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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
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Energía Costa Azul, S. de R.L. de C.V.	)	**FE Docket No. 18-144-LNG**
	)	

APPLICATION FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATIONS TO EXPORT NATURAL GAS TO MEXICO AND TO EXPORT LIQUEFIED NATURAL GAS FROM MEXICO TO FREE TRADE AGREEMENT AND NON-FREE TRADE AGREEMENT NATIONS

ECA MID-SCALE PROJECT

Table of Contents

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Pursuant to section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"),[2] Energía Costa Azul, S. de R.L. de C.V. ("ECA") hereby submits this application ("Application") requesting that the DOE's Office of Fossil Energy ("DOE/FE") grant long-term, multi-contract authorizations for ECA to engage in exports of up to:

(1) 182 billion standard cubic feet ("Bcf") per year ("Bcf/y") (or approximately an average of 500 million cubic feet per day ("MMcf/d")) of natural gas by pipeline to Mexico, through any existing and future cross-border pipeline facilities interconnecting the United States and Mexico; and

(2) The equivalent to 161 Bcf/y (441 MMcf/d) in the form of LNG from Baja California, Mexico, to (a) any other nation that currently has or in the future 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 national treatment for trade in natural gas and LNG; and (b) any nation with which the United States does not have an FTA requiring the national treatment for trade in natural gas ("Non-FTA" nations) which has or will develop

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1 15 U.S.C. § 717b (2012).

2 10 C.F.R. Part 590 (2018).

the capacity to import LNG and with which trade is not prohibited by United States law or policy.[3]

ECA requests each of these authorizations for a 20-year period commencing on the earlier of the date of first export or seven years from the date of issuance of the authorizations requested herein. Consistent with DOE/FE policy, ECA requests that prior to the commencement of exports under its long-term agreements, it be permitted to export commissioning volumes under a short-term, blanket export application to be filed separately at a later date. ECA further requests that it be permitted to continue exporting for a total of three years following the end of the 20-year FTA and non-FTA term requested in this Application, solely to export any make-up volume that ECA may be unable to export during the original export periods.[4]

ECA requests this authorization both on its own behalf and as agent for other parties who hold title to the gas and/or LNG at the time of export. Moreover, ECA requests that DOE/FE neither limit the export locations to a specific set of border-crossing facilities, nor limit the export volumes to the capacity of one or more border-crossing facilities. ECA further requests that the DOE/FE not require ECA to file a subsequent application for supplemental authorization if new or expanded U.S. pipelines are constructed in the future that ECA could use to export natural gas up to ECA's requested export volume.

ECA is submitting this Application in connection with development of one of two sets of proposed Energía Costa Azul liquefaction and export terminal facilities (the "Project" or "ECA

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3 Natural gas that is consumed in Mexico as fuel for pipeline transportation or LNG liquefaction should be considered to be exported to Mexico, an FTA country. Thus, only the volume being re-exported from Mexico as LNG (161 Bcf/y) should require Non-FTA export authorization.

4 *See, e.g., Freeport LNG Expansion, L.P.*, DOE/FE Order Nos. 3282-B & 3357-A, FE Docket Nos. 10-161-LNG & 11-161-LNG, Order Amending DOE/FE Order Nos. 3282 and 3357, at 4-9 (June 6, 2014).

Mid-Scale Project") to be located north of Ensenada, Baja California, Mexico, approximately 31 miles south of the San Diego-Tijuana/San Ysidro border between the United States and Mexico.[5] The proposed ECA Mid-Scale Project will receive, process, and liquefy natural gas into LNG, which will be stored on location and loaded onto ocean-going vessels for export to various foreign nations. The ECA Mid-Scale Project requires various permits from regulatory entities in Mexico, as well as authorization from the DOE/FE for the export of feed gas for the Project and for the re-export of LNG from the Project to FTA and Non-FTA nations. ECA currently anticipates commencing construction activities associated with the ECA Mid-Scale Project in the first part of 2021 and commencing commercial operations no later than 2025.

In this Application, ECA is requesting authorization to export natural gas by pipeline from the United States through any of the existing cross-border pipeline facilities interconnecting the United States and Mexico.[6] ECA is also requesting that DOE/FE authorize the exportation of natural gas from facilities that may be constructed in the future. Given the configuration of the U.S. and Mexican pipeline grids, natural gas necessary to serve as feedstock for the ECA Mid-Scale Project can be sourced from multiple production basins and purchased at various liquid points throughout the United States, exported from existing and future border-crossing facilities

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5 In addition to the ECA Mid-Scale Project, ECA is also proposing to construct the ECA Large-Scale Project, which will be composed of separate LNG liquefaction facilities capable of producing up to approximately the equivalent of 1.3 Bcf/d of LNG at the same site. Concurrently with the filing of this Application, ECA is submitting a separate application with the DOE/FE for authorization to export U.S. natural gas that will be liquefied at the ECA Large-Scale Project. However, as discussed more fully in Part V.E of this Application, the ECA Mid-Scale Project and ECA Large-Scale Project are distinct and independent projects and the export applications associated with each should be processed independently by the DOE/FE.

6 Appendix E attached to this Application contains a listing of the existing cross-border facilities between the United States and Mexico. Throughout this Application ECA refers to "existing" capacity to encompass both pipeline projects that have already been built and placed into service, as well as those projects that were proposed and/or authorized by the FERC prior to and independent of the export applications of the ECA Mid-Scale Project and ECA Large-Scale Project and were therefore not related to ECA's projects. Appendix E sets forth the status of each cross-border facility (*i.e.*, in service, proposed to FERC and under review, approved by FERC and under construction, *etc.*) based upon the record before the FERC and the knowledge and belief of ECA.

across the U.S./Mexican border, and transported by pipelines in Mexico to the planned ECA Mid-Scale Project. ECA is in the process of finalizing arrangements for its upstream supply; however, at this time, ECA notes that the export capacity through existing border-crossing pipeline facilities extending between the United States and Mexico exceeds the amount requested in this application, as discussed below.

The LNG liquefaction facilities associated with the Project will be constructed on or adjacent to the site of ECA's existing regasification terminal in Ensenada, Mexico.[7] These facilities will include: (a) one (1) new APCI liquefaction train with a combined gas pre-treatment unit; (b) new ground flare equipment; (c) piping & utility tie-ins to existing LNG regasification, subject to certain modifications.

As discussed in more detail in Appendix C, the construction and operation of the necessary LNG and pipeline facilities will require permits from various Mexican agencies. ECA has filed applications to initiate the Mexican environmental reviews necessary as part of the permitting process for the construction and operation of the ECA Mid-Scale Project in Ensenada. The Mexican agencies with jurisdiction over the various aspects of the Project have completed the environmental review associated with the Project and have issued most of the environmental authorizations necessary for the Project. At this time, there is only one environmental permit application pending (filed on August 30, 2018), requesting approval of a modification to the issued environmental authorizations, which is expected to be approved in 2018. As discussed below, applications for the necessary permits associated with the Mexican pipeline facilities used to transport natural gas to the Project in Mexico will be filed with the appropriate authorities. The

7 ECA's existing regasification terminal commenced operations in 2008 and consists of two (2) full containment storage tanks with a capacity of 160,000 cubic meters ("m^3") each, regasification facilities with a capacity of approximately 1.0 Bcf/d, one marine berth capable of transferring up to 266,000 m^3 of LNG, and bi-directional interconnections with various Mexican pipeline facilities.

permitting process for those pipeline construction permit applications will involve an environmental review undertaken by Mexican authorities, and construction of the pipeline facilities will not proceed until the necessary Mexican permits have been issued. To assist the DOE/FE in its public interest consideration of the proposed exports, ECA is submitting in Appendix C a summary of the Mexican regulatory processes applicable to the siting, construction, and operation of the ECA Mid-Scale Project and associated pipeline facilities.

Because upstream physical pipeline capacity in the United States and across the U.S./Mexican border exceeds the export volumes contemplated in this Application,[8] consistent with its prior practice in other Non-FTA export proceedings, ECA is requesting that the DOE/FE issue a determination that the Application qualifies for a categorical exclusion from review under the National Environmental Policy Act of 1969 ("NEPA").[9] Specifically, consistent with applicable judicial and DOE/FE precedent, ECA submits that the Project qualifies for Categorical Exclusion B5.7 set forth in the DOE's regulations governing the agency's compliance with NEPA, which applies, in relevant part, to "[a]pprovals . . . of new authorizations . . . to . . . export natural gas under section 3 of the Natural Gas Act that involve minor operational changes (such as changes in natural gas throughput, transportation, and storage operations) but not new construction."[10]

ECA respectfully requests that DOE/FE issue an order granting the requested authorizations to export natural gas from the United States to Mexico for liquefaction and re-export to FTA countries as described in this Application without modification or delay pursuant to Section 3(c) of the NGA not later than December 1, 2018. Further, ECA respectfully requests that the

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8 *See* Appendix E (listing existing cross-border facilities with a combined capacity exceeding 14.8 Bcf/d).

9 42 U.S.C. § 4321 *et seq*. (2012).

10 10 C.F.R. Part 1021, Subpart D, app. B § B5.7.

DOE/FE issue an order granting the requested authorizations to export natural gas from the United States to Mexico for liquefaction and re-export to Non-FTA countries as described in this Application without modification or delay pursuant to Section 3(a) of the NGA not later than May 1, 2019.

In support of its application, ECA states as follows:

I. COMMUNICATIONS AND CORRESPONDENCE

All communications and correspondence regarding this Application, including all service of pleadings and notice, should be directed to the following persons:[11]

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II. DESCRIPTION OF THE APPLICANT

The exact legal name of ECA is Energía Costa Azul, S. de R.L. de C.V. ECA is a variable-capital, limited liability company organized under the laws of Mexico. The principal place of business of ECA is Paseo de la Reforma # 342 Piso 24, Col. Juarez, Del. Cuauhtémoc, Mexico D.F. 06600. ECA is owned by Infrastructura Energetica Nova, S.A.B. de C.V. ("IEnova") and IEnova's subsidiaries. IEnova is one of the largest natural gas infrastructure developers in Mexico and was the first publicly-traded energy infrastructure company listed on the Mexican Stock

[11] ECA requests waiver of Section 590.202(a) of DOE's regulations, to the extent necessary to include outside counsel on the official service list in this proceeding. *See* 10 C.F.R. § 590.202(a).

Exchange (*Bolsa Mexicana de Valores*). A majority of the ownership interests in IEnova (66.43%) is held by indirect, wholly-owned subsidiaries of Sempra Energy, a publicly-traded California corporation.[12] A chart reflecting the ownership structure of ECA is attached as Appendix D.

III. EXECUTIVE SUMMARY

The purpose of this Application is to obtain authorization from the DOE/FE under section 3 of the NGA for the export of surplus natural gas from the United States to Mexico, where it will be liquefied at the ECA Mid-Scale Project site and loaded onto marine vessels for export as LNG to foreign markets. The Project is proposed at the site of the existing ECA regasification terminal in Baja California, Mexico. ECA has already submitted applications with the relevant federal, state, and local authorities in Mexico for the construction and operation of the ECA Mid-Scale Project and has obtained the relevant environmental authorizations from the applicable Mexican agency. On August 30, 2018, ECA filed to modify the existing authorizations to permit it to construct both the ECA Large-Scale Project and the ECA Mid-Scale Project. Specifically, the authorizations that ECA has obtained to date have contemplated a single, 12.4 million tons per annum (mtpa) project. The requested modification would permit the construction of the 3.3 mtpa ECA Mid-Scale Project and the 9.1 mtpa ECA Large-Scale Project as separate undertakings.[13] ECA expects to obtain approval of the modification to those authorizations before the end of 2018. Abundant supplies of natural gas from the United States are available to serve both domestic natural gas needs and the needs of the ECA Mid-Scale Project for the proposed 20-year term. The

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[12] The remaining shares of IEnova are publicly traded.

[13] These figures expressed in mtpa represent the average productive capacity of the liquefaction facilities and are consistent with the authorizations in Mexico that ECA has applied for and received. The export volumes that ECA is requesting in this Application represent the maximum productive capacity of the facilities based upon an assumption of optimal operational and ambient conditions.

use of U.S.-sourced natural gas for ECA exports would not significantly reduce the volume of natural gas potentially available for domestic consumption. The forecasts of the U.S. Energy Information Administration ("EIA"), as well as the Report of ICF International ("ICF") commissioned by ECA,[14] illustrate that there is abundant U.S. natural gas supply currently and during the Project's proposed timeframe for exports. The robust supply of natural gas, largely as a result of increased levels of production from unconventional resources, is forecasted to exceed demand. The ICF Mid-Scale Report indicates that LNG exports from the Project will result in minimal impact on the price of natural gas for U.S. consumers over the analysis period of 2021 to 2045.

The Project presents numerous benefits to the public, including increased U.S. economic activity, tax revenues, and job creation during both the construction and operation phases of the Project. Through 2045, the estimated total economic gains to the U.S. economy associated with the Project are approximately $37.2 billion.[15] In the Southwestern United States, the Project is expected to add $7.16 billion to those state economies over the forecast period.[16] These economic gains are measured in terms of increased net gross domestic product and state product including multiplier effects. In addition, the Project will lead to a cumulative increase of almost 166,000 job-years for the U.S. economy as a whole and 38,000 job-years for the economy in the Southwest through 2045.[17]

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14 *See* Appendix B1, ICF International, *Economic Impacts of the Proposed Energía Costa Azul Mid-Scale Liquefaction Project: Information for DOE Non-FTA Permit Application* (Sept. 11, 2018) [hereinafter ICF Mid-Scale Report].

15 *Id.* at 52.

16 *Id.* at 56. The five Southwestern states included in ICF's analysis are CA, NV, AZ, NM, and TX.

17 *Id.* at 50, 54.

On an international level, the ECA Mid-Scale Project will favorably influence the balance of trade that the United States has with its international trading partners. The expected value of the exports from the Project is projected to reduce the U.S. balance of trade deficit by $0.9 billion annually between 2021 and 2045.[18]

As demonstrated by the ICF Mid-Scale Report, abundant natural gas supplies exist to supply the ECA Mid-Scale Project without adversely affecting the availability of competitively-priced natural gas for U.S. consumption during the proposed term of the requested authorization. Furthermore, existing cross-border pipeline capacity between the United States and Mexico (approximately 14.8 Bcf/d) is well in excess of the volumes requested in this Application. Accordingly, ECA respectfully requests that the DOE/FE issue an order approving the requested exports without limiting the locations at which ECA may export gas from the U.S. to a specific set of cross-border facilities, tying the volume of authorized exports to a particular set of cross-border facilities, or conditioning the authorization upon submission of further applications should ECA choose to export the volumes requested in this Application using U.S. cross-border facilities that are constructed in the future.

IV. AUTHORIZATIONS REQUESTED

ECA respectfully requests that the DOE/FE grant long-term, multi-contract authorizations for ECA to engage in: (1) exports of up to 182 Bcf/y (or an average of approximately 500 MMcf/d) of natural gas by pipeline to Mexico; and (2) re-exports of LNG up to the equivalent of 161 Bcf/y of natural gas (or an average of approximately 441 MMcf/d of natural gas) from Baja California, Mexico, to FTA and Non-FTA countries.

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[18] *Id.* at 53.

As discussed in greater detail in Part VII of the Application below, ECA respectfully requests that the DOE/FE neither limit the locations at which ECA may export gas from the United States to a specific set of border-crossing pipeline facilities, nor tie the quantity of natural gas that may be exported under the requested authorizations to the capacity of any particular cross-border pipeline facilities. ECA further requests that the DOE/FE not require ECA to file additional applications for authorization if new U.S. pipelines are constructed in the future that would transport the gas authorized under the export authorizations requested herein, but at different locations.[19] Approving ECA's request without imposing such restrictions would be consistent with the public interest and the manner in which the DOE/FE has treated Non-FTA export authorizations issued to LNG export projects located in the United States. Further, this proceeding is distinguishable from the only two proceedings in which the DOE/FE found such restrictions to be necessary, each of which involved the export of U.S. natural gas solely through a pipeline that did not at the time have sufficient physical capacity to transport the requested volumes to and across the international border. In contrast, the pipeline facilities identified in this Application as capable of transporting gas supplies for the ECA Mid-Scale Project currently have the physical capacity to transport the required gas to the U.S./Mexican border, and the existing cross-border physical capacity substantially exceeds the volumes ECA is requesting to export into Mexico. Further, the ECA Mid-Scale Project will have access to a wide range of natural gas supply and transportation options through the integrated grid of multiple interstate natural gas pipelines in the U.S., numerous border-crossing facilities, and the Mexican natural gas pipeline grid that may be accessed in the future. Further, given the tendency of gas production profiles and economics to

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[19] To the extent that ECA proposes to export natural gas from the United States to Mexico for re-export from Mexico to other countries in volumes that exceed the volumes requested in this Application, ECA will file any necessary additional application for authorization under the NGA.

vary over long periods of time, gas supply arrangements for the Project may change over the course of the 20-year term requested in this Application, requiring ECA to have some flexibility in the location where gas may be exported from the United States into Mexico. Thus, the restrictions that the DOE/FE has imposed in the past would be inappropriate here.

ECA requests these authorizations for a 20-year term commencing on the earlier of the date of first commercial export or a date seven years from the issuance of an order by the DOE/FE granting the requested authorizations. ECA requests authorization to export natural gas and LNG on its own behalf and as agent for other parties who will hold title to natural gas at the time it is exported across the U.S./Mexican border and LNG at the time it is re-exported from the ECA terminal for delivery to Non-FTA countries, as permitted by DOE/FE policy.[20] ECA will comply with all DOE/FE requirements related to ECA's re-exportation of LNG produced from U.S.-sourced natural gas on behalf of others, including any applicable requirements to register LNG title holders or to file long-term commercial agreements under seal with the DOE/FE.

During the course of its business, ECA and/or its terminal customers may transport natural gas from the United States on their own behalf or may purchase natural gas in Mexico from upstream suppliers that have exported the U.S.-sourced natural gas under the suppliers' own FTA export authorizations or under ECA's export authorization for the purpose of selling natural gas to ECA or its terminal customers at the ECA Mid-Scale Project. ECA respectfully requests that the DOE/FE clarify that ECA will not be required to treat such entities as "registrants" under DOE/FE policies and procedures, notwithstanding the fact that such suppliers may hold title to natural gas at the time it is exported across the U.S./Mexican border. It is unnecessary for the DOE/FE to

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[20] *Freeport LNG Expansion, L.P.*, DOE/FE Order No. 2913, FE Docket No. 10-160-LNG, Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Freeport LNG Terminal to Free Trade Nations (Feb. 10, 2011).

exert the same degree of regulatory oversight over such suppliers given that ECA and its terminal customers (as registrants) will purchase the gas in Mexico and ultimately be responsible for ensuring compliance with the reporting, destination restrictions, and other obligations imposed by the export authorization order and the NGA arising from the re-export of LNG. Further, long-term gas supply agreements between ECA and/or its terminal customers on the one hand, and suppliers delivering U.S.-sourced gas in Mexico on the other, will be filed with the DOE/FE as part of the standard conditions imposed upon the export authorization. Requiring ECA to treat every natural gas supplier as a "registrant" (including those that export gas under their own authorizations or that export under ECA's authorization) would impose an unreasonable and unnecessary burden upon ECA and its counterparties and potentially restrict ECA's access to gas supplies without any corresponding benefit to the public interest.

ECA anticipates entering into one or more long-term export agreements with customers of the Project. Section 590.202(b) of DOE's regulations requires applicants to submit information regarding the terms of certain transactions, which includes long-term supply agreements and long-term export agreements.[21] ECA has not currently entered into any export agreements or finalized supply arrangements for the Project, but will comply with the obligation to file such agreements after they have been executed, consistent with DOE/FE policy.

Accordingly, ECA respectfully requests that the DOE/FE issue an order granting the authorization requested herein to export natural gas and LNG to FTA countries by December 1, 2018. ECA further requests that the DOE/FE issue an order granting the authorization requested

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[21] 10 C.F.R. § 590.202(b)(4).

herein to export LNG to Non-FTA countries by May 1, 2019, which will allow ECA to finalize the commercial development, financing, and contracting of the Project.

V. DESCRIPTION OF THE PROJECT

A. ECA Mid-Scale Project

The ECA Mid-Scale Project will permit the exportation of U.S. natural gas from various sources to Mexico for liquefaction and re-export to foreign markets. The Project will be constructed at the existing 67.85-acre brownfield site owned by ECA and located approximately 19 miles north of the city of Ensenada, Baja California, Mexico, along the Pacific coast, approximately 31 miles south of the San Diego-Tijuana/San Ysidro border between the United States and Mexico. The Project is a joint effort between Sempra Energy and its Mexican affiliate, IEnova, which owns ECA.

The Project will be located on the site of ECA's existing LNG import terminal in Ensenada, which currently includes one marine berth and breakwater, two LNG tanks of 160,000 m^3 each, LNG vaporizers, nitrogen injection systems, and pipeline interconnections. The major components that will be constructed as part of the ECA Mid-Scale Project include: (a) one (1) new APCI liquefaction train and a gas pre-treatment unit for removal of Mercury and acid gas, dehydration, and natural gas liquids removal and fractionation; (b) new ground flare equipment, (c) piping & utility tie-ins to the existing terminal facilities, subject to certain modifications. Feed gas will be supplied through a dedicated high-pressure spur pipeline, with pipeline quality gas exported from the United States. New or modified utilities and offsite facilities will be provided for the Project as required.

The ECA Mid-Scale Project is designed to meet the growing global demand for North American-sourced LNG over the next few decades. The location along the West Coast of North America will provide access to markets in the Pacific Basin including Asia, the Middle East, and South America. Following receipt of the approvals requested in this Application in the second quarter of 2019, ECA plans to reach a final investment decision and commence construction of the ECA Mid-Scale Project to place it in service within seven years of the date of the DOE/FE order.

B. Natural Gas Supply and Transportation

Abundant supplies of natural gas in the United States are available to serve domestic natural gas needs, including the proposed ECA Mid-Scale Project. Natural gas for the proposed exports can be sourced from basins throughout the United States, including the Gulf Coast, Mid-Continent, West Texas, and Rocky Mountain regions, providing the ECA Mid-Scale Project with supply diversity and optionality for the benefit of its customers. Given the size of traditional natural gas resources available to the Project, as well as the rapid growth in emerging unconventional gas and oil technical resource base throughout the United States, the ECA Mid-Scale Project will have a choice of diverse and reliable alternative gas supplies.

The potential sources of natural gas for the Project will include vast supplies available from the producing regions in the Western United States and the Gulf Coast. The EIA reports that, in 2017, these regions collectively produced 15.10 trillion cubic feet ("Tcf") (an average of approximately 41.37 Bcf/d) of natural gas, which was over half of the U.S. total for that year.[22] According to the Potential Gas Committee's year-end 2016 assessment, the Gulf Coast, Rocky

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[22] U.S. Energy Information Administration, *Natural Gas Gross Withdrawals and Production* (Aug. 31, 2018), http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm. For purposes of calculating total marketed production from the Western United States and Gulf Coast, EIA's data has been aggregated for the following categories: TX, LA, MT, WY, CO, NM, UT, CA, and Federal Offshore Gulf of Mexico.

Mountain, and Mid-Continent regions are estimated to have traditional gas resources of 1,344.2 Tcf.[23]

Technological improvements in natural gas exploration, drilling, and production have resulted in significant reductions in the costs of developing shale resources and making shale gas production economically viable. The EIA estimates that the total volume of technically recoverable shale gas and tight oil resources in the Gulf Coast, Midcontinent, Southwest, Rocky Mountain, and West Coast regions is 648.4 Tcf.[24] Natural gas production from shale gas and tight oil plays accounted for 54.5% (14.77 Tcf) of total U.S. production in 2017 (27.1 Tcf).[25] Looking forward, the EIA projects shale gas and associated gas from tight oil plays will account for more than three-quarters of U.S. natural gas production by 2050.[26]

Abundant supplies of natural gas in regions outside of the Western United States and Gulf Coast are also available to serve domestic natural gas needs and, potentially, the Project. The Appalachian Basin, which encompasses both the Marcellus and Utica supply regions, represents one of the most extensive potential sources of natural gas supply in the United States. According to the EIA, continued development of the Marcellus and Utica plays is the main driver of growth in total U.S. shale gas production, as well as the main source of total U.S. dry natural gas production.[27] The EIA estimates total technically recoverable shale gas and tight oil resources in

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23 U.S. Potential Gas Committee, Press Release, *Potential Gas Committee Reports Record Future Supply of Natural Gas in the U.S.* (Jul. 19, 2017), http://www.potentialgas.org/press-release.

24 U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2018*, Oil and Gas Supply Module, tbl.3 (Apr. 5, 2018) [hereinafter Assumptions to the AEO 2018], https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf.

25 U.S. Energy Information Administration, *Annual Energy Outlook 2018*, tbl. 14 (Feb. 6, 2018) [hereinafter AEO 2018], https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2018&cases=ref2018&sourcekey=0.

26 *Id.* at 65-66, https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

27 *Id.* at 68.

the East alone at 579.7 Tcf.[28] In response to the increased production in the Appalachian Basin region, the natural gas industry is building new interstate pipeline projects to transport production out of the Marcellus and Utica Shale Plays, as well as modifying existing systems to allow pipelines originally built and used to move gas into the Northeast to now provide new markets for excess gas out of the Northeast.[29] Appalachian gas production, in addition to Gulf Coast gas production, is therefore well situated to satisfy domestic requirements for natural gas.

When these new resources are added to conventional producing formations, it is evident that the United States has more than sufficient supply to serve domestic needs and accommodate the proposed exports from the ECA Mid-Scale Project. In 2018, the EIA estimated total technically recoverable natural gas resources in the United States at 2,462.3 Tcf.[30] This growth in U.S. natural gas resources is reflected in other recent academic and industry evaluations. In its year-end 2016 assessment, the Potential Gas Committee determined that the United States possesses future available gas supply (reserves and resources) of 3,141.3 Tcf, which is an increase of approximately 288 Tcf (+10%) from the Potential Gas Committee's projections in 2014.[31]

The ECA Mid-Scale Project is well-positioned to access natural gas supplies from the numerous pipelines that are in proximity to the Project. Natural gas to be exported from the Project will be purchased in a market that has sufficient liquidity and capacity to accommodate a variety of purchase arrangements, including spot market transactions and long-term supply arrangements. Natural gas markets are particularly liquid in the Gulf Coast and Western U.S. regions as a result

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28 Assumptions to the AEO 2018, Oil and Gas Supply Module at tbl. 3.

29 *See* U.S. Energy Information Administration, *FERC Certificates Several New Natural Gas Pipelines in 2017* (Mar. 7, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30232; U.S. Energy Information Administration, *Appalachian Basin Infrastructure Growth Will Make Marcellus/Utica Gas Available to Broader Market* (Mar. 18, 2015), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2015/03_19/index.php.

30 Assumptions to the AEO 2018, Oil and Gas Supply Module, at tbl. 2.

31 U.S. Potential Gas Committee, *supra* note 23.

of the key market centers in the area and the availability of readily accessible incremental gas supplies. The ECA Mid-Scale Project will have access to market centers providing ample liquidity to accommodate a wide and geographically diverse range of gas supply arrangements. This access to multiple supply options means that the ECA Mid-Scale Project will be able to respond to shifts in the economics and production profiles of different gas production areas, which may vary significantly over the term of the requested authorizations. Thus, given the integrated nature of the U.S. and Mexican pipeline system, which yields a broad range of supply and transportation options that the ECA Mid-Scale Project currently has at its disposal, it is uncertain where the gas used by the ECA Mid-Scale Project will originate.

Moreover, the abundance of cross-border facilities between the United States and Mexico makes it possible for the ECA Mid-Scale Project to access gas from several cross-border locations through the use of existing Mexican pipeline infrastructure and, potentially, the future construction of new and expanded pipeline facilities in Mexico. To estimate the level of cross-border capacity available, ICF has compiled data from the EIA and other independent sources.[32] In addition, given the DOE/FE's reliance upon orders issued by the Federal Energy Regulatory Commission ("FERC") in previous proceedings to establish cross-border capacity for the administrative record,[33] ECA has undertaken a review of the orders of the FERC and its predecessor, the Federal Power Commission ("FPC") to compile an index and map of the cross-border facilities that have

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32 *See* ICF Mid-Scale Report, app. A.

33 *See Pieridae Energy (USA) Ltd.*, DOE/FE Order No. 3768, FE Docket No. 14-179-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export U.S.-Sourced Natural Gas by Pipeline to Canada for Liquefaction and Re-Export in the Form of Liquefied Natural Gas to Non-Free Trade Agreement Countries, at 196 (Feb. 5, 2016) [hereinafter Pieridae Order]; *Bear Head LNG Corp.*, DOE/FE Order No. 3770, FE Docket No. 15-33-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export U.S.-Sourced Natural Gas by Pipeline to Canada for Liquefaction and Re-Export in the Form of Liquefied Natural Gas to Non-Free Trade Agreement Countries, at 156 (Feb. 5, 2016) [hereinafter Bear Head Order].

either already been approved or have been proposed to the FERC prior to and independent of the ECA Mid-Scale Project, which are attached to this Application as Appendix E.[34] The average volumes of 441 MMcf/d for which ECA is seeking Non-FTA export authorization represent a small fraction of the approximately 15 Bcf/d of cross-border capacity available from existing facilities.

While ECA is considering several gas supply options for the ECA Mid-Scale Project,[35] it notes that the physical capacity of the facilities operated by North Baja Pipeline ("NBP"), an interstate pipeline owned by TransCanada Corporation and subject to the jurisdiction of the FERC, currently exceeds the volumes requested in this Application. NBP's mainline facilities extend approximately 80 miles from an interconnection point with El Paso Natural Gas Company near Ehrenberg, Arizona, to a point on the international border near Ogilby, California, where it interconnects with Gasoducto Rosarito ("GRO"), a pipeline owned by Sempra Energy affiliate, IEnova, and located in Mexico.[36] NBP's existing facilities have a design capacity of approximately 500 MMcf/d for southbound transportation. Also, cross-border facilities east of Ogilby, California can be used to supply the natural gas for the ECA Mid-Scale Project utilizing

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[34] As discussed in note 6 above, this Application refers to such facilities as "existing" facilities. Due to the quality of information available and the different calculation methodologies used, the estimates of total cross-border capacity established in the ICF Mid-Scale Report (14,907 MMcf/d) and Appendix E (14,830 MMcf/d) differ, but only very slightly.

[35] For example, the abundance of cross-border facilities between the United States and Mexico (approximately 15 Bcf/d of cross-border capacity from existing facilities) makes it possible for the ECA Mid-Scale Project to access gas from several cross-border locations through pipeline construction that may occur in the future and that would be located entirely in Mexico.

[36] The relevant portions of the GRO pipeline consist of a mainline segment that begins in Mexico at an interconnection with NBP at the international border and extends west through Baja California to a point near Tijuana ("GRO Mainline"). The system then extends south from Tijuana to the location of ECA's existing LNG regasification terminal ("LNG Spur"). The capacity of the GRO Mainline is approximately 534 MMcf/d and the LNG Spur is approximately 2.6 Bcf/d. Although, as discussed below, any pipeline construction or transportation in Mexico would be beyond the scope of the DOE/FE's review under the NGA or NEPA, ECA notes that the physical capacity on the existing GRO system exceeds the authorized export volume requested in this Application.

gas exported from existing facilities such as the Sierrita Gas Pipeline, Comanche Trail Pipeline, ONEOK Partners' Roadrunner Pipeline, and/or Trans-Pecos Pipeline. The cross-border capacity at these locations exceeds several times the volume requested in this Application.[37] The existing physical capacity on NBP, in addition to other cross-border facilities like Sierrita, Comanche Trail, Roadrunner, and Trans-Pecos, total approximately 4.4 Bcf/d of the nearly 15 Bcf/d of total cross-border capacity at the U.S./Mexican border. Thus, the physical southbound capacity of the cross-border facilities is several times in excess of the full volume requested in this Application. Any issues regarding the takeaway and delivery capacity of the pipeline facilities located in Mexico from the cross-border facilities used—*e.g.*, any construction of new pipeline facilities in Mexico to interconnect to other Mexican facilities receiving gas exported into Mexico from cross-border facilities—will be addressed by ECA and the relevant permitting authorities in Mexico, as discussed in Appendix C.[38]

C. Mexican Regulatory Review of Mid-Scale Project and Pipelines in Mexico

As discussed more fully in Part VII below, the ECA Mid-Scale Project does not involve construction in the United States. Given the location of the ECA Mid-Scale Project in Mexico, the facility will not be subject to the review of the FERC under the NGA or NEPA. Instead, the

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[37] *See* Appendix E, *Summary of Existing Cross-Border Facilities*. The Sierrita, Comanche Trail, Roadrunner, and Trans-Pecos pipelines interconnect to the Gasoducto Aguaprieta/Sonora, San Isidro-Samalayuca, PEMEX/Tarahumara Pipeline, and Gasoducto Ojinaga facilities, respectively, located in Mexico. Each one of these cross-border pipelines individually has physical capacity that exceeds the export volumes requested in this Application.

[38] As noted in its application for authorization to export natural gas associated with the ECA Large-Scale Project, ECA is considering the construction of several miles of pipeline to be built entirely in northern Mexico to interconnect the ECA Large-Scale Project with sources of supply exported from West and/or South Texas. If the ECA Large-Scale Project proceeds and ECA procures the construction of pipeline facilities in northern Mexico to transport supply for that other, independent project, any such pipeline facilities in northern Mexico might also be used to transport natural gas destined for the ECA Mid-Scale Project. However, given that the physical cross-border capacity at locations closer to the ECA Mid-Scale Project exceeds the export volumes requested in this Application, the construction of facilities in association with the Large-Scale Project is not a necessary condition for the implementation of the ECA Mid-Scale Project.

ECA Mid-Scale Project and any pipeline facilities that may be constructed in Mexico are subject to review and approval by Mexican agencies under the state and federal laws of that nation. ECA is submitting as Appendix C a summary of the Mexican regulatory framework applicable to the siting, construction and operation of the ECA Mid-Scale Project, including any liquefaction and pipeline facilities associated with the project. Appendix C lists the Mexican authorizations, permits and approvals required for the ECA Mid-Scale Project.

The Mexican permitting process includes a thorough environmental review under Mexican state and federal legislation similar to the review conducted by U.S. agencies under NEPA. Specifically, Mexico's primary statute governing the environmental reviews of projects is the *Ley General del Equilibrio Ecológico y la Protección al Ambiente*/General Law of Ecological Balance and Environmental Protection ("LGEEPA"), which is administered by the *Secretaría de Medio Ambiente y Recursos Naturales*/Ministry of Environmental and Natural Resources ("SEMARNAT"). Within the SEMARNAT, the *Agencia Nacional de Seguridad Industrial y de Protección al Medio Ambiente del Sector Hidrocarburos*/National Agency for Industrial Security and Environmental Protection for the Hydrocarbon Industry ("ASEA"), is responsible for regulating and supervising industrial, operational and environmental safety for projects related to the hydrocarbon sector, including the construction of natural gas pipelines and liquefaction facilities.

As part of ASEA's review of projects under the LGEEPA, a *Manifestación de Impacto Ambiental*/Environmental Impact Assessment ("MIA") must be prepared.[39] Similar to an Environmental Impact Statement ("EIS") under NEPA, a MIA presents the results of

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[39] *See* Appendix C § 5.

comprehensive analysis and studies of potential environmental impacts associated with a project, including site preparation, construction, operation, and decommissioning, as well as an assessment of measures to mitigate environmental impacts and an analysis demonstrating compliance with Mexican laws and regulations, as well as prudent industry practices and international standards. The MIA must describe the project's stages and the ecosystems in which it will be developed. The document presents the results of comprehensive analyses and environmental studies, including an assessment of mitigation measures. The MIA for gas pipelines and liquefaction facilities must also include an Environmental Risk Analysis, which analyzes safety and risk mitigation procedures.

If ASEA concludes that a project is environmentally viable, it will issue a resolution approving the MIA and an Environmental Impact Authorization ("ERA"), which specifies the authorization's terms and conditions, including required measures to mitigate environmental impacts. In doing so, ASEA considers the comments derived from the public consultation process and the various federal and state agencies that were notified during the evaluation process. The enforcement of the terms of a MIA and ERA falls under the jurisdiction of ASEA, which is entitled to perform periodic verification visits to ensure compliance with all applicable environmental regulations, as well as the terms and conditions of environmental permits. ASEA also oversees a facility's continued compliance with applicable laws, regulations, and conditions governing safety, risk mitigation, technical processes, and the environment through enforcement of the *Sistemas de Administración de Seguridad Industrial, Seguridad Operativa y Protección*/Industrial, Operational, and Environmental Safety Management System.

In addition to review of the MIA and ERA, ASEA reviews and issues authorizations for projects, such as pipelines and liquefaction facilities, that will impact existing land use. In reviewing such proposals, ASEA relies upon a technical opinion issued by the members of the *Consejo Forestal Estatal*/State Forestry Council in the form of an *Estudio Técnico Justificativo*/Technical Justification Study submitted by the applicant to demonstrate that biodiversity will not be negatively affected and that there will be no soil erosion, detriment to water quality, or diminished rate of recovery, among other environmental impacts. Any land use change must be authorized by ASEA in a permit referred to as a *Cambio de Uso de Suelo en Terrenos Forestales*/Forestry Land Use Change Permit, which also specifies mitigation requirements similar to those included in the MIA. A monetary compensation for the impacted area must be made to the *Fondo Nacional Forestal*/Mexican Forestry Fund.

Project proponents in the hydrocarbon industry, including pipeline and liquefaction facilities, must perform an *Evaluación de Impacto Social*/Social Impact Assessment ("EvIS"), which identifies, characterizes and assesses social impacts that could be caused by such project and proposes a social management plan. The EvIS is subject to review and approval of the *Secretaría de Energía*/Ministry of Energy. In addition, permits are required from the *Comisión Reguladora de Energía*/Energy Regulatory Commission to engage in activities that are subject to third-party access and those activities that are not subject to third-party access but require a permit, including the self-supply of electric energy, transportation, liquefaction, regasification, and storage of natural gas in Mexico.

Mexican state and local authorities also exercise regulatory oversight of liquefaction and pipeline facilities. The government of Baja California, where the ECA Mid-Scale Project will be located, has enacted the *Ley de Protección al Ambiente*/Environmental Protection Law, which establishes guidelines for the evaluation and approval of industrial projects in consideration of the environmental impacts of the proposal, among other issues. The state law is administered through the *Secretaria de Proteccion al Ambiente*/Ministry of Environmental Protection, which coordinates the issuance and monitoring of any requested permits from local authorities.

ASEA, the Mexican agency with jurisdiction over various aspects of the Project, has completed the environmental review associated with the Project and has issued several environmental authorizations. Specifically, on December 17, 2017, ASEA completed its environmental review and issued a resolution approving, subject to terms and conditions, ECA's MIA and ERA for a 12.4 mtpa project at the site of the existing ECA regasification terminal. An English translation of that resolution is attached to this Application as Appendix F. On August 30, 2018, ECA filed with ASEA to modify the previously-issued authorizations to permit the construction of the ECA Mid-Scale Project, which the agency is expected to approve in 2018. Furthermore, with the MIA and ERA for the ECA Mid-Scale Project approved, the relevant Mexican authorities will conduct reviews of any additional permits that may be necessary for the construction and operation of any pipeline or other facilities in Mexico that may be proposed in the future.

D. Commercial Structure

ECA is currently in discussions with customers regarding the proposed commercial structure of the ECA Mid-Scale Project (*e.g.*, whether the facilities will sell LNG under sales purchase agreements, provide liquefaction services under tolling agreements, *etc.*). As noted above, ECA has not yet entered into long-term export contracts in connection with the export authorizations requested herein or finalized gas supply arrangements for the Project. However, once executed, ECA will file any such contracts with the DOE/FE in accordance with the DOE/FE's filing requirements.

E. Relationship of the ECA Mid-Scale Project and the ECA Large-Scale Project

As discussed above, ECA is submitting the instant Application concurrently with another application seeking FTA and Non-FTA export authorization in association with a separate project, the ECA Large-Scale Project. While the ECA Mid-Scale Project and the ECA Large-Scale Project will both be built on or near the project site of the existing ECA LNG regasification facility near Ensenada, the two are distinct projects, and the DOE/FE should treat them as such for the purposes of processing the two applications. Specifically, the differences in utility, timing, potential customer base, technology, location and configuration, and ownership and financing arrangements of each of the two projects justifies treating the two projects separately.

Importantly, each project has a utility that is entirely independent of the other inasmuch as each project can move forward on its own merits without dependence on the other for its justification—*i.e.*, neither project is operationally or commercially dependent on the other. Accordingly, ECA expects that the timing for contracting, constructing, and reaching in-service for the ECA Mid-Scale Project and the ECA Large-Scale Project will vary substantively.[40] ECA expects the two projects to supply different customer bases, with the ECA Mid-Scale Project supporting utilities in the Pacific rim and the ECA Large-Scale Project serving large customers in Asia, as well as LNG aggregators.

The ECA Large-Scale and Mid-Scale Projects each use different liquefaction technologies, which would function differently with distinct operational characteristics and efficiency rates. The Large-Scale Project will employ propane and mixed refrigerant cycle (C3MR) liquefaction trains, an efficient technology well suited for a project with a broader scope that is often specifically

[40] For this reason, a separate start date for the term of the Non-FTA export authorization for each project is necessary.

engineered to meet the particular specifications of a given application. On the other hand, the ECA Mid-Scale Project will use a Dual Mixed Refrigerant technology in a more streamlined and flexible application that is designed to be able to react more quickly to process variations. The location and configuration of the two projects will also be different. The ECA Mid-Scale Project is more compact, will fit inside the footprint of the existing ECA regasification facility, and will require few additional utilities and civil works, whereas, the ECA Large-Scale Project will have new land and civil works requirements. Finally, as they are further developed, the ultimate upstream ownership and financing arrangements for the two projects may differ.[41]

Accordingly, ECA respectfully requests that the DOE/FE process the FTA and Non-FTA export application associated with the ECA Mid-Scale Project separately from the application for the ECA Large-Scale Project and permit the two authorizations to have different starting dates for their respective terms.

VI. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standards

Pursuant to sections 301(b) and 402 of the Department of Energy Organization Act,[42] and delegations of authority issued thereunder, the DOE/FE is responsible for evaluating applications to export natural gas and LNG from the United States under section 3 of the NGA.[43] As discussed below, to the extent that this Application requests authority to export natural gas produced in the

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41 To the extent that the participation of such entities results in a "change in control" of the authorization holder, ECA will fully comply with the DOE/FE's policies and procedures with respect to obtaining authorization for such changes. *See* Procedures for Changes in Control Affecting Applications and Authorizations To Import or Export Natural Gas*,* 79 Fed. Reg. 65,541 (Nov. 5, 2014).

42 42 U.S.C. §§ 7151(b), 7172 (2012).

43 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-006.02 (Nov. 17, 2014).

United States to Mexico for consumption in that country, and for re-export to other FTA nations, that request should be deemed in the public interest and granted without modification or delay, as required by NGA section 3(c).[44] As recently clarified in the *Bear Head* and *Pieridae* orders,[45] the applicable legal standard for the portion of the Application that requests authorization to re-export U.S. natural gas from Mexico to Non-FTA countries is set forth in section 3(a) of the NGA.[46]

1. Exports to FTA Countries

Section 3(c) was added to the NGA by section 201 of the Energy Policy Act of 1992.[47] That section provides in relevant part that applications to the DOE/FE requesting authority for the export of natural gas, including LNG, to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas shall be deemed consistent with the public interest and granted without modification or delay.[48] Accordingly, the portion of this Application requesting authority to export U.S. natural gas to Mexico for liquefaction and re-export to FTA countries is deemed by statute to be consistent with the public interest and must be approved without modification or delay.

2. Exports to Non-FTA Countries

The general standard for review of applications to export to Non-FTA countries is established by section 3(a) of the NGA, which provides that:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary] authorizing it to do so. The [Secretary] shall issue such order upon application, unless, after opportunity for hearing, it finds that the

44 15 U.S.C. § 717b(c).

45 Pieridae Order at 3-4; Bear Head Order at 154-55.

46 15 U.S.C. § 717b(a).

47 Energy Policy Act of 1992, Pub. L. No. 102-486, § 201, 106 Stat. 2776, 2866 (1992).

48 15 U.S.C. § 717b(c).

> proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate, and may from time to time, after opportunity for hearing, and for good cause shown, make such supplemental order in the premises as it may find necessary or appropriate.[49]

In applying this provision, the DOE/FE has consistently found that section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[50] The DOE/FE will grant a Non-FTA export application unless opponents of the application make an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[51]

The DOE/FE's prior decisions have looked to the 1984 Policy Guidelines setting out the criteria to be employed in evaluating applications for natural gas imports.[52] While nominally applicable to natural gas import cases, the DOE/FE has found these Policy Guidelines applicable

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[49] *Id*. § 717b(a).

[50] *See e.g., Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, FE Docket No. 11-59-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel From the Lake Charles Terminal in Calcasieu Parish, Louisiana, to Non-Free Trade Agreement Nations, at 13 (July 29, 2016); *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 3868, FE Docket No. 13-04-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal in Calcasieu Parish, Louisiana to Non-Free Trade Agreement Nations, at 11 (Jul. 29, 2016); *Cameron LNG, LLC*, DOE/FE Order No. 3846, FE Docket No. 15-90-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From Trains 4 and 5 of the Cameron LNG Terminal in Cameron and Calcasieu Parishes, Louisiana, to Non-Free Trade Agreement Nations, at 10 (July 15, 2016); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792, FE Docket No. 15-63-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Sabine Pass LNG Terminal Located in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations, at 13 (Mar. 11, 2016).

[51] *Phillips Alaska Nat. Gas Corp. & Marathon Oil Co.*, DOE/FE Order No. 1473, FE Docket No. 96-99-LNG, Order Extending Authorization to Export Liquefied Natural Gas from Alaska, at 13 n.42 (Apr. 2, 1999) (citing *Panhandle Producers & Royalty Owners Ass'n v. ERA,* 822 F.2d 1105, 1111 (D.C. Cir. 1987)); *see also Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, at 13.

[52] New Policy Guidelines and Delegation Orders From Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6,684 (Feb. 22, 1984) [hereinafter Policy Guidelines].

to natural gas export applications, as well.[53] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system. The Policy Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas. . . . The federal government's primary responsibility in authorizing imports [or exports] should be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[54]

The DOE/FE's analysis has also been guided by DOE Delegation Order No. 0204-111.[55] According to the Delegation Order, exports of natural gas are to be regulated primarily "based on a consideration of the domestic need for the gas to be exported and such other matters [found] in the circumstances of a particular case to be appropriate."[56] Although the Delegation Order is no longer in effect, the DOE/FE's review of export applications continues to focus on: (i) the domestic need for natural gas proposed to be exported; (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies; (iii) whether the arrangement is consistent with the DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[57]

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53 *Phillips Alaska Nat. Gas Corp.*, at 14, 42; *see also Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, at 14; *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 3868, at 12; *Cameron LNG, LLC*, DOE/FE Order No. 3846, at 11; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792, at 15.

54 Policy Guidelines at 6,685.

55 U.S. Department of Energy, Delegation Order No. 0204-111 (Feb. 22, 1982) [hereinafter Delegation Order].

56 Delegation Order at para. (b).

57 *See, e.g., Lake Charles Exports, LLC*, DOE/FE Order No. 3324-A, at 15; *Cameron LNG, LLC*, DOE/FE Order No. 3846, at 11-12; *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, FE Docket No. 11-162-LNG, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations, at 9-10 (Sept. 10, 2014); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, FE Docket No. 10-111-LNG, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations, at 29 (May 20, 2011).

The DOE/FE has indicated that the following additional considerations are relevant in determining whether proposed exports are in the public interest: whether the exports will be beneficial for regional economies, the extent to which the exports will foster competition and mitigate trade imbalances with the foreign recipient nations, and the degree to which the exports would encourage efficient management of U.S. domestic natural resources.[58]

As demonstrated below, the exports of natural gas and LNG proposed herein satisfy each of these considerations.

B. Domestic Need for the Gas to be Exported

The ECA Mid-Scale Project is being proposed in light of the rapid growth in U.S. natural gas resources and production. In particular, drilling productivity gains and extraction technology enhancements have enabled significant growth in supplies from unconventional gas-bearing shale formations in the United States. In addition, estimates of recoverable natural gas resources have increased by approximately 715 Tcf (41%) between 2007 and 2016.[59] In light of the substantial addition of resources 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 exports proposed in this Application throughout the 20-year term of the requested authorization.

As U.S. natural gas resources and production have increased, U.S. natural gas prices have fallen significantly. The annual average Henry Hub spot price for natural gas fell from $8.86 per

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[58] *See, e.g., Cameron LNG, LLC*, DOE/FE Order No. 3846, at 105-125; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792, at 162-191, *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, at 125-35; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, at 34-38.

[59] *Compare* Assumptions to the AEO 2018, Oil and Gas Supply Module, at tbl. 2 *with* U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, tbl. 9.2 (Mar. 2009) [hereinafter Assumptions to the AEO 2009], http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.

MMBtu in 2008 to $2.99 per MMBtu in 2017.[60] In its most recently calculated reference case, the EIA estimates that natural gas prices will remain relatively flat at approximately $5.00 per MMBtu between 2030 through 2050.[61] Prices for natural gas in the U.S. market are now significantly below those of most other major gas-consuming countries.[62] The result is that domestic gas can be exported, liquefied, and re-exported to foreign markets on a competitive basis. As discussed below, such exports can be expected to have only a nominal effect on U.S. prices.

1. <u>Domestic Natural Gas Supply</u>

As the EIA has noted, domestic "[n]atural gas production from tight and shale gas formations has grown rapidly in recent years."[63] The EIA estimates that natural gas production over the 2017-2020 period will grow at 6% a year, greater than the 4% per year average growth rate from 2005 to 2015.[64] The EIA further estimates that U.S. dry gas production increased from 21 Tcf in 2010 to 27 Tcf in 2017.[65]

This growth trend is expected to continue over the next several decades. Total U.S. dry gas production is projected to grow to 42.98 Tcf by 2050, with a 1.4% annual growth rate between

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[60] U.S. Energy Information Administration, *Henry Hub Natural Gas Spot Price* (Sept. 12, 2018), https://www.eia.gov/dnav/ng/hist/rngwhhda.htm.

[61] AEO 2018 at 63.

[62] *See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (June 4, 2018), http://pubdocs.worldbank.org/en/799841528151608411/CMO-Pink-Sheet-June-2018.pdf (the average natural gas price in May 2018 was $2.78 per MMBtu in the United States, while the average price in Europe was $7.19 and the average LNG price was $9.40 per MMBtu in Japan); *see also* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (Sept 5, 2018), http://pubdocs.worldbank.org/en/453081536593505013/CMO-Pink-Sheet-September-2018.pdf (the average natural gas price in August 2018 was $2.96 per MMBtu in the United States, and the average LNG price was $10.44 per MMBtu in Japan).

[63] U.S. Energy Information Administration, *Annual Energy Outlook 2016,* at IF-29 (Aug. 2016), https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

[64] AEO 2018 at 62.

[65] U.S. Energy Information Administration, *U.S. Dry Natural Gas Production* (Aug. 31, 2018), https://www.eia.gov/dnav/ng/hist/n9070us2A.htm.

2016 and 2050.[66] Much of the future natural gas production growth is expected to come from unconventional production of shale resources, including horizontal drilling and multi-stage hydraulic fracturing. Specifically, the EIA found that production from shale gas and associated gas from tight oil plays would be the largest contributor to natural gas production growth, comprising almost three-quarters of total U.S. production by 2040.[67] In its 2018 Annual Energy Outlook, the EIA has also significantly increased its estimates of shale gas production through 2035 as compared to its projections in the Annual Energy Outlook 2015. For example, the EIA revised its projection of shale gas production in 2030 from 17.85 Tcf to 26.87 Tcf and in 2035 from 18.85 Tcf to 28.24 Tcf.[68]

This growth in shale production has been accompanied by an increase in the overall volume of U.S. natural gas resources. The EIA's estimates of recoverable natural gas resources have increased by 715 Tcf (41%) between 2007 and 2016.[69] According to ICF – the independent consulting firm commissioned by ECA to assess the domestic market and economic effects of the proposed ECA Mid-Scale Project – there were 3,693 Tcf of technically recoverable gas in the lower-48 U.S. states as of 2016, 2,133 Tcf of which was attributable to shale gas.[70] A large component of the technically recoverable resource is economic at relatively low wellhead prices. ICF estimates that between 1,200 and 1,400 Tcf of gas resources in the United States and Canada

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66 AEO 2018 at tbl. 13, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2018&cases=ref2018&sourcekey=0

67 AEO 2018 at tbl. 14, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2018&cases=ref2018&sourcekey=0.

68 *Compare* AEO 2018 at tbl. 14, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2018&cases=ref2018&sourcekey=0 *with* U.S. Energy Information Administration, *Annual Energy Outlook 2015*, at tbl. A14 (Apr. 2015), https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf.

69 *Compare* Assumptions to the AEO 2018, Oil and Gas Supply Module at tbl. 2 *with* Assumptions to the AEO 2009 at tbl. 9.2.

70 ICF Mid-Scale Report at 23-24.

could economically be developed with gas prices at between $3.50 and $4.00 per MMBtu using today's technology.[71] This "current technology" 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. With the advancement in drilling technology that will exploit additional shale gas development opportunities, further increases are anticipated in the amount of the technically recoverable resource that can be economically developed. ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that is economic at $5.00/MMBtu would increase from 1,225 Tcf to 2,160 Tcf, a 76% increase.[72]

2. Domestic Natural Gas Demand

Although domestic demand for natural gas is anticipated to grow, the rate of demand increase will continue to be outpaced by the growth of available supply. For example, though demand for natural gas has increased since 2009, production of natural gas has increased faster due to the shale gas revolution.[73] According to data published by the EIA, U.S. natural gas consumption was only 16% higher in 2017 than in 2000.[74] In its Annual Energy Outlook 2018, the EIA estimates long-term annual U.S. demand growth of only 0.8%, with demand expected to reach 34.48 Tcf in 2050.[75] In contrast, total U.S. dry gas production during the same period is

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71 *Id.* at 16.

72 *Id.* at 20.

73 The Brattle Group, Understanding Natural Gas Markets, at 3 (Sep. 2014), https://www.api.org/~/media/Files/Oil-and-Natural-Gas/Natural-Gas-primer/Understanding-Natural-Gas-Markets-Primer-High.pdf.

74 U.S. Energy Information Administration, *U.S. Natural Gas Total Consumption* (Aug. 31, 2018), https://www.eia.gov/dnav/ng/hist/n9140us2a.htm.

75 AEO 2018 at tbl. 13.

projected to grow at an annual rate of 1.4%, with dry gas production estimated to reach 42.98 Tcf in 2050, as compared to 26.94 Tcf in 2016.[76]

Growth in demand for natural gas through 2045 is expected to be primarily driven by the power sector due, in part, to environmental regulations.[77] ICF forecasts an increase in gas use in the power generation market from 31% of total consumption in 2017 to 37% by 2045.[78] Similarly, the EIA forecasts that energy consumption in the electric power sector will increase on average by 0.7% per year to 11.44 Tcf in 2050 from 9.97 Tcf in 2016 in the Reference case.[79] Relatively small growth is anticipated in the industrial sector's demand for natural gas, driven by reductions in energy intensity, or energy input per unit of industrial output, which remain a top priority for manufacturers.[80] The EIA estimates that energy consumption in the industrial sector will increase by an average of 1.0% per year to 13.18 Tcf in 2050 from 9.33 Tcf in 2016 in the Reference case.[81] Energy efficiency gains are expected to somewhat offset gas demand growth in the residential and commercial sectors.[82] Natural gas consumption in the commercial sector will increase only by 0.7% per year to 3.94 Tcf in 2050 from 3.11 Tcf in 2016 in the EIA Reference case.[83] The residential sector is forecasted to have only 0.1% growth in natural gas consumption to 4.54 Tcf in 2050 from 4.35 Tcf in 2016.[84] Under the ICF Base Case, which assumes no exports from the

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76 *Id.* at tbl. 14.

77 ICF Mid-Scale Report at 27.

78 *Id.*

79 AEO 2018 at tbl. 13.

80 ICF Mid-Scale Report at 27.

81 AEO 2018 at tbl. 13.

82 ICF Mid-Scale Report at 27.

83 AEO 2018 at tbl. 13.

84 *Id.*

ECA Project, U.S. and Canadian natural gas consumption in 2045 is expected to be over 50 Tcf (LNG and pipeline exports included). This Base Case projection assumes U.S. LNG exports in a total amount of 12.7 Bcf/d by 2045.[85] Despite the projected growth in domestic demand through the forecast period of 2045, U.S. natural gas resources, especially unconventional supply from shale resources, are wholly adequate to satisfy domestic demand as well as the added demand of LNG exports from the Project, even when other LNG exports are assumed.

3. Effects on Domestic Prices of Natural Gas

Analyses performed and commissioned by the DOE/FE demonstrate that LNG exports from the United States would not result in adverse economic outcomes for U.S. consumers. In 2012, the DOE released a two-part study evaluating the effects on the U.S. economy of LNG exports to Non-FTA countries in volumes up to 12 Bcf per day. In 2014 and 2015, DOE/FE released an updated two-part study assessing the economic effects of higher levels of U.S. LNG exports–*i.e.*, between 12 and 20 Bcf per day.

The first part of the 2012 studies consisted of an EIA report evaluating how LNG exports would affect domestic energy consumption, production, and prices under various scenarios involving either 6 Bcf per day or 12 Bcf per day (the "2012 EIA Study").[86] The 2012 EIA Study projected that natural gas prices would rise over time, even without additional LNG exports.[87] In the second part of the 2012 studies, NERA Economic Consulting ("NERA") assessed the macroeconomic effects of increased LNG exports under a range of global natural gas supply and

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[85] ICF Mid-Scale Report at 26.

[86] U.S. Energy Information Administration, *Effect of Increased Natural Gas Exports on Domestic Energy Markets, as Requested by the Office of Fossil Energy* (Jan. 2012), https://www.energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf.

[87] *Id.* at 6.

demand scenarios, including scenarios with unlimited LNG exports ("2012 NERA Study").[88] In each of the scenarios analyzed, NERA found that the United States would experience net economic benefits from increased LNG exports.[89] With regard to the effect of natural gas prices, NERA further projected that "price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios."[90] NERA also indicated that the peak natural gas export levels and resulting price increases analyzed by the 2012 EIA Study are "not likely,"[91] namely because U.S. exports would fall far short of the levels of exports assumed in the 2012 EIA Study.[92] Even in the export scenarios that led to the most significant theoretical price increases projected by the 2012 EIA Study, the 2012 NERA Study found net benefits to U.S. consumers.[93] The 2012 NERA Study further found that the net positive economic results became greater with higher levels of exports.[94]

The DOE/FE's updated studies consisted of a 2014 domestic market analysis by EIA ("2014 EIA Study"), and a 2015 macroeconomic analysis conducted by the Center for Energy Studies at Rice University's Baker Institute and Oxford Economics ("2015 LNG Export Study").[95] The 2014 EIA Study evaluated the effects on U.S. energy markets of increased LNG exports,

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[88] NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (Dec. 2012), https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

[89] *Id.* at 6.

[90] *Id.* at 2.

[91] *Id.* at 9.

[92] *Id.* at 12.

[93] *Id.* at 6.

[94] *Id.* at 12.

[95] U.S. Energy Information Administration, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (Oct. 2014), https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf; Center for Energy Studies at Rice University Baker Institute and Oxford Economics, *The Macroeconomic Impact of Increasing U.S. LNG Exports* (Oct. 29, 2015), https://www.energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf.

ranging from 12 Bcf per day to 20 Bcf per day.[96] The 2014 EIA Study projected that, under the Annual Energy Outlook 2014 Reference Case, the increased LNG export levels analyzed would lead to a 2% to 5% increase in residential natural gas prices between 2015 and 2040 compared to baseline projections.[97] This forecast is less than the predicted 3% to 7% average increase between 2015 and 2035 that EIA had previously projected for a lower level of exports under the Annual Energy Outlook 2011 Reference Case. The 2014 EIA Study found that, even if exports of LNG are greater than forecasted, increased energy production spurs investment, which more than offsets the adverse effects of somewhat higher energy prices when the export scenarios are applied.[98] EIA further noted that the model it relied upon is focused on the domestic U.S. energy system and economy, and does not address several key international linkages that may further increase economic benefits.[99] That limitation notwithstanding, the EIA 2014 Study estimated that higher LNG exports would result in gross domestic product ("GDP") increases across all scenarios.[100]

The 2015 LNG Export Study similarly evaluated the macroeconomic effects of LNG exports ranging from 12 Bcf per day to 20 Bcf per day, and confirmed that increased LNG exports would yield net positive macroeconomic results.[101] The 2015 LNG Export Study found that LNG exports would raise domestic prices and lower international prices.[102] The 2015 LNG Export Study also found that increased exports would lead to small declines in output at the margin for some energy-intensive industries (albeit declines that are offset by positive effects to industries

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96 2014 EIA Study.

97 *Id.* at 12.

98 *Id.*

99 *Id.*

100 *Id.* at 24-25.

101 2015 LNG Export Study at 82.

102 *Id.* at 8.

that benefit from increased exports).[103] Nevertheless, the 2015 LNG Export Study found that these potentially adverse outcomes would be offset by the overall net macroeconomic benefits of increased LNG exports, finding that "[a]cross the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports."[104] Moreover, the 2015 LNG Export Study concluded that rising exports would result in GDP increases between 0.03 and 0.07 percent over the period from 2026 to 2040, equating to $7 to $21 billion USD annually in today's prices.[105] DOE/FE has recognized that the 2014 EIA Study and 2015 LNG Export Study are "fundamentally sound" and "provide substantial support" for authorizing LNG exports.[106] Indeed, the DOE/FE has noted that the 2015 LNG Export Study demonstrates that "the United States will experience net economic benefits from the issuance of authorizations to export domestically produced LNG."[107]

Most recently, NERA published another study ("2018 NERA Study") examining the probability and macroeconomic impact of various lower-48 sourced LNG export scenarios.[108] Like the prior studies the DOE/FE has commissioned, the 2018 NERA Study examines the impacts of varying levels of LNG exports on domestic energy markets. However, the 2018 NERA Study

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[103] *Id.*

[104] *Id.* at 16.

[105] *Id.* at 8.

[106] *See Cameron LNG*, DOE/FE Order No. 3846, at 109-10.

[107] *Id.* at 110.

[108] NERA Economic Consulting, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports*, at 14 (June 7, 2018), https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf. The DOE/FE submitted the 2018 NERA Study for public comment, and the comment period has now closed.

also assesses the likelihood of different levels of "unconstrained" LNG exports (defined as market determined levels of exports) and analyzes the outcomes of different LNG export levels on the U.S. natural gas markets and the U.S. economy as a whole, over the 2020 to 2050 time period. Specifically, the 2018 NERA Study develops 54 scenarios by identifying various assumptions for domestic and international supply and demand conditions to capture a wide range of uncertainty in the natural gas markets.[109] "Throughout the entire range of scenarios, [the 2018 NERA Study found] that overall U.S. economic output is higher whenever global markets call for higher levels of LNG exports, assuming that exports are allowed to be determined by market demand."[110] Further, the 2018 NERA Study found that "[f]or each of the supply scenarios, higher levels of LNG exports in response to international demand consistently lead to higher levels of GDP. . . . Consumer welfare, expressed in dollar terms, is also higher when there is greater domestic oil and gas supply" and higher levels of LNG exports.[111]

In an independent analysis commissioned by ECA, ICF found that the price increases due to additional LNG exports produced by the ECA Mid-Scale Project will be minimal. As a consequence of growing gas demand and increased reliance on new sources of supply, gas prices are expected to increase in the future, even without any exports from the ECA Mid-Scale Project.[112] Nevertheless, because unconventional production will increasingly be relied upon to

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[109] The 2018 NERA Study analyzed "the robustness of unlimited market level determined LNG exports by examining different scenarios that reflect a wide range of natural gas market conditions, where robustness is measured using key macroeconomic metrics such as GDP, aggregate household income, and consumer welfare." *Id.* at 13.

[110] *Id.* at 14.

[111] *Id.* at 18, 20.

[112] ICF Mid-Scale Report at 31.

offset declining conventional production,[113] and the cost of production of unconventional natural gas is estimated to be much lower on a per-unit basis than that of conventional sources,[114] the natural gas price increase resulting from increased demand will be minimal.[115] In the ICF Base Case, gas prices at Henry Hub are expected to increase gradually from approximately \$2.90/MMBtu in 2017 to \$4.41/MMBtu in 2045.[116] As a result, prices will be high enough to foster sufficient supply development to meet growing demand, but not so high as to discourage the demand growth.[117]

The ICF Mid-Scale Report supports the conclusion that the exports proposed in the Non-FTA Application will have a minimal adverse effect on domestic natural gas prices. According to ICF, by 2045, the average increase in the Henry Hub natural gas price attributable to the ECA Mid-Scale Project is only approximately \$0.02/MMBtu, from an estimated 2045 price of \$4.41/MMBtu (with some LNG exports, but not the Project) to a 2045 price with the Project of \$4.43/MMBtu.[118]

As demonstrated above, the overall balance between the domestic supply and demand forecasts for the U.S. natural gas market demonstrates that the volumes proposed to be exported in this Application are not needed by the domestic market. This lack of domestic need, combined with the minimal impacts to U.S. prices that exports to Non-FTA countries are projected to have, demonstrates that the export of such volumes is not inconsistent with the public interest.

C. Other Public Interest Considerations

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[113] *Id.* at 12.

[114] *Id.* at 13.

[115] *Id.* at 31.

[116] *Id.*

[117] *Id.*

[118] *Id.* at 48.

1. Local, Regional, and National Economic Benefits

The Project will stimulate local, regional, and national economies through direct, indirect, and induced job creation, increased economic activity, and tax revenues.

The construction and operation of the Project will result in significant employment benefits across several industries in both the United States and Mexico on a local and nationwide basis. Including direct, indirect, and induced employment, the Project will result in the creation of an average of nearly 6,600 jobs for the U.S. economy annually from 20211 through 2045.[119] Additionally, the Project is expected to result in approximately 1,500 jobs annually in the Southwestern United States over the same forecast period.[120] ICF estimates that, as a result of this substantial job creation, the Project will lead to a cumulative increase of almost 166,000 job-years for the U.S. economy as a whole and 38,000 job-years for the economy in the Southwest through 2045.[121]

Further, exports from the ECA Mid-Scale Project will increase tax revenues on both the state and federal level. Total government revenues in the Southwestern United States (including fees and taxes on personal income, corporate income, sales, property, oil and gas severance, and employment) are estimated to increase by $39 million annually through 2045 with the Project.[122] This equates to a cumulative increase in state government revenues of approximately $982 million.[123] LNG exports from the ECA Mid-Scale Project are estimated to result in an increase in

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[119] *Id*. at 50.

[120] *Id*. at 54.

[121] *Id*. at 50, 54.

[122] *Id*. at 55.

[123] *Id*.

collective government revenues of $535 million annually.[124] This translates to a cumulative increase of $13.3 billion in governmental revenue over the forecast period between 2021 and 2045.[125]

The Project will make a significant contribution to the national economy. The additional LNG volumes exported from the ECA Mid-Scale Project could add an average of $1.5 billion to the U.S. economy annually over the period from 2021 through 2045, resulting in a cumulative contribution of $37.2 billion including the value of associated liquids produced with incremental natural gas and multiplier effects.[126] In the Southwestern United States, the Project is expected to add $0.29 billion to the economy annually ($7.16 billion over the forecast period).[127]

The Project will result in substantial local, regional, and national net economic benefits. With the U.S. economy rebounding from the 2007 financial crisis, the Project will be an important source of new capital investment and job creation. The benefits of the Project will first be realized prior to the commencement of construction (when orders for equipment and engineering and other services are placed) and will continue during construction and over the 20-year export term.

2. Increased Exports and International Trade

According to ICF, the ECA Mid-Scale Project will generate an expected cumulative value of approximately $37.2 billion of natural gas and LNG exports between 2021 and 2045, which will favorably influence the balance of trade that the United States has with its international trading partners.[128] In 2017, the U.S. trade deficit increased to $566.3 billion, reflecting $2.3 trillion in

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[124] *Id.* at 51.

[125] *Id.*

[126] *Id*. at 52.

[127] *Id*. at 56.

[128] *Id*. at 52.

exports and $2.9 trillion in imports.[129] According to ICF, the expected value of the natural gas exports to and LNG exports from the facility is estimated to reduce the U.S. balance of trade deficit by $1.5 billion annually between 2021 and 2045, based on the value of LNG and natural gas export volumes, liquids produced in association with incremental natural gas, and other trade effects.[130]

LNG exports will increasingly diversify the global supply of energy resources, which will support the geopolitical security interests of the United States by providing energy supply alternatives to its allies. The export of domestically produced LNG will promote liberalization of the global gas market by fostering increased liquidity and trade at prices established by market forces. Though the price of LNG has recently been volatile, the price of LNG in Asian markets remains significantly higher than that of U.S. LNG.[131]

By introducing additional market-based price structures, the Project will help to reduce premiums charged to economies which do not currently have sufficient energy supply alternatives and reduce gas price volatility around the world.

3. Environmental Benefits

LNG exports can have significant environmental benefits as natural gas is cleaner burning than other fossil fuels. For example, the DOE's Life Cycle Analysis Greenhouse Gas ("GHG")

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[129] U.S. Department of Commerce Bureau of Economic Analysis, *U.S. International Trade in Goods and Services* (Feb.6, 2018), https://www.bea.gov/news/2018/us-international-trade-goods-and-services-december-2017.

[130] ICF Mid-Scale Report at 52.

[131] *See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (June 4, 2018), http://pubdocs.worldbank.org/en/799841528151608411/CMO-Pink-Sheet-June-2018.pdf (the average natural gas price in May 2018 was $2.78 per MMBtu in the United States, while the average LNG price was $9.40 per MMBtu in Japan); The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (Sept 5, 2018), http://pubdocs.worldbank.org/en/453081536593505013/CMO-Pink-Sheet-September-2018.pdf (the average natural gas price in August 2018 was $2.96 per MMBtu in the United States, and the average LNG price was $10.44 per MMBtu in Japan); *see also* Federal Energy Regulatory Commission Market Oversight, *World LNG Estimated Landed Prices* (Aug. 2018), https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf (average estimated LNG landed price of $10.00 in India, $10.05 in Korea, and $10.05 in China as of August 2018).

Report noted that under most scenarios analyzed in the report, "generation of power from imported natural gas [into both Europe and Asia] has lower life cycle GHG emissions than power generation from regional coal."[132] An increased supply of natural gas made possible through LNG exports can help countries move away from less environmentally friendly fuels by displacing the current consumption of coal in power generation and deterring the construction of additional coal-fired generation capacity.

