
FIGURE: 11
Erosion Control Fabric
Cameron LNG, LLC



NOTES:

1. Method applies to crossing where no flowing water is present at the time of crossing or as otherwise shown on the construction drawings.
2. Contractor may "Mainline Through" the crossing or up to both sides of the crossing; string, weld, coat and weight (if necessary), using the mainline crew with the pipe skidded over the crossing.
3. No refueling of mobile equipment within approximately 100 feet of dry channel. Refuel stationary equipment per the spill prevention procedures outlined in section 11.
4. Installation of temporary equipment crossing is optional at the discretion of the Company.
5. In agricultural land, strip topsoil from soil storage area. Stockpile topsoil and spoil separately. Topsoil and spoil will not be stockpiled in the crossing channel and will be placed a minimum of 10 feet from crossing banks within the construction ROW.
6. Construct sediment barriers across the entire construction ROW following clearing and grading and maintain until construction of the crossing. Erosion control measures shall be reinstalled immediately following backfilling of trench and stabilization of banks. Barriers may be temporarily removed to allow construction activities but must be replaced by the end of each work day.
7. In-stream spoil to be stored out of the stream channel a minimum of 10 feet from high bank and within the construction ROW.
8. Backfill with native material
9. Restore crossing channel to approximate pre-construction profile and substrate.
10. Restore crossing banks to approximate original condition and stabilize with erosion control.

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FIGURE: 12

Typical Open Cut Wet Crossing Method
Non-Flowing Waterbody
Cameron LNG, LLC

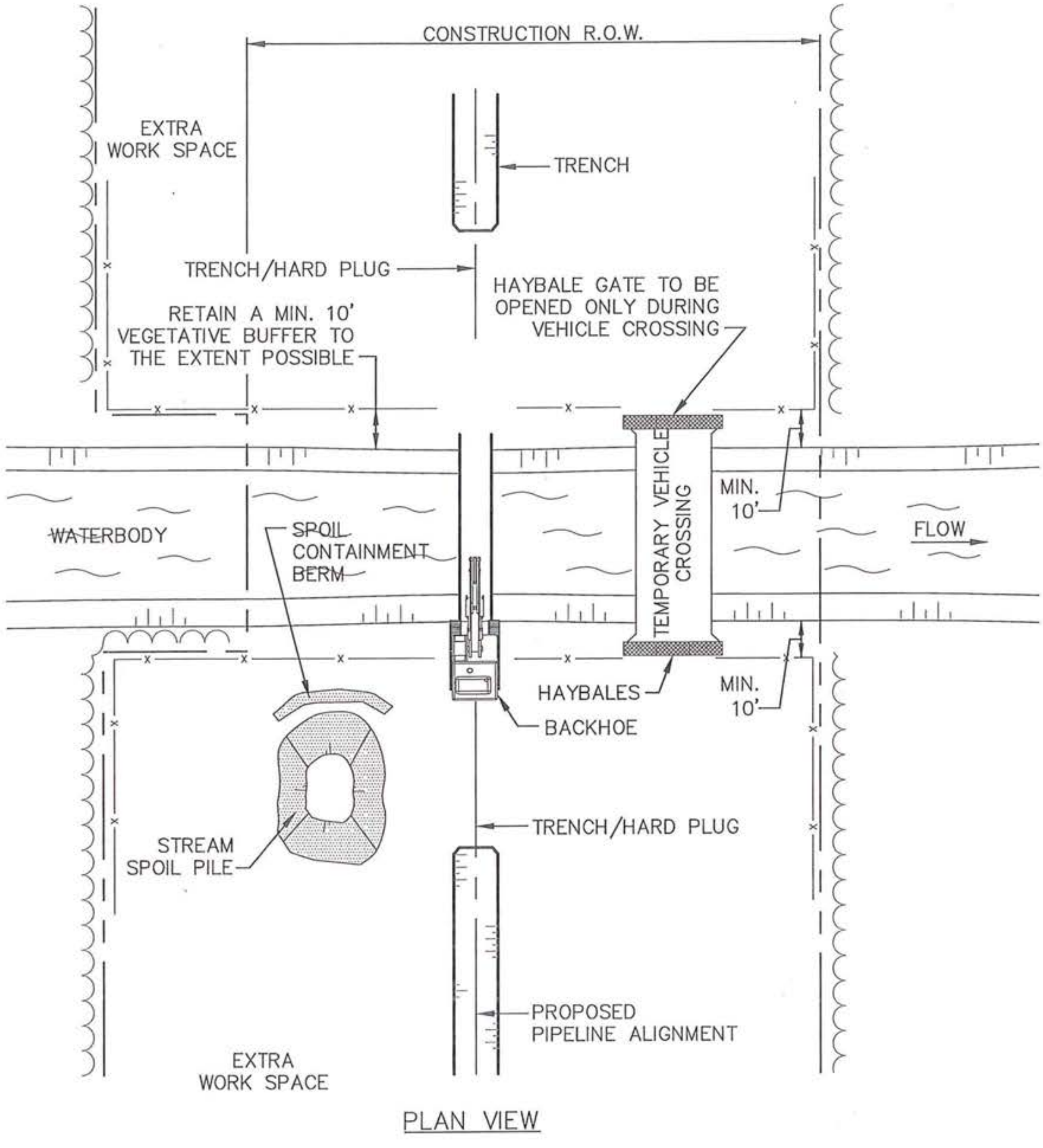

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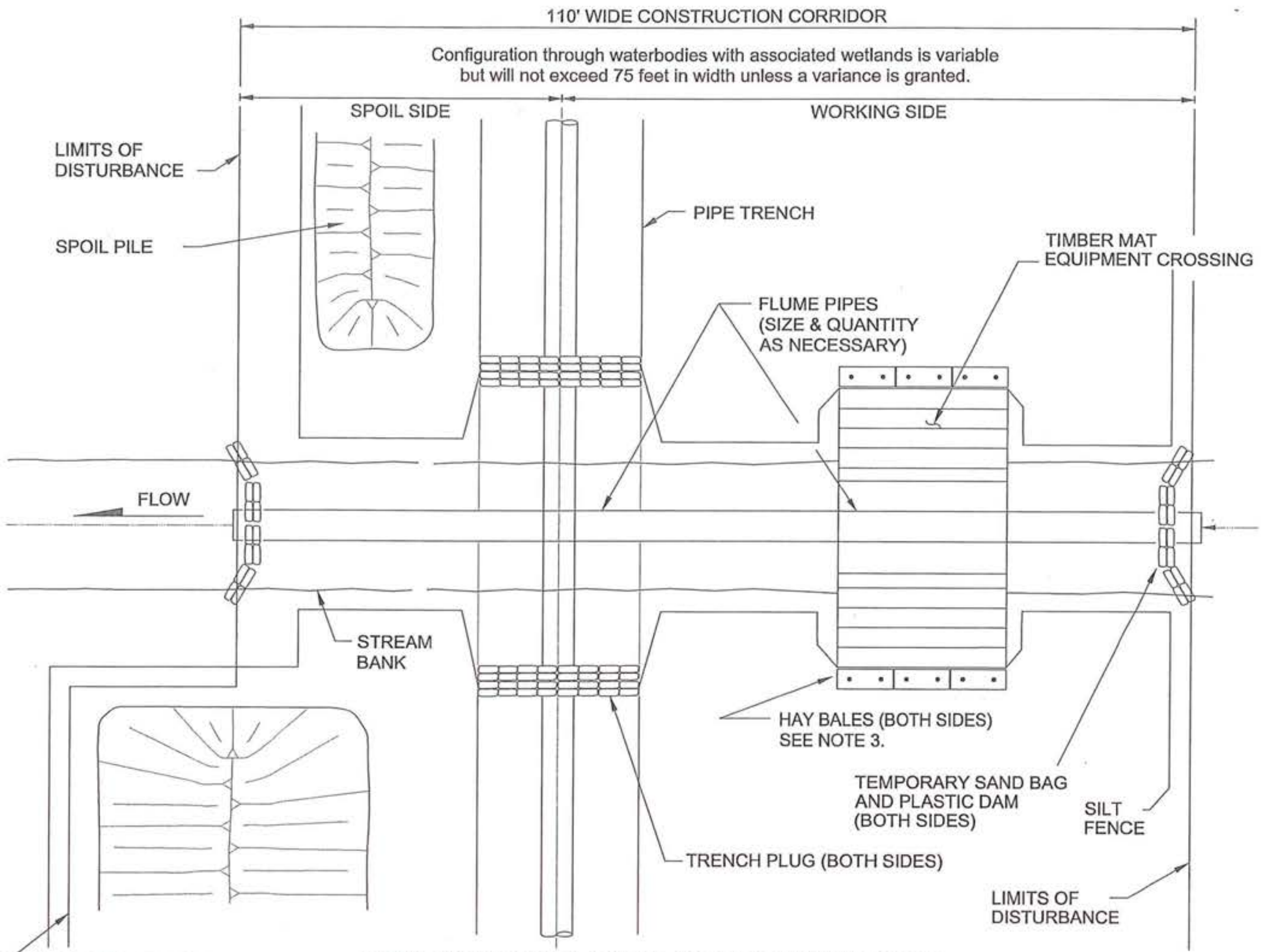
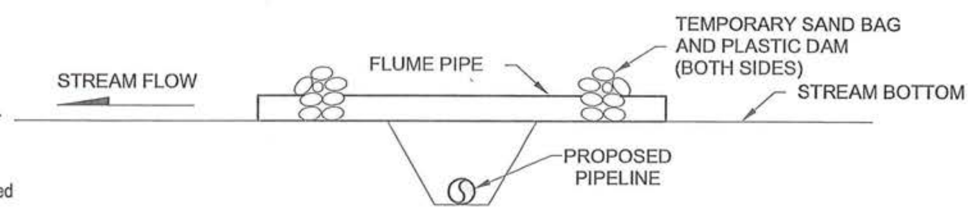
FIGURE: 13

Typical Open Cut Wet Crossing Method
Flowing Waterbody
Cameron LNG, LLC



PLAN VIEW OF FLUMED CROSSING METHOD



CROSS-SECTION OF FLUMED CROSSING METHOD

NOTES:

1. Trench width will vary due to soil conditions which are not known until actual construction takes place.
2. Extra workspace will be located 50 feet from edge of waterbody unless a variance is granted or the adjacent vegetation is actively cultivated as a rotated croplands. For extra workspace locations and dimensions see environmental alignment sheets.
3. Temporary erosion control measures must be replaced at the end of each working day.

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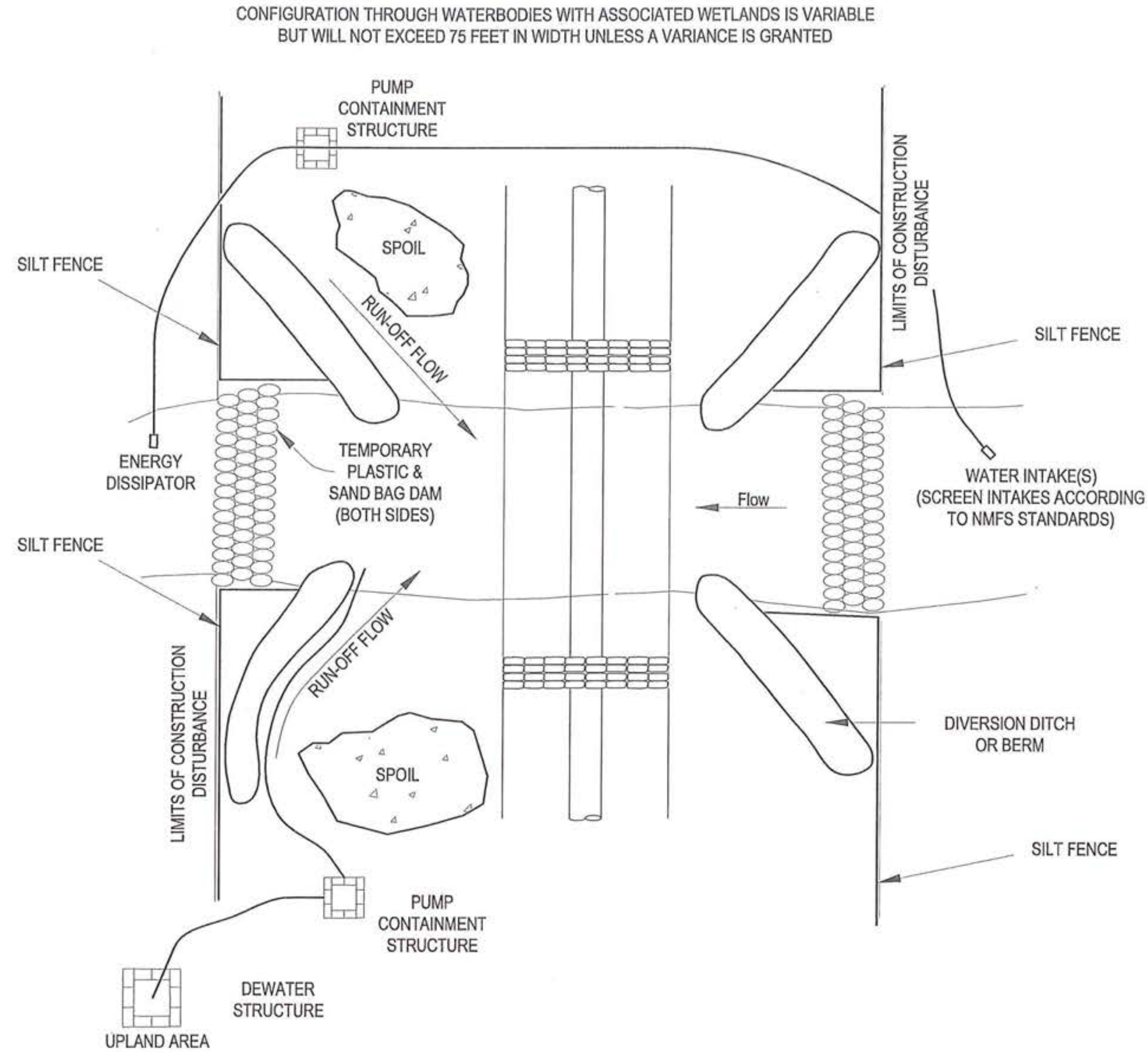
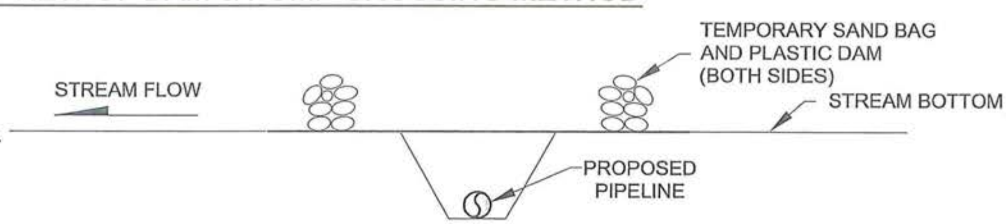
FIGURE: 14
Typical Flume Crossing Method
Cameron LNG, LLC



PLAN VIEW OF DAM & PUMP CROSSING METHOD

NOTES:

1. Trench width will vary due to soil conditions which are not known until actual construction takes place.
2. Extra workspace will be located 50 feet from edge of waterbody unless a variance is granted. for extraworkspace locations and dimensions see environmental alignment sheets.
3. Temporary erosion control measures must be replaced at the end of each working day.



CROSS-SECTION OF
DAM & PUMP CROSSING METHOD

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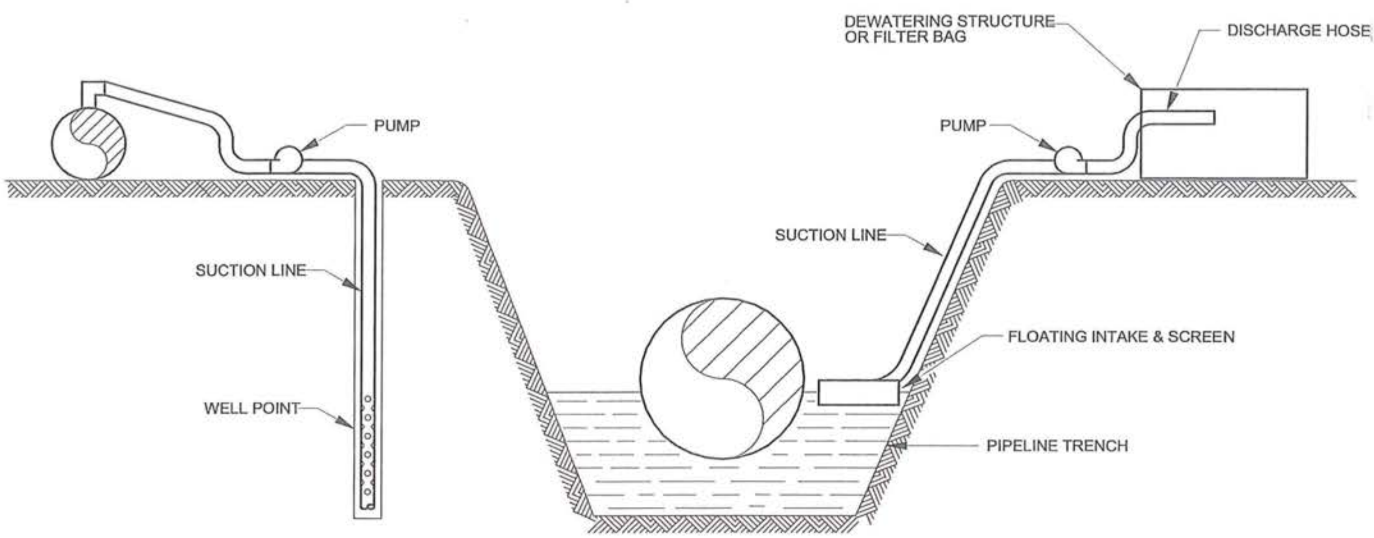
FIGURE: 15

Typical Dam & Pump Crossing Method

Cameron LNG, LLC



NOTES:

1. Dewatering measure/methods
   a. Pump water to a filtering structure typically constructed with hay bales or geotextile and discharge as "sheet flow" out of structure. (see sht. 3)
   b. Pump water into a filter bag. (see sht. 1)
   c. Pump water to a settling tank and haul to a disposal site.
   d. Pump water to a settling tank and discharge overland.
   e. Transfer water to next section of trench.
   f. Install well points and pump to filtering structure and discharge to drainage, channel or sheet flow.
   g. Install well points and discharge sheet flow.
   h. Dispose of water collected in tank or filtration structure by aeration through a sprinkler system.
2. Water pumped out of trench shall not be discharged into waterbodies or wetlands.
3. Pump shall be controlled so that discharge does not overflow dewatering structure.
4. Pump suction hose must not be allowed to settle the trench bottom. provisions must be made to elevate the suction hose to at least one foot above the bottom until bottom dewatering is necessary.

TRENCH DEWATERING

TEMPORARY EROSION CONTROL MEASURE

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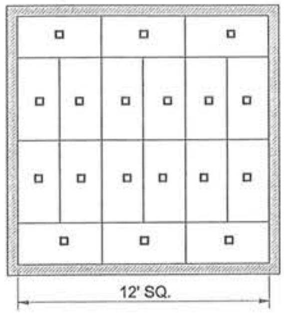
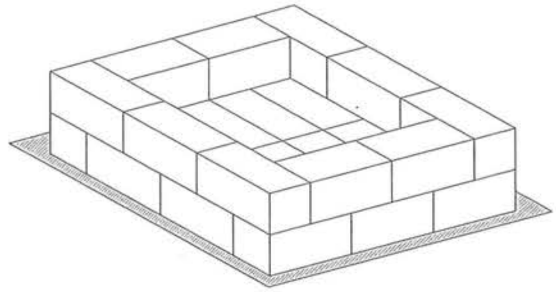
FIGURE: 16
Trench Dewatering
Cameron LNG, LLC



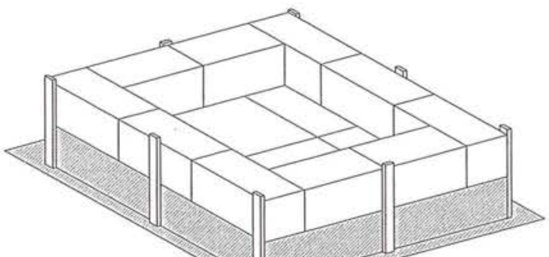
STEP 1

Arrange hay bales over filter fabric on level land tightly packed as shown to cover an area approximately 12' x 12'. Secure each haybale in place by driving rebar or a wooden stake through each of the hay bales.



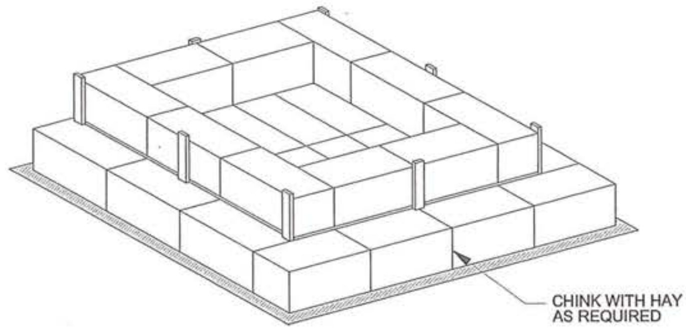
STEP 2

Install another layer of hay bales on the outer edge as shown.y



STEP 3

Install filter fabric all around hay bale structure as shown.



STEP 4

Install another layer of hay bales on the outside of the filter fabric and secure in place by driving rebar or a wooden stake through each of the outer hay bales.

NOTES:

1. Where possible structure shall be placed on a level, well vegetated site such that water will flow away from structure and any work areas, waterbodies or wetlands.
2. This measure shall be removed upon completion of the project. removal is not contingent upon establishment of permanent vegetation. material from bales may be scattered on right-of-way.
3. Contractor shall use certified noxious weed free hay or straw for structure.

TRENCH DEWATERING

TEMPORARY EROSION CONTROL MEASURE

Cameron LNG LLC

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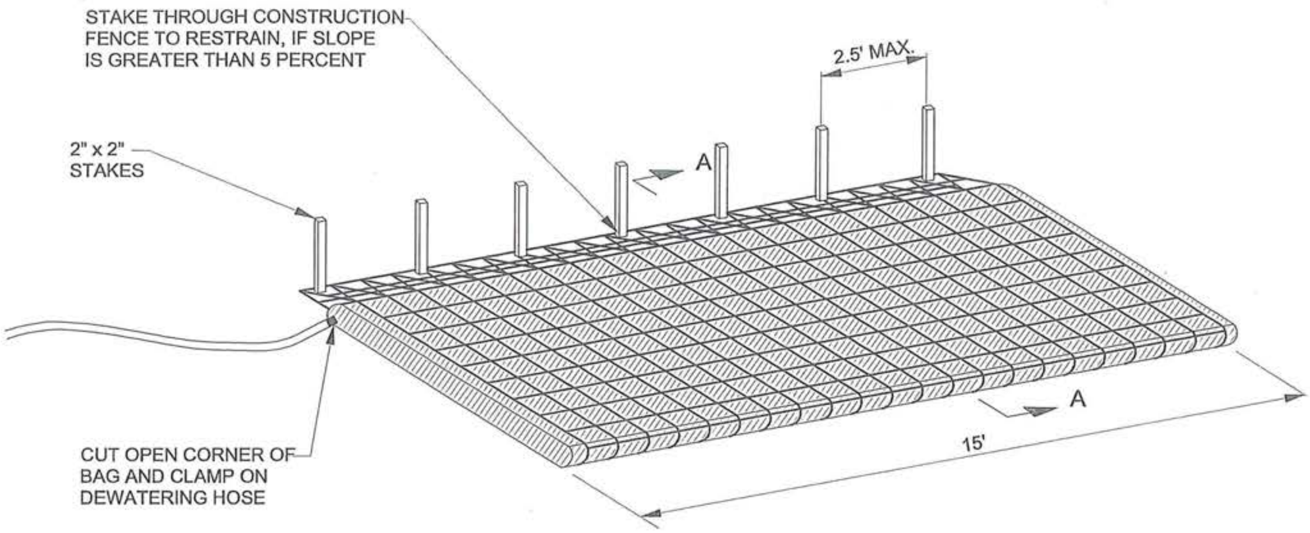
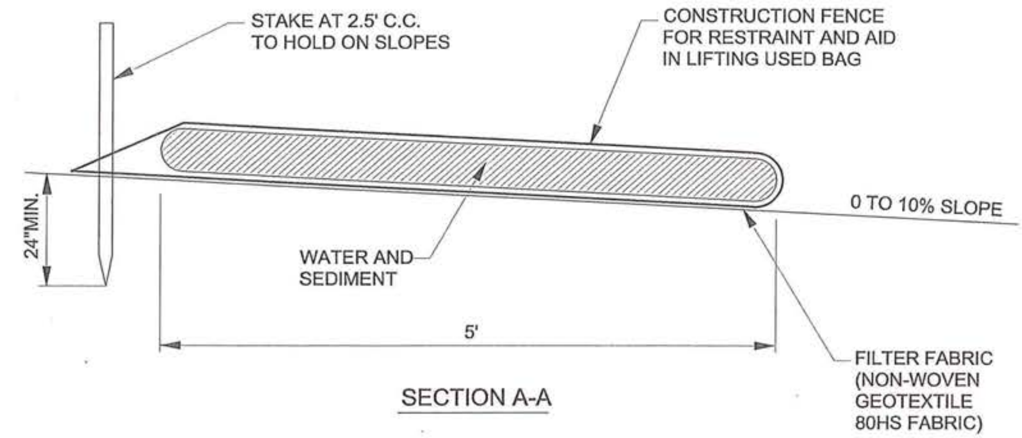
FIGURE: 17

Trench Dewatering – Hay Bale Containment

Cameron LNG, LLC





SECTION A-A

NOTES:

1. Filter bag shall be placed on a gently sloping or level, well graded vegetated site such that water will flow away from device, any work areas, waterbodies or wetlands.
2. The filter bag must be staked in place and secured to the pump discharge line.
3. Filter bag shall not be used for discharge flows greater than 300 gpm.
4. Device shall be removed and disposed of after bag is filled with sediment. sediment from bag shall be spread in an upland area.

TRENCH DEWATERING

TEMPORARY EROSION CONTROL MEASURE

Cameron LNG LLC

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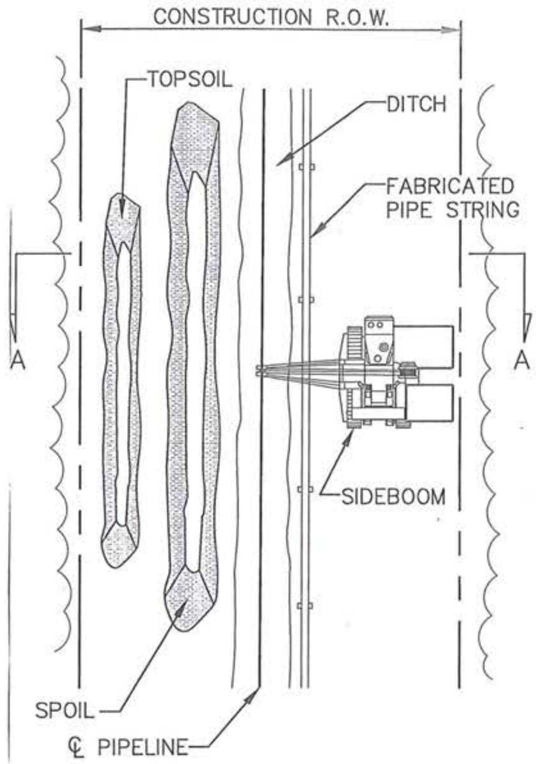
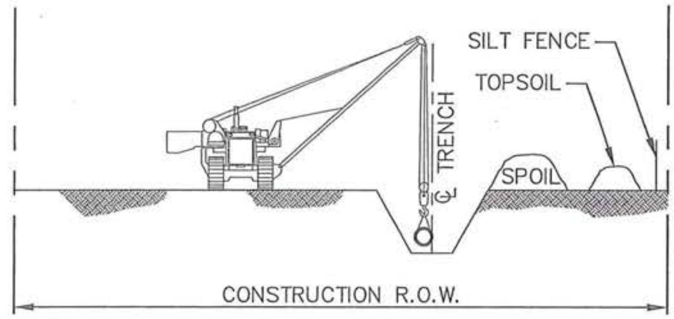
FIGURE: 18

Trench Dewatering – Filter Bag

Cameron LNG, LLC



PLAN VIEW



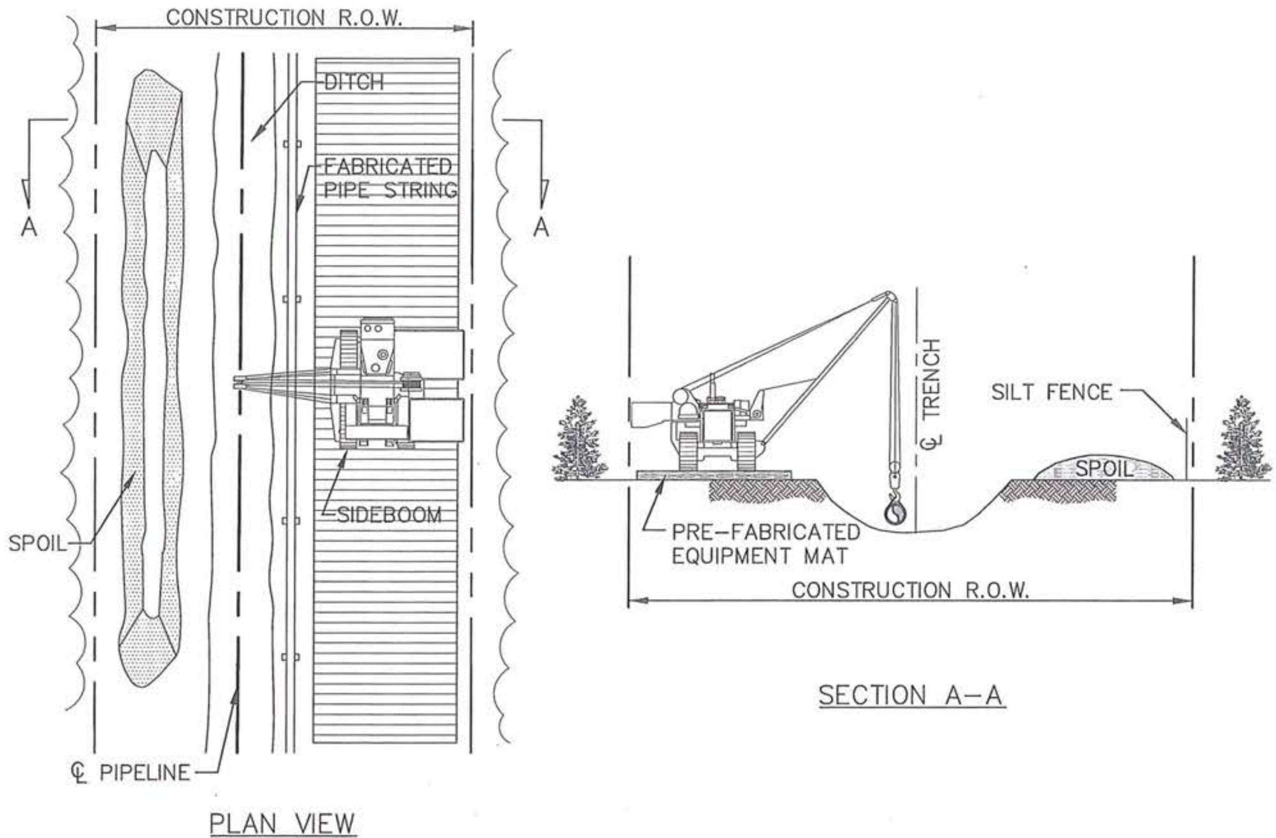
SECTION "A–A"

CONSTRUCTION PROCEDURES:

1. IF A WETLAND IS BEING CULTIVATED AND BEING FARMED, NO WETLAND CONSTRUCTION PROCEDURES ARE REQUIRED.
2. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
3. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS APPROXIMATELY 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
4. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY IF DIRECTED BY THE PROJECT.
5. CONSTRUCT WHEN DRY, IF POSSIBLE. IF SITE BECOMES WET AT TIME OF TRENCHING, AVOID SOIL COMPACTION BY UTILIZING TIMBER RIP–RAP OR PREFABRICATED EQUIPMENT MATS.
6. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT DOWN SLOPE EDGE OF RIGHT–OF–WAY ALONG WETLAND EDGE IF EVIDENT, OTHERWISE INSTALL BARRIER ON BOTH EDGES.
7. RESTRICT ROOT GRUBBING TO ONLY THAT AREA OVER THE DITCHLINE AND REMOVE STUMPS FROM WETLAND FOR DISPOSAL.
8. CONDUCT TRENCH LINE TOPSOIL STRIPPING (IF TOPSOIL IS NOT SATURATED). SALVAGE TOPSOIL TO ACTUAL DEPTH OR A MAXIMUM DEPTH OF 12 INCHES.
9. TRENCH THROUGH WETLANDS.
10. PIPE SECTION TO BE FABRICATED WITHIN THE WETLAND AND ADJACENT TO ALIGNMENT, OR IN STAGING AREA OUTSIDE THE WETLAND AND WALKED IN.
11. LOWER–IN PIPE. PRIOR TO BACKFILLING TRENCH, IF REQUIRED, TRENCH PLUGS SHALL BE INSTALLED AS REQUIRED. BACKFILL TRENCH.
12. RESTORE GRADE TO NEAR PRE–CONSTRUCTION TOPOGRAPHY, REPLACE TOPSOIL AND INSTALL PERMANENT EROSION CONTROL.
13. IF UTILIZED, REMOVE TIMBER MATS OR PRE–FABRICATED MATS FROM WETLANDS UPON COMPLETION.

Cameron LNG LLC
AN AFFILIATE OF SEMPRA LNG

FIGURE: 19
Dry Wetland Crossing Method
Cameron LNG, LLC



CONSTRUCTION PROCEDURES:

1. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
2. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
3. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY IF DIRECTED BY THE PROJECT.
4. INSTALL TIMBER MATS/RIPRAP THROUGH ENTIRE WETLAND AREA. EQUIPMENT NECESSARY FOR RIGHT-OF-WAY CLEARING MAY MAKE ONE (1) PASS THROUGH THE WETLAND BEFORE MATS ARE INSTALLED.
5. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT DOWNSLOPE EDGE OF RIGHT-OF-WAY AND ALONG WETLAND EDGE AS REQUIRED.
6. RESTRICT ROOT GRUBBING TO ONLY THAT AREA OVER THE DITCHLINE AND DITCH SPOIL AREAS AND REMOVED FROM WETLAND FOR DISPOSAL.
7. TOPSOIL STRIPPING SHALL NOT BE REQUIRED IN SATURATED SOIL CONDITIONS.
8. LEAVE HARD PLUGS AT EDGE OF WETLAND UNTIL JUST PRIOR TO TRENCHING.
9. PIPE SECTION MAY BE FABRICATED WITHIN THE WETLAND AND ADJACENT TO ALIGNMENT, OR IN STAGING AREA OUTSIDE THE WETLAND AND WALKED IN.
10. TRENCH THROUGH WETLANDS.
11. LOWER-IN PIPE, INSTALL TRENCH PLUGS AT WETLAND EDGES AS REQUIRED AND BACKFILL IMMEDIATELY.
12. REMOVE TIMBER MATS OR PRE-FABRICATED MATS FROM WETLAND UPON COMPLETION.
13. RESTORE GRADE TO NEAR PRE-CONSTRUCTION TOPOGRAPHY, REPLACE TOPSOIL AND INSTALL PERMANENT EROSION CONTROL.

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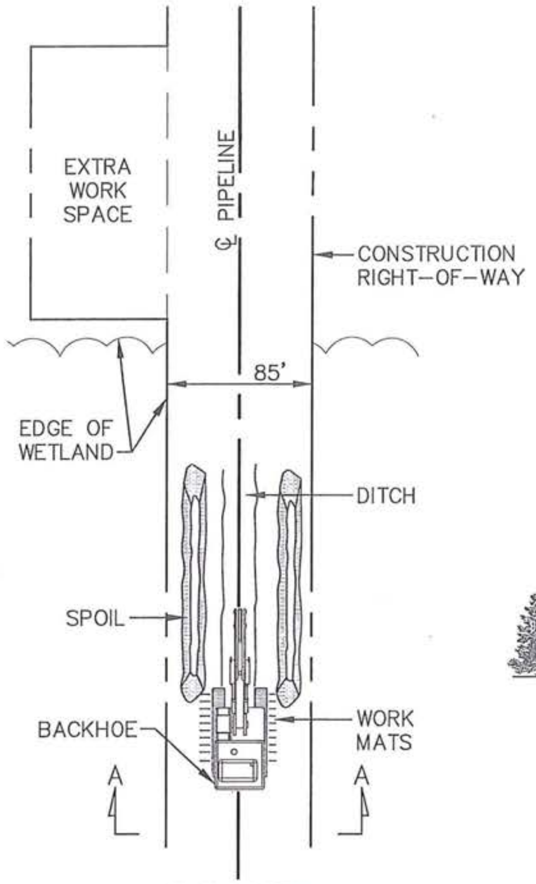
AN AFFILIATE OF SEMPRA LNG

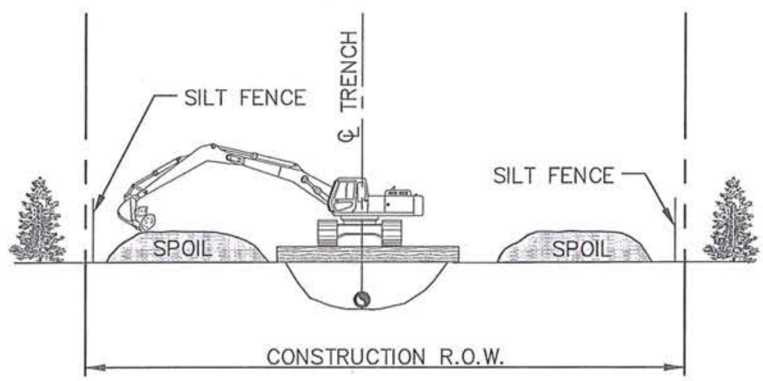
FIGURE: 20

Typical Wetland Crossing Method

Cameron LNG, LLC



PLAN VIEW



SECTION A-A

CONSTRUCTION PROCEDURES:

1. FLAG WETLAND BOUNDARIES PRIOR TO CLEARING.
2. NO REFUELING OF MOBILE EQUIPMENT IS ALLOWED WITHIN APPROXIMATELY 100 FEET OF WETLAND. PLACE "NO FUELING" SIGN POSTS 100 FEET BACK FROM WETLAND BOUNDARY. REFUEL STATIONARY EQUIPMENT AS PER THE PROJECT'S SPILL PREVENTION PROCEDURES.
3. INSTALL TEMPORARY SLOPE BREAKER UPSLOPE WITHIN 100 FEET OF WETLAND BOUNDARY AS DIRECTED BY THE PROJECT.
4. RESTRICT ROOM GRUBBING TO ONLY THE AREA OVER THE DITCHLINE.
5. TOPSOIL STRIPPING SHALL NOT BE REQUIRED IN SATURATED SOIL CONDITIONS.
6. UTILIZE AMPHIBIOUS EXCAVATORS (PONTOON MOUNTED BACKHOES) OR TRACKED BACKHOES SUPPORTED BY FABRICATED TIMBER MATS OR FLOATS TO EXCAVATE TRENCH. IF FABRICATED TIMBER MATS ARE USED FOR STABILIZATION, THE BACKHOE SHALL GRADUALLY MOVE ACROSS THE WETLAND BY MOVING THE MAT FROM IMMEDIATELY BEHIND TO IMMEDIATELY IN FRONT OF THE BACKHOE'S PATH.
7. AVOID ADJACENT WETLANDS. INSTALL SEDIMENT BARRIERS (STRAW BALES AND/OR SILT FENCE) AT EDGE OF RIGHT-OF-WAY AND ALONG WETLAND EDGE IF PRACTICAL.
8. FABRICATE PIPE IN STAGING AREA OUTSIDE THE WETLAND IN THE EXTRA WORK SPACE AS INDICATED ON THE CONSTRUCTION DRAWINGS.
9. LEAVE HARD PLUGS AT THE EDGE OF THE WETLAND UNTIL JUST PRIOR TO PIPE PLACEMENT.
10. FLOAT PIPE IN PLACE, LOWER-IN, INSTALL TRENCH PLUGS AT WETLAND EDGES WHERE REQUIRED AND BACKFILL IMMEDIATELY.
11. REMOVE TIMBER MATS OR PRE-FABRICATED MATS OF NON-NATIVE MATERIAL FROM WETLANDS UPON COMPLETION.
12. RESTORE GRADE TO NEAR PRE-CONSTRUCTION TOPOGRAPHY AND INSTALL PERMANENT EROSION CONTROL.
13. THE CONSTRUCTION RIGHT-OF-WAY FOR THIS TYPE OF CONSTRUCTION SHALL BE 85 FEET.

