BLANKROME
1825 Eye Street NW | Washington, DC 20006
blankrome.com

Phone: *(202) 420-2656*
Fax: *(202) 379-9027*
Email: *bsnyder@blankrome.com*

Rec'd DOE/FE 2/26/2019 via FERGAS

19-34-LNG

February 26, 2019

VIA ELECTRONIC DELIVERY

Ms. Amy Sweeney
Director, Division of Natural Gas Regulation
Office of Fossil Energy
U.S. Department of Energy
Room 3E-052
1000 Independence Ave S.W.
Washington, DC 20585

Re: **Annova LNG Common Infrastructure, LLC,**
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations

Dear Ms. Sweeney:

Enclosed please find the Application of Annova LNG Common Infrastructure, LLC for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations. A receipt confirming electronic payment of the $50.00 filing fee is also enclosed herewith.

Please contact the undersigned with any questions regarding this Application.

Respectfully submitted,

/s/ Brett A. Snyder
Brett A. Snyder
Counsel for Annova LNG Common Infrastructure, LLC

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

	)	
Annova LNG Common	)	**FE Docket No. 19-___-LNG**
Infrastructure, LLC	)	
	)	

APPLICATION OF ANNOVA LNG COMMON INFRASTRUCTURE, LLC
FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION
TO EXPORT LIQUEFIED NATURAL GAS TO
NON-FREE TRADE AGREEMENT NATIONS

Susan B. Bergles
Exelon Corporation
1310 Point Street, 8th Floor,
Baltimore, MD 21231
(410) 470-1553
susan.bergles@exeloncorp.com

Jennifer A. Solomon
Exelon Corporation
101 Constitution Ave, N.W.
Washington, DC 20001
(202) 637-0316
jennifer.solomon@exeloncorp.com

Brett A. Snyder
Mark R. Haskell
Lamiya Rahman
Blank Rome LLP
1825 Eye Street, NW
Washington, DC 20006
(202) 420-2200
bsnyder@blankrome.com
mhaskell@blankrome.com
lrahman@blankrome.com

TABLE OF CONTENTS

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

	)	
Annova LNG Common	)	**FE Docket No. 19-___-LNG**
Infrastructure, LLC	)	
	)	

APPLICATION OF ANNOVA LNG COMMON INFRASTRUCTURE, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT NATIONS

Pursuant to section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the United States Department of Energy's ("DOE") regulations,[2] Annova LNG Common Infrastructure, LLC ("Annova" or "Applicant") hereby requests that the DOE's Office of Fossil Energy ("DOE/FE") grant long-term, multi-contract authorization for Annova to engage in exports of domestically produced liquefied natural gas ("LNG") in an amount up to 6.95 million tonnes per annum ("mtpa") (the equivalent of approximately 360 billion cubic feet ("Bcf") per year ("Bcf/y"), or approximately an average of 0.986 Bcf per day ("Bcf/d")) from proposed natural gas liquefaction and export facilities located on the Brownsville Ship Channel in Cameron County, Texas (the "Project"). Annova requests such authorization, on its own behalf and as agent for other entities that hold title to the LNG at the point of export, to export the requested volumes to any nation with which the United States does not have a free trade agreement ("FTA") requiring the national treatment for trade in natural gas ("Non-FTA" nations), which has or will develop the capacity to import LNG, and with which trade is not prohibited by United States law or policy. Annova requests this authorization for a 20-year term commencing on the earlier of the date of

---

1 15 U.S.C. § 717b (2018).

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

first commercial export or seven years from the date of issuance of the authorization requested herein.

In support of this Application, Annova states as follows:

I. COMMUNICATIONS AND CORRESPONDENCE

All correspondence and communications concerning this Application, including all service of pleadings and notices, should be directed to the following persons:

Susan B. Bergles
Exelon Corporation
1310 Point Street, 8th Floor,
Baltimore, MD 21231
(410) 470-1553
susan.bergles@exeloncorp.com

Jennifer A. Solomon
Exelon Corporation
101 Constitution Ave, N.W.
Washington, DC 20001
(202) 637-0316
jennifer.solomon@exeloncorp.com

Brett A. Snyder
Mark R. Haskell
Lamiya Rahman
Blank Rome LLP
1825 Eye Street, NW
Washington, DC 20006
(202) 420-2200
bsnyder@blankrome.com
mhaskell@blankrome.com
lrahman@blankrome.com