D. Combined Effects of the ECA Mid-Scale and ECA Large-Scale Projects

As discussed above, ECA is separately applying for export authorization for two sets of liquefaction and export terminal facilities—the ECA Mid-Scale Project and the ECA Large-Scale Project. In addition to the ICF Mid-Scale Report, ECA commissioned ICF to prepare a report analyzing the combined effects of the ECA Mid-Scale and Large-Scale Projects (the "ICF Combined Report").[133] The ICF Combined Report confirms that approval of the cumulative volumes of exports requested for both the ECA Mid-Scale Project and ECA Large-Scale Project is in the public interest.

Similar to the ICF Mid-Scale Report, the ICF Combined Report forecasts increases in domestic natural gas supply over the proposed term of the ECA Mid-Scale and Large-Scale Projects. Specifically, the ICF Combined Report estimates that the amount of gas in the Lower 48 that is economic at $5/MMBtu would increase from 1,225 Tcf to 2,160 Tcf, a 76% increase.[134]

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[132] U.S. Department of Energy, *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States,* at 9 (May 29, 2014), https://energy.gov/sites/prod/files/2014/05/f16/Life%20Cycle%20GHG%20Perspective%20Report.pdf.

[133] *See* Appendix B2, ICF International, Economic Impacts of the Proposed Energía Combined Costa Azul Liquefaction Project: Information for DOE Non-FTA Permit Application (Sept. 11, 2018) [hereinafter ICF Combined Report].

[134] *Id.* at 20.

With respect to domestic natural gas demand, the ICF Combined Report projects that U.S. natural gas resources will remain more than adequate to satisfy domestic demand and the added demand of both the ECA Mid-Scale and Large-Scale Projects.[135] The ICF Combined Report further estimates that the combined ECA Mid-Scale Project and ECA Large-Scale Project will have minimal adverse effects on domestic natural gas prices. According to the ICF Combined Report, by 2045, the average increase in the Henry Hub natural gas price attributable to the ECA Mid-Scale and ECA Large-Scale Projects is only approximately $0.11/MMBtu, from an estimated 2045 price of $4.41/MMBtu (including some LNG exports, but not the exports attributable to the ECA Mid-Scale Project and ECA Large-Scale Project) to a 2045 price with the ECA Mid-Scale and Large-Scale Projects of $4.52/MMBtu.[136]

The ICF Combined Report further estimates various benefits to the local, regional, and national economies and to the U.S. balance of trade as a result of the combined ECA Mid-Scale Project and ECA Large-Scale Project. The construction and operation of the ECA Mid-Scale Project and ECA Large-Scale Project will result in significant employment benefits across a number of industries in both the United States and Mexico on a local and nationwide basis. Including direct, indirect, and induced employment, the ECA Mid-Scale Project and ECA Large-Scale Project cumulatively will result in the creation of an average of nearly 27,600 jobs for the U.S. economy annually from 2021 through 2045.[137] Additionally, the ECA Mid-Scale Project and ECA Large-Scale Project are expected to result in approximately 6,200 jobs annually in the

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[135] *Id*. 22-26, 47-48.

[136] *Id*. at 48.

[137] *Id*. at 50.

Southwestern United States over the same forecast period.[138] ICF estimates that, as a result of this substantial job creation, the ECA Mid-Scale Project and ECA Large-Scale Project will lead to a cumulative increase of almost 689,000 job-years for the U.S. economy as a whole and 155,000 job-years for the economy in the Southwest through 2045.[139]

Further, exports from both the ECA Mid-Scale Project and ECA Large-Scale Project will increase tax revenues on both the state and federal level. Total government revenues in the Southwestern United States (including fees and taxes on personal income, corporate income, sales, property, oil and gas severance, and employment) are estimated to increase by $162 million annually through 2045 with the ECA Mid-Scale and Large-Scale Projects.[140] This equates to a cumulative increase in state government revenues of approximately $4.0 billion.[141] LNG exports from the ECA Mid-Scale Project and ECA Large-Scale Project are estimated to result in an increase in collective government revenues of $2.2 billion annually.[142] This translates to a cumulative increase of $54.7 billion in governmental revenue over the forecast period between 2021 to 2045.[143]

The ECA Mid-Scale Project and ECA Large-Scale Project will make a significant combined contribution to the national economy. The additional LNG volumes exported from the ECA Mid-Scale Project and ECA Large-Scale Project could add an average of $6.1 billion to the U.S. economy annually over the period from 2021 to 2045, resulting in a cumulative contribution

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138 *Id*. at 54.

139 *Id*. at 50, 54.

140 *Id*. at 55.

141 *Id*.

142 *Id*. at 51.

143 *Id*.

of $152 billion including the value of associated liquids produced with incremental natural gas and multiplier effects.[144] In the Southwestern United States, the ECA Mid-Scale Project and ECA Large-Scale Project are expected to add $1.2 billion to the economy annually ($29.4 billion over the forecast period).[145]

According to ICF, the ECA Mid-Scale Project and ECA Large-Scale Project will generate an expected cumulative value of approximately $89.2 billion of natural gas and LNG exports between 2021 to 2045, which will favorably influence the balance of trade that the United States has with its international trading partners.[146] According to ICF, the expected value of the natural gas exports to and LNG exports from the ECA Mid-Scale Project and ECA Large-Scale Project is estimated to reduce the U.S. balance of trade deficit by $3.6 billion annually between 2021 and 2045, based on the value of LNG and natural gas export volumes, liquids produced in association with incremental natural gas, and other trade effects.[147]

VII. REVIEW OF ENVIRONMENTAL EFFECTS

A. Review of the Application is Subject to a Categorical Exclusion under NEPA

ECA respectfully requests that the DOE/FE determine that under the circumstances, a categorical exclusion from the requirement to produce an environmental assessment and/or an EIS is both applicable and appropriate for DOE/FE's review of the ECA Mid-Scale Project. Application of a categorical exclusion in this case is appropriate because the ECA Mid-Scale Project will be located in Mexico, beyond the scope of the DOE/FE's jurisdiction. Further, the existing physical pipeline capacity in the U.S. exceeds the volumes ECA is requesting to export to

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144 *Id*. at 52.

145 *Id*. at 56.

146 *Id*. at 53.

147 *Id*.

Mexico. Accordingly, under the relevant DOE regulations and DOE/FE precedent, ECA's construction of the ECA Mid-Scale Project should not be construed to involve the construction of U.S. facilities for the purposes of the Categorical Exclusion under NEPA. In addition, the requested exports associated with the ECA Mid-Scale Project are not expected individually or cumulatively to have significant environmental impacts in the United States.[148] The DOE/FE has no obligation to perform a NEPA analysis of potential future interstate natural gas pipeline expansions in connection with exercising its jurisdiction to approve exports of natural gas under Section 3 of the NGA. Finally, ECA submits that the imposition of a condition similar to the conditions that were imposed in the *Bear Head*/*Pieridae* proceedings would be inconsistent with the public interest because it would place an obligation upon ECA that would be unreasonably vague and unworkable.

The regulations adopted by the Council on Environmental Quality ("CEQ") state that the application of categorical exclusions to certain categories of actions is appropriate where the implementing agency has determined such actions are not expected to have individually or cumulatively significant environmental impacts.[149] The DOE regulations implementing NEPA recognize such an exemption applicable in this situation. Specifically, Categorical Exclusion B5.7 generally exempts "[a]pprovals … of new authorizations . . . to. . . export natural gas under section 3 of the Natural Gas Act that involve minor operational changes (such as changes in natural gas throughput, transportation, and storage operations) **<u>but not new construction</u>**."[150] ECA's Application would qualify for this exclusion since the construction of the Project facilities will

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[148] Categorical exclusions apply in the case of actions the implementing agency has determined are not expected to have individually or cumulatively significant environmental impacts. *See* 40 C.F.R. § 1508.4.

[149] *See* 40 C.F.R. § 1508.4.

[150] 10 C.F.R. Part 1021, Subpart D, app. B § B5.7 (emphasis added).

occur entirely in Mexico. Furthermore, the physical capacity of the existing facilities on NBP and other U.S. pipelines exceeds the proposed export volumes.

As the courts have recognized, the NEPA is generally construed so as not to require the consideration of extraterritorial impacts (*i.e.*, impacts beyond the United States), except under a few defined circumstances not present here. Absent evidence of Congressional intent to the contrary, a federal statute should be construed as applying only within the territorial jurisdiction of the United States.[151] The primary purpose of this presumption is "to protect against unintended clashes between our laws and those of other nations which could result in international discord."[152] Reviewing courts have found that there is no explicit Congressional discussion directing the extraterritorial application of NEPA.[153]

The environmental effects of construction and operation of the ECA Mid-Scale Project facilities are already being reviewed by Mexican regulators. The DOE/FE has served as a cooperating agency in FERC's NEPA review process associated with the construction of LNG export projects located in the United States. In those proceedings, the DOE/FE has relied upon the NEPA analysis prepared by FERC and has adopted FERC's environmental analysis for purposes of meeting DOE/FE's NEPA obligations. However, in the case of the ECA Mid-Scale Project, the construction and operation of the facilities will occur in Mexico. As such, the construction and operation of the Project and associated Mexican pipeline facilities have been or will be reviewed and approved by regulatory authorities within the nation of Mexico. As part of this process, the Mexican agencies with jurisdiction over the Project and associated pipelines

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151 *See Equal Emp't Opportunity Comm'n v. Arabian Am. Oil Co.,* 499 U.S. 244 (1991).

152 *Id.* at 248; *see also NEPA Coal. v. Aspin*, 837 F. Supp. 466, 467-68 (D.D.C. 1993) (holding that NEPA does not apply to U.S. bases in Japan).

153 *Greenpeace USA v. Stone,* 748 F. Supp. 749, 758-59 (D. Haw. 1990); *see also Nat. Res. Def. Fund v. Nuclear Regulatory Comm'n,* 647 F.2d 1345, 1367 (D.C. Cir. 1981).

conduct their own environmental review of the ECA Mid-Scale Project, assuring that the environmental impacts connected to the Project in Mexico have been considered by the appropriate Mexican authorities.

A finding that Categorical Exclusion B5.7 applies to exempt the Application from review under NEPA is consistent with the conclusion that the DOE/FE reached in other instances where it has reviewed proposals to export U.S. gas to a foreign country for re-export to Non-FTA countries. In its decisions in *Bear Head* and *Pieridae*, DOE found that Categorical Exclusion B5.7 was applicable because the only construction proposed would occur outside of the United States, which was "beyond the scope of [DOE's] environmental review under NEPA."[154] In the *Pieridae* decision, the DOE/FE confirmed that an environmental analysis of construction outside of the United States "is outside the scope of [DOE's] environmental review under NEPA . . . which necessarily focuses on potential environmental impacts within the United States."[155]

In addition to determining whether a proposed action falls within the classes of actions qualifying for a categorical exclusion, DOE/FE must also consider whether the proposal has been segmented to meet the definition of a categorical exclusion.[156] Segmentation occurs when "a proposal is broken down into small parts in order to avoid the appearance of significance of the total action. The scope of a proposal must include the consideration of connected and cumulative

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[154] Pieridae Order at 202; Bear Head Order at 162.

[155] Pieridae Order at 190.

[156] 10 C.F.R. § 1021.410(b)(3). DOE/FE is also required to consider whether there are any extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal. *Id.* § 1021.410(b)(2). Extraordinary circumstances are defined as "unique situations presented by specific proposals, including, but not limited to, scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id.* As noted above, the ECA Mid-Scale Project involves no construction of facilities in the United States and will therefore have no environmental effects requiring NEPA review. Accordingly, there can be no extraordinary circumstances affecting the significance of environmental effects.

actions, that is, the proposal is not connected to other actions with potentially significant impacts (40 CFR 1508.25(a)(1)) [and] is not related to other actions with individually insignificant but cumulatively insignificant impacts (40 CFR 1508.27(b)(7)) . . . ."[157]

Connected actions, in turn, are actions that are "closely related and therefore should be discussed in the same impact statement. Actions are connected if they:

> (i) Automatically trigger other actions which may require environmental impact statements.
>
> (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously.
>
> (iii) Are interdependent of a larger action and depend on the larger action for their justification."[158]

With respect to actions with "individually insignificant but cumulatively significant impacts," DOE regulations explain that "[s]ignificance exists if it is reasonable to anticipate a cumulatively significant impact on the environment. Significance cannot be avoided by terming an action temporary or by breaking it down into small component parts."[159]

Under the relevant DOE regulations and DOE/FE precedent, there are no connected actions that have been improperly segmented from the ECA Mid-Scale Project for the purposes of NEPA—the Project will not automatically trigger other actions requiring NEPA review, does not depend on actions occurring in the United States in order to proceed, and is not dependent on a larger action in the United States for its justification. Nor does the Project involve any actions with individually insignificant but cumulatively significant impacts. As discussed in Part V.B above, and as reflected in Appendix E, the physical capacity of the existing cross-border pipeline

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[157] *Id.* § 1021.410(b)(3).

[158] 40 C.F.R. § 1508.25(a)(1).

[159] *Id.* § 1508.27(b)(7).

facilities is well in excess of the full volumes requested in this Application. Furthermore, as explained in Part V.E above, although ECA is separately proposing the ECA Large Scale Project, the ECA Mid-Scale and Large-Scale Projects are two distinct projects that are not dependent on each other. Even if the ECA Mid-Scale and Large-Scale Projects were interdependent, both projects will be located entirely within Mexico and will involve no new construction in the United States; therefore, both projects qualify for Categorical Exclusion B5.7 and cannot be considered to be connected actions or to have cumulatively significant effects for purposes of the DOE/FE's NEPA review.

Finally, the DOE/FE has no obligation to perform a NEPA analysis of potential future interstate natural gas pipeline expansions in connection with exercising its jurisdiction to approve exports of natural gas under section 3 of the NGA. The U.S. Court of Appeals for the D.C. Circuit has recently held[160] that the FERC need not consider the alleged indirect effects of LNG exports in certificating LNG export facilities because those alleged effects are caused by the DOE/FE's decision to authorize the underlying export:

> The [FERC's] NEPA analysis did not have to address the indirect effects of the anticipated *export* of natural gas . . . because [DOE/FE], not the [FERC], has sole authority to license the export of any natural gas going through [the applicant's U.S. LNG terminal] facilities. In the specific circumstances where, as here, any agency "has no ability to prevent a certain effect due to" that agency's "limited statutory authority over the relevant action[]," then that action "cannot be considered the legally relevant 'cause' of the effect" for NEPA purposes.[161]

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[160] *Sierra Club v. FERC*, 827 F.3d 36, 47 (D.C. Cir. 2016) [hereinafter *Sierra Club (Freeport)*] (FERC did not have to consider the indirect effects of the anticipated export of natural gas because DOE/FE has sole authority to authorize such exports); *Sierra Club v. FERC*, 827 F.3d 59, 68 (D.C. Cir. 2016) (same); *EarthReports, Inc. v. FERC,* 828 F.3d 949, 952 (D.C. Cir. 2016) (same).

[161] *Sierra Club (Freeport)*, 827 F.3d at 47 (quoting *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 770 (2004)) (emphasis in original).

In this case, the FERC, not the DOE/FE, has exclusive jurisdiction over certification and siting of interstate natural gas pipelines. Under the rationale of *Public Citizen, Sierra Club (Freeport)*, and *EarthReports,* the DOE/FE should not be required to include in a NEPA analysis the consequences of future actions over which it has no jurisdiction. The DOE/FE cannot be said to be the proximate cause of such alleged effects. While *Bear Head* and *Pieridae* appear to conflict with this position to some degree, both decisions **predate** the relevant D.C. Circuit opinions that were recently issued regarding the scope of NEPA review.

B. DOE/FE Should Not Impose Point-of-Export or Future Construction Restrictions

1. Volume and Facility Point-of-Export Restrictions Are Unnecessary

Given the existence of abundant physical cross-border pipeline capacity to export U.S. gas to the ECA Mid-Scale Project, ECA respectfully requests that the DOE/FE issue the authorizations sought in this Application without imposing any restriction upon the points of export and/or facilities along the U.S./Mexican border that ECA may utilize to export gas destined for the ECA Mid-Scale Project from the United States. If, in the future, the ECA Mid-Scale Project or any other projects proposed at the ECA facility require an aggregate amount of exported U.S. gas in excess of the volumes for which ECA is requesting authorization in this Application, the appropriate applications will be filed with the DOE/FE for any additional or supplemental authorizations that may be necessary with respect to those incremental volumes. However, a requirement to obtain additional DOE/FE approval before exporting natural gas in amounts authorized by the order requested by this Application from specific cross-border facilities is unnecessary and would be inconsistent with the DOE/FE's treatment of other natural gas export applications.

Although in two previous cases the DOE/FE has imposed conditions limiting the scope of an applicant's Non-FTA export authorization in the "unusual circumstances" discussed below, this Application does not involve such unusual circumstances and is materially distinguishable from the situation considered in those proceedings. Accordingly, the DOE/FE should not impose the same conditions on any order approving ECA's proposed exports. Rather, ECA respectfully requests that DOE/FE issue an order without such a restriction tied to future upstream and/or cross-border developments, consistent with the way DOE/FE has treated exports from U.S. LNG facilities.

In *Bear Head* and *Pieridae*, the Non-FTA export authorizations issued in connection with two terminals to be located in Nova Scotia, Canada, were limited to volumes equal to the existing capacity of the Maritimes & Northeast ("M&N") US Pipeline at the border of the United States and Canada. In those proceedings, it was clear that the M&N US Pipeline, which would transport the gas to the U.S. border for export, was physically incapable of transporting the full volume requested by either applicant. The DOE/FE approved both applications based upon Categorical Exclusion B5.7 but limited the scope of the authorizations only to exports using the existing M&N US Pipeline facilities that had been authorized by the FERC at the time. Specifically, the DOE/FE stated that its authorization and the categorical exclusion upon which it relied did "not apply to any future construction or operational changes to expand the capacity of the M&N US Pipeline or other facilities located within the United States **<u>caused either in whole or in part by [the applicant's] export operations.</u>**"[162] The DOE/FE emphasized that if either applicant in *Bear Head* or *Pieridae* proposed to export volumes using "new" or "upgraded" pipeline capacity, *i.e.*,

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[162] Pieridae Order at 10 (emphasis added); *see also* Bear Head Order at 10 (emphasis added).

"new capacity not presently in existence on [M&N US Pipeline], or if it proposes to use capacity on newly constructed or upgraded cross-border pipelines," it would be required to apply to the DOE/FE for new export authorization "[t]o ensure that DOE/FE has an opportunity to review the public interest and environmental impacts of any such capacity additions or the use of other existing pipelines."[163] The DOE/FE stated that pipeline capacity would be considered "new" or "upgraded" for purposes of the limitation it placed on both authorizations "if it is the result of physical changes that increase the northbound capacity of such a pipeline and any such changes require an amendment to the pipeline's certificate issued by FERC under NGA section 7."[164] The DOE/FE noted that it "may participate in the FERC-led NEPA review, as it typically does in proceedings involving LNG export facilities pursuant to NGA section 15, 15 U.S.C. §717n" for any such new Non-FTA export application filed in connection with a Section 7 certificate.[165]

The ECA Mid-Scale Project is not similarly situated to the *Bear Head* and *Pieridae* projects. First, both Canadian projects were geographically remote and served by only one interstate pipeline: M&N US Pipeline. In those cases, the DOE/FE found that transportation on the M&N US Pipeline was "**essential**" to the project but noted in each case that the record had not demonstrated that the M&N US Pipeline was capable of physically transporting the full volume of gas requested to be exported. While there was some discrepancy between the *Bear Head* and *Pieridae* applications as to the actual cross-border capacity of the M&N US Pipeline,[166] neither

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163 Bear Head Order at 5; *see* Pieridae Order at 5.

164 Pieridae Order at 5.

165 Pieridae Order at 5. *See* NGA § 15, 15 U.S.C. § 717n(b) (designating the FERC as the "lead agency" with respect to NEPA reviews associated with projects constructed under NGA Sections 3 and 7 and directing "[e]ach Federal and State agency considering an aspect of an application for Federal authorization [to] cooperate with the [FERC] and comply with the deadlines established by the [FERC]").

166 The *Bear Head* application claimed it was 833,317 Dth/d and the *Pieridae* application claimed it was 440,000 Dth/d. *Compare* Bear Head Order at 4 (citing *Bear Head LNG Corporation*, Application for Long-Term

applicant claimed that the existing cross-border capacity was sufficient to transport its full requested volume. In addition, the DOE/FE noted in both proceedings that the applicants had not demonstrated that the capacity on the M&N US Pipeline mainline facilities from the receipt point in Dracut, Massachusetts, to the U.S./Canadian border was sufficient to transport the full volume of either project. In contrast to the M&N US Pipeline discussed in *Bear Head* and *Pieridae*, in this case, the physical capacity of the cross-border facilities, as established in the ICF Mid-Scale Report and Appendix E to this Application, substantially exceeds the export volumes requested in this Application. There is approximately 15 Bcf/d of cross-border capacity from existing facilities, making it possible for the ECA Mid-Scale Project to access gas from several cross-border locations for the export of its requested 441 MMcf/d volume of natural gas through pipeline construction conducted in Mexico that may occur in the future.[167]

ECA asserts and the DOE/FE has conceded that in prior Non-FTA export proceedings, the DOE/FE "has not afforded weight in its public interest review to the capacity of the interstate pipelines delivering natural gas for export."[168] The DOE/FE recognized an exception to this practice in the cases of *Bear Head* and *Pieridae*, reasoning that the applicants should be treated differently from other Non-FTA LNG export applicants because they "identifie[d] only a single

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Authorizations to Export Natural Gas to Canada and to Export Liquefied Natural Gas from Canada to Free Trade Agreement and Non-Free Trade Agreement Nations, FE Docket No. 15-33-LNG, 5 n.18 (Feb. 25, 2015)) *with* Pieridae Order at 4 (citing *Pieridae Energy (USA) Ltd.*, Application for Long-Term, Multi-Contract Authorization to Export Natural Gas into Canada for Consumption and Through Canada to Free Trade and Non-Free Trade Agreement Nations after Conversion into LNG, FE Docket No. 14-179-LNG, at 17 n.22 (Oct. 24, 2014)).

[167] For example, the physical capacity of the NBP system (500 MMcf/d) is well in excess of the 441 MMcf/d of natural gas exports for which ECA is seeking authorization in this Application. Likewise, the physical capacities of Sierrita Gas Pipeline (627 MMcf/d), Comanche Trail Pipeline (1,100 MMcf/d), Roadrunner Pipeline (875 MMcf/d), and Trans-Pecos Pipeline (1,300 MMcf/d) each exceed the requested volume in this proceeding.

[168] Bear Head Order at 157. ECA considers "upstream facilities" to include any pipeline facilities that are upstream of the pipeline that is directly interconnected with and necessary to transport gas to the facilities of an LNG terminal—in this case, the 42-inch, 2.6 Bcf/d LNG Spur. See note 36, *supra*.

pipeline capable of transporting natural gas to an LNG terminal for export and **<u>that pipeline may not presently have the capacity to meet the anticipated demand for export volumes.</u>**"[169] The DOE/FE specifically noted that the *Bear Head* and *Pieridae* proceedings involved the "unusual circumstance of an applicant proposing to export volumes that **<u>exceed</u>** the capacity of the single pipeline essential to completing the transportation central to the re-export proposal."[170]

This Application does not involve the "unusual circumstance" presented to the DOE/FE in *Bear Head* and *Pieridae* because the existing physical pipeline capacity exceeds the full requested volumes for export. Thus, the DOE/FE should treat the authorizations requested by ECA in this Application similarly to the way in which it has treated other Non-FTA export applications. Unlike the applicants in *Bear Head* and *Pieridae*, the physical capacity of existing cross-border facilities identified as accessible to the Project in this Application exceeds the volumes for which ECA is requesting Non-FTA export authorization.

Accordingly, because the ECA Mid-Scale Project does not involve exports through a pipeline that is physically incapable of transporting its requested volumes, as was the case in *Bear Head* and *Pieridae,* the ECA Mid-Scale Project is not similarly situated to the applicants in those proceedings and the DOE/FE should not impose the same manner of restriction on the location and specific facilities that can be used to export the natural gas for the ECA Mid-Scale Project.

2. <u>Future Capacity Restrictions Are Unnecessary</u>

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169 *Id*. (emphasis added).

170 *Id.* at 4 (emphasis added); *see also* Pieridae Order at 195.

With regard to future pipeline construction or expansion, in both *Bear Head* and *Pieridae*, the DOE/FE stated that a NEPA and an NGA public interest review would be required when new capacity "result[s] proximately" from the issuance of the export authorization.[171] This would "ensure that no U.S.-based pipeline facilities **essential** to [the applicant's] export operations are put into service for those purposes without an opportunity for the necessary environmental review, including opportunity for public participation."[172] The DOE/FE, however, did not define what it meant by a future project being "proximate[ly]" caused or "essential" to an export project. ECA asserts that the DOE/FE should interpret this precedent narrowly to encompass only those situations where proposed exports cannot be physically accomplished without some new construction—*i.e.*, where the proposed "export volumes . . . **exceed** the capacity of the single pipeline essential to completing the transportation central to the re-export proposal," as was the case with *Bear Head* and *Pieridae.*[173] As discussed below, imposing the same future capacity conditions that it applied to *Bear Head* and *Pieridae* under different circumstances would be unnecessary, unworkable, and inconsistent with the way in which DOE/FE treats other applicants.[174]

Like all interstate pipeline facilities, it is possible that the upstream facilities in the U.S. natural gas pipeline grid that will transport gas destined for the ECA Mid-Scale Project will be expanded in the future, and some of those expanded facilities may be used to transport natural gas

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[171] Pieridae Order at 197.

[172] *Id*. at 191-92 (emphasis added).

[173] Bear Head Order at 4 (emphasis added); *see also* Pieridae Order at 195-96.

[174] Further, as discussed in Part VII.A above, the continued vitality of the reasoning underpinning the DOE's conclusions in the *Bear Head* and *Pieridae* proceedings regarding the scope of the agency's obligations under NEPA with respect to the construction of upstream facilities solely within the jurisdiction of the FERC is doubtful in light of the D.C. Circuit's recent conclusions in *Sierra Club (Freeport)* and *EarthReports*.

that is ultimately destined for export at the ECA Mid-Scale Project. However, for the purposes of review under NEPA, this does not mean that any future pipeline construction is either "essential" or caused "proximately" by a particular export authorization that the DOE/FE may have issued. Neither is the DOE/FE required by NEPA or the NGA to condition its export authorization orders to require submission of a new application to ensure the DOE/FE can participate in the FERC proceeding to consider the environmental impacts of such upstream facilities. NEPA requires a "reasonably close causal relationship between the environmental effect and the alleged cause" "akin to proximate cause in tort law."[175] Given the inherent variability of gas supply arrangements in a well-functioning, liquid, and ever-shifting upstream natural gas market and the DOE/FE's lack of authority to permit or deny any particular pipeline facilities, the export authorization requested in this Application cannot be said to be the proximate cause of potential future expansion of upstream facilities for the purposes of NEPA.

The FERC, not the DOE/FE, is responsible for authorizing the siting and construction of interstate pipeline facilities under Section 7 of the NGA and cross-border facilities under Section 3 of the NGA and through the grant of Presidential Permits. It is the primary responsibility of the FERC to ensure that the impacts of such facilities are considered under NEPA and the NGA, which it will do if and when such facilities are proposed. There is no requirement under either statute for the DOE/FE to continue to be involved in every such future proceeding over which the DOE/FE neither has statutory authority nor control, merely because the construction of such upstream facilities may have some connection to a previously-granted export authorization. The DOE/FE

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[175] *Public Citizen*, 541 U.S. at 754, 767.

cannot be said to be the proximate cause of such alleged effects.[176] Further, even though it is possible or even likely that pipeline facilities in the United States may be expanded in the future and those facilities may be used to transport gas to be exported in connection with the ECA Mid-Scale Project, the DOE/FE would not engage in improper segmentation by approving the export of the requested volumes in this Application.[177]

Imposing a condition limiting the export of natural gas destined for the ECA Mid-Scale Project to the use of existing facilities similar to the condition that the DOE/FE imposed on the exports in the *Bear Head* and *Pieridae* proceedings would be both unnecessary and unworkable. Such a broad condition would require ECA to project and submit a new application for every possible upstream capacity expansion that could conceivably transport gas associated with its proposed project.[178] This interpretation would also be burdensome on the DOE/FE, requiring it to institute a new proceeding associated with exports using each new upstream facility and participate in every FERC proceeding involving those facilities. Where, as here, the physical capacity of existing facilities exceeds the requested volumes for export, that should be the end of the inquiry, and the DOE/FE should issue an order approving the Non-FTA exports associated with the ECA

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[176] *See Sierra Club v. FERC (Freeport)*, 827 F.3d at 47 ("The [FERC's] NEPA analysis did not have to address the indirect effects of the anticipated export of natural gas . . . because [DOE/FE], not the [FERC], has sole authority to license the export of any natural gas going through [the applicant's U.S. LNG terminal] facilities. In the specific circumstances where, as here, any agency 'has no ability to prevent a certain effect due to' that agency's 'limited statutory authority over the relevant action[],' then that action 'cannot be considered the legally relevant "cause" of the effect" for NEPA purposes.) (quoting *Public Citizen*, 541 U.S. at 771).

[177] *See O'Reilly v. U.S. Army Corps of Eng'rs*, 477 F.3d 225, 237-38 (5th Cir. 2007) (rejecting the argument "that the current project is wrongly piecemealed [(*i.e.*, improperly segmented)] because [subsequent phases of construction not presently proposed before the agency] are reasonably foreseeable").

[178] Like all LNG export projects, it is not necessarily foreseeable if, when, and where specific upstream facilities in the robust North American natural gas pipeline grid will be constructed or expanded and whether particular volumes of gas destined for export will be transported on those facilities. This is particularly true given the potential for the sources of supply for a project to shift over the course of the life of the project.

Mid-Scale Project under Categorical Exclusion B5.7 without restricting the use of facilities to export gas under that authorization as it did in *Bear Head* and *Pieridae*.

3. The ECA Mid-Scale Project Should Not Be Treated Differently From Other LNG Export Projects

In other proceedings involving U.S. LNG export terminals, the DOE/FE has not conditioned the export of volumes to the use of capacity on specific upstream or interconnecting pipeline facilities.[179] Instead, authorized volumes have been tied to the liquefaction capacity of the LNG terminal, without regard to the upstream facilities necessary to transport the natural gas from the production area to the terminal.[180] Neither has DOE/FE required authorization holders to obtain additional export authority when new pipeline facilities are constructed that directly interconnect with the LNG export terminal. Several pipeline facilities have been approved and/or constructed to interconnect directly with LNG terminals with existing Non-FTA export authorizations, and the DOE/FE has not required any of the relevant authorization holders to obtain additional authorization from the DOE/FE prior to utilizing such new pipeline capacity as an alternative to existing interconnection pipeline facilities.[181] Applying a different requirement to a

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[179] *See* Bear Head Order at 157.

[180] *See, e.g., Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3792 (approving LNG export volumes incremental to previously-authorized volumes in order to align authorized volumes to the maximum liquefaction production capacity of the liquefaction facilities); *Cameron LNG, LLC*, DOE/FE Order No. 3797, FE Docket No. 15-67-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron Terminal Located in Cameron and Calcasieu Parishes, Louisiana to Non-Free Trade Agreement Nations (Mar. 18, 2016) (authorizing LNG export volumes incremental to previously-authorized volumes to match the peak capacity of the relevant liquefaction trains under optimal conditions); *Lake Charles LNG Export Company, LLC*, DOE/FE Order No. 4010, FE Docket No. 16-109-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Lake Charles Terminal in Lake Charles, Louisiana, to Free Trade Agreement and Non-Free Trade Agreement Nations (June 29, 2017) (authorizing additional export volumes to align volumes authorized for export with the project's liquefaction production capacity).

[181] *See, e.g.*, *Transcontinental Gas Pipe Line Co., LLC*, 153 FERC ¶ 61,077 (2015) (approving Transco's Gulf Trace Expansion Project, which would provide transportation of up to 1,200,000 Dth/d of incremental firm transportation service from Transco's existing facilities at St. Helena Parish, Louisiana, to the Sabine Pass LNG

similarly situated applicant, such as ECA, would be arbitrary and capricious.[182] Further, treating the ECA Mid-Scale Project differently from the way it has treated other U.S. applications would be inconsistent with DOE/FE's stated commitment to Congress to treat Mexican and Canadian projects fairly.[183] Accordingly, ECA respectfully requests that any order issued by the DOE/FE not be conditioned on any restriction upon the points of export and/or facilities that ECA may utilize now or in the future to export gas destined for the ECA Mid-Scale Project from the United States.

C. A Condition Similar to *Bear Head*/*Pieridae* Would be Vague and Unworkable

It would be inconsistent with the public interest for the DOE/FE to impose a condition, similar to the condition it imposed in the *Bear Head* and *Pieridae* Non-FTA authorization orders, that would require ECA to file a new application if facilities that might be used to export natural gas are constructed in the future. The scope of ECA's obligations to comply with such a condition would be unreasonably vague. Specifically, if such an order were to require ECA to submit a new or amended application for Non-FTA export authorization, it would be unclear how ECA must

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terminal in Cameron Parish, as well as Sabine Pass's proposal to construct piping and valves at its Section 3 liquefaction terminal to receive the gas from Transco's project); *Cheniere Creole Trail Pipeline, L.P.*, 142 FERC ¶ 61,137 (2013) (original feed gas pipeline for Sabine Pass); *Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214 (2015) (approving Columbia Gulf Transmission's Cameron Access Project, which would provide transportation of up to 800,000 Dth/d of incremental firm transportation service from new and looped facilities in Jefferson Davis, Cameron, and Calcasieu Parishes, Louisiana); *Tennessee Gas Pipeline Co., L.L.C.*, 161 FERC ¶ 61,265 (2017) (approving Tennessee's Lone Star Project to provide up to 300,000 Dth/d of firm transportation service to a new interconnection with the Corpus Christi LNG terminal on Tennessee's 100 Line in San Patricio County, Texas).

182 *Indep. Petroleum Ass'n of Am. v. Babbitt*, 92 F.3d 1248, 1258 (D.C. Cir. 1996) ("An agency must treat similar cases in a similar manner unless it can provide a legitimate reason for failing to do so."); *Westar Energy, Inc. v. Fed. Energy Regulatory Comm'n*, 473 F.3d 1239, 1241 (D.C. Cir. 2007) ("[A] fundamental norm of administrative procedure requires an agency to treat like cases alike."); *Burlington N. & Santa Fe Ry. Co. v. Surface Transp. Bd.*, 403 F.3d 771, 776 (D.C. Cir. 2005) (noting that an agency "must provide an adequate explanation to justify treating similarly situated parties differently").

183 *See, e.g.*, *Strategic Petroleum Reserve Discussion Draft and Title IV Energy Efficiency: Hearing Before the Subcomm. on Energy and Power of the H. Comm. on Energy & Commerce*, 114 Cong. 36 (Apr. 30, 2015) (statement of Assistant Secretary for Fossil Energy Christopher Smith stating "[T]he commitment that we have made is that we are going to treat applicants in Canada, applicants in Mexico, and applicants in the United States in a way that is open, . . . transparent, . . . fair, [and] . . . consistent.").

determine the type of pipeline construction to which such a condition would apply. In the *Bear Head* and *Pieridae* orders, because the physical capacity of the pipeline was less than the export volume requested, it was a logical certainty that some construction was necessary just to move the full volumes to and across the U.S./Canadian border. It was clear from those orders that the condition requiring the submission of a new application would apply to any new capacity that would make up the difference between the export volumes requested and the physical capacity of the M&N US Pipeline, allowing the full volumes to be exported. The ECA Mid-Scale Project does not involve these "unusual circumstances." Given that today the physical capacity on the existing cross-border facilities exceeds the volume requested, it is unclear the circumstances under which ECA would be obliged to file a new application.

Further, compliance with such a condition would be practically unworkable. If the order granting ECA authorization to export natural gas to Non-FTA countries limits ECA's exports to only those using "existing" facilities, it is unclear how ECA could ensure compliance with this requirement if those facilities are expanded for reasons unrelated to the ECA Mid-Scale Project—*e.g.*, to serve other projects and/or load growth in Mexico. In light of the integrated nature of pipelines and the fungibility of gas streams on an interstate pipeline, compliance with a directive requiring ECA to limit its exports only to those that can be accomplished using facilities and/or capacity that was "existing" at the time of the export authorization would be difficult, if not impossible in most cases. For example, in the case of an expansion to an existing pipeline facility, it would be impossible to determine which molecules of gas were transported on "existing" capacity and which were transported using the expanded facilities.[184] Consequently, because such

[184] This unworkability is yet another reason why a narrow interpretation of the condition placed on the applicants in *Bear Head* and *Pieridae* (*i.e.*, an interpretation requiring a new application only where the requested volume <u>exceeds</u> existing physical capacity) makes more logical sense.

an obligation would be vague and unworkable, ECA submits that it would not be consistent with the public interest for DOE/FE to impose conditions on ECA's requested export authorization similar to those imposed in the *Bear Head* and *Pieridae* proceedings.

VIII. APPENDICES

The following attachments and appendices are included with this Application:

Verification

Appendix A: Opinion of Counsel

Appendix B1: ICF Report for the ECA Mid-Scale Project

Appendix B2: ICF Report for the Combined Effects of the ECA Mid-Scale and Large-Scale Projects

Appendix C: Permitting Overview for Pipeline and Liquefaction Projects in Mexico

Appendix D: ECA Ownership Structure

Appendix E: Summary of Existing Cross-Border Facilities

Appendix F: ASEA Resolution Approving MIA (English Translation)

IX. CONCLUSION

For the reasons set forth above, ECA respectfully requests that the DOE/FE issue an order granting ECA authorization to export, on its own behalf and as agent for others: (1) 182 Bcf/y (approximately 500 MMcf/d) of natural gas by pipeline to Mexico; and (2) the equivalent of 161 Bcf/y (approximately 441 MMcf/d) as LNG from Baja California, Mexico to FTA and Non-FTA countries, as described herein. ECA requests each of these authorizations for a 20-year term commencing on the earlier of the date of first export or seven years from the date the requested authorizations are granted.

Respectfully submitted,

/s/ Jerrod L. Harrison_____

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Counsel for Energía Costa Azul, S. de R.L. de C.V.

Dated September 26, 2018

VERIFICATION

I, Tania Ortiz Mena, declare that I am the Director General for Energía Costa Azul, S. de R.L. de C.V. and am duly authorized to make this Verification; that I have read the foregoing instrument and that the facts therein stated are true and correct to the best of my knowledge, information and belief.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed in Mexico City, Mexico on September 26, 2018.

Tania Ortiz Mena
Director General
Energía Costa Azul, S. de R.L. de C.V.
Paseo de la Reforma # 342, Piso 24
Col. Juarez, Del. Cuauhtémoc
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APPENDIX A

Opinion of Counsel

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OPINION OF COUNSEL

September 13, 2018

Ms. Amy Sweeney
Office of Fossil Energy
U.S. Department of Energy
FE-34
Forrestal Building
1000 Independence Avenue, S.W
Washington, DC 20585

RE: *Energía Costa Azul, S. de R.L. de C.V.*
Application for Long-Term, Multi-Contract Authorizations to Export Natural Gas to Mexico and to Export Liquefied Natural Gas from Mexico to Free Trade Agreement and Non-Free Trade Agreement Nations

Dear Ms. Sweeney:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the United States Department of Energy, 10 C.F.R. $ 590.202(c) (2017). I am in house counsel to Energía Costa Azul, S. de R.L. de C.V. ("**ECA**").

I have reviewed the organizational and internal governance documents of ECA and it is my opinion that the proposed export of natural gas as described in the application filed by ECA, to which this Opinion of Counsel is attached as Appendix A, is within the company powers of ECA.

Respectfully submitted,

Rodrigo Cortina
In house Counsel for Energía Costa Azul, S. de R.L. de C.V.

APPENDIX B1

ICF Report for the ECA Mid-Scale Project

Economic Impacts of the Proposed Energía Costa Azul Mid-Scale Liquefaction Project:

Information for DOE Non-FTA Permit Application

Submitted by:
ICF

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September 11, 2018

Submitted to:
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Table of Contents

List of Exhibits

1. Executive Summary

1.1. Introduction

ICF conducted an analysis on behalf of Energía Costa Azul, S. de R.L. de C.V. (Costa Azul), a company owned, in part, by Sempra Energy, to assess the market and economic impacts of the proposed Costa Azul LNG export facility located in Ensenada, Baja California, Mexico, to the U.S. economy. The Costa Azul export facility is proposed to be developed with a Mid-Scale facility to come on-line approximately in 2025 and ramp up to 161[1] Bcf per year, or 0.44 Bcfd (0.50 Bcfd[2] exported volumes to Mexico).

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Costa Azul Mid-Scale export facility. To assess the impacts on the energy market, ICF conducted two alternative scenario runs using its proprietary Gas Market Model (GMM):

1) **Base Case** - No Costa Azul export facility;
2) **Costa Azul Mid-Scale LNG Case** - Base Case with 0.44 Bcfd of additional export volumes from Costa Azul.

The natural gas supplied to the plant is assumed for this analysis to come from the U.S. The changes of natural gas and liquids production value, investment, capital and operating expenditure between these two cases are inputs into IMPLAN, an input-output economic model for assessing the economic and employment impacts. Specifically, the analysis methodology consisted of the following steps:

- **Assess natural gas and liquids production changes:** From the GMM run results, we first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for Costa Azul Mid-Scale exports. GMM also solved for changes in natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins as a whole and from the Southwest[3] United States (U.S.) were both estimated.

- **Quantify upstream and the plant capital and operating expenditures:** ICF translated the natural gas and liquids production changes from GMM into annual capital and operating expenditures that will be required for the additional production. In addition, based on Costa Azul Mid-Scale LNG export facility's cost estimates, ICF assessed the annual capital and operating expenditures in the U.S. to support the LNG exports at the facility.

- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant and upstream expenditures as inputs to the IMPLAN input-output model to assess their economic impacts for the U.S. and the Southwest. The model quantifies the economic stimulus

[1] This volume does not include liquefaction fuel use or lease and plant and pipeline fuel use.

[2] This volume includes liquefaction fuel use and pipeline fuel use.

[3] The Southwest region includes California, Nevada, Arizona, New Mexico, and Texas.

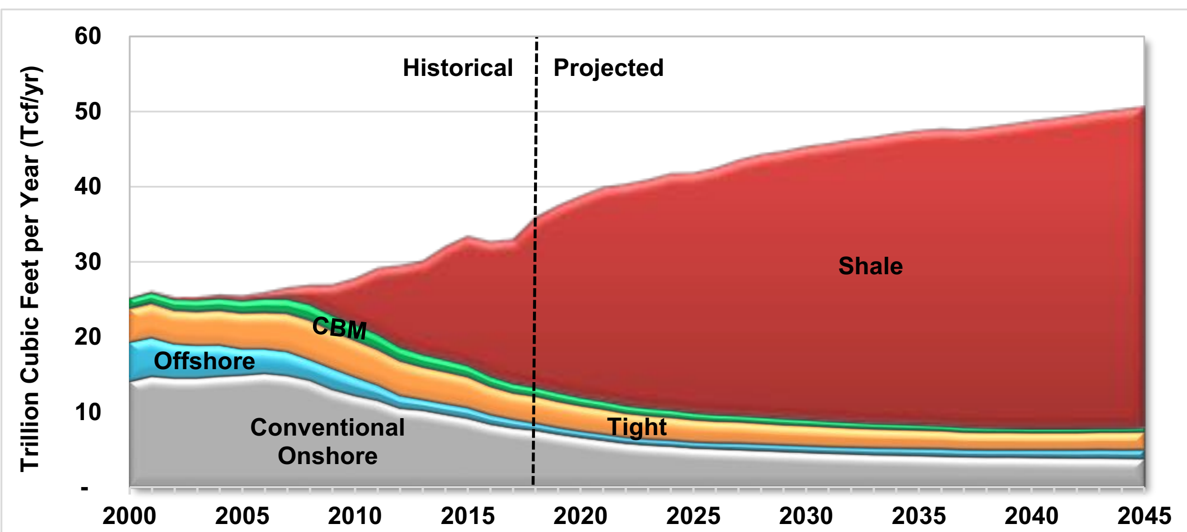
impacts from capital and operational investments. For example, any amount of annual expenditures on drilling and completing new gas wells would support a certain number of direct employees (e.g., natural gas production employees), indirect employees (e.g., drilling equipment manufacturers), and induced employees (e.g., consumer industry employees).

- **Quantify the economic and employment impacts:** Results of IMPLAN allows ICF to estimate the impacts of the projected incremental expenditures from supporting Costa Azul Mid-Scale exports on the national and the Southwest economies. The impacts include direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and international 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, especially from shale resources. The growth trend is expected to continue over the next 30 years (see Exhibit 1-1: U.S. and Canadian Gas Supplies). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, specifically gas-directed horizontal drilling in the Marcellus and Utica shales, which will account for over half of the incremental production and from tight oil production in the Permian Basin and other areas. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

Exhibit 1-1: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q1 2018

In the long-term, the power sector presents 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). Power sector gas demand grew significantly in 2017, as natural gas capacity replaced retired coal capacity. This trend will continue and is expected to accelerate after 2026 when federal carbon regulation is assumed 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 $3.50 per MMBtu[4] after 2025, with long-term prices expected to range between $3.50 and $4.50 per MMBtu. Prices are high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand growth. Long-term demand growth will be shaped by future environmental policies and their impact on power sector gas demand.

U.S. LNG exports are projected to reach 12.1 Bcfd by 2032, with volumes from the Gulf Coast expected to reach 10.9 Bcfd, based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy. These volumes do not include the additional Costa Azul Mid-Scale export volumes associated with this economic impact analysis.

1.3. Key Study Results

ICF's analysis shows that the volume exported via the Costa Azul Mid-Scale LNG export facility has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.02/MMBtu (in real 2016 dollars) on average for the forecast period of 2021 to 2045, averaging $3.64/MMBtu, with the Costa Azul Mid-Scale export facility included in the scenario, compared with $3.62/MMBtu without the export facility in the scenario. The natural gas prices at Henry Hub are expected to reach $4.41/MMBtu in the Base Case and $4.43/MMBtu in the Costa Azul Mid-Scale LNG Case by 2045, indicating a price increase of $0.02/MMBtu attributable to the Costa Azul Mid-Scale LNG export volumes of 0.44 Bcfd.

The Costa Azul Mid-Scale LNG export facility is expected to have minimal impact on the U.S. supply availability and market price because the volume represents a small amount of the North American natural gas resources and total market demand. Total export volumes from the facility over the 20-year period from 2025 to 2045 is approximately 3.3 Tcf. This represents (a) roughly 0.2% to 0.3% of Lower 48 natural gas resources that can be produced with current technology at an 8% rate of return, Henry Hub price at less than $3.50 to 4.00/MMBtu, and crude at $75/Bbl; and (b) about 0.5% of the total U.S. domestic natural gas consumption during the same period.

[4] All dollar figure results in this report are in 2016 real dollars, unless otherwise specified.

Exhibit 1-2: Natural Gas Price Impact of the Costa Azul Mid-Scale LNG Export Facility

Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Costa Azul LNG Case	Costa Azul LNG Case Change
2021	$ 2.90	$ 2.90	$ -
2023	$ 3.19	$ 3.19	$ -
2025	$ 3.41	$ 3.44	$ 0.030
2030	$ 3.54	$ 3.56	$ 0.026
2035	$ 3.48	$ 3.51	$ 0.024
2040	$ 3.83	$ 3.85	$ 0.021
2045	$ 4.41	$ 4.43	$ 0.018
2021-2045 Avg	**$ 3.62**	**$ 3.64**	**$ 0.024**

Source: ICF

ICF's analysis concluded that activity in the U.S. to support Costa Azul Mid-Scale LNG exports could lead to significant economic impacts, on average, creating over 6,600 jobs annually for the U.S. economy, and over 1,500 in the Southwest between 2021 and 2045. This means a cumulative impact through 2045 of roughly 166,000 job-years for the U.S. and 38,000 job-years for the Southwest. In addition, the project could add $1.49 billion to the U.S. economy annually ($37 billion over the forecast period), including $0.29 billion annually in the Southwest ($7.2 billion over the forecast period). The additional Costa Azul Mid-Scale LNG exports would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $535 million annually; and the Southwest state and local tax revenues are expected to increase by $39 million annually. Throughout the 25-year forecast period, the U.S. will receive $13.4 billion additional revenue from taxes and the Southwest states will receive $0.98 billion.

Exhibit 1-3: Economic and Employment Impacts of the Costa Azul Mid-Scale LNG Export Facility

Region	2021-2045 Average Annual Impact			2021-2045 Cumulative Impact		
	Jobs (Jobs)	Value Added (2016$ Million)	Government Revenues (2016$ Million)	Jobs (Job-years)	Value Added (2016$ Million)	Government Revenues (2016$ Million)
U.S.	6,625	$ 1,486.6	$ 534.6	165,613	$ 37,164.9	$ 13,366.2
Southwest States	1,529	$ 286.4	$ 39.3	38,231	$ 7,160.1	$ 982.2

Source: ICF. The Southwest States include California, Nevada, Arizona, New Mexico, and Texas.

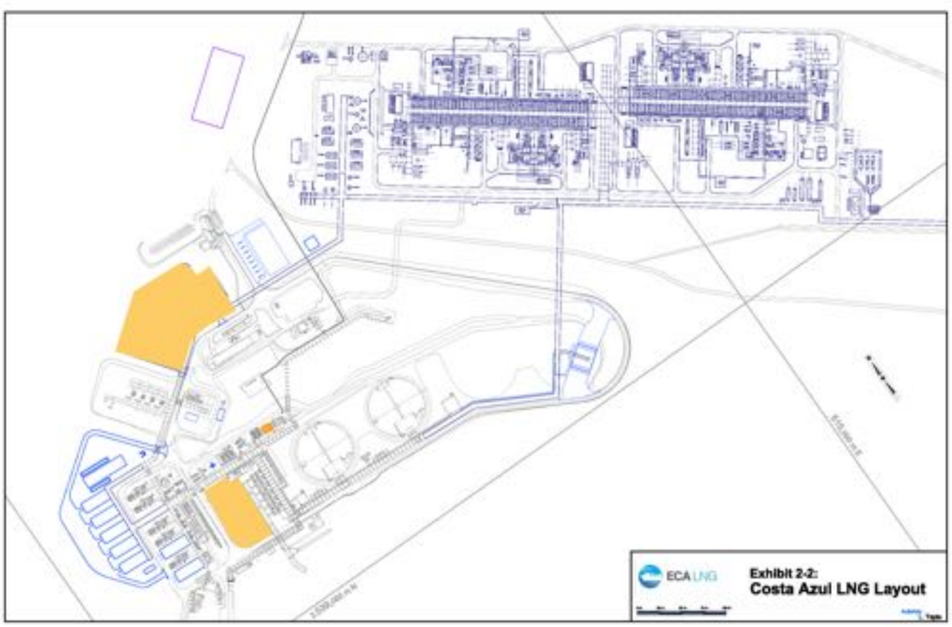
2. Introduction

Costa Azul tasked ICF with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Costa Azul Mid-Scale LNG export facility. Exhibit 2-1 and Exhibit 2-2 show Costa Azul's location and layout, respectively.

Exhibit 2-1: Costa Azul LNG Location Map

Source: Costa Azul

Exhibit 2-2: Costa Azul LNG Layout



Source: Costa Azul

For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the 0.44 Bcfd export facility and estimated the changes between the two scenarios for the total U.S. and the Southwest:

- 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.

The changes in LNG plant capital and operating expenditure and upstream capital and operating expenditures were inputted into the IMPLAN model to estimate the export facility's impacts on the U.S. and the Southwest's economy. The economic metrics include:

- Employment
- Federal, state, and local government revenues
- Value added
- U.S. Balance of Trade

This report is organized as follows.

1) Executive Summary
2) Introduction
3) Base Case U.S. and Canadian Natural Gas Market Overview
4) Study Methodology
5) Costa Azul Mid-Scale LNG Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

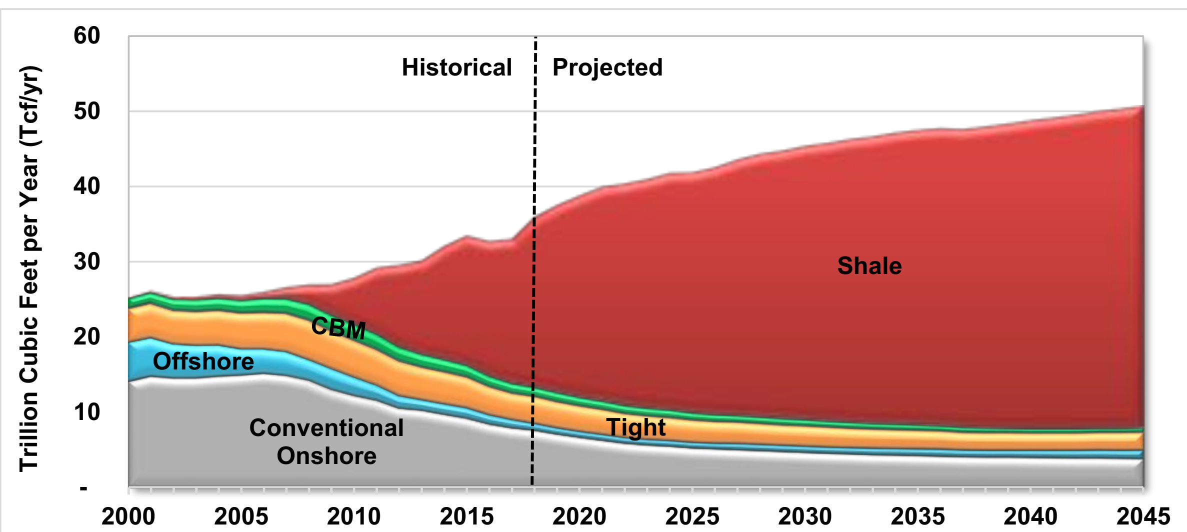
3. Base Case U.S. and Canadian Natural Gas Market Overview

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 2045, including pipeline construction 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 several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2045 and beyond (see Exhibit 3-1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil 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

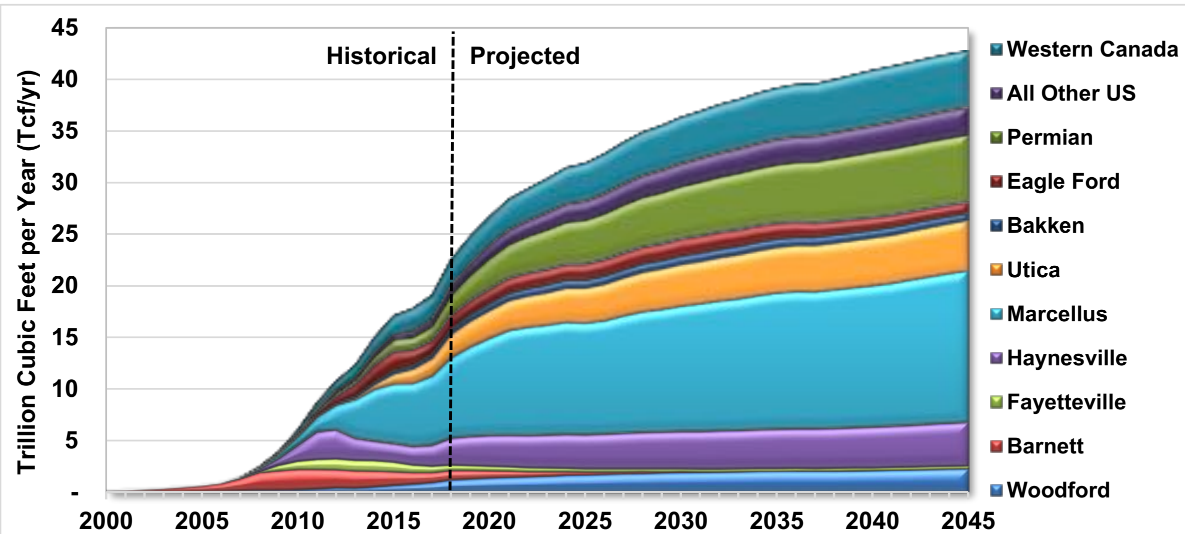


Source: ICF GMM® Q1 2018

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (16 Bcfd) in 2010 to nearly 41.5 Tcf (114 Bcfd) by 2045 (see exhibit above), assuming a crude price of $75/Bbl ($2016). The major shale formations in the U.S. and Canada are located in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, 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, the Permian, and Niobrara are primarily producing oil with associated natural gas volumes. Associated gas production from the Permian, Niobrara, and Bakken is expected to grow significantly in the next 10 years. Production from the lower cost Permian basin will reach 4.5 Tcf (over 12 Bcfd) by 2025, from about 1.8 Tcf (5 Bcfd) in 2017.

ICF did not include in our forecast potential shale and tight oil formations in the U.S. and Canada that have not yet been evaluated or developed for gas and oil 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 GMM® Q1 2018

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 have 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 resource 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 cost curves are all of the resources discussed above – proven reserves, growth, new fields,

[5] Unconventional refers to production that requires some form of stimulation within the well to produce gas economically. Conventional wells do not require stimulation.

and unconventional gas. The detailed unconventional geographic information system (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 and tight oil are almost all development drilling. Offshore undiscovered 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 estimate costs at points farther downstream of the wellhead. Costs can be further adjusted to a “Henry Hub” basis by adding regional basis differentials for certain type of analysis that considers the locations of resources relative to markets.

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 option. 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

U.S. and Canadian 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, 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.

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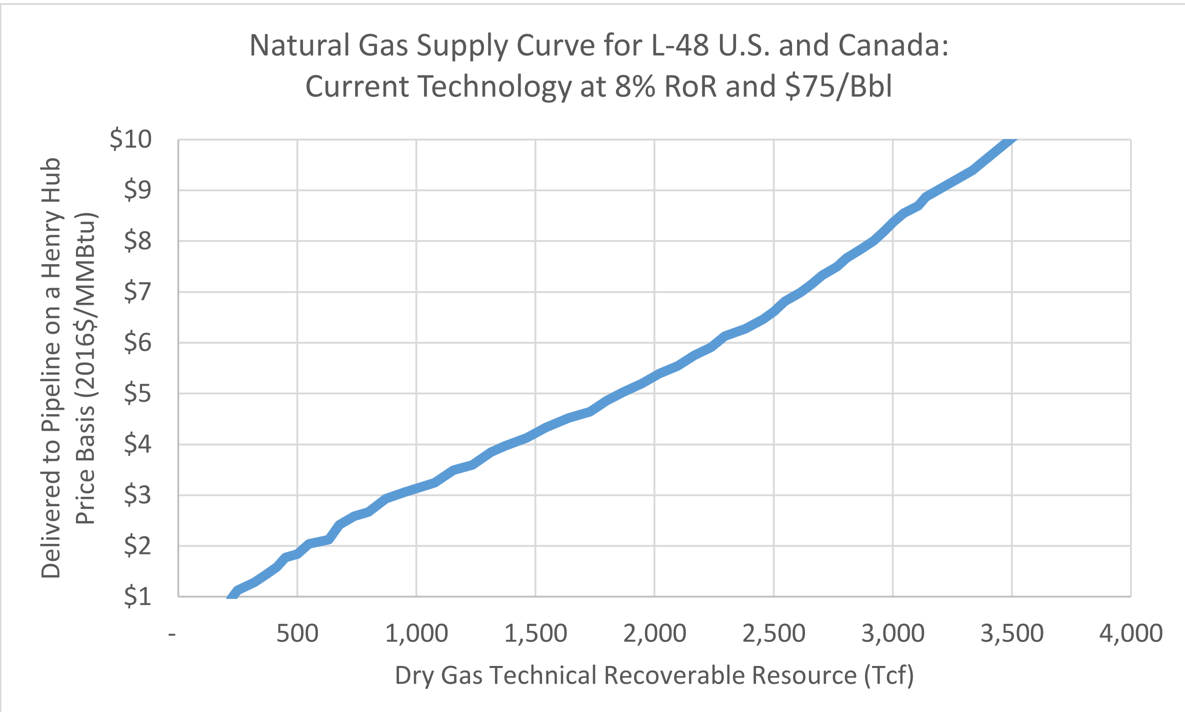
[6] American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.
[7] Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/
[8] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011 and various other years: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

A total of about 1,200 to 1,400 Tcf of gas resource in the U.S. and Canada is available at gas prices between $3.50 and $4.00 per MMBtu.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve 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. (See section 3.1.2 for discussion of technology trends assumed in this study.)

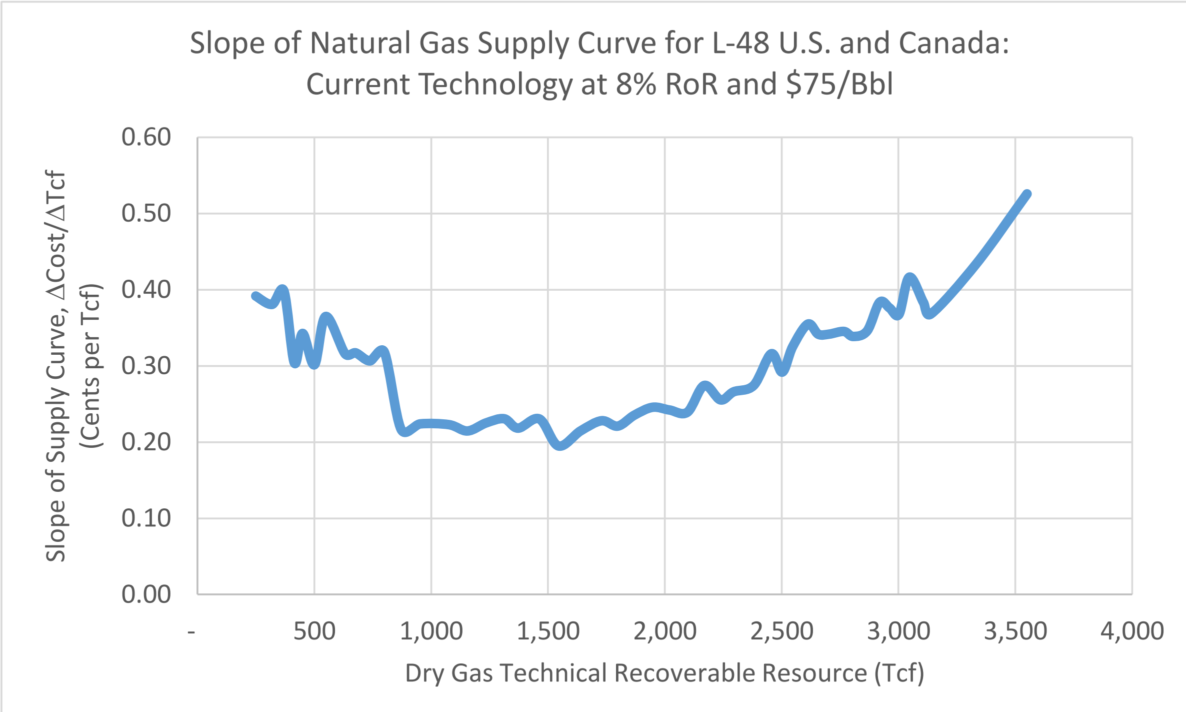
Exhibit 3-3: U.S. and Canada Natural Gas Supply Curves



Source: ICF

A natural gas supply curve can also be described in terms of its slope. Exhibit 3-4 shows the slope of the Lower 48 plus Canada curve in cents per Tcf. In the forecast cases to be shown later in this report, the U.S. is projected to develop approximately 847 to 945 Tcf of natural gas resources through 2040 and Canada to develop another 166 to 176 Tcf. Combining the two countries, depletion for the U.S. and Canada will be in the range of 1,013 to 1,121 Tcf. This means that incremental development of one Tcf of natural through 2040 would have a “depletion effect on price” of natural gas of 0.2 to 0.4 cents (assuming no upstream technological advances to increase available volumes and to decrease costs) during the forecast period. As is explained below, the depletion effect on price is only one of several factors that need to be considered when estimating the price impacts of LNG exports or any other change to demand.

Exhibit 3-4: Slope of U.S. and Canada Natural Gas Supply Curve



Source: ICF

3.1.2. Representation of Future Upstream Technology Improvements

Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the "current technology" gas supply curves.[9]

Technology advances in natural gas development in recent years have been related to the drilling of longer 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 and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. The percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, however, resulting in lower costs per unit of reserve additions.

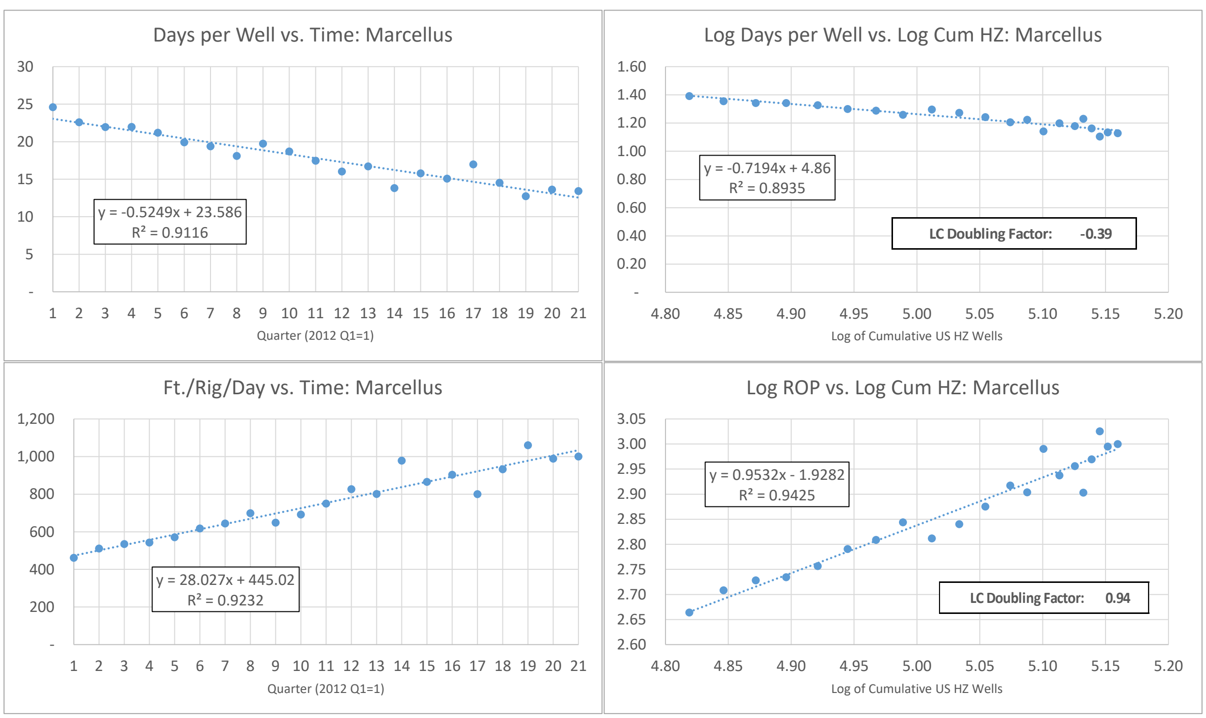
[9] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

<u>Technology Advances in Rig Efficiency</u>

ICF expects that drilling costs (as measured in real dollars per foot of measured well depth) will continue to be reduced largely due to increased efficiency and the higher rate of penetration (feet drilled per rig per day). ICF's modeling of drilling activity and costs takes into account how changes in oil and gas prices and activity levels can influence the unit cost of drilling, stimulation (hydraulic fracturing) services and other equipment and oil field services used to develop oil and gas. Thus, higher oil and gas prices translate into higher factor costs, which partially dampens the ability of higher commodity prices to lead to increase drilling activity and more production.

As illustrated in the upper-left-hand chart in Exhibit 3-5, the number of rig days required to drill a well has fallen steadily in many plays. This chart shows that Marcellus gas shale wells drilled in early 2012 required 24.6 rig days but that by early 2017 that had fallen to 13.4 days. Because lateral lengths increased over this time, total footage per well was going up (from 11,300 to 13,400 feet for Marcellus wells) over this period. As shown in the lower-left-hand chart in Exhibit 3-5 this meant that footage drilled per rig per day (RoP) was going up quickly. For the Marcellus play RoP went from 461 feet in per day early 2012 to 1,000 feet per day in early 2017. Rig day rates and other service industry costs have declined since 2013 due to reduced drilling activity brought on by lower oil and gas prices and lack of demand for rigs. Improved technology and efficiency in combination with lower rig rates and other service costs have allowed industry to develop economic resources despite low oil and gas prices.

Exhibit 3-5: Recent Trends in Rig-Days Required to Drill a Well: Marcellus Shale (first quarter 2012 to first quarter 2017)



To estimate the contributions of changing technologies ICF employs the “learning curve” concept used in several industries. The “learning curve” describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

The two right-hand charts in Exhibit 3-5 show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[10] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What these mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

The rig efficiency learning curve factors shown for the Marcellus are some of the largest among North American gas shale and tight oil plays. The average learning curve doubling factor for rig efficiency among all horizontal multi-stage hydraulically fractured plays is -0.13 when measured as rig days per well and 0.44 when measured as RoP.

<u>Technology Advances in EUR per Well or EUR per 1,000 feet of Lateral</u>

ICF also used the learning curve concept to analyze trends in estimated ultimate recovery (EUR) per well over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. The most technologically immature resources, wherein technological advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells. As with the rig efficiency calculations shown above, when looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of increasing lateral length. This statistical analysis is done using a “stacked regression” wherein each geographic part of the play is treated separately to determine the regression intercepts but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

Generally speaking, we find that the total technology learning curve shows roughly 30 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well

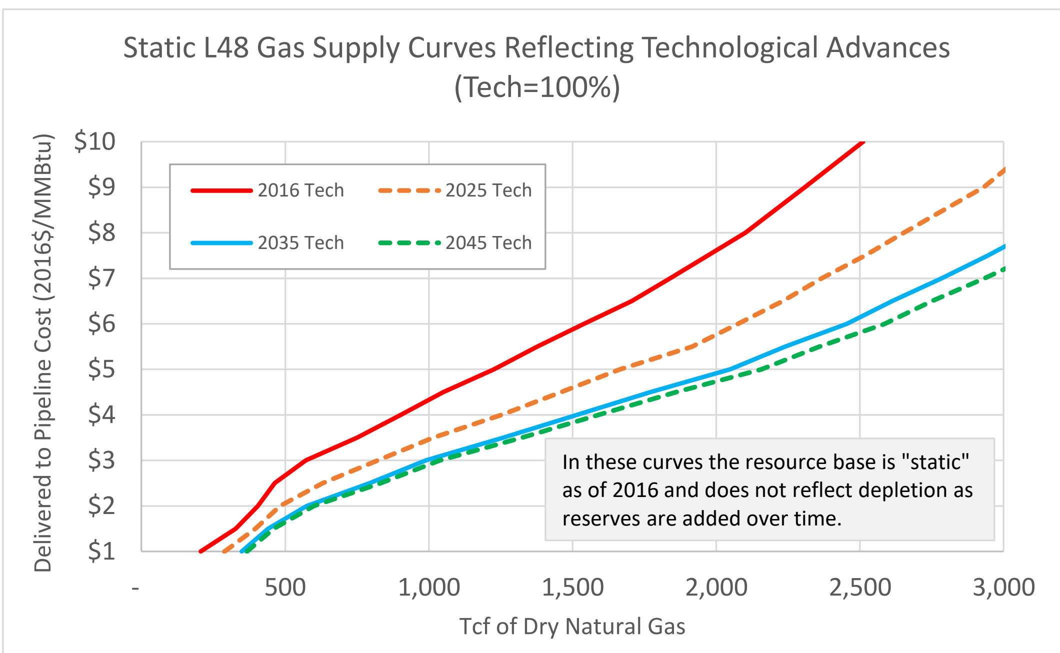
[10] Doubling factor = 2^{C}-1 where C is the regression slope coefficient.

doubling factor is due to increase lateral lengths and about two-thirds is due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs, and so on.