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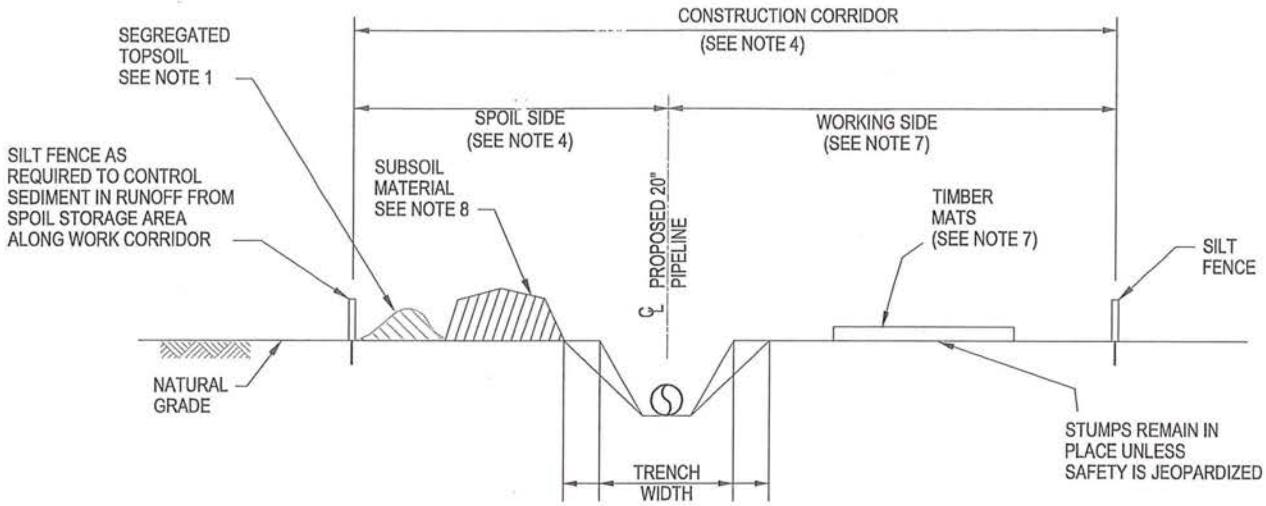
FIGURE: 21

Push/Pull Wetland Crossing Method

Cameron LNG, LLC



TRENCH WIDTH VARIES DEPENDING ON SOILS
ENCOUNTERED DURING CONSTRUCTION

CROSS SECTION

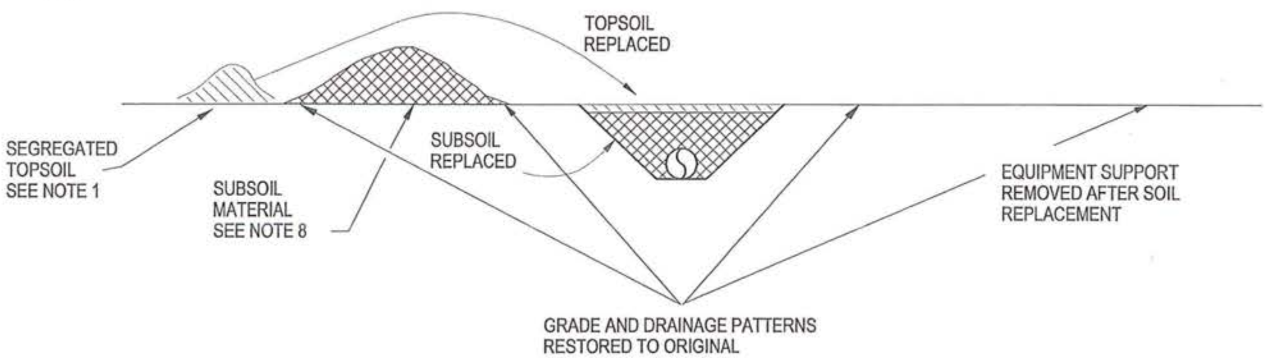
NOTES Continued:

5. Silt fence or straw bales will be used where appropriate to prevent siltation into water bodies or wetlands.

6. Silt fences or straw bales will also be used to prevent stockpiled soil or spoil from leaving the construction right-of-way or workspaces.

7. Timber mats may be used over spoil storage where standing water or saturated soils are present.

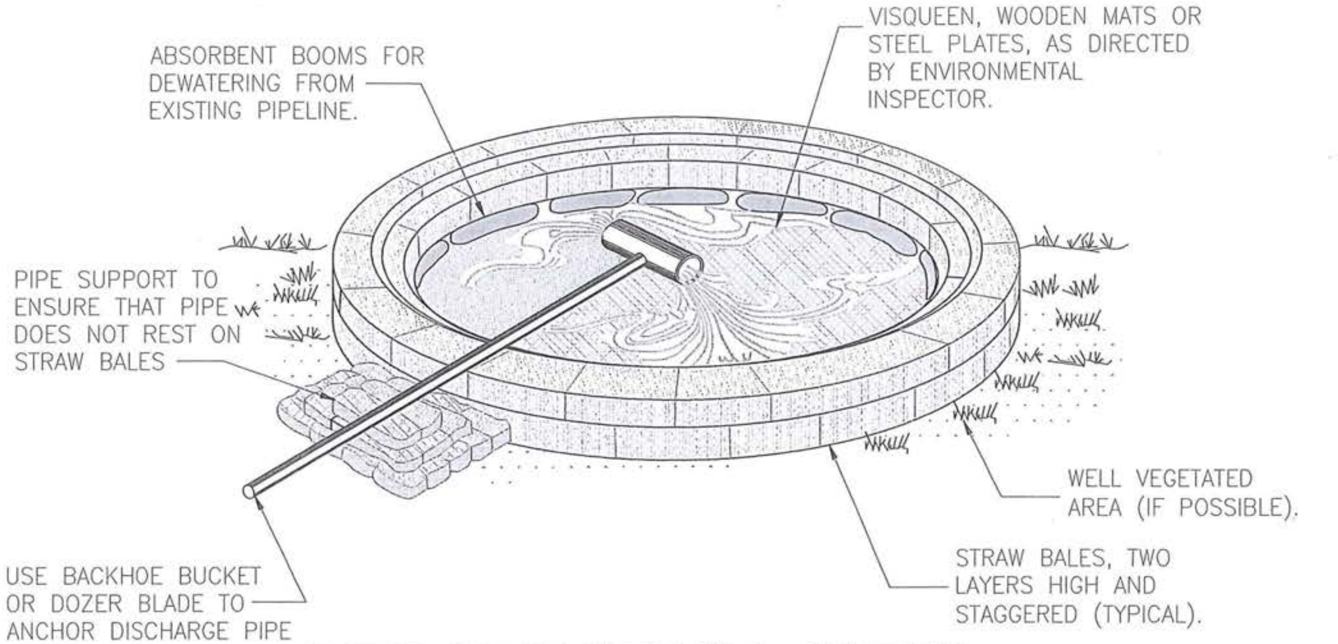
8. If standing water or saturated soils are present, or if construction equipment causes ruts or mixing of topsoil and subsoil in wetlands, use low-ground weight equipment, or operate normal equipment on timber riprap, prefabricated equipment mats or terra mats.



WETLAND RESTORATION

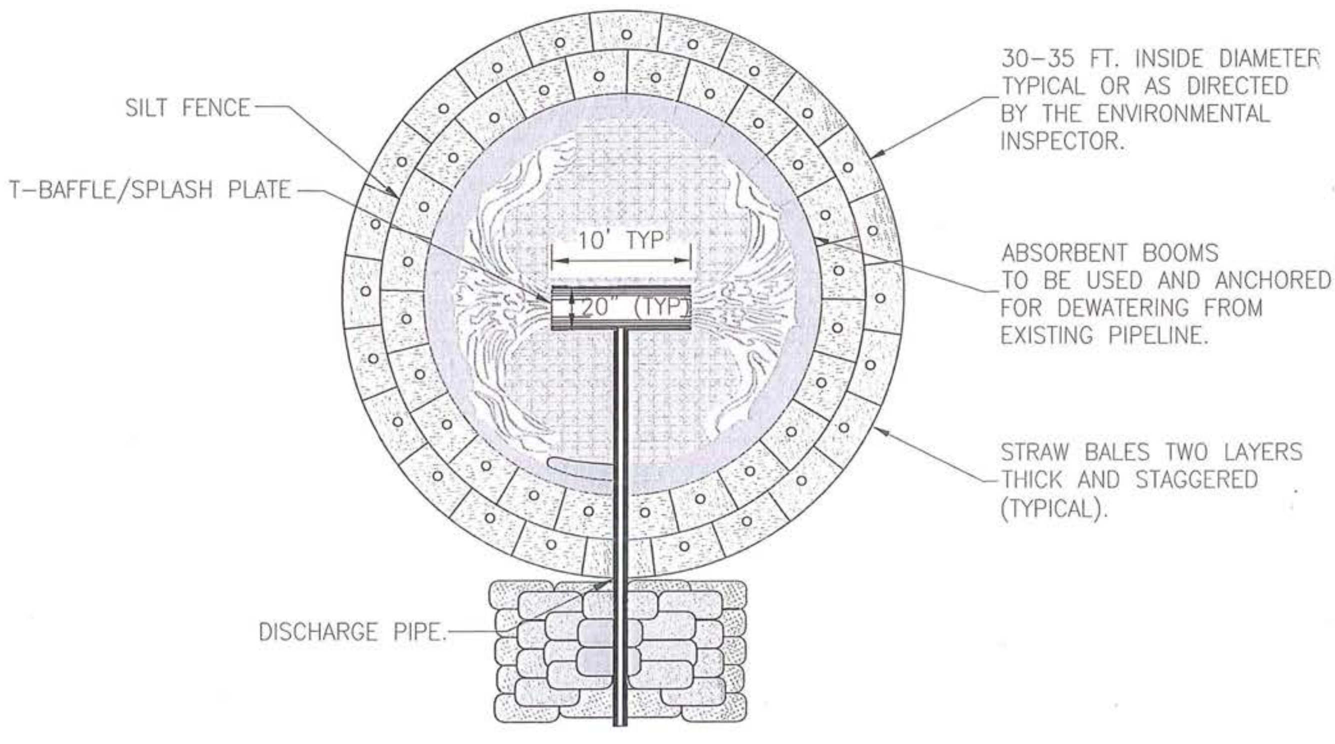
Cameron LNG LLC
AN AFFILIATE OF SEMPRA LNG

FIGURE: 22
Wetland – Trench and Backfill
Cameron LNG, LLC



PERSPECTIVE VIEW

NOT TO SCALE



PLAN VIEW

NOT TO SCALE

Cameron LNG LLC

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FIGURE: 23

Hydrostatic Dewatering Structure

Cameron LNG, LLC

APPENDIX

APPENDIX 1

SPILL NOTIFICATION & AGENCY CONTACTS

LOUISIANA

Excess Air Emissions

Notify the Department of Public Safety within 1 hour of any discharge that may result in **emergency conditions:** any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property.

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, provide notice within 24 hours to:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a Reportable Quantity and do not cause an emergency condition.
2. Report releases into the air that exceed Reportable Quantities (see **Hazardous Substances** at page Louisiana – 3) within any continuous 3-hour or 24-hour period, or below RQs for a greater-than-7-day period.
3. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized emission that exceeds the Reportable Quantities for an air contaminant (Louisiana Administrative Code, Title 33, Part 1, Section 3931), based on total mass emitted within a consecutive 3-hour period from the site or facility, except for leaks already covered under Louisiana requirements.
   b. Any other unauthorized emissions that exceed Reportable Quantities.
   c. Any unauthorized emission that causes an adverse off-site impact such as an odor, an impairment of visibility caused by smoke opacity, or visible deposition of emitted material, in violation of Air Quality Division Regulations.
   d. Emergency occurrences or upsets that will substantially increase emissions.
4. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.

h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:

   (1) Location of the source facility or stack.
   (2) Time at onset of the emission.
   (3) Prevailing local wind direction and estimated velocity at time of onset.
   (4) Duration of emission if stopped at time of notification.

5. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:

   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific indication that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:

      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.

q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925; Part III, Section 927

For sources subject to federal Part 70 emissions permits, refer to the permit for additional conditions regarding testing, monitoring, reporting, and recordkeeping. Sources subject to continuous emissions monitoring will also need to supply information on excess emissions and emergency conditions in their quarterly reports.

Citation: Louisiana Administrative Code, Title 33, Part III, Section 507

Hazardous Materials

Same as **Hazardous Substances** (see below). Report spills to:

Louisiana State Police
(225) 925-6595 (24-hour)
(877) 925-6595

Note: Louisiana has adopted the federal regulations for hazardous materials transportation (see **Federal — Hazardous Materials** at page Federal – 3), using the State Police as the contact point in-state. If reporting a hazardous materials incident, ask the State Police contact about requirements for submitting a written report and to provide you with a copy of any state reporting forms that may be necessary for your particular incident.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 10903

Hazardous Substances

Same as **Oil** (see page Louisiana – 7) when releases are to the air, land, or water environment and exceed Reportable Quantities within any continuous 24-hour period.

Note: Reportable Quantities of hazardous substances can be found in Louisiana Administrative Code, Title 33, Part I, Section 3931. Contact DEQ if you have questions about a substance or would like a complete listing.

Report releases onto land that exceed reportable quantities within any continuous 24-hour period to:

Local Emergency Planning Committee

Local 911 for Emergencies

Louisiana State Police
(225) 925-6595 (24-hour)

Note: Contents and time frames of verbal and written reports are the same as Notes 3 and 4, respectively, under **Oil** (see page Louisiana – 7). The Louisiana Department of Environmental Quality is also encouraging on-line reporting of incidents at: www.deq.louisiana.gov/apps/forms/irf/forms/. See **Louisiana Incident Report Form** (at page Louisiana – 16) for a listing of information collected by state officials. Submit the written report to:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC

Report releases into the air that exceed Reportable Quantities within any continuous 3-hour or 24-hour period, or below RQs for a greater-than-7-day period, to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance

(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Note: Contents of verbal and written reports are the same as Notes 4 and 5, respectively, under **Oil** (see page Louisiana – 8). For hazardous air pollutant releases include (see also reporting requirements under **Excess Air Emissions** at page Louisiana – 1):

1. Location and identity of the source facility or stack.
2. Date and time at onset of emission.
3. Prevailing local wind direction and estimated velocity at time of onset.
4. Duration of emission if stopped at time of report.
5. The approximate total loss during the emission.

Submit the written report to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
Attention: Administrator
P.O. Box 4312
Baton Rouge, LA 70821-4312

Also report releases that exceed Reportable Quantities within any continuous 24-hour period to:

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

Louisiana has issued a new rule establishing procedures for the reporting of information regarding hazardous materials that are in transit and/or temporarily stored at a facility and that could present a threat to human health and the environment if compromised during a Category 3 or higher hurricane. Within 12 hours of a mandatory evacuation order issued by the proper local parish authorities, persons engaged in the transport or temporary storage of hazardous materials shall report by e-mail to DPS (emergency@la.gov) the following:

1. The exact nature of, and the type, location, and relative fullness of the container (i.e., full, half-full, or empty) of all hazardous materials that are located within a parish subject to the evacuation order.
2. The primary and secondary contact persons' phone number, e-mail, and fax number.
3. Whether the facility will be sufficiently manned such that post-event assessments will be performed by company personnel (as soon as safely practicable) and that any releases and/or hazardous situations will be reported in accordance with DEQ and DPS reporting requirements.

Hazardous Wastes

If a release could threaten human health or the environment outside the facility, or when the generator has knowledge that a spill has reached surface water, the emergency coordinator must notify:

National Response Center
(800) 424-8802

Louisiana Department of Environmental Quality
Office of Environmental Assessment
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

The report, to be made immediately, should indicate:

1. Name of person making the notification and telephone number where any return calls from response agencies may be placed.

2. Name, address, and U.S. EPA identification number of the generator.
3. In the event of an incident involving transport, provide the name and address of the transporter and generator.
4. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
5. Date and time the incident began and ended, or estimated time the discharge may continue.
6. Type of incident involved (e.g., spill or fire).
7. Extent of any injuries and identification of any personnel hazards that response agencies may face.
8. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
9. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
10. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
    a. Location of the source facility or stack.
    b. Time at onset of the emission.
    c. Prevailing local wind direction and estimated velocity at time of onset.
    d. Duration of emission if stopped at time of notification.

A written report must be submitted to the Department within 15 days with the above information and describing estimated quantity and disposition of any recovered material. In addition, the owner/operator must note in the operating record for the facility the time, date, and details of any incident that requires implementation of the facility's spill contingency plan.

Note: while Louisiana has adopted general requirements similar to those specified in **Federal — Hazardous Wastes** (see page Federal – 7), state reporting mandates as identified above incorporate and supplement the general reporting standards.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 1109(E)(7)(d)(iv)(c) and 33:V.1513(F)

Under the general Louisiana Discharge Notification Rules, additional requirements are imposed:

Provide notice within 1 hour of any discharge that may result in **emergency conditions**. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property. Notify:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, notify the Department of Environmental Quality within 24 hours.

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a reportable quantity and do not cause an emergency condition.

2. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized discharge of hazardous waste or reusable material from a facility that exceeds any conditions specified in an interim or final RCRA (Resource Conservation and Recovery Act) permit.
   b. Any unauthorized discharge of hazardous waste or reusable material from a site or facility that exceeds any Reportable Quantity (Louisiana Administrative Code, Title 33, Part 1, Section 3931).
   c. Any unauthorized discharge of any hazardous waste or reusable material that may endanger human health or the environment including, but not limited to, events with chemical or biological toxicity, or that have flammable or explosive potential.
3. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.
      (4) Duration of emission if stopped at time of notification.
4. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:
   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific identification that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:
      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.

(3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
k. The reporting party's status (former or present owner, operator, disposer, etc.).
l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
m. What other agencies were notified.
n. Names of all other responsible parties of which the reporting party is aware.
o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
p. The extent of injuries, if any.
q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925

Oil

Report spills that create **emergency conditions** immediately, and spills creating **nonemergency conditions** within 24 hours to:

For Emergency Conditions:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For Nonemergency Conditions:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Louisiana Oil Spill Coordinator's Office
150 Third Street, Suite 405
Baton Rouge, LA 70801
(225) 219-5800 (8 to 5)

1. The Office of the State Police is the lead agency for emergency response in Louisiana. Louisiana Administrative Code Title 33, Part 1, Chapter 39, and Part V, Section 10111, establishes release reporting requirements for all releases of hazardous materials in the state. The requirements of both sections are summarized as follows:

   DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a reportable quantity and do not cause an emergency condition.

   A release of any of the following substances must be reported immediately if it causes **emergency conditions**, no matter what the quantity of discharged material is. An **emergency condition** is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property.

   Reporting can be done within 24 hours for unauthorized discharges that exceed Reportable Quantities, but create **nonemergency conditions**. Report nonemergency conditions to the appropriate division of the DEQ. However, releases that meet or exceed the Reportable Quantity and escape beyond the site of a facility must be reported immediately.

   a. Extremely hazardous substances.
   b. CERCLA hazardous substances.
   c. Hazardous substances established by the Department of Transportation. (Oil is contained in this listing: the RQ is 1 barrel.)
   d. Any material on which maintenance of a material safety data sheet is required by OSHA if it is not on lists a. through c. above and if the material exceeds RQs at 5,000 lbs. (Exceptions: Compressed or refrigerated flammable gases and flammable liquids as defined by 49 CFR will have RQs of 100 lbs., and all other liquids requiring an MSDS will have a 1,000 lb. RQ.)

2. Waters of the state include surface and underground.

3. An unauthorized discharge that results in contamination of the groundwaters of the state or otherwise moves in, into, within, or on any saturated subsurface strata must be reported in writing within 7 days. Follow the written report requirements below.

4. Verbal spill reports shall include:

   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:

      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.
      (4) Duration of emission if stopped at time of notification.

5. A written report must be submitted within 7 days to the Local Emergency Planning Committee, State Police, and DEQ (unless each of the agencies says otherwise). If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:
   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific indication that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:
      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.
   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.
   q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925; Part V, Section 10111

In addition, operators of pipeline systems must report a release of a hazardous liquid (petroleum, petroleum products, or anhydrous ammonia) or carbon dioxide resulting in any of the following:

1. Explosion or fire not intentionally set by the operator.
2. Release of 5 gallons or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels resulting from a pipeline maintenance activity if the release does not trigger other reporting requirements in this section, is confined to company property or the pipeline right-of-way, and is cleaned up promptly.
3. Escape to the atmosphere of more than 5 barrels a day of highly volatile liquids.
4. Death of any person.
5. Bodily harm to any person resulting in 1 or more of the following:
    a. Loss of consciousness.
    b. Necessity to carry the person from the scene.
    c. Necessity for medical treatment.
    d. Disability that prevents the discharge of normal duties or the pursuit or normal activities beyond the day of the accident.
6. Estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.
7. At the earliest practicable moment (within 2 hours) following discovery of a release of the hazardous liquid or carbon dioxide, the operator of the system shall give immediate notice to:

    Louisiana Department of Natural Resources
    Office of Conservation
    P.O. Box 94275
    Baton Rouge, LA 70804-9275
    (225) 342-5585 (8 to 4:30)
    (225) 342-5505 (After-hours)
8. Telephone notice must be provided for pipeline failures that:
    a. Caused a death or a personal injury requiring hospitalization.
    b. Resulted in either a fire or explosion not intentionally set by the operator.
    c. Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.
    d. Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines.
    e. In the judgment of the operator was significant even though it did not meet the above criteria.
9. The following information should be provided:
    a. Name and address of the operator.
    b. Name and telephone number of the reporter.
    c. The location of the failure.
    d. The time of the failure.
    e. The fatalities and personal injuries, if any.
    f. All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.
10. Each operator experiencing an accident that is required to be reported shall as soon as practicable but not later than 30 days after discovery of the accident prepare and file an accident report on Louisiana's Accident Report Form. Contact DNR at the number above for information about the current form.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 30125

In the event that an unauthorized discharge into the Mississippi River or any other water of the state used for potable water supply could reasonably be expected to interfere with or significantly impact downstream potable or industrial water usage, the discharger shall notify immediately, but in no case later than 1 hour after learning of the discharge, by telephone or other rapid communication means:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Report unauthorized discharges or spills that could reasonably be expected to interfere with or significantly impact downstream potable or industrial water usage to the Mississippi River or Bayou Lafourche to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
Surveillance Division
Early Warning Organic Compound Detection System
(225) 219-3600 (8 to 4:30)
(225) 219-3700 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

SARA Title III

Report releases and submit written follow-up emergency notice(s) to:

Louisiana Department of Public Safety
Office of State Police
Transportation and Environmental Safety Section
Right-to-Know Unit
Mail Slip 21
P.O. Box 66614
Baton Rouge, LA 70896-6614
(225) 925-6595 (24-hour)
(225) 925-6113 x227 (9 to 5)

Tank Leaks

Report any release or reasonable suspicion of a release of a regulated substance from an underground storage tank to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. Releases can be identified from:

    a. The discovery by owners and/or operators or others of released regulated substances at the tank site or in the surrounding area (such as the presence of free product or vapors in soils, basements, sewer and utility lines, and nearby surface water).

b. Unusual operating conditions at the tank system observed by owners and/or operators (such as the erratic behavior of product dispensing equipment, the sudden loss of a product from the tank system, or an unexplained presence of water in a tank), unless system equipment is found to be defective but not leaking, and is immediately repaired or replaced.
c. Monitoring results from a Statistical Inventory Reconciliation method, included in a tank system analysis report, are "fail" or "inconclusive".
d. Monitoring system results, unless:
   (1) The monitoring device is found to be defective, and is immediately repaired, recalibrated, or replaced, and additional monitoring conducted within 24 hours does not confirm the initial result.
   (2) Where monitoring is used to control inventory, the second month of data does not confirm the initial result.

2. If the tank holds petroleum, the owner or operator must report within 24 hours spills or overfills that exceed 42 gallons, or that cause a sheen on nearby surface waters. If the spill or overfill results in an emergency (see **Wastewater Excursions** at page Louisiana – 13), regardless of the amount, the Department must be notified immediately.
3. If the tank holds hazardous substances, the owner or operator must report within 1 hour any spills or overfills that equal or exceed the **Reportable Quantity** (see Reportable Quantities section) for that substance under the federal CERCLA law. Also report immediately to the National Response Center: (800) 424-8802.
4. A written report will be required within 7 calendar days. (See **Wastewater Excursions** at page Louisiana – 13.)
5. Owners and/or operators of tank systems must contain and immediately clean up a spill or overfill of petroleum that is less than 1 barrel and a spill or overfill of a hazardous substance that is less than the Reportable Quantity. If cleanup cannot be accomplished within 24 hours, report to DEQ.

Citation: Louisiana Administrative Code, Title 33, Part XI, Sections 707, 713

Report contamination of groundwater shown by routine monitoring to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC

The written report requirements are the same as Note 5, under **Oil** (see page Louisiana – 9), and will also include the following information:

1. The reporting party's status (former or present owner, operator, disposer, etc.).
2. All information of which the reporting party is aware that indicates hazardous waste is migrating, including, but not limited to, monitoring well data.
3. Possible routes of migration.
4. All information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
5. Names of all other responsible parties of which the reporting party is aware.

Wastewater Excursions

Provide notice within 1 hour of any discharge that may result in **emergency conditions**. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public, cause significant adverse impact to the land, water, or air environment, or cause severe damage to property. Notify:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, notify the Department of Environmental Quality within 24 hours:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a Reportable Quantity and do not cause an emergency condition.
2. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized discharge containing a pollutant or pollutants that exceed Reportable Quantities (Louisiana Administrative Code, Title 33, Part 1, Section 3931), and come from sources other than those with federal or state pollutant discharge permits.
   b. An unauthorized discharge containing a pollutant or pollutants that exceed Reportable Quantities, from a source that has a federal or state discharge permit. No reporting is required if such a discharge resulted from circumstances identified, reviewed, and made part of the public record for the discharge permit.
3. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.

(4) Duration of emission if stopped at time of notification.

4. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:

   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific identification that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:

      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.
   q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925

Holders of a state pollutant discharge permit also have a duty to report any noncompliance that may endanger health or the environment within 24 hours. Report to the above telephone numbers and address.

Within 5 days, a written report will be submitted describing:

1. The noncompliance and its cause.
2. The period of the discharge, including dates and times.
3. If uncorrected, how long the discharge will continue.
4. Steps taken to reduce, eliminate, and prevent recurrence of the problem.

The following incidents must also be reported within 24 hours:

1. Any unanticipated bypass or system upset that exceeds permit limitations.
2. Violation of a maximum daily discharge limitation for which the state requires 24-hour reporting in the permit.

Report all other instances of noncompliance at the time the regular monitoring reports are submitted.

Citation: Louisiana Administrative Code, Title 33, Section 2701(L)(6)

Existing manufacturing, commercial, mining, and silvicultural dischargers shall immediately report any activity that has occurred or will occur that would result in the discharge on a routine or frequent basis of any toxic pollutant, not covered in a permit, that exceeds the highest of the following levels:

1. One hundred micrograms per liter (100 μg/l).
2. Two hundred micrograms per liter (200 μg/l) for acrolein and acrylonitrile; 500 micrograms per liter (500 μg/l) for 2,4-dinitrophenol and 2-methyl-4,6-dinitrophenol; and 1 milligram per liter (1 mg/l) for antimony.
3. Five times the maximum concentration value reported for that pollutant in the discharge permit application.
4. Any notification level established by state regulators on a case-by-case basis.

In addition, immediately report any activity that has occurred or will occur that would result in the discharge on a nonroutine or infrequent basis of any toxic pollutant, not covered in a permit, that exceeds the highest of the following levels:

1. Five hundred micrograms per liter (500 μg/l).
2. One milligram per liter (1 mg/l) for antimony.
3. Ten times the maximum concentration value reported for that pollutant in the discharge permit application.
4. Any notification level established by state regulators on a case-by-case basis.

Citation: Louisiana Administrative Code, Title 33, Section 2703(A)

Internet Resources

Agency	Internet Address
Department of Environmental Quality	www.deq.louisiana.gov
DEQ On-line Incident Reporting	www.deq.louisiana.gov/apps/forms/irf/forms/
Department of Public Safety	www.dps.louisiana.gov/dpsweb.nsf
Early Warning Organic Compound Detection System	www.deq.louisiana.gov/portal/tabid/285/default.aspx
Oil Spill Coordinator's Office	www.losco.state.la.us
Department of Natural Resources, Office of Conservation	http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=46&ngid=4

Revised 7/11/00 – ER

INCIDENT REPORT FORM

Received by: ______________ Dispatch # ______________ Incident # ______________

Date Reported: ______________ Time Reported: ______________

Spill Incident/Release ☐ Citizen Complaint ☐ Emergency? ☐ Yes ☐ No Drill? ☐ Yes ☐ No

CALLER INFORMATION: Citizen ☐ Industry ☐ Anonymous Complaint ☐

Other (i.e. Coast Guard): ______________

Name/Company: ______________ Title: ______________

Address: ______________

Is caller requesting a follow-up call? Yes ☐ No ☐ Date of Caller Contact: ______________

Telephone No. ______________ Parish (of occurrence): ______________

SITE INFORMATION:

Company Name/ Alleged Violator: ______________ Agency Interest # ______________ Other: ______________

Location Address: ______________

Date of discharge if different from date report: ______________ Time discharge noticed: Began ______________ Ended ______________

Media Affected: Air ☐ Land ☐ Surface Water ☐ Ground Water ☐ Other

If water affected, name of nearest water body (Basin/Subsegment): ______________

If air affected, note wind direction and weather conditions (if provided): ______________

DESCRIPTION OF RELEASE/SPILL/COMPLAINT:

Product/material release and quantity (reported): ______________

Product/material released and quantity (actual): ______________

Description of release/complaint: ______________

____

How was spill contained? Offsite Impact? ______________

How was spilled cleaned/remediated? ______________

DIRECTIONS FOR REACHING THE SITE: ______________

____

____

____

Investigator's Comments: ______________

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Region Assigned: ______________ Summary Report: Yes ☐ No ☐

Investigator Assigned: ______________ Date: ______________ Time: ______________

Investigator's Signature: ______________ Reviewer's Initials & Date: ______________

Date Closed: ______________ Closed by: Site Visit ☐ Telephone ☐ Other: ______________

Referred to: ______________ Date: ______________ Time: ______________

LOUISIANA

Excess Air Emissions

Notify the Department of Public Safety within 1 hour of any discharge that may result in **emergency conditions:** any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property.

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, provide notice within 24 hours to:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a Reportable Quantity and do not cause an emergency condition.
2. Report releases into the air that exceed Reportable Quantities (see **Hazardous Substances** at page Louisiana – 3) within any continuous 3-hour or 24-hour period, or below RQs for a greater-than-7-day period.
3. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized emission that exceeds the Reportable Quantities for an air contaminant (Louisiana Administrative Code, Title 33, Part 1, Section 3931), based on total mass emitted within a consecutive 3-hour period from the site or facility, except for leaks already covered under Louisiana requirements.
   b. Any other unauthorized emissions that exceed Reportable Quantities.
   c. Any unauthorized emission that causes an adverse off-site impact such as an odor, an impairment of visibility caused by smoke opacity, or visible deposition of emitted material, in violation of Air Quality Division Regulations.
   d. Emergency occurrences or upsets that will substantially increase emissions.
4. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.

h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:

   (1) Location of the source facility or stack.
   (2) Time at onset of the emission.
   (3) Prevailing local wind direction and estimated velocity at time of onset.
   (4) Duration of emission if stopped at time of notification.

5. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:

   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific indication that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:

      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.

q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925; Part III, Section 927

For sources subject to federal Part 70 emissions permits, refer to the permit for additional conditions regarding testing, monitoring, reporting, and recordkeeping. Sources subject to continuous emissions monitoring will also need to supply information on excess emissions and emergency conditions in their quarterly reports.

Citation: Louisiana Administrative Code, Title 33, Part III, Section 507

Hazardous Materials

Same as **Hazardous Substances** (see below). Report spills to:

Louisiana State Police
(225) 925-6595 (24-hour)
(877) 925-6595

Note: Louisiana has adopted the federal regulations for hazardous materials transportation (see **Federal — Hazardous Materials** at page Federal – 3), using the State Police as the contact point in-state. If reporting a hazardous materials incident, ask the State Police contact about requirements for submitting a written report and to provide you with a copy of any state reporting forms that may be necessary for your particular incident.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 10903

Hazardous Substances

Same as **Oil** (see page Louisiana – 7) when releases are to the air, land, or water environment and exceed Reportable Quantities within any continuous 24-hour period.

Note: Reportable Quantities of hazardous substances can be found in Louisiana Administrative Code, Title 33, Part I, Section 3931. Contact DEQ if you have questions about a substance or would like a complete listing.

Report releases onto land that exceed reportable quantities within any continuous 24-hour period to:

Local Emergency Planning Committee

Local 911 for Emergencies

Louisiana State Police
(225) 925-6595 (24-hour)

Note: Contents and time frames of verbal and written reports are the same as Notes 3 and 4, respectively, under **Oil** (see page Louisiana – 7). The Louisiana Department of Environmental Quality is also encouraging on-line reporting of incidents at: www.deq.louisiana.gov/apps/forms/irf/forms/. See **Louisiana Incident Report Form** (at page Louisiana – 16) for a listing of information collected by state officials. Submit the written report to:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC

Report releases into the air that exceed Reportable Quantities within any continuous 3-hour or 24-hour period, or below RQs for a greater-than-7-day period, to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance

(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Note: Contents of verbal and written reports are the same as Notes 4 and 5, respectively, under **Oil** (see page Louisiana – 8). For hazardous air pollutant releases include (see also reporting requirements under **Excess Air Emissions** at page Louisiana – 1):

1. Location and identity of the source facility or stack.
2. Date and time at onset of emission.
3. Prevailing local wind direction and estimated velocity at time of onset.
4. Duration of emission if stopped at time of report.
5. The approximate total loss during the emission.

Submit the written report to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
Attention: Administrator
P.O. Box 4312
Baton Rouge, LA 70821-4312

Also report releases that exceed Reportable Quantities within any continuous 24-hour period to:

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

Louisiana has issued a new rule establishing procedures for the reporting of information regarding hazardous materials that are in transit and/or temporarily stored at a facility and that could present a threat to human health and the environment if compromised during a Category 3 or higher hurricane. Within 12 hours of a mandatory evacuation order issued by the proper local parish authorities, persons engaged in the transport or temporary storage of hazardous materials shall report by e-mail to DPS (emergency@la.gov) the following:

1. The exact nature of, and the type, location, and relative fullness of the container (i.e., full, half-full, or empty) of all hazardous materials that are located within a parish subject to the evacuation order.
2. The primary and secondary contact persons' phone number, e-mail, and fax number.
3. Whether the facility will be sufficiently manned such that post-event assessments will be performed by company personnel (as soon as safely practicable) and that any releases and/or hazardous situations will be reported in accordance with DEQ and DPS reporting requirements.

Hazardous Wastes

If a release could threaten human health or the environment outside the facility, or when the generator has knowledge that a spill has reached surface water, the emergency coordinator must notify:

National Response Center
(800) 424-8802

Louisiana Department of Environmental Quality
Office of Environmental Assessment
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

The report, to be made immediately, should indicate:

1. Name of person making the notification and telephone number where any return calls from response agencies may be placed.

2. Name, address, and U.S. EPA identification number of the generator.
3. In the event of an incident involving transport, provide the name and address of the transporter and generator.
4. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
5. Date and time the incident began and ended, or estimated time the discharge may continue.
6. Type of incident involved (e.g., spill or fire).
7. Extent of any injuries and identification of any personnel hazards that response agencies may face.
8. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
9. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
10. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
    a. Location of the source facility or stack.
    b. Time at onset of the emission.
    c. Prevailing local wind direction and estimated velocity at time of onset.
    d. Duration of emission if stopped at time of notification.

A written report must be submitted to the Department within 15 days with the above information and describing estimated quantity and disposition of any recovered material. In addition, the owner/operator must note in the operating record for the facility the time, date, and details of any incident that requires implementation of the facility's spill contingency plan.

Note: while Louisiana has adopted general requirements similar to those specified in **Federal — Hazardous Wastes** (see page Federal – 7), state reporting mandates as identified above incorporate and supplement the general reporting standards.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 1109(E)(7)(d)(iv)(c) and 33:V.1513(F)

Under the general Louisiana Discharge Notification Rules, additional requirements are imposed:

Provide notice within 1 hour of any discharge that may result in **emergency conditions**. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property. Notify:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, notify the Department of Environmental Quality within 24 hours.

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a reportable quantity and do not cause an emergency condition.

2. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized discharge of hazardous waste or reusable material from a facility that exceeds any conditions specified in an interim or final RCRA (Resource Conservation and Recovery Act) permit.
   b. Any unauthorized discharge of hazardous waste or reusable material from a site or facility that exceeds any Reportable Quantity (Louisiana Administrative Code, Title 33, Part 1, Section 3931).
   c. Any unauthorized discharge of any hazardous waste or reusable material that may endanger human health or the environment including, but not limited to, events with chemical or biological toxicity, or that have flammable or explosive potential.
3. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.
      (4) Duration of emission if stopped at time of notification.
4. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:
   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific identification that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:
      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.