Annova requests waiver of Section 590.202(a) of DOE's regulations to the extent necessary to include outside counsel on the official service list for this proceeding.[3]

II. DESCRIPTION OF APPLICANT

The exact legal name of Applicant is Annova LNG Common Infrastructure, LLC. Applicant is a limited liability company organized under the laws of Delaware. The purpose of Applicant is to facilitate financing of the Project, to construct and operate the export facilities, to own certain common facilities, and to hold the Project's permits. Applicant's principal place of business is 1310 Point Street, 8th Floor, Baltimore, MD 21231. Applicant is an indirect

---

3 10 C.F.R. § 590.202(a).

subsidiary of Exelon Corporation, a publicly traded company formed under the laws of Pennsylvania and headquartered in Chicago, Illinois.

III. BACKGROUND

On February 20, 2014, DOE/FE granted Annova LNG, LLC long-term, multi-contract authorization to export LNG in volumes equivalent to approximately 342 Bcf/y of natural gas to FTA nations from the Project (the "FTA Authorization").[4] DOE/FE subsequently issued an order approving an assignment of the FTA Authorization from Annova LNG, LLC to Applicant.[5]

On July 13, 2016, Applicant, along with Annova LNG Brownsville A, LLC, Annova LNG Brownsville B, LLC, and Annova LNG Brownsville C, LLC, filed with the Federal Energy Regulatory Commission ("FERC") an Application for Authorization Under Section 3 of the Natural Gas Act ("FERC Application"), seeking authorization to site, construct, and operate the Project in FERC Docket No. CP16-480-000.[6] FERC issued the draft Environmental Impact Statement ("EIS") on December 14, 2018.[7] FERC issued a Notice of Schedule for Environmental Review, setting forth FERC's intent to issue the final EIS by April 19, 2019.[8]

---

4 *Annova LNG, LLC*, DOE/FE Order No. 3394, FE Docket No. 13-140-LNG, Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Proposed Annova LNG Terminal in Brownsville, Texas, to Free Trade Agreement Nations (Feb. 20, 2014).

5 *Annova LNG Common Infrastructure, LLC*, DOE/FE Order No. 3464, FE Docket Nos. 14-004-CIC & 13-140-LNG, Order Approving Change in Control to Annova LNG Common Infrastructure, LLC of Authorization Allowing Exports of Liquefied Natural Gas to Free Trade Agreement Nations (July 17, 2014).

6 Application of Annova LNG Common Infrastructure, LLC, et al. for Authorization Under Section 3 of the Natural Gas Act, *Annova LNG Common Infrastructure, LLC*, Docket No. CP16-480-000 (July 13, 2016).

7 Draft Environmental Impact Statement, *Annova LNG Common Infrastructure, LLC*, Docket No. CP16-480-000 (Dec. 14, 2018).

8 Notice of Schedule for Environmental Review of the Annova LNG Brownsville Project, *Annova LNG Common Infrastructure, LLC*, Docket No. CP16-480-000 (Aug. 31, 2018).

DOE is a cooperating agency for purposes of FERC's environmental review of the Project under the National Environmental Policy Act ("NEPA").[9]

IV. AUTHORIZATION REQUESTED

Annova hereby requests authorization to export up to 6.95 mtpa (equivalent to approximately 360 Bcf/y or 0.986 Bcf/d of natural gas) to Non-FTA Nations for a 20-year term commencing on the earlier of the date of first commercial export or seven years from the date of issuance of the authorization requested herein. Annova requests this authorization both on its own behalf and as agent for other parties who will hold title to the LNG at the time of export. Annova will comply with all DOE/FE requirements for an exporter or agent, including all applicable registration requirements.[10]

Additionally, Annova requests that it be permitted to export commissioning volumes prior to the commencement of the export term requested herein pursuant to a separate short-term, blanket export authorization for which Annova shall apply at a later date, and which commissioning volumes will not be counted against the export volumes sought herein. Annova also requests that it be permitted to continue exports for a total of three years following the end of the export term requested herein, solely to export any make-up volume that it was unable to export during the original export period.

Annova respectfully requests that DOE/FE grant this Application by June 18, 2019.