The Effect of Technology Advances on the Gas Supply Curves

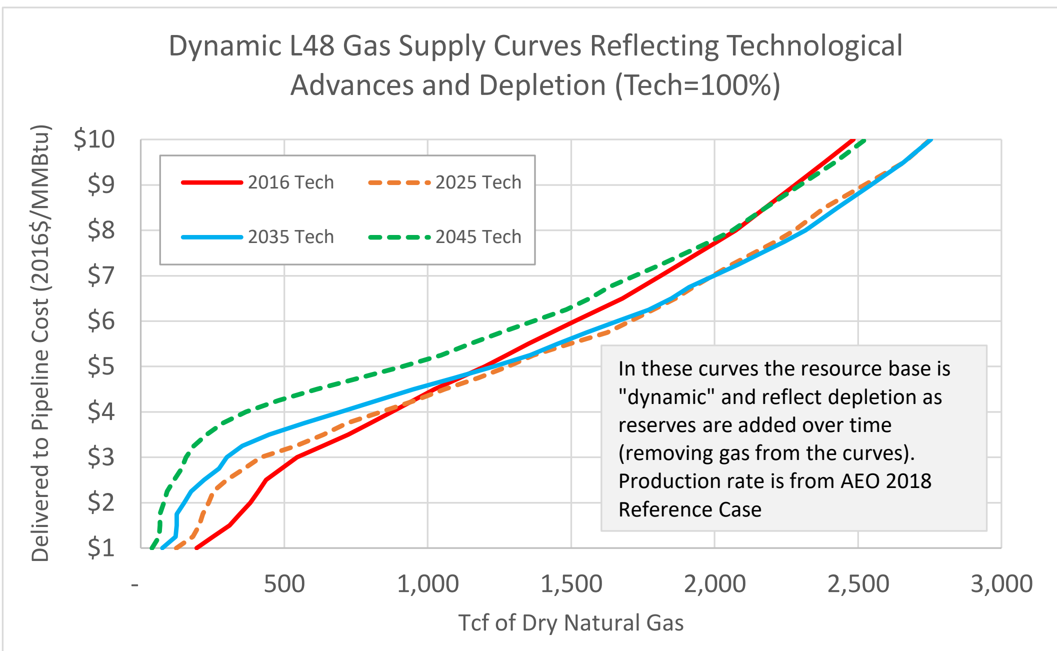
The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve “shifts down and to the right.” This effect is illustrated in Exhibit 3-6 which shows the Lower 48 natural gas supply curve for 2016 technology as a red line (a subset of the Lower 48 plus Canada curve shown in Exhibit 3-3). The other lines in the chart represent the same (undepleted) resource that existed as of the beginning of 2016 but as it could be developed under the improved technologies assumed to exist in 2025 (dashed orange line), 2035 (blue line) and 2045 (dashed green line). ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that are economic at $5/MMBtu would increase from 1,225 Tcf to 2,160 Tcf, a 76% increase. The improved technologies include for gas shales and tight oil the EUR and rig efficiency improvements discussed above. Conventional resources and coalbed methane are assumed to be much more mature technologies with little future improvement (on average one-half of percent per year net reduction in cost per unit of production).

Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



The effect of technology advances on gas supply curves are shown in another way in Exhibit 3-7. Here the Lower 48 curves are adjusted over time to show the effects of depletion based on reserve additions that would be expected to occur under the 2018 AEO Reference Case (that is for instance, cumulative reserve additions of 974 Tcf by 2040). In Exhibit 3-7 the dashed orange line, for example, is the supply curve that would exist in the year 2025 assuming that reserve additions consistent with the 2018 AEO Reference Case production forecast were to occur between now and then and that the technology advances assumed by ICF were to take place through 2025. Since technology adds resources faster than production takes place (consistent with the recent assessments made by ICF, Potential Gas Committee (PGC) and EIA), the upper part of the curve moves to the right from 2016 to 2025 and again from 2025 to 2035. However, because the technology advances for unconventional gas resource are represented by learning curves that flatten out over time, the upper part of the curve for 2045 moves to the left relative to the 2035 curve. Another important observation from these curves is that the lower-cost parts of the supply curve deplete more quickly than the high-cost portions as producers concentrate on low-cost (high profit) segments and will not exploit resources that have costs higher than prevailing market prices. Even so, the amount of natural gas available in these curves at $5.00 per MMBtu increases through 2035 and even by 2045 the curve still has approximately 1,000 Tcf at that price.

Exhibit 3-7: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (dynamic curves showing effects of depletion through time)



The development of supply curves and the projection of how those curves will change through time is inherently uncertain given that:

- Our understanding of the geology of the natural gas and tight oil resource base changes as known plays are developed, their geographic boundaries are expanded, and new plays are discovered and enter development,
- The technologies used to develop those resources evolve, thus, improving their performance and changing the unit cost of equipment and services employed in oil and gas development,
- The market for energy evolves, thus, changing the volumes produced and prices of natural gas and competing fossil and renewable resources.

This means that the estimates provided here for the market impacts of any given amount of LNG exports could be proven in time to be overstated or understated. In reviewing the trends of economic impact studies performed over the last serval years with regard to U.S. LNG exports, we see that the more recent studies show lower impacts in terms of cents per MMBtu of natural gas price increases per 1 Bcfd of exports compared to the older studies. (See Appendix B for discussion of LNG economic impact study comparisons and ICF update report to API on the impact of LNG exports on the U.S. economy[11].) This indicates that the forecasts have tended to:

- Understate natural gas supply robustness (that is, upstream technologies have evolved faster than expected and reduced the cost of developing natural gas more than expected) and also
- Understate energy market forces that have reduced the domestic needs for natural gas (e.g., slower overall growth in demand for all energy and higher market penetration of renewables).

If these apparent forecasting biases still exists, then the price impacts for a given volume of LNG exports shown in this and similar economic impact reports will turn out lower.

3.1.3. 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.

[11] American Petroleum Institute. "Impact of LNG Exports on the U.S. Economy: A Brief Update". API, September 2017, Washington, DC. Available at http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Update-Report-20171003.pdf

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.[12]
>
> ***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. Exhibit 3-8 summarizes 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 current assessment temporal basis is the start of 2016. The current assessment is 3,693 Tcf. Almost 65 percent of the gas resources is from shale gas and tight oil plays. Large portion of the resources is in the Marcellus, Utica, and Haynesville shale gas plays. The largest tight oil gas resource is in the Permian basin. It accounts for almost 30% of the gas resource from tight oil plays.

The latest resource estimate from the Potential Gas Agency at the Colorado School of Mines shows a similar assessment of the U.S. natural gas resource. The most recent estimate published in July 2017 is 3,141 Tcf (including proven reserves) which is 10% greater than its estimate published two years earlier.[13]

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[12] This methodology for estimating growth in old fields was first performed as part of the 2003 NPC study of natural gas and has been updated several times since then. For details of methodology see U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

[13] http://potentialgas.org/press-release

Exhibit 3-8: 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 2016; Excludes Canadian and U.S. Oil Sands)

Lower 48	Total Gas Tcf	Crude and Cond. Bn. Bbls
Proved reserves	320	33
Reserve appreciation and low Btu	161	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	361	71
Shale gas and condensate	2,133	86
Tight oil	252	78
Tight gas	401	7
Coalbed methane	65	0
Lower 48 Total	**3,693**	**334**
Canada		
Proved reserves	71	5
Reserve appreciation and low Btu	23	3
Stranded frontier	40	0
Enhanced oil recovery	0	3
New fields	205	12
Shale gas and condensate	618	14
Tight oil	26	10
Tight gas (with conventional)	0	0
Coalbed methane	75	0
Canada Total	**1,058**	**46**
Lower-48 and Canada Total	**5,751**	**380**

Sources: ICF, EIA (proved reserves)

The U.S. natural gas resource base used in EIA 2018 AEO Reference Case was 2,462 Tcf (including proven reserves) defined as of early 2016.[14] Accounting for production in the intermediate years, this is a 250 Tcf increase from the early-2011 resource base used in the 2013 AEO. On an annual basis, this means the resource assessments used in the AEOs have grown by about 50 Tcf per year. This is slower than the 62 Tcf and 174 Tcf per year growths in the ICF and PGC assessments, but still greater than the rate of natural gas production meaning that even under the more conservative EIA assessments the remaining resources (net of depletion) are growing – not declining.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

3.1.4. Resource Base Estimate Comparisons

The ICF gas resource base is significantly higher than most published assessments. As noted above, the ICF Lower-48 gas assessment of 3,693 Tcf is greater than the EIA's 2,462 Tcf or the PGC's 3,141 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 are 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 are added to the upper end of the natural gas supply curves. Such resources may eventually be 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 2045.

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.

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 gas reservoirs with a net thickness of less than 50 feet.

ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas 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. EIA is using a modified version of the USGS Marcellus that is still low compared to ICF evaluation. The relatively high ICF Barnett Shale assessment is the result of our including a 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.

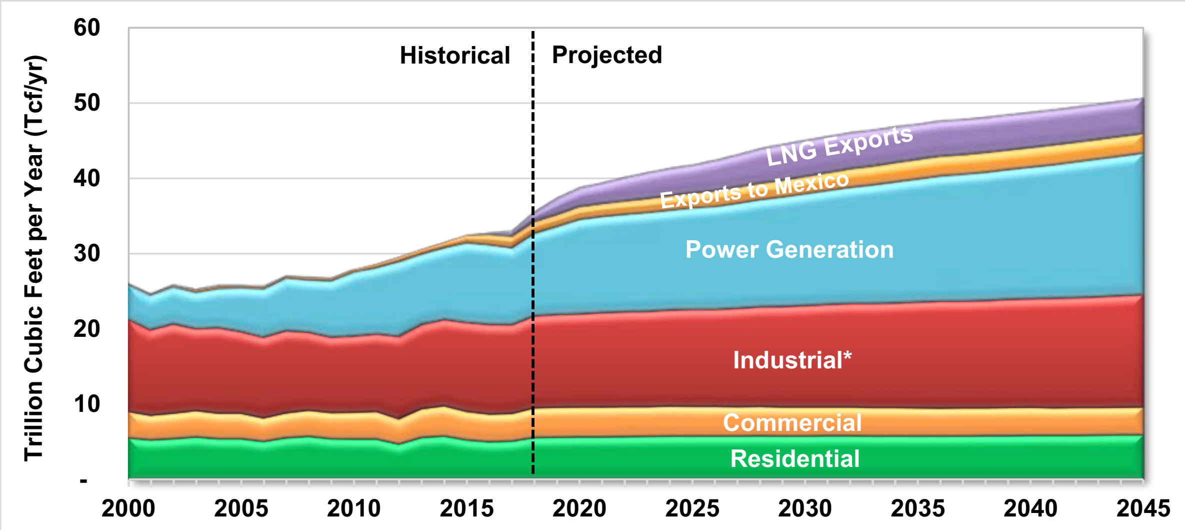
The ICF assessment of tight oil associated gas is much higher than that of other assessments. The difference reflects our inclusion of more plays and entire play areas. It also reflects our methodology, which generally assesses recoverable resources through determination of resource in-place, with an assumed recovery factor that is calibrated to existing well recoveries. Our assessment of several plays in Oklahoma is also based upon a new data-intensive method using GIS and well level recovery estimates, and that method typically results in higher assessments.

3.2. U.S. and Canadian Natural Gas Demand Trends

While new LNG export facilities in the U.S. started production in 2017, power generation will see the bulk of incremental natural gas consumption growth over the near future, along with some growth in the industrial sector, led by gas-intensive end uses such as petrochemicals, fertilizers, and transportation (compressed natural gas and LNG used in vehicles and off-road equipment). Exhibit 3-9 shows ICF's U.S. and Canadian consumption forecast by sector. Under the ICF Base Case, which assumes no exports from the ECA Project, U.S. and Canadian natural gas consumption in 2045 is expected to be over 50 Tcf (LNG and pipeline exports included). This Base Case projection assumes U.S. LNG exports in a total amount of 12.7 Bcf/d by 2045.

Incremental power sector gas use between 2017 and 2045 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. A number of factors drives growth in gas demand for power generation. Currently, about 600 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada. 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 2.1 percent annually from 2019 onward. Electricity load growth is expected to average only about 0.75 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 4,600 Terawatt-hours (TWh) per year by 2045, or growth nearing 23 percent over 2017 levels.

Exhibit 3-9: U.S. and Canadian Gas Consumption by Sector and Exports



Source: ICF GMM® Q1 2018

* 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 EPA's current rules for 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 Cross-State Air Pollution Rule (CSAPR), which was reinstated in January 2015. CSAPR has replaced the CAIR program, imposing regional and state caps on emissions of NO_X and SO_2. 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 over 27 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 demand in 2017 to 37 percent by 2045. 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 18 percent of total gas use growth in U.S. and Canada during the 2017-2045 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.

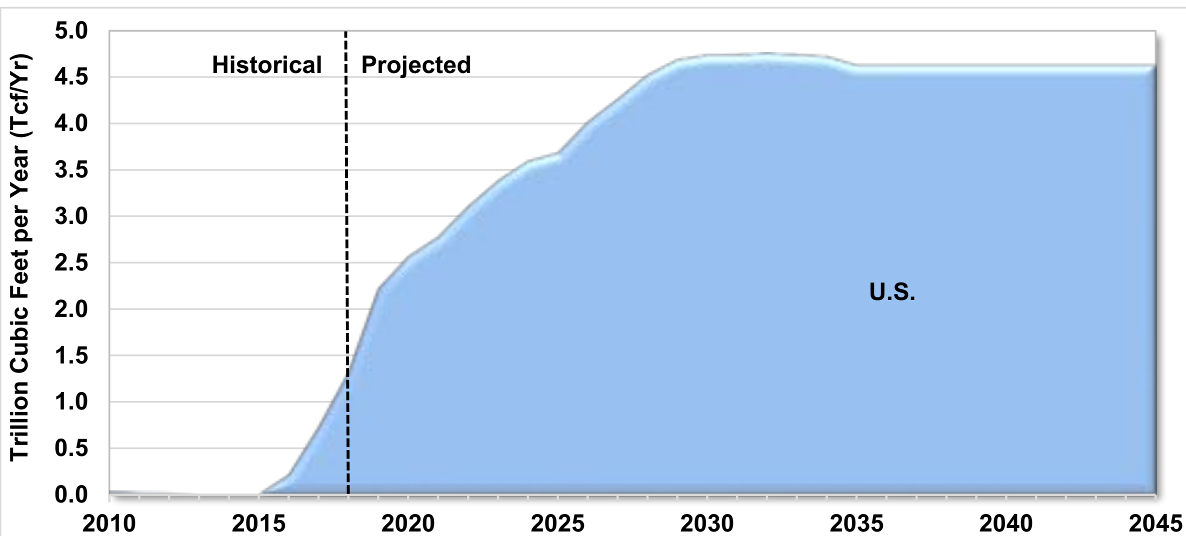
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the 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 2.6 Tcf (7.2 Bcfd) by 2045, up from 1.5 Tcf (4.3 Bcfd) in 2017.

3.2.1. LNG Export Trends

The U.S. Department of Energy (DOE) has received 58 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, 29 applications at 21 sites have received final 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, the Base Case of this study assumes that the U.S. LNG exports reach over 4,500 Bcf per year (over 12 Bcfd) by 2030. Global LNG prices are heavily influenced by oil prices. Given the expectation of low oil price environment in the near-term, U.S. export volumes are projected to be about 7 Bcfd by 2020 and as oil prices increase, the export volume is projected to be over 9 Bcfd by 2025 and over 12 Bcfd by 2030 (see exhibit below).

Exhibit 3-10: U.S. Base Case LNG Export Assumptions



Source: ICF GMM® Q1 2018

3.2.2. Pipeline Exports to Mexico

There is 10.6 Bcf/d of U.S.-Mexico cross-border pipeline capacity currently online. Some of this capacity is designed to serve local markets that lie directly across the border. For example, of the 512 MMcf/d of capacity that El Paso Natural Gas has at the Arizona-Sonora border, only about 200 MMcf/d of that capacity is connected to the PEMEX Sistema Naco Hermosillo, which goes south. The vast majority of the cross-border capacity, though, supplies major interstate pipelines in Mexico. There are also some minor discrepancies between the reported capacity by EIA and other public sources. In the case of the border crossing between San Diego Gas & Electric (SDG&E) and the TGN de Baja California system, the available capacity reported by SDG&E was 115 MMcf/d higher than the EIA.

In 2017, the utilization at the cross-border pipelines was 41%. It appears that the low utilization rates may continue through 2020, as an import pipeline capacity auction held by CFE for the existing pipelines received no bids in August 2017. In November, however, a survey of Mexican natural gas shippers found that there could be as much as 4.62 Bcf/d of mostly new demand for firm transport capacity on the country's main domestic pipeline system, Sistrangas[15]. Based on planned expansions and Presidential Permit applications authorized or pending before the Federal Energy Regulatory Commission, ICF expects there will be 14.9 Bcf/d of cross-border capacity by 2020. ICF's projected pipeline exports to Mexico in that year will be 5.15 Bcf/d. Appendix A of this report provides detailed data and discussion on current U.S.-Mexico cross-border pipeline capacity and flows and expected 2020 capacity.

The same sorts of uncertainties that exist in forecasting the U.S. natural gas market apply for the analysis of Mexican natural gas supply and demand and the utilization of Mexico's cross-border and internal natural gas pipeline capacity. Mexican demand for natural gas will be influenced by many factors including the growth of the overall economy and its energy-intensive sectors, relative energy prices, and government policies encouraging the substitution of natural gas for coal in the power sector. Mexican natural gas supply will be affected by the success of ongoing energy reforms designed to increase private sector upstream investment and by the technical success of applying unconventional oil and gas technologies to Mexico's unconventional resources. Lower future natural gas consumption levels and/or greater production of conventional and unconventional natural gas would reduce the need for natural gas imports into Mexico and would increase the amount of unused cross-border pipeline capacity compared to what is shown here.

3.3. U.S. and Canadian Natural Gas Midstream Infrastructure Trends

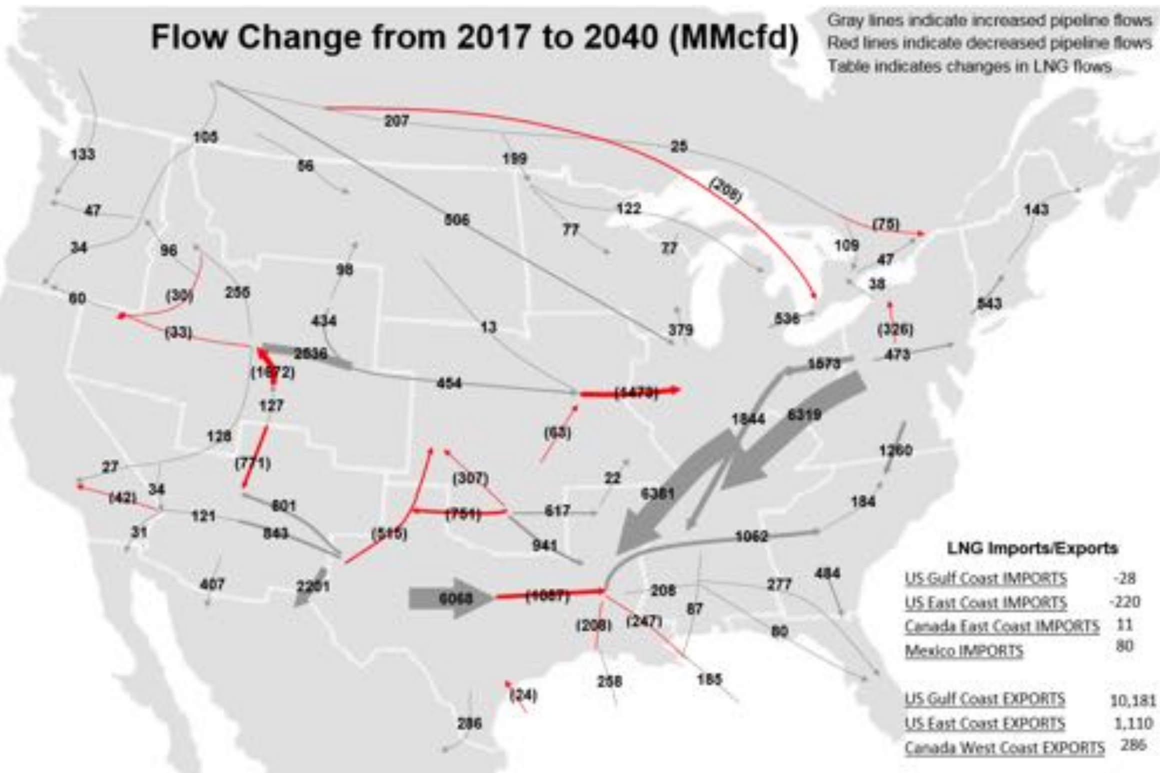
As regional gas supply and demand continue to shift over time, there will likely be significant changes in interregional pipeline flows. Exhibit 3-11 shows the projected changes in interregional pipeline flows from 2017 to 2040 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2017 and 2040, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit 3-11 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

[15] https://www.gob.mx/cms/uploads/attachment/file/268281/Consulta_P_blica_Resultados_v6.pdf

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. The red arrows from the Gulf Coast to the U.S. Northeast point towards a continuing trend of the economic Marcellus and Utica gas supplies displacing the traditional flows from the Gulf Coast towards Northeast.

Exhibit 3-11: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q1 2018

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 South Atlantic Region (Florida to North Carolina) where demand is growing. In addition, natural gas will be exported from the West South Central region via pipeline to Mexico and in the form of LNG exports that started from the Sabine Pass export facility 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.

Eastward flows from western Canada will slightly increase. 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 facilities in British Columbia will also draw off gas supply once exports of LNG begin in 2030. Pipeline flows west out of the Rocky Mountains will increase to California. The completion of the Ruby Pipeline in

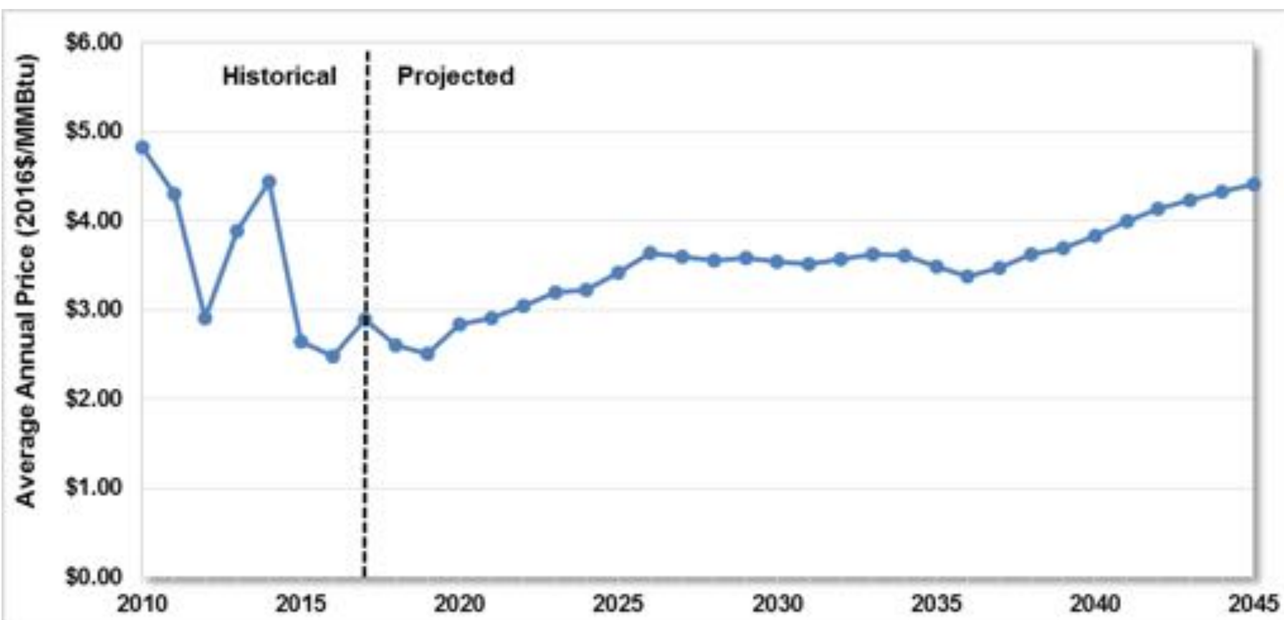
2011 allowed Rocky Mountain gas to displace gas coming from Alberta on Gas Transmission Northwest.

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 than 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 $2.90 per MMBtu in 2017 to $4.41 per MMBtu in 2045 (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. are expected to remain moderate, as shown in Exhibit 3-12.

Exhibit 3-12: GMM Average Annual Prices for Henry Hub

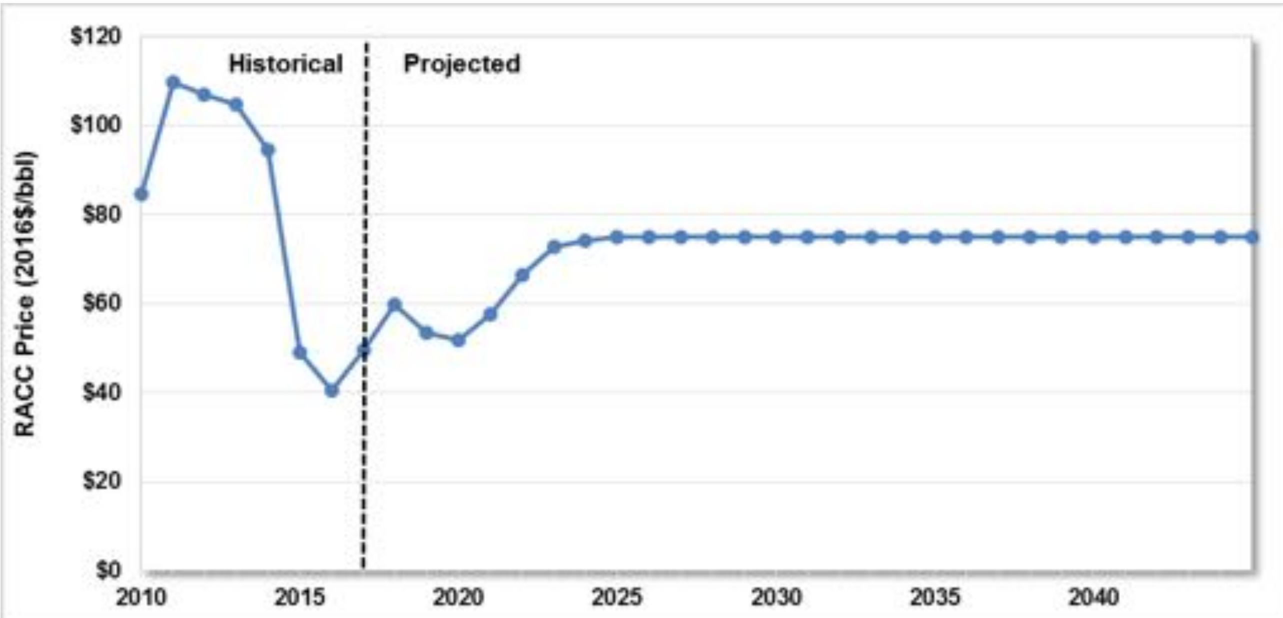


Source: ICF GMM® Q1 2018

3.5. Oil Price Trends

ICF assumes that oil prices will follow a trajectory starting with recent spot prices and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $75/bbl (2016 dollars) after 2025 as shown in the exhibit below.

Exhibit 3-13: ICF Oil Price Assumptions



Source: ICF GMM® Q1 2018

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 American 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 25 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 1992, 1998, 2003 and 2010 National Petroleum Council studies and have been updated periodically by ICF as part of work conducted for several clients.

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 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: ICF and 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 in terms of both 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.[16] Gas resources

[16] 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.

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

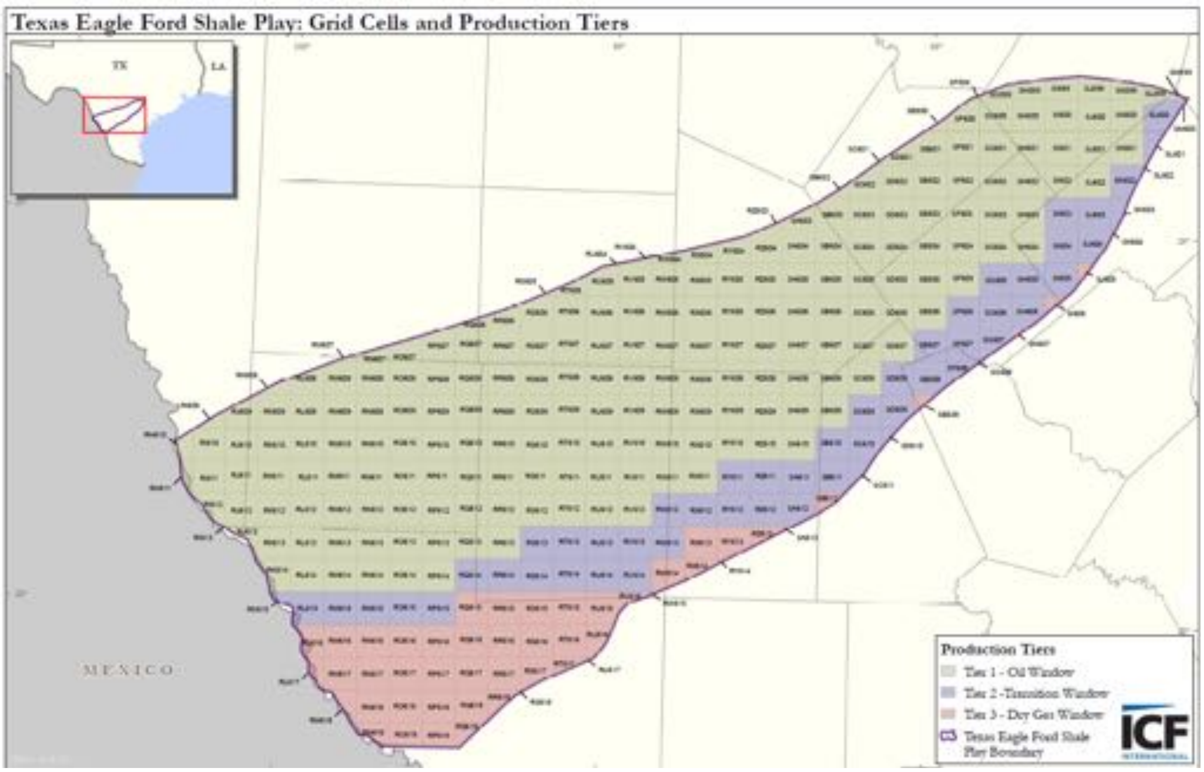
No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Shale		
1	Anadarko Woodford	1,780	40
2	Arkoma Caney	5,300	80
3	Arkoma Moorefield	520	80
4	Arkoma Woodford	1,870	40
5	Barnett	26,320	40
6	Bossier	2,840	40
7	Eagle Ford	10,500	60
8	Fayetteville	2,610	60
9	Green River Hilliard	4,350	20
10	Haynesville	7,420	40
11	Lower Huron	19,530	80
12	Marcellus	39,140	40
13	NY Utica	14,290	80
14	OHPAWV Utica	58,970	40
15	Paradox Cane Creek	3,110	40
16	Paradox Gothic	1,350	80
17	Uinta Mancos	7,080	20
18	Vermillion Baxter	180	20
19	West Texas Barnett	4,500	40
20	West Texas Woodford	4,500	40
	L-48 GIS Assessed Shale Total	**216,160**	
21	Cordova Embayment	1,550	80
22	Frederick Brook	130	80
23	Horn River	9,050	80
24	Montney	13,700	80
25	Quebec Utica	2,210	80
	Canada GIS Assessed Shale Total	**26,640**	
	Tight Gas		
26	Granite Wash	3,540	160
27	GRB Dakota	19,680	10
28	GRB Frontier	19,700	10
29	GRB Lance	13,570	10
30	GRB Lewis	6,820	10
31	GRB Lower Mesaverde	12,660	10
32	GRB MV/Almond	11,820	40
33	GRB MV/Ericson	12,680	10
34	Uinta Mesaverde	4,730	20
35	Uinta Wasatch	2,050	20
	L-48 GIS Assessed Tight Gas Total	**107,250**	
	Coalbed Methane		
36	San Juan Fruitland	8,800	160
	L-48 GIS Assessed Coalbed Methane Total	**8,800**	
37	Horseshoe Canyon	24,740	80
38	Mannville	46,760	320
	Canada GIS Assessed Coalbed Methane Total	**71,500**	
	Tight Oil		
39	Anadarko Mississippi Lime	4,880	40
40	Anadarko SCOOP	2,420	120
41	Anadarko STACK	1,800	103
42	Denver Basin Niobrara Shale	4,190	120
43	Denver Codell-Sussex	2,250	80
44	Green River Basin Niobrara Shale	2,090	80
45	Gulf Coast Austin Chalk	5,110	120
46	Gulf Coast Eaglebine	3,040	120
47	Permian Delaware Basin Bone Springs	4,820	110
48	Permian Delaware Basin Wolfcamp	5,590	108
49	Permian Midland Basin Cline	1,750	193
50	Permian Midland Basin Spraberry	6,260	108
51	Permian Midland Basin Wolfcamp	1,050	108
52	Piceance Basin Niobrara Shale	3,530	80
53	Powder River Basin Niobrara Shale	6,300	80
54	Powder River Basin Other	3,420	120
55	San Joaquin Basin Kreyenhagen Shale	1,850	80
56	San Joaquin Basin Monterey Shale	1,530	80
57	Tuscaloosa Marine Shale	680	120
58	Williston Basin Bakken Shale	14,040	255
	L-48 GIS Assessed Tight Oil Total	**76,600**	
59	WCSB Bakken Shale	1,950	80
60	WCSB Cardium Tight Oil	11,020	72
61	WCSB Duvernay Core Cells Data	2,430	80
62	WCSB Montney Oil	2,800	72
63	WCSB Viking Tight Oil	8,720	40
	L-48 GIS Assessed Tight Oil Total	**26,920**	

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.

Exhibit 4-3: Eagle Ford Play Six-Mile Grids and Production Tiers (Oil, Wet Gas, and 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 2015 was 4.6 million barrels per day (MMbpd) in the U.S., up from almost zero in 2007, and 384,000 bpd in Canada.   U.S. tight oil production is dominated by the Bakken, Eagle Ford, several plays in the Permian Basin, and increasingly, the Anadarko Basin, including the SCOOP and STACK plays. 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.

4.2. Energy and Economic Impacts Methodology

Costa Azul tasked ICF with assessing the economic and employment impacts of LNG exports from its Costa Azul Mid-Scale LNG export facility. This study analyzed two cases[17]:

1) **Base Case** with the assumption of no Costa Azul Mid-Scale LNG export volumes.
2) **Costa Azul Mid-Scale LNG Case** with the assumption of 161 Bcf per year, or 0.44 Bcfd (0.50 Bcfd exported to Mexico) higher than the Base Case due to the new construction at Costa Azul.

The results in this report show the changes between the Base Case and alternative case resulting from the incremental LNG export volumes. The methodology consisted of the following steps:

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 Southwest state level.

Step 2 – LNG plant capital and operating expenditures: Based on Costa Azul Mid-Scale LNG export facility's cost estimates, ICF determined the annual capital and operating expenditures that will be purchased in the U.S. 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 4 – 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 the Southwest. 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

[17] These volumes do not include liquefaction fuel use or lease and plant and pipeline fuel use.

$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 5 – Economic impacts: ICF assessed the impact of LNG exports for the national and the Southwest. This included direct, indirect, and induced impacts on gross domestic product, employment, taxes, and other measures.

Exhibit 4-4: Economic 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.

Key model assumptions are based on ICF analysis of the industry and previous work, and include:

- Costa Azul Mid-Scale LNG export volumes
- LNG plant capital and operating expenditures
- Per-well upstream capital costs
- Fixed and variable upstream operating costs per well
- Tax rates

The following set of exhibits show the key model assumptions.

Exhibit 4-5: Costa Azul Mid-Scale LNG Export Volume Assumptions and LNG Plant Capital and Operating Expenditures in the U.S.

Year	The Costa Azul LNG Case Changes		
	LNG Export Volume Assumptions (Bcfd)	LNG Capital Costs (2016$ MM)	LNG Operating Costs (2016$ MM)
2020	-	-	-
2021	-	$137.1	-
2022	-	$169.7	-
2023	-	$129.6	-
2024	-	$60.6	-
2025	0.17	$14.6	-
2026	0.44	-	$3.6
2027	0.44	-	$3.6
2028	0.44	-	$3.6
2029	0.44	-	$3.6
2030	0.44	-	$3.6
2031	0.44	-	$3.6
2032	0.44	-	$3.6
2033	0.44	-	$3.6
2034	0.44	-	$3.6
2035	0.44	-	$3.6
2036	0.44	-	$3.6
2037	0.44	-	$3.6
2038	0.44	-	$3.6
2039	0.44	-	$3.6
2040	0.44	-	$3.6
2041	0.44	-	$3.6
2042	0.44	-	$3.6
2043	0.44	-	$3.6
2044	0.44	-	$3.6
2045	0.44	-	$3.6

Note: LNG export volumes do not include liquefaction fuel or losses. 0.50 Bcfd exported to Mexico does include liquefaction and pipeline fuel losses.

Source: Costa Azul, ICF

Exhibit 4-6: 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) (%)	Southwest States and Local Own Taxes as % of State Income (%)
2015	18.3%	14.6%	13.7%
2016	18.1%	14.6%	13.7%
2017	18.9%	14.6%	13.7%
2018	19.4%	14.6%	13.7%
2019	19.5%	14.6%	13.7%
2020	19.8%	14.6%	13.7%
2021	20.0%	14.6%	13.7%
2022	20.1%	14.6%	13.7%
2023	20.2%	14.6%	13.7%
2024	20.3%	14.6%	13.7%
2025	20.4%	14.6%	13.7%
2026	20.5%	14.6%	13.7%
2027	20.6%	14.6%	13.7%
2028	20.7%	14.6%	13.7%
2029	20.8%	14.6%	13.7%
2030	20.9%	14.6%	13.7%
2031	21.0%	14.6%	13.7%
2032	21.1%	14.6%	13.7%
2033	21.2%	14.6%	13.7%
2034	21.3%	14.6%	13.7%
2035	21.4%	14.6%	13.7%
2036	21.5%	14.6%	13.7%
2037	21.6%	14.6%	13.7%
2038	21.7%	14.6%	13.7%
2039	21.8%	14.6%	13.7%
2040	21.9%	14.6%	13.7%
2041	22.0%	14.6%	13.7%
2042	22.1%	14.6%	13.7%
2043	22.2%	14.6%	13.7%
2044	22.3%	14.6%	13.7%
2045	22.4%	14.6%	13.7%

Source: ICF extrapolations from Tax Policy Center historical figures

Exhibit 4-7: Liquids Price Assumptions

Year	RACC Price (2016$/bbl)	Condensate Price (2016$/bbl)	Ethane Price (2016$/bbl)	MB Propane Price (2016$/bbl)	Butane Price (2016$/bbl)	Pentanes Plus (2016$/bbl)
2015	$ 49	$ 49	$ 15	$ 20	$ 33	$ 45
2016	$ 41	$ 41	$ 14	$ 20	$ 27	$ 37
2017	$ 50	$ 50	$ 15	$ 22	$ 34	$ 45
2018	$ 60	$ 60	$ 15	$ 23	$ 41	$ 55
2019	$ 53	$ 53	$ 16	$ 24	$ 36	$ 49
2020	$ 52	$ 52	$ 15	$ 27	$ 35	$ 47
2021	$ 57	$ 57	$ 17	$ 31	$ 39	$ 52
2022	$ 66	$ 66	$ 20	$ 34	$ 45	$ 60
2023	$ 73	$ 73	$ 21	$ 36	$ 49	$ 66
2024	$ 74	$ 74	$ 22	$ 37	$ 50	$ 68
2025	$ 75	$ 75	$ 22	$ 39	$ 51	$ 68
2026	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2027	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2028	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2029	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2030	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2031	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2032	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2033	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2034	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2035	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2036	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2037	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2038	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2039	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2040	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2041	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2042	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2043	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2044	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2045	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68

Source: ICF

Exhibit 4-8: Other Key Model Assumptions

Assumption	U.S.	Southwest States
Upstream Capital Costs ($MM/Well)	$7.7	$7.7
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	17.0%

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, for example, 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 and business owners in direct and indirect industries.

5. Costa Azul Mid-Scale LNG Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the Costa Azul Mid-Scale LNG Case. Specifically, differentials between the two cases result from an additional 0.44 Bcfd in LNG exports assumed from Costa Azul (assuming total exports to Mexico of 0.50 Bcfd, which includes feedstock gas liquefied and exported from the Costa Azul Mid-Scale facility, as well as fuel consumed in Mexico for pipeline transportation and liquefaction).

5.1. Energy Market and Economic Impacts

This section discusses the impacts of LNG exports in the Base Case and the Costa Azul Mid-Scale LNG Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade.

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 net natural gas pipeline imports from Canada and Mexico (see Exhibit 5-1). In addition to the incremental LNG export volumes of 0.44 Bcfd (0.50 Bcfd crossing the U.S. and Mexico border), the market also must rebalance for liquefaction and fuel losses, estimated at 8 percent of incremental net gas pipeline import volumes from Canada. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below.

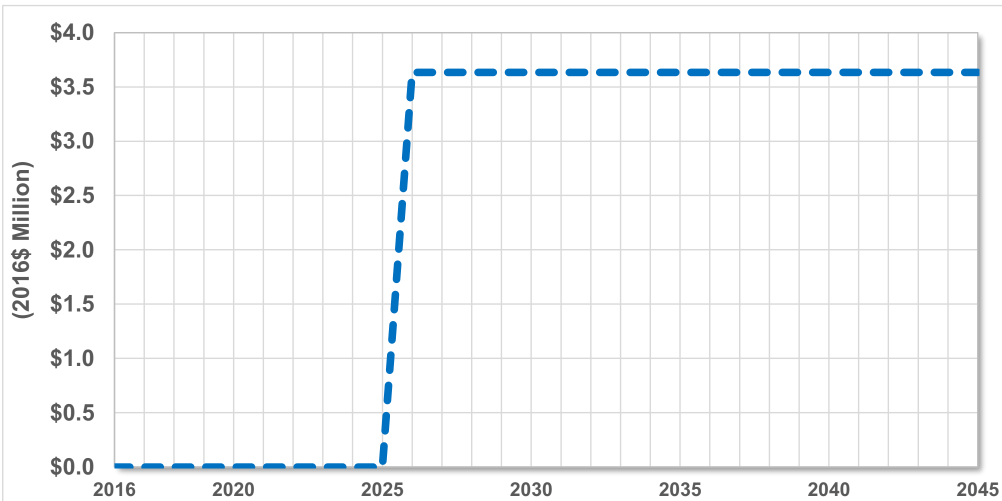
Exhibit 5-1: U.S. Flow Impact Contribution to LNG Exports

2025-2045 Average Supply Sources			
Production Increase	Demand Decrease	Net Gas Pipeline Imports	Total Share of LNG Exports
91% 0.45 Bcfd	11% 0.05 Bcfd	8% 0.04 Bcfd	110% 0.55 Bcfd

Source: ICF

The exhibit below (Exhibit 5-2) shows the impact on LNG export facility operating expenditures (excluding the cost of natural gas feedstock but including employee costs, materials, maintenance, insurance, and property taxes purchased in the U.S.). Over the study period of 2021 to 2045, there is a total cumulative impact on operating expenditures in the U.S. of $72.7 million (in real 2016$) for the Costa Azul Mid-Scale LNG Case. During that period, LNG plant operating expenditures in the U.S. average $3.6 million annually.

Exhibit 5-2: U.S. LNG Export Facility Operating Expenditure Changes

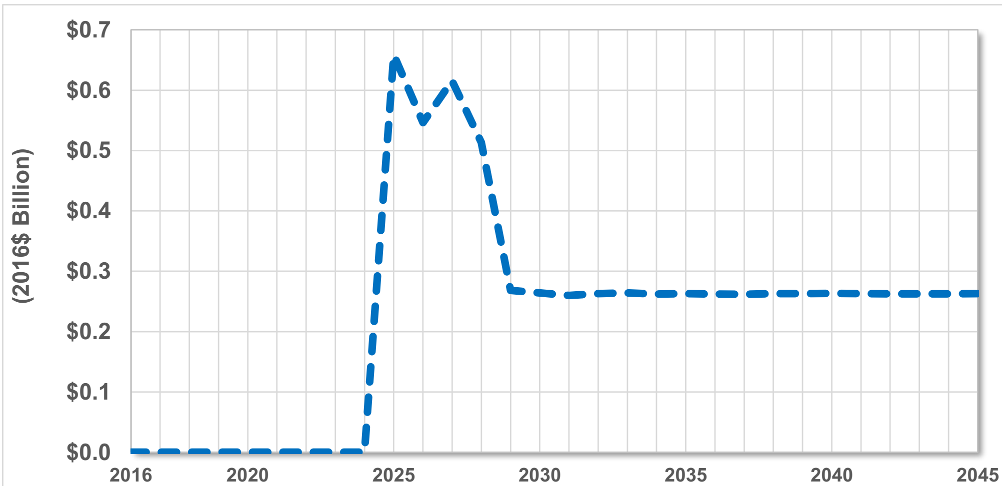


Year	LNG Facility Operating Expenditures (2016$ Million)
2021	$ -
2023	$ -
2025	$ -
2030	$ 3.6
2035	$ 3.6
2040	$ 3.6
2045	$ 3.6
2021-2045 Avg	**$ 3.6**
2021-2045 Sum	**$ 72.7**

Source: ICF

The exhibit below (Exhibit 5-3) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. Investment peaks in the early years as more new wells are drilled 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 2021 to 2045, the cumulative impact on U.S. upstream capital expenditures totals near $6.8 billion in the Costa Azul Mid-Scale LNG Case as compared to the Base Case. U.S. upstream capital expenditures average $0.3 billion higher annually in the Costa Azul Mid-Scale LNG Case than in the Base Case.

Exhibit 5-3: U.S. Upstream Capital Expenditure Changes

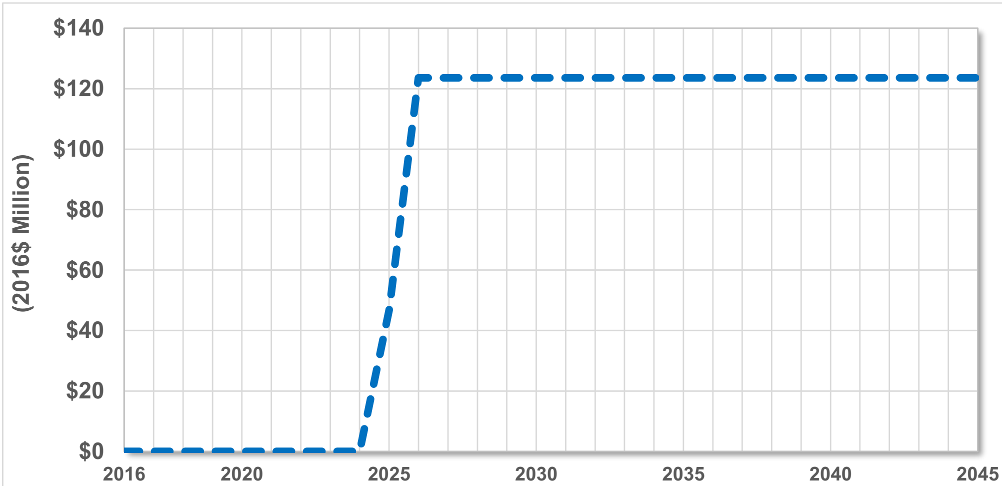


Year	Upstream Capital Expenditures (2016$ Billion)
2021	$ -
2023	$ -
2025	$ 0.66
2030	$ 0.26
2035	$ 0.26
2040	$ 0.26
2045	$ 0.26
2021-2045 Avg	**$ 0.32**
2021-2045 Sum	**$ 6.81**

Source: ICF

As shown below (Exhibit 5-4), U.S. upstream operating expenditures increase $2.5 billion on a cumulative basis, or on average $120 million annually in the Costa Azul Mid-Scale LNG Case as compared to the Base Case between 2021 and 2045.

Exhibit 5-4: U.S. Upstream Operating Expenditure Changes



Year	Upstream Operating Expenditures (2016$ Million)
2021	$ -
2023	$ -
2025	$ 47
2030	$ 124
2035	$ 124
2040	$ 124
2045	$ 124
2021-2045 Avg	**$ 120**
2021-2045 Sum	**$ 2,519**

Source: ICF

The table below (Exhibit 5-5) shows the Base Case and the Costa Azul Mid-Scale LNG Case U.S. natural gas consumption. The additional LNG export volumes of 0.44 Bcfd (that is 0.50 Bcfd additional export volumes to Mexico) are expected to result in only a small reduction in U.S. natural gas consumption of 0.05 Bcfd in 2045, mostly from power sector gas use decline.

Exhibit 5-5: U.S. Domestic Natural Gas Consumption

Year	U.S. Domestic Natural Gas Consumption (Bcfd)		
	Base Case	Costa Azul LNG Case	Costa Azul LNG Case Change
2021	76.6	76.6	-
2023	77.7	77.7	-
2025	78.5	78.5	(0.02)
2030	82.4	82.3	(0.05)
2035	86.8	86.8	(0.05)
2040	90.3	90.2	(0.05)
2045	93.6	93.6	(0.05)
2021-2045 Avg	**85.0**	**84.9**	**(0.05)**
2021-2045 Sum	**2,124.5**	**2,123.3**	**(1.12)**

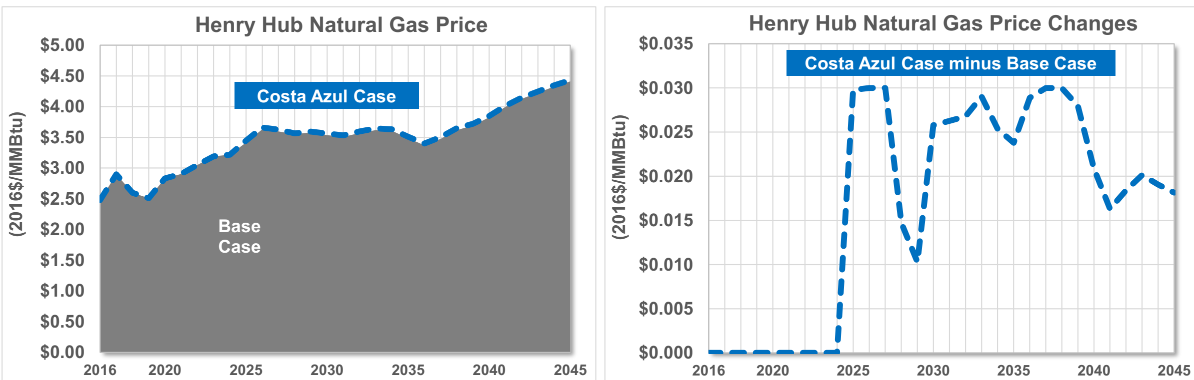
* Industrial demand does not includes pipeline fuel and lease & plant

Note: Charts above do not include LNG exports or liquefaction fuel.

Source: ICF

The Henry Hub natural gas price in the Costa Azul Mid-Scale LNG Case (averaging $3.64/MMBtu from 2025 to 2045) is expected to be on average $0.02/MMBtu higher compared to the Base Case (averaging $3.62/MMBtu), as shown in Exhibit 5-6. The natural gas prices at Henry Hub are expected to reach $4.41/MMBtu in the Base Case and $4.43 in the Costa Azul Mid-Scale LNG Case by 2045, indicating a natural gas price increase of $0.02/MMBtu attributable to the Costa Azul Mid-Scale LNG export volumes of 0.44 Bcfd.

Exhibit 5-6: Annual Average Henry Hub Natural Gas Price Changes

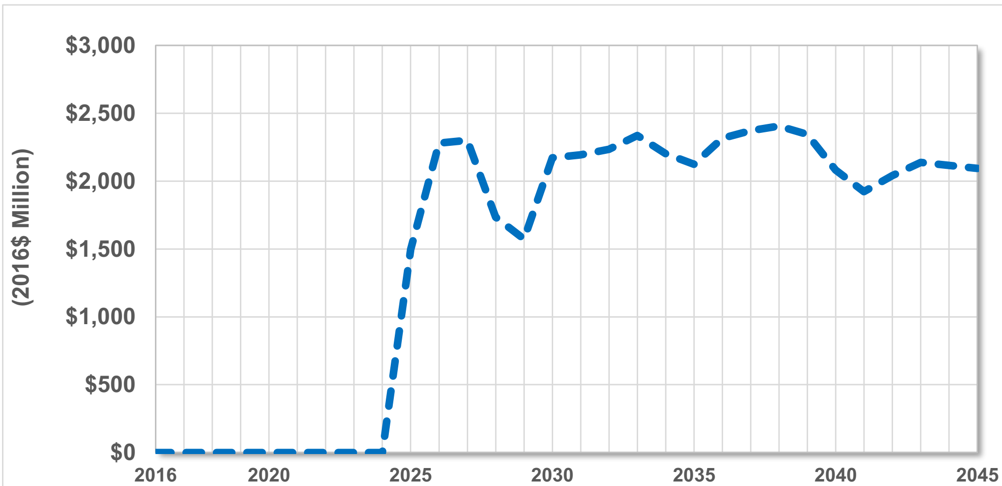


Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Costa Azul LNG Case	Costa Azul LNG Case Change
2021	$ 2.90	$ 2.90	$ -
2023	$ 3.19	$ 3.19	$ -
2025	$ 3.41	$ 3.44	$ 0.030
2030	$ 3.54	$ 3.56	$ 0.026
2035	$ 3.48	$ 3.51	$ 0.024
2040	$ 3.83	$ 3.85	$ 0.021
2045	$ 4.41	$ 4.43	$ 0.018
2021-2045 Avg	**$ 3.62**	**$ 3.64**	**$ 0.024**

Source: ICF

U.S. natural gas and liquids production increases as a result of additional LNG export volumes and higher prices as seen in the Costa Azul Mid-Scale LNG Case (see Exhibit 5-7). Over the forecast period 2021 to 2045, the cumulative impact on natural gas and liquids production value in the Costa Azul Mid-Scale LNG Case is approximately $44.5 billion. This represents an average increase of $2.1 billion per year in the Costa Azul Mid-Scale LNG Case as compared to the Base Case between 2021 and 2045.

Exhibit 5-7: U.S. Natural Gas and Liquids Production Value Changes



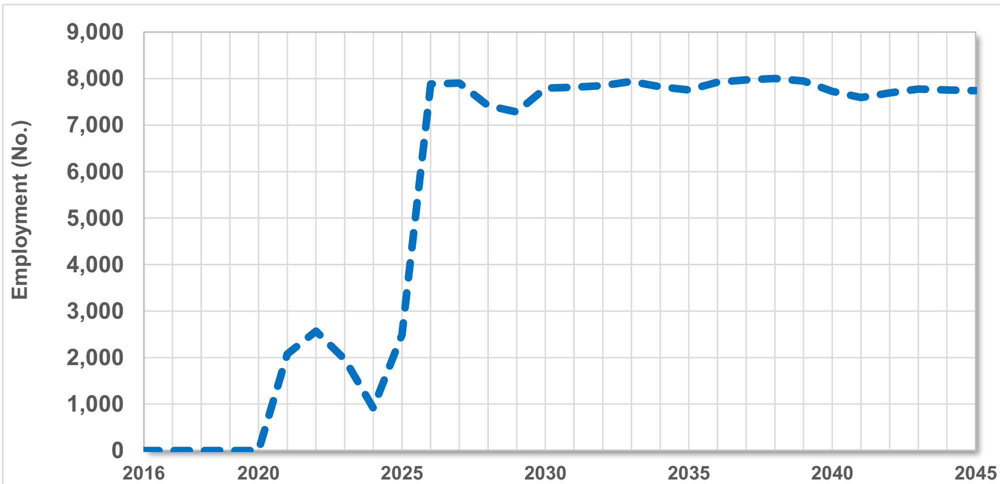
Year	Natural Gas and Liquids Production Value (2016$ Million)
2021	$ -
2023	$ -
2025	$ 1,497
2030	$ 2,172
2035	$ 2,125
2040	$ 2,082
2045	$ 2,095
2021-2045 Avg	**$ 2,119**
2021-2045 Sum	**$ 44,490**

Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

Exhibit 5-8 shows the impacts of additional LNG export volumes on total U.S. employment.[18] 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 incremental employment from direct and indirect impact leads to increased spending in the economy, creating induced impacts throughout the economy.

Exhibit 5-8: Total U.S. Total Employment Changes



Year	Employment (No.)
2021	2,073
2023	1,960
2025	2,491
2030	7,795
2035	7,759
2040	7,726
2045	7,741
2021-2045 Avg	**6,625**
2021-2045 Sum	**165,613**

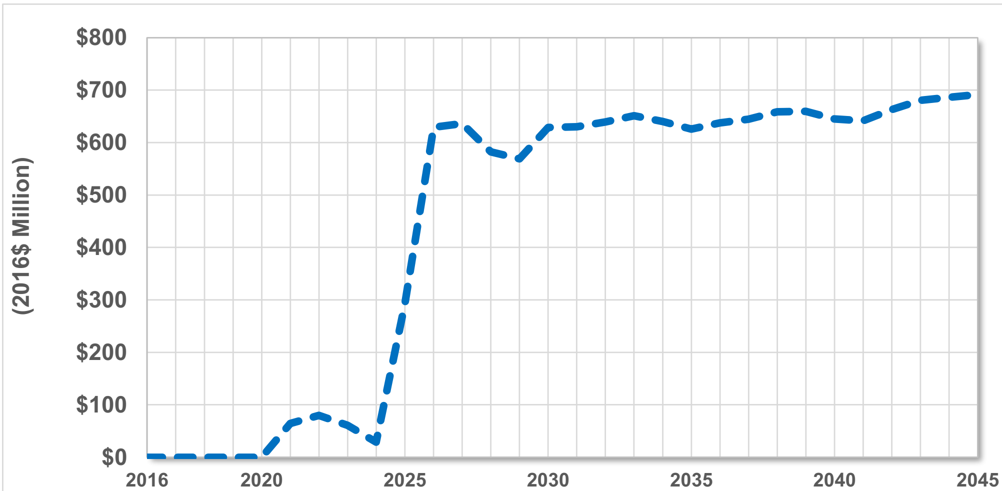
Source: ICF

The construction and operation of the Costa Azul Mid-Scale LNG export facility will likely increase employment through direct, indirect and induced employment that totals over 6,600 of incremental jobs on average between 2021 and 2045. Over the forecast period the added LNG export facilities are expected to increase job-years relative to the Base Case by 166,000 cumulative job-years.

[18] Note that one job in this report refers to a job-year.

Exhibit 5-9 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective incremental government revenues average $535 million annually as a result of the Costa Azul Mid-Scale LNG export facility. This translates to a cumulative impact of $13.4 billion over the forecast period between 2021 and 2045.

Exhibit 5-9: U.S. Federal, State, and Local Government Revenue Changes



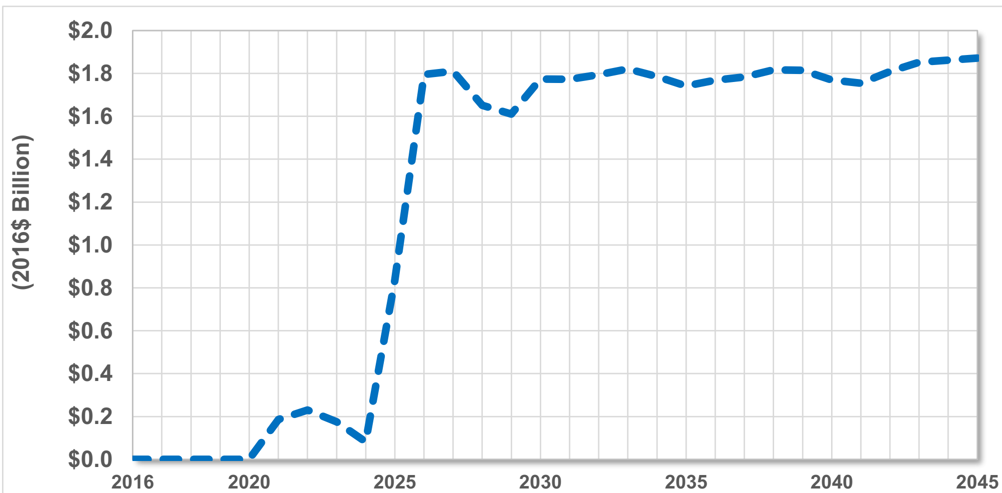
Year	Government Revenues (2016$ Million)
2021	$ 64
2023	$ 61
2025	$ 291
2030	$ 629
2035	$ 626
2040	$ 645
2045	$ 692
2021-2045 Avg	**$ 535**
2021-2045 Sum	**$ 13,366**

Source: ICF

Exhibit 5-10 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 is substantially higher as a result of the the construction and the additional LNG export volumes assumed in the Costa Azul Mid-Scale LNG Case. This activity results in a $1.5 billion annual incremental value added between 2021 and 2045. The cumulative value added over the period between the Base Case and the Costa Azul Mid-Scale LNG Case totals $37.2 billion.

Exhibit 5-10: Total U.S. Value Added Changes

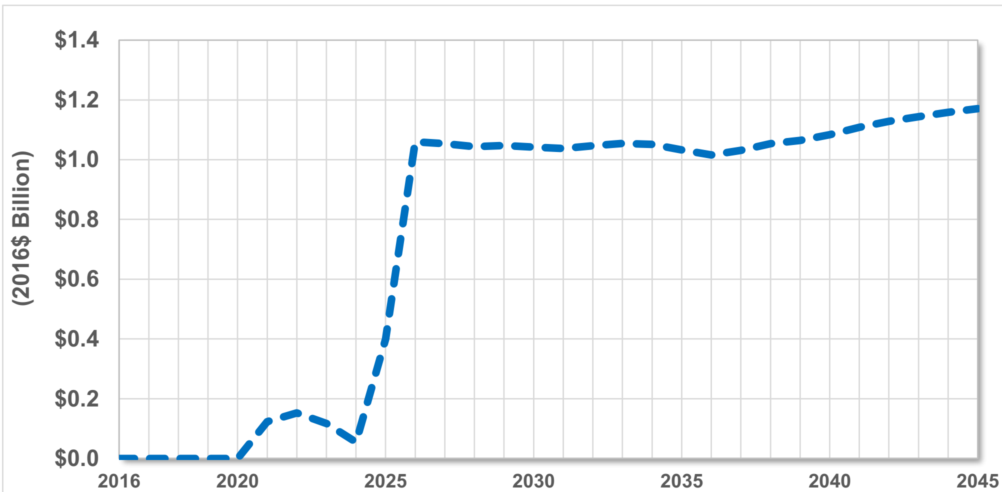


Year	Total Value Added (2016$ Billion)	
2021	$	0.2
2023	$	0.2
2025	$	0.8
2030	$	1.8
2035	$	1.7
2040	$	1.8
2045	$	1.9
2021-2045 Avg	**$**	**1.5**
2021-2045 Sum	**$**	**37.2**

Source: ICF

Exhibit 5-11 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $0.9 billion annually between 2021 and 2045, based on the value of LNG export volumes and incremental associated liquids production, or a cumulative value of $22.3 billion. The improved balance of trade effects begin approximately in 2025 when the plant starts operating and are primarily a result of the LNG exports themselves (encompassing the natural gas feedstock used to make the LNG and the LNG liquefaction process) and the additional hydrocarbon liquids production which is assumed to either substitute for imported liquids or be exported.

Exhibit 5-11: U.S. Balance of Trade Changes



Year	Balance of Trade (2016$ Billion)
2021	$ 0.1
2023	$ 0.1
2025	$ 0.4
2030	$ 1.0
2035	$ 1.0
2040	$ 1.1
2045	$ 1.2
2021-2045 Avg	**$ 0.9**
2021-2045 Sum	**$ 22.3**

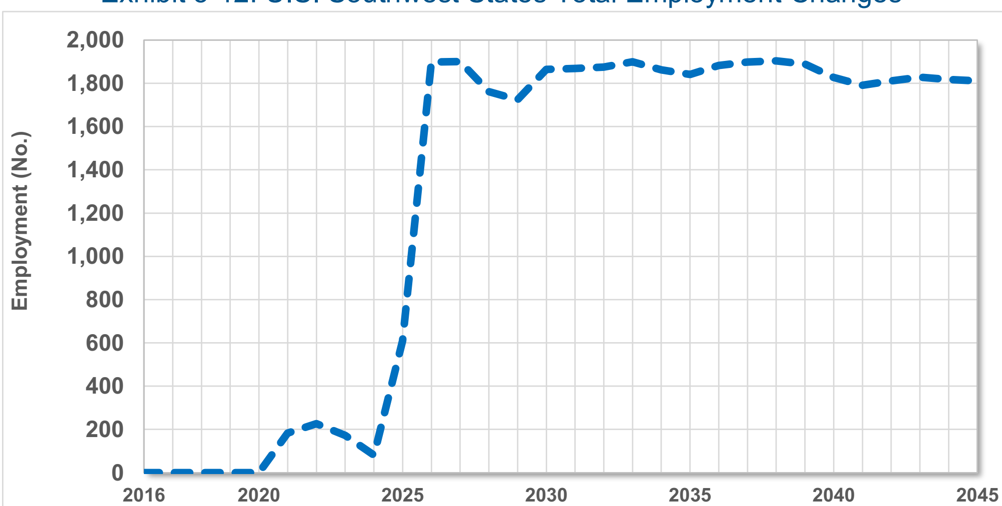
Source: ICF

5.2. U.S. Southwest States Impacts

The exhibits below describe the energy market and economic impacts of the LNG export cases in the five Southwest states that include California, Nevada, Arizona, New Mexico, and Texas.

Exhibit 5-12 shows the impacts of LNG export volumes in the U.S. Southwest total employment, 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 LNG export facility and to the added natural gas production that will take place in the five states and in other states to which companies in the Southwest states offer support services. The Costa Azul Mid-Scale LNG Case exhibits an increase of over 1,500 jobs on an average annual basis from 2021 to 2045 as compared to the Base Case. This equates to a cumulative impact of 38,000 job-years in the Southwest over the 25-year forecast period through 2045.

Exhibit 5-12: U.S. Southwest States Total Employment Changes

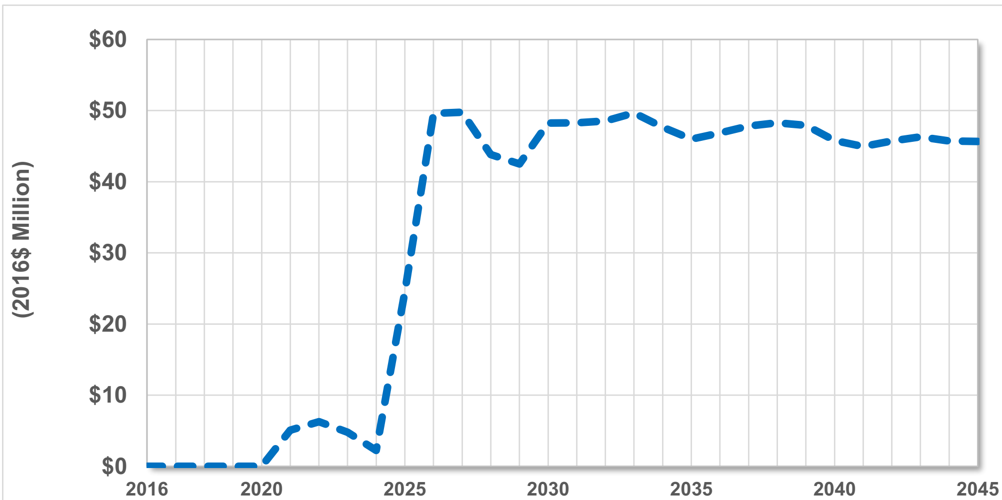


Year	Employment (No.)
2021	183
2023	173
2025	609
2030	1,864
2035	1,841
2040	1,827
2045	1,812
2021-2045 Avg	**1,529**
2021-2045 Sum	**38,231**

Source: ICF

Exhibit 5-13 shows the impacts of LNG export volumes on Southwest states and local government revenues. Total Southwest government revenues include all fees and taxes (personal income, corporate income, sales, property, oil & gas severance and employment) related to incremental activity in the construction and operation of the liquefaction plant; natural gas transportation; port services; oil & gas exploration, development and production; and induced consumer spending. Relative to the Base Case, the Costa Azul Mid-Scale LNG Case results in a $39 million average annual increase to the Southwest local and state government revenues throughout the 25-year forecast period through 2045, or a cumulative impact of $982 million.