(3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
k. The reporting party's status (former or present owner, operator, disposer, etc.).
l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
m. What other agencies were notified.
n. Names of all other responsible parties of which the reporting party is aware.
o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
p. The extent of injuries, if any.
q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925

Oil

Report spills that create **emergency conditions** immediately, and spills creating **nonemergency conditions** within 24 hours to:

For Emergency Conditions:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For Nonemergency Conditions:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Louisiana Oil Spill Coordinator's Office
150 Third Street, Suite 405
Baton Rouge, LA 70801
(225) 219-5800 (8 to 5)

1. The Office of the State Police is the lead agency for emergency response in Louisiana. Louisiana Administrative Code Title 33, Part 1, Chapter 39, and Part V, Section 10111, establishes release reporting requirements for all releases of hazardous materials in the state. The requirements of both sections are summarized as follows:

   DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a reportable quantity and do not cause an emergency condition.

   A release of any of the following substances must be reported immediately if it causes **emergency conditions**, no matter what the quantity of discharged material is. An **emergency condition** is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property.

   Reporting can be done within 24 hours for unauthorized discharges that exceed Reportable Quantities, but create **nonemergency conditions**. Report nonemergency conditions to the appropriate division of the DEQ. However, releases that meet or exceed the Reportable Quantity and escape beyond the site of a facility must be reported immediately.

   a. Extremely hazardous substances.
   b. CERCLA hazardous substances.
   c. Hazardous substances established by the Department of Transportation. (Oil is contained in this listing: the RQ is 1 barrel.)
   d. Any material on which maintenance of a material safety data sheet is required by OSHA if it is not on lists a. through c. above and if the material exceeds RQs at 5,000 lbs. (Exceptions: Compressed or refrigerated flammable gases and flammable liquids as defined by 49 CFR will have RQs of 100 lbs., and all other liquids requiring an MSDS will have a 1,000 lb. RQ.)

2. Waters of the state include surface and underground.

3. An unauthorized discharge that results in contamination of the groundwaters of the state or otherwise moves in, into, within, or on any saturated subsurface strata must be reported in writing within 7 days. Follow the written report requirements below.

4. Verbal spill reports shall include:

   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:

      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.
      (4) Duration of emission if stopped at time of notification.

5. A written report must be submitted within 7 days to the Local Emergency Planning Committee, State Police, and DEQ (unless each of the agencies says otherwise). If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:

   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific indication that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:

      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.
   q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925; Part V, Section 10111

In addition, operators of pipeline systems must report a release of a hazardous liquid (petroleum, petroleum products, or anhydrous ammonia) or carbon dioxide resulting in any of the following:

1. Explosion or fire not intentionally set by the operator.
2. Release of 5 gallons or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels resulting from a pipeline maintenance activity if the release does not trigger other reporting requirements in this section, is confined to company property or the pipeline right-of-way, and is cleaned up promptly.
3. Escape to the atmosphere of more than 5 barrels a day of highly volatile liquids.
4. Death of any person.
5. Bodily harm to any person resulting in 1 or more of the following:
    a. Loss of consciousness.
    b. Necessity to carry the person from the scene.
    c. Necessity for medical treatment.
    d. Disability that prevents the discharge of normal duties or the pursuit or normal activities beyond the day of the accident.
6. Estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.
7. At the earliest practicable moment (within 2 hours) following discovery of a release of the hazardous liquid or carbon dioxide, the operator of the system shall give immediate notice to:

    Louisiana Department of Natural Resources
    Office of Conservation
    P.O. Box 94275
    Baton Rouge, LA 70804-9275
    (225) 342-5585 (8 to 4:30)
    (225) 342-5505 (After-hours)

8. Telephone notice must be provided for pipeline failures that:
    a. Caused a death or a personal injury requiring hospitalization.
    b. Resulted in either a fire or explosion not intentionally set by the operator.
    c. Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.
    d. Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines.
    e. In the judgment of the operator was significant even though it did not meet the above criteria.
9. The following information should be provided:
    a. Name and address of the operator.
    b. Name and telephone number of the reporter.
    c. The location of the failure.
    d. The time of the failure.
    e. The fatalities and personal injuries, if any.
    f. All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.
10. Each operator experiencing an accident that is required to be reported shall as soon as practicable but not later than 30 days after discovery of the accident prepare and file an accident report on Louisiana's Accident Report Form. Contact DNR at the number above for information about the current form.

Citation: Louisiana Administrative Code, Title 33, Part V, Section 30125

In the event that an unauthorized discharge into the Mississippi River or any other water of the state used for potable water supply could reasonably be expected to interfere with or significantly impact downstream potable or industrial water usage, the discharger shall notify immediately, but in no case later than 1 hour after learning of the discharge, by telephone or other rapid communication means:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

Report unauthorized discharges or spills that could reasonably be expected to interfere with or significantly impact downstream potable or industrial water usage to the Mississippi River or Bayou Lafourche to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
Surveillance Division
Early Warning Organic Compound Detection System
(225) 219-3600 (8 to 4:30)
(225) 219-3700 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

SARA Title III

Report releases and submit written follow-up emergency notice(s) to:

Louisiana Department of Public Safety
Office of State Police
Transportation and Environmental Safety Section
Right-to-Know Unit
Mail Slip 21
P.O. Box 66614
Baton Rouge, LA 70896-6614
(225) 925-6595 (24-hour)
(225) 925-6113 x227 (9 to 5)

Tank Leaks

Report any release or reasonable suspicion of a release of a regulated substance from an underground storage tank to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. Releases can be identified from:

   a. The discovery by owners and/or operators or others of released regulated substances at the tank site or in the surrounding area (such as the presence of free product or vapors in soils, basements, sewer and utility lines, and nearby surface water).

b. Unusual operating conditions at the tank system observed by owners and/or operators (such as the erratic behavior of product dispensing equipment, the sudden loss of a product from the tank system, or an unexplained presence of water in a tank), unless system equipment is found to be defective but not leaking, and is immediately repaired or replaced.
c. Monitoring results from a Statistical Inventory Reconciliation method, included in a tank system analysis report, are "fail" or "inconclusive".
d. Monitoring system results, unless:
    (1) The monitoring device is found to be defective, and is immediately repaired, recalibrated, or replaced, and additional monitoring conducted within 24 hours does not confirm the initial result.
    (2) Where monitoring is used to control inventory, the second month of data does not confirm the initial result.

2. If the tank holds petroleum, the owner or operator must report within 24 hours spills or overfills that exceed 42 gallons, or that cause a sheen on nearby surface waters. If the spill or overfill results in an emergency (see **Wastewater Excursions** at page Louisiana – 13), regardless of the amount, the Department must be notified immediately.
3. If the tank holds hazardous substances, the owner or operator must report within 1 hour any spills or overfills that equal or exceed the **Reportable Quantity** (see Reportable Quantities section) for that substance under the federal CERCLA law. Also report immediately to the National Response Center: (800) 424-8802.
4. A written report will be required within 7 calendar days. (See **Wastewater Excursions** at page Louisiana – 13.)
5. Owners and/or operators of tank systems must contain and immediately clean up a spill or overfill of petroleum that is less than 1 barrel and a spill or overfill of a hazardous substance that is less than the Reportable Quantity. If cleanup cannot be accomplished within 24 hours, report to DEQ.

Citation: Louisiana Administrative Code, Title 33, Part XI, Sections 707, 713

Report contamination of groundwater shown by routine monitoring to:

Louisiana Department of Environmental Quality
Office of Environmental Compliance
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC

The written report requirements are the same as Note 5, under **Oil** (see page Louisiana – 9), and will also include the following information:

1. The reporting party's status (former or present owner, operator, disposer, etc.).
2. All information of which the reporting party is aware that indicates hazardous waste is migrating, including, but not limited to, monitoring well data.
3. Possible routes of migration.
4. All information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
5. Names of all other responsible parties of which the reporting party is aware.

Wastewater Excursions

Provide notice within 1 hour of any discharge that may result in **emergency conditions**. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public, cause significant adverse impact to the land, water, or air environment, or cause severe damage to property. Notify:

Local 911

Louisiana Department of Public Safety
(225) 925-6595 (24-hour)

For **nonemergency conditions**, notify the Department of Environmental Quality within 24 hours:

Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312
Attn: ERSD - SPOC
(225) 219-3640 (8 to 4:30)
(225) 342-1234 (24-hour)
(888) 763-5424 (Within Louisiana)

1. DEQ is preparing new regulations to implement changes in state law addressing notice of emergency and nonemergency conditions. These changes include reporting to the DPS for unauthorized discharges that exceed a Reportable Quantity and do not cause an emergency condition.
2. Nonemergency conditions requiring prompt notification include:
   a. Any unauthorized discharge containing a pollutant or pollutants that exceed Reportable Quantities (Louisiana Administrative Code, Title 33, Part 1, Section 3931), and come from sources other than those with federal or state pollutant discharge permits.
   b. An unauthorized discharge containing a pollutant or pollutants that exceed Reportable Quantities, from a source that has a federal or state discharge permit. No reporting is required if such a discharge resulted from circumstances identified, reviewed, and made part of the public record for the discharge permit.
3. For the verbal notification, provide the following information:
   a. Name of person making the notification and telephone number where any return calls from response agencies may be placed.
   b. In the event of an incident involving transport, provide the name and address of the transporter and generator.
   c. Name and location of the facility or site where the unauthorized discharge is imminent or has occurred, using common landmarks.
   d. Date and time the incident began and ended, or estimated time the discharge may continue.
   e. Extent of any injuries and identification of any personnel hazards that response agencies may face.
   f. Common or scientific name, U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all discharged pollutants.
   g. Brief description of the incident sufficient to allow response agencies to decide on the level and extent of response activity.
   h. For unauthorized emissions of toxic air pollutants or radioactive material, the following supplemental information:
      (1) Location of the source facility or stack.
      (2) Time at onset of the emission.
      (3) Prevailing local wind direction and estimated velocity at time of onset.

(4) Duration of emission if stopped at time of notification.

4. A written report must be submitted within 7 days, unless the Department indicates otherwise in a permit or regulation. If sent by U.S. mail or other courier service (e.g., Federal Express, UPS, etc.), the submittal date will be the date of the postmark on the envelope accompanying the written notification report. If delivered by other means (hand or fax), the submittal date of the written notification will be the date of receipt by the Department. The written report should include the following:

   a. Name, address, telephone number, Agency Interest (AI) number (as assigned by the Department) if applicable, and any other applicable identification numbers of the person, company, or other party who is filing the written report.
   b. Specific identification that the document is a written follow-up report.
   c. Time and date of verbal notification, the state official contacted, name of person making the notification, and identification of the site or facility, vessel, transport vehicle, or storage area from which the unauthorized discharge occurred.
   d. Dates, times, and duration of the unauthorized discharge, and if not corrected, the anticipated time it is expected to continue.
   e. Details of the circumstances (unauthorized discharge description and root cause) and events leading to any unauthorized discharge, including incidents of loss of sources of radiation and if the release point is permitted:

      (1) The current permitted limit for the pollutant(s) released.
      (2) The permitted release point/outfall ID.
      (3) Which limits were exceeded (SO_2 limit, mass emission limit, opacity limit, etc.) for air releases.

   f. Common or scientific chemical name of each specific pollutant that was released as the result of an unauthorized discharge, including the CAS number and U.S. Department of Transportation hazard classification, and best estimate of amounts of any or all released pollutants (total amount of each compound expressed in pounds, including calculations).
   g. Statement of actual or probable fate or disposition of the pollutant and what off-site impact resulted.
   h. Remedial actions taken, or to be taken, to stop unauthorized discharges or to recover pollutants.
   i. Procedures or measures that have been or will be adopted to prevent a recurrence of the incident.
   j. If an unpermitted or unlicensed site or facility is involved in the unauthorized discharge, a schedule for submitting a permit or license application to the office, or the rationale for not requiring a permit or license.
   k. The reporting party's status (former or present owner, operator, disposer, etc.).
   l. For discharges to the ground or groundwater, the following information shall also be included: all information of which the reporting party is aware that indicates pollutants are migrating, including, but not limited to, monitoring well data; possible routes of migrations; and all information of which the reporting party is aware regarding any public or private wells in the area of the migration used for drinking, stock watering, or irrigation.
   m. What other agencies were notified.
   n. Names of all other responsible parties of which the reporting party is aware.
   o. A determination by the discharger of whether or not the discharge was preventable; if not, an explanation of why the discharge was not preventable.
   p. The extent of injuries, if any.
   q. The estimated quantity, identification, and disposition of recovered materials, if any.

Citation: Louisiana Administrative Code, Title 33, Part I, Sections 3915, 3917, 3923, 3925

Holders of a state pollutant discharge permit also have a duty to report any noncompliance that may endanger health or the environment within 24 hours. Report to the above telephone numbers and address.

Within 5 days, a written report will be submitted describing:

1. The noncompliance and its cause.
2. The period of the discharge, including dates and times.
3. If uncorrected, how long the discharge will continue.
4. Steps taken to reduce, eliminate, and prevent recurrence of the problem.

The following incidents must also be reported within 24 hours:

1. Any unanticipated bypass or system upset that exceeds permit limitations.
2. Violation of a maximum daily discharge limitation for which the state requires 24-hour reporting in the permit.

Report all other instances of noncompliance at the time the regular monitoring reports are submitted.

Citation: Louisiana Administrative Code, Title 33, Section 2701(L)(6)

Existing manufacturing, commercial, mining, and silvicultural dischargers shall immediately report any activity that has occurred or will occur that would result in the discharge on a routine or frequent basis of any toxic pollutant, not covered in a permit, that exceeds the highest of the following levels:

1. One hundred micrograms per liter (100 μg/l).
2. Two hundred micrograms per liter (200 μg/l) for acrolein and acrylonitrile; 500 micrograms per liter (500 μg/l) for 2,4-dinitrophenol and 2-methyl-4,6-dinitrophenol; and 1 milligram per liter (1 mg/l) for antimony.
3. Five times the maximum concentration value reported for that pollutant in the discharge permit application.
4. Any notification level established by state regulators on a case-by-case basis.

In addition, immediately report any activity that has occurred or will occur that would result in the discharge on a nonroutine or infrequent basis of any toxic pollutant, not covered in a permit, that exceeds the highest of the following levels:

1. Five hundred micrograms per liter (500 μg/l).
2. One milligram per liter (1 mg/l) for antimony.
3. Ten times the maximum concentration value reported for that pollutant in the discharge permit application.
4. Any notification level established by state regulators on a case-by-case basis.

Citation: Louisiana Administrative Code, Title 33, Section 2703(A)

Internet Resources

Agency	Internet Address
Department of Environmental Quality	www.deq.louisiana.gov
DEQ On-line Incident Reporting	www.deq.louisiana.gov/apps/forms/irf/forms/
Department of Public Safety	www.dps.louisiana.gov/dpsweb.nsf
Early Warning Organic Compound Detection System	www.deq.louisiana.gov/portal/tabid/285/default.aspx
Oil Spill Coordinator's Office	www.losco.state.la.us
Department of Natural Resources, Office of Conservation	http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=46&ngid=4

Revised 7/11/00 – ER

INCIDENT REPORT FORM

Received by: ______ Dispatch # ______ Incident # ______

Date Reported: ______ Time Reported: ______

Spill Incident/Release ☐ Citizen Complaint ☐ Emergency? ☐ Yes ☐ No Drill? ☐ Yes ☐ No

CALLER INFORMATION: Citizen ☐ Industry ☐ Anonymous Complaint ☐
Other (i.e. Coast Guard): ______

Name/Company: ______ Title: ______

Address: ______

Is caller requesting a follow-up call? Yes ☐ No ☐ Date of Caller Contact: ______

Telephone No. ______ Parish (of occurrence): ______

SITE INFORMATION:
Company Name/
Alleged Violator: ______ Agency Interest # ______
Other: ______

Location Address: ______

Date of discharge if different from date report: ______ Time discharge noticed: Began ______ Ended ______

Media Affected: Air ☐ Land ☐ Surface Water ☐ Ground Water ☐ Other

If water affected, name of nearest water body (Basin/Subsegment): ______

If air affected, note wind direction and weather conditions (if provided): ______

DESCRIPTION OF RELEASE/SPILL/COMPLAINT:
Product/material release and quantity (reported): ______

Product/material released and quantity (actual): ______

Description of release/complaint: ______

______

How was spill contained? Offsite Impact? ______

How was spilled cleaned/remediated?

DIRECTIONS FOR REACHING THE SITE: ______

______

______

______

Investigator's Comments: ______

______

______

______

______

______

______

______

______

______

______

______

Region Assigned: ______ Summary Report: Yes ☐ No ☐

Investigator Assigned: ______ Date: ______ Time: ______

Investigator's Signature: ______ Reviewer's Initials & Date: ______

Date Closed: ______ Closed by: Site Visit ☐ Telephone ☐ Other: ______

Referred to: ______ Date: ______ Time: ______

APPENDIX 2

Unanticipated Hazardous Waste Discovery Plan

Unanticipated Hazardous Waste Discovery Plan

1. INTRODUCTION

Cameron LNG has established the following procedures to be used in the event that previously unreported or unanticipated hazardous wastes or contaminated sites are discovered during construction of the Liquefaction Project.

2. UNANTICIPATED DISCOVERY OF HAZARDOUS WASTE OF CONTAMINATED SITES RESPONSE

a. Contractor will stop work in the vicinity of the suspected contamination.

b. Contractor will cordon off or otherwise restrict access to the suspected area.

c. Contractor will immediately notify Cameron LNG's on-site Environmental Inspector.

d. Cameron LNG's on-site Environmental Inspector will immediately notify the Environmental, Health and Safety Division Supervisor of Cameron LNG.

3. IMPLEMENTATION PLAN (as deemed necessary by the Environmental, Health and Safety Division)

a. Contact a qualified consultant and/or testing laboratory to assist with the determination of the extent and nature of the contamination.

b. Devise a plan for additional site-specific investigations as necessary.

c. Conduct the necessary level of site-specific testing and/or laboratory analysis to determine extent and nature of contamination.

d. Notify all applicable environmental authorities as required by law.

e. Devise a site-specific plan depending on the nature and extent of the contamination encountered for continuation of construction. This step may involve evaluation avoidance options, exposure minimization options, or cleanup options as necessary to support the construction of the proposed facilities.

f. Devise a strategy or plan for handling wastes in an appropriate manner including waste characterization, hauling, manifesting, disposal, and site stabilization/restoration.

g. Complete any necessary agency follow-ups and reporting.

APPENDIX 3

UNANTICIPATED DISCOVERY PLAN

PLAN AND PROCEDURES ADDRESSING UNANTICIPATED DISCOVERY OF CULTURAL RESOURCES AND HUMAN REMAINS

I. INTRODUCTION

This document outlines the procedures Cameron LNG will follow to prepare for and address any unanticipated discovery. It provides direction to Cameron LNG personnel and their consultants as to the proper procedure to follow in the event that unanticipated discovery of historic properties or human remains are made during construction. Communications, transmittals, reports, etc. may be provided via e-mail to the addresses provided in the contact lists in this document.

II. TRAINING AND ORIENTATION

The Environmental Inspector (EI) will be responsible for advising construction contractor personnel on the procedures to follow in the event that an unanticipated discovery is made. Training will occur as part of the pre-construction on-site training program for foremen, company inspectors, and construction supervisors. The EI will advise all operators of equipment involved in grading, stripping, or trenching activities to:

A. Stop work immediately if they observe any indication of the presence of cultural materials (artifacts or other man-made features), animal bone, or possibly human bone.

B. Contact the EI (or the Chief Inspector if the EI is not available) as soon as possible.

C. Comply with unanticipated discovery procedures.

D. Treat human remains with dignity and respect.

III. PROCEDURE WHEN CULTURAL MATERIALS ARE OBSERVED

Cultural materials include man-made objects (prehistoric, historic, and greater than 50 years of age) and features (e.g., walls constructed of natural materials such as cobbles; surfaces paved by cobbles, brick or other material; or other remnants of cultural activity).

A. Stop work in the immediate vicinity of the observed cultural materials

1. Notify the EI of the discovery.
2. If EI believes that an unanticipated discovery has been made:
    a) EI directs all ground-disturbing activities within 25 feet of the area of the discovery to stop.
    b) EI will protect and secure the evidence in place by delineating the find with flagging or orange safety fencing around the perimeter of the area within which construction activity will be prohibited.

B. Minimize movement of vehicles (limit the passage of equipment to only those essential to continue working at the construction site) and equipment in area immediately surrounding the discovery.

C. EI will immediately notify the Cameron LNG Construction Superintendent, as appropriate.

D. Cameron LNG Construction Superintendent will immediately notify the designated Cameron LNG and TRC Environmental Corporation (TRC) contacts by telephone with written confirmation (via fax or overnight mail). (If primary contact cannot be reached, notify the indicated alternate.)

Cameron LNG Contact
J.D. Morris, P.E.
Manager, Permitting and Compliance
Cameron LNG, LLC
2925 Briarpark Dr
Suite 900
Houston, TX 77042
(713) 298-5479
JMorris@sempraglobal.com

Alternate Cameron LNG Contact
Michael Taylor
Environmental Compliance Specialist
Sempra U.S. Gas & Power
787 Industrial Road
McIntosh, AL 36553
281-630-2187
Mitaylor@SempraUSGP.com

TRC Contact

Dr. Brian Thomas
TRC
4155 Shackleford Road
Suite 225
Norcross, Georgia 30093
Phone: (770) 270-1192 x112
Fax: (770) 270-1392
BThomas@TRCSolutions.com

Alternate TRC Contact

Dr. Larissa Thomas
TRC
4155 Shackleford Road
Suite 225
Norcross, Georgia 30093
Phone: (770) 270-1192 x118
Fax: (770) 270-1392
LThomas@TRCSolutions.com

E. Within 24 hours, if possible, a professional archeologist will examine the location of the discovery, accompanied by the EI.

1. If the archeologist determines that the discovery is not a cultural resource, the archeologist will immediately advise the EI, the Cameron LNG contact, the Chief Inspector and/or the Cameron LNG Construction Superintendent, any of whom will have the authority to remove the stop-work order. The archeologist will submit a letter report including photographs of the discovery site to the Cameron LNG and TRC contacts within 15 business days. No further action regarding this procedure is required.

2. If the archeologist determines that the discovery is a cultural resource, the archeologist will immediately advise the EI who will notify the Cameron LNG and TRC contacts. The Cameron LNG contact will notify the Federal Energy Regulatory Commission (FERC) and the Louisiana State Historic Preservation Officer (Louisiana SHPO) by telephone, with written confirmation by fax or overnight mail. If these conditions are met then proceed to the next step in the Plan, Item F below.

FERC Contact
Laurie Boros
FERC
888 First Street, NE
Washington, D.C. 20426
Phone: (202) 502-8046
Fax: (202) 208-0353
Laurie.Boros@ferc.gov

Alternate FERC Contact
Gertrude Fernandez Johnson
FERC
888 First Street, NE
Washington, D.C. 20426
Phone: (202) 502-6692
Fax: (202) 208-0353
Gertrude.Fernandez.Johnson@ferc.gov

Louisiana SHPO Contact
Dr. Charles "Chip" McGimsey
LA State Archaeologist and Director
Division of Archaeology
Dept. of Culture Recreation & Tourism
1051 N. Third Street, Rm. 405
P.O. Box 44247
Baton Rouge, Louisiana 70804
Phone: (225) 219-4598
Fax: (225) 342-4480
cmcgimsey@crt.la.gov

Alternate Louisiana SHPO Contact
Rachel Watson
Section 106 Review and Compliance
Division of Archaeology
Dept. of Culture Recreation & Tourism
1051 N. Third Street, Rm. 405
P.O. Box 44247
Baton Rouge, Louisiana 70804
Phone: (225) 342-8165
Fax: (225) 342-4480
rwatson@crt.la.gov

3. If the discovery is aboriginal, Cameron LNG will also notify appropriate Native American tribal groups (Jena Band of Choctaw Indians [Louisiana], the Caddo Nation, the Chitimacha Tribe of Louisiana, the Coushatta Tribe of Louisiana, Alabama Coushatta Tribe of Texas, and Tunica-Biloxi Indian Tribe of Louisiana). Notification will be by telephone, with written confirmation by fax and/or overnight mail. Notification will be the responsibility of the Cameron LNG contact.

Tribal Contacts
Alabama Coushatta Tribe of Texas
Mikko Oscola Clayton M. Sylestine
C/O Bryant Celestine, Historic Preservation Officer
571 State Park Rd. 56
Livingston, TX 77351
Phone: (936)563-1100
Celestine.bryant@actribe.org

Caddo Nation
Brenda Shemayme Edwards, Chairperson
P.O. Box 487
Binger, OK 73009
Phone: (580) 924-8280
bgedwards@caddonation.org

Chitimacha Tribe of Louisiana
John Paul Darden, Chairman
P.O. Box 661

Charenton, LA 70523
Phone: (337) 923-4973
Fax: (337) 923-6848
info@chitimacha.gov

Coushatta Tribe of Louisiana
Kevin Sickey, Chairman
P.O. Box 818
Elton, LA 70532
Phone: (337) 584-2902
jzachary@coushatta.org

Jena Band of Choctaw Indians
Christine Norris, Tribal Chief
P.O. Box 14
Jena, LA 71342
Phone: (318) 992-2717
info@jenachoctaw.org

Tunica-Biloxi Indians of Louisiana
Earl J. Barbry, Sr., Chairman
P.O. Box 1589
Marksville, LA 71351
Phone: (318) 253-9767
Fax: (318) 253-9791
ebarbary@tunica.org

F. Notifications to FERC about observations of cultural material will:

1. Describe a scope-of-work for evaluating the significance of the resource and evaluating potential project effects on the resource. A request for authorization to immediately implement the work scope will also be made to FERC and Louisiana SHPO.
2. Invite FERC, SHPO and identified tribal representatives, when appropriate, to observe the implementation of any proposed work.
3. All work to evaluate significance and project effects will be confined to the project's potential area of impact.

G. When the evaluation of the cultural resources is complete:

1. Cameron LNG will notify FERC and the Louisiana SHPO by telephone and discuss the project archeologist's opinion concerning the potential significance of the resource.
2. If the archaeologist believes the resource is not significant, the archaeologist will provide a rationale for the opinion, and request permission from FERC for construction to recommence.

3. As soon as possible following the field investigation, the archeologist will provide TRC and Cameron LNG with a written report describing the results of the fieldwork.
4. If the resource is believed to be significant, the archeologist will prepare a proposal for data recovery.

H. Cameron LNG may choose to prepare an analysis of alternatives to data recovery to determine what form of mitigation is preferable.

1. If an alternatives analysis is conducted, Cameron LNG will submit, by fax or overnight mail, the archeologist's report and the alternatives analysis to the Louisiana SHPO and FERC.
2. If proposed mitigation measures may be carried out without being impeded or affected by construction, the submittal to FERC will be accompanied by a request that construction in the area of the discovery be permitted to resume.

I. Upon receipt of authorization from FERC, implementation of mitigation measures will begin immediately.

1. Cameron LNG will advise FERC and the Louisiana SHPO when all mitigation measures have been completed.
2. If construction has been halted, Cameron LNG will also request authorization from FERC to recommence construction.
3. Cameron LNG will submit a summary report describing the results of mitigation to FERC and the Louisiana SHPO within 30 days of notification that mitigation fieldwork has been completed.
4. If archeological data recovery is a component of the mitigation plan, a full report will be submitted to FERC and the Louisiana SHPO in accordance with a schedule to be established in consultation with FERC.

IV. PROCEDURE WHEN HUMAN REMAINS AND/OR POTENTIALLY HUMAN SKELETAL MATERIALS ARE OBSERVED

Human remains are physical remains of a human body or bodies including, but not limited to, bones, teeth, hair, ashes, and preserved soft tissues (mummified or otherwise preserved) of an individual. Remains may be articulated or disarticulated bones or teeth.

A. Workers will treat all human remains with dignity and respect.

B. Immediately stop work in the vicinity of an unanticipated discovery involving potentially human remains.

C. Immediately notify the EI about the find.

D. If the EI believes that potentially human skeletal remains have been found, EI will stop all ground-disturbing activities within 100 feet of the potential discovery.

1. Protect and secure the evidence of the discovery.
2. Delineate the area with flagging or safety fencing.

3. Minimize movement by vehicles and equipment in the immediate vicinity of the discovery.
4. Limit movement of vehicles in the vicinity of the find to the construction right-of-way authorized by Cameron LNG's FERC certificate.

EI will immediately notify the Cameron LNG Construction Superintendent who will, in turn, immediately notify the designated TRC, FERC and Louisiana SHPO contacts:

Cameron LNG Contact
J.D. Morris, P.E.
Manager, Permitting and Compliance
Cameron LNG, LLC
2925 Briarpark Dr.
Suite 900
Houston, TX 77042
(713) 298-5479
JMorris@sempraglobal.com

Alternate Cameron LNG Contact
Michael Taylor
Environmental Compliance Specialist
Sempra U.S. Gas & Power
787 Industrial Road
McIntosh, AL 36553
281-630-2187
Mitaylor@SempraUSGP.com

TRC Contact

Dr. Brian Thomas
TRC
4155 Shackleford Road
Suite 225
Norcross, Georgia 30093
Phone: (770) 270-1192 x112
Fax: (770) 270-1392
BThomas@TRCSolutions.com

Alternate TRC Contact

Dr. Larissa Thomas
TRC
4155 Shackleford Road
Suite 225
Norcross, Georgia 30093
Phone: (770) 270-1192 x118
Fax: (770) 270-1392
LThomas@TRCSolutions.com

FERC Contact
Laurie Boros
FERC
888 First Street, NE
Washington, D.C. 20426
Phone: (202) 502-8046
Fax: (202) 208-0353
Laurie.Boros@ferc.gov

Alternate FERC Contact
Gertrude Fernandez Johnson
FERC
888 First Street, NE
Washington, D.C. 20426
Phone: (202) 502-6692
Fax: (202) 208-0353
Gertrude.Fernandez.Johnson@ferc.gov

Louisiana SHPO Contact
Dr. Charles "Chip" McGimsey
LA State Archaeologist and Director
Division of Archaeology
Dept. of Culture Recreation & Tourism
1051 N. Third Street, Rm. 405
P.O. Box 44247
Baton Rouge, Louisiana 70804
Phone: (225) 219-4598
Fax: (225) 342-4480
Cmcgimsey@crt.la.gov

Alternate Louisiana SHPO Contact
Rachel Watson
Section 106 Review and Compliance
Division of Archaeology
Dept. of Culture Recreation & Tourism
1051 N. Third Street, Rm. 405
P.O. Box 44247
Baton Rouge, Louisiana 70804
Phone: (225) 342-8165
Fax: (225) 342-4480
rwatson@crt.la.gov

E. Within 24-hours of the discovery, if possible, a professional archeologist will examine the discovery to determine if the remains are human and have an archeological association and, if so, if that association is aboriginal or non-aboriginal.

1. The services of a physical anthropologist or other qualified professional will be retained if the archeologist is unable to determine if the remains are human.

F. If skeletal remains are determined to be non-human and there is no archeological association, the archeologist making the determination will immediately advise the EI and/or the Cameron LNG Construction Superintendent, and construction may resume.

1. The archeologist will submit a letter report including photographs of the discovery site to the Cameron LNG and the TRC contacts within 15 business days of the determination.

G. If the skeletal remains are non-human but are associated with an archeological site, follow the steps described in Section III A through J.

H. If the skeletal remains are human and not associated with an archeological context, the Cameron LNG Construction Superintendent will notify Cameron LNG Contact, Louisiana SHPO, FERC, the landowner, and the appropriate sheriff's office.

In Louisiana, compliance with Title 8, Section 680 of the Louisiana Revised Statutes (Chapter 10-A, Unmarked Human Burial Sites Preservation Act) is required. If human skeletal remains are found, the respective Parish sheriff's office shall notify the Unmarked Burial Sites Board (UBSB) through the Louisiana SHPO. If burial context indicates less than 50 years since burial, then a criminal investigation may ensue. Otherwise, the UBSB may issue a permit to excavate the remains.

Cameron Parish, LA, Sheriff
Ron Johnson, Sheriff
119 Smith Circle
Cameron, LA 70631
Phone: (337) 775-5111
info@cameronso.org

Alternate Cameron Parish, LA, Sheriff

Calcasieu Parish, LA, Sheriff	*Alternate Calcasieu Parish, LA Sheriff*
Sheriff: Tony Mancuso 5400 East Broad Street Lake Charles, LA 70615 Phone: (337) 491-3715 Fax: (337) 494-4522 sheriffmancuso@cpso.com	

I. Human remains found in a prehistoric archeological context will be assumed to be aboriginal. If aboriginal human remains are identified (whether or not in an archeological context), Cameron LNG will immediately notify the TRC Contact. TRC will then notify Louisiana SHPO, as appropriate, and FERC archeologists.

FERC Archaeologist	*Alternate FERC Archaeologist*
Laurie Boros FERC 888 First Street, NE Washington, D.C. 20426 Phone: (202) 502-8046 Fax: (202) 208-0353 Laurie.Boros@ferc.gov	

J. If human remains are present in an aboriginal archeological context, Cameron LNG will follow the procedures described in Section III E through J, except as follows:

1. Notifications to FERC and Louisiana SHPO will make special note that human remains have been found.
2. Cameron LNG will notify appropriate Native American tribal groups, and request that identified Native American representatives advise Cameron LNG, FERC, and Louisiana SHPO of any special desires they have regarding the disposition of the human remains.
3. Proposals for site evaluation will give special consideration to the fact that human remains are present.
   a) No conduct of intrusive examination of the immediate area of the remains prior to receipt of a permit from the UBSB.
   b) Evaluate the potential for the presence of multiple graves and describe procedures for determining if other unidentified graves may be present.
   c) Describe efforts made to contact Native American tribes, the results of contacts, and efforts (as feasible) to accommodate the desires of the Native American tribes regarding the treatment of human remains.
   d) If the discovery was made after pipeline trenching in the vicinity of the discovery has been completed, construction will be permitted to recommence, except within 100 feet of any human remains.

e) Construction within the 100-foot area of the find will be permitted to proceed when the remains have been removed (or when it has been determined that the remains should be left in place).

4. If FERC or the Louisiana SHPO advises Cameron LNG that specific Native American tribal representatives wish to take custody of any human remains and rebury them on non-tribal lands, Cameron LNG will, if requested, assist in any negotiations between the tribe and the landowner that may be necessary.

5. Cameron LNG will make a good faith effort to accommodate any requests from identified Native American tribal groups that they be present during the implementation of mitigation measures related to Native American human remains. Subject to agreements with identified Native American tribal groups, Cameron LNG will offer to compensate a single tribal representative for time spent observing or participating in the removal of human remains. Compensation will include the individual's time (at an hourly rate equivalent to that paid the professional archeologist) and associated travel and living expenses.

K. If human remains are present in a non-aboriginal archeological context, the procedures described in Section IV E through J, will be followed except that:

1. Proposals for site evaluation will give special consideration to the fact that human remains are present (i.e., no intrusive examination of the immediate area of the remains; proposals will include an evaluation of the potential for the presence of multiple graves, and describe procedures for determining if other unidentified graves may be present).

2. If it is determined by FERC, in consultation with Louisiana SHPO, that the associated archeological site is not eligible for the National Register of Historic Places and that no mitigation measures are necessary, the respective sheriff's office will be requested to coordinate with the local coroner and either direct the archeologist to implement an approved plan for removal of the remains or arrange for alternative, appropriate removal of the human remains.

3. Unless directed to do otherwise by FERC, Cameron LNG will assume that it is authorized to resume construction when the remains have been removed.

4. Within 15 business days of the resumption of construction, Cameron LNG will provide FERC with a written report describing the removal activities.

5. Proposals for mitigation will include discussion of what steps will be taken to attempt to identify lineal descendants of the deceased.

6. If the discovery was made after trenching in the vicinity of the discovery has been completed, construction will be permitted to recommence, except within 100 feet of any human remains.

7. Construction within the remaining 100-foot area of the find will be permitted to proceed when the remains have been removed (or when it has been determined that the remains should be left in place).

APPENDIX 4

INVASIVE AQUATIC WEEDS AND ANIMALS PLAN

PLAN FOR ADDRESSING INVASIVE AQUATIC WEEDS AND ANIMALS

I. INTRODUCTION

This document outlines the procedures Cameron LNG will follow to prevent the transport and spread of invasive aquatic weeds or animals. The Louisiana Department of Wildlife and Fisheries has requested that Cameron LNG inspect water extracted from water bodies, as well as equipment before being brought to the site and before being moved from the site to prevent the transport and spread of invasive aquatic weeds or animals. The invasive aquatic weed and animal species include, but are not limited to, giant salvinia (*Salvinia molesta*), water hyacinth (*Eichhornia spp*), esthwaite waterweed (*Hydrilla verticallata*) and apple snails (Family Ampulariidae).

II. APPLICATION

This requirement is applicable to equipment that comes in contact with water bodies during construction and to equipment that has come into contact with water bodies prior to arriving to the project. An example of the type of equipment that may come in contact with water bodies is bull dozers, trackhoes, backhoes and other mechanical equipment as well as water pumps. The pipeline and materials themselves are not a concern, as they will be new materials, manufactured specifically for this project.

III. TRAINING AND ORIENTATION

The Environmental Inspector (EI) or other qualified individuals will be responsible for advising construction contractor personnel on the procedures to follow when working near water bodies. Training will occur as part of the pre-construction on-site training program for foremen, company inspectors, and construction supervisors. The training will include an overview of the identification of invasive aquatic weeds and animals and the procedures to follow when working near or within water bodies.

IV. PROCEDURE BEFORE EQUIPMENT ARRIVES ON SITE

A. Equipment shall be inspected by qualified individual for the presence of invasive aquatic weeds or animals before the equipment arrives on site.

1. **If invasive aquatic weeds and or animals are identified on the equipment then the species must be removed and properly disposed of prior to operation on the site. The equipment shall be clean, dry and free of water from unknown sources.**

V. PROCEDURE BEFORE EQUIPMENT LEAVES SITE

A. Equipment that has come into contact with a water body shall be inspected by qualified individual for the presence of invasive aquatic weeds or animals before equipment leaves the site.

1. **If invasive aquatic weeds and or animals are identified on the equipment then the species must be removed and properly disposed of prior to removal from the site. The equipment shall be clean, dry and free of water from unknown sources.**

APPENDIX 5

FERC UPLAND EROSION CONTROL, REVEGETATION, AND MAINTENANCE PLAN (PLAN)

Note: Cameron LNG has accepted The Commissions Plan without any requested deviations

Federal Energy Regulatory Commission

Office of Energy Projects

May 2013

UPLAND EROSION CONTROL, REVEGETATION, AND MAINTENANCE PLAN

Washington, DC 20426

MAY 2013 VERSION

UPLAND EROSION CONTROL, REVEGETATION, AND MAINTENANCE PLAN

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UPLAND EROSION CONTROL, REVEGETATION, AND MAINTENANCE PLAN (PLAN)

I. APPLICABILITY

A. The intent of this Plan is to assist project sponsors by identifying baseline mitigation measures for minimizing erosion and enhancing revegetation. Project sponsors shall specify in their applications for a new FERC authorization and in prior notice and advance notice filings, any individual measures in this Plan they consider unnecessary, technically infeasible, or unsuitable due to local conditions and fully describe any alternative measures they would use. Project sponsors shall also explain how those alternative measures would achieve a comparable level of mitigation.

Once a project is authorized, project sponsors can request further changes as variances to the measures in this Plan (or the applicant's approved plan). The Director of the Office of Energy Projects (Director) will consider approval of variances upon the project sponsor's written request, if the Director agrees that a variance:

1. provides equal or better environmental protection;

2. is necessary because a portion of this Plan 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.

Sponsors of projects planned for construction under the automatic authorization provisions in the FERC's regulations must receive written approval for any variances in advance of construction.

Project-related impacts on wetland and waterbody systems are addressed in the staff's Wetland and Waterbody Construction and Mitigation Procedures (Procedures).

II. SUPERVISION AND INSPECTION

A. ENVIRONMENTAL INSPECTION

1. At least one Environmental Inspector is required for each construction spread during construction and restoration (as defined by section V). The number and experience of Environmental Inspectors assigned to each construction spread shall be appropriate for the length of the construction spread and the number/significance of resources affected.

2. Environmental Inspectors shall have peer status with all other activity inspectors.

3. Environmental Inspectors shall have the authority to stop activities that violate the environmental conditions of the FERC's Orders, stipulations of other environmental permits or approvals, or landowner easement agreements; and to order appropriate corrective action.

B. RESPONSIBILITIES OF ENVIRONMENTAL INSPECTORS

At a minimum, the Environmental Inspector(s) shall be responsible for:

1. Inspecting construction activities for compliance with the requirements of this Plan, the Procedures, the environmental conditions of the FERC's Orders, the mitigation measures proposed by the project sponsor (as approved and/or modified by the Order), other environmental permits and approvals, and environmental requirements in landowner easement agreements.

2. Identifying, documenting, and overseeing corrective actions, as necessary to bring an activity back into compliance;

3. Verifying that the limits of authorized construction work areas and locations of access roads are visibly marked before clearing, and maintained throughout construction;

4. Verifying the location of signs and highly visible flagging marking the boundaries of sensitive resource areas, waterbodies, wetlands, or areas with special requirements along the construction work area;

5. Identifying erosion/sediment control and soil stabilization needs in all areas;

6. Ensuring that the design of slope breakers will not cause erosion or direct water into sensitive environmental resource areas, including cultural resource sites, wetlands, waterbodies, and sensitive species habitats;

7. Verifying that dewatering activities are properly monitored and do not result in the deposition of sand, silt, and/or sediment into sensitive environmental resource areas, including wetlands, waterbodies, cultural resource sites, and sensitive species habitats; stopping dewatering activities if such deposition is occurring and ensuring the design of the discharge is changed to prevent reoccurrence; and verifying that dewatering structures are removed after completion of dewatering activities;

8. Ensuring that subsoil and topsoil are tested in agricultural and residential areas to measure compaction and determine the need for corrective action;

9. Advising the Chief Construction Inspector when environmental conditions (such as wet weather or frozen soils) make it advisable to restrict or delay construction activities to avoid topsoil mixing or excessive compaction;

10. Ensuring restoration of contours and topsoil;

11. Verifying that the soils imported for agricultural or residential use are certified as free of noxious weeds and soil pests, unless otherwise approved by the landowner;

12. Ensuring that erosion control devices are properly installed to prevent sediment flow into sensitive environmental resource areas (e.g., wetlands, waterbodies, cultural resource sites, and sensitive species habitats) and onto roads, and determining the need for additional erosion control devices;

13. Inspecting and ensuring the maintenance of temporary erosion control measures at least:

    a. on a daily basis in areas of active construction or equipment operation;

    b. on a weekly basis in areas with no construction or equipment operation; and

    c. within 24 hours of each 0.5 inch of rainfall;

14. Ensuring the repair of all ineffective temporary erosion control measures within 24 hours of identification, or as soon as conditions allow if compliance with this time frame would result in greater environmental impacts;

15. Keeping records of compliance with the environmental conditions of the FERC’s Orders, and the mitigation measures proposed by the project sponsor in the application submitted to the FERC, and other federal or state environmental permits during active construction and restoration;

16. Identifying areas that should be given special attention to ensure stabilization and restoration after the construction phase; and

17. Verifying that locations for any disposal of excess construction materials for beneficial reuse comply with section III.E.

III. PRECONSTRUCTION PLANNING

The project sponsor shall do the following before construction:

A. CONSTRUCTION WORK AREAS

1. Identify all construction work areas (e.g., construction right-of-way, extra work space areas, pipe storage and contractor yards, borrow and disposal areas, access roads) that would be needed for safe construction. The project sponsor must ensure that appropriate cultural resources and biological surveys are conducted, as determined necessary by the appropriate federal and state agencies.

2. Project sponsors are encouraged to consider expanding any required cultural resources and endangered species surveys in anticipation of the need for activities outside of authorized work areas.

3. Plan construction sequencing to limit the amount and duration of open trench sections, as necessary, to prevent excessive erosion or sediment flow into sensitive environmental resource areas.

B. DRAIN TILE AND IRRIGATION SYSTEMS

1. Attempt to locate existing drain tiles and irrigation systems.

2. Contact landowners and local soil conservation authorities to determine the locations of future drain tiles that are likely to be installed within 3 years of the authorized construction.

3. Develop procedures for constructing through drain-tiled areas, maintaining irrigation systems during construction, and repairing drain tiles and irrigation systems after construction.

4. Engage qualified drain tile specialists, as needed to conduct or monitor repairs to drain tile systems affected by construction. Use drain tile specialists from the project area, if available.

C. GRAZING DEFERMENT

Develop grazing deferment plans with willing landowners, grazing permittees, and land management agencies to minimize grazing disturbance of revegetation efforts.

D. ROAD CROSSINGS AND ACCESS POINTS

Plan for safe and accessible conditions at all roadway crossings and access points during construction and restoration.

E. DISPOSAL PLANNING

Determine methods and locations for the regular collection, containment, and disposal of excess construction materials and debris (e.g., timber, slash, mats, garbage, drill cuttings and fluids, excess rock) throughout the construction process. Disposal of materials for beneficial reuse must not result in adverse environmental impact and is subject to compliance with all applicable survey, landowner or land management agency approval, and permit requirements.

F. AGENCY COORDINATION

The project sponsor must coordinate with the appropriate local, state, and federal agencies as outlined in this Plan and/or required by the FERC's Orders.

1. Obtain written recommendations from the local soil conservation authorities or land management agencies regarding permanent erosion control and revegetation specifications.

2. Develop specific procedures in coordination with the appropriate agencies to prevent the introduction or spread of invasive species, noxious weeds, and soil pests resulting from construction and restoration activities.

3. Develop specific procedures in coordination with the appropriate agencies and landowners, as necessary, to allow for livestock and wildlife movement and protection during construction.

4. Develop specific blasting procedures in coordination with the appropriate agencies that address pre- and post-blast inspections; advanced public notification; and mitigation measures for building foundations, groundwater wells, and springs. Use appropriate methods (e.g., blasting mats) to prevent damage to nearby structures and to prevent debris from entering sensitive environmental resource areas.

G. SPILL PREVENTION AND RESPONSE PROCEDURES

The project sponsor shall develop project-specific Spill Prevention and Response Procedures, as specified in section IV of the staff's Procedures. A copy must be filed with the Secretary of the FERC (Secretary) prior to construction and made available in the field on each construction spread. The filing requirement does not apply to projects constructed under the automatic authorization provisions in the FERC's regulations.

H. RESIDENTIAL CONSTRUCTION

For all properties with residences located within 50 feet of construction work areas, project sponsors shall: avoid removal of mature trees and landscaping within the construction work area unless necessary for safe operation of construction equipment, or as specified in landowner agreements; fence the edge of the construction work area for a distance of 100 feet on either side of the residence; and restore all lawn areas and landscaping immediately following clean up operations, or as specified in landowner agreements. If seasonal or other weather conditions prevent compliance with these time frames, maintain and monitor temporary erosion controls (sediment barriers and mulch) until conditions allow completion of restoration.

I. WINTER CONSTRUCTION PLANS

If construction is planned to occur during winter weather conditions, project sponsors shall develop and file a project-specific winter construction plan with the FERC application. This filing requirement does not apply to projects constructed under the automatic authorization provisions of the FERC's regulations.

The plan shall address:

1. winter construction procedures (e.g., snow handling and removal, access road construction and maintenance, soil handling under saturated or frozen conditions, topsoil stripping);

2. stabilization and monitoring procedures if ground conditions will delay restoration until the following spring (e.g., mulching and erosion controls, inspection and reporting, stormwater control during spring thaw conditions); and

3. final restoration procedures (e.g., subsidence and compaction repair, topsoil replacement, seeding).

IV. INSTALLATION

A. APPROVED AREAS OF DISTURBANCE

1. Project-related ground disturbance shall be limited to the construction right-of-way, extra work space areas, pipe storage yards, borrow and disposal areas, access roads, and other areas approved in the FERC's Orders. Any project-related ground disturbing activities outside these areas will require prior Director approval. This requirement does not apply to activities needed to comply with the Plan and Procedures (i.e., slope breakers, energy-dissipating devices, dewatering structures, drain tile system repairs) or minor field realignments and workspace shifts per landowner needs and requirements that do not affect other landowners or sensitive environmental resource areas. All construction or restoration activities outside of authorized areas are subject to all applicable survey and permit requirements, and landowner easement agreements.

2. The construction right-of-way width for a project shall not exceed 75 feet or that described in the FERC application unless otherwise modified by a FERC Order. However, in limited, non-wetland areas, this construction right-of-way width may be expanded by up to 25 feet without Director approval to accommodate full construction right-of-way topsoil segregation and to ensure safe construction where topographic conditions (e.g., side-slopes) or soil limitations require it. Twenty-five feet of extra construction right-of-way width may also be used in limited, non-wetland or non-forested areas for truck turn-arounds where no reasonable alternative access exists.

   Project use of these additional limited areas is subject to landowner or land management agency approval and compliance with all applicable survey and permit requirements. When additional areas are used, each one shall be identified and the need explained in the weekly or biweekly construction reports to the FERC, if required. The following material shall be included in the reports:

   a. the location of each additional area by station number and reference to previously filed alignment sheets, or updated alignment sheets showing the additional areas;

   b. identification of the filing at FERC containing evidence that the additional areas were previously surveyed; and

c. a statement that landowner approval has been obtained and is available in project files.

Prior written approval of the Director is required when the authorized construction right-of-way width would be expanded by more than 25 feet.

B. TOPSOIL SEGREGATION

1. Unless the landowner or land management agency specifically approves otherwise, prevent the mixing of topsoil with subsoil by stripping topsoil from either the full work area or from the trench and subsoil storage area (ditch plus spoil side method) in:

   a. cultivated or rotated croplands, and managed pastures;

   b. residential areas;

   c. hayfields; and

   d. other areas at the landowner's or land managing agency's request.

2. In residential areas, importation of topsoil is an acceptable alternative to topsoil segregation.

3. Where topsoil segregation is required, the project sponsor must:

   a. segregate at least 12 inches of topsoil in deep soils (more than 12 inches of topsoil); and

   b. make every effort to segregate the entire topsoil layer in soils with less than 12 inches of topsoil.

4. Maintain separation of salvaged topsoil and subsoil throughout all construction activities.

5. Segregated topsoil may not be used for padding the pipe, constructing temporary slope breakers or trench plugs, improving or maintaining roads, or as a fill material.

6. Stabilize topsoil piles and minimize loss due to wind and water erosion with use of sediment barriers, mulch, temporary seeding, tackifiers, or functional equivalents, where necessary.

C. DRAIN TILES

1. Mark locations of drain tiles damaged during construction.

2. Probe all drainage tile systems within the area of disturbance to check for damage.

3. Repair damaged drain tiles to their original or better condition. Do not use filter-covered drain tiles unless the local soil conservation authorities and the landowner agree. Use qualified specialists for testing and repairs.

4. For new pipelines in areas where drain tiles exist or are planned, ensure that the depth of cover over the pipeline is sufficient to avoid interference with drain tile systems. For adjacent pipeline loops in agricultural areas, install the new pipeline with at least the same depth of cover as the existing pipeline(s).

D. IRRIGATION

Maintain water flow in crop irrigation systems, unless shutoff is coordinated with affected parties.

E. ROAD CROSSINGS AND ACCESS POINTS

1. Maintain safe and accessible conditions at all road crossings and access points during construction.

2. If crushed stone access pads are used in residential or agricultural areas, place the stone on synthetic fabric to facilitate removal.

3. Minimize the use of tracked equipment on public roadways. Remove any soil or gravel spilled or tracked onto roadways daily or more frequent as necessary to maintain safe road conditions. Repair any damages to roadway surfaces, shoulders, and bar ditches.

F. TEMPORARY EROSION CONTROL

Install temporary erosion controls immediately after initial disturbance of the soil. Temporary erosion controls must be properly maintained throughout construction (on a daily basis) and reinstalled as necessary (such as after backfilling of the trench) until replaced by permanent erosion controls or restoration is complete.

1. Temporary Slope Breakers

   a. Temporary slope breakers are intended to reduce runoff velocity and divert water off the construction right-of-way. Temporary slope breakers may be constructed of materials such as soil, silt fence, staked hay or straw bales, or sand bags.

b. Install temporary slope breakers on all disturbed areas, as necessary to avoid excessive erosion. Temporary slope breakers must be installed on slopes greater than 5 percent where the base of the slope is less than 50 feet from waterbody, wetland, and road crossings at the following spacing (closer spacing shall be used if necessary):

Slope (%)	Spacing (feet)
5 - 15	300
>15 - 30	200
>30	100

c. Direct the outfall of each temporary slope breaker to a stable, well vegetated area or construct an energy-dissipating device at the end of the slope breaker and off the construction right-of-way.

d. Position the outfall of each temporary slope breaker to prevent sediment discharge into wetlands, waterbodies, or other sensitive environmental resource areas.

2. Temporary Trench Plugs

Temporary trench plugs are intended to segment a continuous open trench prior to backfill.

a. Temporary trench plugs may consist of unexcavated portions of the trench, compacted subsoil, sandbags, or some functional equivalent.

b. Position temporary trench plugs, as necessary, to reduce trenchline erosion and minimize the volume and velocity of trench water flow at the base of slopes.

3. Sediment Barriers

Sediment barriers are intended to stop the flow of sediments and to prevent the deposition of sediments beyond approved workspaces or into sensitive resources.

a. Sediment barriers may be constructed of materials such as silt fence, staked hay or straw bales, compacted earth (e.g., driveable berms across travelways), sand bags, or other appropriate materials.

b. At a minimum, install and maintain temporary sediment barriers across the entire construction right-of-way at the base of slopes greater than 5 percent where the base of the slope is less than 50 feet from a waterbody, wetland, or road crossing until revegetation is successful as defined in this Plan. Leave adequate room between the base of the slope and the sediment barrier to accommodate ponding of water and sediment deposition.

c. Where wetlands or waterbodies are adjacent to and downslope of construction work areas, install sediment barriers along the edge of these areas, as necessary to prevent sediment flow into the wetland or waterbody.

4. Mulch

a. Apply mulch on all slopes (except in cultivated cropland) concurrent with or immediately after seeding, where necessary to stabilize the soil surface and to reduce wind and water erosion. Spread mulch uniformly over the area to cover at least 75 percent of the ground surface at a rate of 2 tons/acre of straw or its equivalent, unless the local soil conservation authority, landowner, or land managing agency approves otherwise in writing.

b. Mulch can consist of weed-free straw or hay, wood fiber hydromulch, erosion control fabric, or some functional equivalent.

c. Mulch all disturbed upland areas (except cultivated cropland) <u>before</u> seeding if:

(1) final grading and installation of permanent erosion control measures will not be completed in an area within 20 days after the trench in that area is backfilled (10 days in residential areas), as required in section V.A.1; or

(2) construction or restoration activity is interrupted for extended periods, such as when seeding cannot be completed due to seeding period restrictions.

d. If mulching <u>before</u> seeding, increase mulch application on all slopes within 100 feet of waterbodies and wetlands to a rate of 3 tons/acre of straw or equivalent.

e. If wood chips are used as mulch, do not use more than 1 ton/acre and add the equivalent of 11 lbs/acre available nitrogen (at least 50 percent of which is slow release).

f. Ensure that mulch is adequately anchored to minimize loss due to wind and water.

g. When anchoring with liquid mulch binders, use rates recommended by the manufacturer. Do not use liquid mulch binders within 100 feet of wetlands or waterbodies, except where the product is certified environmentally non-toxic by the appropriate state or federal agency or independent standards-setting organization.

h. Do not use synthetic monofilament mesh/netted erosion control materials in areas designated as sensitive wildlife habitat, unless the product is specifically designed to minimize harm to wildlife. Anchor erosion control fabric with staples or other appropriate devices.

V. RESTORATION

A. CLEANUP

1. Commence cleanup operations immediately following backfill operations. Complete final grading, topsoil replacement, and installation of permanent erosion control structures within 20 days after backfilling the trench (10 days in residential areas). If seasonal or other weather conditions prevent compliance with these time frames, maintain temporary erosion controls (i.e., temporary slope breakers, sediment barriers, and mulch) until conditions allow completion of cleanup.

   If construction or restoration unexpectedly continues into the winter season when conditions could delay successful decompaction, topsoil replacement, or seeding until the following spring, file with the Secretary for the review and written approval of the Director, a winter construction plan (as specified in section III.I). This filing requirement does not apply to projects constructed under the automatic authorization provisions of the FERC's regulations.

2. A travel lane may be left open temporarily to allow access by construction traffic if the temporary erosion control structures are installed as specified in section IV.F. and inspected and maintained as specified in sections II.B.12 through 14. When access is no longer required the travel lane must be removed and the right-of-way restored.

3. Rock excavated from the trench may be used to backfill the trench only to the top of the existing bedrock profile. Rock that is not returned to the trench shall be considered construction debris, unless approved for use as mulch or for some other use on the construction work areas by the landowner or land managing agency.

4. Remove excess rock from at least the top 12 inches of soil in all cultivated or rotated cropland, managed pastures, hayfields, and residential areas, as well as other areas at the landowner's request. The size, density, and distribution of rock on the construction work area shall be similar to adjacent areas not disturbed by construction. The landowner or land management agency may approve other provisions in writing.

5. Grade the construction right-of-way to restore pre-construction contours and leave the soil in the proper condition for planting.

6. Remove construction debris from all construction work areas unless the landowner or land managing agency approves leaving materials onsite for beneficial reuse, stabilization, or habitat restoration.

7. Remove temporary sediment barriers when replaced by permanent erosion control measures or when revegetation is successful.

B. PERMANENT EROSION CONTROL DEVICES

1. Trench Breakers

   a. Trench breakers are intended to slow the flow of subsurface water along the trench. Trench breakers may be constructed of materials such as sand bags or polyurethane foam. Do not use topsoil in trench breakers.

   b. An engineer or similarly qualified professional shall determine the need for and spacing of trench breakers. Otherwise, trench breakers shall be installed at the same spacing as and upslope of permanent slope breakers.

   c. In agricultural fields and residential areas where slope breakers are not typically required, install trench breakers at the same spacing as if permanent slope breakers were required.

   d. At a minimum, install a trench breaker at the base of slopes greater than 5 percent where the base of the slope is less than 50 feet from a waterbody or wetland and where needed to avoid draining a waterbody or wetland. Install trench breakers at wetland boundaries, as specified in the Procedures. Do not install trench breakers within a wetland.

2. Permanent Slope Breakers

a. Permanent slope breakers are intended to reduce runoff velocity, divert water off the construction right-of-way, and prevent sediment deposition into sensitive resources. Permanent slope breakers may be constructed of materials such as soil, stone, or some functional equivalent.

b. Construct and maintain permanent slope breakers in all areas, except cultivated areas and lawns, unless requested by the landowner, using spacing recommendations obtained from the local soil conservation authority or land managing agency.

In the absence of written recommendations, use the following spacing unless closer spacing is necessary to avoid excessive erosion on the construction right-of-way:

Slope (%)	Spacing (feet)
5 - 15	300
>15 - 30	200
>30	100

c. Construct slope breakers to divert surface flow to a stable area without causing water to pool or erode behind the breaker. In the absence of a stable area, construct appropriate energy-dissipating devices at the end of the breaker.

d. Slope breakers may extend slightly (about 4 feet) beyond the edge of the construction right-of-way to effectively drain water off the disturbed area. Where slope breakers extend beyond the edge of the construction right-of-way, they are subject to compliance with all applicable survey requirements.

C. SOIL COMPACTION MITIGATION

1. Test topsoil and subsoil for compaction at regular intervals in agricultural and residential areas disturbed by construction activities. Conduct tests on the same soil type under similar moisture conditions in undisturbed areas to approximate preconstruction conditions. Use penetrometers or other appropriate devices to conduct tests.

2. Plow severely compacted agricultural areas with a paraplow or other deep tillage implement. In areas where topsoil has been segregated, plow the subsoil before replacing the segregated topsoil.

If subsequent construction and cleanup activities result in further compaction, conduct additional tilling.

3. Perform appropriate soil compaction mitigation in severely compacted residential areas.

D. REVEGETATION

1. General

   a. The project sponsor is responsible for ensuring successful revegetation of soils disturbed by project-related activities, except as noted in section V.D.1.b.

   b. Restore all turf, ornamental shrubs, and specialized landscaping in accordance with the landowner's request, or compensate the landowner. Restoration work must be performed by personnel familiar with local horticultural and turf establishment practices.

2. Soil Additives

   Fertilize and add soil pH modifiers in accordance with written recommendations obtained from the local soil conservation authority, land management agencies, or landowner. Incorporate recommended soil pH modifier and fertilizer into the top 2 inches of soil as soon as practicable after application.

3. Seeding Requirements

   a. Prepare a seedbed in disturbed areas to a depth of 3 to 4 inches using appropriate equipment to provide a firm seedbed. When hydroseeding, scarify the seedbed to facilitate lodging and germination of seed.

   b. Seed disturbed areas in accordance with written recommendations for seed mixes, rates, and dates obtained from the local soil conservation authority or the request of the landowner or land management agency. Seeding is not required in cultivated croplands unless requested by the landowner.

   c. Perform seeding of permanent vegetation within the recommended seeding dates. If seeding cannot be done within those dates, use appropriate temporary erosion control measures discussed in section IV.F and perform seeding of permanent vegetation at the beginning of the next recommended seeding season. Dormant seeding or temporary seeding of annual species may also be used, if necessary, to establish cover, as approved by the Environmental Inspector. Lawns may be seeded on a schedule established with the landowner.

d. In the absence of written recommendations from the local soil conservation authorities, seed all disturbed soils within 6 working days of final grading, weather and soil conditions permitting, subject to the specifications in section V.D.3.a through V.D.3.c.

e. Base seeding rates on Pure Live Seed. Use seed within 12 months of seed testing.

f. Treat legume seed with an inoculant specific to the species using the manufacturer's recommended rate of inoculant appropriate for the seeding method (broadcast, drill, or hydro).

g. In the absence of written recommendations from the local soil conservation authorities, landowner, or land managing agency to the contrary, a seed drill equipped with a cultipacker is preferred for seed application.

Broadcast or hydroseeding can be used in lieu of drilling at double the recommended seeding rates. Where seed is broadcast, firm the seedbed with a cultipacker or roller after seeding. In rocky soils or where site conditions may limit the effectiveness of this equipment, other alternatives may be appropriate (e.g., use of a chain drag) to lightly cover seed after application, as approved by the Environmental Inspector.

VI. OFF-ROAD VEHICLE CONTROL

To each owner or manager of forested lands, offer to install and maintain measures to control unauthorized vehicle access to the right-of-way. These measures may include:

A. signs;

B. fences with locking gates;

C. slash and timber barriers, pipe barriers, or a line of boulders across the right-of-way; and

D. conifers or other appropriate trees or shrubs across the right-of-way.

VII. POST-CONSTRUCTION ACTIVITIES AND REPORTING

A. MONITORING AND MAINTENANCE

1. Conduct follow-up inspections of all disturbed areas, as necessary, to determine the success of revegetation and address landowner concerns. At a minimum, conduct inspections after the first and second growing seasons.

2. Revegetation in non-agricultural areas shall be considered successful if upon visual survey the density and cover of non-nuisance vegetation are similar in density and cover to adjacent undisturbed lands. In agricultural areas, revegetation shall be considered successful when upon visual survey, crop growth and vigor are similar to adjacent undisturbed portions of the same field, unless the easement agreement specifies otherwise.

   Continue revegetation efforts until revegetation is successful.

3. Monitor and correct problems with drainage and irrigation systems resulting from pipeline construction in agricultural areas until restoration is successful.

4. Restoration shall be considered successful if the right-of-way surface condition is similar to adjacent undisturbed lands, construction debris is removed (unless otherwise approved by the landowner or land managing agency per section V.A.6), revegetation is successful, and proper drainage has been restored.

5. Routine vegetation mowing or clearing over the full width of the permanent right-of-way in uplands shall not be done more frequently than every 3 years. However, to facilitate periodic corrosion/leak surveys, a corridor not exceeding 10 feet in width centered on the pipeline may be cleared at a frequency necessary to maintain the 10-foot corridor in an herbaceous state. In no case shall routine vegetation mowing or clearing occur during the migratory bird nesting season between April 15 and August 1 of any year unless specifically approved in writing by the responsible land management agency or the U.S. Fish and Wildlife Service.

6. Efforts to control unauthorized off-road vehicle use, in cooperation with the landowner, shall continue throughout the life of the project. Maintain signs, gates, and permanent access roads as necessary.

B. REPORTING

1. The project sponsor shall maintain records that identify by milepost:

   a. method of application, application rate, and type of fertilizer, pH modifying agent, seed, and mulch used;

   b. acreage treated;

   c. dates of backfilling and seeding;

   d. names of landowners requesting special seeding treatment and a description of the follow-up actions;

   e. the location of any subsurface drainage repairs or improvements made during restoration; and

   f. any problem areas and how they were addressed.

2. The project sponsor shall file with the Secretary quarterly activity reports documenting the results of follow-up inspections required by section VII.A.1; any problem areas, including those identified by the landowner; and corrective actions taken for at least 2 years following construction.

   The requirement to file quarterly activity reports with the Secretary does not apply to projects constructed under the automatic authorization, prior notice, or advanced notice provisions in the FERC's regulations.

APPENDIX 6

FERC WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES (PROCEDURES)

Note: Cameron LNG has accepted The Commissions Procedures without any requested deviations

Federal Energy Regulatory Commission

Office of
Energy Projects

May 2013

WETLAND AND WATERBODY CONSTRUCTION AND MITIGATION PROCEDURES

Washington, DC 20426

MAY 2013 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 project sponsors by identifying baseline mitigation measures for minimizing the extent and duration of project-related disturbance on wetlands and waterbodies. Project sponsors shall specify in their applications for a new FERC authorization, and in prior notice and advance notice filings, any individual measures in these Procedures they consider unnecessary, technically infeasible, or unsuitable due to local conditions and fully describe any alternative measures they would use. Project sponsors shall also explain how those alternative measures would achieve a comparable level of mitigation.

Once a project is authorized, project sponsors can request further changes as variances to the measures in these Procedures (or the applicant's approved procedures). The Director of the Office of Energy Projects (Director) will consider approval of variances upon the project sponsor's written request, if the Director agrees that a variance:

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.

Sponsors of projects planned for construction under the automatic authorization provisions in the FERC's regulations must receive written approval for any variances in advance of construction.

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 must be filed with the Secretary of the FERC (Secretary) prior to the beginning of construction, for the review and written approval by the Director:

1. site-specific justifications for extra work areas that would be closer than 50 feet from a waterbody or wetland; and

2. site-specific justifications for the use of a construction right-of-way greater than 75-feet-wide in wetlands.

B. The following information must be filed with the Secretary prior to the beginning of construction. These filing requirements do not apply to projects constructed under the automatic authorization provisions in the FERC’s regulations:

1. Spill Prevention and Response Procedures specified in section IV.A;

2. a schedule identifying when trenching or blasting will occur within each waterbody greater than 10 feet wide, within any designated coldwater fishery, and within any waterbody identified as habitat for federally-listed threatened or endangered species. The project sponsor will 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;

3. plans for horizontal directional drills (HDD) under wetlands or waterbodies, specified in section V.B.6.d;

4. site-specific plans for major waterbody crossings, described in section V.B.9;

5. a wetland delineation report as described in section VI.A.1, if applicable; and

6. the hydrostatic testing information specified in section VII.B.3.

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 shall 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. The project sponsor shall develop project-specific Spill Prevention and Response Procedures that meet applicable requirements of state and federal agencies. A copy must be filed with the Secretary prior to construction and made available in the field on each construction spread. This filing requirement does not apply to projects constructed under the automatic authorization provisions in the FERC's regulations.

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 determines that there is 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;

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. These activities can occur closer only if the Environmental Inspector determines that there is 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;

g. pumps operating within 100 feet of a waterbody or wetland boundary utilize appropriate secondary containment systems to prevent spills; and

h. bulk storage of hazardous materials, including chemicals, fuels, and lubricating oils have appropriate secondary containment systems to prevent spills.

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 and unanticipated discoveries of contamination;

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 FERC's Orders.

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 federal and state authorities at least 48 hours before beginning trenching or blasting within the waterbody, or as specified in applicable permits.

B. INSTALLATION

1. Time Window for Construction

Unless expressly permitted or further restricted by the appropriate federal or 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 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, site-specific justification for each extra work area with a less than 50-foot setback from the water's edge, except where the adjacent upland consists of cultivated or rotated cropland or other disturbed land. The justification must specify the conditions that will not permit a 50-foot setback and measures to ensure the waterbody is adequately protected.

c. 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. Where pipelines parallel a waterbody, maintain at least 15 feet of undisturbed vegetation between the waterbody (and any adjacent wetland) and the construction right-of-way, except where maintaining this offset will result in greater environmental impact.

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

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

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

g. Crossing of waterbodies when they are dry or frozen and not flowing may proceed using standard upland construction techniques in accordance with the Plan, provided that the Environmental Inspector verifies that water is unlikely to flow between initial disturbance and final stabilization of the feature. In the event of perceptible flow, the project sponsor must comply with all applicable Procedure requirements for "waterbodies" as defined in section I.B.1.

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 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 and maintain equipment bridges to allow 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 temporary equipment bridges as soon as practicable after permanent seeding.

   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 temporary equipment bridges as soon as practicable after final cleanup.

g. Obtain any necessary approval from the COE, or the appropriate state agency for permanent bridges.

6. Dry-Ditch Crossing Methods

a. Unless approved otherwise by the appropriate federal or 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, or federally-designated as critical habitat.

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 to minimize entrainment of fish;
(iv) prevent streambed scour at pump discharge; and
(v) continuously 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 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

For each waterbody or wetland that would be crossed using the HDD method, file with the Secretary for the review and written approval by the Director, 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) justification that disturbed areas are limited to the minimum needed to construct the crossing;

(3) identification of any aboveground disturbance or clearing between the HDD entry and exit workspaces during construction;

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

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

The requirement to file HDD plans does not apply to projects constructed under the automatic authorization provisions in the FERC's regulations.

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 or protected status (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 must be developed in consultation with the appropriate state and federal agencies and shall include extra work areas, spoil storage areas, sediment control structures, etc., as well as mitigation for navigational issues. The requirement to file major waterbody crossing plans does not apply to projects constructed under the automatic authorization provisions of the FERC's regulations.

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.3.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. Removable sediment barriers (or driveable berms) must be installed across the travel lane. These 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 and the right-of-way slopes toward the waterbody, install sediment barriers along the edge of the construction right-of-way as necessary to contain spoil within the construction right-of-way and prevent sediment flow into the waterbody; and

c. use temporary 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 silt-laden water flowing into any waterbody. Remove the dewatering structures as soon as practicable 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. Install erosion control fabric or a functional equivalent on waterbody banks at the time of final bank recontouring. Do not use synthetic monofilament

mesh/netted erosion control materials in areas designated as sensitive wildlife habitat unless the product is specifically designed to minimize harm to wildlife. Anchor erosion control fabric with staples or other appropriate devices.

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

6. 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.

7. Revegetate disturbed riparian areas with native species of conservation grasses, legumes, and woody species, similar in density to adjacent undisturbed lands.

8. 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.

9. Sections V.C.3 through V.C.7 above also apply to those perennial or intermittent streams not flowing at the time of construction.

D. POST-CONSTRUCTION MAINTENANCE

1. Limit routine vegetation mowing or clearing 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 corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be cleared at a frequency necessary to maintain the 10-foot corridor in an herbaceous state. In addition, trees that are located within 15 feet of the pipeline that have roots that could compromise the integrity of the pipeline coating may be cut and removed from the permanent right-of-way. Do not conduct any routine vegetation mowing or clearing in riparian areas that are between HDD entry and exit points.

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.

3. Time of year restrictions specified in section VII.A.5 of the Plan (April 15 – August 1 of any year) apply to routine mowing and clearing of riparian areas.

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. The requirement to file a wetland delineation report does not apply to projects constructed under the automatic authorization provisions in the FERC's regulations.

   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 excessively wide trenches could occur and/or where spoil piles could be difficult to maintain because existing soils lack adequate unconfined compressive strength.

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 and 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 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, site-specific justification for each extra work area with a less than 50-foot setback from wetland boundaries, except where adjacent upland consists of cultivated or rotated cropland or other disturbed land. The justification must specify the site-specific conditions that will not permit a 50-foot setback and measures to ensure the wetland is adequately protected.

    c. 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.

d. 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 modifications or improvements, other than routine repair, 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. Do not trench the wetland until the pipeline is assembled and ready for lowering in.

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 above ground level, leaving existing root systems in place, and remove it from the wetland for disposal.

The project sponsor can burn woody debris in wetlands, if approved by the COE and in accordance with state and local regulations, ensuring that all remaining woody debris is removed 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. 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. 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.3.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 immediately upslope of the wetland boundary at all wetland crossings where necessary to prevent sediment flow into the wetland.

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 contain spoil within the construction right-of-way and 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 silt-laden water flowing into any wetland. Remove the dewatering structures as soon as practicable after the completion of dewatering activities.

C. RESTORATION

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

2. Restore pre-construction wetland contours to maintain the original wetland hydrology.

3. 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 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.

4. Do not use fertilizer, lime, or mulch unless required in writing by the appropriate federal or state agency.

5. Consult with the appropriate federal or state agencies to develop a project-specific wetland restoration plan. The restoration plan shall include measures for re-establishing herbaceous and/or woody species, controlling the invasion and spread of invasive species and noxious weeds (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.

6. 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).

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

8. Remove temporary sediment barriers located at the boundary between wetland and adjacent upland areas after revegetation and stabilization of adjacent upland areas are judged to be successful as specified in section VII.A.4 of the Plan.

D. POST-CONSTRUCTION MAINTENANCE AND REPORTING

1. Do not conduct routine vegetation mowing or clearing over the full width of the permanent right-of-way in wetlands. However, to facilitate periodic corrosion/leak surveys, a corridor centered on the pipeline and up to 10 feet wide may be cleared at a frequency necessary to maintain the 10-foot corridor in an herbaceous state. In addition, trees within 15 feet of the pipeline with roots that could compromise the integrity of pipeline coating may be selectively cut and removed from the permanent right-of-way. Do not conduct any routine vegetation mowing or clearing in wetlands that are between HDD entry and exit points.

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

3. Time of year restrictions specified in section VII.A.5 of the Plan (April 15 – August 1 of any year) apply to routine mowing and clearing of wetland areas.

4. Monitor and record the success of wetland revegetation annually until wetland revegetation is successful.

5. Wetland revegetation shall be considered successful if all of the following criteria are satisfied:

   a. the affected wetland satisfies the current federal definition for a wetland (i.e., soils, hydrology, and vegetation);

   b. vegetation is at least 80 percent of either the cover documented for the wetland prior to construction, or at least 80 percent of the cover in adjacent wetland areas that were not disturbed by construction;

   c. if natural rather than active revegetation was used, the plant species composition is consistent with early successional wetland plant communities in the affected ecoregion; and

   d. invasive species and noxious weeds are absent, unless they are abundant in adjacent areas that were not disturbed by construction.

6. Within 3 years after construction, file a report with the Secretary identifying the status of the wetland revegetation efforts and documenting success as defined in section VI.D.5, above. The requirement to file wetland restoration reports with the Secretary does not apply to projects constructed under the automatic authorization, prior notice, or advance notice provisions in the FERC's regulations.

   For any wetland where revegetation is not successful at the end of 3 years after construction, develop and implement (in consultation with a professional wetland ecologist) a remedial revegetation plan to actively revegetate wetlands. Continue revegetation efforts and file a report annually documenting progress in these wetlands 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 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 wetland, address secondary containment 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. This filing requirement does not apply to projects constructed under the automatic authorization provisions of the FERC's regulations.

C. INTAKE SOURCE AND RATE

1. Screen the intake hose to minimize the potential for 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.

Exhibit Z-2

ICF Report

Economic Impacts of Cameron Liquefaction Trains 4-5 Expansion: Information for DOE Non-FTA Permit Application

May 12, 2015

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1 Executive Summary

1.1 Introduction

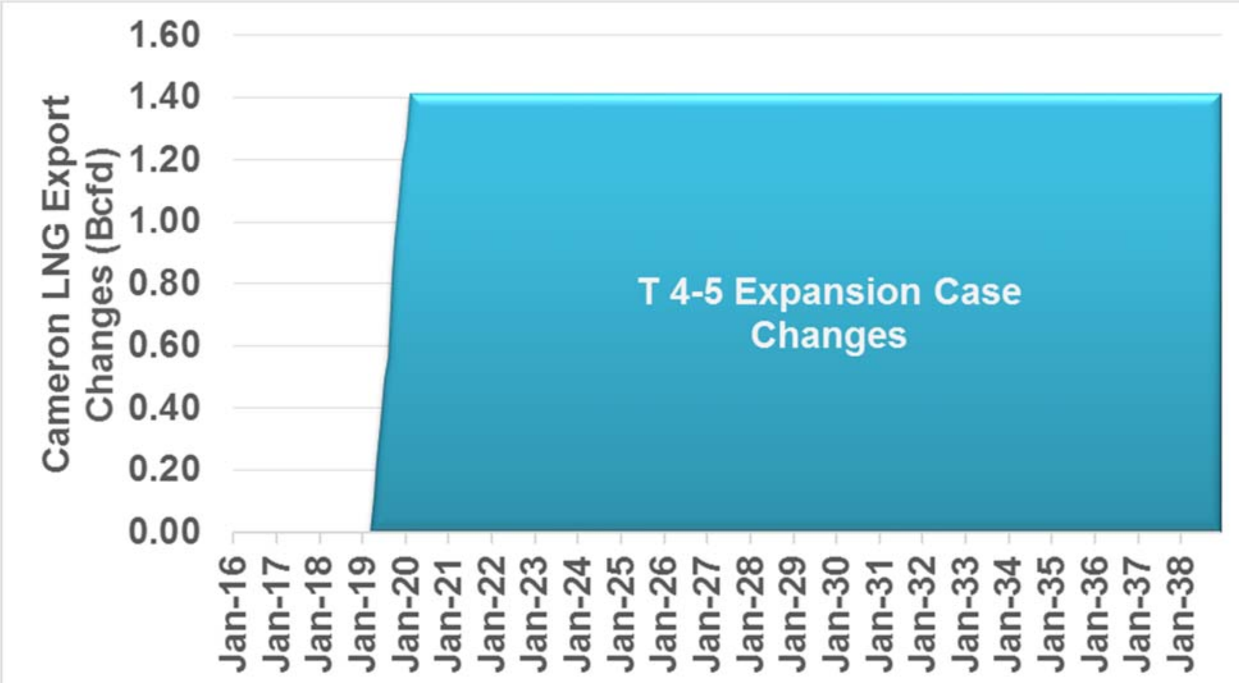
ICF conducted economic impact analysis on behalf of Cameron LNG to assess impacts of LNG export scenarios. Specifically for this report, ICF assessed two Cameron LNG export cases[1]:

1) **Base Case** assumption of currently approved Trains 1-3 volumes of 620 billion cubic feet (Bcf) per year, or 1.70 billion cubic feet per day (Bcfd). Base Case also includes an additional 0.42 Bcfd (or 152 Bcf per year) of exports pending DOE approval at the time of this analysis.
2) **Trains 4-5 Expansion Case** assumption of an additional 515 Bcf per year, or 1.41 Bcfd higher than the Base Case due to the new construction of Trains 4 and 5. This gives a total volume of 1.29 trillion cubic feet (Tcf) per year, or 3.53 Bcfd, including Base Case volumes.