Exhibit 5-13: U.S. Southwest States Government Revenue Changes

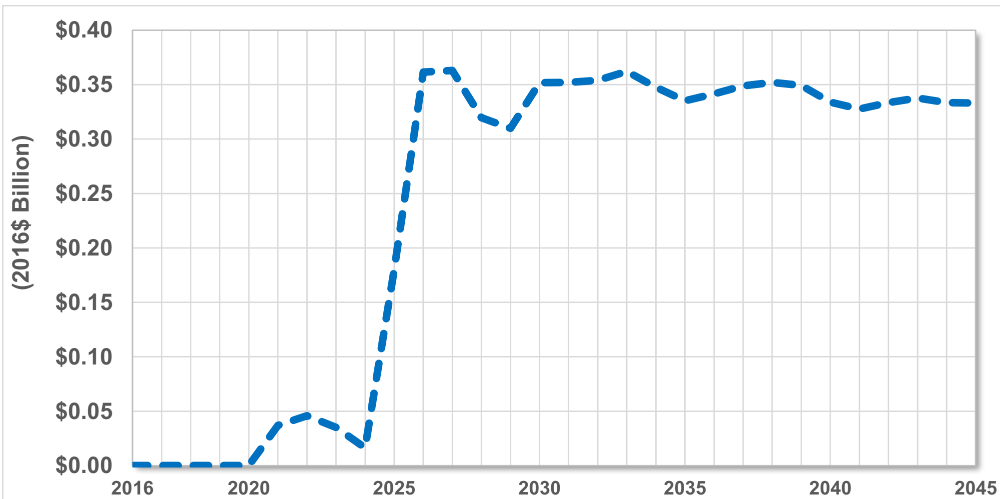


Year	Government Revenues (2016$ Million)
2021	$ 5.1
2023	$ 4.8
2025	$ 24.6
2030	$ 48.2
2035	$ 46.0
2040	$ 45.8
2045	$ 45.7
2021-2045 Avg	**$ 39.3**
2021-2045 Sum	**$ 982.2**

Source: ICF

Exhibit 5-14 shows the impacts of LNG export volumes on total the U.S. Southwest value added (also called gross state product or GSP). The Southwest value added increases as a result of the additional LNG export volumes assumed in the Costa Azul Mid-Scale LNG Case. Throughout the study period 2021 to 2045 the additional LNG volumes in the Costa Azul Mid-Scale LNG Case result in a $0.29 billion annual average increase to value added, relative to the Base Case. The total differential of value added to the Southwest states over the study period between the Base Case and the Costa Azul Mid-Scale LNG Case is $7.2 billion.

Exhibit 5-14: Total U.S. Southwest States Value Added Changes



Year	Total Value Added (2016$ Billion)
2021	$ 0.04
2023	$ 0.03
2025	$ 0.18
2030	$ 0.35
2035	$ 0.34
2040	$ 0.33
2045	$ 0.33
2021-2045 Avg	**$ 0.29**
2021-2045 Sum	**$ 7.16**

Source: ICF

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7. Appendices

7.1. Appendix A: U.S.-Mexico Cross-Border Pipeline Capacity and Flows

Table below shows the natural gas pipeline cross-border capacity in 2017, the cross-border export volumes in 2017 and the expected cross-border capacity in 2020. The "Current Capacity" data provided in the exhibit was verified using multiple sources. The primary source that was used was the U.S. Energy Information Agency (EIA). The EIA provides international export capacity data for each pipeline that exports or imports gas to Mexico and Canada.[19] In addition to using the EIA's pipeline database, ICF attempted to verify each reported capacity using a second source. The second source was either information from the exporting pipeline's operator, information from the importing pipeline's operator, information from documentation from the Federal Energy Regulatory Commission (FERC), or using the historical flow volume data to determine a maximum capacity. In some cases, the capacity quantity provided by the EIA differed from the other sources of information or, for certain pipelines, was missing. In those cases, ICF either used the second source of information or reconciled the two sources.

The "2017 Flows" data provided in the table was determined by calculating the annual average of monthly data from two sources. The primary source of the data were the monthly export volumes provided by the EIA. The EIA aggregates natural gas pipeline exports to Mexico by border crossing town, which meant ICF had to map each pipeline to the each exit point. In some cases, two pipelines' flow data were combined into the same export point. The secondary source of the data were the monthly pipeline throughput volumes provided by PointLogic.

The "2020 Capacity" was calculated by adding the capacity from the pipeline expansion projects that are currently under construction or that ICF expects will be constructed to the "Current Capacity." The capacity of the expansion projects was determined by using their applications with FERC, information from the project websites, and PointLogic.

[19] https://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xlsx

U.S. Pipeline Capacity and Flows to Mexico

U.S. Pipeline	Mexico Pipeline	Current Capacity (MMcf/d)	2017 Flows (MMcf/d)[1]	2020 Capacity (MMcf/d)
California				
San Diego Gas & Electric Co	TGN de Baja California	415	2	415
North Baja	Gasoducto Bajanorte / Rosarito	500	296	500
Southern California Gas	DGN Pipeline	70	52	70
Arizona				
Sierrita	Gasoducto Aguaprieta / Sonora	201	98	524
El Paso	PEMEX	512	234	862
West Texas				
OneOK WesTex and Roadrunner	PEMEX / Tarahumara Pipeline	965	114	965
El Paso	PEMEX / Gasoducto de Chihuahua	360	70	360
Comanche Trail	San Isidro-Samalayuca	1,100	48	1,100
El Paso	San Isidro-Samalayuca	550	230	550
Trans-Pecos	Gasoducto Ojinaga	1,356	0	1,356
South Texas				
Tennessee Gas Pipeline	PEMEX / Gasoducto Del Rio	527	217	527
NET Mexico Pipeline	Los Ramones	2,100	1,896	2,100
KM Texas and KM Tejas	PEMEX / KM Gas Natural de Mexico	990	934	990
Nueva Era Pipeline	Nueva Era Pipeline	0	0	1,000
Valley Crossing	Sur de Texas –Tuxpan Pipeline	0	0	2,600
Texas Eastern	PEMEX	350	22	350
West Texas Gas Co	PEMEX	472	1	472
Houston Pipeline Co	PEMEX	140	86	140
Tidelands Oil & Gas Co	PEMEX	26	22	26
Total		**10,634**	**4,322**	**14,907**

Source: EIA

7.2. Appendix B: 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 fewer 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.

The most recent industry wide study[20] assessing the impact of LNG exports on the U.S. economy was commissioned by DOE and released in October 2015. Oxford Economics & Rice University's Center on Energy Studies studied multiple scenarios assuming the global demand for U.S. LNG Exports ranged from 12 to 20 Bcfd, and a range of U.S. resource recovery rates (Reference, High, and, Low). The gas price impacts range from $0.25 to $0.41 per MMBtu on average (in 2010 dollars) from 2026 to 2040. The DOE study assumes a much more conservative gas resource base (about 2,200 Tcf when the study was conducted) than ICF, which may have contributed to this strong price reaction. However, the DOE study finds that the positive impacts to the U.S. economy largely outweigh this increase in consumer gas prices. As a result of increased U.S. LNG exports relative to 12 Bcfd, the study finds that GDP increases by 0.03 to 0.07 percent from 2026 to 2040 or $7-$20 Billion (in 2014 dollars) over the period. The study also found a net positive impact on employment of 0.01 to 0.02 percent on an average annual basis from 2026 to 2040, or between 9,000 and 35,000 annual jobs. The study finds that the negative impact to some industries with high energy inputs are offset by other industries that benefit from the production increase.

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.[21] 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

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[20] DOE. "The Macroeconomic Impact of Increasing U.S. LNG Exports". Oxford Economics & Rice University Center on Energy studies, Oct 29, 2015. Available at http://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[21] 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

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.[22] In the unconstrained LNG export scenario, the study found that the U.S. could 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.

NERA provided an update to its December 2012 study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[23] 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.[24] 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.[25] 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

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[22] 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

[23] 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

[24] 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

[25] 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

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.[26] Examining export cases from 20 Bcfd to 30 Bcfd by 2030, CRA argued that LNG exports could 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 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 on the next page for more details by study.

[26] 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

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Facility / Study	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Costa Azul Mid-Scale LNG (ICF)	Costa Azul Mid-Scale LNG export of 0.44 Bcfd	0.44 Bcfd LNG Export (0.50 Bcfd Crossing U.S./MX Border)	$0.024	$0.048	91%	11%	8%	110%	1.55	13,253	$224,408	Costa Azul Mid-Scale LNG development leads to positive impact on the U.S. economy and employment.
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.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES)	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for U.S. Exports, and 4 differing domestic scenarios (reference resource recovery, high resource recovery, low resource recovery, and high domestic demand. Study Period referenced here: 2026 to 2040	20 Bcfd LNG Exports, Reference Resource Recovery	$0.27	$0.063	86.0%	2.3%	16.3%	104.7%	N/A	2,233	$ 802,083	Across the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports.
		20 Bcfd LNG Exports, High Resource Recovery	$0.25	$0.049	100.0%	5.9%	7.8%	113.7%	N/A	2,216	$ 646,018	
		Market Determined (Endogenous) LNG Exports, Reference Resource Recovery	$0.32	$0.059	88.9%	1.9%	13.0%	103.7%	N/A	4,463	$ 692,946	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES) cont'd	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for U.S. Exports, and 4 differing domestic scenarios (reference resource recovery, high resource recovery, low resource recovery, and high domestic demand. Study Period referenced here: 2026 to 2040	Market Determined (Endogenous) LNG Exports, High Resource Recovery	$0.41	$0.048	98.8%	5.9%	8.2%	112.9%	N/A	4,141	$ 582,386	Across the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports.
		Market Determined (Endogenous) LNG Exports, Low Resource Recovery	$0.19	$0.070	92.6%	0.0%	7.4%	100.0%	N/A	6,815	$ 679,348	
		Market Determined (Endogenous) LNG Exports, High Domestic Demand	$0.29	$0.067	93.0%	4.7%	9.3%	107.0%	N/A	4,465	$ 750,000	

Facility	Summary of Analysis	Case	Impact LNG Exports										Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact		
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs		
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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
API (ICF, 2012)	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: Henry Hub Price Change Relative to Base Case: $/MMBtu	Henry Hub Price Change Relative to Base Case: $/MMBtu per 1 Bcfd	Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd): Production Increase (%)	Flow Impact: Demand Decrease (%)	Flow Impact: Net Gas Pipeline Imports (%)	Flow Impact: Total Share of LNG Exports (%)	Multiplier Effect of GDP: 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 export facility. 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	$0.20			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$0.23			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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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.

APPENDIX B2

ICF Report for the Combined Effects of the ECA Mid-Scale and Large-Scale Projects

Economic Impacts of the Proposed Energía Combined Costa Azul Liquefaction Project: Information for DOE Non-FTA Permit Application

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Table of Contents

List of Exhibits

1. Executive Summary

1.1. Introduction

ICF conducted an analysis on behalf of Energía Costa Azul, S. de R.L. de C.V. (Costa Azul), a company owned, in part, by Sempra Energy, to assess the market and economic impacts of the proposed Costa Azul LNG export facility located in Ensenada, Baja California, Mexico, to the U.S. economy. The Costa Azul export facility is proposed to be developed with a Combined facility (a Mid-Scale 0.44 Bcfd facility and a Large-Scale 1.3 Bcfd facility) to come on-line approximately in 2025 and ramp up to 636[1] Bcf per year, or 1.74 Bcfd (1.99 Bcfd[2] exported volumes to Mexico).

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Combined Costa Azul export facility. To assess the impacts on the energy market, ICF conducted two alternative scenario runs using its proprietary Gas Market Model (GMM):

1) **Base Case** - No Costa Azul export facility;
2) **Combined Costa Azul LNG Case** - Base Case with 1.74 Bcfd of additional export volumes from Costa Azul.

The natural gas supplied to the plant is assumed for this analysis to come from the U.S. The changes of natural gas and liquids production value, investment, capital and operating expenditure between these two cases are inputs into IMPLAN, an input-output economic model for assessing the economic and employment impacts. Specifically, the analysis methodology consisted of the following steps:

- **Assess natural gas and liquids production changes:** From the GMM run results, we first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for the Combined Costa Azul exports. GMM also solved for changes in natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins as a whole and from the Southwest[3] United States (U.S.) were both estimated.

- **Quantify upstream and the plant capital and operating expenditures:** ICF translated the natural gas and liquids production changes from GMM into annual capital and operating expenditures that will be required for the additional production. In addition, based on the Combined Costa Azul LNG export facility's cost estimates, ICF assessed the annual capital and operating expenditures in the U.S. to support the LNG exports at the facility.

- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant and upstream expenditures as inputs to the IMPLAN input-output model to assess their economic

[1] This volume does not include liquefaction fuel use or lease and plant and pipeline fuel use.
[2] This volume includes liquefaction fuel use and pipeline fuel use.
[3] The Southwest region includes California, Nevada, Arizona, New Mexico, and Texas.

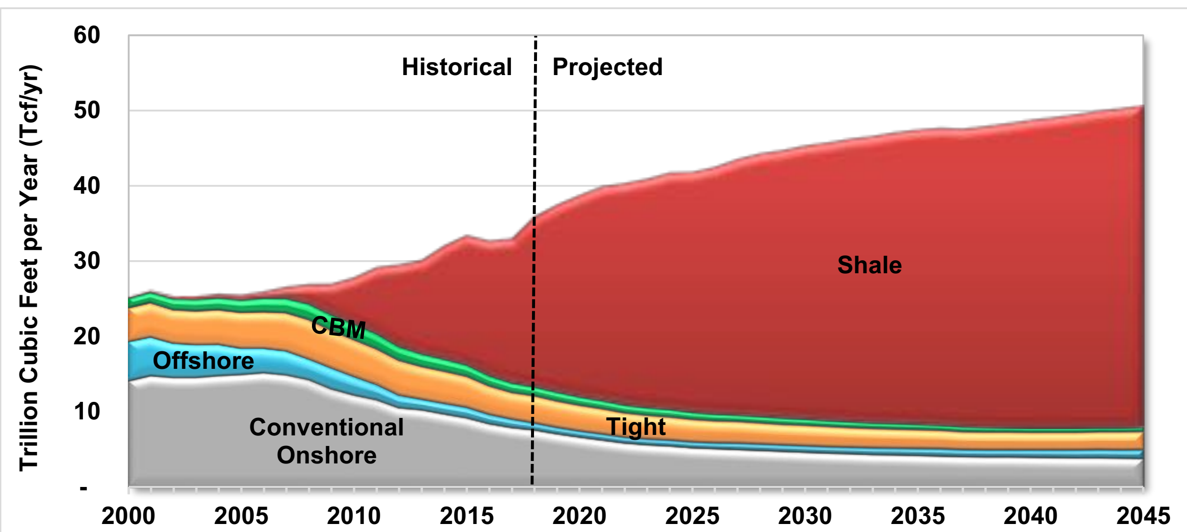
impacts for the U.S. and the Southwest. The model quantifies the economic stimulus impacts from capital and operational investments. For example, any amount of annual expenditures on drilling and completing new gas wells would support a certain number of direct employees (e.g., natural gas production employees), indirect employees (e.g., drilling equipment manufacturers), and induced employees (e.g., consumer industry employees).

- **Quantify the economic and employment impacts:** Results of IMPLAN allows ICF to estimate the impacts of the projected incremental expenditures from supporting the Combined Costa Azul exports on the national and the Southwest economies. The impacts include direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and international 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, especially from shale resources. The growth trend is expected to continue over the next 30 years (see Exhibit 1-1: U.S. and Canadian Gas Supplies). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, specifically gas-directed horizontal drilling in the Marcellus and Utica shales, which will account for over half of the incremental production and from tight oil production in the Permian Basin and other areas. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

Exhibit 1-1: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q1 2018

In the long-term, the power sector presents 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). Power sector gas demand grew significantly in 2017, as natural gas capacity replaced retired coal capacity. This trend will continue and is expected to accelerate after 2026 when federal carbon regulation is assumed 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 $3.50 per MMBtu[4] after 2025, with long-term prices expected to range between $3.50 and $4.50 per MMBtu. Prices are high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand growth. Long-term demand growth will be shaped by future environmental policies and their impact on power sector gas demand.

U.S. LNG exports are projected to reach 12.1 Bcfd by 2032, with volumes from the Gulf Coast expected to reach 10.9 Bcfd, based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy. These volumes do not include the additional Combined Costa Azul export volumes associated with this economic impact analysis.

1.3. Key Study Results

ICF's analysis shows that the volume exported via the Combined Costa Azul LNG export facility has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.11/MMBtu (in real 2016 dollars) on average from 2025 to 2045, averaging $3.83/MMBtu, with the Combined Costa Azul export facility included in the scenario, compared with $3.72/MMBtu without the export facility in the scenario. The natural gas prices at Henry Hub are expected to reach $4.41/MMBtu in the Base Case and $4.52/MMBtu in the Combined Costa Azul LNG Case by 2045, indicating a price increase of $0.11/MMBtu attributable to the Combined Costa Azul LNG export volumes of 1.74 Bcfd.

The Combined Costa Azul LNG export facility is expected to have minimal impact on the U.S. supply availability and market price because the volume represents a small amount of the North American natural gas resources and total market demand. Total export volumes from the facility over the 20-year period from 2025 to 2045 is approximately 12.6 Tcf. This represents (a) roughly 0.9% to 1.1% of Lower 48 natural gas resources that can be produced with current technology at an 8% rate of return, Henry Hub price at less than $3.50 to 4.00/MMBtu, and crude at $75/Bbl; and (b) about 1.9% of the total U.S. domestic natural gas consumption during the same period.

[4] All dollar figure results in this report are in 2016 real dollars, unless otherwise specified.

Exhibit 1-2: Natural Gas Price Impact of the Combined Costa Azul LNG Export Facility

Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Combined Costa Azul LNG Case	Combined Costa Azul LNG Case Change
2021	$ 2.90	$ 2.90	$ -
2023	$ 3.19	$ 3.19	$ -
2025	$ 3.41	$ 3.44	$ 0.030
2030	$ 3.54	$ 3.65	$ 0.115
2035	$ 3.48	$ 3.60	$ 0.114
2040	$ 3.83	$ 3.94	$ 0.112
2045	$ 4.41	$ 4.52	$ 0.109
2021-2045 Avg	**$ 3.62**	**$ 3.71**	**$ 0.091**
2025-2045 Avg	**$ 3.72**	**$ 3.83**	**$ 0.108**

Source: ICF

ICF's analysis concluded that activity in the U.S. to support the Combined Costa Azul LNG exports could lead to significant economic impacts, on average, creating 27,600 jobs annually for the U.S. economy, and 6,200 in the Southwest between 2021 and 2045. This means a cumulative impact through 2045 of 689,000 job-years for the U.S. and 155,000 job-years for the Southwest. In addition, the project could add $6.1 billion to the U.S. economy annually ($152 billion over the forecast period), including $1.2 billion annually in the Southwest ($29.4 billion over the forecast period). The additional Combined Costa Azul LNG exports would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $2.2 billion annually; and the Southwest state and local tax revenues are expected to increase by $162 million annually. Throughout the 25-year forecast period, the U.S. will receive $54.7 billion additional revenue from taxes and the Southwest states will receive $4.0 billion.

Exhibit 1-3: Economic and Employment Impacts of the Combined Costa Azul LNG Export Facility

Region	2021-2045 Average Annual Impact			2021-2045 Cumulative Impact		
	Jobs (Jobs)	Value Added (2016$ Million)	Government Revenues (2016$ Million)	Jobs (Job-years)	Value Added (2016$ Million)	Government Revenues (2016$ Million)
U.S.	27,566	$ 6,075.5	$ 2,186.1	689,142	$ 151,887.3	$ 54,652.4
Southwest States	6,202	$ 1,177.6	$ 161.5	155,056	$ 29,439.3	$ 4,038.5

Source: ICF. The Southwest States include California, Nevada, Arizona, New Mexico, and Texas.

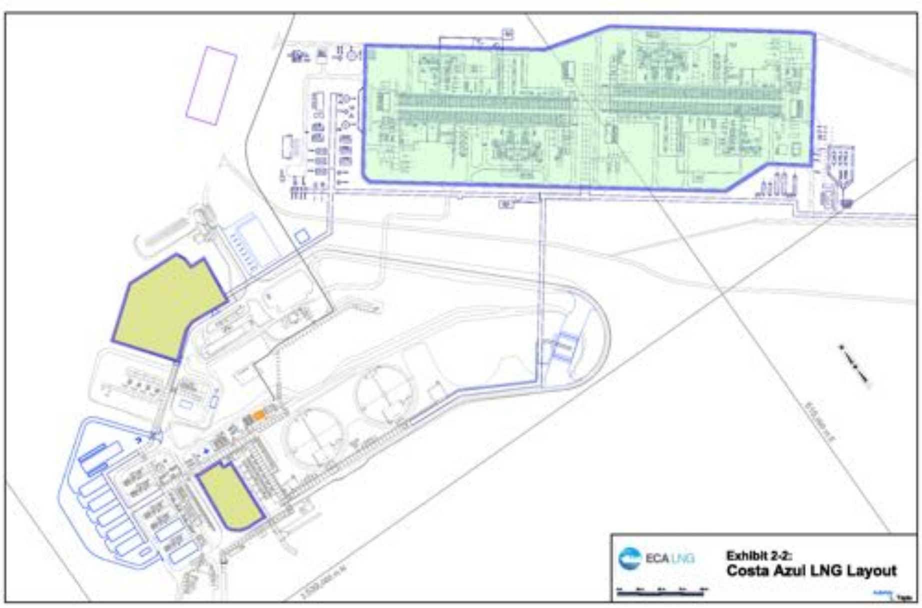
2. Introduction

Costa Azul tasked ICF with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Combined Costa Azul LNG export facility. Exhibit 2-1 and Exhibit 2-2 show Costa Azul's location and layout, respectively.

Exhibit 2-1: Costa Azul LNG Location Map

Source: Costa Azul

Exhibit 2-2: Costa Azul LNG Layout



Source: Costa Azul

For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the 1.74 Bcfd export facility and estimated the changes between the two scenarios for the total U.S. and the Southwest:

- 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.

The changes in LNG plant capital and operating expenditure and upstream capital and operating expenditures were inputted into the IMPLAN model to estimate the export facility's impacts on the U.S. and the Southwest's economy. The economic metrics include:

- Employment
- Federal, state, and local government revenues
- Value added
- U.S. Balance of Trade

This report is organized as follows.

1) Executive Summary
2) Introduction
3) Base Case U.S. and Canadian Natural Gas Market Overview
4) Study Methodology
5) Combined Costa Azul LNG Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

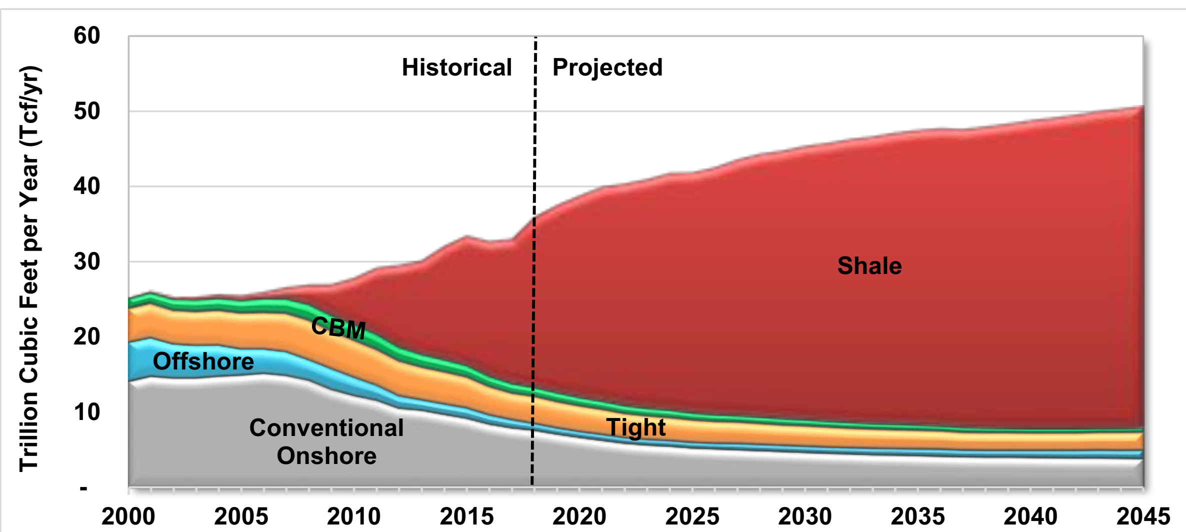
3. Base Case U.S. and Canadian Natural Gas Market Overview

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 2045, including pipeline construction 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 several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2045 and beyond (see Exhibit 3-1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil 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

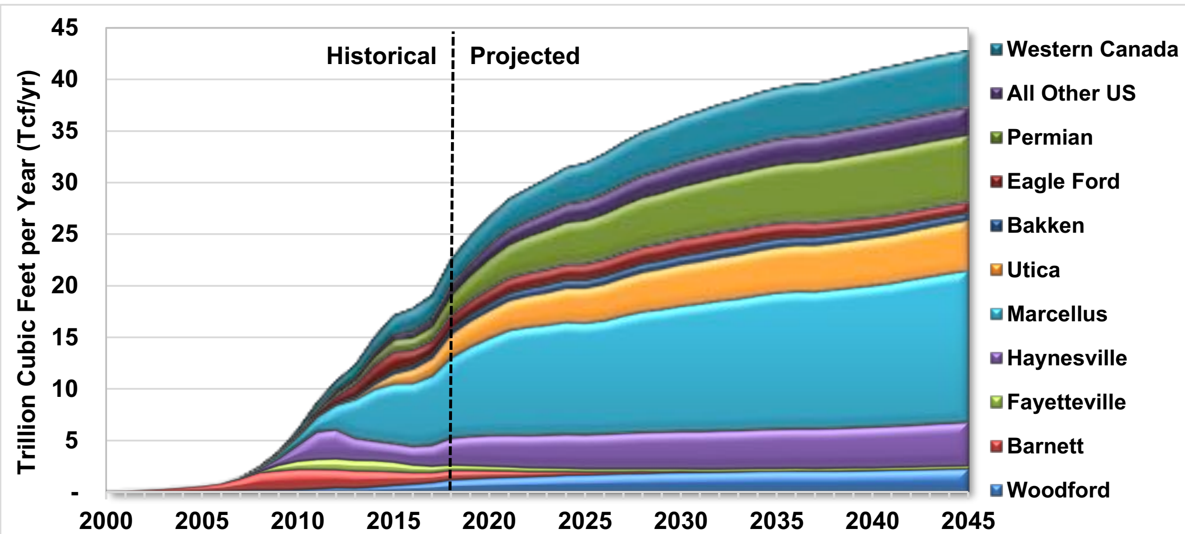


Source: ICF GMM® Q1 2018

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (16 Bcfd) in 2010 to nearly 41.5 Tcf (114 Bcfd) by 2045 (see exhibit above), assuming a crude price of $75/Bbl ($2016). The major shale formations in the U.S. and Canada are located in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, 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, the Permian, and Niobrara are primarily producing oil with associated natural gas volumes. Associated gas production from the Permian, Niobrara, and Bakken is expected to grow significantly in the next 10 years. Production from the lower cost Permian basin will reach 4.5 Tcf (over 12 Bcfd) by 2025, from about 1.8 Tcf (5 Bcfd) in 2017.

ICF did not include in our forecast potential shale and tight oil formations in the U.S. and Canada that have not yet been evaluated or developed for gas and oil 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 GMM® Q1 2018

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 have 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 resource 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 cost curves are all of the resources discussed above – proven reserves, growth, new fields,

[5] Unconventional refers to production that requires some form of stimulation within the well to produce gas economically. Conventional wells do not require stimulation.

and unconventional gas. The detailed unconventional geographic information system (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 and tight oil are almost all development drilling. Offshore undiscovered 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 estimate costs at points farther downstream of the wellhead. Costs can be further adjusted to a “Henry Hub” basis by adding regional basis differentials for certain type of analysis that considers the locations of resources relative to markets.

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 option. 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

U.S. and Canadian 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.

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6 American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.

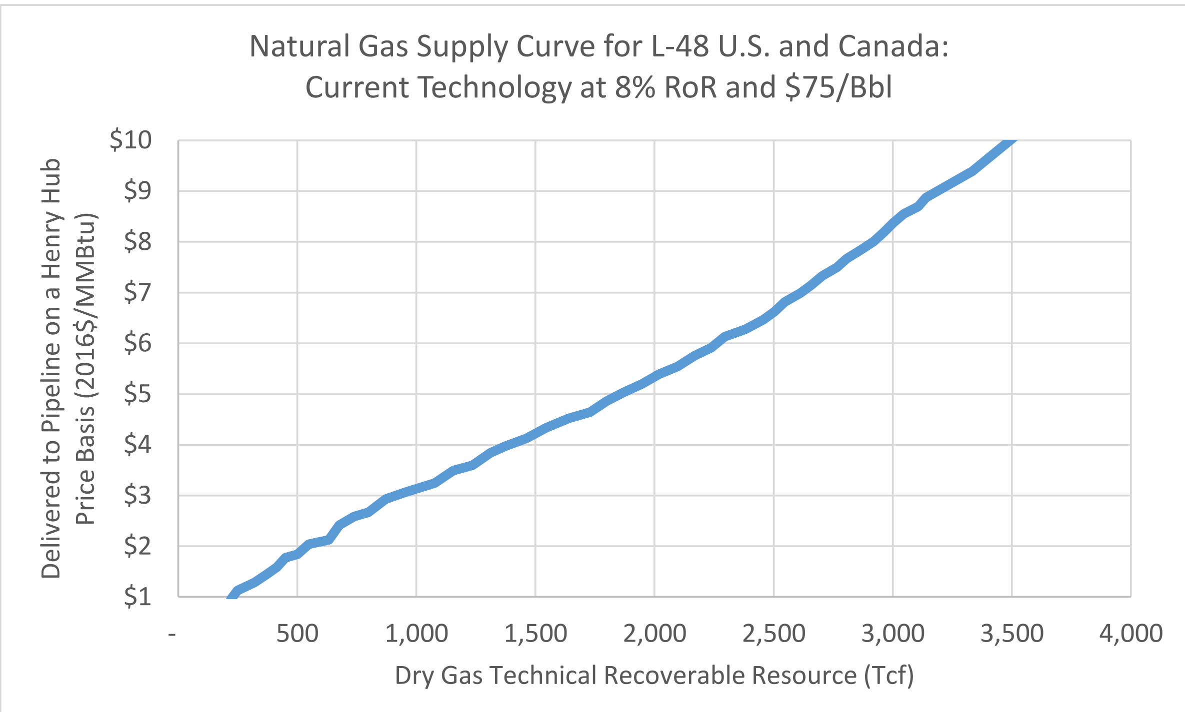
7 Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/

8 U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011 and various other years: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

A total of about 1,200 to 1,400 Tcf of gas resource in the U.S. and Canada is available at gas prices between $3.50 and $4.00 per MMBtu.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve 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. (See section 3.1.2 for discussion of technology trends assumed in this study.)

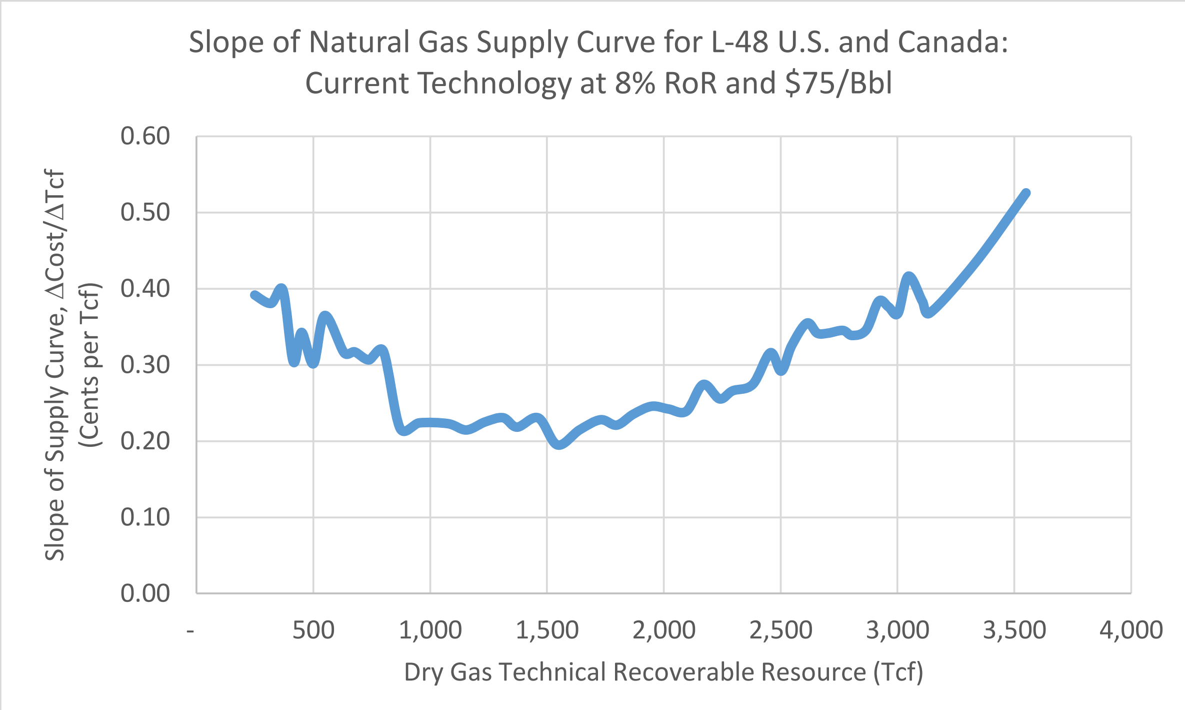
Exhibit 3-3: U.S. and Canada Natural Gas Supply Curves



Source: ICF

A natural gas supply curve can also be described in terms of its slope. Exhibit 3-4 shows the slope of the Lower 48 plus Canada curve in cents per Tcf. In the forecast cases to be shown later in this report, the U.S. is projected to develop approximately 847 to 945 Tcf of natural gas resources through 2040 and Canada to develop another 166 to 176 Tcf. Combining the two countries, depletion for the U.S. and Canada will be in the range of 1,013 to 1,121 Tcf. This means that incremental development of one Tcf of natural through 2040 would have a “depletion effect on price” of natural gas of 0.2 to 0.4 cents (assuming no upstream technological advances to increase available volumes and to decrease costs) during the forecast period. As is explained below, the depletion effect on price is only one of several factors that need to be considered when estimating the price impacts of LNG exports or any other change to demand.

Exhibit 3-4: Slope of U.S. and Canada Natural Gas Supply Curve



Source: ICF

3.1.2. Representation of Future Upstream Technology Improvements

Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the "current technology" gas supply curves.[9]

Technology advances in natural gas development in recent years have been related to the drilling of longer 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 and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. The percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, however, resulting in lower costs per unit of reserve additions.

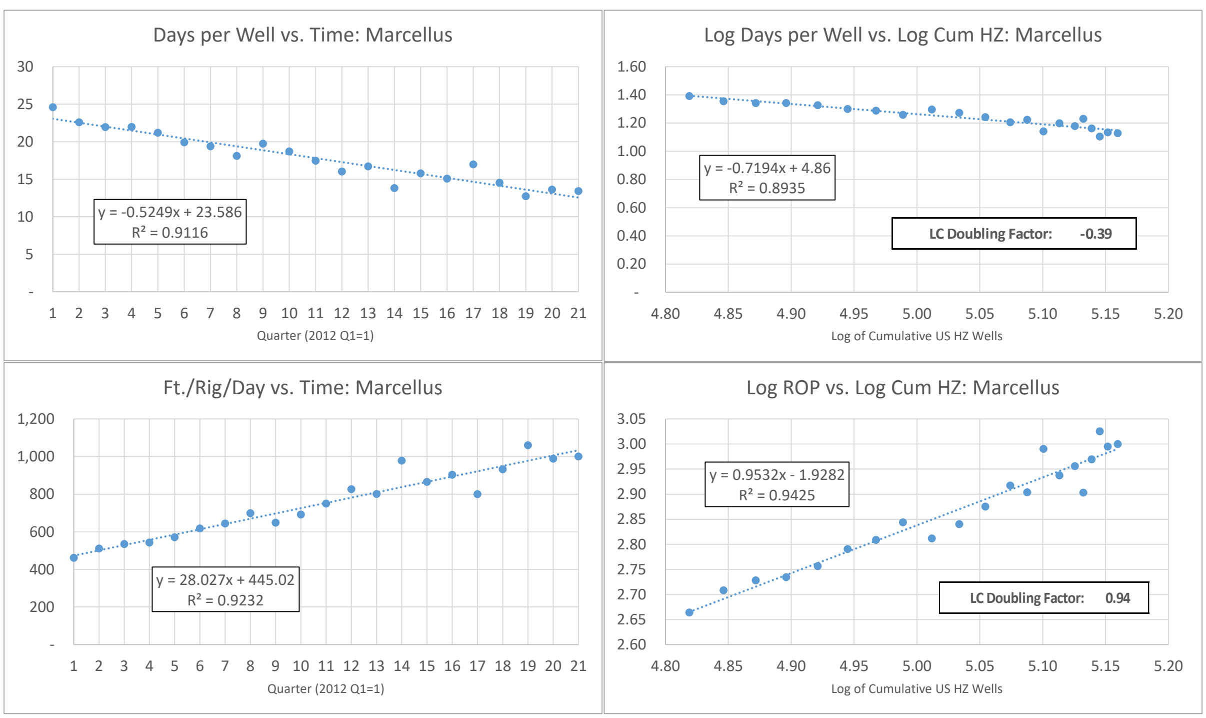
[9] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

Technology Advances in Rig Efficiency

ICF expects that drilling costs (as measured in real dollars per foot of measured well depth) will continue to be reduced largely due to increased efficiency and the higher rate of penetration (feet drilled per rig per day). ICF's modeling of drilling activity and costs takes into account how changes in oil and gas prices and activity levels can influence the unit cost of drilling, stimulation (hydraulic fracturing) services and other equipment and oil field services used to develop oil and gas. Thus, higher oil and gas prices translate into higher factor costs, which partially dampens the ability of higher commodity prices to lead to increase drilling activity and more production.

As illustrated in the upper-left-hand chart in Exhibit 3-5, the number of rig days required to drill a well has fallen steadily in many plays. This chart shows that Marcellus gas shale wells drilled in early 2012 required 24.6 rig days but that by early 2017 that had fallen to 13.4 days. Because lateral lengths increased over this time, total footage per well was going up (from 11,300 to 13,400 feet for Marcellus wells) over this period. As shown in the lower-left-hand chart in Exhibit 3-5 this meant that footage drilled per rig per day (RoP) was going up quickly. For the Marcellus play RoP went from 461 feet in per day early 2012 to 1,000 feet per day in early 2017. Rig day rates and other service industry costs have declined since 2013 due to reduced drilling activity brought on by lower oil and gas prices and lack of demand for rigs. Improved technology and efficiency in combination with lower rig rates and other service costs have allowed industry to develop economic resources despite low oil and gas prices.

Exhibit 3-5: Recent Trends in Rig-Days Required to Drill a Well: Marcellus Shale (first quarter 2012 to first quarter 2017)



To estimate the contributions of changing technologies ICF employs the “learning curve” concept used in several industries. The “learning curve” describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

The two right-hand charts in Exhibit 3-5 show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[10] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What these mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

The rig efficiency learning curve factors shown for the Marcellus are some of the largest among North American gas shale and tight oil plays. The average learning curve doubling factor for rig efficiency among all horizontal multi-stage hydraulically fractured plays is -0.13 when measured as rig days per well and 0.44 when measured as RoP.

Technology Advances in EUR per Well or EUR per 1,000 feet of Lateral

ICF also used the learning curve concept to analyze trends in estimated ultimate recovery (EUR) per well over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. The most technologically immature resources, wherein technological advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells. As with the rig efficiency calculations shown above, when looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of increasing lateral length. This statistical analysis is done using a “stacked regression” wherein each geographic part of the play is treated separately to determine the regression intercepts but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

Generally speaking, we find that the total technology learning curve shows roughly 30 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well

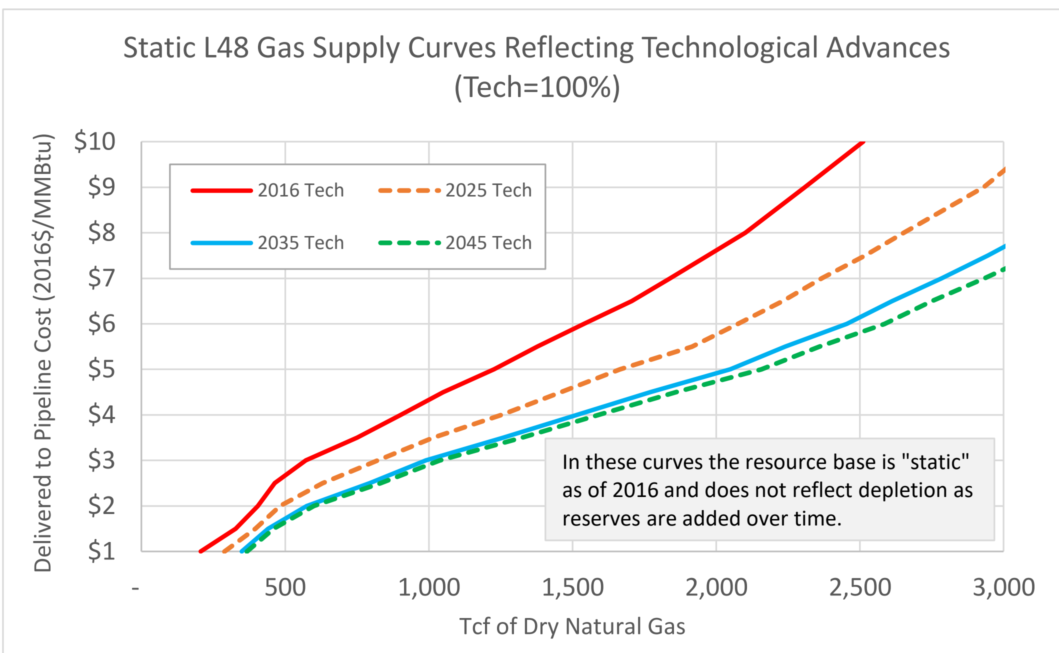
[10] Doubling factor = 2^C-1 where C is the regression slope coefficient.

doubling factor is due to increase lateral lengths and about two-thirds is due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs, and so on.

The Effect of Technology Advances on the Gas Supply Curves

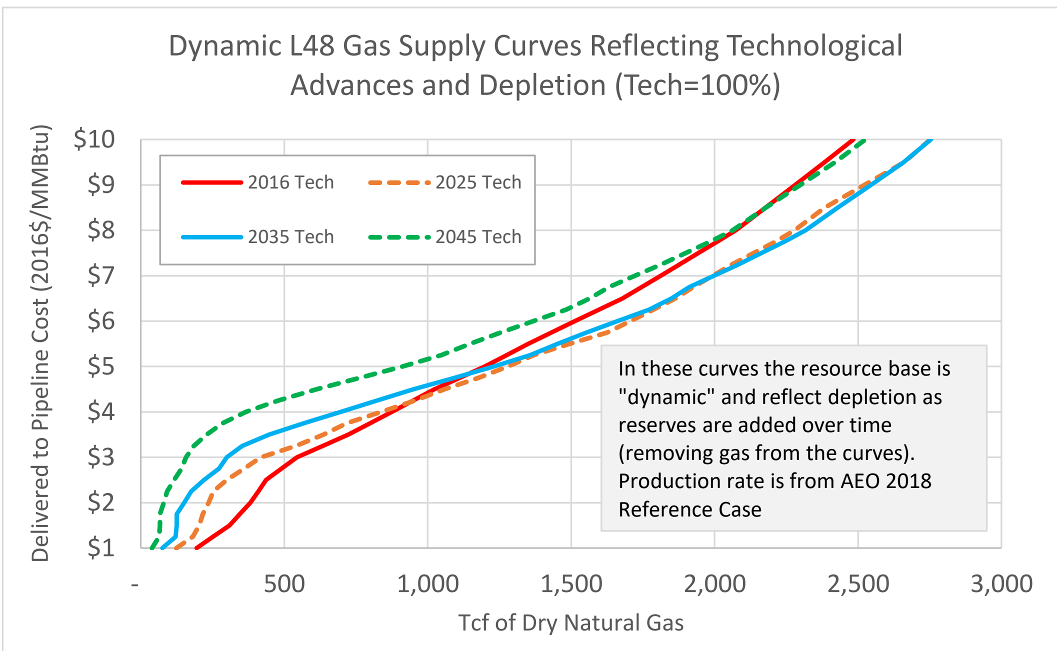
The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve "shifts down and to the right." This effect is illustrated in Exhibit 3-6 which shows the Lower 48 natural gas supply curve for 2016 technology as a red line (a subset of the Lower 48 plus Canada curve shown in Exhibit 3-3). The other lines in the chart represent the same (undepleted) resource that existed as of the beginning of 2016 but as it could be developed under the improved technologies assumed to exist in 2025 (dashed orange line), 2035 (blue line) and 2045 (dashed green line). ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that are economic at $5/MMBtu would increase from 1,225 Tcf to 2,160 Tcf, a 76% increase. The improved technologies include for gas shales and tight oil the EUR and rig efficiency improvements discussed above. Conventional resources and coalbed methane are assumed to be much more mature technologies with little future improvement (on average one-half of percent per year net reduction in cost per unit of production).

Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



The effect of technology advances on gas supply curves are shown in another way in Exhibit 3-7. Here the Lower 48 curves are adjusted over time to show the effects of depletion based on reserve additions that would be expected to occur under the 2018 AEO Reference Case (that is for instance, cumulative reserve additions of 974 Tcf by 2040). In Exhibit 3-7 the dashed orange line, for example, is the supply curve that would exist in the year 2025 assuming that reserve additions consistent with the 2018 AEO Reference Case production forecast were to occur between now and then and that the technology advances assumed by ICF were to take place through 2025. Since technology adds resources faster than production takes place (consistent with the recent assessments made by ICF, Potential Gas Committee (PGC) and EIA), the upper part of the curve moves to the right from 2016 to 2025 and again from 2025 to 2035. However, because the technology advances for unconventional gas resource are represented by learning curves that flatten out over time, the upper part of the curve for 2045 moves to the left relative to the 2035 curve. Another important observation from these curves is that the lower-cost parts of the supply curve deplete more quickly than the high-cost portions as producers concentrate on low-cost (high profit) segments and will not exploit resources that have costs higher than prevailing market prices. Even so, the amount of natural gas available in these curves at $5.00 per MMBtu increases through 2035 and even by 2045 the curve still has approximately 1,000 Tcf at that price.

Exhibit 3-7: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (dynamic curves showing effects of depletion through time)



The development of supply curves and the projection of how those curves will change through time is inherently uncertain given that:

- Our understanding of the geology of the natural gas and tight oil resource base changes as known plays are developed, their geographic boundaries are expanded, and new plays are discovered and enter development,
- The technologies used to develop those resources evolve, thus, improving their performance and changing the unit cost of equipment and services employed in oil and gas development,
- The market for energy evolves, thus, changing the volumes produced and prices of natural gas and competing fossil and renewable resources.

This means that the estimates provided here for the market impacts of any given amount of LNG exports could be proven in time to be overstated or understated. In reviewing the trends of economic impact studies performed over the last serval years with regard to U.S. LNG exports, we see that the more recent studies show lower impacts in terms of cents per MMBtu of natural gas price increases per 1 Bcfd of exports compared to the older studies. (See Appendix B for discussion of LNG economic impact study comparisons and ICF update report to API on the impact of LNG exports on the U.S. economy[11].) This indicates that the forecasts have tended to:

- Understate natural gas supply robustness (that is, upstream technologies have evolved faster than expected and reduced the cost of developing natural gas more than expected) and also
- Understate energy market forces that have reduced the domestic needs for natural gas (e.g., slower overall growth in demand for all energy and higher market penetration of renewables).

If these apparent forecasting biases still exists, then the price impacts for a given volume of LNG exports shown in this and similar economic impact reports will turn out lower.

3.1.3. 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.

[11] American Petroleum Institute. "Impact of LNG Exports on the U.S. Economy: A Brief Update". API, September 2017, Washington, DC. Available at http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Update-Report-20171003.pdf

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.[12]

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. Exhibit 3-8 summarizes 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 current assessment temporal basis is the start of 2016. The current assessment is 3,693 Tcf. Almost 65 percent of the gas resources is from shale gas and tight oil plays. Large portion of the resources is in the Marcellus, Utica, and Haynesville shale gas plays. The largest tight oil gas resource is in the Permian basin. It accounts for almost 30% of the gas resource from tight oil plays.

The latest resource estimate from the Potential Gas Agency at the Colorado School of Mines shows a similar assessment of the U.S. natural gas resource. The most recent estimate published in July 2017 is 3,141 Tcf (including proven reserves) which is 10% greater than its estimate published two years earlier.[13]

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[12] This methodology for estimating growth in old fields was first performed as part of the 2003 NPC study of natural gas and has been updated several times since then. For details of methodology see U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

[13] http://potentialgas.org/press-release

Exhibit 3-8: 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 2016; Excludes Canadian and U.S. Oil Sands)

	Total Gas	Crude and Cond.
Lower 48	Tcf	Bn. Bbls
Proved reserves	320	33
Reserve appreciation and low Btu	161	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	361	71
Shale gas and condensate	2,133	86
Tight oil	252	78
Tight gas	401	7
Coalbed methane	65	0
Lower 48 Total	**3,693**	**334**
Canada		
Proved reserves	71	5
Reserve appreciation and low Btu	23	3
Stranded frontier	40	0
Enhanced oil recovery	0	3
New fields	205	12
Shale gas and condensate	618	14
Tight oil	26	10
Tight gas (with conventional)	0	0
Coalbed methane	75	0
Canada Total	**1,058**	**46**
Lower-48 and Canada Total	**5,751**	**380**

Sources: ICF, EIA (proved reserves)

The U.S. natural gas resource base used in EIA 2018 AEO Reference Case was 2,462 Tcf (including proven reserves) defined as of early 2016.[14] Accounting for production in the intermediate years, this is a 250 Tcf increase from the early-2011 resource base used in the 2013 AEO. On an annual basis, this means the resource assessments used in the AEOs have grown by about 50 Tcf per year. This is slower than the 62 Tcf and 174 Tcf per year growths in the ICF and PGC assessments, but still greater than the rate of natural gas production meaning that even under the more conservative EIA assessments the remaining resources (net of depletion) are growing – not declining.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

3.1.4. Resource Base Estimate Comparisons

The ICF gas resource base is significantly higher than most published assessments. As noted above, the ICF Lower-48 gas assessment of 3,693 Tcf is greater than the EIA's 2,462 Tcf or the PGC's 3,141 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 are 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 are added to the upper end of the natural gas supply curves. Such resources may eventually be 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 2045.

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.

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 gas reservoirs with a net thickness of less than 50 feet.

ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas 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. EIA is using a modified version of the USGS Marcellus that is still low compared to ICF evaluation. The relatively high ICF Barnett Shale assessment is the result of our including a 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.

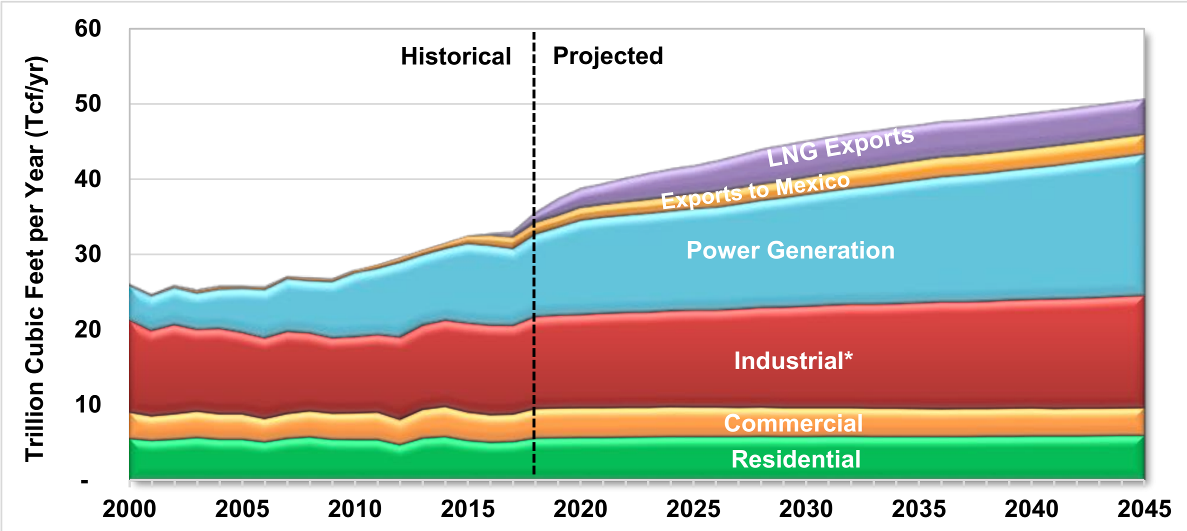
The ICF assessment of tight oil associated gas is much higher than that of other assessments. The difference reflects our inclusion of more plays and entire play areas. It also reflects our methodology, which generally assesses recoverable resources through determination of resource in-place, with an assumed recovery factor that is calibrated to existing well recoveries. Our assessment of several plays in Oklahoma is also based upon a new data-intensive method using GIS and well level recovery estimates, and that method typically results in higher assessments.

3.2. U.S. and Canadian Natural Gas Demand Trends

While new LNG export facilities in the U.S. started production in 2017, power generation will see the bulk of incremental natural gas consumption growth over the near future, along with some growth in the industrial sector, led by gas-intensive end uses such as petrochemicals, fertilizers, and transportation (compressed natural gas and LNG used in vehicles and off-road equipment). Exhibit 3-9 shows ICF's U.S. and Canadian consumption forecast by sector. Under the ICF Base Case, which assumes no exports from the ECA Project, U.S. and Canadian natural gas consumption in 2045 is expected to be over 50 Tcf (LNG and pipeline exports included). This Base Case projection assumes U.S. LNG exports in a total amount of 12.7 Bcf/d by 2045.

Incremental power sector gas use between 2017 and 2045 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. A number of factors drives growth in gas demand for power generation. Currently, about 600 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada. 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 2.1 percent annually from 2019 onward. Electricity load growth is expected to average only about 0.75 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 4,600 Terawatt-hours (TWh) per year by 2045, or growth nearing 23 percent over 2017 levels.

Exhibit 3-9: U.S. and Canadian Gas Consumption by Sector and Exports



Source: ICF GMM® Q1 2018

* 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 EPA's current rules for 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 Cross-State Air Pollution Rule (CSAPR), which was reinstated in January 2015. CSAPR has replaced the CAIR program, imposing regional and state caps on emissions of NO_X and SO_2. 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 over 27 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 demand in 2017 to 37 percent by 2045. 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 18 percent of total gas use growth in U.S. and Canada during the 2017-2045 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.

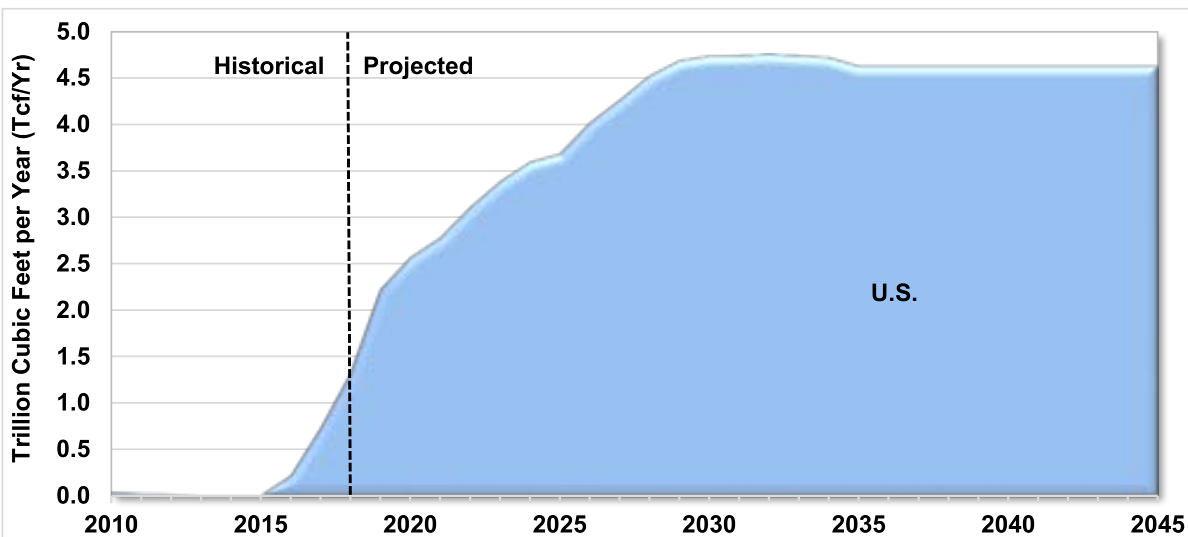
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the 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 2.6 Tcf (7.2 Bcfd) by 2045, up from 1.5 Tcf (4.3 Bcfd) in 2017.

3.2.1. LNG Export Trends

The U.S. Department of Energy (DOE) has received 58 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, 29 applications at 21 sites have received final 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, the Base Case of this study assumes that the U.S. LNG exports reach over 4,500 Bcf per year (over 12 Bcfd) by 2030. Global LNG prices are heavily influenced by oil prices. Given the expectation of low oil price environment in the near-term, U.S. export volumes are projected to be about 7 Bcfd by 2020 and as oil prices increase, the export volume is projected to be over 9 Bcfd by 2025 and over 12 Bcfd by 2030 (see exhibit below).

Exhibit 3-10: U.S. Base Case LNG Export Assumptions



Source: ICF GMM® Q1 2018

3.2.2. Pipeline Exports to Mexico

There is 10.6 Bcf/d of U.S.-Mexico cross-border pipeline capacity currently online. Some of this capacity is designed to serve local markets that lie directly across the border. For example, of the 512 MMcf/d of capacity that El Paso Natural Gas has at the Arizona-Sonora border, only about 200 MMcf/d of that capacity is connected to the PEMEX Sistema Naco Hermosillo, which goes south. The vast majority of the cross-border capacity, though, supplies major interstate pipelines in Mexico. There are also some minor discrepancies between the reported capacity by EIA and other public sources. In the case of the border crossing between San Diego Gas & Electric (SDG&E) and the TGN de Baja California system, the available capacity reported by SDG&E was 115 MMcf/d higher than the EIA.

In 2017, the utilization at the cross-border pipelines was 41%. It appears that the low utilization rates may continue through 2020, as an import pipeline capacity auction held by CFE for the existing pipelines received no bids in August 2017. In November, however, a survey of Mexican natural gas shippers found that there could be as much as 4.62 Bcf/d of mostly new demand for firm transport capacity on the country's main domestic pipeline system, Sistrangas[15]. Based on planned expansions and Presidential Permit applications authorized or pending before the Federal Energy Regulatory Commission, ICF expects there will be 14.9 Bcf/d of cross-border capacity by 2020. ICF's projected pipeline exports to Mexico in that year will be 5.15 Bcf/d. Appendix A of this report provides detailed data and discussion on current U.S.-Mexico cross-border pipeline capacity and flows and expected 2020 capacity.

The same sorts of uncertainties that exist in forecasting the U.S. natural gas market apply for the analysis of Mexican natural gas supply and demand and the utilization of Mexico's cross-border and internal natural gas pipeline capacity. Mexican demand for natural gas will be influenced by many factors including the growth of the overall economy and its energy-intensive sectors, relative energy prices, and government policies encouraging the substitution of natural gas for coal in the power sector. Mexican natural gas supply will be affected by the success of ongoing energy reforms designed to increase private sector upstream investment and by the technical success of applying unconventional oil and gas technologies to Mexico's unconventional resources. Lower future natural gas consumption levels and/or greater production of conventional and unconventional natural gas would reduce the need for natural gas imports into Mexico and would increase the amount of unused cross-border pipeline capacity compared to what is shown here.

3.3. U.S. and Canadian Natural Gas Midstream Infrastructure Trends

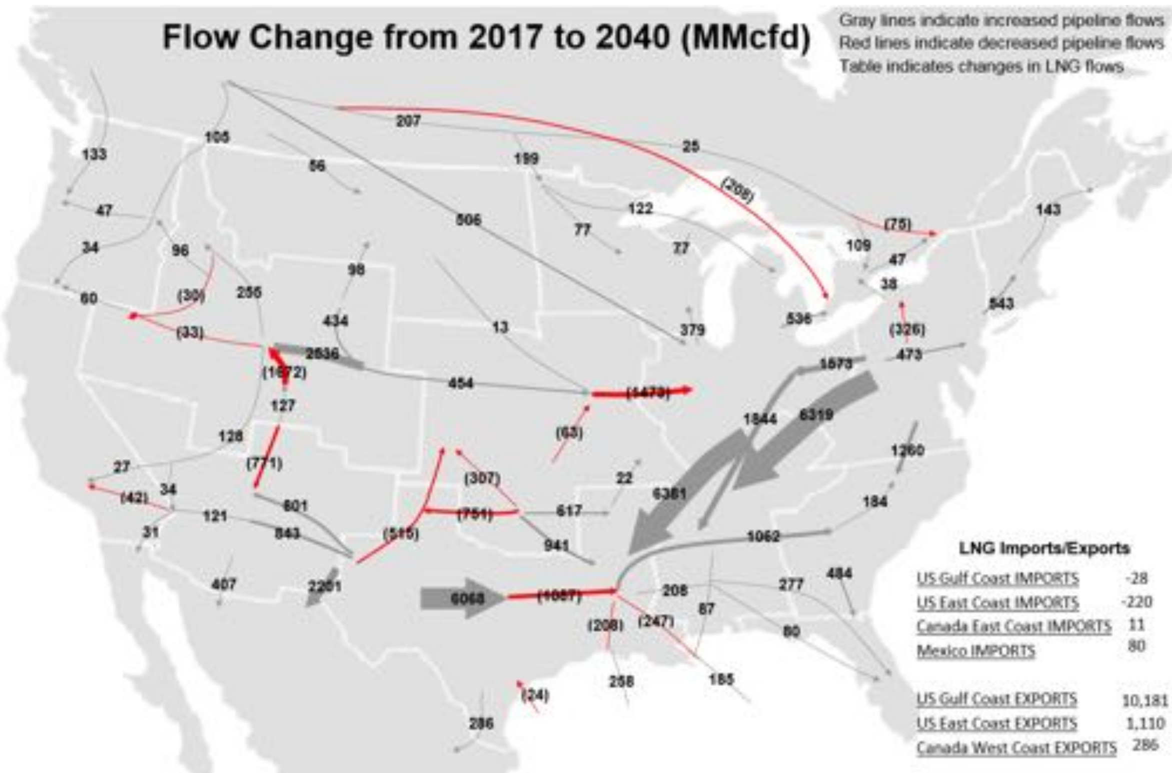
As regional gas supply and demand continue to shift over time, there will likely be significant changes in interregional pipeline flows. Exhibit 3-11 shows the projected changes in interregional pipeline flows from 2017 to 2040 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2017 and 2040, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit 3-11 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

[15] https://www.gob.mx/cms/uploads/attachment/file/268281/Consulta_P_blica_Resultados_v6.pdf

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. The red arrows from the Gulf Coast to the U.S. Northeast point towards a continuing trend of the economic Marcellus and Utica gas supplies displacing the traditional flows from the Gulf Coast towards Northeast.

Exhibit 3-11: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q1 2018

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 South Atlantic Region (Florida to North Carolina) where demand is growing. In addition, natural gas will be exported from the West South Central region via pipeline to Mexico and in the form of LNG exports that started from the Sabine Pass export facility 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.

Eastward flows from western Canada will slightly increase. 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 facilities in British Columbia will also draw off gas supply once exports of LNG begin in 2030. Pipeline flows west out of the Rocky Mountains will increase to California. The completion of the Ruby Pipeline in

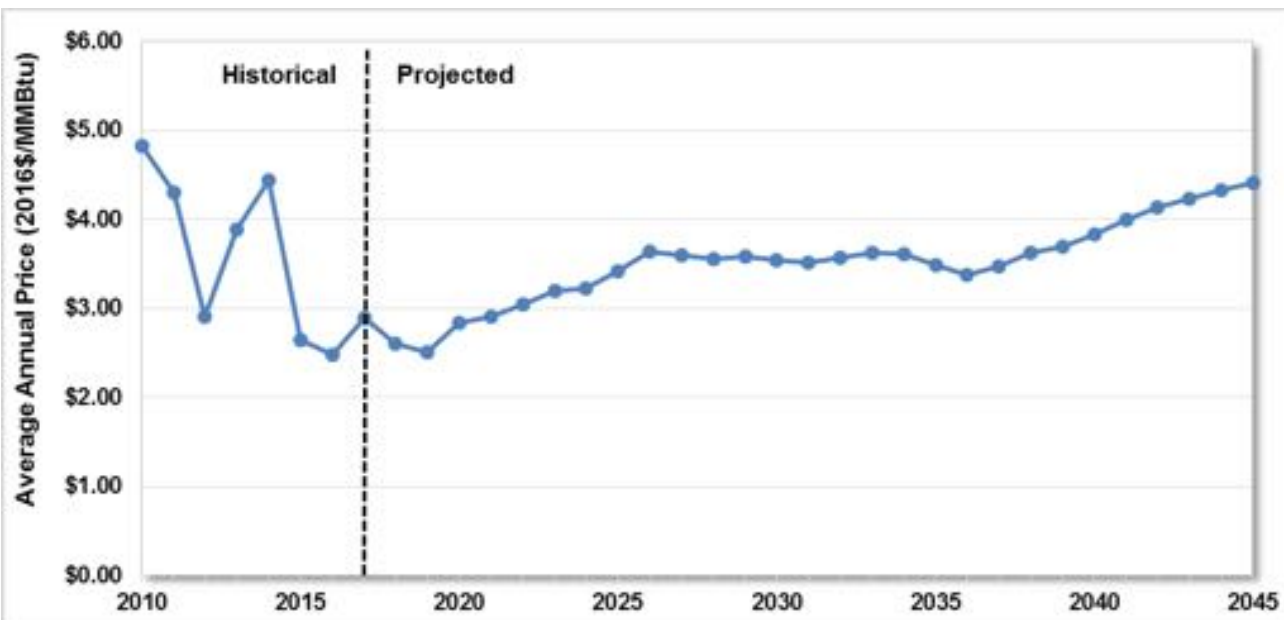
2011 allowed Rocky Mountain gas to displace gas coming from Alberta on Gas Transmission Northwest.

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 than 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 $2.90 per MMBtu in 2017 to $4.41 per MMBtu in 2045 (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. are expected to remain moderate, as shown in Exhibit 3-12.

Exhibit 3-12: GMM Average Annual Prices for Henry Hub

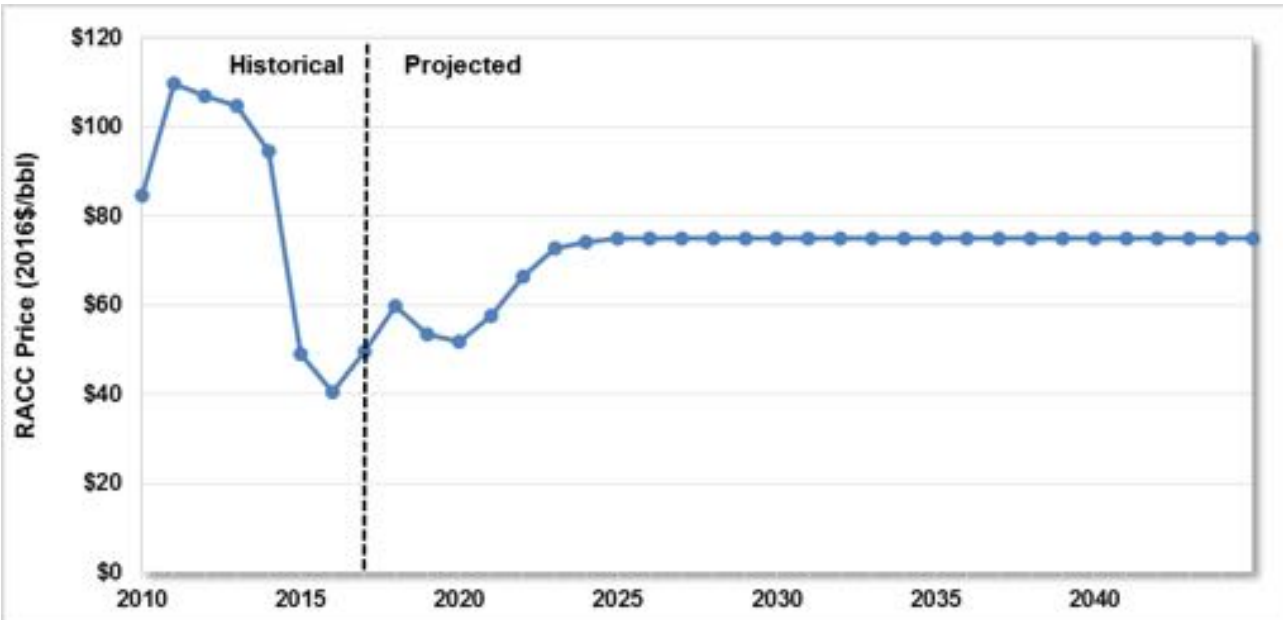


Source: ICF GMM® Q1 2018

3.5. Oil Price Trends

ICF assumes that oil prices will follow a trajectory starting with recent spot prices and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $75/bbl (2016 dollars) after 2025 as shown in the exhibit below.

Exhibit 3-13: ICF Oil Price Assumptions



Source: ICF GMM® Q1 2018

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 American 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 25 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 1992, 1998, 2003 and 2010 National Petroleum Council studies and have been updated periodically by ICF as part of work conducted for several clients.

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 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: ICF and 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, in terms of both 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.[16] Gas resources

[16] 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.