Both cases above include Trains 1-3 supplemental volumes of 152 Bcf per year (or 0.42 Bcfd), as the incremental Trains 1-3 volumes were under review by the U.S. Department of Energy (DOE) during the analysis. The results in this report show the changes between the Base Case and alternative case resulting from the incremental LNG export volumes. The exhibit below shows the assumed incremental LNG export volumes from Cameron LNG.

[1] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Exhibit 1-1: Trains 4-5 Cameron LNG Export Changes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

ICF was tasked with assessing the economic and employment impacts of Cameron LNG Trains 4-5 Expansion Case. In order to assess these impacts, ICF used an input-output economic model. The methodology consisted of the following steps:

- **Assess natural gas and liquids production and investment changes:** We first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs), including ethane, propane, butane, and pentanes plus) production changes using the ICF Gas Market Model (GMM) based on the additional natural gas needed for LNG exports. The GMM also solved for changes to natural gas prices and demand levels. The added production volumes were assessed both on a national- and Louisiana-level. ICF then translated the natural gas and liquids production changes from the GMM into annual capital and operating expenditures that will be required for that additional production.

- **Quantify LNG plant and upstream capital and operating expenditures:** Based on Cameron LNG's cost estimates, ICF assessed the annual capital and operating expenditures that will be required to support the LNG exports.

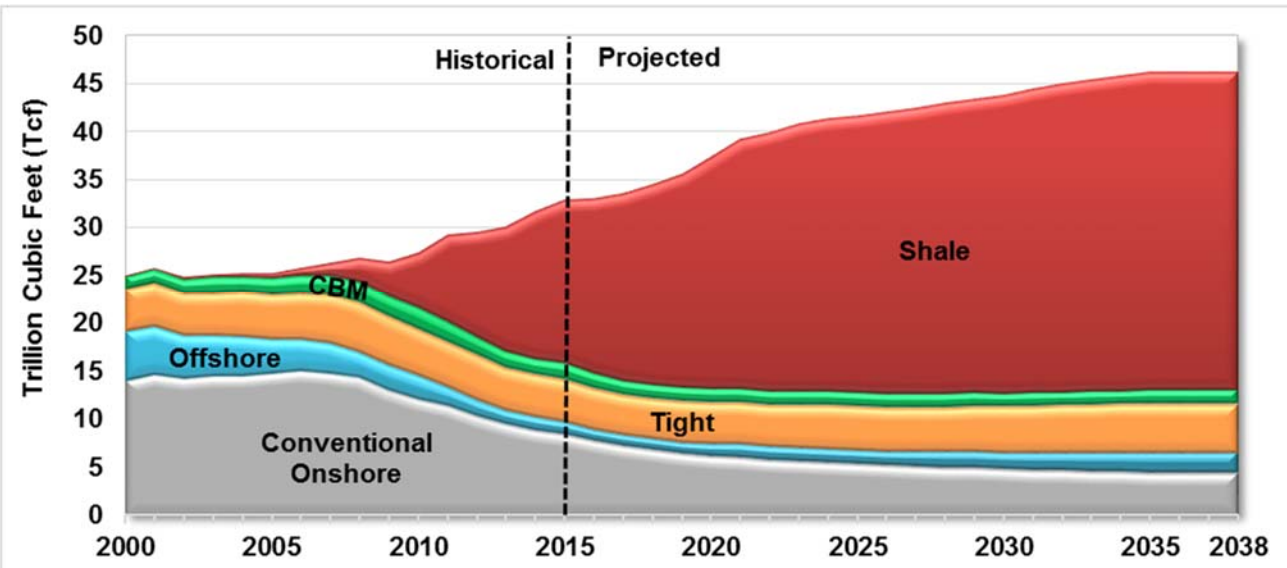
- **Create IMPLAN input-output matrices:** ICF entered both LNG plant and upstream expenditures to the IMPLAN input-output model to assess the economic impacts for the U.S. and Louisiana of a given level of expenditures. For instance, the model found that $100 million in annual expenditures on drilling and completing new gas wells would support a certain number of direct employees (e.g., natural gas production employees), indirect employees (e.g., drilling equipment manufacturers), and induced employees (e.g., consumer industry employees).

- **Quantify economic and employment impacts:** ICF assessed the impact of LNG exports for the national and Louisiana levels for the forecasted level of expenditures. This included direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes and balance of trade.

1.2 Key U.S. and Canadian Natural Gas Market Trends

U.S. and Canadian natural gas production has grown considerably over the past several years, led by unconventional production, and is expected to grow further over the next 20 years or more (see Exhibit 1-2). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, including gas-directed drilling activity in the Marcellus and Utica shales, which will account for over half of the incremental production. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

Exhibit 1-2: U.S. and Canadian Gas Supplies



Source: ICF

In terms of demand-side dynamics, the power sector is the largest single source of incremental domestic gas consumption, though near-term gas market growth is driven by growth in export markets (LNG and Mexican exports). Significant power sector gas demand growth is expected to continue, particularly after 2015, as natural gas capacity replaces coal capacity, with accelerated growth after 2020 when federal carbon regulation is expected to be initiated. After 2030, nuclear power plant retirements start a new round of growth in natural gas consumption.

Increased demand growth will push gas prices above $5 per MMBtu[2] after 2020, with long-term prices are expected to range between $6 and $7 per MMBtu. Prices are high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand growth.

U.S. and Canadian LNG exports are projected to reach 11.9 Bcfd by 2025, with LNG exports from the U.S. Gulf Coast expected to reach 9.6 Bcfd, based on ICF's review of approved projects. These volumes do not include the additional Cameron Trains 4-5 exports associated with this economic impact analysis.

Continued lower oil prices are expected to moderate growth of associated gas production from oil plays. While associated gas production has increased due to growth in domestic oil production, it still accounts for only 18 percent of total gas production.

1.3 Key Study Results

For each case, ICF examined the economic and employment impacts between 2016 and 2038 on both a national level and Louisiana state level. Impacts included natural gas and liquids[3] production, LNG plant and upstream capital and operating expenditures, natural gas consumption, natural gas and liquids prices, production value, LNG plant and upstream employment, government revenues, value added, and the U.S. balance of trade.

1.3.1 Trains 4-5 Results

The Cameron LNG Trains 4-5 development will mean an additional 1.41 Bcfd in LNG exports. These incremental LNG export volumes could lead to significant economic impacts, including over 35,000 annual jobs for the U.S. economy, close to 2,800 in Louisiana, or a cumulative impact through 2038 of over 800,000 U.S. and 64,000 Louisiana job-years between 2016 and 2038. In addition, the project could add $12.7 billion to the U.S. economy annually ($292 billion over the forecast period), and $847.4 million annually in Louisiana ($19.5 billion cumulative). The additional Cameron LNG exports could also lead to additional tax revenues. Federal, state, and local governments could receive an additional $4.4 billion annually on the U.S. level, and $131.4 million at the state-level in Louisiana, leading to cumulative government revenues of $101.2 billion throughout the U.S. and $3.0 billion within Louisiana between 2016 and 2038.

Exhibit 1-3: The T 4-5 Expansion Case Economic and Employment Impacts

Region	2016-2038 Average Annual Impact			2016-2038 Cumulative Impact		
	Jobs (Jobs)	Value Added (2015$ Million)	Government Revenues (2015$ Million)	Jobs (Job-years)	Value Added (2015$ Million)	Government Revenues (2015$ Million)
U.S.	35,489	$ 12,694.3	$ 4,401.5	816,244	$ 291,969.2	$ 101,233.7
Louisiana	2,773	$ 847.4	$ 131.4	63,790	$ 19,491.0	$ 3,021.1

Source: ICF

[2] All dollar figure results in this report are in 2015 real dollars, unless otherwise specified.

[3] Includes oil, condensate, and natural gas liquids (NGLs), such as ethane, propane, butane, and pentanes plus.

2 Introduction

Cameron LNG tasked ICF International with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Hackberry, LA LNG export facility. This study assessed two cases[4]:

1) **Base Case** assumption of currently approved Trains 1-3 volumes of 620 billion cubic feet (Bcf) per year, or 1.70 billion cubic feet per day (Bcfd). Base Case also includes an additional 0.42 Bcfd (or 152 Bcf per year) of exports pending DOE approval at the time of this analysis.
2) **Trains 4-5 Expansion Case** assumption of an additional 515 Bcf per year, or 1.41 Bcfd higher than the Base Case due to the construction of additional Trains 4 and 5. This gives a total volume of 1.29 trillion cubic feet (Tcf) per year, or 3.53 Bcfd, including Base Case volumes.

Both cases include Trains 1-3 supplemental volumes of 152 Bcf per year (or 0.42 Bcfd), as the incremental Trains 1-3 volumes were under review by the U.S. Department of Energy (DOE) during the analysis. The results in this report show the changes in economic metrics between the Base Case and alternative case resulting from the incremental LNG export volumes. ICF assessed the U.S. and state-level Louisiana changes between 2016 and 2038, including:

- Natural gas production.
- Liquids production, including oil, condensate, and natural gas liquids (NGLs), including ethane, propane, butane, and pentanes plus.
- LNG plant capital expenditures.
- LNG plant operating expenditures.
- Upstream capital expenditures to support the natural gas and liquids production.
- Upstream operating expenditures.
- Natural gas consumption.
- Henry Hub natural gas prices.
- Natural gas and liquids production value.
- Employment.
- Federal, state, and local government revenues.
- Value added.
- U.S. Balance of Trade.

This study is organized as follows:

1) Executive Summary
2) Introduction
3) Base Case U.S. and Canadian Natural Gas Market Overview
4) Study Methodology

[4] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

5) Trains 4-5 Expansion Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

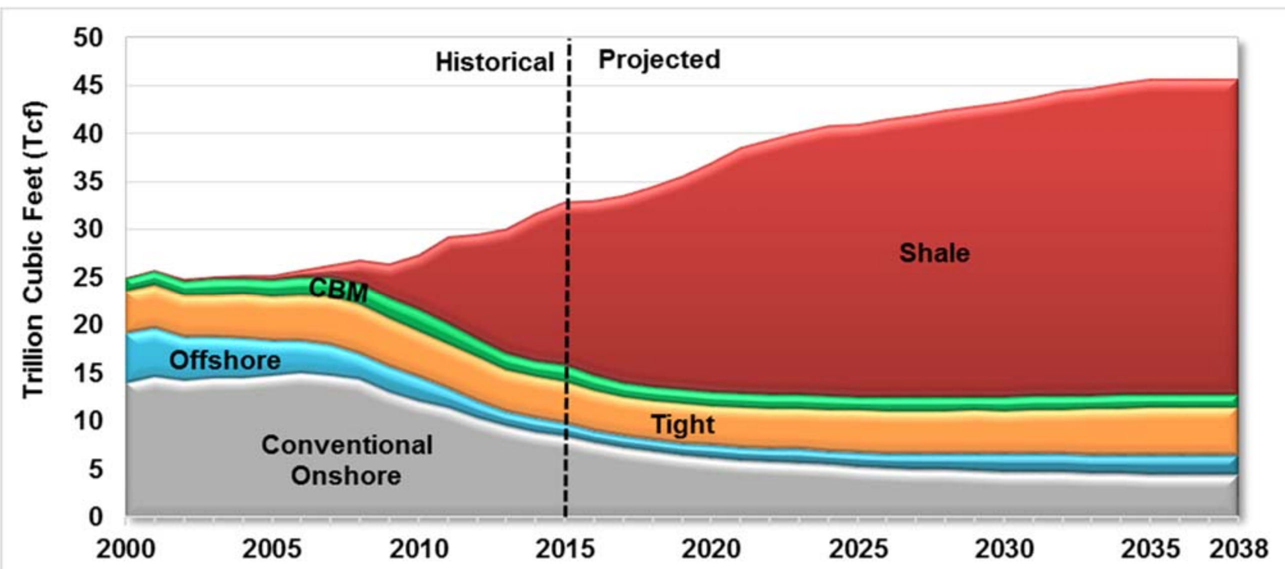
3 Base Case U.S. and Canadian Natural Gas Market Overview

This section discusses U.S. and Canadian Base Case natural gas market forecasts, starting with natural gas supply trends, including ICF's resource base assessment and comparisons with other assessments. The section then discusses trends in U.S. and Canadian demand through 2038, including pipeline and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

3.1 U.S. and Canadian Natural Gas Supply Trends

Over the past five years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production, and is expected to grow further through 2038 and beyond (see Exhibit 3-1). Unconventional production technologies (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional production expected to offset declining conventional production. These production changes will call for significant infrastructure investments to create pathways between new supply sources and demand markets.

Exhibit 3-1: U.S. and Canadian Gas Supplies

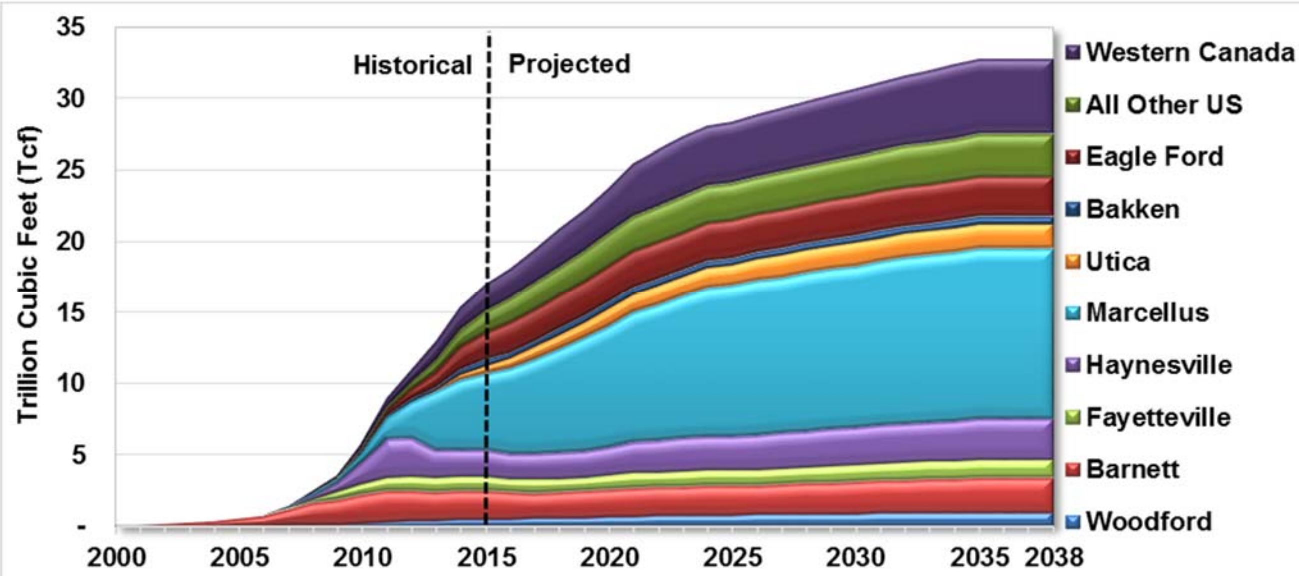


Source: ICF

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (15.9 Bcfd) in 2010 to 32.7 Tcf (89.6 Bcfd) by 2038 (see exhibit above). The major shale formations in the U.S. and Canada are located in the U.S. Northeast (Marcellus and Utica), the Mid-continent (Barnett, Woodford, Fayetteville, and Haynesville), South Texas (Eagle Ford), and western Canada (Montney and Horn River). The Bakken Shale, which in the U.S. spans parts of North Dakota and Montana, is primarily an oil formation, but also has significant natural gas volumes.

There are other shale formations in the U.S. that have not yet been evaluated or developed for gas production.

Exhibit 3-2: U.S. and Canadian Shale Gas Production



Note: Haynesville production includes production from other shales in the vicinity (e.g., the Bossier Shale).

Source: ICF

3.1.1 Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane, (CBM)) will generally be much lower cost on a per-unit basis than conventional sources.[5] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base in total. While the emerging stage of shale gas production, as well as the site-specific nature of unconventional production costs, mean uncertain production costs, shale plays such as the Marcellus are proving to be among the least expensive (on a per-unit basis) natural gas sources.

ICF has developed supply cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the curve are all of the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The unconventional GIS plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas is almost all development drilling. Offshore undiscovered

[5] Unconventional refers to production that requires some form of stimulation within the well to produce gas economically. Conventional wells do not require stimulation.

conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and transportation. Then, those cost factors are added to allow costing at points farther downstream of the wellhead. Costs can be adjusted to a "Henry Hub" basis for certain type of analysis that consider the remoteness of the resource.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies, and have been subsequently refined and expanded. North American plays include all of the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration (EIA) is a source for operating and equipment costs.[6,7,8] Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon commercial well databases, producer surveys, investor slides, and other sources.

In developing the aggregate North American supply curve, the play supply curves were adjusted to a Henry Hub, Louisiana basis by adding or subtracting an estimated differential to Henry Hub. This has the effect of adding costs to more remote plays and subtracting costs from plays closer to demand markets than Henry Hub.

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 120-acre-per-well development, and one for a 60-acre-per-well. This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down-spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

The initial resource assessment is based on current practices and costs and therefore does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study anticipates there will be more resources available in the future than indicated by a static supply curve based on current technology.

Aggregate Cost of Supply Curves

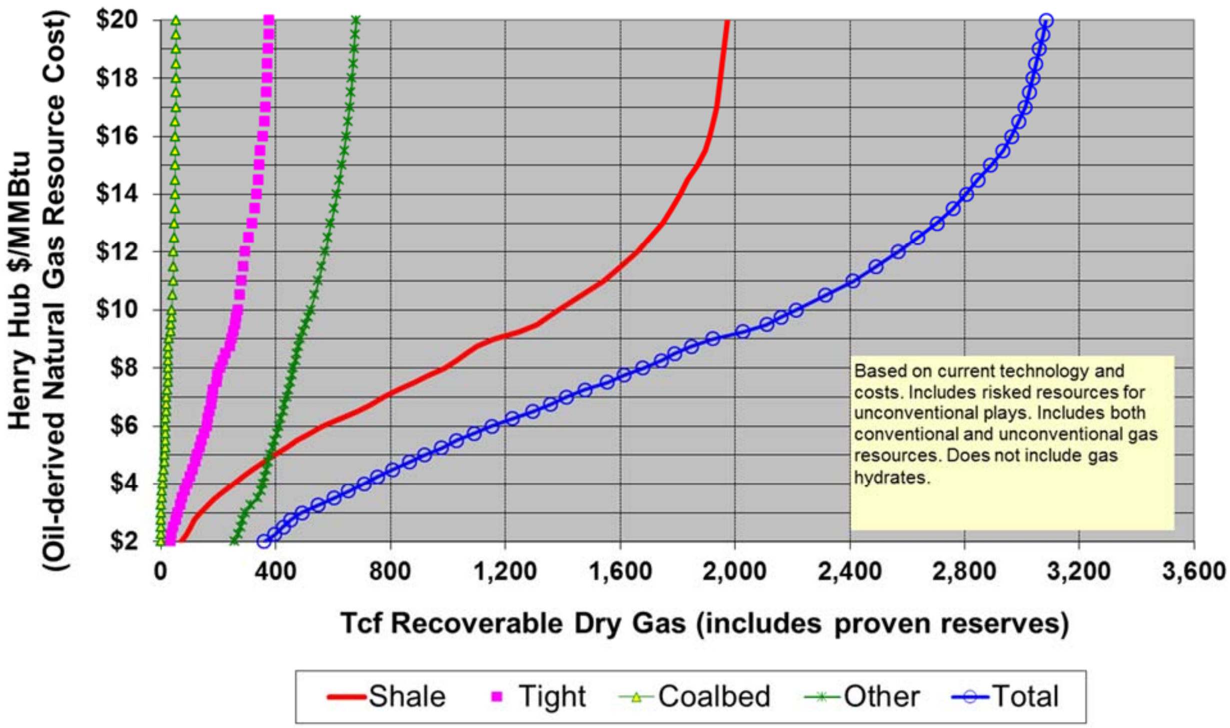
North American supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in Exhibit 3-3. The supply curves were developed on an "oil-derived" basis. That is to say that the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

[6] American Petroleum Institute. "2012 Joint Association Survey of Drilling Costs". API, various years: Washington, DC.
[7] Petroleum Services Association of Canada (PSAC). "2009 Well Cost Study". PSAC, 2009. Available at: http://www.psac.ca/
[8] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

For the Lower-48, 2,200 Tcf of gas resource is available at $10.00 per MMBtu or less. For Canada there is 500 Tcf at $10.00 per MMBtu or less. At $5.00 per MMBtu, 900 Tcf is available in the Lower-48 and approximately 150 Tcf is available in Canada.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future.

Exhibit 3-3: U.S. Lower-48 Gas Supply Curves



Source: ICF

3.1.2 ICF Resource Base Estimates

ICF has assessed conventional and unconventional North American oil and gas resources and resource economics. ICF's analysis is bolstered by the extensive work we have done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system (GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays. Resource assessments are derived either from credible public sources or are generated in-house using ICF's GIS-based models.

The following resource categories have been evaluated:

> ***Proven reserves*** – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

Reserve appreciation – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[9]

Enhanced oil recovery (EOR) **–** defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane – defined as the remaining recoverable volumes of gas from the development of coal seams.

[9] U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

Exhibit 3-4 and Exhibit 3-5 summarize the current ICF gas and crude oil assessments for the U.S. and Canada. Resources shown are “technically recoverable resources.” This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The assessment basis is year-end 2013 (as this is the latest date for published proved reserves).

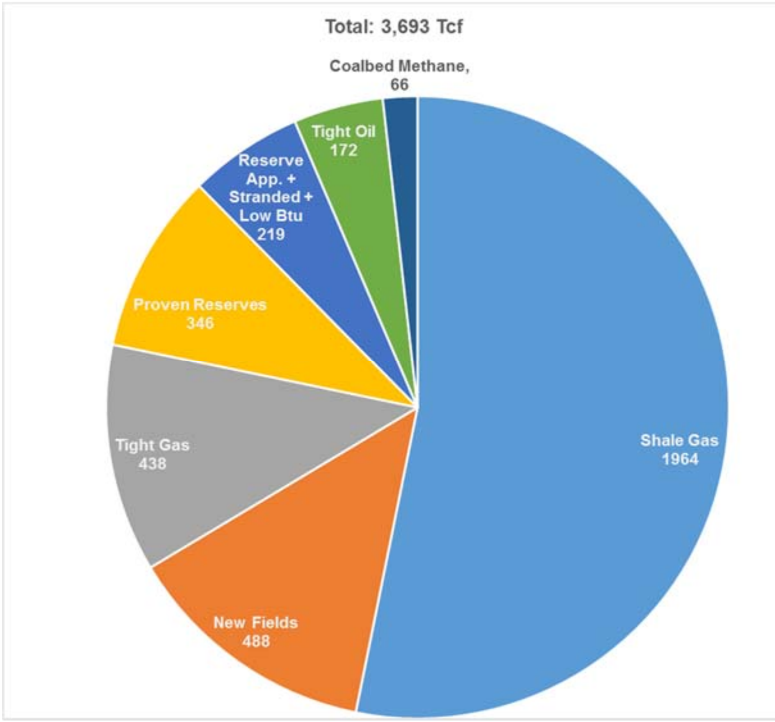
Exhibit 3-4: ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of year-end 2013; excludes Canadian and U.S. oil sands)

Lower 48	Total Gas Tcf	Crude and Cond. Bn Bbls
Proved reserves	346	34
Reserve appreciation and low Btu	219	23
Stranded frontier	0	0
Enhanced oil recov.	0	42
New fields	488	68
Shale gas and condensate	1,964	31
Tight oil (non -GIS)	172	54
Tight gas	438	4
Coalbed methane	66	0
Lower 48 Total	**3,693**	**256**
Canada		
Proved reserves	72	4.9
Reserve appreciation and low Btu	29	3.0
Stranded frontier	40	0.0
Enhanced oil recov.	0	3.0
New fields	219	12.0
Shale gas and condensate	699	0.3
Tight oil	114	20.3
Tight gas (with conv.)	0	0.0
Coalbed methane	76	0.0
Canada Total	**1,249**	**44**
Lower-48 and Canada Total	**4,942**	**299**

Sources: ICF, EIA (proved reserves)

Exhibit 3-5: Lower-48 Gas Resources



Source: ICF

3.1.3 Resource Base Estimate Comparisons

The ICF gas resource base is significantly higher than most published assessments. A comparison of Lower-48 resources by category is shown in Exhibit 3-6. For example, the ICF Lower-48 shale gas assessment of 1,964 Tcf can be compared to the EIA's 489 Tcf or the Potential Gas Committee's 1,073 Tcf.

The ICF natural gas resource base assessment for the U.S. lower 48 states is higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and get added to the upper end of the natural gas supply curves. Such resources may eventually get exploited if natural gas prices increase substantially or if upstream technological advances improve well recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2040.

There are several other reasons for the magnitude of the differences:

- More plays are included. ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.

- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.

- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.

- ICF looks at infill drilling (or new technologies that can substitute for infill wells) that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas. ICF shale resources are based upon the first level of infill drilling, with primary spacing based upon current practices. In other words, if the current practice is 120 acres and 1,000 feet spacing between horizontal well laterals, our assessment assumes an ultimate spacing can be (if justified by economics) 60 acres and 500 feet spacing between laterals.

- For conventional new fields, ICF includes areas of the Outer Continental Shelf (OCS) that are currently off-limits, such as the Atlantic and Pacific OCS.

- ICF evaluates all hydrocarbons at the same time (i.e., dry gas, NGLs, and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.

- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

Exhibit 3-6: Comparison of Published Lower-48 Gas Resource Assessments

TCF of technically recoverable gas; excludes proved reserves

Group	Shale Gas	Tight Oil	Tight Gas	Coalbed	Conventional	Unproved Total
ICF (current)	**1,964**	**172**	**438**	**66**	**707**	**3,347**
EIA AEO, 2014	489	49	365	120	637	1,660
USGS (current)	393	---	190	71	---	---
Potential Gas Committee, 2013	1,073	---	(with conv.)	101	955	2,129
Advanced Resources Inc., 2012	1,219	---	561	124	730	2,634
EIA AEO, 2011	827	---	369	117	703	2,016
Potential Gas Committee, 2011	687	---	(with conv.)	102	858	1,647
MIT, 2011	631	---	173	115	951	1,870
Advanced Resources Inc., 2010	660	---	471	85	831	2,047

Source: ICF

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although we generally did not include shale reservoirs with a net thickness of less than 50 feet. A detailed comparison of the ICF, EIA, and U.S. Geological Survey (USGS) shale assessments by region is presented in Exhibit 3-7. The exhibit provides a better understanding of the differences in the major assessments. Most of the difference is with the Marcellus, Utica, Haynesville, and Fort Worth Barnett Shale plays. Another area of difference relates to plays such as the Paradox Basin and Bossier Shale that ICF has assessed but the other groups generally do not.

ICF has evaluated the USGS Marcellus assessment in order to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, the well spacing assumptions differ from current practices. The high ICF Barnett Shale assessment is the result of our including a very large fringe area of low-quality resource. The great majority of this fringe area is uneconomic, so the comparison is not for an equivalent play area.

Exhibit 3-7: Play-level Shale Gas Comparison

Technically Recoverable Resource, Tcf

		ICF	AEO 2014	USGS Current
Appalachia				
Marcellus		698	119	84
Huron		35	0	0
Other Devonian		15	21	10
Utica		322	37	38
	subtotal	1,070	177	132
Midcontinent				
Arkoma Fayetteville		44	30	13
Arkoma Caney		19	1	1
Arkoma Woodford		39	7	11
Anadarko Woodford (CANA)		37	9	16
	subtotal	139	47	41
Gulf Coast and Permian				
Haynesville		410	71	60
Bossier Shale		51	0	0
Fort Worth Barnett		89	20	26
Eagle Ford		91	53	52
Gulf Coast Pearsall		0	8	9
W. Texas Barnett/Woodford		23	16	35
Floyd/Conasauga		0	2	2
	subtotal	664	170	184
Rockies				
Green River Hilliard, etc		9	11	0
Uinta Mancos		0	11	0
San Juan Lewis		0	10	0
Paradox Basin		34	0	0
	subtotal	43	32	0
Michigan and Illinois		10	57	11
Other Lower- 48		38	6	25
Total		**1,964**	**489**	**393**

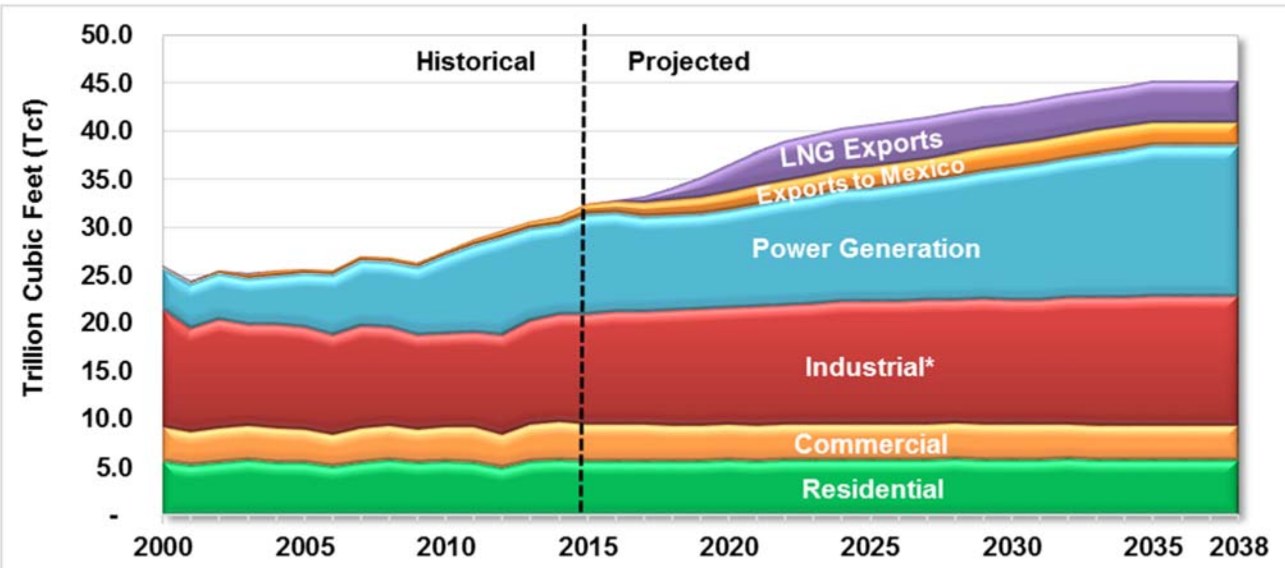
Source: Various compiled by ICF

3.2 U.S. and Canadian Natural Gas Demand Trends

While new LNG export facilities in the U.S. and Canada are expected to come online starting in 2016, power generation will see the bulk of incremental natural gas consumption growth over the foreseeable future, along with some growth in the industry sector, led by gas-intensive end uses such as petrochemicals, fertilizers, and transportation (compressed natural gas vehicles and LNG vehicles).

Incremental power sector gas use between 2014 and 2038 is expected to comprise the largest share of total *incremental* U.S. and Canadian gas growth over the period, with gas-fired power generation expected to increase significantly over time. Growth in gas demand for power generation is driven by a number of factors. In the past 15 years, there have been 460 gigawatts (GW) of new gas-fired generating capacity built in the U.S. and Canada, and much of that capacity is underutilized and readily available to satisfy incremental electric load growth. Electricity demand has historically been linked to Gross Domestic Product (GDP). Prior to the 2007-2008 global recession, demand for electricity was growing at about two percent per year. Over the next twenty years, although GDP is forecast to grow at 2.6 percent annually from 2016 onward, electricity demand growth is expected to average only about 1.2 percent per year, mainly due to implementation of energy efficiency measures. Even at this lower growth rate, annual electricity sales are expected to increase to nearly 4,484 Terawatt-hours (TWh) per year by 2020, or growth nearing 10.6 percent over 2010 levels (3,700 TWh annually).

Exhibit 3-8: U.S. and Canadian Gas Consumption by Sector and Exports



Source: ICF

* Includes pipeline fuel and lease & plant

The expanding use of natural gas in the power sector is driven in part by environmental regulations, primarily in the United States. ICF's Base Case reflects one plausible outcome of EPA's proposals for major rules that have been drawing the attention of the power industry – include the Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes a charge on CO_2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO_2 to be implemented. The case generally leads to retirement and replacement of some coal-generating capacity with gas-based capacity. ICF also assumes that all current state renewable portfolio standards are met and other forms of generation are fairly flat. We also assume existing nuclear units have a maximum lifespan of 60 years, which results in 17 GW of nuclear retirements by 2035. The Base Case forecasts an increase in gas use in the power generation market from 31 percent of total consumption in 2014 to 41 percent by 2038. This growth in gas-fired generation and the accompanying growth in gas consumption is the primary driver of gas demand growth throughout the forecast period.

Industrial demand accounts for 28 percent of total gas use growth in U.S. and Canadian natural gas demand during the 2014-2038 period. A large share of the industrial gas demand increase is from development of the western Canadian oil sands. Excluding natural gas use for oil sands, the growth in industrial sector gas demand in the Base Case is relatively small, as reducing energy intensity (i.e., energy input per unit of industrial output) remains a top priority for manufacturers.

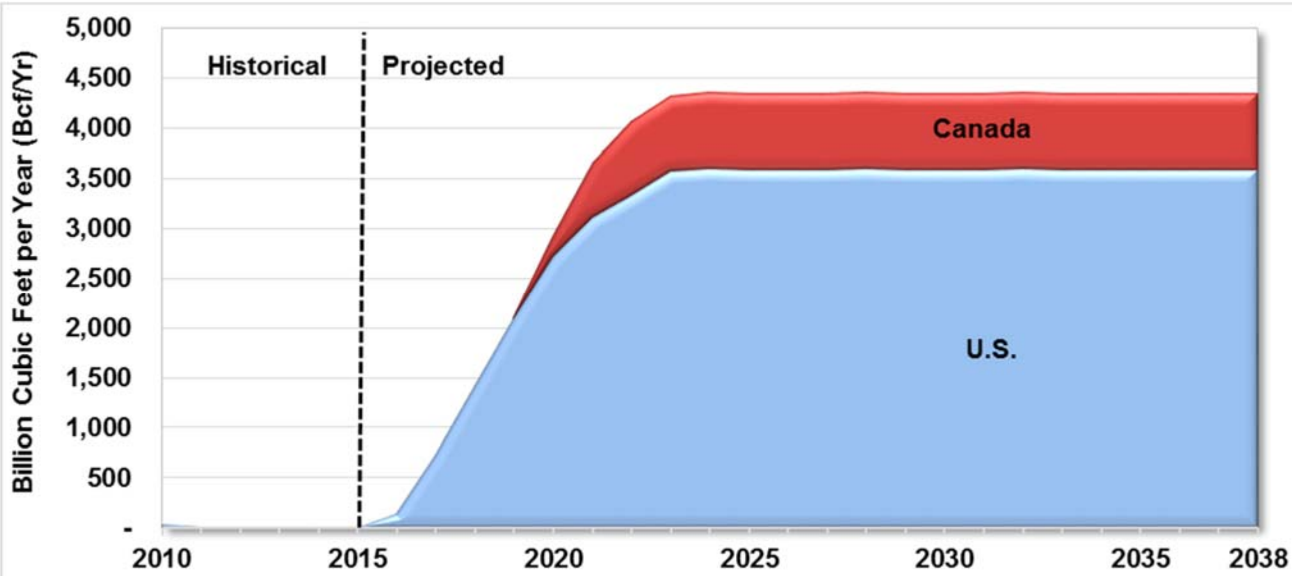
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the residential and commercial sectors, which lead to lower per-customer gas consumption. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The Base Case assumes that the growth of NGVs is primarily in fleet vehicles (e.g., urban buses), and vehicular gas consumption is not a major contributor to total demand growth. In addition, pipeline exports to Mexico are expected to increase to over 2.4 Tcf (6.7 Bcfd) by 2038, up from 730 Bcf/year (2.0 Bcfd) in 2014.

3.2.1 LNG Export Trends

LNG exports are expected to provide additional markets for both Canadian and U.S. natural gas production. In Canada, the National Energy Board (NEB) has granted approval for nine projects located on the West Coast. Several other LNG projects in British Columbia are in various stages of development, but have not yet received NEB approval. In the U.S., the U.S. Department of Energy (DOE) has received 38 applications to export LNG to non-Free Trade Agreement (FTA) countries. Most of the major LNG-consuming countries, including Japan, do not have free trade agreements with the U.S. So far, eight facilities (five located on the U.S. Gulf Coast) have received approval for both FTA and non-FTA exports.

The number of LNG facilities that may eventually enter the market remains highly uncertain. Based on our assessment of world LNG demand and other international sources of LNG supply, this study projects completion of a total of 12 U.S. and Canadian export plants between late 2015 and 2021 (three in Canada, eight on the U.S. Gulf Coast, and one on the East Coast), exporting a total of 4.4 Tcf (11.9 Bcfd) by 2023 in LNG exports (see exhibit below).

Exhibit 3-9: U.S. and Canadian LNG Exports



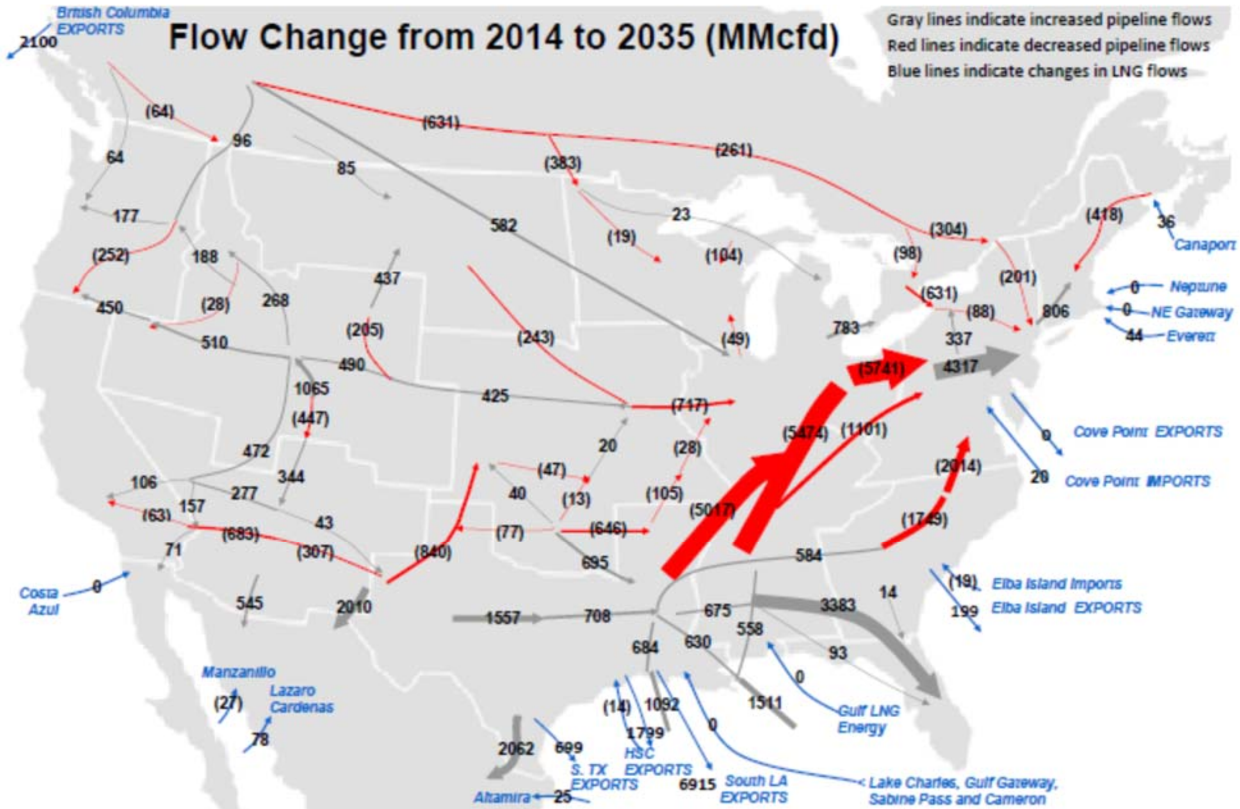
Source: ICF

3.3 U.S. and Canadian Natural Gas Midstream Infrastructure Trends

As regional gas supply and demand continue to shift over time, there are likely to be significant changes in interregional pipeline flows. Exhibit 3-10 shows the projected changes in interregional pipeline flows from 2013 to 2035 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2013 and 2035, where the gray arrows indicate increases in flows and red arrows indicate decreases. The blue lines indicate changes in LNG flows.

Exhibit 3-10 illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. The growth in Marcellus Shale gas production in the Mid-Atlantic Region will displace gas that once was imported into that region, hence the red arrows entering the Mid-Atlantic Region from points north (Canada), Midwest (Ohio), and South Atlantic (North Carolina). In effect, the Mid-Atlantic Region becomes a major producer of gas and supplies gas to consumers throughout the East Coast. The flow of natural gas from Alberta through eastern Canada to the eastern U.S. will decline as Marcellus production displaces both imports from Canada and flows from the U.S. Gulf Coast. While the red arrows from the Gulf Coast to the U.S. Northeast indicate that gas continues to flow into the U.S. Northeast, Marcellus gas over the past five years has significantly narrowed those volumes, a trend that will continue over the foreseeable future.

Exhibit 3-10: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q1 2015

The large increases in flows eastward from the West South Central Region (Texas, Louisiana, and Arkansas) are due to growing shale gas production in the region. However, most of this gas is consumed in the East South Central Region (Mississippi, Alabama, Tennessee, and Kentucky) and South Atlantic Region (Florida to North Carolina) where demand is growing. In addition, natural gas will be exported from the West South Central in the form of LNG starting in 2016. The growing Marcellus gas production in the Mid-Atlantic Region will also displace gas flows from the West South Central Census Region to the South Atlantic states.

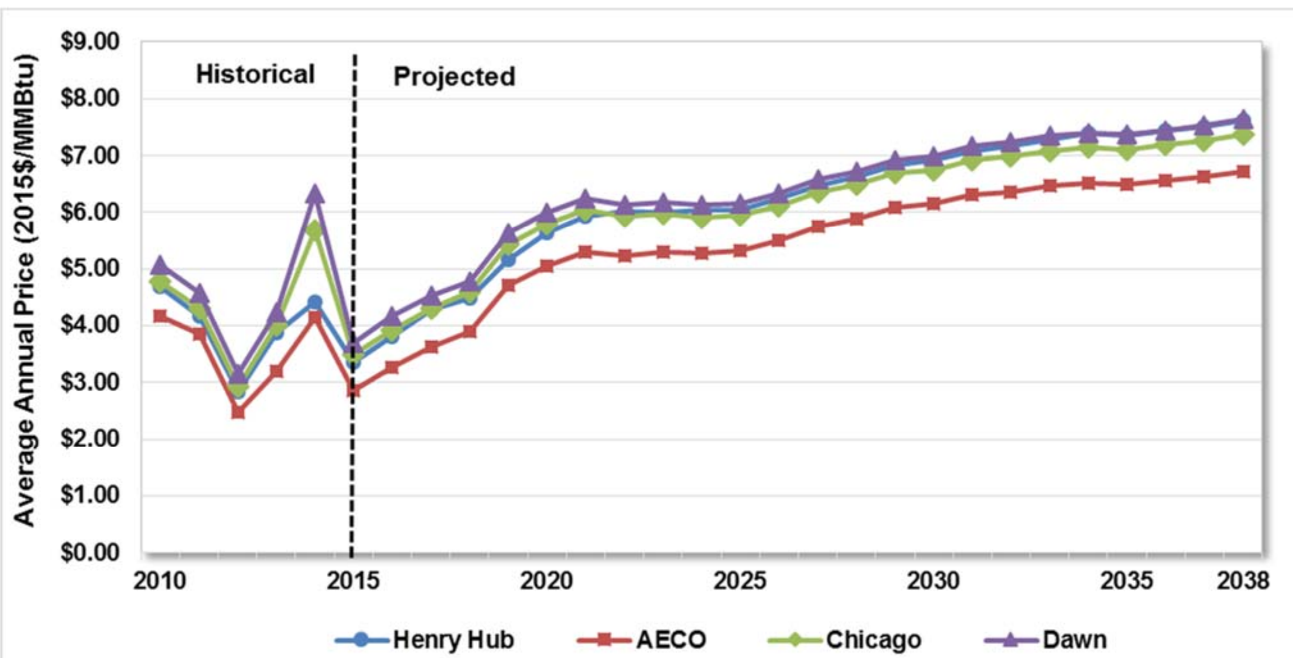
Gas flows out of western Canada are projected to decline. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong industrial demand growth in western Canada for producing oil from oil sands will keep more gas in the western provinces. The planned LNG export terminals in British Columbia will also draw off gas supply once exports of LNG begin. Pipeline flows west out of the Rocky Mountains will increase to northern California. The completion of the Ruby Pipeline in 2011 allowed Rocky Mountain gas to displace gas coming from Alberta on Gas Transmission Northwest.

3.4 Natural Gas Price Trends

With growing gas demand and increased reliance on new sources of supply, the Base Case forecasts higher gas prices from current levels. Nevertheless, the cost of producing shale gas moderates the price increase. In the Base Case, gas prices at Henry Hub are expected to increase gradually, climbing from approximately $4.43 per MMBtu in 2014 to $7.52 per MMBtu in 2038 (in 2015 dollars) (see exhibit below). This gradual increase in gas prices supports development of new sources of supply, but prices are not so high as to discourage demand growth. This growth in demand requires the exploitation of lower-quality natural gas resources and leads to higher drilling levels and an increase in drilling and completion factor costs. These depletion and factor cost effects are partly offset by upstream technological advances, but some real cost escalation is expected to be needed to meet the fast-growing demand expected in the ICF Base Case.

Gas prices throughout The U.S. and Canada are expected to remain moderate; however, in some regions other market dynamics will influence regional prices. The price difference (or basis) between Henry Hub and Alberta, for example, is projected to narrow in 2013-2015, thereafter widening somewhat through around 2020. As more gas is produced in the U.S. Northeast from shale resources, the market price in this region is expected to decline, relative to Henry Hub.

Exhibit 3-11: GMM Average Annual Prices for Selected Markets

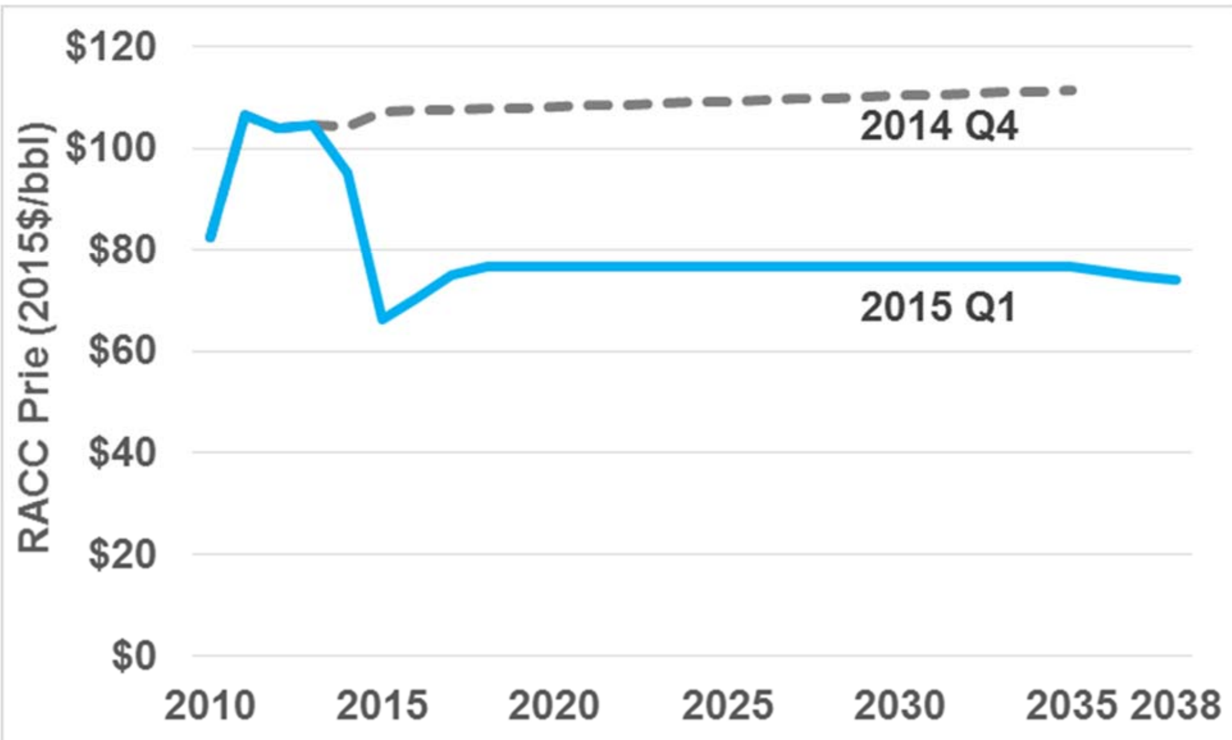


Source: ICF

3.5 Oil Price Trends

In the wake of recent market declines, ICF has revised its oil price assumption downward from a real price of over $100/bbl due to the ongoing global supply surplus and slowing economic growth. The revised assumption is based on futures trading patterns over the past quarter. ICF assumes that oil prices will follow a trajectory starting with the December spot price and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $77/bbl (2015 dollars) after 2017, as shown in the exhibit below.

Exhibit 3-12: ICF Oil Price Assumptions



Source: ICF

4 Study Methodology

This section describes ICF's methodologies in assessing U.S. and Canadian natural gas market dynamics, resource base assessments, and energy and economic impact modeling.

4.1 Resource Assessment Methodology

ICF assessments combine components of publicly available assessments by the USGS and the Bureau of Ocean Energy Management (BOEM/formerly the Mineral Management Service, MMS), industry assessments such as that of the National Petroleum Council, and our own proprietary work. As described in the previous section, in recent years, ICF has done extensive work to evaluate shale gas, tight gas, and coalbed methane using engineering-based geographic information system (GIS) approaches. This has resulted in the most comprehensive and detailed assessment of North America gas and oil resources available. It includes GIS analysis of over 30 unconventional gas plays.

On the resource cost side, ICF uses discounted cash flow analysis at various levels of granularity, depending upon the category of resource. For undiscovered fields, the analysis is done by field size class and depth interval, while for unconventional plays, DCF analysis is generally done on each 36-square-mile unit of play area. Exhibit 4-1 is a map of the U.S. Lower-48 ICF oil and gas supply regions.

4.1.1 Conventional Undiscovered Fields

Undiscovered fields are assessed by 5,000-foot drilling depth intervals and a distribution of remaining fields by USGS "size class." Hydrocarbon ratios are applied to convert barrel of oil equivalent (BOE) per size class into quantities of recoverable oil, gas, and NGLs. U.S. and Canadian conventional resources are based largely on USGS and BOEM (formerly MMS) (and various agencies in Canada) assessments made over the past 15 years. The USGS provides information on discovered and undiscovered oil and gas and number of fields by field size class. The ICF assessments were reviewed by oil and gas producing industry representatives in the U.S. and Canada as part of the 2003 National Petroleum Council study.[10]

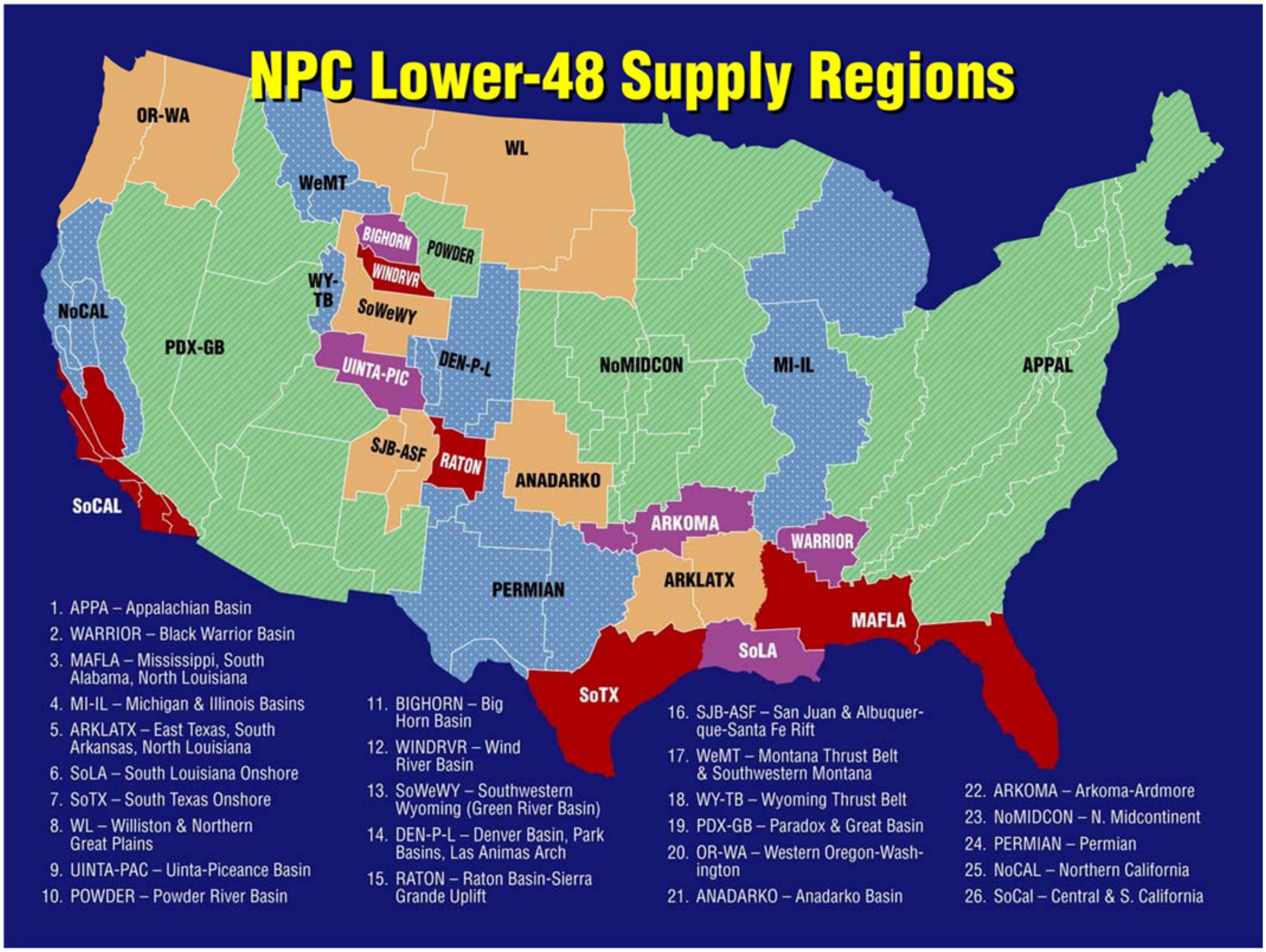
4.1.2 Unconventional Oil and Gas

Unconventional oil and gas is defined as continuous deposits in low-permeability reservoirs that typically require some form of well stimulation such as hydraulic fracturing and/or horizontal drilling. ICF has assessed future North America unconventional gas and liquids potential, represented by **shale gas, tight oil, tight sands, and coalbed methane**. Prior to the shale gas revolution, ICF relied upon a range of sources for our assessed volumes, including USGS, the National Petroleum Council studies, and in-house work for various clients. In recent years, we

[10] U.S. National Petroleum Council (NPC). "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy". NPC, 2003. Available at: http://www.npc.org/

developed our GIS method of assessing shale and other unconventional resources. The current assessment is a hybrid assessment, using the GIS-derived data where we have it.

Exhibit 4-1: ICF Oil and Gas Supply Region Map



Source: NPC

ICF developed a GIS-based analysis system covering 32 major North American unconventional gas plays. The GIS approach incorporates information on the geologic, engineering, and economic aspects of the resource. Models were developed to work with GIS data on a 36-square-mile unit basis to estimate unrisked and risked gas-in-place, recoverable resources, well recovery and resource costs at a specified rate of return. The GIS analysis focuses on gas and NGLs and addresses the issue of lease condensate and gas plant liquids, both in terms of recoverable resources and their impact on economics.

The ICF unconventional gas GIS model is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about porosity, pressure gradient, and other information. The unit of analysis for gas-in-place and recoverable resources is a 6-by-6 mile or 36-square-mile grid unit. Gas-in-place is determined for free gas, adsorbed gas, and gas dissolved in liquids, and well recovery is modeled using a reservoir simulator.[11] Gas resources and recovery per well are estimated as a function of well spacing. Exhibit 4-2 is a listing of the GIS plays in the model.

Exhibit 4-2: ICF Unconventional Plays Assessed Using GIS Methods

no.	Play	Play Area Sq. Mi.	Assess-ment well spacing (acres)
	Shale		
1	Appalachian Marcellus Shale	39,100	40
2	Appalachian Huron Shale	22,941	80
3	NY Utica Shale	14,280	80
4	Ft. Worth Barnett Shale	26,300	40
5	Gulf Coast Haynesville Shale	7,400	40
6	Gulf Coast Bossier Shale	2,830	40
7	Texas Eagle Ford Shale	9,097	60
8	West Texas Barnett Shale	4,500	40
9	West Texas Woodford Shale	4,500	40
10	Arkoma Fayetteville Shale	2,600	60
11	Arkoma Woodford Shale	1,863	40
12	Arkoma Moorefield Shale	520	80
13	Arkoma Caney Shale	6,340	80
14	Anadarko Woodford Shale	1,776	40
15	Uinta Mancos Shale	7,100	20
16	Paradox Gothic Shale	1,350	80
17	Paradox Cane Creek Shale	3,110	40
18	Green River Vermillion Baxter Shale	180	20
19	Green River Hilliard Shale	4,350	20
	L-48 GIS- assessed shale total	**160,137**	

no.	Play	Play Area Sq. Mi.	Assess-ment well spacing (acres)
20	WCSB Montney Siltstone	13,700	40
21	WCSB Horn River Muskwa/Evie Shale	5,100	80
22	WCSB Cordova Embayment Shale	1,544	160
23	Quebec Utica Shale	1,600	80
24	New Brunswick Frederick Brook Sh.	120	80
	Canada GIS-assessed shale total	**22,064**	
	Tight Gas		
25	Anadarko Granite Wash Tight	3,533	213
26	Uinta Mesaverde Tight	4,721	10
27	Uinta Wasatch Tight	2,045	10
28	Green River Lance Tight	16,200	5
29	Green River Mesaverde/Almond Tight	13,400	20
	L-48 GIS-assessed tight total	**39,899**	
	Coalbed Methane		
30	**San Juan Fruitland CBM (L-48 GIS total)**	**6,599**	**160**
31	WCSB Horseshoe Canyon CBM	24,730	80
32	WCSB Mannville CBM	46,758	320
	Canada GIS-assessed CBM total	**71,488**	

Source: ICF

Exhibit 4-3 shows an example of the granularity of analysis for a specific play. This map shows the six-mile grid base and oil and gas production windows for the Eagle Ford play in South Texas. Economic analysis is also performed on a 36-square-mile unit basis and is based upon discounted cash flow analysis of a typical well within that area. Model outputs include risked and unrisked gas-in-place, recoverable resources as a function of spacing, and supply versus cost curves.

One of the key aspects of the analysis is the calibration of the model with actual well recoveries in each play. These data are derived from ICF analysis of a commercial well-level production database. The actual well recoveries are compared with the model results in each 36-square-mile model cell to calibrate the model. Thus, results are not just theoretical, but are ground-truthed to actual well results.

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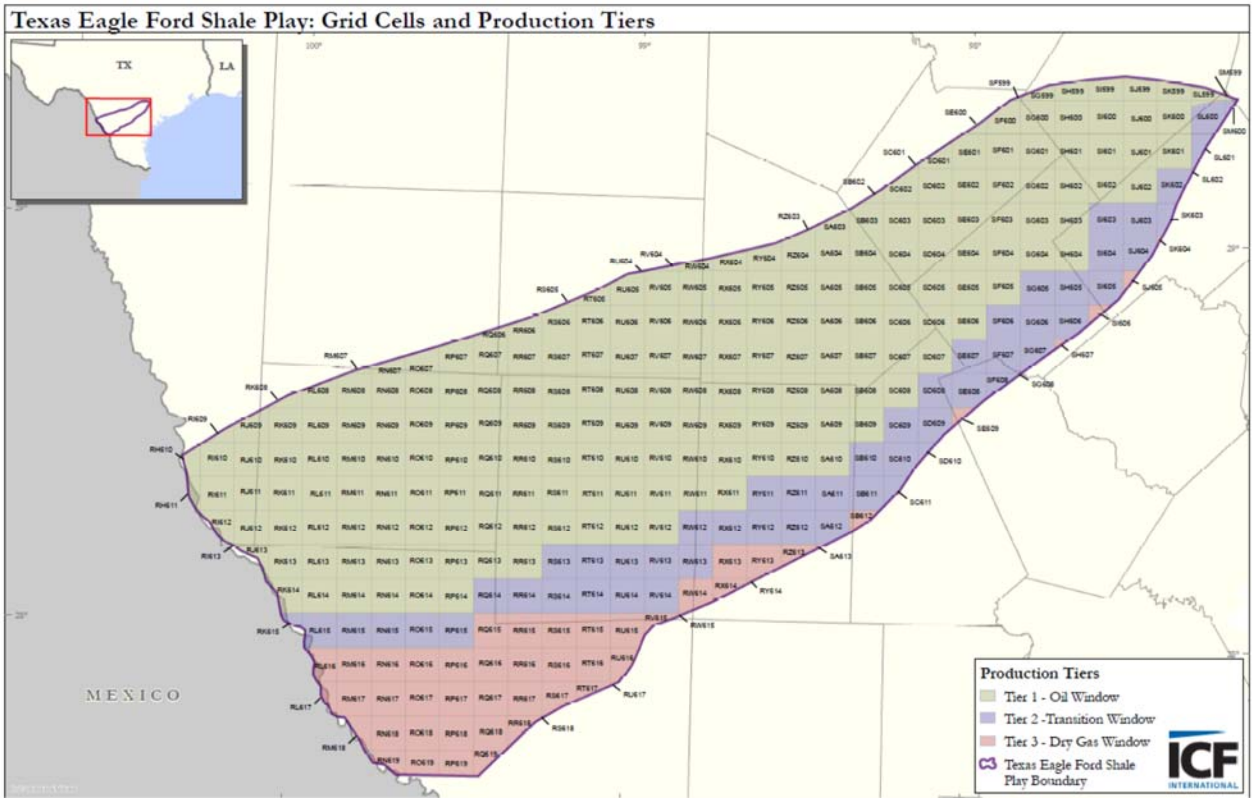
[11] Free gas is gas within the pores of the rock, while adsorbed gas is gas that is bound to the organic matter of the shale and must be desorbed to produce.

Exhibit 4-3: Eagle Ford Play Six-Mile Grids and Production Tiers (Oil, Wet Gas, Dry Gas)



Source: ICF

Tight Oil

Tight oil production is oil production from shale and other low-permeability formations including sandstone, siltstone, and carbonates. The tight oil resource has emerged as a result of horizontal drilling and multi-stage fracturing technology. Tight oil production in both the U.S. and Canada is surging. Production in 2014 was approximately 3.5 to 4.0 million barrels per day (MMbpd) in the U.S., up from less than 250,000 barrels per day (bpd) in 2007, and 350,000 bpd in Canada. The 3.5 MMbpd of U.S. tight oil production is dominated by the Bakken, Eagle Ford, and Permian Basin. The Eagle Ford volumes include a large amount of lease condensate.

Tight oil production impacts both oil and gas markets. Tight oil contains a large amount of associated gas, which affects the North American price of natural gas. Growing associated gas production has resulted in the need for a great deal of midstream infrastructure expansion.

Tight oil resources may be represented by previously undeveloped plays, such as the Bakken shale, and in other cases may be present on the fringes of old oil fields, as is the case in western Canada. ICF assessments are based upon map areas or “cells” with averaged values of depth, thickness, maturity, and organics. The model takes this information, along with assumptions about porosity, pressure, oil gravity, and other factors to estimate original oil and gas-in-place, recovery per well, and risked recoverable resources of oil and gas. The results are compared to actual well recovery estimates. A discounted cash flow model is used to develop a cost of supply curve for each play.

4.1.3 Technology and Cost Assumptions

An important aspect of the resource assessment is the underlying assumptions about technology. The ICF economic resource assessment is based upon existing technology. This is a conservative assumption, as has been demonstrated by the very rapid technology growth in shale gas and tight oil development in just five years.

In recent years, there have been great gains in technology related to the drilling of long horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time microseismic monitoring.

In general, lateral lengths and the number of stimulation stages are increasing in most plays. This increases the cost per well over prior configurations. However, the gas recovery is much greater than the increased cost, resulting in lower costs per unit of production.

Drilling costs have been reduced largely due to increased efficiency and the higher rate of penetration. In some cases, the number of rig days to drill a well is a fraction of what it was several years ago. A factor that has limited the reduction in drilling costs has been the rig day rate, which has been relatively high due to large demand for specialized rigs. However, with recent declines in oil prices and drilling activity, rig rates and some other cost factors are expected to decline significantly.

4.2 Energy and Economic Impacts Methodology

Cameron LNG tasked ICF with assessing the economic and employment impacts of additional LNG exports from its Hackberry, LA LNG export facility. This study assessed two cases[12]:

1) **Base Case** assumption of currently approved Trains 1-3 volumes of 620 billion cubic feet (Bcf) per year, or 1.70 billion cubic feet per day (Bcfd). Base Case also includes an additional 0.42 Bcfd (or 152 Bcf per year) of exports pending DOE approval at the time of this analysis.
2) **Trains 4-5 Expansion Case** assumption of an additional 515 Bcf per year, or 1.41 Bcfd higher than the Base Case due to the new construction of Trains 4 and 5. This gives a total volume of 1.29 trillion cubic feet (Tcf) per year, or 3.53 Bcfd, including Base Case volumes.

Both cases above include the Trains 1-3 supplemental volumes of 152 Bcf per year (or 0.42 Bcfd) which were under review by the U.S. Department of Energy (DOE) during the analysis. The results in this report show the changes in impacts between the Base Case and alternative case resulting from the incremental LNG export volumes. ICF assessed the economic impacts of additional LNG exports from Cameron LNG for two cases. The methodology consisted of the following steps:

[12] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Step 1 – Natural gas and liquids production: We first ran the ICF Gas Market Model to determine supply, demand, and price changes in the natural gas market. The natural gas and liquids production changes required to support the additional LNG exports were assessed on both a national and Louisiana level.

Step 2 – LNG plant capital and operating expenditures: Based on Cameron LNG's cost estimates, ICF determined the annual capital and operating expenditures that will be required to support the LNG exports.

Step 3 – Upstream capital and operating expenditures: ICF then translated the natural gas and liquids production changes from the GMM into annual capital and operating expenditures that will be required to support the additional production.

Step 3 – IMPLAN input-output matrices: ICF entered both LNG plant and upstream expenditures into the IMPLAN input-output model to assess the economic impacts for the U.S. and Louisiana. For instance, if the model found that $100 million in a particular category of expenditures generated 390 direct employees, 140 indirect employees, and 190 induced employees (i.e., employees related to consumer goods and services), then we would apply those proportions to forecasted expenditure changes. If forecasted expenditure changes totaled $10 million one year, according to the model proportions, that would generate 39 direct, 14 indirect, and 19 induced employees in the year the expenditures were made.

Step 4 – Economic impacts: ICF assessed the impact of LNG exports for the national and Louisiana levels. This included direct, indirect, and induced impacts on gross domestic product, employment, taxes and other measures.

Exhibit 4-4: Impact Definitions

Classification of Impact Types

Direct – represents the immediate impacts (e.g., employment or output changes) due to the investments that result in direct demand changes, such as expenditures needed for the construction of LNG liquefaction plant or the drilling and operation of a natural gas well.

Indirect – represents the impacts due to the industry inter-linkages caused by the iteration of industries purchasing from other industries, brought about by the changes in direct demands.

Induced – represents the impacts on all local and national industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

Definitions of Impact Measures

Output – represents the value of an industry's total output increase due to the modeled scenario (in millions of constant dollars).

Employment – represents the jobs created by industry, based on the output per worker and output impacts for each industry.

Total Value Added – is the contribution to Gross Domestic Product (GDP) and is the "catch-all" for payments made by individual industry sectors to workers, interests, profits, and indirect business taxes. It measures the specific contribution of an individual sector after subtracting out purchases from all suppliers.

Tax Impact – breakdown of taxes collected by the federal, state and local government institutions from different economic agents. This includes corporate taxes, household income taxes, and other indirect business taxes.[13]

Key model assumptions are based on ICF analysis of the industry and previous work, and include:

- Cameron LNG export volumes
- LNG plant capital and operating expenditures
- Per-well upstream capital costs
- Fixed and variable upstream operating costs per well
- Tax rates

[13] The tax impacts are not part of the GDP accounting framework used for the other impacts. These are calculated in IMPLAN using standard assumptions about tax rates.

The following set of exhibits show the key model assumptions.

Exhibit 4-5: Cameron LNG Exports by Case (Bcfd)

Year	Base Case	The T 4-5 Expansion Case	The T 4-5 Expansion Case Changes
2016	-	-	-
2017	0.07	0.07	0.00
2018	1.52	1.52	0.00
2019	2.12	2.60	0.48
2020	2.12	3.52	1.40
2021	2.12	3.53	1.41
2022	2.12	3.53	1.41
2023	2.12	3.53	1.41
2024	2.12	3.53	1.41
2025	2.12	3.53	1.41
2026	2.12	3.53	1.41
2027	2.12	3.53	1.41
2028	2.12	3.53	1.41
2029	2.12	3.53	1.41
2030	2.12	3.53	1.41
2031	2.12	3.53	1.41
2032	2.12	3.53	1.41
2033	2.12	3.53	1.41
2034	2.12	3.53	1.41
2035	2.12	3.53	1.41
2036	2.12	3.53	1.41
2037	2.12	3.53	1.41
2038	2.12	3.53	1.41
2016-2038 Average	1.91	3.09	1.19

Source: Cameron LNG, ICF

Exhibit 4-6: Cameron LNG plant Capital and Operating Expenditures by Case

Year	The T 4-5 Expansion Case Changes	
	LNG Capital Costs (2015$ MM)	LNG Operating Costs (2015$ MM)
2010	$0.00	$0.00
2011	$0.00	$0.00
2012	$0.00	$0.00
2013	$0.00	$0.00
2014	$0.00	$0.00
2016	$0.00	$0.00
2016	$2,000.00	$0.00
2017	$2,000.00	$0.00
2018	$2,000.00	$0.00
2019	$1,000.00	$62.47
2020	$0.00	$124.93
2021	$0.00	$124.93
2022	$0.00	$124.93
2023	$0.00	$124.93
2024	$0.00	$124.93
2025	$0.00	$124.93
2026	$0.00	$124.93
2027	$0.00	$124.93
2028	$0.00	$124.93
2029	$0.00	$124.93
2030	$0.00	$124.93
2031	$0.00	$124.93
2032	$0.00	$124.93
2033	$0.00	$124.93
2034	$0.00	$124.93
2035	$0.00	$124.93
2036	$0.00	$124.93
2037	$0.00	$124.93
2038	$0.00	$124.93

Source: Cameron LNG, ICF

Exhibit 4-7: Assumed Federal, State, and Local Tax Rates

Year	Federal Tax Rate on GDP (%)	Weighted Average State and Local Tax Rate on GDP (% of own-source) (%)	Louisiana State and Local Own Taxes as % of State Income (%)
2010	14.6%	15.1%	15.5%
2011	15.0%	14.9%	15.4%
2012	15.3%	14.5%	15.5%
2013	16.7%	14.5%	15.5%
2014	17.5%	14.5%	15.5%
2015	17.7%	14.5%	15.5%
2016	18.7%	14.5%	15.5%
2017	19.1%	14.5%	15.5%
2018	19.1%	14.5%	15.5%
2019	19.2%	14.5%	15.5%
2020	19.3%	14.5%	15.5%
2021	19.4%	14.5%	15.5%
2022	19.5%	14.5%	15.5%
2023	19.6%	14.5%	15.5%
2024	19.7%	14.5%	15.5%
2025	19.8%	14.5%	15.5%
2026	19.9%	14.5%	15.5%
2027	20.0%	14.5%	15.5%
2028	20.1%	14.5%	15.5%
2029	20.2%	14.5%	15.5%
2030	20.3%	14.5%	15.5%
2031	20.4%	14.5%	15.5%
2032	20.5%	14.5%	15.5%
2033	20.6%	14.5%	15.5%
2034	20.7%	14.5%	15.5%
2035	20.8%	14.5%	15.5%
2036	20.9%	14.5%	15.5%
2037	21.0%	14.5%	15.5%
2038	21.1%	14.5%	15.5%

Source: ICF extrapolations from Tax Policy Center historical figures

Exhibit 4-8: Liquids Price Assumptions

Year	RACC Price (2015$/bbl)	Condensate Price (2015$/bbl)	Ethane Price (2015$/bbl)	Propane Price (2015$/bbl)	Butane Price (2015$/bbl)	Pentanes Plus (2015$/bbl)
2010	$ 82.33	$ 82.33	$ 27.16	$ 48.93	$ 55.80	$ 75.06
2011	$ 106.57	$ 106.57	$ 24.22	$ 61.46	$ 72.23	$ 97.17
2012	$ 103.92	$ 103.92	$ 16.39	$ 42.19	$ 70.43	$ 94.75
2013	$ 104.73	$ 104.73	$ 22.50	$ 42.03	$ 70.99	$ 95.49
2014	$ 95.09	$ 95.09	$ 25.67	$ 43.74	$ 64.45	$ 86.70
2015	$ 66.13	$ 66.13	$ 19.46	$ 35.05	$ 44.82	$ 60.29
2016	$ 70.59	$ 70.59	$ 22.02	$ 37.42	$ 47.85	$ 64.37
2017	$ 74.85	$ 74.85	$ 22.18	$ 39.68	$ 50.73	$ 68.25
2018	$ 76.73	$ 76.73	$ 22.33	$ 40.68	$ 52.01	$ 69.96
2019	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2020	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2021	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2022	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2023	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2024	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2025	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2026	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2027	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2028	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2029	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2030	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2031	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2032	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2033	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2034	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2035	$ 76.73	$ 76.73	$ 22.65	$ 40.68	$ 52.01	$ 69.96
2036	$ 75.74	$ 75.74	$ 22.35	$ 40.15	$ 51.33	$ 69.06
2037	$ 74.84	$ 74.84	$ 22.09	$ 39.67	$ 50.72	$ 68.24
2038	$ 74.04	$ 74.04	$ 21.85	$ 39.25	$ 50.18	$ 67.51

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Louisiana
Upstream Capital Costs ($MM/Well)	$7.7	$10.6
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	21.9%
LNG Tanker Capacity (Bcf/Ship)		3.60 (135,000-170,000 m^3)
U.S. Port Fee ($/Port Visit)		$100,000
Cameron LNG Liquefaction Fee ($/MMBtu)		$3.00

Source: Various compiled or estimated by ICF

4.3 IMPLAN Description

The IMPLAN model is an input-output model based on a social accounting matrix that incorporates all flows within an economy. The IMPLAN model includes detailed flow information for hundreds of industries. By tracing purchases between sectors, it is possible to estimate the economic impact of an industry's output (such as the goods and services purchased by the oil and gas upstream sector) to impacts on related industries.

From a change in industry spending, IMPLAN generates estimates of the direct, indirect, and induced economic impacts. Direct impacts refer to the response of the economy to the change in the final demand of a given industry to those directly involved in the activity, in this case, the direct expenditures associated with an incremental drilled well. Indirect impacts (or supplier impacts) refer to the response of the economy to the change in the final demand of the industries that are dependent on the direct spending of industries for their input. Induced impacts refer to the response of the economy to changes in household expenditure as a result of labor income generated by the direct and indirect effects.

After identifying the direct expenditure components associated with LNG plant and upstream development, the direct expenditure cost components (identified by their associated North American Industry Classification System (NAICS) code) are then used as inputs into the IMPLAN model to estimate the total indirect and induced economic impacts of each direct cost component.