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.	Assessment Well Spacing (acres)
	Shale		
1	Anadarko Woodford	1,780	40
2	Arkoma Caney	5,300	80
3	Arkoma Moorefield	520	80
4	Arkoma Woodford	1,870	40
5	Barnett	26,320	40
6	Bossier	2,840	40
7	Eagle Ford	10,500	60
8	Fayetteville	2,610	60
9	Green River Hilliard	4,350	20
10	Haynesville	7,420	40
11	Lower Huron	19,530	80
12	Marcellus	39,140	40
13	NY Utica	14,290	80
14	OHPAWV Utica	58,970	40
15	Paradox Cane Creek	3,110	40
16	Paradox Gothic	1,350	80
17	Uinta Mancos	7,080	20
18	Vermillion Baxter	180	20
19	West Texas Barnett	4,500	40
20	West Texas Woodford	4,500	40
	L-48 GIS Assessed Shale Total	**216,160**	
21	Cordova Embayment	1,550	80
22	Frederick Brook	130	80
23	Horn River	9,050	80
24	Montney	13,700	80
25	Quebec Utica	2,210	80
	Canada GIS Assessed Shale Total	**26,640**	
	Tight Gas		
26	Granite Wash	3,540	160
27	GRB Dakota	19,680	10
28	GRB Frontier	19,700	10
29	GRB Lance	13,570	10
30	GRB Lewis	6,820	10
31	GRB Lower Mesaverde	12,660	10
32	GRB MV/Almond	11,820	40
33	GRB MV/Ericson	12,680	10
34	Uinta Mesaverde	4,730	20
35	Uinta Wasatch	2,050	20
	L-48 GIS Assessed Tight Gas Total	**107,250**	

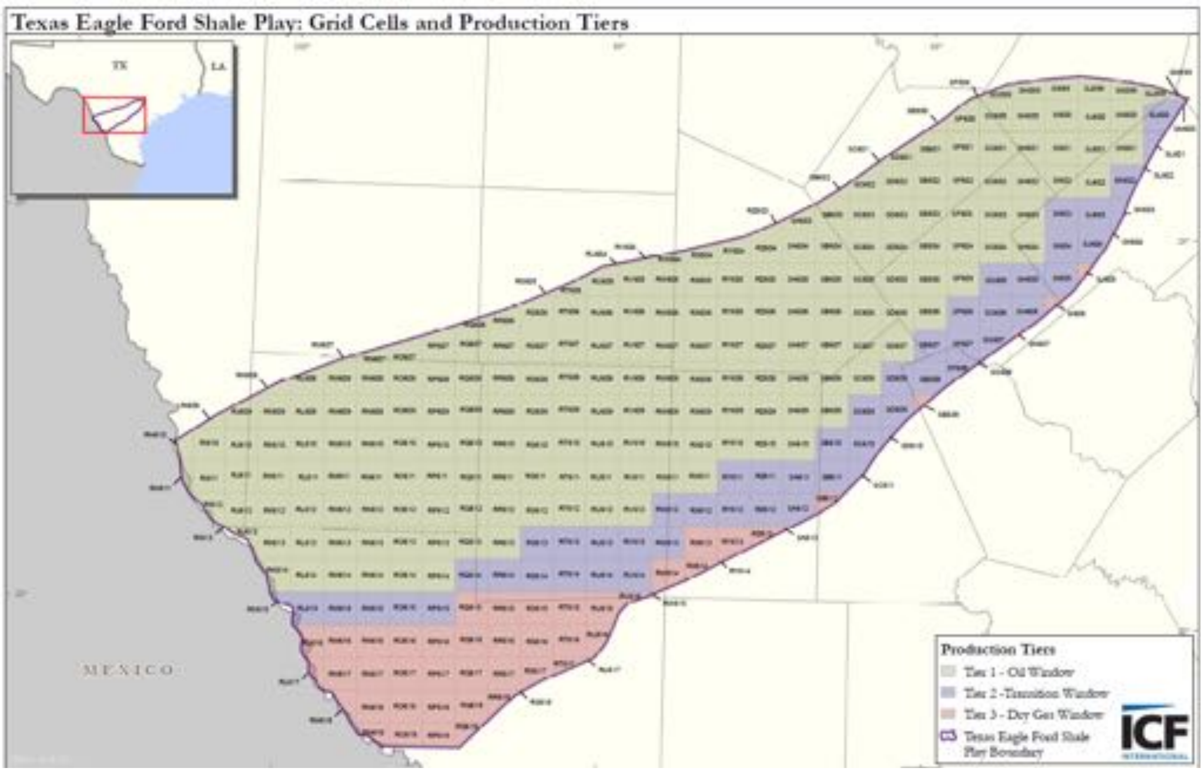
No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Coalbed Methane		
36	San Juan Fruitland	8,800	160
	L-48 GIS Assessed Coalbed Methane Total	**8,800**	
37	Horseshoe Canyon	24,740	80
38	Mannville	46,760	320
	Canada GIS Assessed Coalbed Methane Total	**71,500**	
	Tight Oil		
39	Anadarko Mississippi Lime	4,880	40
40	Anadarko SCOOP	2,420	120
41	Anadarko STACK	1,800	103
42	Denver Basin Niobrara Shale	4,190	120
43	Denver Codell-Sussex	2,250	80
44	Green River Basin Niobrara Shale	2,090	80
45	Gulf Coast Austin Chalk	5,110	120
46	Gulf Coast Eaglebine	3,040	120
47	Permian Delaware Basin Bone Springs	4,820	110
48	Permian Delaware Basin Wolfcamp	5,590	108
49	Permian Midland Basin Cline	1,750	193
50	Permian Midland Basin Spraberry	6,260	108
51	Permian Midland Basin Wolfcamp	1,050	108
52	Piceance Basin Niobrara Shale	3,530	80
53	Powder River Basin Niobrara Shale	6,300	80
54	Powder River Basin Other	3,420	120
55	San Joaquin Basin Kreyenhagen Shale	1,850	80
56	San Joaquin Basin Monterey Shale	1,530	80
57	Tuscaloosa Marine Shale	680	120
58	Williston Basin Bakken Shale	14,040	255
	L-48 GIS Assessed Tight Oil Total	**76,600**	
59	WCSB Bakken Shale	1,950	80
60	WCSB Cardium Tight Oil	11,020	72
61	WCSB Duvernay Core Cells Data	2,430	80
62	WCSB Montney Oil	2,800	72
63	WCSB Viking Tight Oil	8,720	40
	L-48 GIS Assessed Tight Oil Total	**26,920**	

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.

Exhibit 4-3: Eagle Ford Play Six-Mile Grids and Production Tiers (Oil, Wet Gas, and 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 2015 was 4.6 million barrels per day (MMbpd) in the U.S., up from almost zero in 2007, and 384,000 bpd in Canada.   U.S. tight oil production is dominated by the Bakken, Eagle Ford, several plays in the Permian Basin, and increasingly, the Anadarko Basin, including the SCOOP and STACK plays. 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.

4.2. Energy and Economic Impacts Methodology

Costa Azul tasked ICF with assessing the economic and employment impacts of LNG exports from its Combined Costa Azul LNG export facility. This study analyzed two cases[17]:

1) **Base Case** with the assumption of no Combined Costa Azul LNG export volumes.
2) **Combined Costa Azul LNG Case** with the assumption of 636 Bcf per year, or 1.74 Bcfd (1.99 Bcfd exported to Mexico) higher than the Base Case due to the new construction at Costa Azul.

The results in this report show the changes between the Base Case and alternative case resulting from the incremental LNG export volumes. The methodology consisted of the following steps:

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 Southwest state level.

Step 2 – LNG plant capital and operating expenditures: Based on Combined Costa Azul LNG export facility's cost estimates, ICF determined the annual capital and operating expenditures that will be purchased in the U.S. 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 4 – 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 the Southwest. 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

[17] These volumes do not include liquefaction fuel use or lease and plant and pipeline fuel use.

$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 5 – Economic impacts: ICF assessed the impact of LNG exports for the national and the Southwest. This included direct, indirect, and induced impacts on gross domestic product, employment, taxes, and other measures.

Exhibit 4-4: Economic 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.

Key model assumptions are based on ICF analysis of the industry and previous work, and include:

- Combined Costa Azul LNG export volumes
- LNG plant capital and operating expenditures
- Per-well upstream capital costs
- Fixed and variable upstream operating costs per well
- Tax rates

The following set of exhibits show the key model assumptions.

Exhibit 4-5: Combined Costa Azul LNG Export Volume Assumptions and LNG Plant Capital and Operating Expenditures in the U.S.

Year	The Combined Costa Azul LNG Case Changes		
	LNG Export Volume Assumptions (Bcfd)	LNG Capital Costs (2016$ MM)	LNG Operating Costs (2016$ MM)
2020	-	-	-
2021	-	$554.6	-
2022	-	$832.6	-
2023	-	$830.3	-
2024	-	$669.3	-
2025	0.17	$563.7	-
2026	1.20	$443.4	$24.4
2027	1.74	-	$24.4
2028	1.74	-	$24.4
2029	1.74	-	$24.4
2030	1.74	-	$24.4
2031	1.74	-	$24.4
2032	1.74	-	$24.4
2033	1.74	-	$24.4
2034	1.74	-	$24.4
2035	1.74	-	$24.4
2036	1.74	-	$24.4
2037	1.74	-	$24.4
2038	1.74	-	$24.4
2039	1.74	-	$24.4
2040	1.74	-	$24.4
2041	1.74	-	$24.4
2042	1.74	-	$24.4

Note: LNG export volumes do not include liquefaction fuel or losses. The 1.99 Bcfd exported to Mexico does include liquefaction and pipeline fuel losses.

Source: Costa Azul, ICF

Exhibit 4-6: 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) (%)	Southwest States and Local Own Taxes as % of State Income (%)
2015	18.3%	14.6%	13.7%
2016	18.1%	14.6%	13.7%
2017	18.9%	14.6%	13.7%
2018	19.4%	14.6%	13.7%
2019	19.5%	14.6%	13.7%
2020	19.8%	14.6%	13.7%
2021	20.0%	14.6%	13.7%
2022	20.1%	14.6%	13.7%
2023	20.2%	14.6%	13.7%
2024	20.3%	14.6%	13.7%
2025	20.4%	14.6%	13.7%
2026	20.5%	14.6%	13.7%
2027	20.6%	14.6%	13.7%
2028	20.7%	14.6%	13.7%
2029	20.8%	14.6%	13.7%
2030	20.9%	14.6%	13.7%
2031	21.0%	14.6%	13.7%
2032	21.1%	14.6%	13.7%
2033	21.2%	14.6%	13.7%
2034	21.3%	14.6%	13.7%
2035	21.4%	14.6%	13.7%
2036	21.5%	14.6%	13.7%
2037	21.6%	14.6%	13.7%
2038	21.7%	14.6%	13.7%
2039	21.8%	14.6%	13.7%
2040	21.9%	14.6%	13.7%
2041	22.0%	14.6%	13.7%
2042	22.1%	14.6%	13.7%
2043	22.2%	14.6%	13.7%
2044	22.3%	14.6%	13.7%
2045	22.4%	14.6%	13.7%

Source: ICF extrapolations from Tax Policy Center historical figures

Exhibit 4-7: Liquids Price Assumptions

Year	RACC Price (2016$/bbl)	Condensate Price (2016$/bbl)	Ethane Price (2016$/bbl)	MB Propane Price (2016$/bbl)	Butane Price (2016$/bbl)	Pentanes Plus (2016$/bbl)
2015	$ 49	$ 49	$ 15	$ 20	$ 33	$ 45
2016	$ 41	$ 41	$ 14	$ 20	$ 27	$ 37
2017	$ 50	$ 50	$ 15	$ 22	$ 34	$ 45
2018	$ 60	$ 60	$ 15	$ 23	$ 41	$ 55
2019	$ 53	$ 53	$ 16	$ 24	$ 36	$ 49
2020	$ 52	$ 52	$ 15	$ 27	$ 35	$ 47
2021	$ 57	$ 57	$ 17	$ 31	$ 39	$ 52
2022	$ 66	$ 66	$ 20	$ 34	$ 45	$ 60
2023	$ 73	$ 73	$ 21	$ 36	$ 49	$ 66
2024	$ 74	$ 74	$ 22	$ 37	$ 50	$ 68
2025	$ 75	$ 75	$ 22	$ 39	$ 51	$ 68
2026	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2027	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2028	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2029	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2030	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2031	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2032	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2033	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2034	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2035	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2036	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2037	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2038	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2039	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2040	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2041	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2042	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2043	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2044	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2045	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68

Source: ICF

Exhibit 4-8: Other Key Model Assumptions

Assumption	U.S.	Southwest States
Upstream Capital Costs ($MM/Well)	$7.7	$7.7
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	17.0%

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, for example, 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 and business owners in direct and indirect industries.

5. Combined Costa Azul LNG Energy Market and Economic Impact Results

This section describes the difference in economic and employment impacts between the Base Case and the Combined Costa Azul LNG Case. Specifically, differentials between the two cases result from an additional 1.74 Bcfd in LNG exports assumed from Costa Azul (assuming total exports to Mexico of 1.99 Bcfd, which includes feedstock gas liquefied and exported from the Combined Costa Azul facility, as well as fuel consumed in Mexico for pipeline transportation and liquefaction).

5.1. Energy Market and Economic Impacts

This section discusses the impacts of LNG exports in the Base Case and the Combined Costa Azul LNG Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade.

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 net natural gas pipeline imports from Canada and Mexico (see Exhibit 5-1). In addition to the incremental LNG export volumes of 1.74 Bcfd (1.99 Bcfd crossing the U.S. and Mexico border), the market also must rebalance for liquefaction and fuel losses, estimated at 8 percent of incremental net gas pipeline import volumes from Canada. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below.

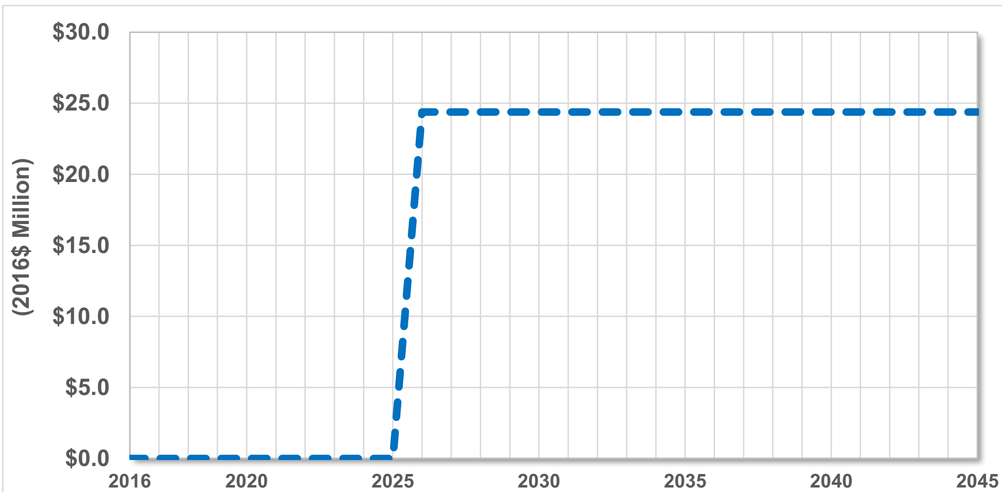
Exhibit 5-1: U.S. Flow Impact Contribution to LNG Exports

2025-2045 Average Supply Sources			
Production Increase	**Demand Decrease**	**Net Gas Pipeline Imports**	**Total Share of LNG Exports**
91% 1.81 Bcfd	11% 0.22 Bcfd	8% 0.16 Bcfd	110% 2.19 Bcfd

Source: ICF

The exhibit below (Exhibit 5-2) shows the impact on LNG export facility operating expenditures (excluding the cost of natural gas feedstock but including employee costs, materials, maintenance, insurance, and property taxes purchased in the U.S.). Over the study period of 2021 to 2045, there is a total cumulative impact on operating expenditures in the U.S. of $488 million (in real 2016$) for the Combined Costa Azul LNG Case. During that period, LNG plant operating expenditures in the U.S. average $24.4 million annually.

Exhibit 5-2: U.S. LNG Export Facility Operating Expenditure Changes

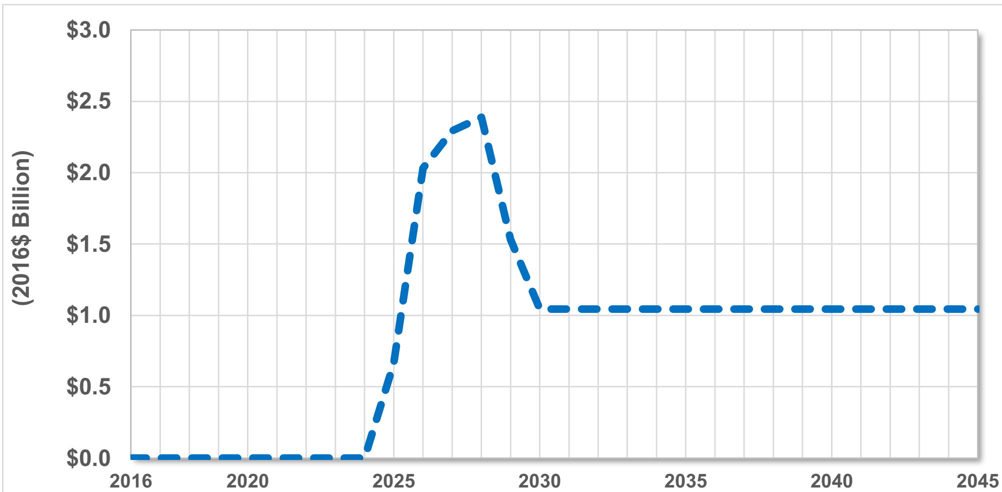


Year	LNG Facility Operating Expenditures (2016$ Million)	
2021	$	-
2023	$	-
2025	$	-
2030	$	24.4
2035	$	24.4
2040	$	24.4
2045	$	24.4
2021-2045 Avg	**$**	**24.4**
2021-2045 Sum	**$**	**487.6**

Source: ICF

The exhibit below (Exhibit 5-3) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. Investment peaks in the early years as more new wells are drilled 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 2021 to 2045, the cumulative impact on U.S. upstream capital expenditures totals near $25.6 billion in the Combined Costa Azul LNG Case as compared to the Base Case. U.S. upstream capital expenditures average $1.2 billion higher annually in the Combined Costa Azul LNG Case than in the Base Case.

Exhibit 5-3: U.S. Upstream Capital Expenditure Changes

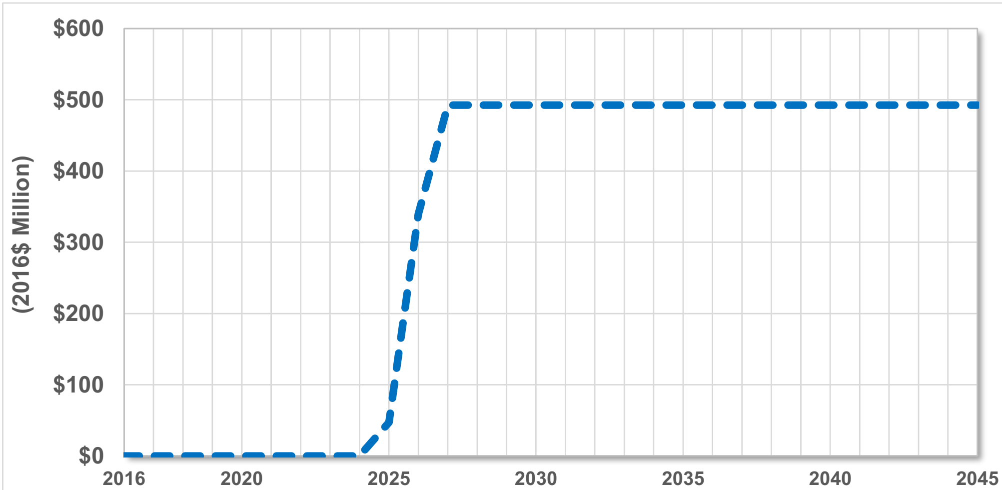


Year	Upstream Capital Expenditures (2016$ Billion)
2021	$ -
2023	$ -
2025	$ 0.66
2030	$ 1.04
2035	$ 1.04
2040	$ 1.04
2045	$ 1.04
2021-2045 Avg	**$ 1.22**
2021-2045 Sum	**$ 25.62**

Source: ICF

As shown below (Exhibit 5-4), U.S. upstream operating expenditures increase $9.7 billion on a cumulative basis, or on average $464 million annually in the Combined Costa Azul LNG Case as compared to the Base Case between 2021 and 2045.

Exhibit 5-4: U.S. Upstream Operating Expenditure Changes



Year	Upstream Operating Expenditures (2016$ Million)
2021	$ -
2023	$ -
2025	$ 47
2030	$ 493
2035	$ 493
2040	$ 493
2045	$ 493
2021-2045 Avg	**$ 464**
2021-2045 Sum	**$ 9,746**

Source: ICF

The table below (Exhibit 5-5) shows the Base Case and the Combined Costa Azul LNG Case U.S. natural gas consumption. The additional LNG export volumes of 1.74 Bcfd (that is, 1.99 Bcfd additional export volumes to Mexico) are expected to result in only a small reduction in U.S. natural gas consumption of 0.22 Bcfd in 2045, mostly from power sector gas use decline.

Exhibit 5-5: U.S. Domestic Natural Gas Consumption

Year	U.S. Domestic Natural Gas Consumption (Bcfd)		
	Base Case	Combined Costa Azul LNG Case	Combined Costa Azul LNG Case Change
2021	76.6	76.6	-
2023	77.7	77.7	-
2025	78.5	78.5	(0.02)
2030	82.4	82.2	(0.22)
2035	86.8	86.6	(0.22)
2040	90.3	90.1	(0.22)
2045	93.6	93.4	(0.22)
2021-2045 Avg	**85.0**	**84.8**	**(0.21)**
2021-2045 Sum	**2,124.5**	**2,120.1**	**(4.34)**

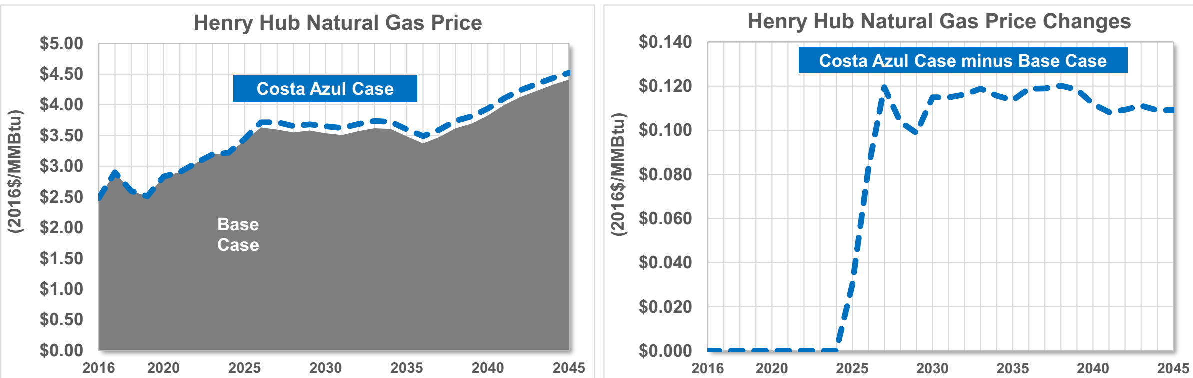
* Industrial demand does not includes pipeline fuel and lease & plant

Note: Charts above do not include LNG exports or liquefaction fuel.

Source: ICF

The Henry Hub natural gas price in the Combined Costa Azul LNG Case, averaging $3.83/MMBtu from 2025 to 2045, is expected to be on average $0.11/MMBtu higher compared to the Base Case (averaging $3.72/MMBtu), as shown in Exhibit 5-6. The natural gas prices at Henry Hub are expected to reach $4.41/MMBtu in the Base Case and $4.52 in the Combined Costa Azul LNG Case by 2045, indicating a natural gas price increase of $0.11/MMBtu attributable to the Combined Costa Azul LNG export volumes of 1.74 Bcfd.

Exhibit 5-6: Annual Average Henry Hub Natural Gas Price Changes

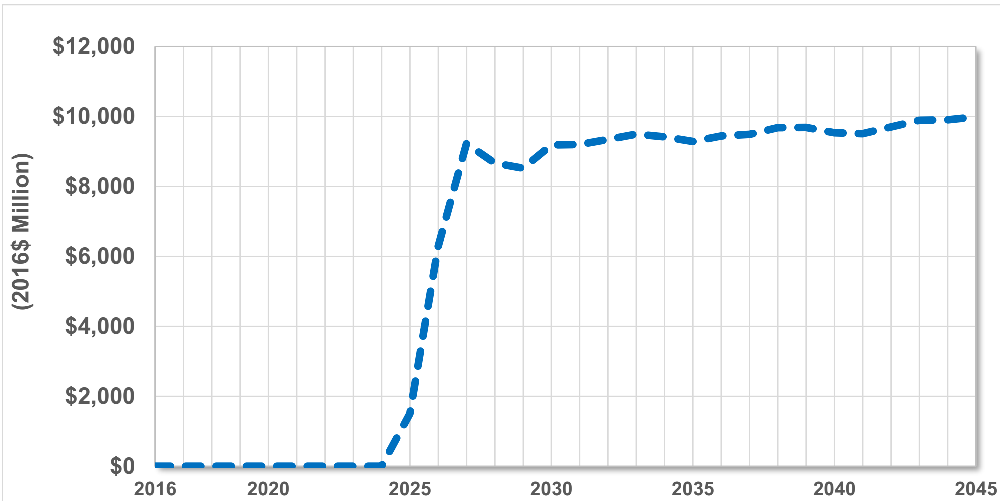


Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Combined Costa Azul LNG Case	Combined Costa Azul LNG Case Change
2021	$ 2.90	$ 2.90	$ -
2023	$ 3.19	$ 3.19	$ -
2025	$ 3.41	$ 3.44	$ 0.030
2030	$ 3.54	$ 3.65	$ 0.115
2035	$ 3.48	$ 3.60	$ 0.114
2040	$ 3.83	$ 3.94	$ 0.112
2045	$ 4.41	$ 4.52	$ 0.109
2021-2045 Avg	**$ 3.62**	**$ 3.71**	**$ 0.091**
2025-2045 Avg	**$ 3.72**	**$ 3.83**	**$ 0.108**

Source: ICF

U.S. natural gas and liquids production increases as a result of additional LNG export volumes and higher prices as seen in the Combined Costa Azul LNG Case (see Exhibit 5-7). Over the forecast period 2021 to 2045, the cumulative impact on natural gas and liquids production value in the Combined Costa Azul LNG Case is approximately $187 billion. This represents an average increase of $8.9 billion per year in the Combined Costa Azul LNG Case as compared to the Base Case between 2021 and 2045.

Exhibit 5-7: U.S. Natural Gas and Liquids Production Value Changes



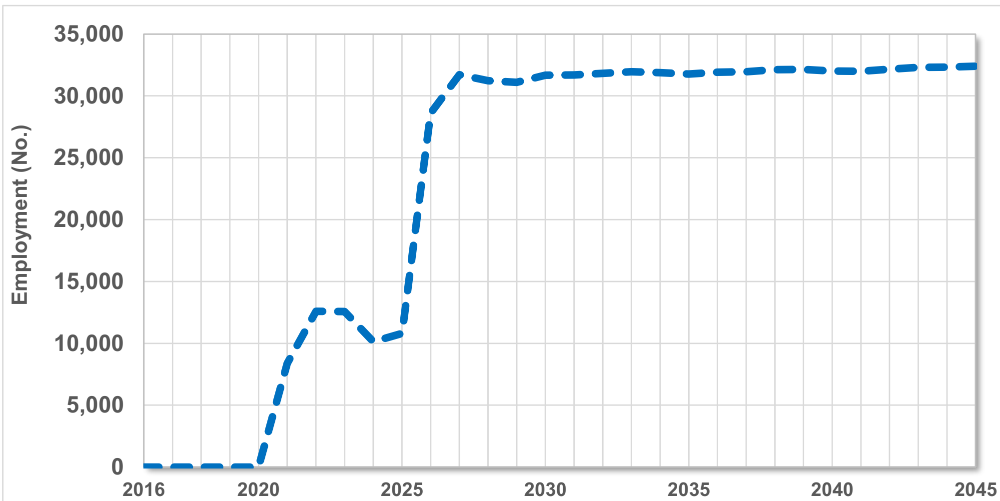
Year	Natural Gas and Liquids Production Value (2016$ Million)
2021	$ -
2023	$ -
2025	$ 1,499
2030	$ 9,187
2035	$ 9,285
2040	$ 9,535
2045	$ 9,987
2021-2045 Avg	**$ 8,903**
2021-2045 Sum	**$ 186,955**

Note: Liquids includes natural gas liquids (NGLs), oil, and condensate.

Source: ICF

Exhibit 5-8 shows the impacts of additional LNG export volumes on total U.S. employment.[18] 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 incremental employment from direct and indirect impact leads to increased spending in the economy, creating induced impacts throughout the economy.

Exhibit 5-8: Total U.S. Total Employment Changes



Year	Employment (No.)
2021	8,389
2023	12,559
2025	10,806
2030	31,671
2035	31,771
2040	32,001
2045	32,402
2021-2045 Avg	**27,566**
2021-2045 Sum	**689,142**

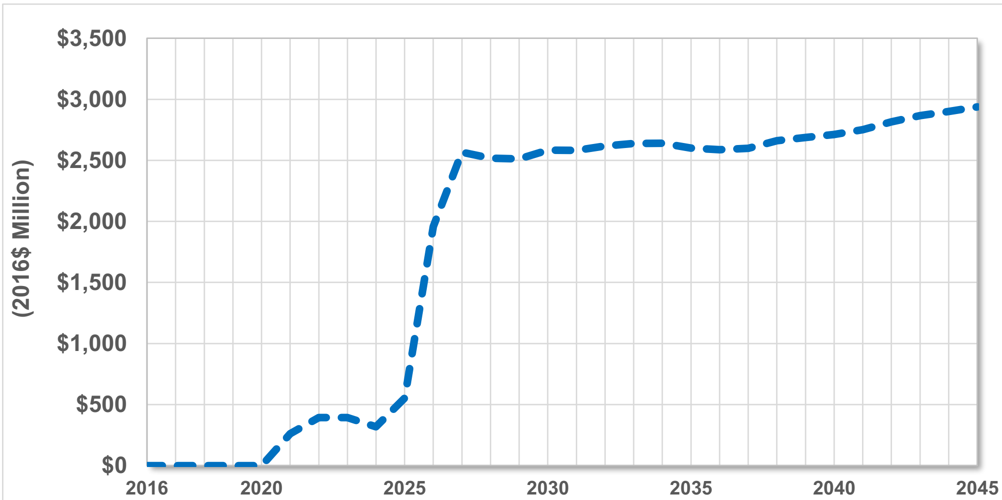
Source: ICF

The construction and operation of the Combined Costa Azul LNG export facility will likely increase employment through direct, indirect and induced employment that totals about 27,600 of incremental jobs on average between 2021 and 2045. Over the forecast period the added LNG export facilities are expected to increase job-years relative to the Base Case by 689,000 cumulative job-years.

[18] Note that one job in this report refers to a job-year.

Exhibit 5-9 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective incremental government revenues average $2.2 billion annually as a result of the Combined Costa Azul LNG export facility. This translates to a cumulative impact of $54.7 billion over the forecast period between 2021 and 2045.

Exhibit 5-9: U.S. Federal, State, and Local Government Revenue Changes



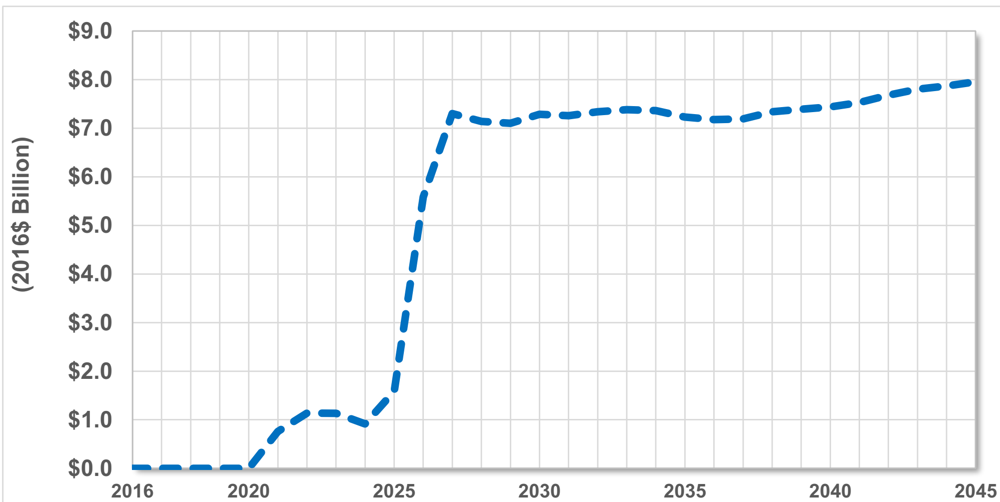
Year	Government Revenues (2016$ Million)
2021	$ 261
2023	$ 394
2025	$ 554
2030	$ 2,584
2035	$ 2,600
2040	$ 2,711
2045	$ 2,939
2021-2045 Avg	**$ 2,186**
2021-2045 Sum	**$ 54,652**

Source: ICF

Exhibit 5-10 shows the impacts of additional LNG exports 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 is substantially higher as a result of the the construction and the additional LNG export volumes assumed in the Combined Costa Azul LNG Case. This activity results in a $6.1 billion annual incremental value added between 2021 and 2045. The cumulative value added over the period between the Base Case and the Combined Costa Azul LNG Case totals $152 billion.

Exhibit 5-10: Total U.S. Value Added Changes

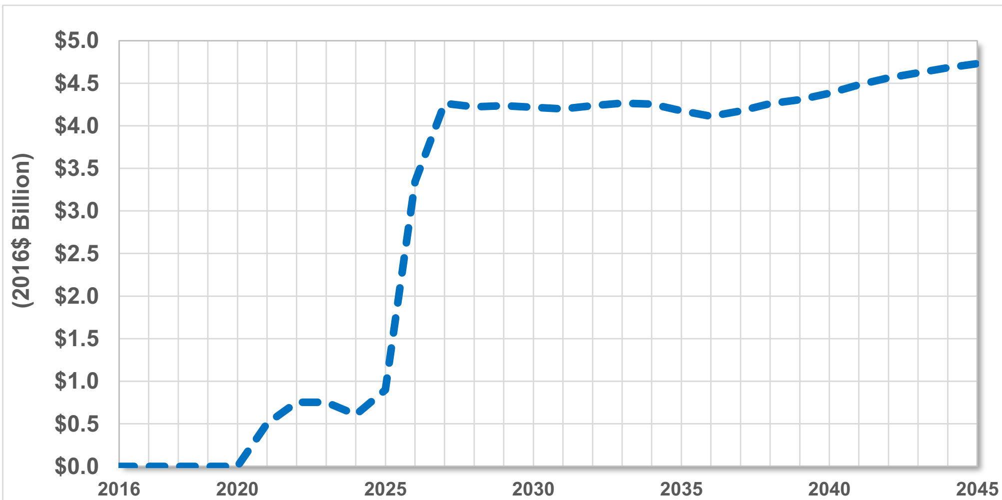


Year	Total Value Added (2016$ Billion)	
2021	$	0.8
2023	$	1.1
2025	$	1.6
2030	$	7.3
2035	$	7.2
2040	$	7.4
2045	$	8.0
2021-2045 Avg	**$**	**6.1**
2021-2045 Sum	**$**	**151.9**

Source: ICF

Exhibit 5-11 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $3.6 billion annually between 2021 and 2045, based on the value of LNG export volumes and incremental associated liquids production, or a cumulative value of $89.2 billion. The improved balance of trade effects begin approximately in 2025 when the plant starts operating and are primarily a result of the LNG exports themselves (encompassing the natural gas feedstock used to make the LNG and the LNG liquefaction process) and the additional hydrocarbon liquids production which is assumed to either substitute for imported liquids or be exported.

Exhibit 5-11: U.S. Balance of Trade Changes



Year	Balance of Trade (2016$ Billion)	
2021	$	0.5
2023	$	0.8
2025	$	0.9
2030	$	4.2
2035	$	4.2
2040	$	4.4
2045	$	4.7
2021-2045 Avg	**$**	**3.6**
2021-2045 Sum	**$**	**89.2**

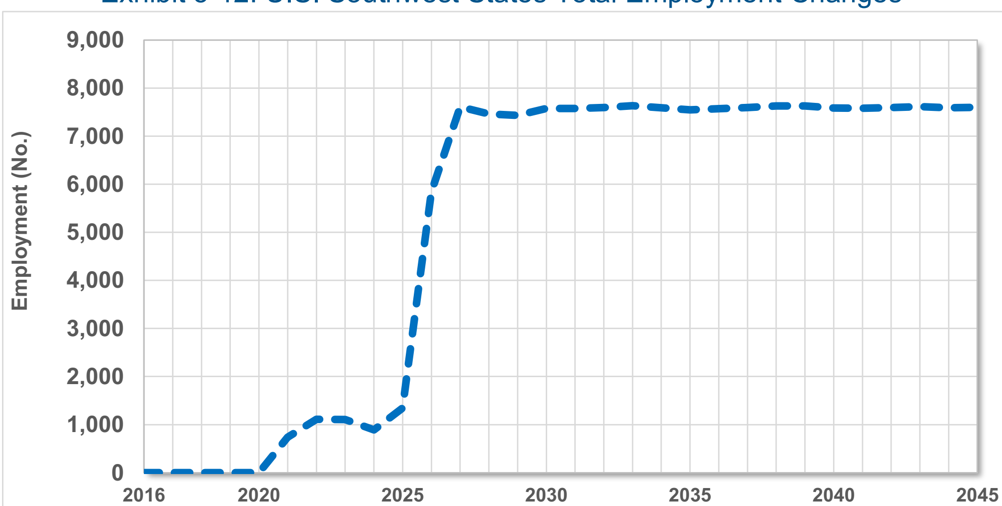
Source: ICF

5.2. U.S. Southwest States Impacts

The exhibits below describe the energy market and economic impacts of the LNG export cases in the five Southwest states that include California, Nevada, Arizona, New Mexico, and Texas.

Exhibit 5-12 shows the impacts of LNG export volumes in the U.S. Southwest total employment, 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 LNG export facility and to the added natural gas production that will take place in the five states and in other states to which companies in the Southwest states offer support services. The Combined Costa Azul LNG Case exhibits an increase of 6,200 jobs on an average annual basis from 2021 to 2045 as compared to the Base Case. This equates to a cumulative impact of 155,000 job-years in the Southwest over the 25-year forecast period through 2045.

Exhibit 5-12: U.S. Southwest States Total Employment Changes

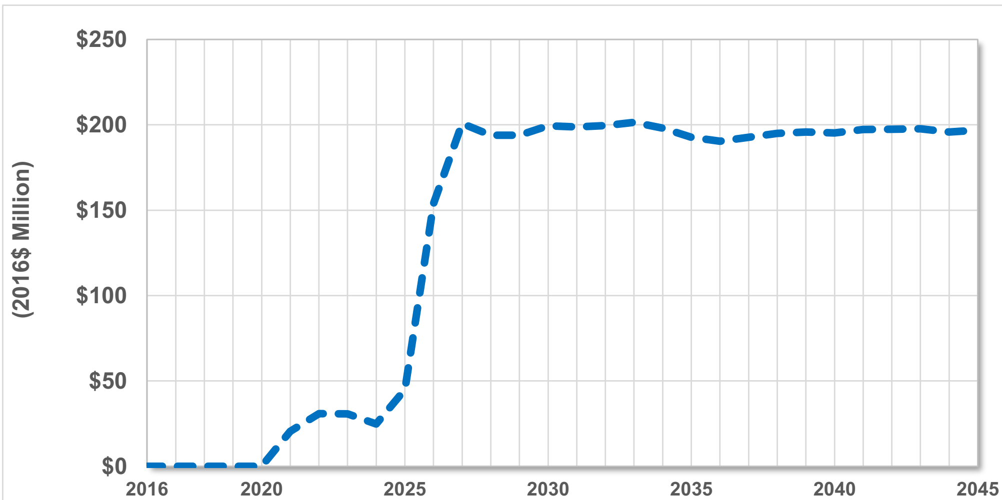


Year	Employment (No.)
2021	739
2023	1,107
2025	1,343
2030	7,577
2035	7,548
2040	7,586
2045	7,603
2021-2045 Avg	**6,202**
2021-2045 Sum	**155,056**

Source: ICF

Exhibit 5-13 shows the impacts of LNG export volumes on Southwest states and local government revenues. Total Southwest government revenues include all fees and taxes (personal income, corporate income, sales, property, oil & gas severance and employment) related to incremental activity in the construction and operation of the liquefaction plant; natural gas transportation; port services; oil & gas exploration, development and production; and induced consumer spending. Relative to the Base Case, the Combined Costa Azul LNG Case results in a $162 million average annual increase to the Southwest local and state government revenues throughout the 25-year forecast period through 2045, or a cumulative impact of $4.0 billion.

Exhibit 5-13: U.S. Southwest States Government Revenue Changes

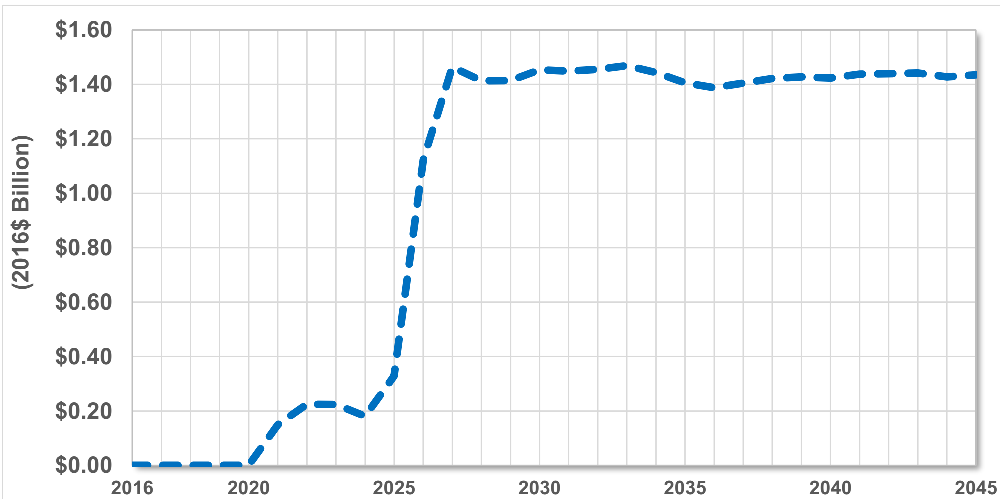


Year	Government Revenues (2016$ Million)	
2021	$	20.5
2023	$	30.7
2025	$	45.0
2030	$	199.4
2035	$	192.8
2040	$	195.2
2045	$	196.8
2021-2045 Avg	**$**	**161.5**
2021-2045 Sum	**$**	**4,038.5**

Source: ICF

Exhibit 5-14 shows the impacts of LNG export volumes on total the U.S. Southwest value added (also called gross state product or GSP). The Southwest value added increases as a result of the additional LNG export volumes assumed in the Combined Costa Azul LNG Case. Throughout the study period 2021 to 2045 the additional LNG volumes in the Combined Costa Azul LNG Case result in a $1.2 billion annual average increase to value added, relative to the Base Case. The total differential of value added to the Southwest states over the study period between the Base Case and the Combined Costa Azul LNG Case is $29.4 billion.

Exhibit 5-14: Total U.S. Southwest States Value Added Changes



Year	Total Value Added (2016$ Billion)	
2021	$	0.15
2023	$	0.22
2025	$	0.33
2030	$	1.45
2035	$	1.41
2040	$	1.42
2045	$	1.43
2021-2045 Avg	**$**	**1.18**
2021-2045 Sum	**$**	**29.44**

Source: ICF

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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/

7. Appendices

7.1. Appendix A: U.S.-Mexico Cross-Border Pipeline Capacity and Flows

Table below shows the natural gas pipeline cross-border capacity in 2017, the cross-border export volumes in 2017 and the expected cross-border capacity in 2020. The “Current Capacity” data provided in the exhibit was verified using multiple sources. The primary source that was used was the U.S. Energy Information Agency (EIA). The EIA provides international export capacity data for each pipeline that exports or imports gas to Mexico and Canada.[19] In addition to using the EIA’s pipeline database, ICF attempted to verify each reported capacity using a second source. The second source was either information from the exporting pipeline’s operator, information from the importing pipeline’s operator, information from documentation from the Federal Energy Regulatory Commission (FERC), or using the historical flow volume data to determine a maximum capacity. In some cases, the capacity quantity provided by the EIA differed from the other sources of information or, for certain pipelines, was missing. In those cases, ICF either used the second source of information or reconciled the two sources.

The “2017 Flows” data provided in the table was determined by calculating the annual average of monthly data from two sources. The primary source of the data were the monthly export volumes provided by the EIA. The EIA aggregates natural gas pipeline exports to Mexico by border crossing town, which meant ICF had to map each pipeline to the each exit point. In some cases, two pipelines’ flow data were combined into the same export point. The secondary source of the data were the monthly pipeline throughput volumes provided by PointLogic.

The “2020 Capacity” was calculated by adding the capacity from the pipeline expansion projects that are currently under construction or that ICF expects will be constructed to the “Current Capacity.” The capacity of the expansion projects was determined by using their applications with FERC, information from the project websites, and PointLogic.

[19] https://www.eia.gov/naturalgas/pipelines/EIA-StatetoStateCapacity.xlsx

U.S. Pipeline Capacity and Flows to Mexico

U.S. Pipeline	Mexico Pipeline	Current Capacity (MMcf/d)	2017 Flows (MMcf/d)[1]	2020 Capacity (MMcf/d)
California				
San Diego Gas & Electric Co	TGN de Baja California	415	2	415
North Baja	Gasoducto Bajanorte / Rosarito	500	296	500
Southern California Gas	DGN Pipeline	70	52	70
Arizona				
Sierrita	Gasoducto Aguaprieta / Sonora	201	98	524
El Paso	PEMEX	512	234	862
West Texas				
OneOK WesTex and Roadrunner	PEMEX / Tarahumara Pipeline	965	114	965
El Paso	PEMEX / Gasoducto de Chihuahua	360	70	360
Comanche Trail	San Isidro-Samalayuca	1,100	48	1,100
El Paso	San Isidro-Samalayuca	550	230	550
Trans-Pecos	Gasoducto Ojinaga	1,356	0	1,356
South Texas				
Tennessee Gas Pipeline	PEMEX / Gasoducto Del Rio	527	217	527
NET Mexico Pipeline	Los Ramones	2,100	1,896	2,100
KM Texas and KM Tejas	PEMEX / KM Gas Natural de Mexico	990	934	990
Nueva Era Pipeline	Nueva Era Pipeline	0	0	1,000
Valley Crossing	Sur de Texas –Tuxpan Pipeline	0	0	2,600
Texas Eastern	PEMEX	350	22	350
West Texas Gas Co	PEMEX	472	1	472
Houston Pipeline Co	PEMEX	140	86	140
Tidelands Oil & Gas Co	PEMEX	26	22	26
Total		**10,634**	**4,322**	**14,907**

Source: EIA

7.2. Appendix B: 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 fewer 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.

The most recent industry wide study[20] assessing the impact of LNG exports on the U.S. economy was commissioned by DOE and released in October 2015. Oxford Economics & Rice University's Center on Energy Studies studied multiple scenarios assuming the global demand for U.S. LNG Exports ranged from 12 to 20 Bcfd, and a range of U.S. resource recovery rates (Reference, High, and, Low). The gas price impacts range from $0.25 to $0.41 per MMBtu on average (in 2010 dollars) from 2026 to 2040. The DOE study assumes a much more conservative gas resource base (about 2,200 Tcf when the study was conducted) than ICF, which may have contributed to this strong price reaction. However, the DOE study finds that the positive impacts to the U.S. economy largely outweigh this increase in consumer gas prices. As a result of increased U.S. LNG exports relative to 12 Bcfd, the study finds that GDP increases by 0.03 to 0.07 percent from 2026 to 2040 or $7-$20 Billion (in 2014 dollars) over the period. The study also found a net positive impact on employment of 0.01 to 0.02 percent on an average annual basis from 2026 to 2040, or between 9,000 and 35,000 annual jobs. The study finds that the negative impact to some industries with high energy inputs are offset by other industries that benefit from the production increase.

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.[21] 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

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[20] DOE. "The Macroeconomic Impact of Increasing U.S. LNG Exports". Oxford Economics & Rice University Center on Energy studies, Oct 29, 2015. Available at http://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[21] 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

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.[22] In the unconstrained LNG export scenario, the study found that the U.S. could 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.

NERA provided an update to its December 2012 study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[23] 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.[24] 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.[25] 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

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[22] 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

[23] 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

[24] 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

[25] 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

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.[26] Examining export cases from 20 Bcfd to 30 Bcfd by 2030, CRA argued that LNG exports could 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 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 on the next page for more details by study.

[26] 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

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Facility / Study	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Combined Costa Azul LNG (ICF)	Combined Costa Azul LNG export of 1.74 Bcfd	1.74 Bcfd LNG Export (1.99 Bcfd Crossing U.S./MX Border)	$0.108	$0.054	91%	11%	8%	110%	1.55	13,837	$220,401	Combined Costa Azul LNG development leads to positive impact on the U.S. economy and employment.
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.

ICF

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES)	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for U.S. Exports, and 4 differing domestic scenarios (reference resource recovery, high resource recovery, low resource recovery, and high domestic demand. Study Period referenced here: 2026 to 2040	20 Bcfd LNG Exports, Reference Resource Recovery	$0.27	$0.063	86.0%	2.3%	16.3%	104.7%	N/A	2,233	$ 802,083	Across the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports.
		20 Bcfd LNG Exports, High Resource Recovery	$0.25	$0.049	100.0%	5.9%	7.8%	113.7%	N/A	2,216	$ 646,018	
		Market Determined (Endogenous) LNG Exports, Reference Resource Recovery	$0.32	$0.059	88.9%	1.9%	13.0%	103.7%	N/A	4,463	$ 692,946	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES) cont'd	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for U.S. Exports, and 4 differing domestic scenarios (reference resource recovery, high resource recovery, low resource recovery, and high domestic demand. Study Period referenced here: 2026 to 2040	Market Determined (Endogenous) LNG Exports, High Resource Recovery	$0.41	$0.048	98.8%	5.9%	8.2%	112.9%	N/A	4,141	$ 582,386	Across the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports.
		Market Determined (Endogenous) LNG Exports, Low Resource Recovery	$0.19	$0.070	92.6%	0.0%	7.4%	100.0%	N/A	6,815	$ 679,348	
		Market Determined (Endogenous) LNG Exports, High Domestic Demand	$0.29	$0.067	93.0%	4.7%	9.3%	107.0%	N/A	4,465	$ 750,000	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
API (ICF, 2012)	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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
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 export facility. 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	$0.20			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$0.23			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 Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline 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.

APPENDIX C

Permitting Overview for Pipeline and Liquefaction Projects in Mexico

Permitting Overview for
Pipeline and Liquefaction Projects in Mexico

	Name	Position	Date	Signature
Reviewed by	Sergio Romero	Director, Regulation and Industry Affairs (IENOVA)	Sept 13, 2018	
Prepared by	Santiago Aranda	Manager Social and Environmental Regulation (IENOVA)	Sept 13 2018	
	Alvaro Pinto	Coordinator Social and Environmental Regulation (IENOVA)	Sept 13 2018	

1. Purpose

This document provides a general overview of the permitting process in Mexico, as well as an outline of the required environmental and social permits for projects related to the hydrocarbon sector, specifically those regarding the construction and operation of natural gas pipelines and liquefaction facilities.

2. Document overview

This document outlines and describes all required regulatory permits, their scopes and mechanics, and their potential statutory processing times, in order to achieve a successful development of natural gas pipelines and liquefaction projects (section 3). The document also summarizes the approximate time it takes to prepare applications for necessary permits (Section 4) and describes the elements taken into consideration by Mexican governmental agencies for obtaining said environmental and social permits (section 5). The document concludes with a brief description of IEnova and its extensive experience in permitting energy infrastructure projects in Mexico (Section 6).

3. Mexican agencies involved in authorizations and permits

This section includes a high-level scope of the required permits for hydrocarbon activities, including liquefaction and natural gas pipeline projects, as well as the involved Government agencies and their statutory resolution times.

As discussed above, **Table 1** lists all appropriate agencies, as well as the main necessary permits, which are applicable to the construction and operation of natural gas pipelines and liquefaction projects. It is worth mentioning that all descriptions, requirements and sequencing will vary depending on the overall purpose of each project.

Table 1. Agencies and permits involved in liquefaction and natural gas pipeline projects.

Mexican Agency	Permit	Comments	Statutory Time	Term	Liquefaction	Pipelines
Environmental Permits (find a detailed description in Section 5)						
Agencia de Seguridad, Energía y Ambiente / Environmental and Safety Agency for the Hydrocarbon Industry (**ASEA**)	Environmental Impact Assessment (**MIA**)	❖ Art. 28 of the General Law of Ecological Equilibrium and Environmental Protection (LGEEPA), a MIA authorized by ASEA is needed in order to develop construction and or operating activities.	120 - 180 business days	Regularly these permits' validity last for the entire lifespan of the project. Any modification to such parameters, would require amendments to this authorization, and in some cases, a new MIA could be required.	●	●
	Environmental Risk Assessment (**ERA**)	❖ An ERA must be included in the MIA, based on the fact that these activities usually involve hazardous processes that could compromise industrial and environmental safety.				
	Management System (**SASISOPA**)	❖ Industrial, Operational, and Environmental Safety Management System is required for any project related to the hydrocarbon sector. ❖ Detailed engineering must be included in order for the ASEA to grant this permit. ❖ All activities related to the project must be regulated by the SASISOPA, from construction to decommissioning of the project.	165 business days	Does not have a term. This is *ad hoc* to the construction phase and operation phase of the projects. Related to a construction and operation management system.	●	●
	Change of Land Use (**ETJ**)	❖ A Technical Justification Study, which demonstrates that the ecosystem's biodiversity will not be jeopardized, is required for areas in which natural vegetation will be removed.	90 business days	Granted upon request based on the described time in the file. No legal term established, though it is needed prior to any project activity.	●	●

Mexican Agency	Permit	Comments	Statutory Time	Term	Liquefaction	Pipelines
Other Infrastructure Permits (not related to environment permitting)						
Comisión Reguladora de Energía / Energy Regulatory Commission (**CRE**)	Transportation permit	❖ Permit needed for the transportation of natural gas through pipelines, which consists of receiving, conducting and delivering natural gas through an authorized route. ❖ The permit must include a Tariff with approved General Terms and Conditions, as well as a procedural approval to conduct an open season in terms of the Hydrocarbons Law and its regulations.	140 business days	30 year from granting date to build and operate the infrastructure.		●
	Liquefaction permit	❖ Permit that allows for the construction of facilities and operation of liquefaction processes, for a specific capacity and specific technology.	140 business days	30 year from granting date to build and operate the infrastructure.	●	
Secretaría de Energía / Secretary of Energy (**SENER**)	Social Impact Assessment (**EvIS**)	❖ According to Art. 121 of the Hydrocarbons Law, all activities related to hydrocarbon sector (regasification, liquefaction, transportation, distribution, and storage) must perform a social impact assessment, which identifies, characterizes and assesses social impacts that could be caused by the project.	90 business days	This is related to the implementation of a social management system. This permit's validity lasts for the entire lifespan of the project.	●	●
Secretaría de Comunicaciones y Transportes / Secretary of Roads and Communications (SCT)	Road crossing permit	❖ SCT must grant a permit when the pipeline crosses federal right of ways (roads and highways).	65 calendar days	Indefinite duration. The SCT also grants a construction authorization for 180 natural days, which could be renewed or extended 10 business days before it expires.		●
	Construction and operation of a port terminal	❖ If the liquefaction project were to be developed near the shoreline and will	90 calendar days	20 – 50 years	●	

Mexican Agency	Permit	Comments	Statutory Time	Term	Liquefaction	Pipelines
		develop marine infrastructure, an SCT Concession is required. ❖ This Concession applies for port terminals.				
	Start of construction authorization	❖ In order to build any port terminal (whether it is public (API) or private), SCT must grant a start of construction authorization.	45 calendar days	Does not have a term. This is an authorization to perform a task.	●	
	Permit to execute maritime works and dredging	❖ If the project were to be nearby the shoreline and were to develop marine infrastructure, a maritime works and dredging permit must be issued by the SCT.	90 calendar days	Does not have a term. This is an authorization to perform a task.	●	
Consejo Nacional del Agua / Federal Water Commission (CONAGUA)	Bodies of water occupation permit	❖ CONAGUA must grant a permit if the pipeline project crosses any rivers or other bodies of water.	60 business days	No less than 5 and no more than 30 years.		●
Instituto Nacional de Antropología e Historia / National Institute of Anthropology and History (INAH)	Archaeological Clearance	❖ Archeological survey conducted by INAH, before any studies and/or construction are conducted. ❖ If the INAH concludes the existence of archaeological vestiges, an archeological clearance must be granted by the same Institute.	30 business days	Does not have a term. This is an authorization to perform a task.	●	●
Municipality of Ensenada, Baja California, Mexico	Construction permit	❖ The Government of the State of Baja California must issue a construction permit for every new project. ❖ The Department of Infrastructure and Urban Development of the State of Baja California is the agency that issues such permits.	30 business days	Does not have a term. This is an authorization to perform a task.	●	●
Secretaría de Desarrollo Agrario, Territorial y Urbano /	National Agrarian Registry (**RAN**)	❖ The Department of Agrarian, Urban, and Territorial Development regulates the rights of way located in *ejidos* or common lands, through the National Agrarian Registry (RAN).	60 business days	Indefinite duration		●

Mexican Agency	Permit	Comments	Statutory Time	Term	Liquefaction	Pipelines
Secretary of Development of Agriculture, Land and Urbanism (SEDATU)		❖ If the project is established in ejidos or common lands, a signed agreement for the cession of rights with the owner of the land must be executed. Subsequently, the developer must notify and request a registry to the RAN.				

4. Elaboration and Preparation Timing for Key Permits

Permit	Topic	Timing
MIA	Preparation of engineering	2 – 3 months (basic eng.)
		10-12 months (detailed eng.)
	Permitting elaboration (by environmental consultant)	8 weeks (upon reception of overall arrangement)
ERA	Preparation of engineering	2 – 3 months (basic eng.)
		10-12 months (detailed eng.)
	Permitting elaboration (by consultant)	8 – 10 weeks
SASISOPA	Preparation of engineering	2 – 3 months (basic eng.)
		10-12 months (detailed eng.)
	Permitting elaboration (by consultant)	10 weeks
ETJ*	Permitting elaboration (by environmental consultant)	8 weeks
	Rights of Way (Timing varies depending on distance, ownership, status of land)	2 – 15 months
CRE	Preparation of engineering	2 – 3 months (basic eng.)
		10-12 months (detailed eng.)
	Permitting elaboration	2 – 3 weeks
SENER	Preparation of engineering	2 – 3 months (basic eng.)
	Permitting elaboration	4 – 6 weeks
SCT	Preparation of engineering	2 – 3 months (basic eng.)
CONAGUA*	Permitting elaboration	2 - 3 weeks
	Rights of Way	2 – 15 months

*Rights of way are needed before the conduct of any study regarding these permits. There are many variables as to the timing to resolve contracts regarding rights of ways, such as the pipeline's required distance, if the land where the pipeline were to cross is private or of common ownership, how many owners does the land have (if there are more than one), if the land is in legal dispute, *etc*.

5. Environmental permits

This section describes a general overview on the Federal environmental regulatory requirements during the permitting filing and review process. The filing and granting of the environmental permits listed below are required in order to start construction and operation of gas pipeline projects and liquefaction projects in Mexico.

5.1. Environmental Impact Assessment (Federal)

- Mexico's main federal environmental law, *Ley General del Equilibrio Ecológico y la Protección al Ambiente* / General Law of Ecological Balance and Environmental Protection ("**LGEEPA**"), issued in 1988, is designed to preserve and protect the environment and, alongside its regulations, dictates guidelines for the use of natural resources and sets out pollution prevention and control methods. All facilities located in Mexico are subject to this Mexican environmental law. The LGEEPA is administered by the *Secretaría de Medio Ambiente y Recursos Naturales* / Ministry of Environmental and Natural Resources ("**SEMARNAT**"), the federal environmental agency in Mexico analogous to the U.S. Environmental Protection Agency.
- The Federal Government created the *Agencia Nacional de Seguridad Industrial y de Protección al Medio Ambiente del Sector Hidrocarburos* ("**ASEA**"), which is a decentralized Agency of the SEMARNAT responsible for regulating and supervising industrial, operational and environmental safety for projects related to the hydrocarbon sector, including the construction of natural gas pipelines and liquefaction facilities.
- Article 28 of the LGEEPA requires SEMARNAT to set standards to evaluate environmental impacts and establish conditions applicable to the development of infrastructure, with the objective of reducing and mitigating any impacts that a project may have on the environment. This process involves the preparation and filing with ASEA of a "*Manifestación de Impacto Ambiental* / Environmental Impact Assessment" ("**MIA**"). Similar to an Environmental Impact Statement under the U.S. National Environmental Policy Act, a MIA presents the results of comprehensive analysis and studies of potential environmental impacts associated with a project, including site preparation, construction,

operation, and decommissioning, as well as an assessment of measures to mitigate environmental impacts and an analysis demonstrating compliance with Mexican laws.

- The MIA process also provides for extensive public involvement, including notices published in the ASEA's "Ecological Gazette" (included in their webpage: http://104.209.210.233/gobmx/Gaceta_ASEA), a public consultation process and hearings. In addition, ASEA solicits and considers comments from various government agencies (including CRE, SENER, etc.).
- If ASEA concludes, based on its review of the MIA, that a project is environmentally viable, it will issue an Environmental Impact Authorization ("EIA") which specifies the authorization's terms and conditions, including required measures to mitigate environmental impacts. In doing so, ASEA takes into account the comments derived from the public consultation process and the various federal and state agencies that were notified during the evaluation process.
- The MIA must describe the project's stages, as well as the ecosystems in which it will be developed. Furthermore, the MIA should include the results of comprehensive analyses and environmental studies, as well as an assessment of mitigation measures, often based on the following **Table *2***.

Table 2. Main environmental factors under evaluation for the MIA.

❖ Agricultural and Soil ❖ Air Quality ❖ Biological Resources ❖ Cultural Resources ❖ Geological Hazards ❖ Visual Resources ❖ Waste Management / Hazardous Materials and Handling ❖ Wildfire / Fire Safety	❖ Land Use ❖ Noise ❖ Paleontological Resources ❖ Public Health and Safety ❖ Traffic and Transportation ❖ Transmission System Safety and Nuisance ❖ Water Resources ❖ Worker Safety

- The enforcement of the terms of a MIA falls under the jurisdiction of ASEA, which is entitled to perform periodic verification visits to ensure compliance with all applicable environmental regulations, as well as the terms and conditions of environmental permits. If a project is noncompliant, ASEA may issue warnings or fines, depending on the severity of the noncompliance, and may terminate a project if there are continued violations of the regulation or if the violations represent a risk to the integrity of the ecosystem.

5.2. Environmental Risk Analysis (Federal)

- According to Article 147 of the LGEEPA and its Regulations, if a project involves certain highly-regulated industrial activities, such as in the hydrocarbons industry, the MIA presented to ASEA must include an Environmental Risk Analysis ("**ERA**") for review and ruling. Both a gas pipeline and a liquefaction project will always involve an ERA.
- The ERA is a preventive tool that establishes specific policies, analytical procedures, evaluations and risk control measures to protect the environment and nearby communities by anticipating the possibility of a high-consequence event.
- The ERA must incorporate all preventive measures and scenarios based on technical studies performed at the site where the pipeline will be located (analysis of High Risk and Buffer Zones, technical feasibility studies, among others), a description of the facility's safe-zones, and clear indications of environmental safety measures.
- The LGEEPA provides a comprehensive regulatory framework, which addresses all associated environmental risks during the construction and operation phases for any highly-regulated industrial activity.

5.3. Forestry Land Use Change (Federal)

- The "*Ley General de Desarrollo Forestal Sustentable* / General Law of Sustainable Forestry Development ("**LGDFS**"), issued in 2003 with implementing regulations enacted in 2005, regulates the management, protection, restoration and conservation of natural ecosystems. According to this law, all projects, including the construction of pipelines and liquefaction facilities, must obtain authorization to change the use of soil in forestry lands. Although the LGDFS uses the term "forest", the requirements apply to any natural undeveloped lands, not just forested lands. A forestry land is consider a natural vegetation area.
- Article 117 of the LGDFS establishes that ASEA may authorize a forestry land use change based on a technical opinion issued by the members of the State Forestry Council (*Consejo Forestal Estatal*) contingent to a "*Estudio Técnico Justificativo*" (Technical Justification Study or "**ETJ**") submitted by the applicant where it demonstrates that biodiversity will not be negatively affected and that there will be no soil erosion, detriment to water quality or diminished rate of recovery.

- Furthermore, the ETJ must include the duration of each of the project's stages, change in land use implementation methods, and should suggest that the proposed alternative land uses will be more productive in the long-run.
- Any land use change must be authorized by a "*Cambio de Uso de Suelo en Terrenos Forestales*" permit (Forestry Land Use Change or "**CUSTF**") issued by ASEA. This federal permit authorizes the change of the environmental designation of the land from forested lands to others such as industrial and urban lands, and includes mitigation requirements similar to those included in the MIA. To complete this process, a payment must be made to the Mexican Forestry Fund (*Fondo Nacional Forestal*) to compensate for the vegetation that will be removed.

5.4. SASISOPA

- The Industrial, Operational, and Environmental Safety Management System / *Sistema de Administración de Seguridad Industrial, Seguridad Operativa y Protección al Medio Ambiente* ("**SASISOPA**") is a tool that regulates a facility's performance during every industrial stage. All pipeline and liquefaction projects must follow every term and condition established by the ASEA to mitigate all plausible risks that could be caused by the pipeline and liquefaction industrial activities and to improve its performance in order to guarantee industrial, social and environmental safety.
- This system is governed by ASEA's federal Law *(Ley de la Agencia Nacional de Seguridad Industrial y de Protección al Medio Ambiente del Sector Hidrocarburos*), which gives ASEA the institutional power to regulate, monitor, implement and authorize a pipeline and/or liquefaction project based on the technical opinion derived from it.
- Additionally, those who will develop a pipeline or liquefaction project must be registered under a Unique Regulated Registry Number ("**CURR**") / *Clave Única de Registro del Regulado*, which is a code that allows the ASEA to identify who is requesting a specific authorization.

5.5. Environmental Impact Authorization (State-level)

- The Government of Baja California enacted the "*Ley de Protección al Ambiente*" / "Environmental Protection Law" on November 30, 2001 to comply with federal requirements stated in the LGEEPA in order to establish decision-making power on states' environmental conditions.

- The Baja California Environmental Protection Law and its regulations set the guidelines to evaluate and authorize environmental impacts, among other issues, for construction and use of the internal roads for the development of industrial projects within the State of Baja California.
- The Ministry of Environmental Protection of Baja California, often through its Environmental Protection State Council and any corresponding local authorities, will grant, revoke, condition and monitor any requested permits.

6. About IEnova

IEnova (IENOVA.MX), a subsidiary of Sempra Energy (SRE:US), is one of the largest private energy companies in Mexico that develops builds and operates energy infrastructure with more than 900 employees and approximately $7.6 billion invested.

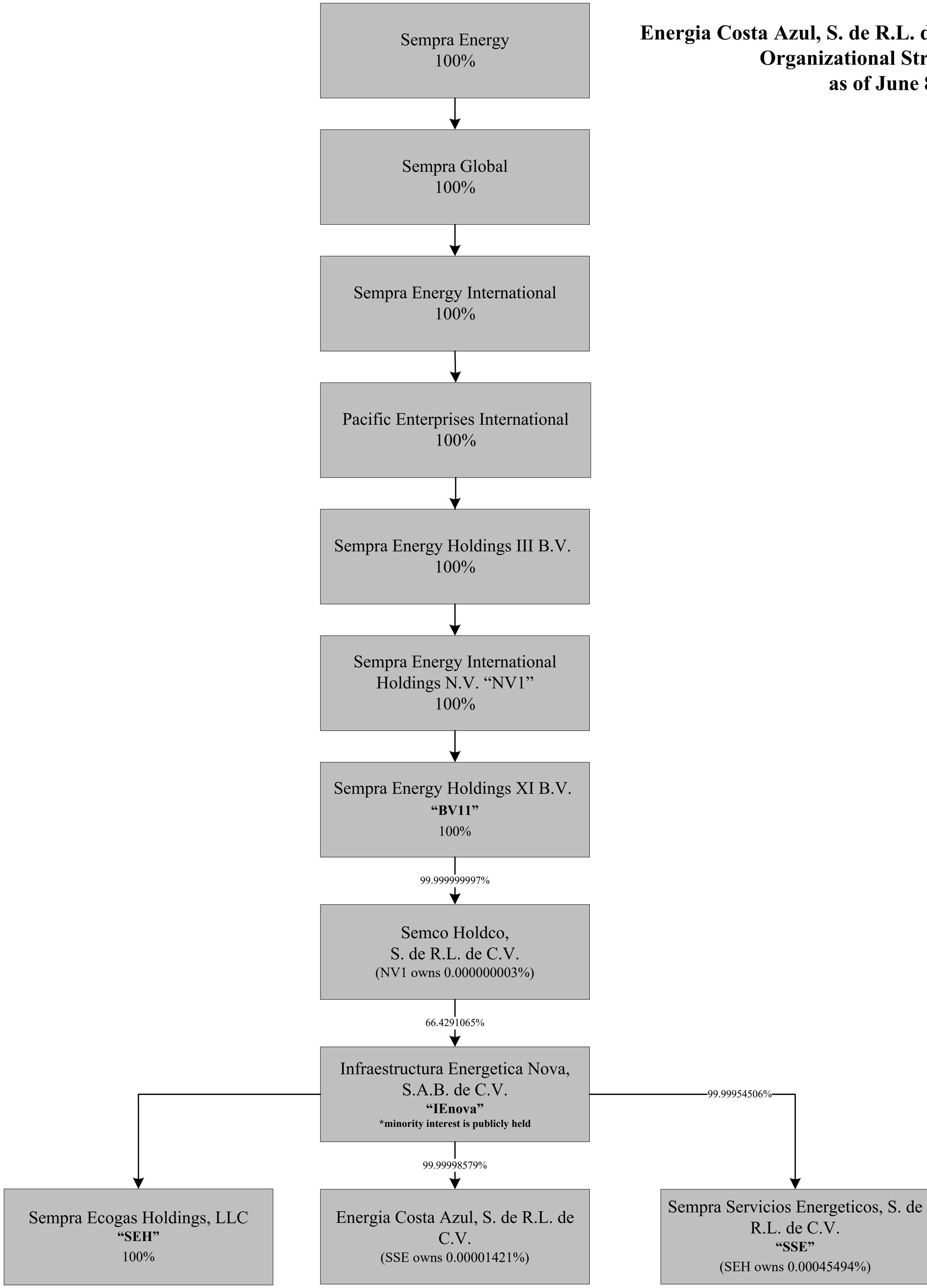
IEnova currently has a presence in 16 states in Mexico, including those states bordering the U.S. IEnova owns 3,391 km of Natural Gas, LPG and Ethane pipelines across Mexico and a LNG reception, storage and regasification terminal with a send-out capacity of 1300 MMcfd in Baja California. Currently IEnova is developing with Sempra a project to add liquefaction capabilities to its LNG terminal.

Since 1996, IEnova has secured environmental permits for more than 25 company assets, which are still in force and effect for the operation of such assets.

APPENDIX D

ECA Ownership Structure

Energia Costa Azul, S. de R.L. de C.V.
Organizational Structure
as of June 8, 2018



* Ownership is 100% unless otherwise specified.