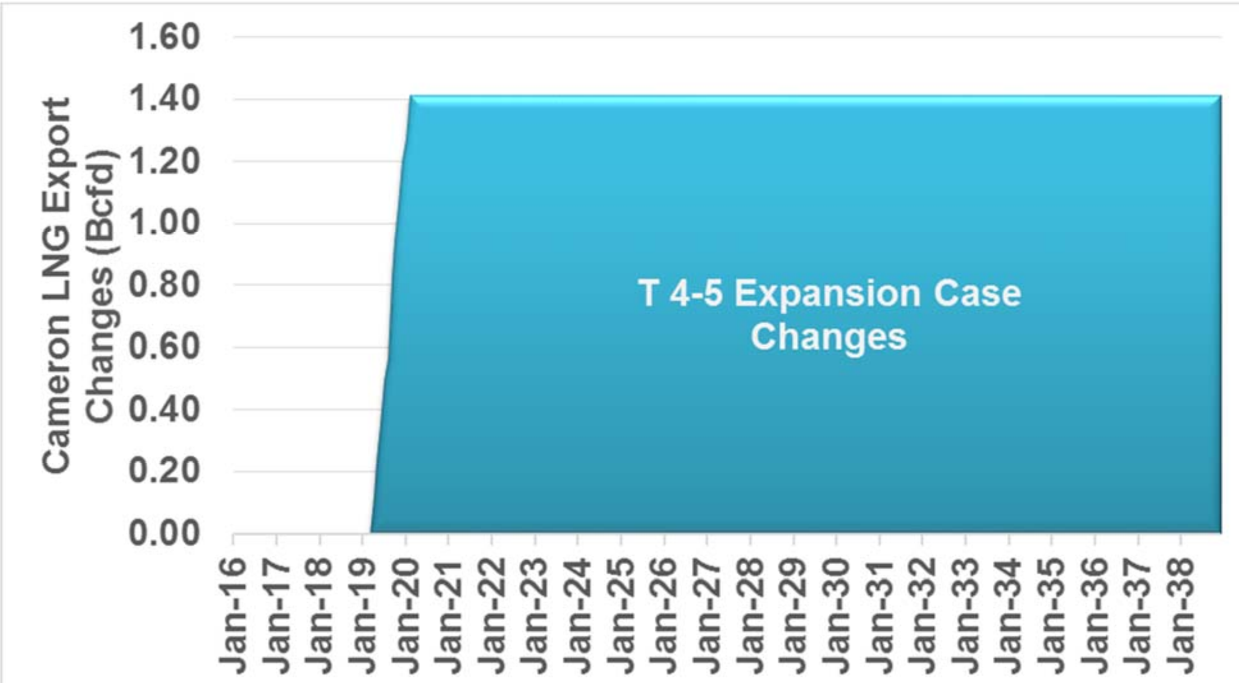
Direct, Indirect, and Induced Economic Impacts

ICF assessed the economic impact of LNG exports on three levels: direct, indirect, and induced impacts. Direct industry expenditures (e.g., natural gas drilling and completion expenditures) produce a domino effect on other industries and aggregate economic activity, as component industries' revenues (e.g., cement and steel manufacturers needed for well construction) are stimulated along with the direct industries. Such secondary economic impacts are defined as "indirect." In addition, further economic activity, classified as "induced," is generated in the economy at large through consumer spending by employees in direct and indirect industries.

5 Trains 4-5 Expansion Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the T 4-5 Expansion Case. Specifically, differentials between the two cases result from an additional 1.41 Bcfd (see exhibit below) in LNG exports assumed from Cameron LNG from Trains 4 and 5.

Exhibit 5-1: Trains 4-5 Cameron LNG Export Changes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

5.1 U.S. Impacts

This section discusses the impacts of LNG exports in the Base Case and the T 4-5 Expansion Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade. Below discusses the U.S. impacts of the LNG export cases on the U.S. economy, as well as energy market impacts.

Overall, in order to accommodate the incremental increases in LNG exports, the U.S. natural gas market rebalances through three sources: increasing U.S. natural gas production, a contraction in U.S. domestic natural gas consumption, and an increase in natural gas pipeline imports from Canada and Mexico. In addition to the incremental LNG export volumes of 1.41 Bcfd, the market also must rebalance for liquefaction and fuel losses, estimated at 10 percent of incremental export volumes. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below, which shows the flow sources.

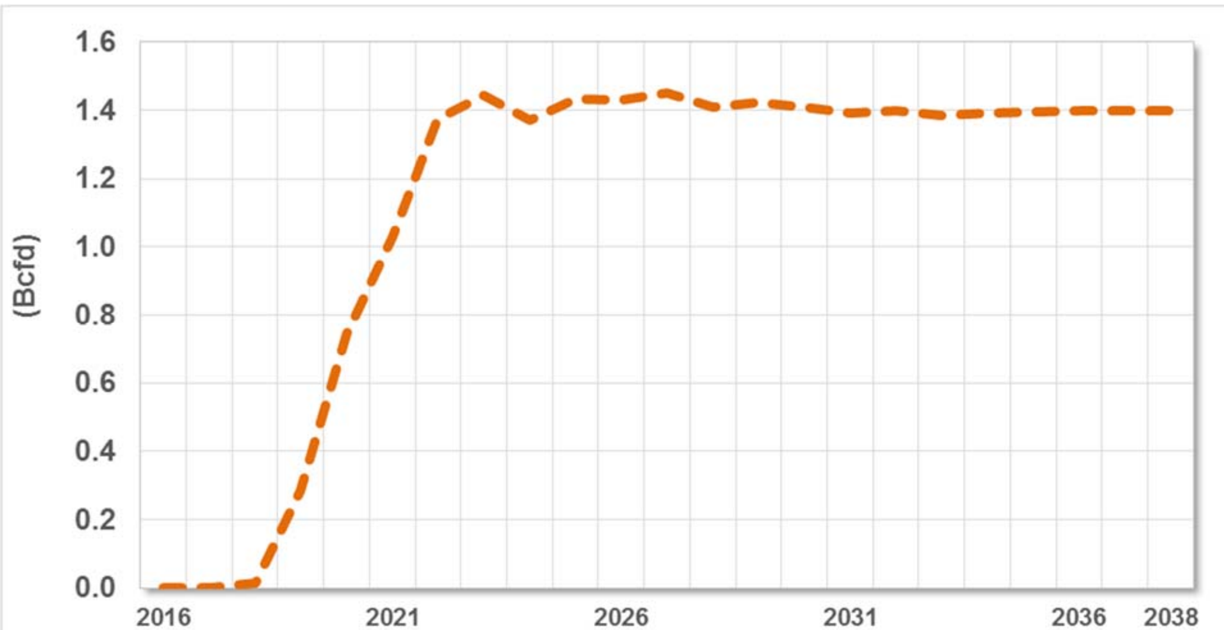
Exhibit 5-2: U.S. Flow Impact Contribution to LNG Exports

Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)
94%	9%	7%	110%

Source: ICF

As seen in Exhibit 5-3, illustrates that the T 4-5 Expansion Case causes an increase in U.S. natural gas production of 1.4 Bcfd relative to the Base Case by 2038. On average, between 2016 and 2038, the T 4-5 Expansion Case shows that U.S. natural gas production is expected to increase by 1.1 Bcfd over the Base Case.

Exhibit 5-3: U.S. Natural Gas Production Changes

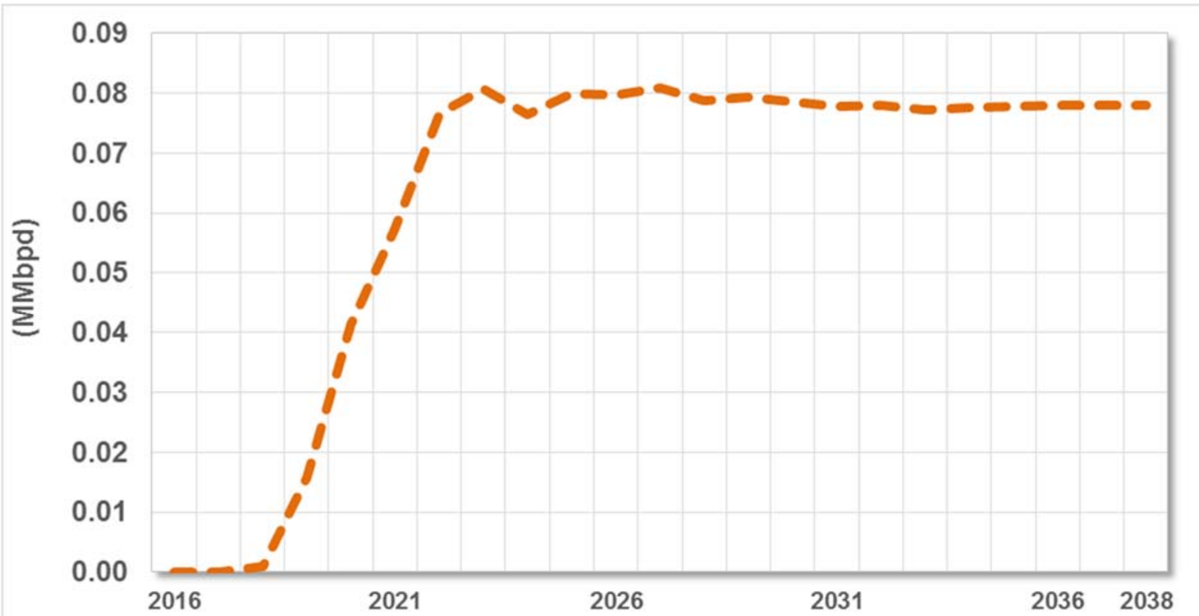


Year	Natural Gas Production (Bcfd) T 4-5 Exp Case Change
2016	-
2021	1.0
2026	1.4
2031	1.4
2036	1.4
2038	1.4
2016-2038 Avg	*1.1*

Source: ICF

As seen in Exhibit 5-4, in the T 4-5 Expansion Case, U.S. crude oil, lease condensate, and natural gas liquids production is expected to exceed Base Case levels by 0.08 MMbpd in 2038. Between 2016 and 2038, liquids production is expected to increase on an annual average by 0.06 MMbpd over the Base Case as a result of increased natural gas production needed for the additional LNG exports.

Exhibit 5-4: U.S. Liquids Production Changes



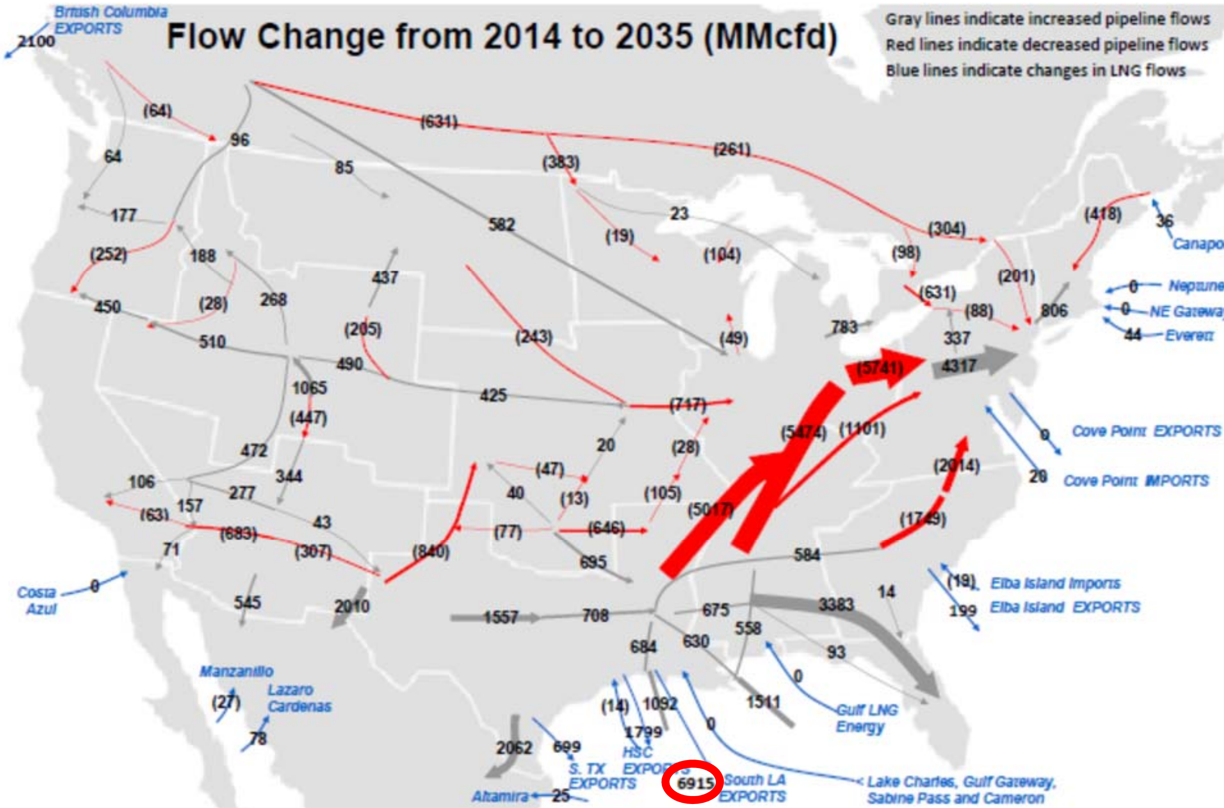
Year	Liquids Production (MMbpd) T 4-5 Exp Case Change
2016	-
2021	0.06
2026	0.08
2031	0.08
2036	0.08
2038	0.08
2016-2038 Avg	*0.06*

Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

As mentioned in the previous section, the map below shows Base Case natural gas market flows, with the red circle below indicating Louisiana LNG export volumes of 6.9 Bcfd.

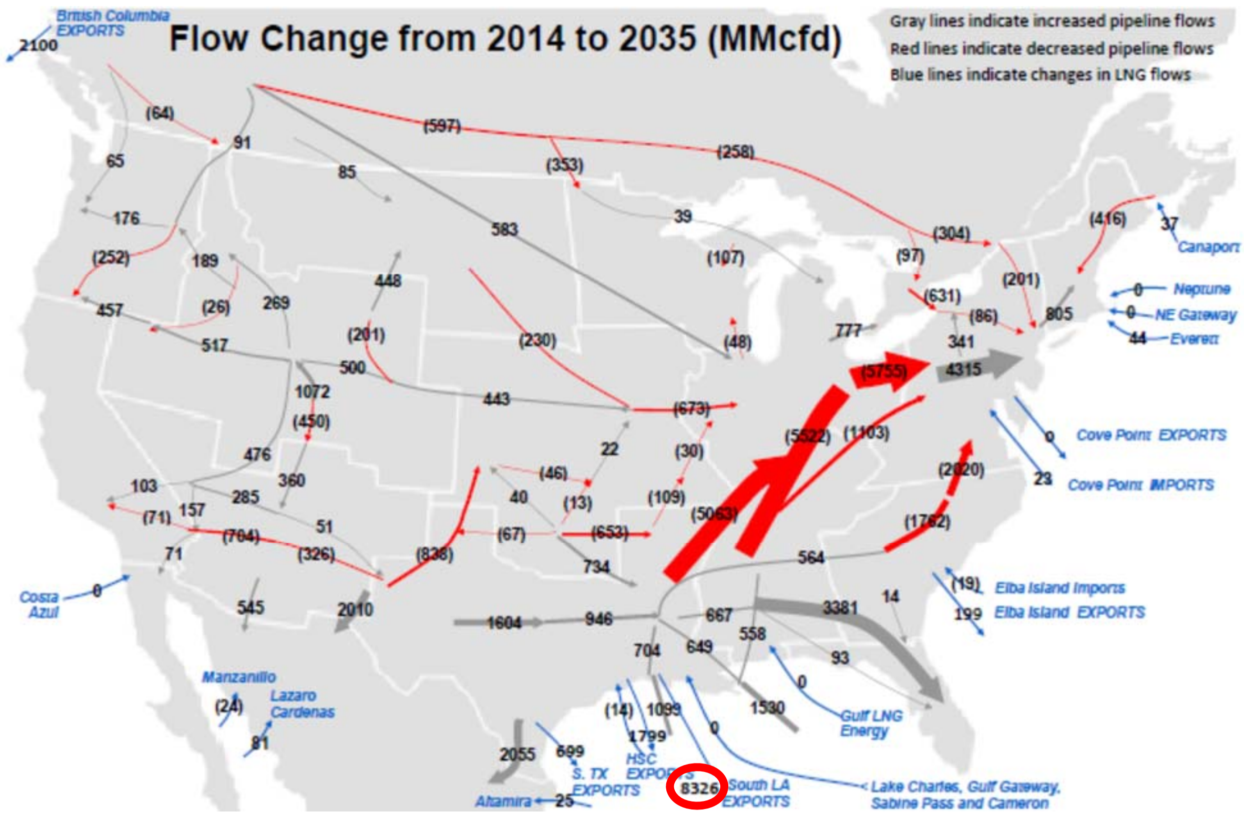
Exhibit 5-5: Base Case U.S. Natural Gas Market Flow Changes



Source: ICF

The map below shows The T 4-5 Expansion Case U.S. natural gas flows, which are similar to Base Case Flows. However, the red circle below shows the export volumes from Louisiana, which are 8.3 Bcfd in The T 4-5 Expansion Case, relative to 6.9 Bcfd in the Base Case.

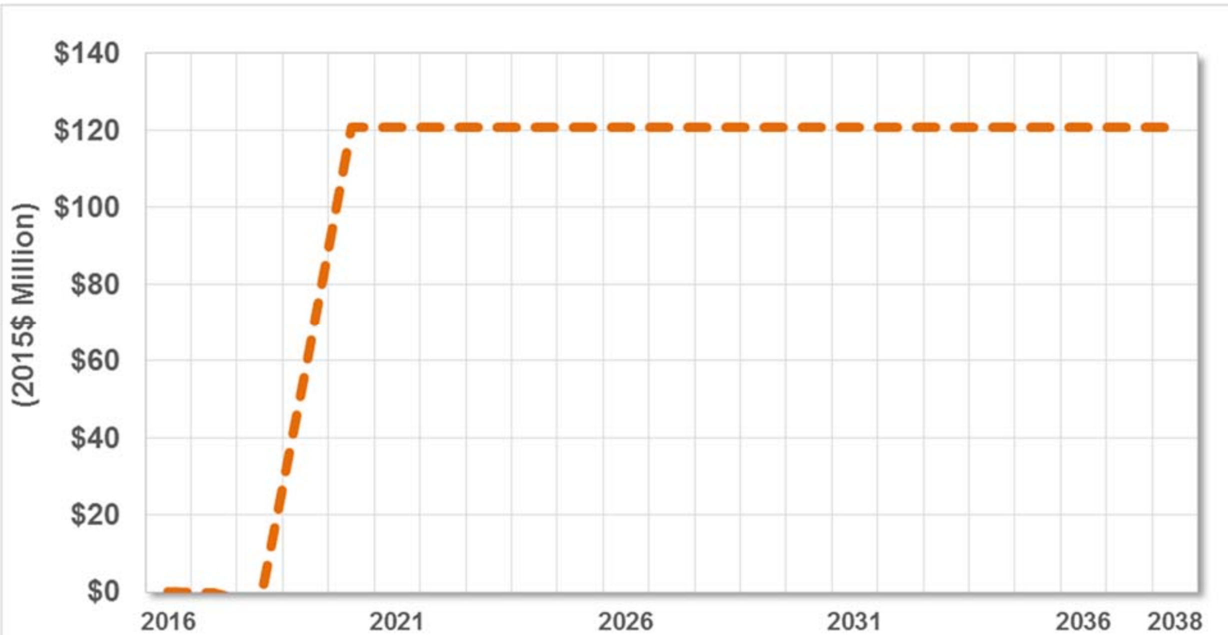
Exhibit 5-6: The T 4-5 Expansion Case U.S. Natural Gas Market Flow Changes



Source: ICF

The exhibit below (Exhibit 5-7) shows the impact on LNG plant operating expenditures (excluding the cost of natural gas feedstock but including employee costs, materials, maintenance, insurance, and property taxes). Port fees paid by the shipper during the tanker loading process are also included here. Over the study period of 2016 to 2038, there is a total cumulative impact on operating expenditures of $2.4 billion in the T 4-5 Expansion Case as compared to the Base Case. LNG plant operating expenditures average $102.1 million higher *annually* in the T 4-5 Expansion Case, as compared to the Base Case.

Exhibit 5-7: U.S. LNG plant Operating Expenditure Changes

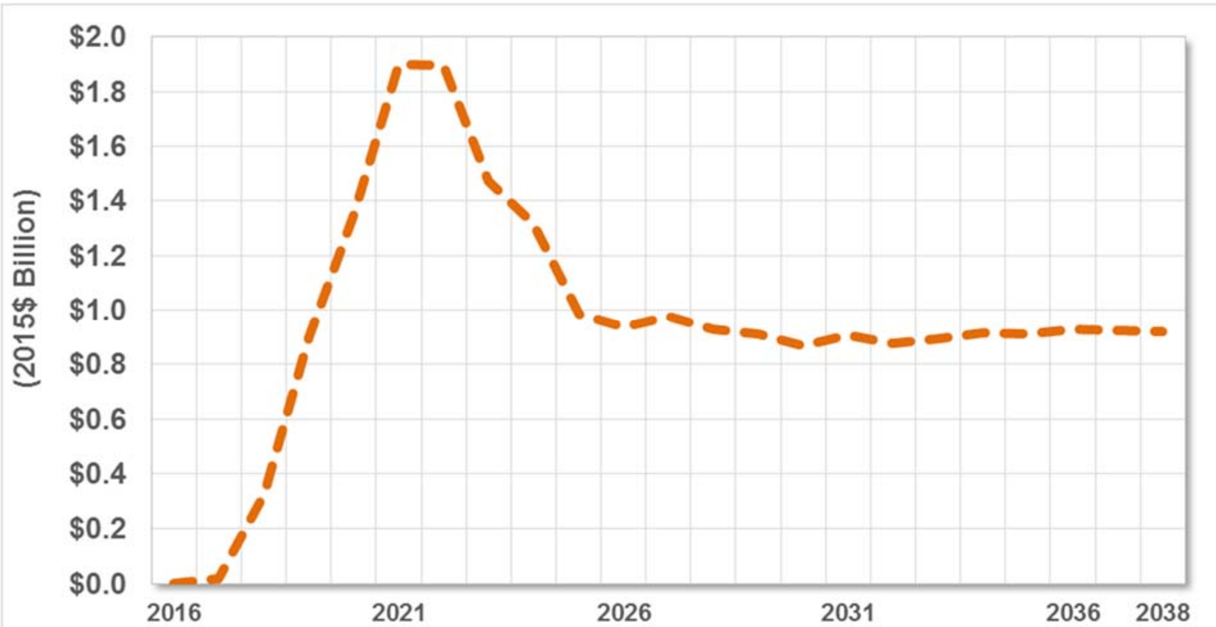


Year	LNG Facility Operating Expenditures
	T 4-5 Exp Case Change
2016	$ -
2021	$ 120.7
2026	$ 120.7
2031	$ 120.7
2036	$ 120.7
2038	$ 120.7
2016-2038 Avg	*$ 102.1*
2016-2038 Sum	**2,348.1**

Source: ICF

The exhibit below (Exhibit 5-8) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. There is a spike in investment in the early years as more drilling is needed to add the extra deliverability needed as LNG production ramps up. Once full LNG production is reached, fewer new wells are required to sustain production. Over the forecast period of 2016 to 2038, there is a total cumulative impact on U.S. upstream capital expenditures of $22.1 billion in the T 4-5 Expansion Case as compared to the Base Case. U.S. upstream capital expenditures average $1 billion more annually in the T 4-5 Expansion Case as compared to the Base Case.

Exhibit 5-8: U.S. Upstream Capital Expenditure Changes

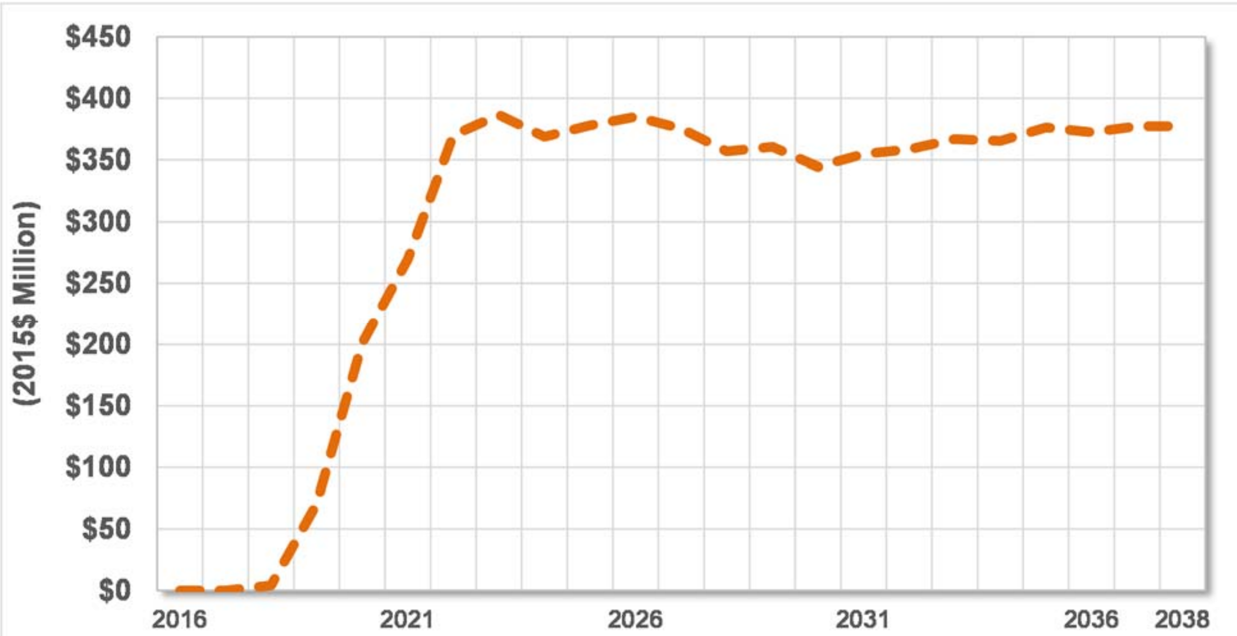


Year	Upstream Capital Expenditures (2015$ Billion) T 4-5 Exp Case Change
2016	$ -
2021	$ 1.9
2026	$ 0.9
2031	$ 0.9
2036	$ 0.9
2038	$ 0.9
2016-2038 Avg	*$ 1.0*
2016-2038 Sum	**$ 22.1**

Source: ICF

As shown below (Exhibit 5-9), U.S. upstream operating expenditures are expected to increase $306.7 million annually in the T 4-5 Expansion Case as compared to the Base Case between 2016 and 2038, on average. This represents a cumulative expenditure increase of $7 billion.

Exhibit 5-9: U.S. Upstream Operating Expenditure Changes



Year	Upstream Operating Expenditures (2015$ Million)	
	T 4-5 Exp Case Change	
2016	$	-
2021	$	279.5
2026	$	388.1
2031	$	378.4
2036	$	379.5
2038	$	379.9
2016-2038 Avg	*$*	*306.7*
2016-2038 Sum	**$**	**7,053.2**

Source: ICF

The exhibit below (Exhibit 5-10) shows the Base Case and the T 4-5 Expansion Case U.S. natural gas consumption and LNG exports. The additional LNG export volumes of 1.41 Bcfd (plus liquefaction fuel use of 10 percent, thus totaling 1.55 Bcfd) are expected to lead to a small reduction in U.S. natural gas consumption of 0.13 Bcfd in 2038. This is driven primarily by reduced power sector gas use, as well as a slight decline in residential and commercial gas use. This contraction in U.S. domestic natural gas consumption is the equivalent to 9 percent of the Trains 4-5 incremental export volumes, with the remainder coming from additional U.S. natural gas production and natural gas imports over the forecast period.

Exhibit 5-10: U.S. Domestic Natural Gas Consumption by Sector

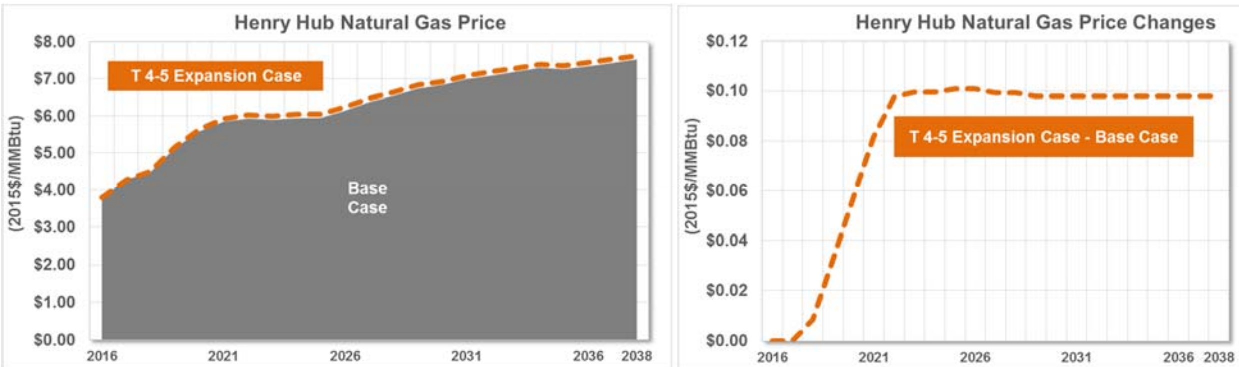
* Includes pipeline fuel and lease & plant

Note: Charts above do not include LNG exports or liquefaction fuel.

Source: ICF

The Henry Hub natural gas price is expected to increase $0.08/MMBtu on average over the forecast period through 2038, averaging $6.32/MMBtu over the forecast period, compared with $6.24/MMBtu in the Base Case, as shown in Exhibit 5-11Exhibit 5-12. The T 4-5 Expansion Case natural gas prices at Henry Hub are expected to reach $7.52/MMBtu in the Base Case and $7.62 in the T 4-5 Expansion Case by 2038, indicating a natural gas price increase of $0.08/MMBtu attributable to the T 4-5 LNG export volumes of 1.41 Bcfd. Between 2020 and 2038, Henry Hub natural gas prices are expected to increase an average of $0.10/MMBtu over the Base Case.

Exhibit 5-11: Annual Average Henry Hub Natural Gas Price Changes

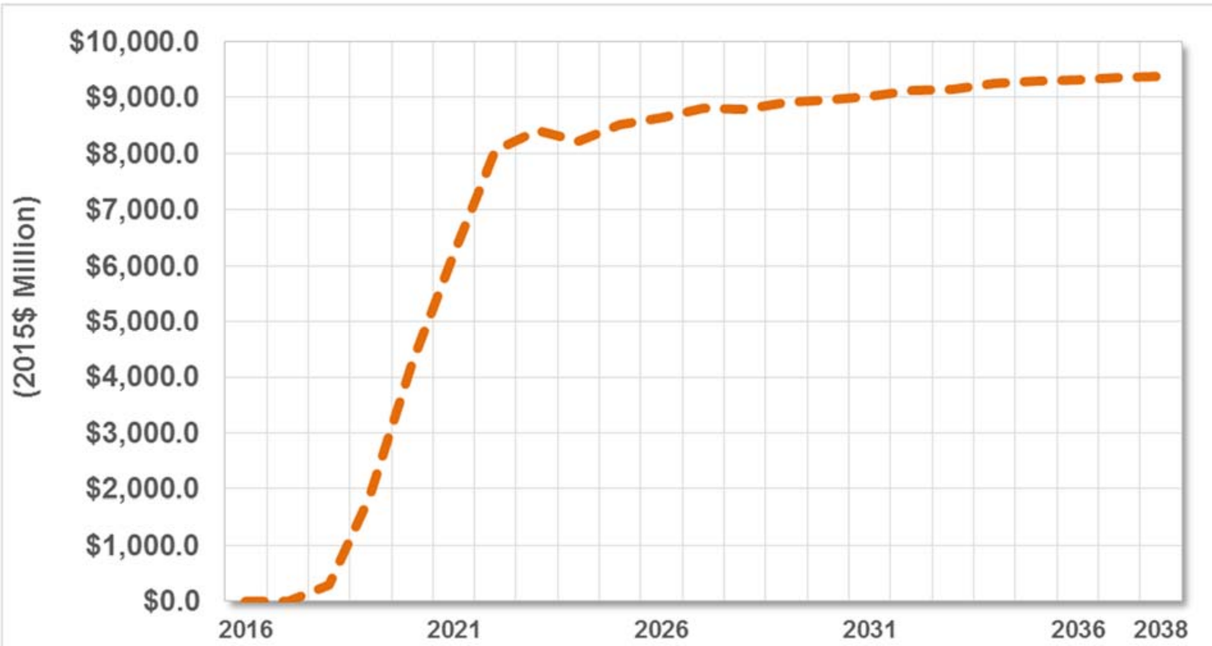


Year	Henry Hub Natural Gas Price (2015$/MMBtu)		
	Base Case	T 4-5 Exp Case	T 4-5 Exp Case Change
2016	$ 3.80	$ 3.80	$ -
2021	$ 5.85	$ 5.93	$ 0.08
2026	$ 6.14	$ 6.24	$ 0.10
2031	$ 6.98	$ 7.08	$ 0.10
2036	$ 7.33	$ 7.43	$ 0.10
2038	$ 7.52	$ 7.62	$ 0.10
2016-2038 Avg	*$ 6.24*	*$ 6.32*	*$ 0.08*

Source: ICF

Exhibit 5-12 illustrates the impacts of additional volumes on the U.S. natural gas and liquids production value, which increases as a result of additional LNG export volumes and higher prices as seen in the T 4-5 Expansion Case. Over the forecast period 2016 to 2038, the natural gas and liquids production value in the T 4-5 Expansion Case sums to $163.8 billion higher than the Base Case. Production values are nearly $7.1 billion larger annually in the T 4-5 Expansion Case as compared to the Base Case between 2016 and 2038.

Exhibit 5-12: U.S. Natural Gas and Liquids Production Value Changes



Year	Natural Gas and Liquids Production Value (2015$ Million)
	T 4-5 Exp Case Change
2016	$ -
2021	$ 6,215.3
2026	$ 8,635.7
2031	$ 9,012.1
2036	$ 9,316.4
2038	$ 9,380.0
2016-2038 Avg	*$ 7,123.9*
2016-2038 Sum	**$ 163,849.4**

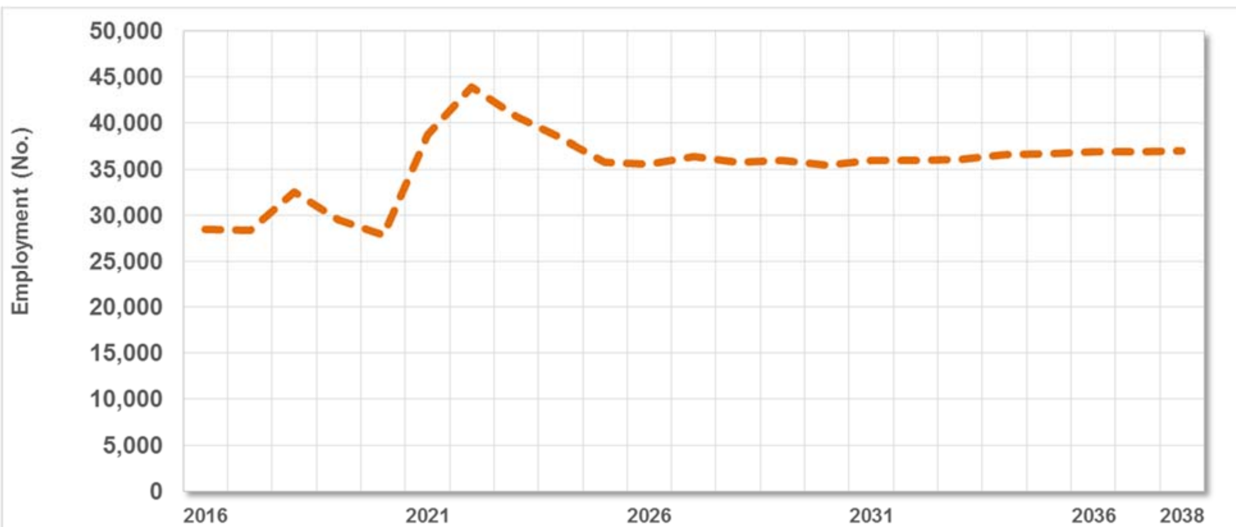
Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

Exhibit 5-13 shows the impacts of additional volumes on total U.S. employment by case.[14] The employment impacts are across all industries nationwide, and include direct, indirect, and induced employment. For example, the employment changes include direct and indirect jobs related to additional oil and gas production (such as drilling wells, drilling equipment, trucks to and from the drilling sites, construction workers), as well as induced jobs. Induced jobs are created when direct and indirect employment increases, and direct and indirect workers spend their higher incomes, creating induced impacts throughout the economy.

Employment numbers are expected to increase as a result of the additional LNG export terminal capacity construction and operation, as well as the indirect and induced employment impacts. The number of anticipated average annual jobs between 2016 and 2038 is nearly 35,500 jobs greater in the T 4-5 Expansion Case than in the Base Case. Over the forecast period the added LNG export terminals are expected to increase job-years relative to the Base Case by over 816,200 job-years.

Exhibit 5-13: Total U.S. Total Employment Changes



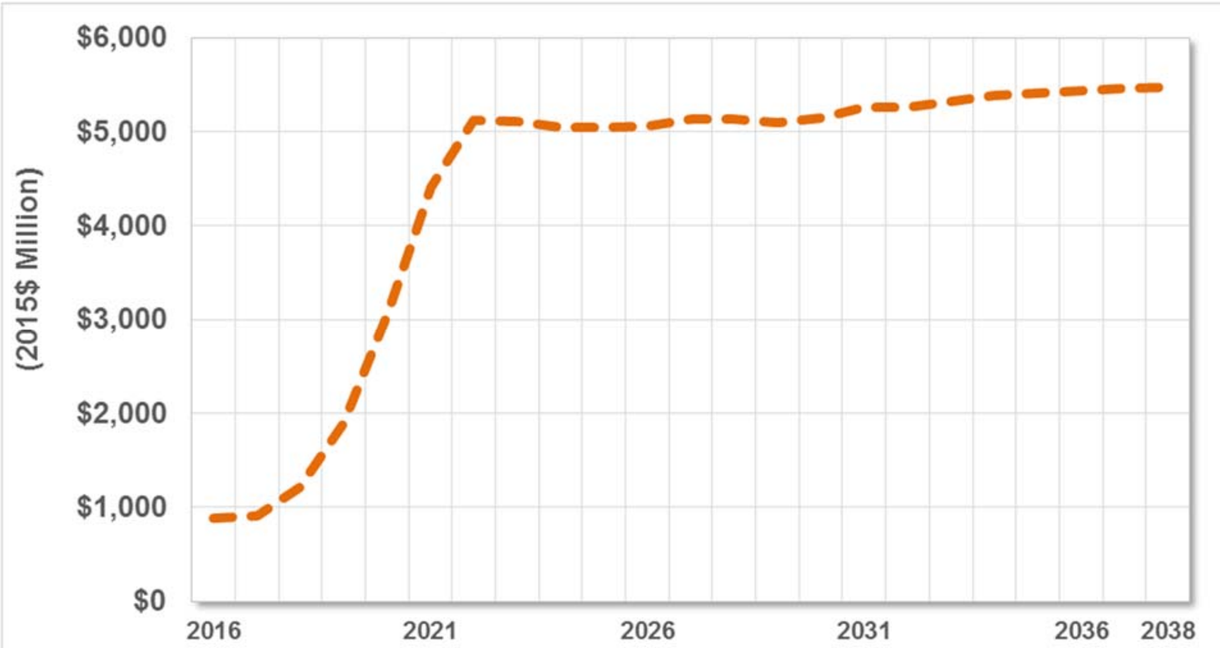
Year	Employment (No.)
	T 4-5 Exp Case Change
2016	28,492
2021	38,758
2026	35,573
2031	36,032
2036	36,957
2038	37,008
2016-2038 Avg	*35,489*
2016-2038 Sum	**816,244**

Source: ICF

[14] Note that one job in this report refers to a job-year.