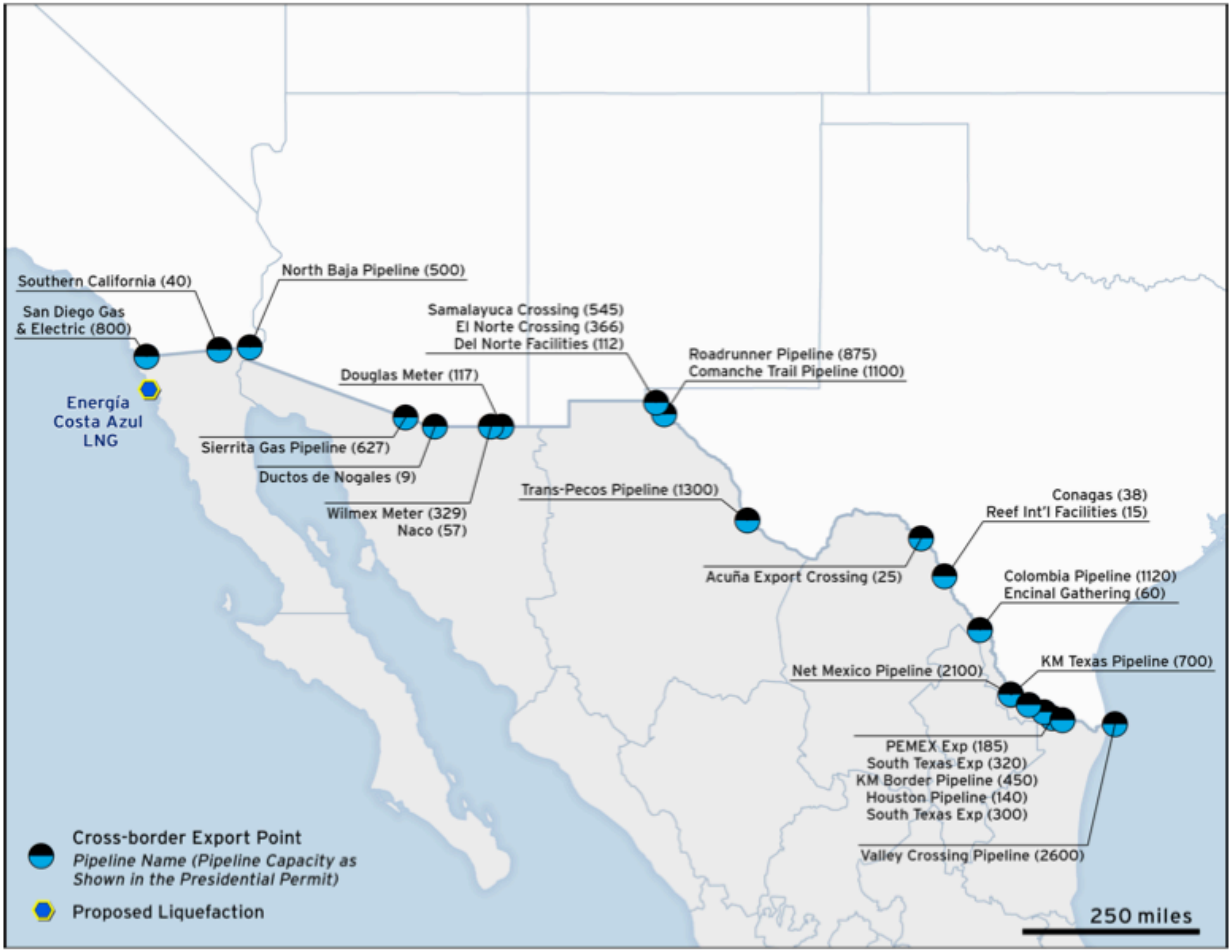
APPENDIX E

Summary of Existing Cross-Border Facilities

Summary of Existing Cross-Border Facilities

	Pipeline / Operator	FERC Order Granting Presidential Permit or Establishing Capacity	FERC Docket Nos.	Point of Entry / Exit	Status as of ECA Application Submission Date	Approved / Proposed Capacity (mmcfd)
1	San Diego Gas & Electric Co.	116 FERC ¶ 61,246 (2006)	CP93-117	Otay,CA / Tijuana, BC	In Service	800
2	Southern California Gas Co.	68 FERC ¶ 61,277 (1994)	CP94-207	Calexico, CA/ Mexicali, BC	In Service	40
3	North Baja Pipeline Co.	98 FERC ¶ 61,020 (2002)	CP01-23, CP06-61	Ogilby, CA/ Los Algodones, BC	In Service	500
4	Sierrita Gas Pipeline	147 FERC ¶ 61,192 (2014)	CP13-74, CP18-38	Sasabe, AZ/ Sasabe, Son	Original Pipeline in Service; Compression Expansion under FERC Review	627
5	El Paso Natural Gas Co (Ductos de Nogales)	94 FERC ¶ 61,393 (2001)	CP01-41	Santa Cruz, AZ/ Nogales, Son	In Service	9
6	El Paso Natural Gas Co (Douglas Meter)	141 FERC ¶ 61,026 (2012)	CP98-357, CP12-7	Cochise, AZ/ Agua Prieta, Son	In Service	117
7	El Paso Natural Gas Co (El Fresnal/Willmex Meter)	141 FERC ¶ 61,026 (2012)	CP99-323, CP12-7	Cochise, AZ/ Agua Prieta, Son	In Service	329
8	El Paso Natural Gas Co (Naco/Monument 90 Facilities)	154 FERC ¶ 61,257 (2016)	G-104, CP15-493	Cochise, AZ/ Naco, Son	In Service	57
9	El Paso Natural Gas Co (Samalayuca Crossing)	140 FERC ¶ 61,072 (2012)	CP93-253, CP12-74	El Paso, TX/ Cd. Juarez, Chih	In Service	545
10	El Paso Natural Gas Co (El Norte Crossing)	140 FERC ¶ 61,174 (2012)	CP12-96	Clint, TX/ Cd. Juarez, Chih	In Service	366
11	ONEOK Partners (Roadrunner – Tarahumara PL)	153 FERC ¶ 61,041 (2015)	CP15-161	San Elizario, TX/ San Isidro, Chih	In Service	875
12	Comanche Trail Pipeline LLC (ETP Waha-San Elizario)	155 FERC ¶ 61,182 (2016)	CP15-503	San Elizario, TX/ San Isidro, Chih	In Service	1,100
13	Trans-Pecos Pipeline LLC (ETP Waha-Presidio)	155 FERC ¶ 61,140 (2016)	CP15-500	Presidio, TX/ Ojinaga, Chih	In Service	1,300
14	OkTex Pipeline Co., (Del Norte Facilities)	105 FERC ¶ 61,047 (2003)	CP03-99, CP00-384 CP91-2128	El Paso, TX / Juarez, Chih.	In Service	112
15	West Texas Gas Co (Acuña Export Crossing)	101 FERC ¶ 61,058 (2002)	CP02-97	Val Verde, TX/ Cd. Acuña, Coah	In Service	25
16	West Texas Gas Co (Conagas)	76 FERC ¶ 61,264 (1996)	CP84-361, CP84-366, CP96-497, CP02-382	Eagle Pass, TX/ Piedras Negras, Coah	In Service	38
17	West Texas Gas Co. (Reef Int'l Facilities)	99 FERC ¶ 61,221 (2002).	CP02-74, CP08-410	Eagle Pass, TX / Piedras Negras, Chih.	In Service	15
18	Kinder-Morgan Texas Pipeline Co.	77 FERC ¶ 61,205 (1996)	CP96-583, CP12-440, CP13-94	Roma, TX/ Cd. Miguel Aleman, Tam	In Service	700
19	NET Mexico Pipeline	145 FERC ¶ 61,112 (2013)	CP13-482	Starr, TX/ Cd. Camargo, Tam	In Service	2,100
20	Tennessee Gas Pipeline Co (PEMEX Exp)	86 FERC ¶ 61,244 (1999)	CP99-28	Hidalgo, TX/ Reynosa, Tam	In Service	185
2	Tennessee Gas Pipeline Co (South Texas Exp)	101 FERC ¶ 61,360 (2002)	CP02-117	Hidalgo, TX/ Reynosa, Tam	In Service	320
2	Coral Energy Corp. / Kinder Morgan Border Pipeline LLC	89 FERC ¶ 61,171 (1999)	CP99-564, CP17-474	Hidalgo, TX/ Reynosa, Tam	In Service	450
23	Houston Pipeline (Energy Transfer)	146 FERC ¶ 61,195 (2014)	CP14-13	Hidalgo, TX/ Reynosa, Tam	In Service	140
24	Texas Eastern Transmission (South Texas Exp)	16 FPC 27 (1956) 9 FERC ¶ 61,362 (1979)	G-9785, CP80-93	Hidalgo, TX/ Reynosa, Tam	In Service	300
25	Colombia Pipeline , LLC (Howard Energy - Impulsora)	151 FERC ¶ 61,117 (2015)	CP14-513, CP16-70	Webb, TX/ Colombia, NL	In Service	1,120
26	Encinal Gathering Ltd	121 FERC ¶ 61,248 (2007)	CP07-418	Webb, TX/ Coahuila	In Service	60
27	Valley Crossing Pipeline Co (Spectra Energy)	161 FERC ¶ 61,084 (2017)	CP17-19	Brownsville, TX/ Offshore with Sur de Texas-Tuxpan Interconnect	Authorized by FERC; Under Construction	2,600
	Total Existing Cross-Border Capacity					**14,830**

Summary of Existing Cross-Border Facilities



APPENDIX F

ASEA Resolution Approving MIA
(English Translation)

Mexico City, November 30, 2017.
"2017, Centenary of the Promulgation of the Political Constitution of the United Mexican States"

MR. JUAN RODRIGUEZ CASTAÑEDA
LEGAL REPRESENTATIVE OF
ENERGÍA COSTA AZUL, S. DE R. L. DE C. V.
PASEO DE LA REFORMA 342, 24th FLOOR
COLONIA JUAREZ, DEL. CUAUHTMEOC
C.P. 06600, MEXICO CITY
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Reference: Authorized Resolution.
File: 02BC2016G0068.

Once the Environmental Impact Manifest, Regional Mode (EIM-R), and the Environmental Risk Study (ERS) of the **PROJECT** named "**NATURAL GAS LIQUEFACTION PROJECT IN ENERGÍA COSTA AZUL**", hereafter the **PROJECT**, presented by the company **ENERGÍA COSTA AZUL**, **S. DE R. L. DE C. V.**, hereafter the **REGULATED PARTY**, with location proposed in the Municipality of Ensenada, in the state of Baja California; and

RESULTING

I. On December 14, 2016, the **REGULATED PARTY** delivered to the National Agency for Industrial Safety and Environmental Protection of the Hydrocarbons Sector *(Agencia Nacional de Seguridad Industrial and de Protection al Medio Ambiente del Sector Hidrocarburos)* (**AGENCY**), Administrative Unit which owns the General Direction of Industrial Processes Management *(Dirección General de Gestión de Processes Industriales)* **(DGGPI)**, Document No. ECA/193/16 not dated, used to receive the **EIM-R** and **ERS** of the **PROJECT**, to be evaluated and ruled on the Environmental Impact and Risk Subject, which was registered with code **02BC2016G0068**.

II. That on December 15, complying with Article 34, Third Paragraph, Fraction I of the General Law of Ecological Balance and Environmental Protection *(Ley General del Equilibrio Ecológico and la Protection al Ambiente)* (**LGEEPA**), ordering the publication of the authorization request on the environmental impact subject, on its Ecological Gazette *(Ecological Gazette)*; and complying with Article 37 of the LGEEPA Regulation (R-LGEEPA) on Environmental Impact Assessment *(Reglamento en Materia de Evaluación del Impacto Ambiental)* (**REIA**), it was published in Separated Part No. **ASEA/038/2016** of the Ecological Gazette, the list of projects received, and the decisions issuance and projects submitted to public consultation arising from the

Environmental Impact and Risk Evaluation Procedure, from December 08 to 14, 2016, including this **PROJECT**.

III. That on January 03, 2017, in document ECA/203/16 not dated, the **REGULATED PARTY** delivered to this **DGGPI**, the newspapers issues publishing the **PROJECT** summary, under Article 34, Fraction I of the **LGEEPA**, which were included in the administrative file, under Article 26, Fraction III of the **REIA**, as described in the following table:

Publication Date	Newspaper	Page	State
December 16	Frontera	16	Baja California
	El Vigía	17	
	El Mexicano	5th	

IV. That on January 09, 2017 in document without number, dated January 09, 2017, this **DGGPI** received a Public Consultation request, promoted by Jesús José Chinchillas Elizalde, Juan de Dios Batís Castro, Estela María Guadalupe Álvarez Mariscal, Miguel Lara Cardozo, Alejandro Verastegui Calderón, and María Cristina García Munguía; identified as members of the community where the **PROJECT** development has been proposed.

V. That on January 11, 2017, under Article 35 of the **LGEEPA**, the **DGGPI** prepared the **PROJECT** file and, under Article 34, First Paragraph of the **LGEEPA**, made it publicly available in the address located on Av. Melchor Ocampo 469, Colonia Nueva Anzures, Delegación Miguel Hidalgo, C.P. 11590, Mexico City.

VI. That on January 16, 2017, the Industrial Management Unit *(Unit de Gestión Industrial)* **(UGI)**, notified the community requestors from the place where the **PROJECT** development has been proposed, that the Public Consultation corresponds to proceed with full rights granted, as it complies with Articles 34 of the **LGEEPA**, and 40 and 41 of the **R-LGEEPA**, according to the following official letters:

Official Letter	**Date**	**Addressed to**
ASEA/UGI/0009/2017	January 16, 2017	Jesús José Chinchillas Elizalde
ASEA/UGI/0010/2017	January 16, 2017	Juan De Dios Batíz Castro
ASEA/UGI/0011/2017	January 16, 2017	Miguel Lara Cardoso

ASEA/UGI/0012/2017	January 16, 2017	Alejandro Verastegui Calderon
ASEA/UGI/0013/2017	January 16, 2017	María Cristina García Murguía
ASEA/UGI/0016/2017	January 16, 2017	Estela María Guadalupe Álvarez Mariscal

VII. That on January 16, 2017, on official letter ASEA/UGI/0014/2017, the **UGI** notified the **REGULATED PARTY** on the legitimacy of conducting the Public Consultation, as such request was received from six members of the community in the Municipality of Ensenada, that will be impacted by the **PROJECT** development. Therefore, complying with the law, such decision was made. Also, two additional printed copies of the **PROJECT** where requested; one of them shall be directly delivered in the offices of the Federal Delegation of the SEMARNAT in the state of Baja California, and the other to this **AGENCY**.

VIII. That on January 16, 2017, through office letter ASEA/UGI/0015/2017, the **UGI** notified the Federal Delegation of the SEMARNAT in the state of Baja California, the legitimacy of the Public Consultation request, as it was determined that it was properly filed. Therefore, and using powers, I hereby request the Federal Delegation to make one copy of the **PROJECT's** Environmental Impact Manifest publicly available, forwarding the compact disc containing it, and the attachment containing the corresponding minute requesting that the multicited **EIM-R** is made available for public consultation before that Administrative Unit,

IX. That on January 19, 2017, through Gazette **ASEA/003/2017**, this **AGENCY** informed the citizenry in general, on the launching of the Public Consultation process for the **PROJECT**, under Article 34, Fraction 1 of the **LGEEPA**, for any interested party to propose the implementation of additional prevention and mitigation measures, and any pertinent observations thereon.

X. That on January 20, 2017, the **REGULATED PARTY** sent to this **DGGPI**, an additional copy of the **EIM-R** and **ERS**, complying with items specified on official letter ASEA/UGI/0014/2017, dated January 16, 2017.

XI. That on January 26, 2017, through official letter No. ASEA/UGI/DGGPI/0009/2017, this **DGGPI** requested the opinion of the Secretariat of Environmental Protection of the Government of the State of Baja California, on the development of the **PROJECT**, as related to planning instruments and legal framework within their competence.

XII. January 26, 2017, through official letter without number ASEA/UGI/DGGPI/0010/2017, this **DGGPI** requested the opinion of the City Hall of Ensenada, in the state of Baja California, on the development of the **PROJECT**, as related to planning instruments and legal framework within their competence, and the legitimacy, congruence and/or compatibility of the inclusion of the **PROJECT** works and activities in areas selected.

XIII. That on January 26, 2017, through official letter without number ECAL/001/17, the **REGULATED PARTY** delivered to this **DGGPI**, the newspaper issues publishing the **PROJECT** summary in three wide circulation newspapers, in the state where the **PROJECT** execution has been proposed, complying with items specified on official letter ASEA/**UGI**/0014/2017, dated January 16, 2017, as described in the following table:

Publication Date	Newspaper	Page	State
January 20	Frontera	04	Baja California
	El Vigía	08	
	El Mexicano	11th	

XIV. That on January 16, 2017, through office letter No. ECAL/001/17 not dated, the **REGULATED PARTY** delivered to this **DGGPI**, the acknowledgement receipt ECA/14/17 not dated, where the Federal Delegation of the SEMARNAT in the state of Baja California acknowledges receipt, on January 19, 2017, an additional copy of the **PROJECT's EIM-R** and **ERS**, complying with items specified in official letter ASEA/UGI/0014/2017, dated January 16, 2017.

XV. That on January 26, 2017 through document without number, dated January 25, 2017, this **DGGPI** received a Public Meeting Request, promoted by **Juan de Dios Bátiz Castro**, identified as member of the community where the **PROJECT** development has been proposed**.**

XVI. That on January 27, 2017, through official letter ASEA/**UGI**/0030/2017, the **UGI** requested the **REGULATED PARTY** to provide **one (01) additional printed copy** of the **EIM-R and ERS**, in the offices of the Federal Delegation of the SEMARNAT in the Municipality of Ensenada, state of Baja California, to give the citizens in the Municipality an opportunity to access information related to the **PROJECT.**

XVII. That on January 27, 2017, through official letter ASEA/**UGI**/0029/2017, the **UGI** requested to the Federal Delegation of the SEMARNAT in the state of Baja California, to make publicly available a copy of the EIM of the **PROJECT**, in the offices of the Federal Delegation of the SEMARNAT in the Municipality of Ensenada, state of Baja California.

XVIII. That on January 27, 2017, this **DGGPI** received 01 questionnaire of the **PROJECT** Public Consultation, sent by civil organizations, private corporations and members of communities from the area selected for the development.

XIX. That on January 30, 2017, this **DGGPI** received 03 questionnaires of the **PROJECT** Public Consultation, sent by civil organizations, private corporations and members of communities from the area selected for the development.

XX. That on February 01, 2017, through official letter number ASEA/UGI/**DGGPI**/0034/2017, this **DGGPI** notified **Juan de Dios Bátiz Castro**, that if this **AGENCY**, under Article 43 of the **REIA**, decided to conduct a **Public Information Meeting**, such decision would be communicated through the media specified on environmental legislation.

XXI. That on February 10, 2017, through document without number, dated February 08, 2017, **Gustavo Alanís Ortega**, made comments on the **PROJECT**, under Article 34, Fraction IV of the **LGEEPA.**

XXII. That on February 10, 2017, through document without number, dated February 08, 2017, **Gerardo Farid Tallavas Gascón**, made comments on the **PROJECT**, under Article 34, Fraction IV of the **LGEEPA**.

XXIII. That on February 13, 2017, through document without number dated February 13, 2017, **Gerardo Farid Tallavas Gascón**, delivered a second document with comments on the **PROJECT**, under Article 34, Fraction IV de la **LGEEPA.**

XXIV. That on February 16, 2017, through document without number or date, **Agustín Bravo Gaxiola**, made comments on the **PROJECT**, under Article 34, Fraction IV of the **LGEEPA**.

XXV. That on February 16, 2017, through document without number or date, **Jazmín Edith Samaniego Ojeda**, made comments on the **PROJECT**, under Article 34, Fraction IV of the **LGEEPA.**

XXVI. That on February 16, 2017, through official letter number ASEA/DE/COAS/005/2017, the Advisors Coordination of this **AGENCY** notified **Juan Rodríguez Castañeda**, as Legal Representative of **ENERGÍA COSTA AZUL**, **S. DE R. L. DE C. V.**, on the decision of holding a Public Information Meeting **(PIM)** for the **PROJECT**.

XXVII. That on February 20, **AGENCY** published the Invitation for the PIM of the **PROJECT**, on **Page 11A** of the newspaper “El Mexicano”, of wide circulation, in the municipality of Ensenada, Baja California, under articles 34, Fraction III of the **LGEEPA** and 43 of the **REIA.**

XXVIII. That on February 24, 2017, in the city of Ensenada, municipality of Ensenada, state of Baja California, in the facilities of the Hotel San Nicolás, on Primera and Guadalupe without number, Development of Playa Ensenada, the PIM for the **PROJECT** named “**NATURAL GAS liquefaction PROJECT IN ENERGÍA COSTA AZUL**”, promoted by the company **ENERGÍA COSTA AZUL**, **S. DE R. L. DE C. V.**

XXIX. That on March 01, 2017, the General Direction of Social Communication of this **AGENCY**, through official letter ASEA/DE/DGCS/035/2017, dated March 01, 2017, sent to this **DGGPI** a compact disc containing the video recording of the **PROJECT** PIM.

XXX. That on March 07, 2017, arising from the content analysis of the **EIM-R** and **ERS**, and under articles 35 bis of the LGEEPA, and 22 of the R-LGEEPA on Environmental Impact Assessment (EIA), the **DGGPI** requested to the **REGULATED PARTY**, additional information (AI) on the **PROJECT**, through official letter ASEA/**UGI**/**DGGPI**/0072/2017.

XXXI. That on March 31, 2017, The Secretariat of Environmental Protection of the state of Baja California, through official letter number SPA-ENS-351/17, dated March 29, 2017, sent to this **DGGPI** its technical opinion on the **EIM-R**, containing a series of observations and additional conditions, which are considered as viable by this **DGGPI**, to be implemented in the **PROJECT** development and included in this Resolution.

XXXII. That on June 15, 2017, the **REGULATED PARTY** delivered all **AI** to this **AGENCY**, through document number ECA/021/17, without date. Such AI was included in the administrative file under Article 26, Fraction I of the **REIA.**

XXXIII. That on June 21, 2017, through official letter ASEA/UGI/DGGPI/0161/2017, dated June 20, 2017, the **DGGPI** notified to the **REGULATED PARTY** the term extension for the EIA Procedure, for an additional period of up to 60 days, resulting from the **AI** delivered on June 15, 2017, highlighting both technical and legal aspects enabling this **DGGPI** to make a well informed and motivated resolution, given the legal relation and potential effects of the **PROJECT** works and activities.

XXXIV. That on July 11, 2017, **Gustavo Adolfo Alanís Ortega** signed by the CMEDA, delivered a document without number, dated July 10, 2017, including a number of technical considerations and comments on the **PROJECT**. Comments and observations applicable were considered in the corresponding assessment, which was analyzed under the corresponding terms and scopes.

XXXV. That based on Agreements published in the Federal Official Gazette dated September 21, 2017 and September 29, 2017, activities in the **AGENCY** were suspended on September 21, 22, 25, 26, 27, 28 and 29, 2017; and October 2, 3, 4, 5 and 6, 2017, respectively. Thus, times and terms to execute activities and diligences on administrative procedures under development in the **AGENCY**, and all activities, requirements, requests or promotions made on any days specified above, were effective until the first following working day, under Article 28 of the Federal Law of Administrative Procedures, i.e., October 09, 2017.

XXXVI. That on October 30, 2017, through document ECAL/025/17, not dated, the **REGULATED PARTY** delivered a copy of the resolution on the Social Impact Assessment for the **PROJECT**, issued by the General Direction of Social Impact and Superficial Occupation *(Dirección General de Impacto*

Social and Ocupación Superficial) of the Secretariat of Energy, through official letter 117.DGAEISyCP.0895/17, dated September 13, 2017.

XXXVII. That through official letter ASEA/UGI/DGGPI/0228/2017, dated November 24, 2017, the **DGGPI** orders to add on the file in question, the document delivered by **Gustavo Adolfo Alanís Ortega** signed by the CMEDA, for the effects of Article 34, Fractions IV and V of the LGEEPA, correlated to Article 26, Fraction III of the R-LGEEPA, on Environmental Impact Assessment.

XXXVIII. That, on the issuance date of this resolution, and notwithstanding what is established in other legal and administrative systems, this **DGGPI** had no response to the opinion request made by the City Hall of Ensenada. Therefore, after the expiration of terms specified on official letters above, this **DGGPI** shall make a decision under powers granted to it by the Internal Regulation of ASEA, the **LGEEPA** and its **REIA**.

CONSIDERING

I. That this **DGGPI** is **competent** to review, assess and decide on the **EIM-R** and the **ERS** of the **PROJECT**, under articles 4, Fraction XIX and 29, Fraction II of the Internal Regulation of ASEA.

II. That the **REGULATED PARTY** is planning to conduct the liquefaction of Natural Gas (NG), therefore, its activity belongs to the Hydrocarbons Sector, which is competence of this **AGENCY** according to the definition made in Article 3, Fraction XI, sentence c), of the Law of the ASEA.

III. That, given the description, characteristics and location of activities integrating the **PROJECT**, it is under federal jurisdiction on EIA, as it is related to the construction, operation and maintenance of NG liquefaction facilities, under articles 28, fractions II, VII and X of the **LGEEPA** and 5 sentences D), fractions IV and VII, O) and R) of the **REIA**. It has also been proposed to develop an activity of the Hydrocarbons Sector, under Article 3, Fraction XI, sentence c), of the Law of the ASEA.

IV. That the Procedure for Environmental Impact Assessment *(Procedimiento de Evaluación de Impacto Ambiental)* **(PEIA)**, is the mechanism specified by the **LGEEPA**, in which the authority establishes conditions applicable to works and activities prone to cause ecological imbalance, or which may exceed limits and conditions specified in applicable environmental protection provisions, aiming to avoid or minimize their negative effects on the ecosystems. To this end, the **REGULATED PARTY** delivered an EIM-R, requesting the **PROJECT** authorization. The mode is adequate, as it is covered by the hypothesis specified in Article 11 of the **REIA.**

V. That, complying with Article 35 of the **LGEEPA**, once the **EIM-R** was delivered, the **PEIA** started, ensuring that the request complies with requirements specified in this **LGEEPA**, its **REIA** and applicable Mexican Official Standards; the Law of the ASEA, and its Internal regulation. Therefore, after the corresponding file has been prepared, this **DGGPI** determines that it shall be submitted to provisions stated above, and the urban development and ecological ordering programs of the territory, declarations of protected natural areas, and any other legal provisions applicable. Also, all potential effects of the operation, maintenance and abandonment in the ecosystem(s) in question, considering the ensemble of elements integrating them, and not only the resources that, in turn, would be subject of exploitation or impact. Therefore, this **DGGPI** starts the **EIM-R** assessment of the **PROJECT**, and under terms established by the **REIA** for such effect.

Background

VI. That on April 08, 2003, through official letter S.G.P.A-DGIRA-DIA-788/03, the **DGIRA** granted conditioned authorization the **PROJECT** named "Liquefied Natural Gas Reception, Storage and Regasification Terminal," with proposed location on lots 24 to 29, and lot without number, in the property named Costa Azul, approximately 28 km North of the city of Ensenada, municipality of Ensenada, state of Baja California, in favor of **ENERGÍA COSTA AZUL**, **S. DE R. L. DE C. V.**

Project General Information

VII. That under Article 13, Fraction I of the **REIA**, stating that the **EIM-R** shall include general information on the **PROJECT**, the **REGULATED PARTY** and people responsible for the EIS, and that information included in **Chapter I** of the **EIM-R**, it was specified that the **REGULATED PARTY** is currently operating a regasification plant receiving Liquefied Natural Gas (LNG) from gas tankers, storing it in total contention LNG tanks, to regasify it and sent it in gaseous state to the NG transportation system owned by Gas pipeline Rosarito. This **PROJECT** consist of the development and construction of a NG liquefaction plant designed with production capacity of 6.175 million tons per annum (MTPA), per each liquefaction train, or 12.35 MTPA for the two liquefaction trains; and use, modification or expansion of some process and service units of facilities currently existing in the regasification plant, that will be common to both processes. Based on the **PROJECT** dimensions, it is intended to expand the current surface polygon of the regasification plant from **163.8415 ha** up to **332.99 ha**. For the permanent areas, the **PROJECT** is considering **81.42 ha**, out of which **69.94 ha** will be terrestrial ecosystems, and **11.48 ha** marine ecosystems.

Description of works or activities, and development programs or partial plants, if any.

VIII. That Article 13, Fraction II of the **REIA**, imposes on the **REGULATED PARTY** the obligation of including in the **EIM-R** delivered to be evaluated, the description of works and activities, and development programs or partial plans, if any. Here, once the information delivered in the **EIM-R** and the **ERA** is analyzed, and according to what was stated by the **REGULATED PARTY**, the description of works and activities for the **PROJECT** execution is summarized below:

a. The **REGULATED PARTY** is planning to develop and build facilities, onshore and offshore, to liquefy natural gas in the site currently used to operate the regasification plant already authorized mentioned in **Item VI** of this document. Some existing facilities will have to be expanded, modified and/or relocated, as needed, to accommodate the addition of new facilities for the liquefaction project, while maintaining the operation capacity of the current regasification plant, not simultaneously with the liquefaction activities.

b. This **PROJECT** consist of the development and construction of a NG liquefaction plant designed with production capacity of 6.175 MTPA, per each liquefaction train, or 12.35 MTPA for the two liquefaction trains; and use, modification or expansion of some process and service units of facilities currently existing in the regasification plant, that will be common to both processes.

c. For these purposes, the **REGULATED PARTY** requires the expansion of the current regasification plant polygon surface from **163.8415 ha** to a total of **332.99 ha**. Additionally, the **PROJECT** polygon is considering lots 20, 30, 31, 32, 33, 34, 35, 36, 37, and Fraction “A”, limits of the Terrestrial-Maritime Federal Zone *(Maritime-Terrestrial Federal Zone)* (ZOFMEAT), and land reclaimed to the sea, where the **REGULATED PARTY** has offshore facilities.

d. The **PROJECT** is considering the following facilities, areas and components:

- Liquefaction plant: Including the area destined for two liquefaction trains, NG pre-treatment and conditioning common facilities, and multi-points enclosed flare for emergency venting.
- Expansion, modification and/or relocation process units and services of the existing regasification plant.
- Area for the liquefaction process control room and a minor parking lot.
- Area for the power substation and racks for services and pipelines.
- Racks: support structures for services and pipelines.
- Material Offloading Facilities (MOF): causeway, breakwater, mooring and services areas.
- MOF material area: to store materials from dredging works for the MOF construction
- Heavy traffic road: interconnection between the MOF and the liquefaction plant.
- Parking lots.
- Roads.
- Plant nursery.
- 09 areas for temporary facilities during the site preparation and construction stages.

e. The **PROJECT** will install 8 additional process and services units for liquefaction and use or modify 16 process and services units from the existing regasification plant. The **PROJECT** requires the following new units: Unit 00, Unit 11, Unit 12, Unit 14, Unit 16, Unit 19, Unit 31, and Unit 82. It also requires the following existing units: Unit 10, Unit 20, Unit 50, Unit 55, Unit 60, Unit 71, Unit 72, Unit 81, Unit 83, Unit 85, Unit 86, Unit 87, Unit 88, Unit 89, Unit 91, and Unit 92, as follows:

Units				
Unit Number	Process	Service	Currently Used or Modified	New
Unit 00: Common NG entry facilities	Common entry facilities			X
Unit 10: LNG loading/unloading	LNG loading/unloading		X	X
Unit 11: NG entry and mercury removal facilities	Entry and mercury removal facilities			X
Unit 12: Removal and disposal of Acid Gas and Amine Storage	Removal of sequestering acid gas from H_2S and amine thermal oxidizers	Amine storage		X
Unit 14: Dehydration	Dehydration			X
Unit 16: Liquid removal and NG fractionation	LGN recovery and fractionation			X
Unit 19: Liquefaction	Liquefaction, feeding gas pre-cooling and main cryogenic heat exchanger			X
Unit 20: LNG tanks and marine flare	LNG tanks and LNG tank-trucks loading station	Marine flare	X	X
Unit 31: Refrigerant storage and refrigeration system with propane and MR	Refrigeration with MR refrigerant and propane	Ethane and propane refrigerant treatment and storage		X

Units				
Unit Number	Process	Service	Currently Used or Modified	New
Unit 50: Open rack vaporizers (ORVs)		ORVs	X	
Unit 55: Nitrogen Injection Plant (NIF)		NIF	X	
Unit 60: BOG compressors, return blowers and burners system	Boil-off gas (BOG) compression system	Burners system	X	X
Unit 71: Power generation		Power generation	X	X
Unit 72: Emergency power generation		Emergency power generation	X	
Unit 81: Fuel gas system	Expansion Fuel Gas (EFG), and High Pressure Fuel Gas System (ISBL)	Fuel gas	X	X
Unit 82: Tempered water and thermal oil	Tempered water system	Thermal oil storage		X
Unit 83: Aqueous ammonia storage		Aqueous ammonia storage	X	X
Unit 85: Plant and instrument air		Plant and instrument air	X	
Unit 86: Nitrogen storage and distribution		Liquid nitrogen package	X	X
Unit 87: Water System	Recovered water tank	Sea water system, electrochlorination system, desalination packages I and II, services and potable water, demineralized water for the	X	X

Units				
Unit Number	Process	Service	Currently Used or Modified	New
		regasification and liquefaction areas		
Unit 88: Sanitary system		Sanitary system	X	X
Unit 89: Streams and stormwater		Streams and stormwater	X	X
Unit 91: Firefighting water system		Firefighting water system	X	X
Unit 92: Foam package		Foam package	X	X

f. The **REGULATED PARTY** stated that the **PROJECT** polygon will have a surface of **332.99** ha, and where the regasification plant is currently in operation. As a whole, it is integrated by lots 20, WO/N, 24- 37 and Fraction "A", ZOFMEAT, and land reclaimed to the sea. The following table summarizes UTM WGS84 Zone 11 of the **PROJECT** polygon.

Vertex	Coordinates		Vertex	Coordinates		Vertex	Coordinates	
	X	Y		X	Y		X	Y
V1	513,981.53	3,4139,289.04	V50	514,912.49	3,538,927.20	V99	515,573.95	3,539,538.64
V2	513,983.09	3,939,283.98	V51	514,944.01	3,538,960.09	V100	515,558.65	3,539,541.05
V3	513,982.99	3,539,263.90	V52	514,966.18	3,538,966.97	V101	515,459.02	3,539,556.73
V4	514,014.97	3,539,191.66	V53	514,986.13	3,538,969.00	V102	515,345.14	3,539,571.92
V5	514,059.53	3,539,135.57	V54	514,993.43	3,538,964.89	V103	515,204.15	3,539,590.73
V6	514,076.22	3,539,121.46	V55	515,008.40	3,538,950.15	V104	515,156.09	3,539,596.84
V7	514,038.33	3,539,094.62	V56	515,027.25	3,538,940.93	V105	515,065.64	3,539,608.33
V8	514,045.92	3,539,032.18	V57	515,038.04	3,538,918.57	V106	514,882.68	3,539,633.57
V9	514,056.89	3,539,027.96	V58	515,055.43	3,538,897.98	V107	514,724.46	3,539,655.42
V10	514,056.89	3,538,996.73	V59	515,062.63	3,538,876.58	V108	514,719.85	3,539,660.93
V11	514,063.64	3,538,977.32	V60	515,100.45	3,538,852.46	V109	516,194.11	3,540,658.56
V12	514,071.24	3,538,957.91	V61	515,108.03	3,538,847.62	V110	516,179.69	3,540,667.60
V13	514,037.48	3,538,907.28	V62	515,133.91	3,538,815.70	V111	516,164.87	3,540,675.96

Vertex	Coordinates		Vertex	Coordinates		Vertex	Coordinates	
	X	Y		X	Y		X	Y
V14	514,016.39	3,538,901.37	V63	515,150.36	3,538,809.36	V112	516,149.67	3,540,683.63
V15	514,009.64	3,538,875.21	V64	515,156.91	3,538,788.53	V113	516,134.14	3,540,690.58
V16	514,037.48	3,538,870.99	V65	515,191.52	3,538,760.80	V114	516,118.30	3,540,696.81
V17	514,102.46	3,538,946.94	V66	515,241.63	3,538,703.97	V115	516,102.19	3,540,702.29
V18	514,154.78	3,538,950.32	V67	515,252.90	3,538,679.62	V116	516,085.84	3,540,707.03
V19	514,181.79	3,538,973.10	V68	515,292.06	3,538,618.84	V117	516,069.29	3,540,711.00
V20	514,202.04	3,538,989.98	V69	515;332.48	3,538,583.23	V118	516,052.58	3,540,714.21
V21	514,211.32	3,539,024.58	V70	515,352.03	3,538,558.67	V119	516,035.73	3,540,716.64
V22	514,211.32	3,539,049.05	V71	515,369.39	3,538,553.39	V120	516,018.79	3,540,718.28
V23	514,231.58	3,539,056.65	V72	515,377.42	3,538,549.32	V121	516,001.80	3,540,719.14
V24	514,263.91	3,539,047.02	V73	515,396.62	3,538,539.59	V122	515,709.85	3,540,724.72
V25	514,266.47	3,539,055.63	V74	515,404.68	3,538,535.97	V123	515,671.64	3,540,726.29
V26	514,305.13	3,539,061.24	V75	515,409.25	3,538,520.14	V124	515,122.99	3,540,484.82
V27	514,323.72	3,539,052.49	V76	515,429.74	3,538,470.51	V125	514,956.71	3,540,734.53
V28	514,345.95	3,539,042.02	V77	515,461.25	3,538,432.72	V126	513,926.41	3,540,024.67
V29	514,390.69	3,539,046.66	V78	515,480.98	3,538,388.05	V127	513,839.25	3,540,155.58
V30	514,440.67	3,539,028.50	V79	515,544.15	3,538,346.86	V128	513,442.83	3,539,856.62
V31	514,456.90	3,539,061.38	V80	515,570.02	3,538,330.08	V129	513,423.72	3,539,842.21
V32	514,481.23	3,539,059.87	V81	515,598.10	3,538,262.07	V130	513,424.12	3,539,842.15
V33	514,495.03	3,539,057.27	V82	515,620.41	3,538,239.39	V131	513,427.14	3,539,841.69
V34	514,516.25	3,539,057.86	V83	515,626.72	3,538,232.97	V132	513,448.05	3,539,832.96
V35	514,553.21	3,539,041.62	V84	515,633.73	3,538,225.84	V133	513,478.14	3,539,809.89
V36	514,592.56	3,539,036.49	V85	515,653.47	3,538,214.01	V134	513,517.96	3,539,739.32
V37	514,636.12	3,539,029.51	V86	515,671.96	3,538,209.50	V135	513,547.58	3,539,714.15
V38	514,646.01	3,539,026.21	V87	515,696.07	3,538,183.93	V136	513,581.92	' 3,539,683.50
V39	514,655.11	3,539,008.08	V88	515,713.23	3,538,182.53	V137	513,647.25	3,539,657.78
V40	514,671.24	3,538,988.95	V89	515,715.61	3,538,178.64	V138	513,663.61	3,539,658.73
V41	514,694.48	3,538,983.28	V90	515,729.47	3,538,192.64	V139	513,680.25	3,539,643.62
V42	514,703.04	3,538,968.07	V91	516,306.56	3,538,775.13	V140	513,688.20	3,539,626.95
V43	514,732.86	3,538,943.41	V92	516,197.17	3,538,889.13	V141	513,704.22	3,539,639.03
V44	514,777.87	3,538,912.49	V93	516,094.01	3,538,996.64	V142	514,023.07	3,539,879.49
V45	514,837.74	3,538,912.39	V94	516,010.48	3,539,083.69	V143	514,335.51	3,540,117.72
V46	514,845.66	3,538,906.82	V95	516,826.21	3,539,806.42	V144	514,431.76	3,540,002.94
V47	514,863.75	3,538,886.78	V96	516,567.79	3,540,175.3?	V145	514,529.01	3,539,887.74
V48	514,869.78	3,538,880.09	V97	515,699.64	3,539,407.65	V146	514,626.11	3,539,772.37
V49	514,906.08	3,538,839.87	V98	515,654.77	3,539,454.41	V147	513,998.53	3,539,301.79

Vertex	Coordinates		Vertex	Coordinates		Vertex	Coordinates	
	X	Y		X	Y		X	Y
						Surface (ha)		332.99

g. Within the **PROJECT** polygon, the REGULATED PARTY specified the location coordinates of the liquefaction plant (including the liquefaction trains, burners and embankments areas), with surface of **44.78 ha**, as follows:

Vertex	Coordinates		Vertex	Coordinates	
	X	Y		X	Y
V1	514,545.26	3,539,477.04	V18	515,289.85	3,539,301.22
V2	514,557.53	3,539,447.36	V19	515,100.46	3,539,436.67
V3	514,979.52	3,539,134.98	V20	515,050.12	3,539,453.89
V4	515,033.94	3,539,018.29	V21	514,968.13	3,539,512.42
V5	515,185.45	3,538,906.46	V22	514,931.90	3,539,512.20
V6	515,212.30	3,538,863.84	V23	514,750.84	3,539,651.77
V7	515,604.36	3,538,588.47	V24	514,724.46	3,539,655.42
V8	515,629.20	3,538,687.81	V25	514,719.85	3,539,660.93
V9	515,867.14	3,538,783.33	V26	514,692.39	3,539,641.13
V10	515,862.39	3,538,837.11	V27	514,691.87	3,539,641.51
V11	515,811.52	3,538,891.52	V28	514,688.50	3,539,640.04
V12	515,724.77	3,538,895.40	V29	514,684.87	3,539,642.71
V13	515,630.33	3,538,920.89	V30	514,684.04	3,539,641.57
V14	515,535.11	3,539,007.06	V31	514,688.48	3,539,638.30
V15	515,418.68	3,539,148.47	V32	514,551.97	3,539,539.83
V16	515,380.66	3,539,222.38	V33	514,550.27	3,539,534.88
V17	515,380.93	3,539,251.87	V34	514,548.17	3,539,523.62

h. The **REGULATED PARTY** specified the need to construct a heavy traffic road from the MOF to the liquefaction plant, to transport heavy and/or huge loads, occupying **11.08 ha**, including embankments, with approximate length of **1,700.90 m**, and maximum width of **30.5 m**, located in the following coordinates:

Chainage	Coordinates UTM WGS 84 Time Zone 11		Chainage	Coordinates UTM WGS 84 Zona 11	
	X	Y		X	Y
0+000	514,670.4044	3,539,623.6024	0+900	514,244.2185	3,540,115.4218
0+050	514,657.9914	3,539,671.5009	0+950	514,204.4544	3,540,085.1212
0+100	514,670.0618	3,539,719.4869	1+000	514,164.9353	3,540,054.4646
0+150	514,693.3817	3,539,763.6753	1+050	514,125.4563	3,540,023.8080
0+200	514,706.6977	3,539,811.7346	1+100	514,085.8138	3,539,993.3415
0+250	514,707.7097	3,539,861.5942	1+150	514,042.8970	3,539,967.8000
0+300	514,701.7534	3,539,911.2380	1+200	513,996.3377	3,539,949.7321
0+350	514,693.6323	3,539,960.5271	1+250	513,947.4261	3,539,939.6386
0+400	514,676.7356	3,540,007.5038	1+300	513,897.5179	3,539,937.7991

Chainage	Coordinates UTM WGS 84 Time Zone 11		Chainage	Coordinates UTM WGS 84 Zona 11	
	X	Y		X	Y
0+450	514,651.1721	3,540,050.3851	1+350	513,847.8834	3,539,943.6030
0+500	514,617.8841	3,540,087.5901	1+400	513,798.1284	3,539,948.0093
0+550	514,578.0989	3,540,117.7472	1+450	513,748.3306	3,539,944.2155
0+600	514,533.2834	3,540,139.7444	1+500	513,699.8521	3,539,932.2129
0+650	514,485.0899	3,540,152.7707	1+550	513,654.0366	3,539,912.3343
0+700	514,435.3116	3,540,157.0333	1+600	513,612.1538	3,539,885.1306
0+750	514,385.3603	3,540,159.1488	1+650	513,573.6200	3,539,853.2721
0+800	514,335.6951	3,540,154.1440	1+700	513,535.2035	3,539,821.2694
0+850	514,288.0142	3,540,139.3721	1+700.89	513,534.5126	3,539,820.6938

Also, to improve traveling conditions, the liquefaction plant will require primary roads approximately **6 m** wide, strategically distributed to access each working area. Interconnection with other areas will require four main roads, specified in the following table:

Roads	Initial Coordinates		Final Coordinates		Length (m)	Width (m)
	X	Y	X	Y		
Access road, Meeting Center	514,522.64	3,539,573.77	515,338.49	3,538,746.41	1,187.33	4.5
Access road, Control Room	514,536.87	3,539,331.61	514,767.08	3,539,357.19	302.77	6
Road No. 1 – Personnel Emergency Exit	514,899.04	3,539,138.53	515,097.42	3,539,060.37	213.23	2.5
Road No. 2 – Personnel Emergency Exit	515,583.19	3,538,577.13	515,617.68	3,538,694.34	310.31	2.5
Primary roads – liquefaction Plant	Main perimeter road around liquefaction trains				4,530	6

i. The **REGULATED PARTY** stated that the MOF dock will be used to load and unload equipment, modules and materials. It will have roll on/roll off and lifting maneuvering capacity, and mooring dock for tugboats needed to assist tankers docking activities in the **PROJECT** operation and maintenance stage. The MOF will be located in the following coordinates:

Component	Vertex	Coordinates		Surface (ha)
		X	Y	
MOF – Terrestrial Ecosystem	V1	513,583.86	3,539,682.73	1.08
	V2	513,602.71	3,539,696.81.	
	V3	513,623.60	3,539,714.21	
	V4	513,501.68	3,539,859.94	
	VS	513,474.84	3,539,837.62	
	V6	513,459.07	3,539,824.51	
	V7	513,478.14	3,539,809.89	
	V8	513,517.96	3,539,739.32	
	V9	513,547.58	3,539,714.15	
	V10	513,581.92	3,539,683.50	
	V11	513,583.86	3,539,682.73	
MOF in the Marine Ecosystem (including dock, causeway, breakwater and mooring area)	V1	513,517.96	3,539,739.32	11.48
	V2	513,478.14	3,539,809.89	
	V3	513,448.05	3,539,832.96	
	V4	513,427.14	3,539,841.69	
	VS	513,423.72	3,539,842.21	
	V6	513,170.23	3,539,651.04	
	V7	513,385.88	3,539,391.78	
	V8	513,688.20	3,539,626.95	
	V9	513,680.25	3,539,643.62	
	V10	513,663.61	3,539,658.73	
	V11	513,647.25	3,539,657.78	
	V12	513,581.92	3,539,683.50	
	V13	513,547.58	3,539,714.15	

j. El **REGULATED PARTY** specified that dredging activities will be required in the area considered for the MOF temporary marine dike, considering the area bathymetry and level of -8 m. The drenching technique will be limited and confined underwater blasting, to eliminate potential dangers, to enable safe, smooth vessel access in the MOF area. It will use a drilling pattern of 1.5 m x 1.5 m, with charge weight of 27 kg per hole, with maximum limit of 10 shots, aiming to minimize environmental impacts. Capped drill holes will be prepared, with minimum diameter of 100 mm, that will be drilled with individual or multiple drilling equipment, mounted on the sides of a Jack-up platform or a static work platform. The time of the year proposed for the blasting activities is before the second half of December, considering that whales migrate north and south from December through April.

k. Onshore, the **REGULATED PARTY** will require a total surface of **332.99 ha**, including the area where the regasification plant is currently operating. For the permanent areas, the **PROJECT** will consider **81.42 ha**; out of which **69.94 ha** will be on the terrestrial ecosystem and **11.48 ha**, on the marine ecosystem. Temporary surfaces will require a total of **45.48 ha** in the terrestrial ecosystem, as detailed in the following table:

Component		Permanent Facilities, Surface (ha)	Permanent Embankments, Surface (ha)	Total Permanent Surface (ha)
Liquefaction Plant	Liquefaction Trains	21.83	15.21	44.78
	Burners	7.74		
Heavy traffic road		5.17	5.92	11.08
Parking lot		0.47	-	0.47
Control room area		1.01	-	1.01
Substation and racks area		4.31	-	4.31
Access road to the Meeting Center		0.27	-	0.27
Road No. 2 – Personnel emergency exit		0.01	-	0.01
Primary roads to the liquefaction Plant		0.02	-	0.02
Plant Nursery		2.91	-	2.91
Racks		0.01	-	0.01
MOF material area		2.85	1.15	3.99
MOF (Terrestrial ecosystem)		1.08	-	1.08
Total (ha)		**47.67**	**22.27**	**69.94**

l. The **REGULATED PARTY** specified that, during the site preparation and construction stages of the **PROJECT**, it has been considered to use temporary construction facilities (TCF), as follows:

Component	Surface		
	Temporary Platform (ha)	Temporary Embankments (ha)	Total Temporary (ha)
TCF #1	6.41	0.28	6.69
TCF #2	0.55	-	0.55
TCF #3	1.22	0.41	1.63
TCF #4	2.69	0.77	3.46
TCF #5	4.71	-	4.71
TCF #6	3.24	0.58	3.82
TCF #7	7.11	1.22	8.33
TCF #8	8.57	2.78	11.36
TCF #9	4.93	-	4.93
Total	**39.44**	**6.04**	**45.48**

m. As specified by the REGULATED PARTY, the PROJECT total surface is of 129.43 ha, distributed as follows:

Concept	Surface (ha)
Permanent surface - Terrestrial Ecosystem	69.94
Permanent surface - Marine Ecosystem	11.48
Temporary Surface	45.48
Permanent surface to be occupied within the Project Areas, not cleared and authorized for the regasification plant	2.53
Total PROJECT Surface (ha)	**129.43**

m. The **REGULATED PARTY** mentioned that, within temporary facilities to be placed in the temporary areas are: offices, the storehouse complex, concrete mixing plants, parking lots,

n. workshops, switching yards, and communication machinery and facilities.

o. The **REGULATED PARTY** indicated that the feeding gas pipeline will arrive to the perimeter of the liquefaction plant, from an upstream measuring station (supplied by third parties), at minimum pressure of 5,500 kPag (55 barg), and temperature ranging from 10°C to 50°C. La feeding gas pipeline will split in two heads feeding trains 1 and 2, respectively.

p. That the **REGULATED PARTY** described the **PROJECT**, process, which is summarized below:

Unit	Description
00. Common NG Entry Facilities	This unit is the process starting point. This is a new process unit consisting only of the line that will be connected to the gas pipeline supplying NG to the liquefaction plant downstream the custody transfer measuring station (owned and operated by Gasoducto Rosarito), that in turn, will split in two lines supplying both liquefaction trains.
11. Entry and Mercury Removal Facilities	Feeding NG from the gas pipeline enters arrives to the perimeter limit of the liquefaction process, from a new measuring station (owned and operated by Gasoducto Rosarito), at minimum pressure of 5,500 kPag and maximum of 10,200 kPag; and minimum temperature of 10°C and maximum of 50°C. The NG supply line splits in two heads, each one feeding one of both trains. This includes the entry and mercury removal facilities.
12. Acid Gas Removal	Feeding NG from Unit 11, Entry and Mercury Removal Facilities, will flow to the AGRU (Unit 12). The main purpose of the AGRU will be the removal of carbon dioxide (CO_2) and hydrogen sulfur (H_2S) to avoid clogging due to CO_2 freezing in cryogenic units downstream, and comply with LNG specifications for H_2S. The AGRU will use an absorption process based on formulated MDEA. The Acid Gas Absorption Tower (J1-1201), and the Amine Regenerator (J11202), and their associated equipment, are a part of this unit.
14. Dehydration	Treated feeding gas will flow from Unit 12 to Unit 14 to be dried. Feeding gas from the AGRU will be saturated with water. The purpose of Unit 14 will be reduce such water content to <0.1 ppmv, to avoid freezing of cryogenic equipment downstream.
16. LNG Recovery and Fractionation	Unit 16 is located downstream Unit 14, and its objective is reducing contents of heavy hydrocarbons (C5+) in dry feeding gas to less than 500 ppmv (0.05 mol%), and of benzene to less than 1 ppmv, to

Unit	Description
	avoid freezing in cryogenic lines and equipment downstream. This unit will also recover LGNs from feeding NG, which will be later fractionated to ethane and propane (for refrigerant replenishment), and residual condensate C5+ (to be used as fuel gas).
19. Liquefaction	Feeding NG from Unit 16 will flow to Unit 19. The objective of the liquefaction system is liquefying NG to produce LNG desired. The liquefaction process is based on the C3MR liquefaction process, licensed by APCI.
31. Refrigeration with Propane and MR	The APCI's C3MR process will use propane for the pre-cooling and a refrigerant blend for NG liquefaction. The refrigeration system will have two independent closed loops, the propane refrigerant loop, and the MR refrigerant loop. In general, the propane refrigerant will provide the initial refrigeration demand, up to ≈ -34°C, which will include feeding gas and MR refrigerant pre-cooling, and refrigeration for other process users. The MR refrigerant will provide final cooling, up to ≈ -160°C, depending on the composition, and provide most of the refrigeration required to cool and condense feeding NG and MR. The MR composition will be optimized to suit the feeding cooling characteristics, and get high thermodynamic efficiency.
8.1. Expansion Fuel Gas (EFG), and High Pressure Fuel Gas System (ISBL)	The EFG system will expand light inert components of LNG product coming out from the MCHE. The separated liquid stream will flow to the tanks, and the EFG will be compressed to be used as ISBL High Pressure Fuel Gas. The High Pressure Fuel Gas System will provide fuel gas to the gas turbine of the MR refrigerant High/Medium pressure compressors (G1-3101); to the gas turbine of the propane/refrigerant high pressure compressors (G13102); and the low pressure fuel gas system.
8.2 ISBL Thermal Oil	Each LNG train will be equipped with a thermal oil system to provide the heating medium for different users at two different temperature levels, depending on the exchanger heat load: Thermal oil temperature for low temperature users will be regulated by a flow ratio controller that will determine a thermal oil flow from the thermal oil heater (H1-3109), and a thermal oil proportional flow from the thermal oil expansion tank (D1-8202). Thermal oil temperature for high temperature users will be regulated by a temperature controller regulating a control valve on the discharge line of the thermal oil setting cooler (H1-8202). Under this scheme, the more thermal oil circulating through the cooler, the lower the temperature of thermal oil entering into the WHRU and, therefore, the lower the temperature of thermal oil exiting from it, vice-versa.
82. ISB Tempered water and thermal oil L	Tempered water will be used as cooling fluid for auxiliary systems of different rotatory equipment units, including thermal oil pumps, poor amine pumps, propane compressors, MR refrigerant compressors, and turbine actuators, expansion fuel gas compressor, NG reinforcement compressor, and regeneration gas compressors.
87. Recovered water tank	NG will leave the Acid Gas Absorption Tower (J1-1201), saturated with water of the amine solution. Water recovered from the NG stream will be collected in the liquid separation tank of the feeding gas dryer (D1-1411), and the regeneration gas separator (D1-1412). From these tanks, recovered water will flow to the recovered water tank (D1-8703) operating under level control. From the recovered water tank, recovered water pumps (P1-81712A/B) will send water to the top (water washing section) of the Acid Gas Absorption Tower (J1-1201). This configuration will reduce amine solvent losses in the system.

q. The **REGULATED PARTY** explained that, as the **PROJECT** site is mainly composed by solid and fractured basalt rock, ground leveling and foundations lying works will require blasting activities in the following areas: process trains, multi-points enclosed burner, process area available in the regasification plant, heavy traffic road, and temporary facilities.

r. The **REGULATED PARTY** specified that given its location, the **PROJECT** has no potable water supply from the municipal network. As sea water is the only supply source, there is a desalination plant with capacity for 20 m^3/hr. Therefore, a new desalination plant with the same capacity has to be built, to satisfy following needs: general services in the different process areas, firefighting water network; administrative buildings, workshops, emergency showers and eye-wash stations, and drinking fountains. Sea water will be treated by a desalination system fed by sea water pumps, to be later treated in the sea water reverse osmosis (SWRO) package. A cleaning-in-site system is also available for chemical cleaning and maintenance.

s. The **REGULATED PARTY** mentioned having two effluent discharges authorized in the regasification plant, and will include two more to supplement the MOF area. The following table describes the new effluent discharges:

Component	Vertex	Coordinates	
		X	Y
Discharge 3	V1	513565.5096	3539675.2690
	V2	513561.7300	3539671.9957
	V3	513565.0034	3539668.2161
	V4	513568.7830	3539671.4894
Discharge 4	V1	513484.7714	3539790.0542

- **Discharge 1:** This is an existing discharge that will be modified during the **PROJECT** development to collect and discharge a larger flow volume. Effluents treated by this discharge, which were clean stormwater, now will include treated contaminated stormwater. A collection pond will be added, with concrete overflow weir to intercept light hydrocarbons and solids, and a sliding gate for emergency closing. The discharge will be made into the sea. The design flow in the dry season will be 19.6 m^3/hr.
- **Discharge 2:** This is an existing discharge that will be no modified. This is the current discharge of the regasification plant, originally designed to discharge the ORVs and all effluents in the facilities. This stream will also receive the rejection effluents from the desalination plant and the sanitary wastewater treatment considered for the **PROJECT**. It is not expected to change the discharge design, and it will be poured into the sea. The design flow in the dry season will be 200 m^3/hr.

- **Discharge 3:** This is a fully new discharge. Stormwater will be collected in ditches installed along the heavy traffic road; it will have sewers, collection pond, sliding door and discharge channel. The discharge will go to the sea.
- **Discharge 4:** This is a fully new discharge receiving wastewater from sanitary services and bilge water generated by tugboats. It will have a septic tank and a clarification biodigester. Treated water will be used to irrigate the plant nursery and reforested areas. Water discharged will comply with NOM-003-SEMARNAT-1997, establishing the maximum allowable contaminants limits for treated wastewater used in public services. Discharges 3 and 4 will be located in the MOF.

t. In the Overall Work Program, the **REGULATED PARTY** established a **10-years** period for the site preparation and construction stages, considering two phases, each one of them including the construction of each liquefaction train, **35 years** for the operation and maintenance stage, and **1.5 years** for the abandonment stage. The following table summarizes the main activities included in each stage:

Works and Activities		**Duration (months)**
1.0	**Environmental Programs**	**9**
1.1	Boundaries demarcation – Topography	3
1.2	Flora and fauna rescue	6
1.3	Plant nursery relocation and enabling	9
2.0	**Site Preparation**	**12**
2.1	Mobilization of temporary facilities	6
2.2	Land clearing	10
2.3	Installation of perimeter fences	10
2.4	Road preparation (temporary)	6
3.0	**Civil Works – Earthmoving (in the liquefaction area)**	**18**
3.1	Cut and fill	16
3.2	Road preparation (permanent)	10
3.3	Excavation and leveling	12
4.0	**Works – Heavy traffic road (HHR)**	**12**
4.1	Cut and fill	6
4.2	Unpaved roads	4
4.3	Finishes	4
5.0	**Offshore Works (MOF)**	**28**
5.1	Boundaries demarcation in the marine ecosystem	1
5.2	Rescue of marine flora and fauna	3
5.3	Civil work (cut, filling, excavation and leveling	10
5.4	Breakwater construction	6
5.5	Temporary dock	4
5.6	Dredging	6

Works and Activities		Duration (months)
5.7	Civil work (dock and associated infrastructure)	10
5.8	Mooring works	4
5.9	Marine marking	2
6.0	**LNG – Third Tank**	**40**
6.1	Foundation	4
6.2	Exterior tank - concrete	12
6.3	Interior tank – steel/nickel	12
6.4	Mechanical/electrical installation	12
6.5	Testing	3
7.0	**Power Generation**	**12**
7.1	Foundation	3
7.2	Mechanical work	5
7.3	Electric work	3
7.4	Testing	1
8.0	**First Liquefaction Train (including burners)**	**46**
8.1	Foundation	20
8.2	Equipment assembly	24
8.3	Lines installation	24
8.4	Electric and mechanical installation	18
8.5	Hydrostatic testing	6
8.6	Performance testing	3
9.0	**Modification of Existing Facilities**	**48**
9.1	Boundaries demarcation in the marine ecosystem	3
9.2	Rescue of marine flora and	6
9.3	Expansion of the existing breakwater and dock	44
9.4	Electric and mechanical installation/modification	18
10.6	Performance testing	3
11.0	**Decommissioning of Temporary Facilities and General Cleaning**	**6**
11.1	Temporary facilities dismantling	4
11.2	General cleaning	4
12.0	**Site abandonment**	**36**
12.1	Full operation close down	3
12.2	Dismantling and demolition	21
12.3	Abandonment	12.

Development and description of activities included in each **PROJECT** stage were detailed in Chapter II of the **EIM-R** delivered by the **REGULATED PARTY**.

Correlation with Legal Planning and Ordering Instruments Applicable

IX. That under Article 35, Second Paragraph of the **LGEEPA**, and Article 13, Fraction III of the **REIA**, stating the **REGULATED PARTY** obligation to include in the EIM-R, the correlation of works and activities proposed with legal planning and ordering instruments applicable among activities included in the **PROJECT**. Here, and considering that the proposed location for the **PROJECT** is in the municipality of Ensenada, in the state of Baja California; it has been found that such site is submitted to the following legal instruments:

a. General Territory Ecological Ordering Program

On **Pages 39** to **47** of **Chapter III** de la **EIM-R**, the **REGULATED PARTY** specified that the **PROJECT** is submitted to the **General Territory Ecological Ordering Program *(Programa de Ordenamiento Ecológico General del Territory)*** **(POEGT)**, as the site proposed is within the Biophysical Environmental Unit *(Unidad Ambiental Biofísica)* **(UAB) No. 1.**

The **POEGT** specifically promotes a coordination and co-responsibility scheme among sectors of the Federal Public Administration enabling the generation of synergies and promote sustainable development in every ecological region identified across the national territory. Therefore, the **PROJECT** area will be located within the **UAB No. 1**, which has the following characteristics:

UAB	Name	Environmental Policy	Strategies
1	Sierras of Baja California	Sustainable Exploitation and Preservation	1, 2, 3, ,4 ,5, 6,7, 8, 12, 14, 15, 15BIS, 16, 17, 19, 20, 21, 22, 23, 27, 30, 31, 32, 33, 37, 40, 41, 42, 43, 44

Also, the strategies and ecological criteria applicable to the **Ecological Region 10.32 and UAB 1** and their correlation with the **PROJECT** proposed by the **REGULATED PARTY** are described below:

Type	Strategy Number	Correlation with the PROJECT
Group 1. Aimed to achieve the environmental sustainability of the Territory		
A) Preservation	**Strategy 1:** Preservation *in situ* of ecosystems and their biodiversity.	The **PROJECT** is considering implementation of control, prevention, mitigation and compensation measures to develop preservation strategies for local ecosystems and their biodiversity, with specific programs to rescue flora and wildlife inhabiting in areas specified, as it was addressed in previous infrastructure authorized projects.

Type	Strategy Number	Correlation with the PROJECT
	Strategy 2: Recovery of endangered species.	All three environmental stages of the **PROJECT**, control, prevention, mitigation and compensation measures focused on the rescue and immediate relocation of flora and wildlife species listed in any risk category of NOM059-SEMARNAT-2010, and all other species with ecological relevance in the region.
	Strategy 3: Knowledge, analysis and monitoring of ecosystems and their biodiversity.	Information developed during the **EIM-R** preparation and programs arising from the implementation of infrastructure authorized, has increased knowledge of the ecosystem and biodiversity present in the proposed location.
B) Sustainable Exploitation	**Strategy 4.** Sustainable exploitation of ecosystems, species, genetic resources, and natural resources.	The **PROJECT** is not pursuing, as such, the exploitation of natural resources. However, all applicable prevention and mitigation measures will be implemented to ensure continuity of biological processes under development in the influence zone.
	Strategy 7: Sustainable exploitation of forest resources.	For the forest clearing required for the **PROJECT**, despite not pursuing its exploitation, the environmental impact due to the forest soil use change has been evaluated, and will be presented in the corresponding Technical-Justification Study.
	Strategy 8: Valuation of environmental services.	As related to this strategy, one of the main objectives of the **PROJECT** implementation is maintaining the continuity of environmental services currently provided by the ecosystem. Therefore, several control, prevention and mitigation measures will be implemented, to avoid and mitigate environmental adverse effects.
C) Protection of Natural Resources	**Strategy 12:** Protection of ecosystems.	The **PROJECT** has considered control, prevention, mitigation and compensation measures coadjuvating to reduce adverse impacts in the ecosystem and the environment, and actions that will be implemented to protect the ecosystem.
D) Protection of Natural Resources	**Strategy 14:** Restoration of forest ecosystems and agricultural soils.	Control, prevention, mitigation and compensation measures considered by **PROJECT**, include restoration actions in specific sites, to compensate impacts on forest soils.
E) Sustainable use of non-renewable resources, and economical activities based on production and services	**Strategy 19.** Strengthen the electric power reliability and security supply in the Territory, based on diversification of power sources, increasing participation of clean technologies to reduce the dependence on fossil fuels, and emissions of greenhouse gases (GHGs).	The **PROJECT** is coherent with this strategy, as the final product to be obtained is an alternative energy source with lower atmospheric emissions and GHGs generation.
	Strategy 20. Mitigate the increment of GHGs and reduce the Climate Change effects by promoting clean power generation technologies, and facilitating the bioenergetics market under competitive conditions,	Supplementing correlation above, using LNG as energy source with lower GHGs emissions, shall coadjuvate to displace other fossil fuels in mitigation strategies, thus reducing the Climate Change effects.

Type	Strategy Number	Correlation with the PROJECT
	protecting food safety and environmental sustainability.	
Group III. Aimed to Strengthen Institutional Management and Coordination		
B) Territory Ordering Planning	**Strategy 44**: Promote regional development with actions coordinated among all three government levels, and agreed with the civil society.	The **PROJECT** is intended to promote the regional economic development, with participation of all three government levels, with benefit for the civil society.

The **REGULATED PARTY** expressed that the applicability of measures proposed for each strategy above will be observed. Also, based on the analysis conducted by this **DGGPI**, on condition that the **REGULATED PARTY** observes the implementation of each proposal, no guideline or strategy within the **POEGT** restricts the operation of the **PROJECT** in the state of Baja California.

b. Ecological Ordering Program of the state of Baja California (POEBC)
On **Pages 47** to **87** of **Chapter III** de la **EIM-R**, the **REGULATED PARTY** specified that the **PROJECT** is submitted to the **General Territory Ecological Ordering Program *(Programa de Ordenamiento Ecológico General del Territory)*** **(POEGT)**, as the site proposed is within the Environmental Management Unit *(Unidad de Gestión Ambiental)* **(UGA) No. 2** and has the following characteristics:

UGA/ Polygon	Environmental Policy	Ecological Guidelines/Goals	Ecological Regulation Criteria
2 / 2.a	Sustainable Exploitation	Irrigation agriculture, seasonal agricultura, human settlements, vegetation, grasslands	Suburban: ah1 al ahl6 Turism: tu0 1 al tu 13 Forestal: fo04 al fo08 Ecological footprint: he01 al he07; he09 al he 15 Industrial: ind01 al ind18 Cattle raising: pe01 al pe06 Preservation: con01 al con05, con07 al con15 Hidrological: hidro0l al hidro08 Roads: cam01 al cam03 Agriculture: agrO1 al agr06 Mining: min07; min10 al min22 Aquaculture and fisheries: acip01 al acip 09

The **List of General Criteria** on ecological regulation applicable across the ordering area, and their correlation with the **PROJECT**, is described in the following table:

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
1. Compliance with local territorial and ecological ordering programs.	Consistent with this general criterion, the **PROJECT** development will be conducted under a Sustainable

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
	Exploitation environmental policies with no prohibitions and/or restrictions to its execution.
2. Development of any type of works and activities – including exploitation of natural resources – shall comply with provisions established in environmental legislation in effect, with environmental guidelines specified in this ordering, and with the corresponding plans and programs in effect.	The **PROJECT** is consistent with this criterion, as it complies with provisions stipulated in the environmental legislation in effect, with environmental guidelines specified in this ordering, and with the corresponding plans and programs, as established in this analysis.
3. Activities in the state will be developed according to their natural vocation, and will be compatible with adjacent activities, with strict adherence to applicable legislation.	Consistent with this criterion the **PROJECT** development has been proposed in a site where the regasification gas already authorized for ECA is currently operating, in the *Centro Energético La Joyita*, the vocation of which, according to the Coastal Tijuana- Rosarito-Ensenada Corridor (COCOTREN) Program, is energy infrastructure. Also, according to the POEBC, the site proposed belongs to an UGA with an environmental policy of “Sustainable Exploitation”. Therefore, it is evident that the **PROJECT** complies and is compatible with this criterion.
4. In areas with no local ecological ordering programs locales or specific management plans, specific regulations are applicable, according to the nature of activities to be conducted: preparation of a strict site analysis, environmental impact assessment, declarations, specific control rules, and all other mechanisms ensuring and assuring the operations safety, and maintenance of environmental functions and services.	The **PROJECT** area is included in other instruments regulating soil use from different competence spheres, for example, the COCOTREN.
5. Works and activities conducted in areas with use restriction shall adhere to legal provisions in effect, and acquire environmental easement, adopt environmental impact compensation areas and mechanisms, safeguarding conditions and values of environmental relevance.	This criterion is not applicable to the **PROJECT** as there are no use restrictions.
6. No human settlements or buildings are allowed in risky zones, for example, creek beds or courses, steep slopes, geological faults, or areas susceptible to landslides; shores exposed to storm waves and erosion processes.	This criterion is not applicable to the **PROJECT**, as it is not found in risky zones, for example, creek beds or courses, steep slopes, geological faults, or areas susceptible to landslides; shores exposed to storm waves and erosion processes.
7. Development of infrastructure works around creeks and river courses, shall be submitted to the environmental impact authorization granted by the competent authority.	The **PROJECT** is not placed around creeks or river courses. Nevertheless, it has been submitted to an environmental impact assessment.
8. Works and activities conducted in the state shall consider measures adequate to ensure continuity of water streams and wild biological corridors.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework. The **PROJECT** has

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
	considered specific mitigation measures on water, flora and wildlife.
9. Productive activities allowed in the state shall consider using clean technologies to prevent environmental deterioration and promote energy efficiency.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
10. Construction shall be developed in harmony with the surrounding environment.	The **PROJECT** is related to, and complies, with this criterion, as it considers implementing a Landscape Conditions Compliance Program (visual impact)
Waste Integral Management	
1. Every development and construction work shall consider integral waste management measures.	Consistent with this criterion, several integral waste management activities have been considered, including minimization, segregation, collection and storage, transportation, treatment and disposal; and specific personnel training.
2. Management and final disposal of construction works, productive and domestic activities shall comply with all legal provisions for the prevention and integral management of urban solid waste, hazardous waste, and special management waste.	Consistent with this criterion, the **PROJECT** has included a number of waste integral management activities, such as: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training.
3. Promoters of development works and activities shall prepare integral waste management plans and programs, promoting sustainable development by reducing source generation, conversion, reuse and reclaiming of solid urban waste, hazardous waste, and special management waste.	Consistent with this criterion, the **PROJECT** has included a number of waste integral management activities, such as: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training.
4. In contaminated sites, remediation programs and measures shall be applied, including awareness raising campaigns focused on the right management of such sites.	This criterion is not applicable to the **PROJECT**, as the site proposed has no contaminated sites.
5. Solid urban waste and hazardous waste generators shall condition a waste collection and temporary storage area within their facilities, to receive, transfer and store waste, before sending it to treatment, recycling, reuse, co-processing and/or final disposal authorized facilities.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training.
6. site selection, construction and operation of hazardous waste final disposal facilities, shall comply with all legal provisions applicable.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training. Activities above will comply with all applicable municipal, state and federal legislation.

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
7. Industrial waste, hazardous waste and special management waste generated by maquiladora industry in the state, shall be returned to their country of origin, under environmental customs and foreign trade legislation applicable.	This criterion is not applicable to the **PROJECT**, as it does not include activities described.
8. Hazardous waste controlled confinement places, and their storage, collection, transportation and final disposal, shall comply with legal provisions applicable.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training. Activities above will comply with all applicable federal legislation.
9. It is priority that hazardous materials and waste management complies with all legislation applicable.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training. Activities above will comply with all applicable federal legislation.
10. Construction of waste disposal infrastructure shall not be made on water table recharge zones, or near water tables, or very permeable soils.	This criterion is not applicable to the **PROJECT**, as it does not include activities described.
11. Creation and expansion of population centers and human settlements, and suburban areas, shall promote installation of transfer stations complying with technical and legal regulations applicable.	This criterion is not applicable to the **PROJECT**, as it does not include activities described.
12. Disposal of waste such as PVC, PCP, agrochemicals and other organic compounds require adequate management to protect the users, the population and the environment, complying with all applicable legislation.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training.
13. Disposal of industrial waste, special management waste, hazardous waste and solid urban waste, and or garbage is forbidden in unauthorized sites.	Consistent with this criterion, it has been planned to conduct several integral waste management activities, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training. Waste transportation, treatment and disposal, will be made through contract companies properly authorized, that will provide final disposal manifests for all waste generated by the **PROJECT**.
14. Open burning of any type of waste and/or garbage is forbidden. People conducting agricultural activities shall be trained to avoid slash and burn practices.	Consistent with this criterion, the **PROJECT** is not considering burning any waste type.
15. Development of all kind of public private activities, shall prepare waste reduction, reuse and recycling plans.	Consistent with this criterion, and based on waste related to the **PROJECT**, a number of integral waste management activities have been considered, including: minimization, segregation, collection and storage, transportation, treatment and disposal, and specific personnel training. Waste transportation, treatment and disposal, will be made

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
	through contract companies properly authorized, for waste storage, transportation, recycling and final disposal, that will provide final disposal manifests for all waste generated by the **PROJECT**. Also a solid urban waste and hazardous waste programs have been developed.
16. No organic waste containing toxic or contaminating substances shall be used as organic fertilizers.	This criterion is not applicable to the **PROJECT**, as it does not include activities described.
17. In conurbated and rural areas having no sanitary sewage, installation of septic tanks and/or ecological toilets, complying with all legislation in effect, is priority.	This criterion is not applicable to the **PROJECT**, as it does not include activities described.
18. Transportation of construction and stone materials, and debris from works and activities shall avoid emission of dust, and damages on the public health, streets, roads, public services, existing constructions and on any type of public or private property.	Consistent with this criterion, it is intended to control particulate material emissions with irrigation and stabilization of unpaved roads.
Water Resource	
1. All activities conducted in the state using water, shall comply with all applicable legislation.	The **PROJECT** will not extract water from wells or any other surface or underground source. If needed, the current ECA concession shall be updated or modified to use seawater, or sources already authorized.
2. All activities generating waste water, shall comply with all applicable legislation on treatment and further reuse.	Consistent with this criterion, the **PROJECT** will comply with all applicable legislation to treat waste water properly.
3. Developers of works and activities using large water volumes shall promote sustainable, integral water management plans including payment of rights, installation of water treatment and reuse facilities, and water saving systems, among other measures, allowing the sustainable use of this resource.	Consistent with this criterion, and framed by the water integral management policy, the **PROJECT** will pay the corresponding use rights; will install a water treatment facility for further reuse, under applicable legislation. Also, the **PROJECT** will install water saving systems to promote sustainable use of this resource.
4. Productive activities generating waste water from their processes shall have a treatment system before discharching such water to receiving bodies, including sewage and sanitation systems.	The **PROJECT** will have a waste water treatment plant; and systems or devices to collect light and solid hydrocarbons. All discharges shall comply with applicable legislation. Treatment systems will have their own sewage and sanitation facilities to comply with this item.
5. Urban waste water shall be treated before being discharged into rivers, courses, ponds, marine waters, streams and underground.	The **PROJECT** has no urban nature. However, consistent with this criterion, waste water will be treated in a treatment plant.
6. People conducting waste water treatment activities shall reuse treatment water to irrigate green areas.	Consistent with this criterion, the **PROJECT** will reuse waste in the plant nursery and reforested areas.
7. In the development of general activities, potable water saving and reuse of gray waste water instead will be promoted.	ECA is aware of the relevance and scarcity of the water resource in this region of Ensenada. Therefore, in the

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
	PROJECT facilities and its daily operation, water saving actions will be promoted. Also, treated waste water will be used in the plant nursery and reforested areas. Water use mitigation measures have been described and considered in the Water Compliance Measures Program *(Programa de Cumplimiento de Measures de Water)*, which is a part of the Environmental Quality Follow-up Program *(Programa de Seguimiento de Calidad Ambiental)* (PSCA), currently implemented by ECA in the site.
8. Desiccation of water bodies and obstruction of fluvial runoffs is forbidden.	No water body will be desiccated, nor natural fluvial runoffs will be obstructed.
9. Construction of buildings or human settlements in water table recharge areas are forbidden.	Nature of the **PROJECT** activities is different to those described in this criterion. However, it will not be developed in water table recharge areas.
10. Modification of areas essential for water table recharge processes, including presence of riparian vegetation is forbidden.	The **PROJECT** is not intended to impact riparian vegetation, which, on the other hand is not present in the site. No water table recharge process will be impacted.
11. Development of works and activities near water courses shall avoid impacts on the beds of rivers and creeks, and on water table recharge processes, and promote the creation of biological corridors or lineal parks.	The **PROJECT** will not develop works and/or activities near water courses. Therefore, no beds of rivers and creeks, and on water table recharge processes will be impacted.
12. Closure periods established on water tables exploitation shall be observed.	The **PROJECT** will not extract water from wells or any other surface or underground source. If needed, the current ECA concession shall be updated or modified to use seawater, or sources already authorized.
13. Septic tanks, absorption wells and oxidation ponds shall be placed and built considering the soil type and permeability, and the water table depth, to avoid contaminating the aquifers. Authorization of such works will consider their environmental impact and replacement of latrines with dry toilets.	Consistent with this criterion, the **PROJECT's** environmental impact has been delivered to be evaluated, and it includes implementing a clarification biodigester in the MOF area, that will collect sanitary water and tugboats bilge water. Water from the septic tank will be treated and reused to irrigate the plant nursery and reforested areas.
14. Transportation of hazardous chemicals by sea shall comply with provisions established by the Secretary of the Navy and the International Maritime Law.	All ECA's contractors must fully comply with all requirements specified by the Secretariat of the Navy and other agencies related to transportation of hazardous chemicals, and the International Maritime Law. All transportation units and equipment shall be in optimum operation and maintenance conditions, aiming to avoid accidents which may have negative environmental impacts.
Environmental Education	
1. The federal, state and municipal governments will implement, in their offices and agencies, information systems to generate specialized data to enforce and follow-up their environmental	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
policies, and support knowledge on environmental topics.	
2. Private companies, service providers and government entities shall implement Environmental Education and Outreach Programs to promote knowledge on the natural richness of the state, and preservation mechanisms, also promoting public participation in the environmental protection and right use of natural resources.	Included among prevention and mitigation measures of the **PROJECT**, are environmental awareness programs targeted to workers in the different implementation stages. This initiative also includes actions and measures focused on environmental protection and right use of natural resources in the zone.
3. Authorities responsible for developing preservation programs for beaches and green areas, shall summon the active participation of the community to identify potential risks, and promote the right use and management of such spaces.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
4. The authorities shall launch campaigns promoting the right use of natural resources, disaster prevention, health promotion, and use of energy saving alternative technologies.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
5. Environmental education programs shall include compost preparation methods.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
6. Natural protected areas shall include routes, biological corridors and interpretative trails.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
Management and Preservation of Natural Resources	
1. Development of productive activities involving use of natural resources shall comply with provisions established in this regulation and all other applicable legislation.	The **PROJECT** is compatible with this criterion, as it complies with, and is consistent with, provisions established in this regulation and all other applicable legislation.
2. Urban areas are not allowed to extend over high agricultural, cattle raising or forestal productivity areas, buffer zones, water table recharge areas, risky areas, natural protected areas, fragile ecosystems, areas of ecological relevance, or cultural/natural heritage.	This criterion is not applicable to the **PROJECT**, as it does not include works or activities described.
3. In the development of works and activities, change of forest soil use will depend on the environmental impact authorization made by the corresponding authorities.	Complying with this criterion, the EIM has been delivered, and the corresponding Technical-Justification Study will be delivered to obtain the Change of Soil Use in Forest Lands *(Cambio de Uso del Soil en Terrenos Forestales)* (CUSTF) authorization, for the forest surface that will be impacted by the **PROJECT** works and activities.
4. The evaluation of environmental impacts of works and activities shall also consider any secondary, synergic or cumulative regional impacts.	Consistent with this criterion, all cumulative and synergic impacts with the regasification plant currently operation, facilities of the *Centro Energético La Joyita*, tourist facilities, and other soil uses existing in the RES, have been evaluated.

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
5. Regional and local ecological ordering programs, and urban development programs for population centers, must establish natural protected areas in zones identified as ecological preservation areas, special preservation areas, and priority regions.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
6. Preservation and management programs for natural protected areas shall identify their corresponding core zones and the buffer zones.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
7. The protection of natural elements with ecological value within tourist sites shall be considered.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
8. Use of natural resources must prevent soil degradation by applying prevention, mitigation and restoration measures.	Consistent with this criterion, the **PROJECT** was submitted to the environmental impact evaluation procedure.
9. Those conducting activities in areas with steeped slopes or vulnerable zones, must apply mechanical, reforestation and ground stabilization techniques.	The **PROJECT** is not located in areas with steeped slopes, however, it considers a reforestation program with regional native species, and specimens rescued from the impacted area. Such organisms can be located in the slopes near the **PROJECT** to provide ground stabilization.
10. Soil protection, erosion prevention and control works shall include protection structures such as trenches, countercurrent ramps, windbreakers, and forestation.	Consistent with this criterion, the **PROJECT** will implement erosion control actions, including soil protection and restoration measures.
11. Clearing works for any type of industrial, commercial, services or residential works or activities shall remove only the minimum layer of soil required, promoting the maintenance of soil and vegetation in adjacent properties.	Nature of this **PROJECT** is different from activities considered in this criterion. However, clearing works in surfaces specified include rescue of the organic soil horizon, that will be reused in reforestation activities.
12. Construction of off-roads require an EIM, that will be evaluated by the corresponding authority.	This criterion is not applicable to the **PROJECT**, as it does not correspond to works or activities described.
13. Construction of off-roads shall be limited to routes established and resolutions made by competent authorities.	This criterion is not applicable to the **PROJECT**, as it does not correspond to works or activities described.
14. Public entities executing forestation activities shall establish plant nurseries to produce native species.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.
15. Real estate developers shall use native flora species to populate green areas, parks and gardens.	The **PROJECT** nature is different from real estate development, therefore, this criterion is not applicable. However, it contributes to it, as all reforestation activities will use native plant species.
16. To propose any state territory as Natural Protected Area, all requirements stipulated in the General Law and its law and regulation on Natural Protected Area shall be fulfilled.	This criterion is not applicable to the **PROJECT**, as it lays within the public management framework.

Development of Works and Activities	Correlation Determined by the REGULATED PARTY
17. As related to flora and wildlife and their habitats, all use, possession, management, preservation, repopulation, and development activities, shall observe all applicable laws and regulations.	Complying with this criterion and all wildlife applicable legislation, the **PROJECT** has proposed the implementation of a wildlife rescue, protection and conservation program, together with a wildlife monitoring program.
Restoration	
1. Establishment of ecological restoration zones will be promoted in areas with environmental deterioration, to enable their recovery.	At the end of the construction stage of the **PROJECT**, restoration actions will be implemented on surfaces temporarily impacted, such as reforestation with native species kept and produced in the plant nursery.
2. Species tolerant to high salt or sodium concentrations will be introduced to avoid soil erosion.	This criterion is not applicable to the PROJECT, as it does not correspond to works or activities described.
3. Clearing debris will be used to recover soils eroded or poor in nutrients.	Clearing debris can be ground and reused in soil improvement activities, to satisfy this criterion.
4. Any person contaminating or damaging the environment, or impacting natural resources, is obliged to repair such damages, and/or restore the ecosystem and ecological balance components.	It will be strictly forbidden to contaminate and/or deteriorate the environment with actions related to the **PROJECT.** Potential impacts will be reversed with control, prevention and mitigation measures.

The **REGULATED PARTY** expressed that measures proposed for each strategy above will be applied. Also, based on the analysis conducted by this **DGGPI**, as long as the **REGULATED PARTY** complies with the implementation of each proposal, no guideline and/or strategy under **POEGT** restricts the **PROJECT** operation in the state of Baja California.

c. Regional Urban Tourist and Ecological Development Program for the Coastal Tijuana- Rosarito-Ensenada Corridor.

As expressed by the **REGULATED PARTY** and the analysis conducted by this **DGGPI**, the **PROJECT** is covered by the Regional Urban Tourist and Ecological Development Program for the Coastal Tijuana- Rosarito-Ensenada Corridor *(Corredor Costero Tijuana- Rosarito-Ensenada* **(COCOTREN)**. The following table specifies the **UGT** proposed for the **PROJECT** location:

UGT / Environmental Unit	Policy	General Urban Development Criteria per Particular Policy
26 / 2.3.4.1.b	Sustainable Use, Conservation and Protection	**ASE**, Aprovechamiento Sustentable Energético *(Sustainable Energy Use)*. Addresses the regular soil use and exploitation for energy and services infrastructure, complying with federal, state and municipal legislation.

		Regulates use of soil for energy infrastructure activities, located in buffering zones which are exposed to risks inherent to the activity.

Among the main **COCOTREN** criteria applicable to the **PROJECT** are the following:

General Urban Development Criteria per Particular Policy	General Infrastructure, and Furnishing	Correlation
ASE Addresses the regular soil use and exploitation for energy and services infrastructure, complying with federal, state and municipal legislation. Regulates use of soil for energy infrastructure activities, located in buffering zones which are exposed to risks inherent to the activity.	Promote economic development investments on energy and services infrastructure, complying with legislation promoting the sound use of the territory and regulating environmental impacts. Regulate compatibility of activities in adjacent zones, favoring soil uses in storage or industrial activities, and minimizing population settlements and concentrations in the influence radius determined by risk and urban assessments required for uses related to energy infrastructure.	The **PROJECT** is about energy, and its development will comply with all applicable federal, state and municipal legislation on soil use, environmental impact and risk, and energy, among others. Also, it promotes the regional economic development, as it implies a significant investment. Potential employment generation ranges from 5,000 to 6,000 positions in the site preparation and construction stages, and 220 for the operation, together with relevant investment on regional materials and equipment.

Also the **REGULATED PARTY** describes urban development and use in energy centers criteria, and their correlation with the **PROJECT**, as follows:

<table>
<tr><th colspan="4">Urban Development Criteria</th></tr>
<tr><th colspan="3">Use in Energy Centers</th><th>Correlation</th></tr>
<tr><td colspan="3">As related to soil uses for urbanization actions for infrastructure and services in energy centers, soil use approval requires complying with federal, state and municipal legislation. Energy infrastructure and services, for energy and service centers are:</td><td>The PROJECT nature is other than urbanization. However, it will comply with applicable federal, state and municipal legislation on soil use. It has to be noted that the project is located in the site where the regasification plant Energía Costa Azul is currently operating, in the Centro Energético La Joyita, which belongs to the infrastructure energy sector. Therefore, it correlates to, and is compatible with the Urban Development General Criteria ASE.</td></tr>
<tr><th rowspan="2">Activities and Processes</th><th colspan="2">Activities in Energy Center</th><th rowspan="2">Correlation</th></tr>
<tr><th>Rosarito</th><th>La Joyita</th></tr>
<tr><td>Operation of facilities for the transportation, reception and delivery of fuels by land or by sea.</td><td>X</td><td>X</td><td>Operation of facilities for the transportation, reception and delivery of fuels by land or by sea are expressly addressed and allowed for the Centro Energético La Joyita, in which the PROJECT, is located, therefore, it is consistent and compatible with this activity.</td></tr>
</table>

Fuels storage and blending.	**X**	**X**	Fuel storage is expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located.
Regasification of LNG.		**X**	Regasification of LNG expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located, therefore, it is consistent and compatible with this activity. On year 2003, the “LNG Reception, Storage and Regasification Terminal” owned by Energía Costa Azul was authorized on the environmental impact subject.
Water desalination.	**X**	**X**	Water desalination is expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located. Therefore, it is consistent and compatible with this activity authorized by the COCOTREN.
Power generation and transmission.	**X**	**X**	Power generation and transmission is expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located. Therefore, it is consistent and compatible with this activity authorized by the COCOTREN.
Management of fuel components and additives	**X**	**X**	Management of fuel components and additives is correlated to activities in question.
Fuel supply.	**X**	**X**	Isolated fuel supply for the isolated for the LNG plant is defined in the soil use item of this program.
Processing of NG, LP, and their components, and NG liquefaction.		**X**	The **PROJECT** consists of the development and construction of a NG liquefaction plant with production capacity of 6.2 MTPA, which in terms of urban development criteria applicable to the site proposed, i. e., the Centro Energético La Joyita, is fully compatible, as established in this activity and the process under analysis.
Use of sea water as heat transfer media (for cooling or heating purposes), in the conversion processes.	**X**	**X**	Use of sea water as heat transfer media (for cooling or heating purposes), in the conversion processes, is expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located, therefore, it is consistent and compatible with this activity.
Reception, generation, conversion, shipment, transfer, loading, storage, compression, processing, control of atmospheric emissions, transportation of fuel products or sub-products, the management of which is	**X**	**X**	Reception, generation, conversion, shipment, transfer, loading, storage, compression, processing, control of atmospheric emissions, transportation of fuel products or sub-products, the management of which is compatible with processes above, previously related to the **PROJECT**, are expressly addressed and allowed for the Centro Energético La Joyita, in which the **PROJECT**, is located, therefore, it is consistent and compatible with this activity.

<table>
<tr><td>compatible with processes above.</td><td></td><td></td><td></td></tr>
<tr><th colspan="3">Guidelines for Beaches Maritime-Terrestrial Federal Zone and Territorial Sea</th><th>Correlation</th></tr>
<tr><td colspan="3">For coastal developments, construction and operation of port infrastructure and port services facilities: ramps, launching posts, marines, moorings, etc., are submitted to financial feasibility, federal regulations and authorizations on environmental studies; the Maritime-Terrestrial Federal Zone, and the technical opinion issued by the pertinent state authorities. Coastal areas shall include the following studies:
• Tides and currents
• Bathymetry.

Based on articles 7 and 17 del of the Regulation for Use and Exploitation of the Territorial Sea, Waterways, Beaches, Maritime-Terrestrial Federal Zone and Lands Reclaimed to the Sea, published in the DOF on August 21, 1991, establishing the right of every person to enjoy the beaches and the maritime-terrestrial federal zone, and the respect owners must have for the free access, it has been determined that:

In authorizations for urban developed issued in the COCOTREN, the right of way must be considered, and public accesses to the beaches must be provided, with distances of 200 m, and maximum 500 m between them; preferably in the property limits, according to the beaches features and existing buildings, and considering if the coasts are cliffs, natural viewpoints, or have any recreational, tourist or cultural value, as determined by specific studies approved by municipal authorities. This urban development for beach Access is applicable to studies and projects developed in the COCOTREN, with any limitations applicable, and according to their technical feasibility and municipal approval.

The following criteria published in the DOF on August 14, 1990, and established in the National Urban Development Program 1990-1994, are applicable:
• Urban development is not allowed in the first dune of the beach along the coast.</td><td>The REGULATED PARTY is planning to develop and build onshore and offshore facilities for the NG liquefaction process, where the regasification plant already authorized is currently operating. Therefore, and consistent with this guideline, such activities will be conducted under all Maritime-Terrestrial Federal Zone, and state and municipal legislation applicable. A mitigation measure for the environmental factor “Sea Floor” in the geomorphology component is foreseen: monitor the coastal dynamics in the MOF area after the construction stage, according to the modeling results, with annual frequency, after completing the site preparation and construction stages. Environmental quality proposed indicators to confirm impacts are bathymetric surveys. On the other hand, the PROJECT nature is not urban, but it will comply with all Maritime-Terrestrial Federal Zone applicable legislation, and has received concession titles ISO MR DGZF-269/04 and DGZF-394/16.</td></tr>
</table>

• The coastal safety strip will have, as a minimum 20 m from the maximum tide height level reached in 20 years (high tide). It is not recommended to build 5 m below the maximum tide height marked. • Urban development in areas below the maximum tide height level, on cyclic flood areas – such as marshes, maritime channels or lagoons. Any urban areas vulnerable to hurricane tides shall be protected with ditches, breakwaters, or dredging, and establish safety strip with minimum distance of 30 m from the maximum tide height registered in the last 20 years, depending on the continental and/or marine relief.	
Ecological Evaluation Studies	**Correlation**
EIM. Integral management plan for existing ecosystems including the following aspects: environmental characterization, identification of relevant habitats; environmental services provided by the ecosystem; tourist exploitation scenarios; and preservation strategies. Studies required for the evaluation of territorial spaces with ecological value, such as natural protected areas, national parks, RAMSAR sites, and special preservation areas, identified in the Ecological Ordering Program of the state of Baja California.	Given the **PROJECT** nature, the **REGULATED PARTY** has proposed its Environmental Management Plan, which is translated into the PSCA, which is the program currently implemented by ECA in the site. Mitigation measures proposed by this **PROJECT** add to the environmental quality follow-up subprograms addressing the following factors: air, water, soil, flora, fauna, landscape and risk. On the other hand, it has to be noted that the **PROJECT** is not located within any federal, state or municipal protected area, and this criterion is focused on public management as related to the evaluation of territorial spaces with ecological value identified.
Environmental guidelines established in the Ecological Ordering Program of the state of Baja California, as ecological regulation, and applicable in the territorial ordering, aim to optimize the use, exploitation and, as applicable, the preservation of natural resources; policy guidelines, applicable to UGAs, and specific guidelines, applicable to special conservation areas.	The **REGULATED PARTY** made the correlation with legal applicable environmental legislation, and soil use regulations, corresponding to instruments updated and in effect, according to the official outreach means.

d. Official Mexican Standards

As stated by the **REGULATED PARTY** and based on the analysis conducted by this **DGGPI**, the following Official Mexican Standards *(Normas Oficiales Mexicanas)* (NOMs), are applicable to the **PROJECT** development:

Official Mexican Standard	Correlation with the Project
NOM-001-SEMARNAT-1996.	Waste water discharges in marine waters from the operation stage shall comply with this standard, never exceeding parameters established as discharge limits. Also, it will have all permits required by the National

Official Mexican Standard	Correlation with the Project
Establishing the maximum allowable limits for contaminants in waste water discharges in national waters and assets.	Water Commission *(Comisión Nacional del Water)* (CNA), and comply with all monitoring requirements specified thereon. A Discharge Measuring Program will be implemented.
NOM-003-SEMARNAT-1997. Establishing the maximum allowable limits for contaminants in treated waste waters reused in public services.	The **PROJECT** will reuse treated waste water in the plant nursery and reforested areas, and will use limits established in this standard as reference.
NOM-004-SEMARNAT-2002. Environmental protection. Sludges and biosolids. Specifications and maximum allowable limits for contaminants, for use and final disposal.	Sludges from the treatment will be analyzed to report to the environmental authority that limits specified in Tables I and 2 of this NOM are not exceeded.
NOM-041-SEMARNAT-2015. Establishing the maximum allowable emission limits for contaminant exhaust gases of gasoline fueled automotive vehicles in use.	Vehicles used for the **PROJECT** activities in the implementation stages, will be taken to certified Verification Centers, or Verification Units, to measure their contaminant exhaust emissions, according to the schedule and documents specified in the vehicle verification program, implemented by the environmental authorities. Vehicles and machinery will be submitted to periodic maintenance routines to ensure good operation conditions, and avoiding excessive hydrocarbon emissions. Such activities will be recorded in an activities control log.
NOM-045-SEMARNAT-2006 Environmental Protection. Diesel Fueled Vehicles in use. Maximum opacity limits, testing procedures, and technical characteristics of measuring equipment.	Vehicles used for the **PROJECT** activities will be submitted to the contaminant emissions verification. Diesel fueled vehicles and machinery will be submitted to periodic maintenance routines to ensure good operation conditions, and avoiding excessive hydrocarbon emissions. Such activities will be recorded in an activities control log.
NOM-052-SEMARNAT-2005. Establishing the characteristics, the identification procedure, classification and hazardous waste lists.	The **REGULATED PARTY** will manage chemicals and materials identified as hazardous, based on their corrosiveness, reactivity, explosivity and toxicity (CRETIB) characteristics, according to procedures and lists established in this NOM, and the LGPGIR provisions.
NOM-054-SEMARNAT-1993. Establishing the procedures to determine incompatibilities among two or more types of waste, considered as hazardous under NOM-052-SEMARNAT-1993.	During the site preparation, construction, operation and abandonment stages, the **PROJECT** will fully comply with this NOM, by segregating all waste types (hazardous, special management or urban solids. The facility will use waste containers properly labeled, and identifying the

Official Mexican Standard	Correlation with the Project
	corresponding hazardous waste type according to their CRETIB characteristics.
NOM-059-SEMARNAT-2010. Environmental Protection. Native Mexican flora and wildlife species. Risk categories and inclusion, exclusion or change specifications. List of endangered species.	For field works conducted in the **RES** surface for this study, flora and wildlife species included in NOM-059-SMEARNAT2010, identified with some risk category, were found. The **PROJECT** will implement prevention, control, mitigation and/or compensation measures focused on the preservation and protection of such species, and any other wildlife of ecological relevance that may be found in the **PROJECT** property.
NOM-080-SEMARNAT-1994. Establishing the maximum allowable limits for exhaust noise levels of automotive vehicles, motorcycles and tricycles in use, and their measuring method.	The **REGULATED PARTY** will check that all vehicles covered by this NOM and used in any stage of this **PROJECT**, comply with its provisions and do not exceed the maximum allowable noise limits.
NOM-081-SEMARNAT-1994. Establishing maximum allowable noise limits for fixed sources, and their measuring methods.	The **REGULATED PARTY** will install devices such as silencers, enclosures, and pipeline insulation; low-noise equipment will be selected, particularly as related to compressor, gas turbines, expanders, large transition lines, air-cooled heat exchangers, high pressure drop control valves, large motors and pumps, and units with large noise generation levels in the Operation and Maintenance stages.
NOM-085-SEMARNAT-2011 Establishing the maximum allowable atmospheric contamination emission levels for indirect heating combustion equipment, and their measuring methods.	The **REGULATED PARTY** will prepare and maintain a logbook reporting maintenance activities on combustion equipment and emissions control devices, to comply with this NOM. Also, the corresponding measures will be made by a certified lab, that will deliver all reports to be attached to the Annual Operation Schedule *(Cedula de Operation Annual)*. Emissions will be determined by Tables 1 and 2 of the standards, and any other provisions specified by the authority.
NOM-138-SEMARNAT/SSA1-2012 Establishing the maximum allowable limits of hydrocarbons on the ground, characterization sampling guidelines, and remediation specifications.	In case of an accidental spill of hydrocarbons or any chemical listed in this NOM, on the ground or adjacent surface, the **REGULATED PARTY** shall implement emergency actions and measures, and will characterize and remediate the site, according to this NOM and all environmental legislation applicable.
NOM-161-SEMARNAT-2011.	The **REGULATED PARTY** will identify all special management waste generated by the **PROJECT** (construction debris, air filters, and molecular sieves), and

Official Mexican Standard	Correlation with the Project
Establishing criteria to classify special management waste and determine which are submitted to the Management Plant; a waste list, the list inclusion or exclusion procedure, and elements and procedures to prepare management plans.	listed in this NOM, to prepare the corresponding Management Plan and deliver it to the corresponding authority. It has to be noted, that such waste will be managed by a certified contractor for the adequate treatment, reuse and/or reclamation.
NOM-006-CNA-1997. Pre-fabricated septic tanks. Specification and testing methods.	The installation, sizing, total capacity, testing and maintenance methods for the septic tank that will be installed to collect water streams from the **PROJECT** service, will be conducted under this NOM. Sanitary effluents will be sent to the planta de treatment to be reused.

This **DGGPI** has determined that NOMs above are applicable for the construction, operation, maintenance and abandonment stages of the **PROJECT**. Therefore, the REGULATED PARTY must comply with each and every criterium established thereon, to minimize all potential environmental impacts of each stage. This **DGGPI** has not identified any contravention, legal or environmental, of the **PROJECT**, preventing its viability.

OPINIONS RECEIVED

X. That the Environmental Protection Secretariat of the state of Baja California, through official letter number SPA-ENS-351/17, dated March 29, 2017, forwarded to this **DGGPI** the technical opinion and observations to the **EIM-R**, and the following outstands as related to the **POEBC** and the **COCOTREN**:

1. The **PROJECT** proposed fits in the Sustainable Exploitation Policy, under the **POEBC**. However, in UGA **2.a**, where the **PROJECT** is located, require measures to strengthen and ensure the adequate use of the territory, as a function of economic, urban, and ecological criteria, and the corresponding legislation and standards, to minimize harmful environmental impacts.

2. Even when the **POEBC** is not specifying a **CRE** for the energy sector, ecological criteria are mandatory for all types of work and/or activity, despite of the main sector of the activity intended. Therefore, the **REGULATED PARTY** is urged to comply with all **POEBC** provisions applicable.

3. In general terms, the **PROJECT** proposed is consistent with most general ecological general and applicable criteria of the **POEBC**. However, their full compliance must follow all **POEBC's CREs**, affected by the **PROJECT.**

4. As related to the **COCOTREN**, it is determined that the **PROJECT** proposal fits into the Sustainable Exploitation Policy, with energy use, and adheres to the Urban Development Criteria, and in general, to the environmental guidelines, as established in the **POEBC.**

Additionally, such agency made several recommendations to promote compliance with the environmental legislation applicable:

1. The **REGULATED PARTY** shall conduct a detailed geotechnical study across the area that may be impacted by the **PROJECT** development, as the **EIM-R** includes a preliminary study providing not enough information for the Secretariat makes an informed decision, on the full compliance of the **CRE** with Number 6 of the item Development of Works and Activities of the **POEBC.**

2. The **REGULATED PARTY** shall conduct a seismic risk stud, as the **PROJECT** area is surrounded by seismically active faults, with potential to generate earthquakes at close range (< 100 km), with magnitude up to 7.5. For LNG facilities in Seismic Zones, the standard NFPA 59A 2001 defines two earthquake movement levels: OBE *(*Operating Basis Earthquake*)* and the SSE *(*Safe Shutdown Earthquake). As related to design specifications, it is proposed to follow the International Building Code, 2006.

3. To give certainty to the citizenry as related to risks posed by the **PROJECT**, due to extraordinary events, the **REGULATED PARTY** shall prepare and analyses a failure scenario for some measures and specifications, for example:

   a. What would be the response before a close earthquake with magnitude above 6, and which damages are estimated on the storage tanks or other facilities?

   b. Which is the emergency response plan for a LNG spill?

   c. What would be the impact on the facility of a tsunami with a 3-m high wave, on a high tide period?

4. The **REGULATED PARTY** shall install accelerometers in the **PROJECT** site to assess potential land and structure accelerations, and analyze the effect of the soil-structure interaction, and determine if such accelerations exceeded the design parameters.

5. El **REGULATED PARTY** shall identify the geological risk potential for the **PROJECT** site (slope instability), that may be reactivated by an earthquake of significant magnitude, at close range, or due to the effect of water infiltration, inadequate cuts, or excessive weight, among others.

Having mentioned the foregoing, and considering the opinion of the Secretariat of Environmental Protection of the state of Baja California, this **DGGPI** determines that observations made by the

Secretariat are adequate, as each one of them includes a part of the analysis that this General Direction considers within the **PEIA**, which also follows legal applicable provisions, among them, the Ecological Ordering Programs and the Ecological Regulation Criteria, applicable to works and activities intended for the site, which are considered as viable, if observations and conditions specified by the Secretariat, and included in this resolution, are implemented.

XI. That on February 24, 2017, in the City of Ensenada, Baja California, in the Conventions Room of the San Nicolas Hotel, the Public Information Meeting for the **PROJECT** was held. There, citizens registered for such effect made four presentations, addressing the following general topics:

1. Presentation "<u>Legal considerations on the Natural Gas Liquefaction Project of Energía Costa Azul</u>". Gustavo Alanís Ortega. Centro Mexicano de Derecho Ambiental A. C.

   In his presentation, the speaker identified omissions he found in the document delivered for the **PROJECT**, authorization, including:

   - Omission in the **EIM-R** to assess environmental impacts in the **PROJECT** abandonment stage.
   - Omission in the **EIM-R** to assess environmental impacts on the ecological landscape in the property, and in the terrestrial and marine environmental systems of the **PROJECT.**
   - Omission in the **EIM-R** to assess environmental impacts caused by the **PROJECT** noise, specifically on marine mammals.
   - Omission in the **EIM-R** to assess environmental impacts on environmental services generated in the property and in the terrestrial and marine environmental systems of the **PROJECT**.
   - Omission in the **EIM-R** and the Risk Study to assess environmental impacts on the public life and health caused by blasting activities for the **PROJECT** development
   - Omission in the **EIM-R** to assess cumulative and residual environmental impacts of the **PROJECT.**
   - Omission in the **EIM-R** to assess environmental impacts in terms of sub-lethality, on marine and terrestrial wildlife.
   - Omission in the **EIM-R** to assess environmental impacts of the **PROJECT**, as related to the seabed dredging activities.
   - General omission in the **EIM-R** to establish prevention and mitigation measures to effectively address all environmental impacts caused by the **PROJECT.**

The speaker concluded that, given the information omissions of the **PROJECT** above, this **AGENCY** cannot issue an Environmental Impact Resolution and, in consequence, is obliged to request to the **REGULATED PARTY** all additional information to address such omissions and, based on information received, to assess the feasibility, or not feasibility, of the **PROJECT**.

2. Presentation "Omissions, inaccuracies, and errors of ECA's **EIM-R** and Risk Study".
   Cuauhtémoc León Diez. Centro de Especialistas en Gestión Ambiental, A. C.

   The speaker started by stating that risk is a social agreement, i. e., how willing we are. This social agreement is a part of the dialogue, of the **PIM.** Then, he highlighted a series of items to be analyzed in the **EIM-R** delivered by the **REGULATED PARTY**, as follows:

   - The speaker said that this **AGENCY** should request that the risk estimation and calculation methods are specified and improved, as synergies among its own processes (all potential chaining within the facilities), are not included. The **REGULATED PARTY** has not provided data or methods to calculate damages inside or outside the **PROJECT** polygon, to estimate fatalities. As other adjacent companies are not included (Z Gas and the CFE), cumulative risk generated by all three facilities disappears.
   - The **REGULATED PARTY** did not include the correlation of works previously approved by the **SEMARNAT**, nor the links of impacts and risks, despite being a fully different industrial system. Therefore, it requires to demonstrate how processes previously approved are different from and match the new conditions. As they are not included in this regional report, the authority and the society have no elements to assess the implication of such impacts and risks, their synergy and their correlation, or their potential conditions. This omission goes together with an over-simplification of meteorological, geological and oceanographic variables, i. e., the climate change is absent from the report (sea level rising, extreme events, etc.).
   - The risk study omits potential exposure to tides or storms of this **PROJECT**; frequent and regular wildfires, or heat waves, that would modify the models.
   - Assumptions and impact radius differ from what was originally calculated and reported in the study delivered by the **REGULATED PARTY** to the SEMARNAT in year 2002. Risk radius appear too convenient, inside a regular polygon. As no methods are explained, their criteria and probabilities seem to unreal, compared with accidents in other sites around the world, even more because their scenarios are not explained.
   - The analysis of cumulative risks from activities developed in the area is missing, and such information is required by the **AGENCY** to make the environmental impact evaluation under development.
   - Throughout the study, the buffering concept and definition is unclear. They call buffer zones to less risk or less radiation zones, which is confusing. Therefore, the resulting estimation for the radiation zones and the buffer zone for the project as a whole (limited to the **PROJECT** polygon), are wrong, and thus, underestimated.

- The speaker states that conclusions made by the **REGULATED PARTY** are hasty, when stating that *"based on results for impact radius and profiles for high risk zones due to thermal radiation and overpressure from LNG and propane events with the highest risk, the **PROJECT** will not interact with the facilities, infrastructure, services and human settlements analyzed".*
- One example of this over simplification of the risk, is observing that the risk radius of Z Gas is > 1.7 km (several times the one proposed by the **REGULATED PARTY**), leading us to think that Z Gas is, by far, more honest, and that poses a risk lower than the whole ECA process. Nevertheless, this figure is ignored and omits the overlap and overexposure of a synergic risk, which also adds to the conditions developed by ECA. It is essential to present this risks addition and potentiation.

The speaker finished concluding that the **AGENCY** is responsible for the local beneficial conditions and the negative social, environmental and safety impacts, given that:

1. The capacity of the municipality of Ensenada is not enough to respond to an accident of dimensions that cannot be foreseen or sized.
2. The municipality ignores if its civil protection capacity is enough to face any danger associated to this industry in this site.
3. The municipality ignores all risks posed for the society and the future development of the zone.

The speaker concluded that the **AGENCY** cannot issue the environmental resolution requested by the **REGULATED PARTY**, as it has no information enough; that it must request additional information required, enough and complete to assess the **PROJECT** as related to it and its implications.

3. Presentation "What is missing from the ECA's **EIM-R** and Risk Study: and if they had consulted us, who are inside the RES". Roberto Jesús Valdez Sánchez. La Quinta Bajamar, S. A. de C. V.

   The speaker said that the perspective of people living in Bajamar is very different from those who don't. Thus the title of the presentation "and if they had consulted us, who are inside the RES". He said that 10 days to review a document of 1,000 pages that required two years of work, were not enough. Therefore, he said that the community was not consulted, under **NOM-013-SECRE-2012**, Safety requirements for the design, construction, operation and maintenance of LNG storage systems including systems, equipment and facilities for the NG reception, transportation, vaporization and delivery, specifically Article 107.3, sentence b) Risk Assessment, reading:

b) *"Formal risk assessment techniques shall be applied with the participation and judgement of seasoned personnel, the authorities, and the community".*

This Article of the NOM, clearly states that risk studies shall be conducted with the community participation. Then, he stated that:

- The first parties to be consulted are members of the community adjacent to the **PROJECT**.
- It is clear that the risk study delivered by the **REGULATED PARTY** did not comply with the NOM, therefore, conclusions are incomplete and inaccurate, as parties directly impacted by the **PROJECT** were missing.
- This reveals a lack of interest of the promoter, to protect the community directly impacted by their **PROJECT**.

In the RES image, the Bajamar Project is included, but the effects on the community are never mentioned, and the following questions for we, who live in Bajamar, arise:

- Which are the impacts on people living in Bajamar?
- Which risks are facing people living and working in Bajamar?
- Which is the emergency program for Bajamar residents?
- Which is the value loss caused by this **PROJECT** to the Bajamar properties?
- Who is responsible for such value loss?
- Who would be responsible for property destruction or human loss in Bajamar?

At the end, the speaker summarized a number of accidents in similar facilities around the world, emphasizing the high risk impact radius, and overlapping such radius to the **PROJECT** facilities.

4. Presentation "Considerations on the Environmental Risk Study". Carlos Francisco Peynador Sanchez. Lorax Consultores.

   This presentation addressed risks not considered in the **PROJECT** operation, particularly vessel emergencies, as follows:

   - No emergency scenario considering LNG tankers before unloading, is included in risk studies delivered by the **REGULATED PARTY** for the **PROJECT** operation,
   - All risks evaluated in such studies focused on the facilities operation, and omit potential emergencies associated to external events in the tankers.

- This type of emergencies is not only possible, but also are risk scenarios with consequences more serious than any other related to the regular operation of the facility.

Based on the above, the speaker concluded that risk studies conducted (and authorized) for the **PROJECT** in operation, are ignoring all relevant risks, specifically the consequences of a tanker emergency. Risks must be reassessed to include prevention and mitigation measures adequate for scenarios identified. The risk analysis for the new facility must include risks ignored in the previous ones, and correct buffer zones proposed.

Also, in the Q&A session, **PIM** attendants expressed their concerns on the **PROJECT**, which were addressed by the REGULATED PARTY. The exercise is summarized below:

No.	Questions Made by the PIM Attendants
1	Was the economic damage caused on adjacent properties, such as Bajamar in the COCOTRAIN analyzed and evaluated? **Answer:** *All environmental impacts and risks generated have been analyzed. This is not the forum to analyze economic impacts, however, the social management policy of the Company is addressing all concerns. For example, there are workgroups working with Bajamar neighbors to address their concerns*.
2	Have you contacted the adjacent neighbors (Bajamar), to implement emergency evacuation plans? ***Answer:*** *We will contact neighbors in communities near the facility and the site, and a Social Impact Study, parallel to the EIM was prepared and delivered to the SENER. In this study, we came closer to the parties interested in the* ***PROJECT****, and we have an open dialogue to hear and address their concerns. In is important for everyone to have the right information?*
3	Which is your safety plan to prevent fire accidents, and identify evacuation routes, first aid measures, terrorism? ***Answer:*** *Of course, we have a safety plan, this is a high-risk facility, there is an accident prevention plan, not only developed by the company, but supported by the authority. There is also a mutual aid plan with other facilities, and it is a common practice. It has to be said that, based on results all the facilities, models, and forecasted events, Bajamar is not impacted.*
4	Which plan has been implemented to protect lives of Bajamar residents, and which building will be identified as community meeting point? ***Answer:*** *We are considering the options of purchasing or constructing. However, results from the risk study models clearly show that zones impacted by an undesirable event are limited to the property polygon. It has to be noted that the COCOTREN polygon for the energy center includes a buffer zone, therefore there is no event leading us to consider this as a necessity.*
5	Are you going to build a blast wall? ***Answer:*** *It is not convenient to build any type of wall in case of accident or overpressure, as that would turn it into a projectile. This is not a feasible solution.*

No.	Questions Made by the PIM Attendants
6	Have your risk models considered that coastal rosetophylous scrubs are a flammable type of vegetation, as its survival depends on fire, and is found in the area of influence of your **PROJECT**? ***Answer****: Coastal scrubs ignite in the dry season, and wildfires are common. There is a program in the facility to respond to any emergency if the scrubs ignite in the* ***PROJECT*** *area. This type of vegetation is not found inside the facility, as we don't want an ignition source; but it can be found outside, in the buffer and preservation areas.*
7	Is a seismic and geological risk study considered, including the design seismic coefficient and the slope stability? The tsunami risk standard will be followed (wave height, impact area)? **Answer**: Our models considering seismic factors, include equipment damage, thus, the topic is included in our risk analysis.
8	Why is the geological risk not being considered? Why a seismic scenario is missing? Are there geophysical works characterizing the subsoil? ***Answer****: As related to factors needing to be considered, as we are in an active seismic zone, there here are specific geotechnical studies characterizing the zone, and all factors are included in the design, supplemented with the CFE's Design Specifications Manual, the NOM 013 de la SENER and the NFPA Safety Code. The civil design and mechanical operations of the facility are fed by our safety factors. Our compliance is certified by a specialized third party*.
9	In the presentation, it was said that all tanks are safe. I think that, from the engineering perspective, the project is not using world-class technology. When and how will you disclose the seismic risk analysis for the **PROJECT** facilities and expansions? ***Answer****: Our tanks comply with Mexican regulations, NOM-013, gathering legislations from other parts of the world. These are double contention, full contention, with an internal tank made of nickel, and an external one made of concrete. We are using the same technology we use in the US. They have seismographs, and inclinometers, which monitor the subsoil behavior.*
10	Out of the 43 liquefaction plants existing, 17 in construction, how many of them are considering establishing a safeguarding zone minimizing risks and ensuring people's safety and, if so, which radius are considered? ***Answer:*** *In general, all plants in the world follow the same procedure based on models arising from the risk analysis. All cases in high risk zones must be self-contained within the facility perimeter, so no high-risk areas are offsite.*
11	What is your opinion on the fact that the municipal authority of Ensenada has expressly denied authorizations for tourist developments adjacent to CFE, ECA, and Zeta Gas? ***Answer:*** *All commitments made on environmental risk and impact topics, arising from previous authorization, have been fulfilled. And there is evidence of such compliance in reports delivered to the authorities. All risks are contained within the site facilities, and there are buffer zones for the most relevant risks in the plant.*
12	Will the **PROJECT** compete with Z Gas, as both are gas suppliers, and have their plants at so short distance? Which is ECA's target market by expanding their facilities and functions? How will ECA address the lack of an adequate buffer zone? ***Answer:*** *We will not compete with Z Gas, as there are two different fuels. Energía Costa Azul manages NG and LNG, which are very different from LP Gas managed by Z Gas, their composition is different. Energía Costa Azul, will serve the power generation market. Our clients are CFE and other thermoelectric power generation plants in the region, electrifying most of the northern part of Baja California. We have national and international markets, and we have the opportunity of being the first facility in the North American Pacific that can serve isolated markets in Mexico. Obviously, our main market is international, particularly in Asia.*

No.	Questions Made by the PIM Attendants
13	How many carbon tons will be emitted each year, including fugitive emissions from the regular process, and climate change, how are you going to neutralize your emissions? Which are the main social impacts reported in the EIM? ***Answer:*** *The EIM includes the analysis of potential GHG emissions. There are two emission sources: one related to noise, and the other with power generation. As the last will be increased, there are some emissions, but low NOx burners will be used. For all cases, an air quality monitoring network will be installed, to ensure full compliance with air quality criteria, at all times. as related to social impacts, the SENER requires a social impact assessment, apart from the environmental one, which is under development.*
14	What has been proposed with NH impurities? What will be done with mercury or H_2S? ***Answer****: By NG contaminants we mean contaminants to our process. Propane gas and a portion of ethane will be used as refrigerants. For H_2S, the process sequestering beds, designed to last four years, will turn it into elementary sulfur, and at the end this time, a hazardous waste contractor company will dispose them of according to the Mexican regulation. We are talking about nanograms of mercury that may have serious effects on the process.*
15	When the Company was installed, they promised a buffer zone, which was never established. So, why would we believe it now? ***Answer****: This is a perspective issue. We complied, then. If a condition to be mitigated was identified, having a buffer zone, covering the environmental impact and risk radius, it was mitigating by changing the plant design, the tanks and the process area, to let risk rings contained inside the property, and the buffer zone already established.*
16	Which economic opportunities for the region, and specially for Ensenada will come from the **PROJECT**? ***Answer****: This **PROJECT** has clear benefits. It is a large direct investment in the region, with significant revenue. But, also, it will have the benefit of connecting Baja California with other energy markets of the world. This will give energy safety to this region. Other infrastructure projects will be developed.*
17	Can you explain the impact on the Ensenada economy, not only from the construction, but also long term benefits? ***Answer****: This investment will exceed US$6,000 M, with a multiplier effect across the economy. There will be a local supplying program for all supplies and personnel; we will work with local industrial chambers. And obviously, employment generation. In the construction stage, this **PROJECT** will have 3,000 to 4,000 workers. The construction peak stage will require up to 7,000 people. This is a relevant employment source. The operation stage will require around 200 technical positions.*
18	Do you know the geometry of fault and fractures in this zone? The groundwater movement? ***Answer:*** *Several geophysical studies were conducted in this zone, including the land sliding potential. It was determined that no faults run in the **PROJECT** zone, which is complicated from the geological perspective. However, it was concluded that there are no faults, and the land sliding probability is low. This information was used in the facility design, to minimize such risks. We have information on the groundwater movement. There are no discharges to the water tables. The only impact could be runoffs, running to the sea. No infiltration in this area.*
19	As related to the MOF, what do you mean by “blasts on the coast line” during the site preparation and construction stages? ***Answer:*** *The MOF is the construction, a causeway and protection breakwater in the northern side. Blasts will be made inside the MOF, with a very specialized technique. First, you build the breakwater, it is closed, and blasts are made within a close breakwater. No overpressure waves are exported to the sea. A rescue will be conducted in the MOF, with compensation measures. Blasts are made with a drill. You drill a hole and introduce a specific explosive, to break the rock and move it. A bubble curtain will be established, to reduce overpressure and protect marine mammals.*
20	Do you have anti-terrorism plans to protect your facility?

No.	Questions Made by the PIM Attendants
	Answer: *The international maritime commerce has allocated resources, for the IMO to issue specific guidelines to protect the facilities and the vessels dedicated to international transportation by sea. The terminal, as other Mexican ports follows that code, establishing strict and specific guidelines to prevent and avoid terrorist attacks in ports and vessels. Each year, the Mexican government audits facilities submitted to the International Code, using a trust managed by the FIDENA, using certified auditors. Their expert report is validated every five years. Each vessel arriving to the terminal is previously checked, and must deliver a certificate of compliance with its own vessel protection plan. This is an international treaty of the IMO, signed by Mexico, implemented after the 9/11 attacks.*

As related to the above, all presentations and questions in the PIM were analyzed and considered during the evaluation process, and in the preparation of specific conditions for the **PROJECT.**

Description of the regional environmental system, and identification of development and deterioration trends in the region.

XII. That Fraction IV of Article 13 of the **REIA** under analysis, obliges the **REGULATED PARTY** to include in the **EIM-R**, a description of the Regional Environmental System and describe development and deterioration trends in the region. That is, first, locate and describe the **RES** corresponding to the **PROJECT**, then, identify the environmental problems detected in the influence area.

- **RES**: The **REGULATED PARTY** specified that the **RES** delimitation was made across terrestrial ecosystem (**TE**) and marine ecosystem (**ME**). The **RES** resulting polygon covers **4,891.41 ha.**
  - **TE:** The **TE** was delimited by overlapping the **TIA** on **UGA 2a** of the **POEBC**, micro-hydrographical basing, and the elevation model, with elevation at every 20 m, the Maritime-Terrestrial Federal Zone of the ECA, and the surface hydrology layer. On such criteria, the resulting area covers **2,142.51 ha.**
  - **ME:** The delimitation considered the Maritime-Terrestrial Federal Zone granted to ECA and the coastal dynamics study, identifying the existing littoral cell and sub-cells, or littoral inter-cells, as this is a homogeneous environmental zone. The **ME** Surface covers **2,748.90 ha**.
  - **PROJECT** Influence Area **(PIA):** The **PIA** includes the Terrestrial Influence Area (**TIA)** and the Marine Influence Area (**MAI)**. The total resulting area covers **2,381.67 ha.**
  - **TIA:** The **TIA** delimitation was based on the **PROJECT** polygon, in the node Energético La Jovita and the area covered by atmospheric emissions (per

contaminant type and dispersion plume), evaluated and modelled. The **TIA** surface is **480.07 ha.**

- **MAI:** The **MAI** delimitation is a function of the **PROJECT** facilities and needs, and the Maritime-Terrestrial Federal Zone granted to ECA in the littoral part and the sea. It also considered the littoral inter-cell. The total **MAI** surface is **1,901.60 ha.**

- The following table summarizes areas delimited by REGULATED PARTY:

Concept	Code	Hectares
Area of influence - Terrestrial	TIA	480.07
Area of influence - Marine	MAI	1,901.60
PROJECT polygon	**PROJECT** Polygon	332.99
PROJECT	**PROJECT**	129.10
RES Terrestrial ecosystem	TE-RES	2,142.51
RES Marine ecosystem	ME-RES	2,748.90
Regional Environmental System	RES	4,891.41

TERRESTRIAL ECOSYSTEM

- Abiotic aspects characterizing the **RES**, are**:**

CLIMATE. In the **RES** exists only one climate type, BSks, which is defined as temperate arid, annual average temperature between 12°C and 18°C, temperature of the coldest month between -3°C and 18°C; temperature of the warmest month < 22°C. Winter rains with average >36% of the annual total. Average annual precipitation in the climatological enclosure is 24.10 mm.

GEOLOGY and GEOMORPHOLOGY. About 90% of the Baja California Peninsula belongs to the single physiographical province of the same name, and a single physiographical sub-province (Sierras of Baja California Norte). A geotechnical study conducted by the **REGULATED PARTY** determined that, in general subsoil materials found in surface explorations, are basalt and volcanoclastic deposits covered by thin terrace deposits. The main rock components, identified in compression tests include vesicular basalt, porphyritic basalt, volcanic breccia and ash tuff in layers ranging from thin to moderately tick of very soft deposits, aphanitic deposits to medium grain. This set of characteristics confirms the geological type of the **PROJECT** and its **TIA**. The **PROJECT** and its **TIA** are located in the middle terrace of the three marine terraces, with ages of 120,000 years; a paleo-cliff separates the two terraces, with height increase from 5 m to 15 m, from West to East.

The geological type in the **RES** is intermediate, extrusive igneous rock. The material is formed by magma crystallization, rapidly cooling on the earth surface. Therefore, consolidated crystals are small, with fine granulometry. They are mainly composed by alkaline feldspar without quartz contents (which requires slow cooling underground). They belong to the Tertiary Cenozoic (T).

FAULTS and FRACTURES. The Baja California Peninsula is moving northeast, at estimated speed of 6 cm/year, causing fragmentation of blocks such as the "Juarez Block" (containing the **RES)**, limiting North with the "Tijuana Block," and south with the "San Pedro Martir Block", these blocks are cut by active faults (Water Blanca, Vallecitos-San Miguel, Calabazas, San Pedro Martir, etc.). None of these faults crosses the **RES**, but they can influence the micro-seismic movements originated in that part of the Peninsula. The **RES** is surrounded (not crossed), by the following active faults Water Blanca (south), Vallecitos (northeast), and San Miguel (southeast).

SEISMIC RISK. El **RES** is located in the seismic risk Zone C, where movements have low frequency, and terrain acceleration <70% of the gravity, thus posing a medium risk. The main source of seismic activity is in the Water Blanca Faults system, with estimated recurrence period of 175 to 200 years for earthquakes of magnitude >6. In a period of 13 years, not more than 10 earthquakes with ML>3. Also, it is known that the fault has been moving at average speed of 4 mm/year without causing large earthquakes, and is considered of low seismicity.

Additionally, the **REGULATED PARTY** indicated that, on year 2005, the consulting company Kleinfilder conducted a geotechnical research and a seismic risk assessment specific for the regasification plant. And the Category 1 foundations (structures, components and systems critical to safety, including tanks, contention systems and risk protection systems), were designed based on NOM-013-SECRE-2012.

SOILS. In the **TE**-**RES**, predominant soils are haplic phaeozem and lithosol. In the **TIA**, the **PROJECT** polygon has a distribution near 50% of both soil types; and in the **PROJECT** area the predominant soil is lithosol, covering 84.43% of its surface, and haplic phaeozem on 15.57%.

HYDROLOGY. The **RES** is located in the Hydrological Region 1, "Baja California Northeast", which covers approximately one half of the municipality of Ensenada, and subdivides into three basins: Arroyo Escopeta-Canon de San Fernando, Arroyo de las Animas-Arroyo Santo Domingo and Rio Tijuana-Arroyo de Maneadero. The Sub-basin "El Farito", fully containing the **RES**, lies within Basin 1C, Rio Tijuana-Arroyo de Maneadero

In the **TE-RES**, the **TIA**, the **PROJECT** polygon and the **PROJECT**, are surface runoffs, with coverage areas summarized in the following table:

Evaluated Area	Intermittent Surface Runoffs (m)
TE-RES	31,082.33
TIA	3,925.94
PROJECT Polygon	3,886.7

PROJECT	1,524.63

- Biotic aspects characterizing the **RES** are:

TERRESTRIAL FAUNA. The **REGULATED PARTY** conducted fauna samplings in the field, in November 2-7, 2015, in the same flora sampling sites, identifying 73 organisms in the **TE-RES**, distributed in 15 species; out of which 8 are birds, 3 reptiles and 4 mammals, which are summarized in the following table.

Family	Species	Common Name
Reptiles		
Phrynosomatidae	*Sceloporus sp.*	Spiny Lizard
Teildae	*Aspidoscelis sackii*	Giant Spotted Whiptail
Viperidae	*Crotalus sp.*	Rattlesnake
Birds		
Accipitridae	*Buteo jamaicensis*	Red-tailed hawk
Cathartidae	*Cathartes aura*	Turkey Vulture
Corvidae	*Corvux corax*	Commun raven
Emberizidae	*Melospiza melodic*	Song sparrow
Falconidae	*Falco peregrinus*	Peregrine Falcon
Odontophoridae	*Callipepla californica*	California quail
Troglodytidae	*Thryomanes bewickii*	Bewick's wren
Tyrannidae	*Tyrannus vociferans*	Cassin's kingbird
Mammals		
Canidae	*Canis latrans*	Coyote
Felidae	*Lynx rufus*	Barred bobcat
Leporidae	*Lepus californicus*	Black-tailed jackrabbits
Muridae	*Peromyscus sp.*	Deer mice

Additionally, the **REGULATED PARTY** reported that in the fauna field works inside the **PROJECT**, the following species were identified:

Family	Species	Common Name
Reptiles		
Colubridae	*Bogertophis rosalies*	Baja California Rat Snake
	Masticophis sp.	Baja California Coachwhip
Birds		
Corvidae	*Corvux corax*	Commun raven
Emberizidae	*Melospiza melodic*	Song sparrow
Falconidae	*Falco peregrinus*	Peregrine Falcon
Fringillidae	*Carpodacus mexicanus*	House finch

Laridae	*Larus occidentalis*	Western gull
Pelicanidae	*Pelecanus occidentalis*	California Brown Pelican
Mammals		
Canidae	Canis latrans	Coyote
Felidae	*Lynx* rufus	Barred bobcat
Muridae	*Peromyscus sp.*	Deer mice

Based on the above, the **REGULATED PARTY** only identified the species Peregrine Falcon *(Falco peregrinus),* as under special protection **(Pr)** in the lists of **NOM-059-SEMARNAT-2010**. Additionally, this DGGPI stated that many species of genus *Masticophis sp*, and subspecies of *Melospiza melodia* and *Carpodacus mexicanus*, reported by the **REGULATED PARTY** are also protected under **NOM-059-SEMARNAT-2**.

TERRESTRIAL FLORA. The **REGULATED PARTY** reported that the only forest community found in the soil use and vegetation in the **ETSAR**, **TIA** and the **PROJECT**, is the "Coastal Rosetophylous Scrub", represented by bush and succulent plants (cacti and agaves). From the forest delimitation conducted in the coastal rosetophylous scrub, the following surfaces were identified: a total of **65.5 ha** for permanent components; **40.43 ha** of temporary components; and **2.53 ha** for uncleared vegetation of ECALNG, totaling **108.52 ha** of forest vegetation.

Based on plant samplings conducted by the **REGULATED PARTY**, in the terrestrial **RES**, a total of 1,432 organisms, belonging to 22 species of 18 families, distributed as shown in the following table:

Stratum	Family	Scientific Name	Common Name in Mexico
Arbustive	Rosaceae	*Adenostoma fasciculatum*	Chamise o greasewood
	Aesculaceae	*Aesculus parryi*	Parry buckeye
	Ericaceae	*Arctostaphylos glandulosa*	Eastwood manzanita's
	Rutaceae	*Cneoridium dumosum*	Bushrue
	Rhanbaceae	*Condalia brandegeei*	Snakewood
	Polygonaceae	*Eriogonum fasciculatum*	California buckwheat
		Eriogonum wrightii	Wright's buckwheat
	Euphorbiaceae	*Euphorbia misera*	Cliff spurge
	Oleaceae	*Fraxinus dipetala*	Two-petal ash
	Asteraceae	*Haplopappus squarrosus*	Sawtooth bristleweed
	Malvaceae	*Malacothamnus fasciculatus*	Chaparral mallow
	Anacardiaceae	*Malosma laurina*	Laurel sumac
	Rhamnaceae	*Rhamnus crocea*	Spiny redberry
	Anacardiaceae	*Rhus integrifolia*	Lemonade sumac
	Salvia apiana	*Salvia apiana*	White sage
	Simmondsiaceae	*Simmondsia chinensis*	Jojoba

Stratum	Family	Scientific Name	Common Name in Mexico
	Ericaceae	*Xylococcus bicolor*	Mission manzanita
Succulent	Asparagaceae	*Agave shawii*	Coastal agave
	Cactaceae	*Bergerocactus emoryi*	Golden cereus cactus
		Ferocactus viridescens	Coast barrel cactus
		Mammillaria dioica	Strawberry cactus
		Opuntia littoralis	Coastal prickly pear

The **REGULATED PARTY** reported 02 species under some protection status and/or listed in **NOM-059-SMEARNAT-2010**, as follows:

Common Name	Scientific Name	Status
Asparragaceae	*Ferocactus viridescens*	Threatened
Fabaceae	*Mammillaria dioica*	Special Protection

MARINE ECOSYSTEM

WAVES. The **ME-RES** has two waves regimes clearly differentiated for winter (November-May), and Summer (June-October). The Regasification Plant has a wave buoy, used to develop the wave rose, showing predominance from west and south-southwest, with maximum exceptional wave heights of 2.0 to 3.0 m. There are two temporary extreme wave regimes: in summer, in SSO direction with 202.5°, and in winter in W direction and 270°.

GEOLOGY. The coast has rocky character, due to several outcrops of igneous material. It is mainly composed by riffs of medium height (3 m to 15 m), with evidence of large stability and minimum erosion. Beaches have boulders of medium size (from 10 cm to 50 cm), and no sandy surfaces due to the direct wave action of the open sea. There are high and low energy zones with similar characteristics. The cliff coastline is rocky, with average heights of 16 m (northeast) and 6 m (southeast), with evidence of mass landslides.

TSUNAMI RISK. The tsunami risk was evaluated. This is the wave increase due to distant seismic events, which may range from 2.0 m to 4.0 m, for a return period of 100 years. In a tsunami emergency, the terminal manager notifies alarm level to the area managers. Depending on such level, measures specified in the procedure will be taken, including:

- Securing equipment with minimum operational level (turbines, water pumps, etc.)
- Notify the authorities
- Shutdown the terminal operations

- Evacuation to safe locations, before the tsunami endangers the evacuation and while communications are still operating.

SEAWATER QUALITY. The seawater quality was analyzed in 6 transects located within the **PROJECT MAI**. Each transect had three points in each of the following isobaths: 12 m, 22 m and 32 m. Main results are summarized as follows:

Temperature: Surfaces showed a temperature gradient from higher to lower, south to north and towards the shore, with the minimum temperature, resulting from the inclusion of surface seawater, the warmest coming south to the internal part of the breakwater. Temperatures ranged from 13.02 °C to 18.30 °C, and the low variability suggest water mixed along the coastline.

Salinity: This parameter ranged from 33.361 to 33.836 ups, average of 33.633 ups, mode of 33.412 and CV = 0.47%, for all data. All values are within the range reported for the area (32.4 to 34 ups). Differences are not significant among depths, but slightly significant among seasons.

Dissolved oxygen: Values reported ranged from 5.07 to 10.63 mg/L, indicating good mixture across the water column, with good oxygen concentration (saturation of 85-90%), based on temperatures and salinities reported.

pH: pH values ranged from 7.25 to 7.93. In general, low pH values are associated to the respiration processes, when CO_2 dissolves, and the high ones, to higher photosynthesis levels. This suggests that station 1112 has high biological activity, mainly from deep respiration processes.

Chlorophyll: This is an indicator of phytoplanktonic biomass, associated to primary producers, mainly diatoms. In coastal zones, concentrations range from 0.05 to 1.0-2.0 mg/m^3, and in waters with high nutrient contents (eutrophication), can reach up to 5.0 to 40.0 mg/m^3. Concentrations were below detection limits (< 0.158 mg/m^3), and only one simple had 5.688 mg/m^3, station 1122 at 0 m.

Fats and oils: Concentrations > 2.0 mg/L are usually associated to contributions of hydrocarbons or hydrophobic compounds from normal phytoplankton or macroalgae blooms, or coastal contributions from estuaries and coastal lagoons, or areas impacted by domestic/industrial wastewater, or hydrocarbons. All samples evaluated in the study had concentrations no detectable with techniques used (<5 mg/L). The only example was station 412 at 0 m, with 5.2 mg/L. This value is not significant, based on the ANOVA results, at confidence limits of 98%. This reveals that the **AI-M** has no measurable perturbations caused by hydrophobic compounds extractable with hexane.

MARINE FLORA. The **REGULATED PARTY** reported that in the marine medium level, algae richness was of 23 species, and of 26 species in the low level. Presence of introduced and/or invasive species was reported in the North, including *Sargossum muticum* and *Sargassim horneri,* which were found across the area of study. These species have become conspicuous and abundant in the intertidal and subtidal zones in different parts of the world, with different impact level on native communities. *Sargassim horneri* was observed drifting in the intertidal zone of La Joya, Baja California in year 2005. Later, on 2008-2010, samplings were conducted in the intertidal and subtidal zones of several locations in Todos Santos Bay, Baja California, Mexico (up to 10 m depth), revealing well established populations.

MARINE FAUNA. In the upper and medium level, a total of 10 species were found, outstanding snail species of *Tegula sp*, *Littorina spp* and *Tegula sp*, which are usually found in the splash zone. Limpets are dominant, as they are highly resistant to desiccation. Black abalone, *Haliotis cracherodii* and California mussel, *Mytilus californianus*, are also common.

The low level included 12 species, the largest, as compared with upper and medium levels. Two species had the highest index values: the California mussel, *Mytilus californianus*, with IVB of 12, and the purple sea urchin, *Strongylocentrotus purpuratus*. Both species are of commercial interest. The black abalone, *Haliotis cracherodii* was also found. Another commercial species, with the lowest index is the red sea urchin, *Strongylocentrotus franciscanus*.

In the rock sustrate, 13 species were identified, dominated by tube worms, *Serpula sp*., and the purple sea urchin *Strongylocentrotus purpuratus,* followed by anemone *Anthopleura xanthogrammica,* red sea urchin, *Strongylocentrotus franciscanus* and *Dioptra ornata*, among others.

FISH. The study reported 21 fish species, in 16 genera and 10 families. Families best represented per number of speces were *Sebastidae* (rockcodes) and *Embiotocidae* (perchs), with 8 and 5 species, respectively. Three families were represented by a single species: *Hexagrammidae, Haemulidae* and *Clinidae.* Genus best represented in species was *Sebastes* with 7; while *Paralabrax*, *Embiotoca* and *Rhacochilus* had 2 species each.

Hypsypops rubicundus and *Semicossyphus pulcher* were the most abundant, with 20.59%; and a group of eight species makeup 90%, including *Paralabrax clathratus, Oxyjulis californica, Chromis punctipipnis, Girella nigricans, Rhacochilus vacca, Ernbiotoca jacksoni* and *Embiotoca lateralis.*

In the central section of the **MAI**, fish density of species *Oxyjulis californica, Paralabrax clathratus* and *Semicossyphus pulcher* was higher, with percent values of 16, 13 and 10, respectively. A group of nine species makeup 90% of specimen density, including *Paralabrax nebulifer, Chromis punctipinnis, Girella nigricans, Rhacochilus vacca, Embiotoca jacksoni* and *Embiotoca lateralis.*

MARINE MAMMALS. The **REGULATED PARTY** conducted a Marine Mammals Monitoring Program (MMMP), from November 2003 through May 2015, and the 2016 season, with two work teams, each one with two observers, using a Nikon telescope (20 x 60), adapted to a digital camera (Nikon D60); and Baker Marine binoculars (7x50), to detect marine mammal species, estimate the group size, registering the watching starting and ending times; and a chronometer to register the time of each observation. The following table summarizes abundance results (number of individuals/time):

Common Name	Scientific Name	2003-2006	2006-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	Average (2008 - 2015)
Gray Whale	*Eschrichtius robustus*	2.409	2.312	1.900	2.320	2.864	3.103	2.92	3.292	4.005	2.915
Blue Whale	*Balaenoptera musculus*	0.028	0.018	0.070	0.083	0.161	0.211	0.042	0.065	0.013	0.092
Common Rorqual	*Balaenoptera physalus*	0.059	0.013	0.004	0.003	0.334	0.129	0.016	0.080	0.008	0.082
Humpback Whale	*Megaptera novaeangliae*	0.023	0.002	0.000	0.013	0.035	0.287	0.226	0.159	0.097	0.117
Finned Pilot Whale	*Globicephala sp.*	0.000	0.000	0.067	0.003	0.000	0.000	0.000	0.000	0.000	0.010
Whale	*W/O Name*	0.079	0.107	0.066	0.152	0.213	0.441	0.596	0.498	0.432	0.343
Common Dolphin	*Delphinus spp.*	44.490	64.412	30.000	33.953	32.817	38.477	11.266	21.976	22.794	27.326
Pacific white-sided dolphin	*Lagenorhynchus obliquidens*	3.382	6.190	4.700	8.992	2.847	1.011	0.888	0.949	3.187	3.225
Risso's Dolphin	*Grampus griseus*	0.613	0.642	0.046	0.008	0.468	0.546	0.132	0.202	0.032	0.205
Bottlenose Dolphin	*Tursiops truncatus*	0.880	0.609	0.132	1.782	0.629	0.211	0.086	0.133	0.050	0.432
Killer Whale	*Orcinus orca*	0.045	0.036	0.004	0.003	0.000	0.004	0.000	0.000	0.000	0.002
	Pseudorca crassidens	0.057	0.032	0.000	0.000	0.000	0.000	0.000	0.000	0.047	0.007
False Killer Whale	*Sin nombre*	10.326	10.878	7.000	17.442	2.327	0.087	0.006	0.008	9.336	5.172
Dolphin	*Zalophus californianus*	0.371	1.210	0.433	0.568	1.221	1.347	0.618	0.232	0.188	0.658
California Sea Lion	*Phoca vitulina*	0.000	0.000	0.000	0.000	0.003	0.006	0.005	0.001	0.009	0.003

Based on the marine mammal species reported by the **REGULATED PARTY**, the following are under some protection status:

Scientific Name	NOM-059-SEMARNAT-2010	CITES	Red List- IUCN
Eschrichtius robustus	Protected	Appendix I	Minor concern
Balaenoptera musculus	Protected	Appendix I	Endangered
Megaptera novaeangliae	Protected	Appendix I	Minor concern
Balaenoptera physalus	Protected	Appendix I	Endangered
Tursiops truncatus	Protected	Appendix I	Minor concern
Lagenorhynchus obliquidens	Protected		Minor concern
Grampus griseus	Protected		Minor concern
Pseudorca crassidens	Protected		
Orcinus orca	Protected		
Zalophus califomianus	Protected		Minor concern
Phoca vitulina	Protected		Minor concern

Environmental Diagnosis

On **Pages 242** to **254** of the **EIM-R**, the **REGULATED PARTY** states that there is low connectivity among habitat fragments, due to anthropogenic activity, as follows:

- Industrial activity is concentrated in the Centro Energético La Jovita.
- The natural coastal dynamics keeps low diversity and abundance.
- Habitat blocks enable maintenance of terrestrial vegetal communities.
- The natural profile of the seabed keeps low diversity and abundance.
- Fragments are quite isolated, disturbed landscape makes dispersion impossible for most taxa.
- Offshore facilities of the **PROJECT** (docks and MOF), and prohibition of performing extraction activities, may promote an increase in the number of organisms; however, the coastal dynamics prevents dispersion.
- Human communities are scattered in low density, centers and settlements.
- Agricultural activates are scattered and cause habitat fragmentation.