Exhibit 5-14 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective government revenues increase $4.4 billion annually as a result of the T 4-5 Expansion Case additional LNG export trains, or $101.2 billion cumulative over the forecast period between 2016 and 2038.

Exhibit 5-14: U.S. Federal, State, and Local Government Revenue Changes



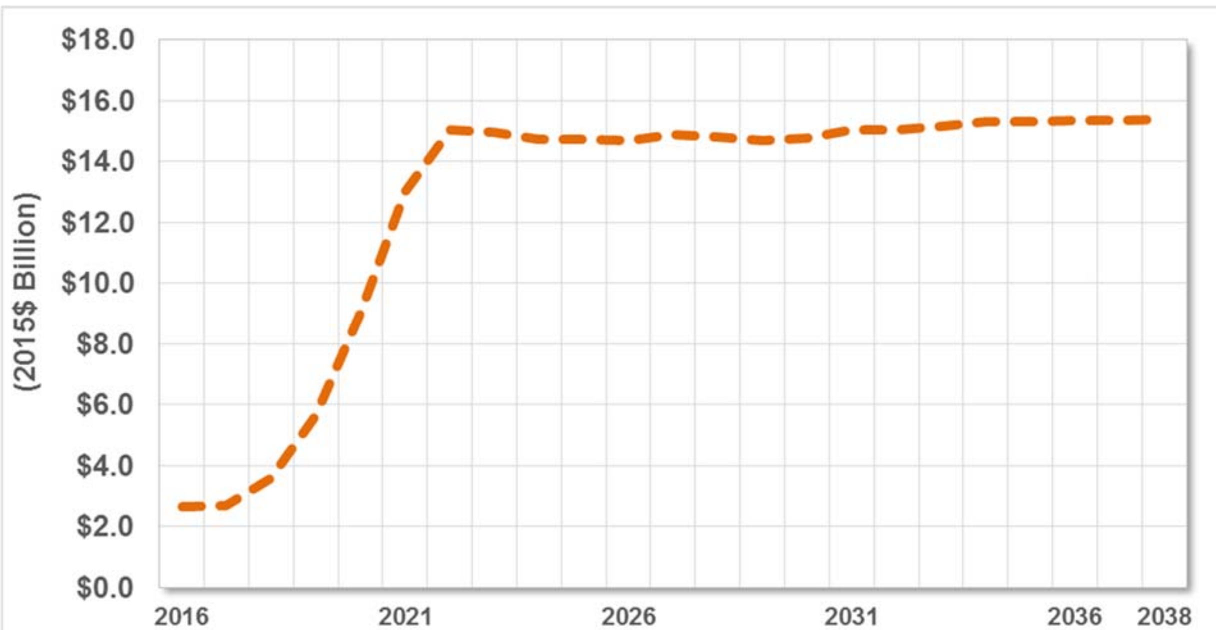
Year	Government Revenues (2015$ Million)	
	T 4-5 Exp Case Change	
2016	$	885.6
2021	$	4,416.0
2026	$	5,058.7
2031	$	5,255.5
2036	$	5,435.2
2038	$	5,475.6
2016-2038 Avg	*$*	*4,401.5*
2016-2038 Sum	**$**	**101,233.7**

Source: ICF

Exhibit 5-15 shows the impacts of additional LNG export on total U.S. value added (that is, additions to U.S. GDP). The value added is the total U.S. output changes attributable to the incremental LNG exports minus purchases of imported intermediate goods and services. Based on U.S. historical averages across all industries, about 16 percent of output is made of imported goods and services. The value for imports used in the ICF analysis differs by industry and is computed from the IMPLAN matrices.

Total value added increases substantially as a result of the additional LNG export volumes assumed in the T 4-5 Expansion Case. The additional LNG volumes in the T 4-5 Expansion Case result in a $12.7 billion annual average increase of value added over the 2016-2038 23-year period. The cumulative value added over the period between the Base Case and the T 4-5 Expansion Case Volumes Case totals $292 billion.

Exhibit 5-15: Total U.S. Value Added Changes

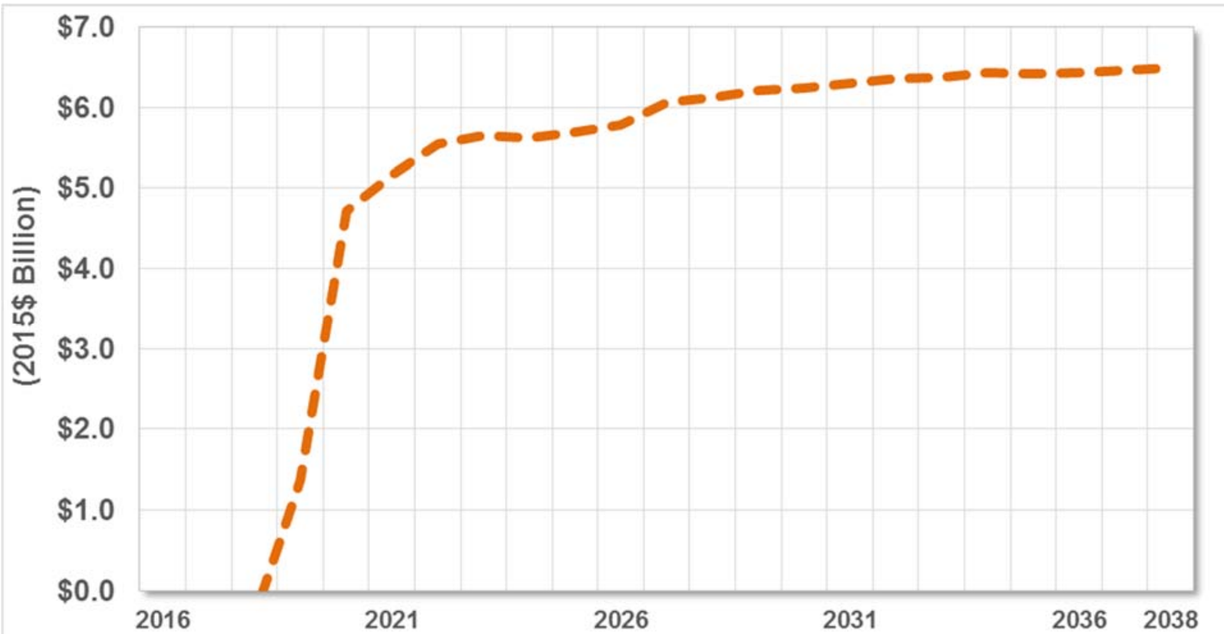


Year	Total Value Added (2015$ Billion)	
	T 4-5 Exp Case Change	
2016	$	2.7
2021	$	13.0
2026	$	14.7
2031	$	15.1
2036	$	15.4
2038	$	15.4
2016-2038 Avg	*$*	*12.7*
2016-2038 Sum	**$**	**292.0**

Source: ICF

The expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $5.0 billion annually between 2016 and 2038, based on the value of LNG export volumes, or a cumulative value of $114.4 billion. The improved balanced of trade is primarily a result of the LNG exports themselves (encompassing the natural gas feedstock used to make the LNG, the LNG liquefaction process and the port services) and the additional hydrocarbon liquids production which is assumed to either substitute for imported liquids or be exported.

Exhibit 5-16: U.S. Balance of Trade Changes



Year	Balance of Trade (2015$ Billion)	
	T 4-5 Exp Case Change	
2016	$	(0.4)
2021	$	5.2
2026	$	5.8
2031	$	6.3
2036	$	6.4
2038	$	6.5
2016-2038 Avg	*$*	*5.0*
2016-2038 Sum	**$**	**114.4**

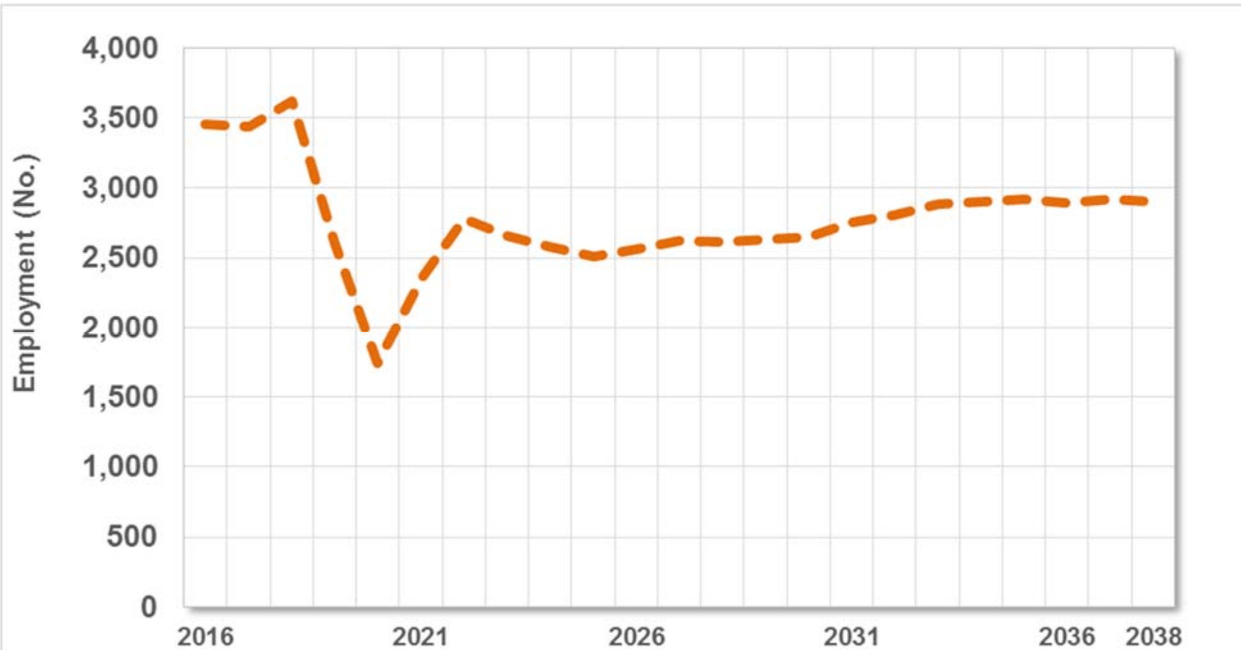
Source: ICF

5.2 Louisiana Impacts

The exhibits below describe the energy market and economic impacts of the LNG export cases in Louisiana.

Exhibit 5-17 shows the impacts of LNG export volumes on Louisiana total employment by case, including direct, indirect, and induced jobs. Employment numbers increase as a result of additional LNG export volumes and can be attributed to the construction and operation of the added LNG trains and to the added natural gas production that will take place in the state and in other state to which Louisiana companies offer support services. The T 4-5 Expansion Case exhibits an increase of nearly 2,800 jobs on an average annual basis from 2016 to 2038 as compared to the Base Case. This equates to a cumulative impact of over 63,800 Louisiana job-years over the 23-year forecast period through 2038.

Exhibit 5-17: Louisiana Total Employment Changes

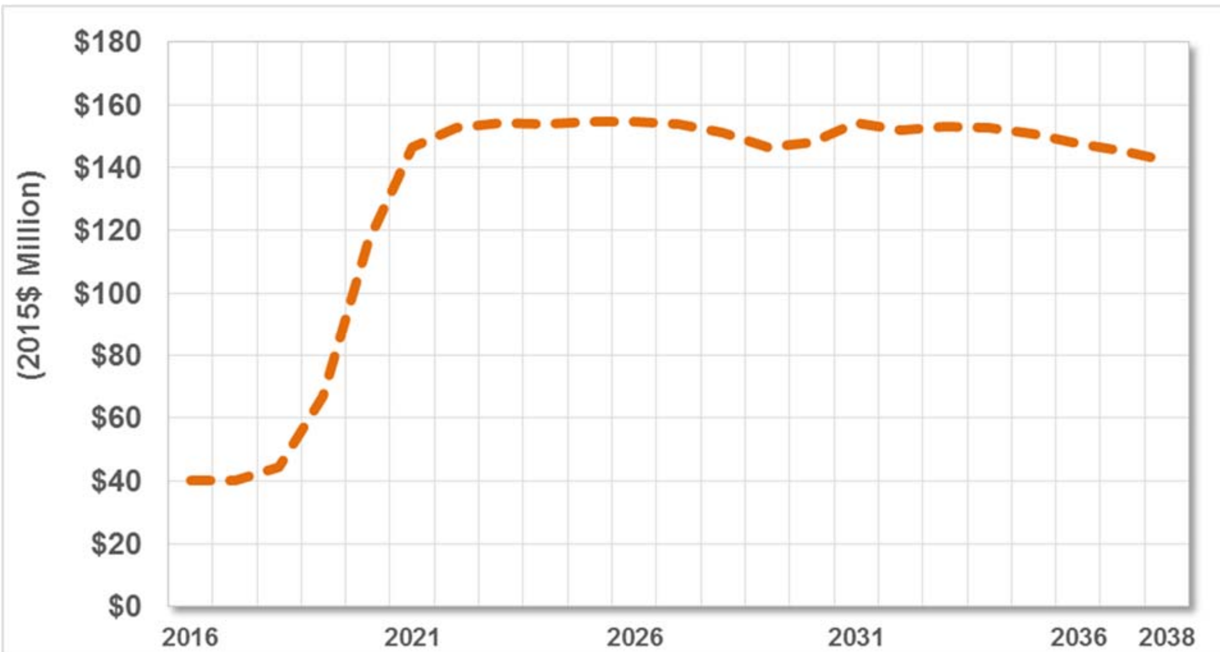


Year	Employment (No.) T 4-5 Exp Case Change
2016	3,455
2021	2,353
2026	2,564
2031	2,754
2036	2,897
2038	2,906
2016-2038 Avg	*2,773*
2016-2038 Sum	**63,790**

Source: ICF

Exhibit 5-18 shows the impacts of LNG export volumes on Louisiana state and local government revenue changes by case, as well as federal government revenues taking place within Louisiana. Total Louisiana government revenues increase as a result of the additional LNG export volumes assumed in the T 4-5 Expansion Case. Relative to the Base Case, the additional LNG volumes in the T 4-5 Expansion Case result in a $131.4 million average annual increase to government revenues throughout the 23-year forecast period through 2038, or a cumulative impact of approximately $3.0 billion.

Exhibit 5-18: Louisiana Government Revenue Changes

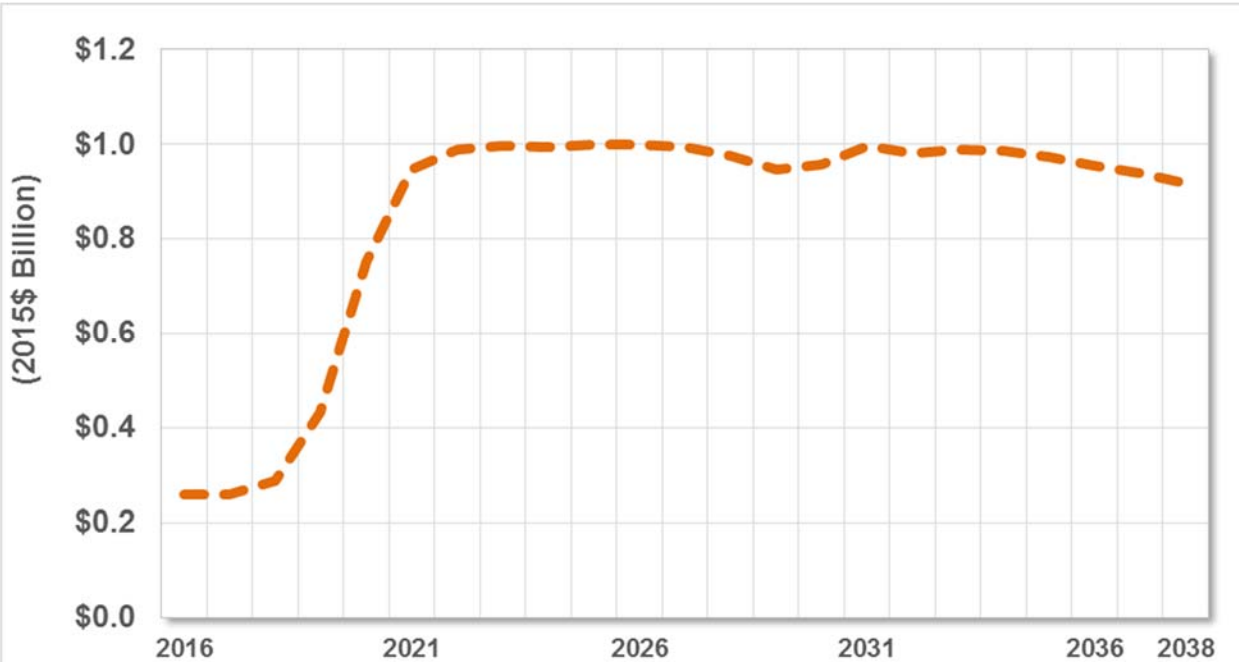


Year	Government Revenues (2015$ Million)	
	T 4-5 Exp Case Change	
2016	$	40.1
2021	$	146.3
2026	$	154.7
2031	$	154.1
2036	$	147.7
2038	$	142.2
2016-2038 Avg	*$*	*131.4*
2016-2038 Sum	**$**	**3,021.1**

Source: ICF

Exhibit 5-19 shows the impacts of LNG export volumes on total Louisiana value added to gross state product (GSP) by case. Louisiana value added increases substantially as a result of the additional LNG export volumes assumed in the T 4-5 Expansion Case. Throughout the study period 2016 to 2038 the additional LNG volumes in the T 4-5 Expansion Case result in a $0.8 billion annual average increase to government revenues, relative to the Base Case. The total differential of value added to Louisiana over the study period between the Base Case and the T 4-5 Expansion Case is $19.5 billion.

Exhibit 5-19: Total Louisiana Value Added Changes



Year	Total Value Added (2015$ Billion)	
	T 4-5 Exp Case Change	
2016	$	0.3
2021	$	0.9
2026	$	1.0
2031	$	1.0
2036	$	1.0
2038	$	0.9
2016-2038 Avg	*$*	*0.8*
2016-2038 Sum	**$**	**19.5**

Source: ICF

6 Bibliography

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7 Appendices

Appendix A: LNG Economic Impact Study Comparisons

This section explores ICF's assessment of LNG export impacts on the U.S. economy versus previous studies performed by ICF and others. This study differs from previous ICF studies in that productivity of new wells has improved due to upstream technology advances. This means that fewer wells need to be drilled and less upstream expenditures are needed per Bcfd of LNG exports than calculated in past ICF analyses. The lower expenditures translate into few upstream job gains. In addition, GDP gains per Bcfd of LNG exports are lower relative to past studies, largely due to lower assumed crude oil, condensate and natural gas liquids prices, which reduce the value of liquids produced along with the gas used as a feedstock and fuel in the liquefaction plants. In addition, due to higher well productivity rates (driven by upstream technology advances) this study finds that U.S. gas production is more elastic and thus a smaller reduction in gas consumption is needed to rebalance the market to accommodate LNG exports.

ICF International's May 2013 study for the American Petroleum Institute looked at impacts of LNG exports on natural gas markets, GDP, employment, government revenue and balance of trade.[15] The four cases considered include no exports compared to 4, 8, and 16 Bcfd of exports. LNG exports are expected to increase domestic gas prices in all cases, raising Henry Hub prices by $0.32 to $1.02 (in 2010 dollars) on average during the 2016-2035 period. GDP and employment see net positive gains from LNG exports, as employment changes reach up to 665,000 annual jobs by 2035 while GDP gains could reach $78-115 billion in 2035. Different sectors feel varying effects from LNG exports. In the power sector, electricity prices are expected to increase moderately with gas prices. The petrochemicals industry benefit from the incremental 138,000-555,000 bpd of NGL production due to the drilling boost fueled by higher gas demand.

NERA's December 2012 study for the EIA looked at four LNG export cases from 6 Bcfd to unconstrained LNG exports using four EIA Annual Energy Outlook (AEO) 2011 scenarios.[16] In the unconstrained LNG export scenario, the study found that the U.S. can support up to 22.9 Bcfd of LNG exports. Gas price impacts range from zero to $0.33 per thousand cubic feet (Mcf) (in 2010 dollars), peaking in the earlier years and are higher in high production cases. Overall, LNG exports have positive impacts on the economy, boosting the GDP by up to 0.26 percent by 2020 and do not change total employment levels. According to NERA, sectors likely to suffer from gas price increases due to intensive gas use will experience only small output and employment losses.

[15] ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy". ICF International, May 15, 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf
[16] NERA Economic Consulting. "Macroeconomic Impacts of LNG Exports from the United States". NERA, December 3, 2012: Washington, DC. Available at: http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf

NERA provided an update to its December 2012 study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[17] The report examined various export cases from no exports to 53.4 Bcfd in the High Oil and Gas Resource Case with no export constraints. The U.S. continues to maintain a low natural gas price advantage even when exports are not constrained. GDP gains could reach as much as $10-$86 billion by 2038 and are positive across all cases. LNG exports also lower the number of unemployed by 45,000 between 2013 and 2018. NERA's March 2014 report acknowledged the contribution of LNG exports to increasing NGL production and thus lowering feedstock prices for the petrochemicals industry. Electric sector growth will likely slow somewhat, however, compared to the No Exports Case.

The EIA released its first study of LNG export impacts on energy markets in January 2012, looking at four export scenarios from 6 to 12 Bcfd based on AEO 2011 case assumptions.[18] The study found that LNG exports lead to gas price increases by up to $1.58/Mcf by 2018 while boosting gas production by 60 to 70 percent of LNG export levels. Within the power sector, gas-fired generation sees the most dramatic decline while coal and renewable generation show small increases. This study did not look at economic impacts of LNG exports.

The EIA's October 2014 study revisited five AEO 2014 cases with elevated levels of LNG exports between 12 and 20 Bcfd, a sharp increase from the range considered in the EIA's January 2012 study.[19] Relative to the January 2012 study, LNG exports further increase average gas prices by 8 to 11 percent depending on the case, and boosts natural gas production by 61 percent to 84 percent of the LNG export level. Imports from Canada increase slightly while domestic consumption declines by less than 2 Bcfd on average mostly in power generation and industrial consumption. The overall impact on the economy is positive, with GDP increased by 0.05 percent. Consumer spending on gas and electricity increases by "modest" levels, about 1-8 percent for gas and 0-3 percent for electricity compared to the January 2012 results.

Charles River Associates (CRA) released a study on LNG export impacts for Dow Chemical Company in February 2013 with different methodologies and conclusions from the studies mentioned above.[20] Examining export cases from 20 Bcfd to 30 Bcfd by 2030, CRA argued that LNG export can raise gas prices to between $8.80 to $10.30/MMBtu by 2030, significantly above the reference price of $6.30/MMBtu. Electricity price impacts are also much greater than other studies, about 60 percent to 170 percent above the No Exports Case. CRA also compared

[17] NERA Economic Consulting. "Updated Macroeconomic Impacts of LNG from the United States". NERA, March 24, 2014: Washington, DC. Available at: http://www.nera.com/content/dam/nera/publications/archive2/PUB_LNG_Update_0214_FINAL.pdf
[18] U.S. Energy Information Administration. "Effect of Increased Natural Gas Exports on Domestic Energy Markets". EIA, January 2012: Washington, DC. Available at: http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[19] U.S. Energy Information Administration. "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets". EIA, October 2014: Washington, DC. Available at: http://www.eia.gov/analysis/requests/fe/pdf/lng.pdf
[20] Charles River Associates (CRA). "U.S. LNG Exports: Impacts on Energy Markets and the Economy". ICF International, May 15, 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf

economic values of gas use in manufacturing versus in LNG exports, finding that manufacturing creates much higher output and more jobs than do LNG exports.

See the exhibit below for more details by study.

Exhibit 7-1: Selected LNG Export Studies

Facility	Summary of Analysis	Case	Impact LNG Exports: Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	Main Conclusions
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	∆GDP/∆ Jobs	
Cameron LNG (ICF 2015)	Trains 4-5 expansion of 1.41 Bcfd	1.41 Bcfd incremental increase in LNG exports	$0.08	$0.06	94%	9%	7%	110%	1.5	25,200	$358,861	Increasing exports at Cameron LNG is anticipated to lead to value added and job increases for the U.S.
Cameron LNG (ICF 2015)	Trains 1-3 supplemental volumes of 0.42 Bcfd in LNG exports	0.4 Bcfd incremental increase in LNG exports	$0.03	$0.07	96%	8%	6%	110%	1.5	21,900	$420,000	Increasing exports at Cameron LNG is anticipated to lead to value added and job increases for the U.S.
Sabine Pass (Navigant)	5 cases examining different levels of U.S. demand and LNG export ranging from 0 to 2 Bcfd (only 2 relevant cases - 1 bcfd exports, 2 bcfd exports)	1 Bcfd LNG exports	$0.18	$0.18	58%	-1%	43%	75%	N/A	Construction: 3000 (or 1500 per Bcfd) Upstream: 30,000 - 50,000 (or 15,000-25,000/Bcfd) for "regional and national economies"	N/A	North American shale growth can support development of Sabine Pass LNG facility. Gas price impact of LNG export is modest.
		2 Bcfd LNG exports	$0.35	$0.18	55%	-1%	55%	100%	N/A		N/A	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Jordan Cove (Navigant)	7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd	2.9 Bcfd [0.9 Bcfd incremental LNG exports from Jordan Cove (in addition to 2 Bcfd assumed in the base case)]	$0.03 (0.9 Bcfd)	$0.03	14%	7%	95%	0%	N/A	Construction: 1768 direct, 1530 indirect, 1838 induced (5136 total or 6188 per Bcfd) Operation: 99 direct, 404 indirect, 182 induced (736 total or 887 per Bcfd) Upstream: 20359 average, 27806 through 2035, 39366 through 2045 (in attached ECONorthwest study or 33501 per Bcfd through 2035)	N/A (separate reports on GDP impact attributed to regional, trade, upstream but no total)	Gas price impacts of Jordan Cove are "negligible". Jordan Cove creates positive economic and employment benefits for Oregon and Washington states.
		5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to Base Case Bcfd and 0.9 Bcfd incremental)]	$0.38 (3.9 Bcfd)	$0.10	80%	11%	12%	116%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports: Henry Hub Price Change Relative to Reference Case		Impact LNG Exports: Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	Main Conclusions
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Freeport (Deloitte)	Single scenario, with and without	6 Bcfd LNG exports	$0.12 citygate national average, $0.22 at HH (2016-2035)	$0.02 (citygate) , $0.04 (HH)	63%	17%	20%	80%	1.34-1.90 (based on GDP)	Construction: more than 3000 Operation:20 - 30 permanent Indirect: 2015-2040 avg: M.E. = 1.34: 18,211 (or 12,141 per Bcfd) 2015-2040 avg: M.E. = 1.55: 20,929 (or 13,953 per Bcfd) 2015-2040 avg: M.E. = 1.90: 16,852 (or 11,235 per Bcfd) (attached Altos study). 1.5 Bcfd project	2015-2040 avg: M.E. = 1.34: $200,000 2015-2040 avg: M.E. = 1.55: $201,300 2015-2040 avg: M.E. = 1.90: $306,432	Freeport has "minimal" gas price impacts. The project creates 17,000-21,000 new jobs and contributes $3.6-$5.2 billion for the economy.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
EIA (NEMS Modeling)	Total of 16 cases with 4 export scenarios examining impacts of either 6 or 12 Bcfd of exports phased in at a rate of 1 Bcfd per year or 3 Bcfd per year	5.3 Bcfd - 11.2 Bcfd (AEO Ref)	$0.55-$1.22	$0.10-$0.12	61%-64%	36%-39%	2%-3%	103%	N/A	N/A	N/A	Gas price impacts vary depending on the level of exports and pace of export ramp-up and moderate over time in all cases. Drilling and production get a boost while power and industrial gas use decline somewhat.
		5.3 Bcfd - 11.2 Bcfd (High Shale)	$0.38-$0.87	$0.07-$0.12	61%-64%	34%-37%	5%	103%	N/A	N/A	N/A	
		5.3 Bcfd - 11.2 Bcfd (Low Shale)	$0.77-$1.65	$0.15-$0.17	55%-60%	32%-37%	11%-12%	104%	N/A	N/A	N/A	
		5.3 Bcfd - 11.2 Bcfd (High GDP)	$0.55-$1.26	$0.10-$0.12	71%-72%	29%-30%	2%-3%	103%	N/A	N/A	N/A	
EIA (NERA)	8 cases examining different levels of U.S. demand and LNG export ranging from 3.75 to 15.75 Bcfd	6 Bcfd (Reference)	$0.34-$0.60	$0.09 to $0.10	51%	49%	0%	100%	N/A	Not likely to affect overall employment	N/A	LNG export leads to higher gas prices, with impacts ranging from $0.14 to $1.61/Mcf. The economy reaps positive benefits from LNG exports across all cases.
		12 Bcfd (Reference)	$1.20		51%	49%	0%	100%	N/A			
		Unlimited Bcfd (Reference)	$1.58		50%	50%	0%	100%	N/A			
	7 cases examining different levels of U.S. demand and LNG exports ranging from 6 to 23 Bcfd	6 Bcfd (High EUR)	$0.42	$0.07	50%	50%	0%	107%	N/A			
		12 Bcfd (High EUR)	$0.84		49%	51%	0%	100%	N/A			
		Unlimited Bcfd (High EUR)	$1.08 - $1.61		46%	54%	0%	100%	N/A			
	Single scenario with LNG exports reaching 1.42 Bcfd	6 Bcfd (Low EUR)	$0.14 (1 Bcfd)	$0.14	51%	49%	0%	115%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
EIA (2014 Update)	5 export cases with supply and demand assumptions based on AEO 2014 and DOE	Reference	$0.30 - $0.50	N/A	61-84%	10-18%	N/A	N/A	N/A	Change in nonfarm employment less than 0.1 million, representing up to 0.1% increase relative to the baseline	N/A	LNG exports result in positive economic benefits, enough to overcome the impact of higher gas prices.
		High Oil and Gas Resource	0 - $0.20	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		Low Oil and Gas Resource	$0.90 - $1.40	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		High Macroeconomic Growth	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		Accelerated Coal and Nuclear	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
NERA (2014 Update)	5 cases with export ranging from 6 to unlimited	6 Bcfd (Reference)	$0.43/MMBtu by 2038	$0.07	61%	38-39%	0%	99-100%	N/A	LNG Exports could reduce unemployment by 45,000 before the economy returns to full employment by 2018.	N/A	LNG export leads to gas price increases. It also leads to gains in GDP, employment, and the chemical sectors.
		Unlimited Bcfd (Reference)	$0.36-$1.33	$0.02-$0.03	63%	36-104%	0%	99-167%	N/A			
	7 cases with export ranging from 6 to unlimited	6 Bcfd (High Oil and Gas Resource)	$0.16	$0.03	65-168%	33-34%	0%	98-202%	N/A			
		12 Bcfd (High Oil and Gas Resource)	$0.30-$0.34	$0.03	65-67%	33-35%	0%	98-102%	N/A			
		Unlimited Bcfd (High Oil and Gas)	$0.96-$1.38	$0.96	68%	32%	0%	100%	N/A			
	2 cases with	6 Bcfd (Low Oil and Gas)	$0.90	$0.15	59%	41%	0%	100%	N/A			
		Unlimited Bcfd (Low Oil and Gas)	$1.78	$0.03	58%	42%	0%	100%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports										Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact		
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs		
Dow Chemical (CRA)	3 export scenarios with CRA Base Demand (adjusted AEO 2013 for industrial demand)	4 Bcfd LNG export (AEO export), CRA Base Demand	$0.90 (2013-2030)	$0.23 (using 4 bcfd)	N/A	N/A	N/A	N/A	GDP-based M.E. not given. Indirect value not estimated. Employment-based M.E.: 30 (each direct job leads to 30 jobs along the supply chain)	N/A	N/A		LNG export increases gas prices significantly. Gas use in manufacturing yields higher benefits than in LNG exports. Impacts on gas and NGL production and the economy are not given.
		9 Bcfd LNG exports by 2025 and 20 Bcfd by 2030 layered on CRA Base Demand	$2.50 (2013-2030)	$0.13 (using 20 bcfd)	N/A	N/A	N/A	N/A		N/A	N/A		
		20 Bcfd LNG exports by 2025 and 35 Bcfd by 2030 layered on CRA Base Demand	$4.00 (2013-2030)	$0.11(using 35 bcfd)	N/A	N/A	N/A	N/A		N/A	N/A		
RBAC, REMI	2 export scenarios: 3 Bcfd and 6 Bcfd relative to a no export scenario	3 Bcfd	About $0.60 (2012-2025)	$0.20	N/A	N/A	N/A	N/A	N/A	2012-2025 avg: 41,768 per Bcfd. Multiplier not given.	2012-2025 avg: $35,357/job in 2011 dollars		LNG exports have mixed impacts on the economy, peaking in the earlier years due to infrastructure investments. Gas price impacts range from $0.60-$2.00/MMBtu.
		6 Bcfd	About $2.00 (2012-2025)	$0.33	N/A	N/A	N/A	N/A	N/A	2012-2025 avg: 67,236 per Bcfd. Multiplier not given.	2012-2025 avg: $46,349/job in 2011 dollars		

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
API (ICF)	ICF Base Case	4 Bcfd	$0.35	$0.10	88%	21%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 17,800, M.E. = 1.9: 35,200	2015-2035 avg: M.E. = 1.3: $208,600 , M.E. = 1.9: $150,900	LNG exports have moderate gas price impacts. Depending on the scenario LNG exports increase employment by up to 452,300 and GDP by $73.6 billion by on average during 2016-2035.
	Middle Exports Case	8 Bcfd	$1.19	0.11	82%	26%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,700, M.E. = 1.9: 28,000	2015-2035 avg: M.E. = 1.3: $207,100 , M.E. = 1.9: $149,300	
	High Exports Case	12 Bcfd	$1.33	$0.10	79%	27%	8%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,400, M.E. = 1.9: 27,400	2015-2035 avg: M.E. = 1.3: $208,800 , M.E. = 1.9: $150,200	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Cameron LNG (Black & Veatch)	1 Bcfd demand curve shift relative to EIA cases	Various	$0.088/Mcf by 2025		67.8% (by 2025)		N/A		from RIMS II (Department of Commerce)	construction: 63,000; operation:53000	$211,000 /job	Gas price impacts are small, between $0.064 and $0.088/Mcf. Terminal generates 1.1 million job-years and $45 billion economic value over project lifetime.

Facility	Summary of Analysis	Case	Impact LNG Exports: Henry Hub Price Change Relative to Reference Case: $/MMBtu	Henry Hub Price Change Relative to Reference Case: $/MMBtu per 1 Bcfd	Flow Impact Contribution to LNG Exports (flows add to 1 bcfd): Production Increase (%)	Flow Impact Contribution to LNG Exports (flows add to 1 bcfd): Demand Decrease (%)	Flow Impact Contribution to LNG Exports (flows add to 1 bcfd): Canadian Gas Imports (%)	Flow Impact Contribution to LNG Exports (flows add to 1 bcfd): Total Share of LNG Exports (%)	Multiplier Effect: Multiplier	Employment Impact: Jobs per Bcfd	GDP Impact: ΔGDP/Δ Jobs	Main Conclusions
Golden Pass (Perryman Group)	Refer to Deloitte's Mkt Point report for price impacts	N/A	N/A	N/A	N/A	N/A	N/A	N/A		3,860 permanent jobs for 2bcfd export	1.9 billion in 2012 dollars avg for all jobs	The project generate over $31 billion GDP and 324,000 job-years over the project life.
Southern LNG (Navigant)	3 North America LNG cases and 2 demand cases	Base Case (3.7 Bcfd)	N/A	N/A	N/A	N/A	N/A	N/A	RIMS II multipliers			North American gas resources can support the SLNG terminal. LNG exports have minimal gas price impacts and improve price stability.
		SLNG Export Case (base + 0.5)	$0.14/MM Btu by 2025	$0.28	60%	0%	N/A	N/A		during operation: 8933 avg	$145,136 .01	
		Aggregate Export Case (base + 3.5)	$0.39/MM Btu by 2025	$0.10	60%	15%	N/A	N/A				
		High Demand Base Case	$0.59/MM Btu	$1.18			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$1.64			N/A	N/A				
Pangea LNG (Black & Veatch for price and Perryman for economic impacts)	4 demand cases	Base Case			N/A	N/A	N/A	N/A				The project has limited impact on U.S. gas prices and bring significant economic benefits, including $1.4 billion in GDP and 17,230 person-years of employment.
		Pangea Export Case	$0.17/MM Btu (2018-27)	$0.14	N/A	100%	N/A	N/A		29860 permanent jobs in total	2.7 billion in total	
		High LNG Export	$0.26/MM Btu	0.09	N/A	100%	N/A	N/A				
		High LNG Export + Pangea	$0.37/MM Btu	0.09	N/A	N/A	N/A	N/A				

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Magnolia LNG (Berkeley Research Group)	6 gas market cases	Reference Case (4.6 Bcfd)										Project has negligible market and price impacts. Impacts increase with higher LNG and demand levels.
		Magnolia Scenario (5.7 bcfd)	$0.14/MM Btu by 2035	$0.13	45%	18%	9%	73%	N/A	N/A	N/A	
		Moderate LNG Scenario (9.9 Bcfd)	$0.49/MM Btu	$0.09	77%	15%	6%	98%	N/A	N/A	N/A	
		High LNG Scenario (13.9 Bcfd)	$0.90/MM Btu	$0.10	69%	16%	1%	86%	N/A	N/A	N/A	
		High Demand/ Moderate LNG (9.9 Bcfd)	$0.93/MM Btu	$0.18	138%	53%	0%	191%	N/A	N/A	N/A	
		High Demand/ High LNG (13.9 Bcfd)	$1.40/MM Btu	$0.15	109%	22%	0%	130%	N/A	N/A	N/A	
Downeast LNG (Resource Report by ICF, Market Impacts by Concentric Energy Advisors, Economic Impacts by Todd Gabe)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	County-level multiplier: 1.25 (output), 2.00 (employment) State-level multiplier: 1.59 (output), 2.73 (employment)	3525 jobs statewide during construction, 310 jobs statewide during operations	N/A	Downeast unlikely to have material impacts on North American prices or in the Northeast region. The project would have positive impacts on employment and the economy.

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