Identification, description and evaluation of cumulative and residual environmental impacts in the regional environmental system, and prevention and mitigation strategies.

XIII. That Article 13, Fraction V and VI of the **REIA**, obliges the **REGULATED PARTY** to include in the **EIM-R** the identification, description and evaluation of cumulative and residual environmental impacts, under the PEIA, considering that such impacts may affect the functional integrity and the ecosystem carrying capacity[1]; as well as prevention and mitigation strategies of the **RES**. Here, and based on the zone diagnosis made by the **REGULATED PARTY**, and its environmental conditions, it has been considered that it has been modified by different anthropogenic activities. However, the **REGULATED PARTY** determined the presence of coastal rosetophylous scrubs, and identified actions susceptible to cause impacts, and environmental factors susceptible to receive them. Modeling used to identify potential environmental impacts in the development areas (atmospheric emissions, coastal dynamics, bathymetry of the seabed, noise generation, aero photogrammetry, and level curves); cartographic analysis, SIG, interaction matrixes and expert judgement. This initiative also analyzed potential impacts on the **RES** structures and functions caused by the **PROJECT** construction and operation, using the Leopold Matrix, and valuation of environmental impacts using the Gomez Orea methodology; and identifying the number of impacts caused in each **PROJECT** stage:

Stage	Impact Interaction		
	Positive (+)	Negative (-)	Total
Site Preparation and Construction	12	68	80

[1] According to the CONABIO (www://conabio.gob.mx), is defined as the complexity of trophic and successional relations found in a system. That is, the higher the integrity in a system, the higher the number of levels in the trophic chain found, considering native and wild species, and their natural ecological succession processes, that ultimately determine their functional activities (environmental services).

Operation and Maintenance	11	17	28
Total	23	85	108
Total (%)	21.30	78.70	100

Results ranking show that most significant negative impacts are caused by land clearing activities, as they remove vegetation and affect flora and wildlife species, including those in special protection status lists of **NOM-059- SEMARNAT-2010**; stumping, impacting the upper soil layer, and cut, filling, excavation, compacting and/or leveling, and blasting activities, including noise levels, and changes on the terrestrial relief and soil structure.

Other significant impacts are caused by offshore construction activities, due to rock blasting, with impacts on the seabed, the water quality, marine flora and wildlife identified, and species under special protection status (**NOM-059-SEMARNAT-2010)**. Finally, for the operation and maintenance stages, the most significant negative impacts will come from process and service units, due to emissions and noise generation.

Based on the above, the REGULATED PARTY identified all environmental impacts of the PROJECT, and proposed mitigation, prevention and compensation measures, through the implementation of a **PSCA**, describing the impacts, type of measure, applicable procedures and supervision per stage, and summarized in the following table:

Measure		**Application Stage**	**Preventive/Corrective Measures**
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Air Air Quality Monitoring Program – Atmospheric Emissions Monitoring Program - Air Measures Compliance Program			
MA-05	Control particulates with irrigation and/or unpaved roads stabilization.	Site preparation and Construction	• Road stabilization • Stop working with strong winds • Irrigate roads to minimize dust generation • Corrective Maintenance Plan for machinery and equipment
MA-07	Drive under speed limits, and use canvas to cover trucks to reduce particulates dispersion.	Site preparation and Construction	• Irrigate roads to avoid dust generation
MA-08	Install an air quality monitoring network, including CO, NO_2, PM_{10}, $PM_{2.5}$, SO_2; locate sampling stations on a map according to the technical descriptive memory.	Site preparation , Construction, Operation and Maintenance	• Development of technical descriptive memory, construction installation • Revision of the emissions control system • Revision of the data acquisition system

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
MA-09	Implement a preventive maintenance program for machinery, equipment and vehicles. During the Operation and Maintenance stage, all machinery, equipment and vehicles will be included in the Maintenance Plan in the Automated Maintenance Management System selected by ECA.	Site preparation, Construction, Operation and Maintenance	• Revision and operation failure identification and correction in machinery, equipment and vehicles. • Corrective maintenance program for machinery, equipment and vehicles • Replace obsolete machinery and equipment
MA 10	Correlate stack emissions, results from the atmospheric monitoring network, and data from ECA's meteorological station, throughout the **PROJECT** life cycle.	Operation and Maintenance	• Use meteorological data from the nearest station to correlate emissions and air quality. • Revision and operation failure identification and correction in machinery, equipment and vehicles
MA-11	During pre-operational tests, and in the Operation and Maintenance stages, as needed, provide control technologies for equipment generating atmospheric emissions. Power generation equipment will have continuous measuring technology for such end.	Site preparation, Construction, Operation and Maintenance	• Revision and operation failure identification and correction in machinery, equipment and vehicles

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Air - Perimeter Noise Monitoring Program			
MA-01	Implement a preventive maintenance program for machinery, equipment and vehicles. During the Operation and Maintenance stage, all machinery, equipment and vehicles will be included in the Maintenance Plan in the Automated Maintenance Management System selected by ECA.	Site preparation, Construction, Operation and Maintenance	• Revision and operation failure identification and correction in machinery, equipment and vehicles
MA-02	Include high noise emission equipment in the preventive maintenance program for machinery and equipment in the Maintenance Plan in the Automated Maintenance Management System selected by ECA.	Site preparation, Construction (only during pre-operational testing), Operation and Maintenance	• Corrective maintenance program for machinery, equipment and vehicles.
MA 03	Prepare and execute a blasting plan including, but not limited to: • Permits and licenses • Location of the blast proposed area and duration • Charges pattern • Number of charges • Type of explosive • Charge size	Site preparation and Construction	• Prepare and execute a blasting plan

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
	• Depth of bores to be drilled • Intervals • Notifications • Name of shutter • Warning system.		
MA 04	Installation of silencers, enclosures, and insulation of pipelines in machinery and equipment that are large noise generators.	Site preparation and Construction	Install silencers, enclosures and pipeline insulation. Replace obsolete machinery and equipment

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Water - Water Measures Compliance Program			
MH-01	Design gravity-based storm drainages to reduce distances in crosses with roads and/or sewage lines, including: • Ditches • Collection ponds • Discharge channels • Trenches • Sewers	Site preparation and Construction	• Implement physical measures to avoid erosion.
MH-02	Continuous maintenance of sewage/drainage works to avoid obstruction.	Site preparation and Construction, Operation and Maintenance	• Structure cleaning and maintenance.
MH-04	Restore surface of temporary facilities: soil compaction, arrangement connectivity of pluvial steams respecting their original trajectory, direction and depth.	Operation and Maintenance	• Implement physical measures to avoid erosion.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Soil - Soil Preservation Programa – Soil Preservation Monitoring Program - Soil Measures Compliance Program			
ME-01	Soil grading works shall use balanced cut and filling methods, to minimize debris generation, and use all materials avoiding transportation and disposal offsite.	Site preparation and Construction	• Implement physical measures to avoid erosion and sediment carrying.
ME-02	Contract companies authorized for the final disposal of sludges from the sanitary water treatment plant.	Operation and Maintenance	• Avoid spills in the waste water treatment plant

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
			• Contract companies authorized for the final disposal of sludges.
ME-03	Move and store dredging materials to MOF areas specified, and use them in other **PROJECT** activities.	Site preparation and Construction	• Store dredging materials in MOF areas specified.
ME-04	Consider the following waste management activities: a) Minimization • Minimize residual materials waste • Establish policy measures and agreements with materials and equipment suppliers to minimize package materials throughout the **PROJECT**. b) Segregation • Urban solid waste will be segregated as recyclable and not recyclable; hazardous waste will be segregated according to their risk characteristics. • Identification of solid urban and hazardous waste. c) Collection and storage • Working areas will have containers for different waste types, properly labeled. • Use of temporary storage areas for solid urban waste and hazardous waste currently existing in the regasification plants. • Storage areas above shall be properly identified, minimizing risks and complying with NOMs applicable and in effect. • Waste stored will be periodically removed for treatment or final disposal, not exceeding limits specified in the NOMs. • Maintenance of waste entry and exit registration logbooks. • Regular inspection of storage areas. d) Transportation, Treatment and Disposal • Contract companies authorized for waste storage, transportation, treatment, recycling and final disposal. • Keep records of final disposal manifests of waste generated. e) Personnel training on waste management) • Prepare and implement a personnel training plant on solid urban waste and hazardous waste management, complying with federal, state and municipal legislation in effect, throughout the **PROJECT** lifecycle. • Initial training will be delivered during the site preparation and construction, stages, and	Site preparation and Construction, Operation and Maintenance	• Procedures revision • Personnel training – reinforcement and effectiveness.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
	refresher training will be delivered every six months, from that moment on. • Initial training will be included in the induction period of newly hired personnel during the Operation and Maintenance stages. Refresher training will be once a year, minimum, according to the Training Program.		
ME-05	Implement a preventive maintenance program for machinery, equipment and vehicles. During the Operation and Maintenance stage, all machinery, equipment and vehicles will be included in the Maintenance Plan in the Automated Maintenance Management System selected by EC.	Site preparation and Construction, Operation and Maintenance	• Replace obsolete machinery and equipment
ME 06	Recover and store the organic soil layer avoiding mixing with other materials, to be used in the reforestation activities.	Site preparation and Construction	• Use the organic soil layer.
ME-08	Use explosives with low density detonator agents in the blasting activities.	Site preparation and Construction	• Use low density detonator agents.
ME-09	Build embankments to keep soil stability and restore slope impacted areas considered in the Flora and Wildlife Rescue, Protection and Preservation Program of the regasification plant.	Site preparation and Construction	• Implement physical measures to prevent erosion
ME-11	Use the following erosion prevention methods: • Material compaction • Gravel cover on the heavy traffic road • Slope design minimizing water carrying and maximizing stability • Gravel cover around foundations	Site preparation and Construction	• Implement physical measures to prevent erosion
ME-12	Channel intermittent runoffs through pluvial works, preventing soil carrying.	Site preparation and Construction	• Implement physical measures to prevent erosion

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: **Flora** - Flora Rescue, Protection and Preservation Program – Wild Flora Monitoring Program – Forestation and reforestation program to compensate forestal soil use change.			
MV-01	Implement the Impacted Forest Vegetation Rescue and Relocation, and Adaptation to the New Habitat Program, including but not limited to: • Rescue cacti specimens in areas to be cleared, and relocated them in selected areas. • Compensate individuals of bush species in areas selected within the **PROJECT** polygon.	Site preparation and Construction	• Monitor mortality causes, check actions conducted • Replace dead plants with organisms from the nursery.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
	• Rescue all *Ferocactus viridescens* transplanted in the rescue program of the regasification plant in areas to be cleared, and relocate them in selected areas.		
MV-0 2	Enable development of terrestrial flora communities in the **PROJECT** polygon, through the following activities: • Relocate them in compensation, reforestation, and restoration areas of the rescue program of the regasification plant to be cleared for the **PROJECT**. • Forest temporary facilities platforms after restoration proposed with soil-decompression, and conformation of storm water channels. • Maintain sloped areas with natural vegetation where foresting activities are not possible. • Increase plant density in conservation areas of the regasification plant that will be not used by the **PROJECT**. • Reforest and increase density in areas with natural vegetation available out of the preservation areas of the regasification plant. • After completing activities above, keep all areas as preservation areas.	Site preparation, Construction, Operation and maintenance	• Monitor mortality causes, check actions conducted • Replace dead plants with organisms from the nursery.
MV 04	Forbid burn practices to keep clear areas.	Site preparation, Construction, Operation and maintenance	• Administrative penalties.
MV-05	Develop and implement an ongoing training program for personnel, on the ecological importance of protecting terrestrial flora in the **PROJECT** area, including but not limited to: Ongoing training for people working in all **PROJECT** stages. Initial training for newly hires during the site preparation and construction stages, and every 6 months thereafter. Initial training will be included in the induction period of newly hired personnel during the Operation and Maintenance stages. Refresher training will be once a year, minimum, according to the Training Program.	Site preparation, Construction, Operation and maintenance	• Training and awareness raising program for workers, on the relevance of protecting terrestrial flora.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Fauna - Wildlife Rescue, Protection and Preservation Program – Wildlife Monitoring Program			

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
MF-01	Before the site preparation and construction stages, implement the Wildlife Rescue, Protection and Preservation Program evaluated and authorized, including, but not limited to: • Shoo and rescue species with underground habits or moving slow, particularly those with special protection status. • Release in sites selected. • Conduct preventive activities to avoid damaging wildlife in impacted sites.	Before the Site preparation and Construction stages	• Analyze mortality causes, monitor activities performed.
MF 02	Forbid hunting, capture, fishing, species smuggling and/or any other activities directly damaging wildlife species.	Site preparation, Construction, Operation and Maintenance	• Animals hurt, especially those under special protection status, shall receive immediate medical attention, and keep captive until ready to be reintroduced in the wild. • Any person caught hunting, capturing or trading species will be reported to the authorities.
	Establish speed limits to avoid running over wildlife specimens.	Site preparation, Construction, Operation and Maintenance	• Animals hurt, especially those under special protection status, shall receive immediate medical attention, and keep captive until ready to be reintroduced in the wild.
MF-04	Urban solid waste and hazardous waste will be managed according to their class, to avoid attracting harmful fauna.	Site preparation, Construction, Operation and Maintenance	• Solid urban waste and hazardous waste management programs.
MF-05	Develop and implement an ongoing training program for personnel, on the ecological importance of protecting terrestrial flora in the **PROJECT** area, including but not limited to: Ongoing training for people working in all **PROJECT** stages. Initial training for newly hires during the site preparation and construction stages, and every 6 months thereafter. Initial training will be included in the induction period of newly hired personnel during the Operation and Maintenance stages. Refresher training will be once a year, minimum, according to the Training Program.	Site preparation, Construction, Operation and Maintenance	• Training and awareness raising program for workers, on the relevance of protecting terrestrial flora

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Terrestrial. ENVIRONMENTAL FACTOR: Risk - Risk Measures Compliance Program			
MS-01	Comply with, and follow-up measures specified in the Environmental Risk Study.	Operation and Maintenance	• Monitoring safety measures.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Marine. ENVIRONMENTAL FACTOR: Seawater - Seawater Quality Monitoring Program - Waste Water Discharges Monitoring Program Water Measures Compliance Program			
MM O1	Control physic-chemical waste water conditions with treatment systems: • Septic tank and clarification biodigester in effluents discharge No. 4. • Grease traps in storm sewage works of the liquefaction plant. • Sanitary water treatment plant.	Site preparation, Construction, Operation and Maintenance	• Discharge analysis to implement corrective measures.
MM-02	Monitor seawater quality.	Before starting activities, supplement baseline, Site preparation, Construction, Operation and Maintenance	• Discharge analysis to implement corrective measures.
MM-03	Develop and implement a preventive maintenance and service program for tugboats.	Operation and Maintenance	• Forbid maintenance activities for boats in the site. • Penalties to violator contractors.
MM-04	Use collection ponds for water used in washing activities of concrete and asphalt hopers.	Site preparation and Construction	• Ponds cleaning and maintenance.
MM-05	Use portable latrines for workers. Waste will be disposed of by authorized companies.	Site preparation and Construction	• Latrines use revision and maintenance.
MM-06	Continue with the implementation of the waste water discharges monitoring program in discharges 1 and 2.	Site preparation, Construction, Operation and Maintenance	• Discharge analysis to implement corrective measures.

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
ECOSYSTEM: Marine. ENVIRONMENTAL FACTOR: Coastal Dynamics - Coastal Dynamics Monitoring Program			

Measure		Application Stage	Preventive/Corrective Measures
Code	Description		
MD-01	Monitor coastal dynamics in the MOF area after the construction stage is completed, based on modelling results.	Site preparation and Construction	• Modelling analysis to implement corrective measures

Measure		Application Stage	Preventive/Corrective Measures
Code	Description		
ECOSYSTEM: Marine. ENVIRONMENTAL FACTOR: Flora - Intertidal and Subtidal Flora Monitoring Program			
MV-06	One year after the site preparation and construction stages in the marine ecosystem, monitor intertidal and subtidal flora in the MAI of the **PROJECT.**	Site preparation and Construction	• Analyze mortality causes, monitor activities performed
ECOSYSTEM: Marine. ENVIRONMENTAL FACTOR: Fauna - Marine Fauna Rescue, Protection and Preservation Program. – Benthic Fauna Rescue, Protection and Preservation Program – Benthic Fauna Monitoring Program – Intertidal and Subtidal Fauna Monitoring Program			
MF-06	Before starting dredging activities, build a temporary offshore ditch to separate works from these, and mitigate effects of underwater drilling and blasting operations.	Site preparation and Construction	• Blast only in the authorized area.
MF-07	Implement the Benthic Fauna Rescue, Protection and Preservation Program of the PSCA, in the MOF area, based on results of the **PROJECT** sampling. Benthic organisms rescued will be relocated in ECA's marine concession areas (current or future).	Site preparation and Construction	• Analyze mortality causes, monitor activities performed
MF-08	One year after finishing the offshore site preparation and construction stages, monitor benthic fauna rescued and relocated in ECA's marine concession areas (current or future).	Site preparation and Construction	• Analyze mortality causes, monitor activities performed
MF-09	One year after finishing the offshore site preparation and construction stages, monitor the intertidal and subtidal fauna in the MAI.	Site preparation and Construction	• Analyze mortality causes, monitor activities performed
Measure		**Application Stage**	**Preventive/Corrective Measures**
Code	**Description**		
ECOSYSTEM: Marine. ENVIRONMENTAL FACTOR: Marine Mammals - Marine Mammals Monitoring Program - Manual of Good Navigation Practices and their relation to the preservation of marine mammals			
MF-10	Ensure the construction of a temporary offshore ditch before underwater blasting operations.	Site preparation and Construction	• Analyze mortality causes, monitor activities performed
ME-11	Include MOF construction, operation and maintenance activities into the Manual of Good Navigation Practices and their relation to the preservation of marine mammals, which is a part of the PSCA.	Site preparation, Construction, Operation and Maintenance	• Analyze mortality causes, monitor activities performed

Measure		Application Stage	Preventive/Corrective Measures
Code	**Description**		
MF-12	Continue the marine mammal monitoring program.	Site preparation, Construction, Operation and Maintenance	• Analyze mortality causes, monitor activities performed

Measure		Preventive/Corrective Measures
Code	**Description**	
ECOSYSTEM: Terrestrial and Marine. ENVIRONMENTAL FACTOR: Air, Edaphology, Surface Hydrology - Air Quality Monitoring Program – Perimeter Noise Monitoring Program - Water Measures Compliance Program – Soils Preservation Program – Soils Preservation Monitoring Program		
MAA-1	Implement a preventive maintenance program for machinery, equipment and vehicles.	• Site abandonment
MAA-2	Include high noise emission equipment in the preventive maintenance program for machinery and equipment in the Maintenance Plan in the Automated Maintenance Management System selected by ECA.	• Site abandonment
MAA-3	Control particulates with irrigation and/or unpaved roads stabilization.	• Site abandonment
MAA-4	Drive under speed limits, and use canvas to cover trucks to reduce particulates dispersion.	• Site abandonment
MAA-5	Implement a preventive maintenance program for machinery, equipment and vehicles.	• Site abandonment
MAA-6	Consider the following waste management activities: • Segregation of urban solid waste and hazardous waste. • Use adequate containers to collect and store urban solid waste and hazardous waste. • Build a temporary storehouse for hazardous waste, complying with NOMs applicable and effect. • Urban solid waste will be segregated as recyclable and not recyclable; hazardous waste will be segregated according to their risk characteristics. • Waste will be managed through companies authorized for waste treatment, recycling o final disposal, according to their class and characteristics.	• Site abandonment
MAA-7	Implement a preventive maintenance program for machinery, equipment and vehicles.	• Site abandonment
MAA-8	Use portable latrines for workers. Waste will be disposed of by authorized companies.	• Site abandonment
MAA-9	Implement reconditioning programs to leave the site in conditions adequate for new uses in the Centro Energético La Jovita.	• Site abandonment

The **REGULATED PARTY** reported that show that most significant negative impacts are caused by land clearing activities, as they remove vegetation and affect flora and wildlife species, including those in special protection status lists of **NOM-059- SEMARNAT-2010**; stumping, impacting the upper soil layer, and cut, filling, excavation, compacting and/or leveling, and blasting activities, including noise levels. To prevent potential impacts, the REGULATED PARTY specified the implementation of the following sub-programs within the PSCA:

Ecosystem	Environmental Factor	Environmental Quality Follow-Up Subprogram
Terrestrial	Air (air quality)	• Air Quality Monitoring Program • Atmospheric Emissions Monitoring Program • Air Measures Compliance Program
	Air (noise level)	• Perimeter Noise Monitoring Program
	Surface Hydrology (drainage pattern)	• Water Measures Compliance Program
	Soil (soil quality, structure and erosion)	• Soil Preservation Programa • Soil Preservation Monitoring Program • Soil Measures Compliance Program
	Flora (coastal rosetophylous scrubs, species under special protection status)	• Flora Rescue, Protection and Preservation Program • Wild Flora Monitoring Program
	Flora (coastal rosetophylous scrubs, species under special protection status)	• Forestation and reforestation program to compensate forest soil use change. • Wild Flora Monitoring Program
	Fauna (abundance and richness in terrestrial habitats, species with special protection status)	• Wildlife Rescue, Protection and Preservation Program • Wildlife Monitoring Program
	Risk	• Risk Measures Compliance Program
Marine	Sea Water (water quality)	• Seawater Quality Monitoring Program • Waste Water Discharges Monitoring Program • Water Measures Compliance Program
	Coastal dynamics (sediments carrying)	• Coastal Dynamics Monitoring Program
	Flora (marine flora)	• Intertidal and Subtidal Flora Monitoring Program
	Fauna (marine fauna)	• Marine Fauna Rescue, Protection and Preservation Program. • Benthic Fauna Rescue, Protection and Preservation Program • Benthic Fauna Monitoring Program • Intertidal and Subtidal Fauna Monitoring Program
	Marine mammals	• Marine Mammals Monitoring Program • Manual of Good Navigation Practices and their relation to the preservation of marine mammals

Based on the above, and under Article 30, Paragraph I of the **LGEEPA**, the **REGULATED PARTY** describes in **EIM-R**, the potential aspects in the ecosystem that may be impacted by the **PROJECT** works and/or activities, during the operation and maintenance stages. This description considers all elements integrating the ecosystem in question, describes preventive, mitigation and other measures required to reduce negative impacts, which this **DGGPI** considers as environmentally viable, as they will prevent, control, minimize and/or compensate the impact levels. Also, this complies with Article 44 of the **REIA**, as each and every element of the ecosystem has been evaluated, as well as use of natural resources considering the functional integrity and the carrying capacity of the ecosystem to which they belong.

Regional environmental forecasts and alternatives evaluation, as needed.

XIV. That Article13, Fraction VII of the **REIA**, establishes that the **EIM-R** shall contain environmental forecasts, and alternatives evaluation, as needed, for the **PROJECT**. Here, and considering punctual effects on the air, surface hydrology, soil, flora and fauna (terrestrial and marine), seawater, and coastal dynamics. However, impacts identified will not disturb the **RES** terrestrial or marine ecosystem, thanks to prevention, mitigation, compensation, remediation or rehabilitation measures that control and minimize impacts from the design stage and throughout all **PROJECT** stages. It has to be noted that risks of impacts due to LNG and propane handling in the operation were addressed with mitigation measures required, as specified in the ERA. Based on the above, impacts caused by the **PROJECT** are considered as compatible. Relevant impacts foreseen during the construction and operation stages are potential, i. e., can only occur in case of accident, which is unlikely and will be minimized with prevention, safety and control measures to be implemented. The **PROJECT** development has beneficial impacts in terms of regional infrastructure, services, and employment, bringing economical revenues for the state and the municipality, on condition that the **REGULATED PARTY** complies with mitigation measures specified in the **EIM-R**.

Identification of methodological and technical elements sustaining EIM results

XV. That under Article 13 Fraction VIII of the **REIA**, the **REGULATED PARTY**, shall provide an argument to justify methodological instruments for technical elements sustaining **EIM-R** results, and information used to comply with Fractions II and VII, thereof. This **DGGPI** determines that information provided to describe the **PROJECT RES**, considered and used such instruments to valuate environmental impacts arising from the **PROJECT** development stage.

XVI. That according to the Agreement[2] and based on the Environmental Risk Study of the **PROJECT**, the **REGULATED PARTY** will conduct Highly Risky Activities, as it will manage LNG and propane in volumes exceeding the report quantity of 500 kg specified in the Second List of the Agreement. This classification is based on the action, or group of actions, natural or anthropogenic, associated to management of substances with flammable and explosive properties, in such volumes that any release – either leak or spill – or explosion, would have a significant impact on the environment, the communities or their assets.

[2] Agreement through which the Secretariats of Government and Urban Development and Ecology issued the second list of highly risky activities, published in the DOF on May 4, 1992.

XVII. Also, when an activity is related with on chemical with hazardous characteristics described above, in amounts equal or above their **report amount**, as specified in Article 3 of the Agreement as "*minimum amount of a chemical substance in production, processing, transportation, storage, use or final disposal, or their sums, present in a given facility or transportation means*", will be considered as high risk activities.

Based on information provided in the **ERA** and the **EIM-R**, the **REGULATED PARTY** will manage Liquefied Natural Gas and propane in amounts exceeding the reporting amount of 500 kg, assessing the risk possibility in the LNG plant operation, based on conceptual engineering, modeling scenarios resulting from the significant contention loss, using the Preliminary Hazards Analysis Methodology, the events ranking and identification of impact radius, using the PHAST software for the following scenarios:

No.	Scenario
1	LNG leak in the LNG containment dike
2	LNG leak in containment dike on the LNG transfer line
3	LNG leak in existing containment dike
4	Propane leak in the liquefaction train

These scenarios have the following radius and characteristics:

Impact radius of thermal radiation for pool fire scenarios for LNG and propane

Scenario	Product	Containment Areas	High Risk Distance at 5 kW/m² (m)	Buffering Distance at 1.4 kW/m² (m)
1	LNG	LNG containment dike	113	198
2	LNG	LNG containment dike on the transfer line	81.4	143
3	LNG	LNG containment in existing dike	113	198
4*	Propane	Liquefaction	219	352
*Observe that the PHAST model input used a leak diameter of 190.5 mm to match the massic flow, keeping a monophasic liquid propane leak, as it does not allow modelling two-phases discharges (liquid and vapor). The PHAST models only a discharge 100% liquid or 100% vapor. To model the release, the model inputs shall be manipulated to allow only one discharge with single phase, at the flow speed specified. This is achieved by reducing the hole sizes, until the model calculates a liquid phase 100%, matching the flow specified.				

Fire Jets

Scenario	Leak Diameter (mm)	Maximum Flow (kg/hr)	Orientation	High Risk Distance at 5 kW/m² (m)	Buffering Distance at 1.4 kW/m² (m)
Results for LNG Fire Jets					
2	610	1,720,000	Vertical	172	307
Results for Propane Fire Jets					
4	244	432,000	Vertical	174	313
*Observe that the PHAST model input used a leak diameter of 190.5 mm to match the massic flow, keeping a monophasic liquid propane leak, as it does not allow modelling two-phases discharges (liquid and vapor). The PHAST models only a discharge 100% liquid or 100% vapor. To model the release, the model inputs shall be manipulated to allow only one discharge with single phase, at the flow speed specified. This is achieved by reducing the hole sizes, until the model calculates a liquid phase 100%, matching the flow specified.					

The **PROJECT** management shall be adequate and based on compliance with federal, state and municipal legislation in effect, for each incidence sphere. For that end, the **REGULATED PARTY** has proposed prevention and safety measures to reduce occurrence possibilities for undesired events specified in the **ERS**. Safety systems and measures considered for this liquefaction **PROJECT** are described below:

1. Technical Operational Recommendations

a. Ensure that safety margins are adequate for traffic weight limits on road portions crossing over the underground section of the existing and new supply gas pipelines, considering transportation of heavy machinery for the construction stage.
b. Consider revising implications of the simultaneous operation of existing facilities, construction of liquefaction train 2 and/or the third LNG gas tank, after liquefaction train 1 is operating, to ensure that all connections and construction plans are developed accordingly.
c. Develop siting plans for temporary construction buildings based on results from consequences modeling, for simultaneous operation of existing construction facilities, as specified by standard API 753.
d. Confirm overpressure contours caused by vapor cloud explosions, associated to the new facilities, and evaluate potential impacts on buildings currently occupied.
e. Confirm the purpose and need of occupying the storage building proposed north of liquefaction train 2. If the need is confirmed, check that it explosion resistance is consistent with overpressure patterns of the explosion of a vapor cloud associated to LNG trains.
f. Assess the location of thermal oxidizers as related to the EFG area in the liquefaction train 2, which is a close release upwind source.
g. Consider studying implications of the simultaneous operation of existing facilities, as related to the construction of new facilities in the regasification plant currently operation, and ensure

that all interconnection points, process isolation plans, and construction are developed accordingly.

h. Consider installing height limiting or warning devices on each side of La Joyita transmission line, to avoid accidental contact with construction equipment.
i. Assess options to complete modifications on the process, pipelines, and structural/mechanic in the existing LGN tanks, to ensure that the execution can be safe.
j. Consider conducting a dispersion analysis for new and existing atmospheric venting valves on LNG gas tanks, to ensure dispersion and safe elimination of potential ignition sources.
k. Consider the possibility to confirm that all equipment will be designed for cold startup conditions, after depressurization, in the following **PROJECT** stage.
l. Consider providing instrumented protections on the vapor return gas from the LNG tanker to the BOG, supplementing operative procedures to avoid CO_2 contamination, the freezing possibility, and blocking of the BOG system during the tanker purge in dry dock.
m. Consider segregating the collection of condensate spills and other heavy hydrocarbons, to avoid accumulations in collection tanks of LNG/refrigerant, as they could be pumped to the stormwater discharge channel.
n. Minimize the jam level in the services area, west of liquefaction train 2, providing a separation among equipment groups to reduce the overpressure potential in the control room and other occupied buildings, in case of vapor cloud explosion.
o. Check and update the tsunami and storm wave analysis prepared for the regasification plant, to identify any additional measures required (i. e., increase elevation of new equipment in the power generation island, and confirm elevation in the unloading area during the construction.)
p. Determine rainfall levels to be used as design basis for the new facilities, embankments, embankment protection system, and stormwater management equipment.
q. Review management of the stormwater discharge in the adjacent GLP plant, and topography in the **PROJECT** area, to determine if they can impact the new LNG plant (for example, multi-points enclosed burners.)
r. Work with the GLP Zeta Gas adjacent plan to review their liquid containment and emergency response plans, to minimize impacts on the LNG plant.
s. Update the mutual aid agreement with Zeta Gas and La Joyita power station, as needed, to include the construction and operation of the liquefaction plant and other facilities.
t. Check risk and impact contours of accidents in La Joyita power station, based on its permit and applicable codes, to determine if the LNG plant could be impacted by ignition or non-ignition events in the power plant.
u. Evaluate the safety vulnerability of the liquefaction plant, to determine additional safety measures, as needed.

v. Include results of accidental emissions dispersion modelling to select the elevation, sites and monitoring of compressors intakes.
w. Reassess the orientation of refrigerant storage tanks to reduce impact possibilities on the burner tanks or the LNG facilities.
x. Ensure that scheduling of construction materials in the MOF is included in the IPC contract, and that it will follow the Manual of Maritime Operations in the Terminal, to minimize the collision possibilities between a LNG tanker and a construction boat.
y. Review the current agreement among ECA and local fishermen associations, to cover MOF operations and minimize the collision possibilities between a construction boats and fishing boats.
z. Review potential effects of the MOF breakwater on the wave conditions of the LNG mooring area, to ensure that operations are not interrupted, including LNG tankers. Check all other LNG breakwater effects on the MOF LNG mooring area.
aa. Update the spill response manual in the terminal, to include diesel spills from the tugboats fuel supply activities.
bb. Review the separation distance between liquefaction trains 1 and 2, as related to escalation of a vapor cloud explosion event in any train, to determine if additional separation, or other protection measures are required.
cc. Develop a traffic management plan in the **PROJECT** area, to ensure safe vehicle circulation (including LNG and refrigerant tank-trucks, from and to the LNG plant.
dd. Update the LNG plant emergency response plan, to include the liquefaction and other facilities, and accidents with LNG and refrigerant tank-trucks.
ee. Assess additional protection measures for BLEVE events involving refrigerant storage vessels, given proximity to liquefaction train 1.
ff. Ensure installation of positive isolation devices for enclosed burners sections, for maintenance purposes.
gg. After receiving updated results of the Exponent consequences analysis, assess the need of additional mitigation measures to protect equipment or structures exposed to radiant heat from fires in containment dikes.
hh. Ensure that occupied buildings have adequate protection to avoid inhalation of flammable vapors in a large release event.
ii. Update the IPC construction interface appendix, to ensure that all interfaces among construction and existing operations are understood and controlled.
jj. Review locations and depths of seawater intakes and discharges of the Power Central La Joyita, and update the MOF approaching channel, as needed, to minimize collisions between construction boats and such structures.
kk. Conduct a simulation of the construction boats maneuvers, to confirm that tankers can safely access the MOF mooring area.

ll. Update the loading separation plan to include liquefaction in the next **PROJECT** stage.

mm. Ensure the development of procedures to change mercury adsorption beds and H_2S, addressing the safe management of spent materials.

2. SAFETY SYSTEMS

Safety systems considered in the liquefaction facilities include:

a) Emergency Stop System (ESS)

For process conditions exceeding values specified and some flammable gas or flame detection, the liquefaction plant will automatically trigger the emergency stop system, which can also be manually triggered.

b) Isolation Valves

In abnormal conditions, the liquefaction plant can trigger automatic isolation valves. Some of them will automatically close, as a part of the ESS. These valves can also be triggered manually by the facility personnel, and their purpose is reducing the amount of material released in a containment loss event.

c) High Expansion Foam System

The facilities are designed to trigger high expansion foam system if a containment loss causes spills of flammable or cryogenic materials, or fire.

d) Safety Interlocks

The safety instrumented system (SIS), monitoring and operating the facilities, will have multiple safety interlocks, that will connect process equipment and measuring devices. In cases of process disturbances or release events, safety interlocks can prevent the occurrence of the subsequent catastrophic events. For example, if a line losses flow (indicating possible clogging), the interlock will stop flow and turn pumps down, to prevent the line over-pressurization.

e) Emergency depressurization system

This system will be installed in the new liquefaction facility. Emergency depressurization valve are protection devices against fires and/or controlled process, in areas where conventional self-actuating relief valves are not able to stop containment loss, due to fire exposure. These are provided together with relief valves, not to replace them.

Depressurization systems will reduce the equipment loss of integrity during a fire, or the consequences of a local containment loss caused by a leak that, otherwise would escalate the event or the catastrophic structural failure.

Depressurization can be started manually from the emergency stop matrix board, or automatically as follows: in a fire situation, fire detectors in the area will start the train stop with a 2 of 2 voting arrangement. After a 120 seconds delay, the automatic depressurization will activate only in the impacted zone. For a gas leak, gas detectors in the zone will start the train stop with a 2 of 2 voting arrangement, but depressurization will be manual, and at the operator discretion, after evaluating the risk.

f) Overpressure protection

All emergency scenarios caused by equipment overpressure will be considered, including exposure to offsite fires, services failures, equipment failures and malfunctions, abnormal process conditions, thermal expansion, condensation, changes in the barometric pressure, operation alternative modes, startup and shutdown, and human errors.

For each emergency scenario, the resulting overpressure will be evaluated, and the need of higher design pressure (to resist emergency pressure or vacuum); or pressure relief services or protection to avoid overpressure will be provided (if applicable, with calculated relief levels.)

The High Integrity Pressure Protection is an instrumented system typically involving arrangement of instruments, final control elements (i. e., valves, switches, etc.), and logic controllers, configured to avoid overpressure incidents, either by eliminating the overpressure source or reducing the overpressure emergency probability to a level, so low, that it is no longer considered a credible case.

g) Risk Detection System

A fire and gas system will be installed, to monitor, detect and trigger an alarm when detecting fire and flammable/toxic gases, low temperatures associated to LNG, or refrigerant leaks or spills across the facility, and trigger the firefighting systems: deluge, foam and water pumps. The fire and gas system starts mitigation actions associated to containment loss or fire.

The fire and gas system will be designed under standard NFPA 72, and will have the main fire alarm panel in the main control room, that will be manned 24/7. This system is a part of the Safety Control Integrated System, also including the Process Basic Control System and the Emergency Stop System. The design intention is integrating such systems as far as possible. This system will have self-diagnosis and failure detection.

The whole control and monitoring of the fire system will be provided by the Main Control Room, with redundant screens in alternative locations. Calls to the designed Fire Department will also be made through this system.

The fire and gas system will be supplemented with fire detection and alarm systems in the buildings, that will be fully addressable, and compatible with standard NFPA 72. They will send summary fire alarms to the fire and gas system. Alarms will be audible and visible, in the area and in the main control room.

Gas detection and subsequent actions required for all areas – process and buildings – will be directly monitored and controlled by the fire and gas system. Equipment packages such as turbines enclosures, will have self-contained fire detection systems and gas alarms, and will start the executive action to shut all related equipment down, turn on and off the ventilation systems, etc., according to the associated package logic. These systems will send summary alarms to the fire and gas system, that will start additional executive actions, as needed. All sirens and warning lights on the dock already exist.

The dock already has all fire, gas, and leaks detection infrastructure required. This site will be monitored via CCTV from the main control room, providing additional detection capacity.

The risk detection system will include logics to send signals to the Emergency Stop System of the LNG plant, and/or activate automatic fire protection systems.

The risk detection system of the LNG plant will have interface with the following systems:

- Process Basic Control System – redundant links via Ethernet or serial
- Emergency Stop System – wired
- General Loudspeakers Systems – wired.

All danger signs turn on in the main control room and locally. Local signs will be audible and visual (strobe lights), have distinctive color alarms for fire and flammable gas risks (leaks), and toxic gas (leaks). As needed, a danger sign trigger can start the equipment and systems automatic shutdown, and may also start the emergency stop system.

Components of the Risk Detection System:

- Fire alarm boards
- Fuel gas detectors
- Toxic gas detectors
- Low temperature spills detectors
- Flame detectors
- High temperature detectors (temperature-based release devices)
- Heat detectors
- Smoke detectors
- Button manual stations.

h) Risks Mitigation Systems

The risk mitigation system will include the following units:

- Dry chemical system
- Firefighting water system
- Low expansion foam system
- High expansion foam system
- Nitrogen purge system.

Fire Fighting and Safety Equipment

i) Portable Fire Extinguishers

Portable fire extinguishers will be located across the LNG facility, under standard NFPA 59A. Their type, number and mounting will depend on standard NFPA 10. Portable, dry chemical extinguishers with capacity for 9 kg (20 lb), for multiple purposes (ABC), with mounting brackets and/or cabinets, will be installed inside selected, not process, buildings, spaced according to standard NFPA 10. This will be used to fight Class A and Class C fires.

Areas prone to LNG, refrigerant or hydrocarbon fires, will have portable Purple K (BC), dry chemical, fire extinguishers, full with mounting brackets and/or cabinets, inside the LNG plant, based on the local risk level, and spaced according to standard NFPA 10, and the fire risk assessment. Portable fire extinguishers with capacity for 13 kg (30 lb) will be installed near equipment using hydrocarbons. In some locations, wheeled, dry chemical, fire extinguishers, with capacity for 68 kg (150 lb) or 136 kg (300 lb), will be provided, for example, near the compressors.

j) Personal Protective Equipment (PPE)

PPE will be provided across the LNG plant, including fireproof clothing, hard hats, safety glasses, safety shoes, safety harnesses, hearing protection, gloves, goggles, welding helmets, and aprons. According to standard NFPA 59A, safety clothing protecting against LNG exposure must be available and readily accessible.

As a minimum, three portable flammable gases indicators will be available. CO_2 and H_2S portable gas detectors will be available for personnel working near the aniline stripper and the reflux drum in the acid gas extraction systems.

Safety clothing and respirators protecting against exposure to ammonia hydroxide, shall be available and readily accessible across the LNG plant, as recommended in the manufacturer material safety data sheets. Portable gas detectors are already available in the transfer marine zone.

k) Emergency Response Brigade

The current emergency response brigade, trained for fire emergencies in the LNG plant will be maintained. Personnel training will continue to provide early response to the local emergency agencies, and will provide sustained firefighting response.

l) Fire Prevention Plan

The LNG plant personnel will be considered as the primary response providers in a risk condition in the plant. Operators will communicate regularly with the Fire Department designated, and the Ensenada Port, according to the emergency response plan, the Accidents Prevention Program (APP), and the Plant Integrated System, to review fire response plans, conduct inspections, deliver training, and conduct joint drill exercises and other activities, to improve the response coordination in potential risk events.

The current emergency response plan of the plant will be updated to include the following policies, procedures and practices, to protect the liquefaction facilities against fires:

- The Fire Protection organization and their responsibilities
- Hot works control
- Temporary fuel control
- Confined/hazardous spaces entry
- Maintenance and testing of firefighting equipment
- Order and cleanliness, and general inspection of hazardous conditions
- Coordination with the Fire Department designated and the Port of Ensenada.

3. PREVENTIVE MEASURES

Preventive measures include maintenance and inspection programs, and emergency programs to be activated during the **PROJECT** normal operation, to avoid environmental deterioration, as follows:

a) Preventive and Predictive Maintenance

To reduce unexpected stops, the LNG plant will adopt a preventive and predictive maintenance philosophy, as follows:

- Preventive maintenance and routine inspection during the operation, not impacting functions or safety.
- Maintenance stop and equipment inspection to diagnose major deterioration. The equipment may be stopped, but the plant operation will not be impacted, as it can use

backup units. Inspection and maintenance works required by law shall be addressed in the detailed design stage, to minimize their effects, for example, all pressure relief valves must be properly insulated (double block and venting), to achieve regulatory calibration without compromising the plant operation.

- Periodic inspections on LNG tanks, the pier and other major components to identify settlements, collapsing, and other situations leading to a failure. These inspections are also required after earthquakes, storms or major floods. The periodic program shall include control inspections for these events.

b) Scheduled Maintenance

The purpose is providing safe, stable operation to the facility throughout its useful life, reducing or eliminating downtime due to failures or deterioration of the process conditions.

c) Routine Maintenance/Inspection During Operation

Routine maintenance includes daily visual inspections in the line or the field, lubrication, calibration or minor adjustments of equipment idle or in operation. The operator will perform the following activities:

- Check temperature and pressure transmitter for wrong readings
- Check oil levels in pumps, gearboxes and oil pots.
- Refill oil levels as needed, using the right oil type and amounts
- Listen for unusual noises (pumps, turbines and compressors)
- Clean pump filters and sieves
- Check and adjust forced feed lubricators
- Keep cleaning standards.

d) Planned Preventive Maintenance /Time Based

This maintenance will be based on a schedule or on the operation hours. The frequency will depend on the suppliers' recommendations.

e) Maintenance Legally Regulated

Mandatory inspection and maintenance (from a legal perspective), will be conducted according to regulatory requirements, and will be fully isolated from the LNG plant operation.

f) Emergency Programs

Emergency procedures will be developed within the Health, Safety and Environmental Protection Management Program, that will be kept as a part of the current operations to reflect changes. Situations covered in the facility include:

- Fire or explosion
- Serious injuries or diseases, including evacuation of injured personnel
- Gas/liquid discharges
- Hydrocarbons/diesel spills
- Integrity threats
- First aid injuries
- Weather conditions and natural disasters
- Marine emergencies

g) Emergency Response

The site will develop emergency response capacities including emergency services and personnel training, and assignment of organizational responsibilities. specific emergency procedures and instructions will also be developed. The emergency response capacity will be tested in drills and regular exercises, for the personnel to respond in any emergency situation endangering their safety, the environment, the assets or the operations.

The emergency response plan of the IPC contractor will operate simultaneously, with an interface program with the emergency response plan of the regasification plant, while they are working in the **PROJECT** area

XVIII. That this **DGGPI**, under the **LGEEPA**, specifically Article 35 Third Paragraph, and Article 44 of its **REIA**, analyzed potential effects on the ecosystems caused by the **PROJECT** construction, operation and maintenance. It also evaluated the effectiveness of the impacts evaluation and assessment and their effect on the different environmental components, the correlation between the technical feasibility and the mitigation and compensation measures proposed by the **Regulated Party**, framed by the **RES**. Based on the above, this **DGGPI** found no significant environmental impact caused by the **PROJECT** operation, maintenance and abandonment. Therefore, the REGULATED PARTY complied with Article 30, First Paragraph of the **LGEEPA**, by describing all potential effects and the corresponding mitigation and minimization measures. It also complies with Article 44 fractions I and II of the **REIA**, by evaluating each and every ecosystem component

Based on the above, the **PROJECT** complies with Article 44 del **REIA**, as:

1. The **RES** proposal delivered enabled the assessment of works and/or activities on the **PROJECT** ecosystem and area of influence, during the operation and maintenance stages.

2. The **PROJECT**, will not have potential effects on natural resources in the zone, not endangering the functional integrity and carrying capacity of the ecosystem.
3. The **REGULATED PARTY** delivered to this **DGGPI** a series of preventive measures to avoid or minimize negative effects from environmental impacts, which this **DGGPI** has considered as applicable and viable.

XIX. That under **Items VIII** to **XVIII** of this document, this **DGGPI** conditionally authorizes, on the environmental impact and risk, the execution of the **PROJECT** activities, under articles 35, Fraction II of the **LGEEPA**, correlated with Article 45, Fraction II of the **REIA.**

Under articles 28 fractions II, VII and X, 35, Fraction II of the LGEEPA; 1, 3, Fraction XI sentence c), 4, 5, Fraction XVIII, 7, Fraction I of the Environmental Protection Law of the Hydrocarbons Sector; 2 Second Paragraph, 3, Fraction I Bis; 5 sentences D), fractions IV and VII, O) and R), 45, Fraction II of the R-LGEEPA, on Environmental Impact Evaluation; 4, Fraction XIX, 18, Fraction III and 29, Fraction II of the Internal Regulation of the National Agency for Industrial Safety and Environmental Protection of the Hydrocarbons Sector; **NOM-001-SEMARNAT-1996**, **NOM-003-SEMARNAT-1997**, **NOM-004-SEMARNAT-2002**, **NOM-041-SEMARNAT-2015**, **NOM045-SEMARNAT-2006**, **NOM-05 2-SEMARNAT-2005**, **NOM-054-SEMARNAT-1993**, **NOM-059-SEMARNAT-2010**, **NOM-080-SEMARNAT-1994**, **NOM-081-SMEARNAT1994**, **NOM-085-SEMARNAT-2011**, **NOM-138-SEMARNAT/SSA1-2012**, **NOM-161- SEMARNAT-2011;** the POEGTE, the **POEBC**, the Regional Urban Development Program for the COCOTREN, and based on provisions and orders applicable, this **DGGPI** determines that the **PROJECT** under evaluation is environmentally viable, and has decided to **AUTHORIZE IT IN A CONDITIONED MANNER**, and submitted to the following

TERMS:

FIRST. This resolution is issued on the environmental aspects related to the construction, operation and maintenance of the **PROJECT** named **"PROJECT NATURAL GAS LIQUEFACTION PROJECT IN ENERGÍA COSTA AZUL"**, with proposed location in the municipality of Ensenada, in the state of Baja California.

The **PROJECT** is detailed in **Item VIII.** Operation conditions are those specified in the corresponding **EIM-R** Chapters.

SECOND. This authorization will be effective for **10 years**, for the **PROJECT** site preparation and construction stages, and for **30 years**, for the operation, maintenance and abandonment stages. Such term starts on the firs working date after the notification of this resolution. The term can be modified as requested by the **REGULATED PARTY**, having fulfilled all terms and conditions herein, and the prevention, mitigation and/or compensation measures specified in documentation delivered.

To that end, the **REGULATED PARTY** shall request in writing to this **DGGPI**, the request approval, under the COFMEER proceeding, with code **SEMARNAT-04-008**, before the expiration date. The request shall include a report delivered by the legal representative, under fractions II, IV and V of Article 420 Quater of the Federal Penal Code. This report shall detail how and what results were obtained from the fulfillment of terms and conditions specified in this authorization.

The report may be replaced by official document issued by the **Unit of Supervision, Inspection and Industrial Surveillance** of this **AGENCY**, certifying that the **REGULATED PARTY** complied with terms and conditions specified in this authorization. Otherwise, the proceeding will not be effective.

THIRD. As a part of the risk management process, within a term of **60 working days** before the construction stage, the REGULATED PARTY shall deliver the updated ERA, starting from basic or extended detail engineering, for this **DGGPI** to assess any risks resulting, and consider any new recommendations or conditions, as needed.

Noncompliance with terms and conditions specified in this authorization by the **REGULATED PARTY** cause inherent administrative responsibilities before this **AGENCY**.

FORTH – Once the **PROJECT** is in the operation stage, the **REGULATED PARTY**, shall deliver, within a term of 60 working days, the ERS, proceeding No. **ASEA-00-032**, different to that specified in the **THIRD TERM** of this resolution letter. To that end the **REGULATED PARTY** shall considered the conduction of an **ARP** including all facilities of the **PROJECT** and of the **regasification plant**, using final engineering information and plans *as built*. Also, a **systematic, methodological approach**, based on qualitative and quantitative ARP methodologies shall be used to identify hazards and evaluate risks, to establish risk scenarios chosen for consequences simulation, safety systems and preventive measures; or propose preventive, control and mitigation scenarios. Additionally, and based on the **ERS**, the **PPA** shall be delivered, **considering the facilities of both the PROJECT and the regasification plant**, proceeding No. **ASEA-00-030**, consistent with the **ERS** risk management scenarios.

Before the **PROJECT** construction, the REGULATED PARTY shall deliver the approval of its Risks Management System, to comply with administrative provisions published in the DOF on January, 24, 2017.

FIFTH – Under Article 35, last paragraph of the **LGEEPA** and 49 of the **REIA**, this authorization refers solely and exclusively to **environmental aspects** of works and activities described in the **FIRST TERM** for **PROJECT**, notwithstanding decisions made by local authorities, including authorizations, permits and licenses, among others.

SIXTH. This resolution does not exempt the **REGULATED PARTY** from requesting and obtaining the corresponding authorization for the forest lands soil use change, under Article 58, Fraction I and 117 of the General Law of Sustainable Forest Development, and Article 12, Fraction 1, sentence a) of the Internal

Regulation of the National Agency for Industrial Safety and Environmental Protection of the Hydrocarbons Sector.

SEVENTH – This resolution is issued only on the environmental subject for the construction, operation and maintenance described in the FIRST TERM herein, corresponding to the evaluation of environmental impacts caused by a facility of the hydrocarbons sector, and liquefaction of NG, under Article 28 fractions II, VII and X of the **LGEEPA** and 5, sentences D) fractions IV and VII, O) and R) of the **REIA**.

EIGHTH. This resolution is not authorizing the construction, operation and/or expansion of any activities different to those considered in the **FIRST TERM** herein. However, if the **REGULATED PARTY** decides to change the activity, it must be reported to this **DGGPI**, under the **TENTH TERM** herein.

NINETH. The **REGULATED PARTY** is obliged to comply with Article 50 of the **REIA**, if desisting from conducting works and activities in question, for this **DGGPI** to proceed under Fraction II, and determines any measures to be adopted, aiming to cause no negative environmental impacts.

TENTH. If **REGULATED PARTY**, decides to modify **PROJECT**, shall request the corresponding authorization to this **DGGPI**, under Article 28 of the **REIA**, providing information enough to determine if changes proposed will not cause ecological imbalance, exceed limits and conditions established by law, or the Terms and Conditions herein. Before starting any works or activities to be modified, the REGULATED PARTY shall notify the situation to this **DGGPI**, based on the COFMEER proceeding, with number SEMARNAT-04-008. Activities different from those specified in this authorization are forbidden.

ELEVENTH. Under Article 35, Fourth Paragraph, Fraction II of the **LGEEPA**, stating that after the EIM has been reviewed, the corresponding resolution to authorize the work or activity in a conditioned manner, and under Article 47, First Paragraph of the **REIA**, establishing that the work or activity must adhere to the corresponding resolution, this **DGGPI** establishes that the **PROJECT** activities authorized are submitted to descriptions in the **EIM-R**, the **ERS**, the **AI**, and plans included in the reference documentation applicable NOMs and other legal dispositions, according to the following:

CONDITIONS:

The **REGULATED PARTY** shall:

1. Under articles 15 fractions I a la V and 28, First Paragraph of the **LGEEPA**, and Article 44 of the **REIA**, fractions I and III, after the EIM has been completed, the Secretariat may consider any preventive or mitigation measures voluntarily proposed by the **REGULATED PARTY** to avoid or minimize negative environmental impacts, this **DGGPI** establishes that the **REGULATED PARTY** shall comply with each and every measure proposed in the **EIM-R**, that this **DGGPI** considers as viable and consistent with the purpose of protect the environment, and the **RES**. It also shall comply with the **LGEEPA**, the **REIA**, the NOMs and any other legal provision applicable, notwithstanding decisions made by other federal, state or local competent agencies. The

REGULATED PARTY shall deliver compliance reports with measures proposed in the **EIM-R**, to the Supervision, Inspection and Industrial Surveillance of this **AGENCY**, during the construction stage and 5 years thereafter. The first report shall be delivered 12 months after receiving this resolution.

The **REGULATED PARTY** will be responsible for the quality of information on reports above, as they will be used by the authority to evaluate and confirm, its compliance with valuation criteria and conditions specified herein.

2. Under articles 35 of the **LGEEPA** and Article 51, Second Paragraph, Fractions I, II and III of the **REIA**, the **PROJECT** execution may release substances that, in contact with the environment become toxic, persistent and bioaccumulable. The site proposed has water bodies, flora and wildlife species, endemic species; or species threatened, endangered or under special protection (presence of species listed in **NOM-059- SEMARNAT-2010** was reported. The **REGULATED PARTY** also intends conducting activities considered as high risks, given that it manages methane and propane with stocks exceeding the reporting amounts. Therefore, this **DGGPI** determines that the **REGULATED PARTY** shall contract a warranty to ensure compliance with conditions specified herein. It has to be noted, that the warranty amount shall correspond to a Technical Economical Study (**TES**), to be used by the REGULATED PARTY to determine the type and amount of such instrument (surety bond, trust, credit letter), implying compliance of terms and conditions in the site preparation and construction stages specified in the **EIM-R**, and covering any damage reparation due to non-compliance.

   The REGULATED PARTY shall deliver to this **DGGPI**, the **TES** with its financial warranty proposal, within a period of THIRTY DAYS, starting on the reception date of this document. Then, the **DGGPI** will analyze the case, approve the warranty type and amount, and the **REGULATED PARTY** shall comply with Article 53, First Paragraph of the **REIA**.

   On the other hand, once the **PROJECT** operation starts, the REGULATED PARTY shall acquire an environmental risk insurance, under Article 147 Bis of the **LGEEPA**, and deliver a copy of the policy to this **DGGPI**. The policy must be effective throughout the **PROJECT** useful life. To this end, the **REGULATED PARTY** shall follow the "Administrative Provisions of General Character, setting the rules for the minimum insurance requirements for regulated parties conducting hydrocarbon exploration and extraction, oil treatment and refining, and GN processing works or activities," published in the DOF on June 23, 2016. Such provisions describe elements and characteristics of mandatory insurance policies covering public liability, liability for environmental damage, or wells control, to face damages caused by activities conducted in the hydrocarbons sector.

3. Update and implement the **PSCA**, reflecting all measures and programs proposed, and comments made by this **DGGPI**, for follow-up, monitoring and evaluation purposes. This program shall be annual, and delivered as the **PROJECT** works and activities progress for **12** (**twelve**) years.

4. To follow-up preventive measures specified in the **EIM-R**, the **REGULATED PARTY** shall appoint a person responsible with technical skills enough to detect critical aspects of the operation and maintenance, from the environmental perspective, and to make decisions in the field, define strategies or modify activities with negative environmental impacts.

5. Comply with all preventive, control and/or attention measures proposed in the **ERS** of the **PROJECT**, those arising from any **ERS** updating (with final information), and those specified by this **DGGPI**, as follows:
   a. Implement all preventive measures specified in the **EIM-R**, **ERS** and AI, and those arising from any **ERS** updating (with final information), under Condition I, herein.
   b. Deliver to the municipality of Ensenada, Baja California, an executive summary of the **ERS** and any updates thereon, according to the project life cycle, showing potential impact radius, to be considered in the Risk Atlas. A copy of the receipt acknowledge, properly certified, shall be delivered to this **DGGPI**.
   c. The **REGULATED PARTY** shall implement all sub-subprograms specified in the PSCA, as follows:

Ecosystem	Environmental Factor	Environmental Quality Follow-Up Subprogram
Terrestrial	Air (air quality)	• Air Quality Monitoring Program • Atmospheric Emissions Monitoring Program • Air Measures Compliance Program
	Air (noise level)	• Perimeter Noise Monitoring Program
	Surface Hydrology (drainage pattern)	• Water Measures Compliance Program
	Soil (soil quality, structure and erosion)	• Soil Preservation Program • Soil Preservation Monitoring Program • Soil Measures Compliance Program
	Flora (coastal rosetophylous scrubs, species under special protection status)	• Flora Rescue, Protection and Preservation Program • Wild Flora Monitoring Program
	Flora (coastal rosetophylous scrubs, species under special protection status)	• Forestation and reforestation program to compensate forest soil use change. • Wild Flora Monitoring Program
	Fauna (abundance and richness in terrestrial habitats, species with special protection status)	• Wildlife Rescue, Protection and Preservation Program • Wildlife Monitoring Program
	Risk	• Risk Measures Compliance Program
Marine	Sea Water (water quality)	• Seawater Quality Monitoring Program • Waste Water Discharges Monitoring Program • Water Measures Compliance Program
	Coastal dynamics (sediments carrying)	• Coastal Dynamics Monitoring Program
	Flora (marine flora)	• Intertidal and Subtidal Flora Monitoring Program

Ecosystem	Environmental Factor	Environmental Quality Follow-Up Subprogram
	Fauna (marine fauna)	• Marine Fauna Rescue, Protection and Preservation Program. • Benthic Fauna Rescue, Protection and Preservation Program • Benthic Fauna Monitoring Program • Intertidal and Subtidal Fauna Monitoring Program
	Marine mammals	• Marine Mammals Monitoring Program • Manual of Good Navigation Practices and their relation to the preservation of marine mammals

6. The **REGULATED PARTY** shall implement any measures specified by the Secretariat of Environmental Protection of the state of Baja California for the **PROJECT before the operation stage**, particularly as follows:
   a. A detailed geotechnical study in the area, as the document delivered in the **EIM-R** is a preliminary study, with no sufficient information, as related to compliance with **CRE** No. 6 of the **POEBC**.
   b. A seismic risk study, as the **PROJECT** site is surrounded by seismically active faults, with potential to generate close range (<100 km) earthquakes with magnitudes of up to 7.5.
   c. Develop and analyze a failure scenario for some **PROJECT** measures and specifications:

      - What would be the response before a close earthquake with magnitude above 6, and which damages are estimated on the storage tanks or other facilities?
      - Which is the emergency response plan for a LNG spill?
      - What would be the impact on the facility of a tsunami with a 3-m high wave, on a high tide period?

   d. Install accelerometers in the **PROJECT** site to assess potential land and structure accelerations, and analyze the effect of the soil-structure interaction, and determine if such accelerations exceeded the design parameters.

   e. Identify the geological risk potential for the **PROJECT** site (slope instability), that may be reactivated by an earthquake of significant magnitude, at close range, or due to the effect of water infiltration, inadequate cuts, or excessive weight, among others.

7. The **PROJECT** design shall consider risks associated to geological, seismic, tsunamis, floods, chemicals, and forest hazards, according to the Risk Atlas of the state of Baja California. It shall also consider geological risks, hazards and vulnerabilities (faults, fractures, tsunamis, landslides, collapses, and erosion); hydro meteorological risks (hurricanes, tropical storms, droughts, extreme temperatures, floods, snowfalls, and wildfires, according to the Risk Atlas of the state of Baja California.

8. During the MOF dredging activities, the **REGULATED PARTY** shall monitor the presence of marine mammals to protect them. All shots shall stop when any organisms enter in the area, as follows:

   a. Surveillance must consider the following zones:

   - Danger Zone (DZ), where the external limit of the radius is the minimum distance where no mortality would be expected: 310 m (1,020 ft.)
   - Safe Zone: largest radius to ensure that species are beyond the minimum distances with potential for aggression or injuries caused by blasting in open areas 620 m (2,030 ft.)
   - Monitoring Zone, it measures three times the DZ radius, to ensure that all animals entering or traveling near the safety zones are observed, to take any pertinent actions, before entering the impact area. 930 m (3,050 ft.)

   b. The time of the year proposed for the blasting activities is before the second half of December, considering that whales migrate north and south from December through April.
   c. lasting debris will be disposed of in the site previously approved.
   d. Minimize impacts on the water quality and turbidity, by following good dredging practices.
   e. Implement physical barriers to reduce overpressure waves impact zones.
   f. Prevent fish species mortality due to blasting activities. Any massive mortality case shall be reported to this **AGENCY**. Any additional measures to prevent such cases must be implemented. All of the above must be documented and attached to the terms and conditions compliance reports.

9. As related to the Monitoring Program de flora marine, monitor species of *Sargassum muticum* and *Sargassim horneri*, to describe their space and temporal variations in the **AlM** of **PROJECT**.

10. As related to the Marine Mammals Monitoring Program and the Manual of Good Navigation Practices and their relation to the preservation of marine mammals, the REGULATED PARTY shall provide evidence of compliance, particularly arrival and departure reports of each vessel, to and from the Maritime Terminal Energía Costa Azul, throughout the year, according to the sonification: core zone <3 knots, buffer zone <6 knots and approaching <8 knots). Within these programs, any incident or accident between vessels and marine mammals shall be reported.

11. At the end of the **PROJECT's** useful life (abandonment), the **REGULATED PARTY** will proceed to the decommissioning, dismantling and/or demolition, and is obliged to restore the site to its original conditions, as much as possible. To that end, it shall deliver to this DGGPI, a program to be validated, and then, notify the Unit of Supervision, Inspection and Industrial Surveillance, to certify the compliance, and deliver the final site abandonment and rehabilitation report.

12. Include results of the **ERS** updating, with final information and plans *"as built"*, to design gas and fire systems.

13. Provide evidence of the proper implementation of the inspection and maintenance programs.
14. Consider adequate measures or facilities to control a fire event in the plant surroundings.
15. Evaluate historical information of serious accidents (1969, Portland Oregon, EUA; 1971, LaSpezia Italy; 1973, Staten Island NY, EUA; 1979, Cove Point, Maryland, EUA; 1979, Gibraltar; 1980, Philipines; 1980, Tobata, Japan; 2001, EUA; 2005, Nigeria; 2013, Yokohama, Japan; and 2014, Oregon, EUA); in the **ERS** updating based on basic expanded engineering.
16. In the **ERS** updating, consider LNG spill scenarios in the transfer line.
17. Ensure that the liquefaction facilities are inherently safe, and the materials, equipment, pipelines, and fixtures selection and specifications shall consider national and international codes, standards, and good practices.
18. To prevent the cumulative effect due to containment loss in LNG storage tanks, due to overfilling, the **REGULATED PARTY** shall have, as a minimum, the following instrumentation:
    a. Pressure protection
    b. Vacuum protection
    c. Anti-reversion devises (recirculation systems, evaporation speed control systems; and tank temperature and density measuring)
    d. Temperature sensors (leak detectors, temperature gradient monitoring)
    e. Level indicators and controllers (high-high and low-low level alarms)
    f. Pressure indicators and controllers (high pressure, low pressure or vacuum detection)
    g. Liquid circulation tank connections (automatic closure valves in case of fire, remote actuation valves, etc.).
    h. Leak detection in primary container
    i. Containment dike.
19. Avoid potential ignition sources by ensuring:
    a. Adequate design of grounding systems to avoid accumulation of static electricity
    b. Design of intrinsically safe electrical installations
    c. Classification of electrical areas
    d. Adequate design and installation of fire detection and suppression systems, complying with international standards for the type of flammable and combustible materials in the facility.
20. Prepare general plans of equipment arrangement, respecting distribution distances, according to international standards and practices, and based on final approved engineering information.
21. To mitigate environmental impacts caused by atmospheric emissions and waste discharges:

- From the design stage, estimate total GHG of the facility as a whole, using nationally and internationally recognized methodologies.
- Consider atmospheric emissions specifications for equipment selection and purchasing purposes.
- The liquefaction facilities must have a waste water treatment, before discharging in receiving bodies.

22. To prevent H_2S releases from Unit 12, specify monitoring systems triggering warning signs (audible, visible), when detecting concentrations >10 ppm.

23. Control rooms must have adequate specifications and HVAC systems (closing on gas detection), explosion proof, and based on updated risk studies.

24. To prevent leaks, fires and explosions during loading and unloading activities, provide:

    a. Position alarm system for loading/unloading arms
    b. Arm position control system
    c. Emergency disengagement systems
    d. Emergency disengagement for full electrical failure
    e. Vapor return line
    f. Spill containment dike in the pier
    g. Hydrants, monitors
    h. Dry chemical fixed firefighting systems
    i. Dry chemical portable firefighting systems
    j. Water curtains
    k. Spraying water systems
    l. Gas detectors
    m. Flame detectors
    n. "Ship-to-Shore" safety systems
    o. Portable extinguishers.

25. Implement a quality assurance mechanism or procedure to ensure that all liquefaction equipment, lines and fixtures are specified, purchased, evaluated and installed according to the process nature and following all applicable national and international codes and practices.

26. El **REGULATED PARTY** shall conduct periodic inspections on storage tanks and their components, following the manufacturer recommendations:

    a. Corrosion detection (Semiannual)
    b. Visual inspection (maintenance activities)
    c. Safety valves revision and calibration (quarterly)

d. Revision of cathodic protection systems (bimonthly, if applicable)
e. Calibration of gas detectors (quarterly)

TWELFTH. The **REGULATED PARTY** shall deliver reports of compliance with terms and conditions herein, and measures proposed in the **EIM-R**. The report shall be delivered to the **Unit of Supervision, Inspection and Industrial Surveillance**, in an annual basis for **twelve years** starting after the first working day after the enactment of this resolution.

THIRTEENTH. Under Article 35, last Paragraph of the LGEEPA, and First Paragraph of Article 49 of the R-LGEEPA on environmental impact evaluation, this resolution solely addresses works and activities described in **ITEM VIII** for this **PROJECT**. Therefore, this is not a permit or authorization to start working, as those are competence of municipal authorities, as specified by the law.

The **REGULATED PARTY** is responsible to have, before starting any activity related to the **PROJECT**, with all permits, authorizations, licenses, and decisions required, under applicable legislation in effect for any subject different from that of this resolution.

The resolution issued by this **DGGPI** is not binding for other authorities to grant any authorizations, licenses, and decisions allowed by their competencies.

FOURTEENTH. The **REGULATED PARTY** shall notify to this **DGGPI**, the starting and termination dates of the different **PROJECT** stages, under Article 49, Second Paragraph of the **REIA**, within **15 days** after starting, and **15 days** after terminating.

FIFTEENTH. This resolution in favor of the **REGULATED PARTY** is personal. Therefore, in case of changes in the ownership, and under Article 49, Second Paragraph, of the **REIA**, the **REGULATED PARTY** shall deliver to this **DGGPI** the Ownership Change Notice of the Environmental Impact Authorization, with COFMEER proceeding, number **SEMARNAT- 04-009**.

SIXTEENTH. The **REGULATED PARTY** will be the sole responsible for ensuring the execution of mitigation, restoration and control activities to address all environmental impacts arising from the **PROJECT** construction, operation and maintenance, not considered in the description included in the documentation delivered with the **EIM-R**.

If works and activities authorize endanger or cause impacts disturbing the behavioral patterns of biotic resources and/or any type of impact, damage or deterioration on abiotic elements in the **PROJECT** site, this **DGGPI**, can demand their suspension, and the implementation of compensation programs, among other safety measures under Article 170 de la **LGEEPA**.

SEVENTEENTH. The **DGGPI**, through the Unit of Supervision, Inspection and Industrial Surveillance, will monitor the compliance with terms and conditions established herein and in applicable environmental impact legislation, using powers granted to it in articles 55. 59 and 61 of the **REIA**.

EIGHTEENTH. Given the **PROJECT** nature, this **DGGPI** reserves the faculty of establishing additional conditions and requirements in the different development stages, to determine that prevention, compensation and mitigation measures proposed and specified are adequate for their purpose, under Article 48 of the **REIA**.

NINTH. The **REGULATED PARTY** shall keep in the address registered in the **EIM-R**, copies of the files, the **EIM-R**, of the **PROJECT** plans of the **ERS**, of the **AI**, and of this document, to present them as required by the competent authority

TWENTIETH. The REGULATED PARTY is informed that this resolution, issued under the **LGEEPA**, its **REIA** and any other legal provisions applicable, can be objected through the revision resource, under Article 176 of the **LGEEPA**, which can be presented within **fifteen** working days, starting from the formal notification of this resolution.

TWENTY FIRST. Notify **Mr. JUAN RODRIGUEZ CASTAÑEDA**, Legal Representative of **ENERGÍA COSTA AZUL**, **S. DE R. L. DE C. V.**, un person, under Article 167 Bis of the LGEEPA.

SINCERELY, THE GENERAL DIRECTOR

ENG. DAVID RIVERA BELLO