---

[9] 42 U.S.C. § 4321 et seq. (2018).

[10] *See, e.g.*, *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).

V. DESCRIPTION OF THE PROJECT

A. *Project Facilities*

The Project will serve as a mid-scale natural gas liquefaction facility for the purpose of exporting natural gas to international markets. The Project will be located on an approximately 731-acre parcel of undeveloped land on the south bank of the Brownsville Ship Channel in Cameron County, Texas, which is available to Annova through a real estate lease option agreement with the Brownsville Navigation District.

As requested in the FERC Application, Annova seeks to construct and operate liquefaction and marine transfer facilities that include: (a) gas pre-treatment facilities; (b) six liquefaction trains—each with a nameplate capacity of 1.0 mtpa, for an aggregate nameplate capacity of 6 mtpa and a maximum output at optimal operating conditions of 6.95 mtpa—and six approximately 72,000 horsepower electric motor-driven compressors; (c) two single-containment LNG storage tanks designed to store approximately 160,000 cubic meters ("m^3"); (d) boil-off gas handling and flare systems; (e) marine transfer facilities designed to accommodate 138,000 m^3 to 177,000 m^3 LNG carriers; and (f) other associated infrastructure, such as control, administrative and support buildings, a new main access road, and utilities infrastructure for power, water, and telecommunications systems. Annova will commission the Project in three stages, each of which will add two liquefaction trains and a total nameplate capacity of 2.0 mtpa.

B. *Export Sources*

Annova seeks authorization to export natural gas available in the U.S. natural gas supply and transmission system. The Project will receive natural gas supply from a third-party owned and operated intrastate pipeline, estimated to be constructed in 2023.

C. *Commercial Arrangements*

Annova intends to enter into one or more long-term natural gas supply or LNG export contracts in connection with the authorization requested herein. However, Annova has not yet entered into any such agreements. Therefore, Annova is not submitting the transaction information required by sections 590.202(b) and 590.202(c) with this Application, and requests that DOE/FE make a determination similar to that in prior DOE/FE proceedings that Annova may submit transaction-related information "when practicable" (*i.e.*, when the relevant contracts are executed).[11]

VI. PUBLIC INTEREST ANALYSIS

The Project satisfies the NGA's standard for a Non-FTA export application, pursuant to which the DOE/FE must grant the application absent an affirmative showing that it is inconsistent with the public interest. As demonstrated below, estimated natural gas supplies over Annova's requested authorization term will be more than sufficient to satisfy both forecasted demand and the volumes of LNG proposed to be exported from the Project. Additionally, any natural gas price increases attributable to the Project's exports will not only be minimal, but will also be outweighed by numerous benefits to the economy in the form of job creation, increased tax revenues, higher economic output, trade deficit reductions, and other national and international benefits.

---

[11] *See, e.g.*, *Golden Pass Prods. LLC*, DOE/FE Order No. 3978, FE Docket No. 12-156-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Golden Pass LNG Terminal Located in Jefferson County, Texas, to Non-Free Trade Agreement Nations at 171 (Apr. 25, 2017) [hereinafter Golden Pass]; *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413, FE Docket No. 12-32-LNG, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Jordan Cove LNG Terminal in Coos Bay, Oregon to Non-Free Trade Agreement Nations at 149-50 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391, FE Docket No. 11-162-LNG, Order Conditionally 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 138-39 (Feb. 11, 2014); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2833, FE Docket No. 10-85-LNG, Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Free Trade Nations at 5-6 (Sept. 7, 2010).

A. *Applicable Legal Standard*

Section 3(a) of the NGA governs the review of Non-FTA export applications. Under this statutory standard:

> [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 Commission authorizing it to do so. ***The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.***[12]

NGA Section 3(a) creates a rebuttable presumption that a proposed export is in the public interest.[13] DOE/FE has explained that it must grant an export application unless opponents of the application overcome the "presumption favoring export authorizations" by making an affirmative showing that the application is inconsistent with the public interest.[14]

The NGA does not define "public interest" or specify the criteria DOE/FE must evaluate in its analysis. Consequently, the DOE/FE has identified several factors that it considers when reviewing Non-FTA export applications. These include, *inter alia*, economic impacts, international impacts, security of natural gas supply, and environmental impacts.[15] The DOE/FE is also guided by the 1984 Policy Guidelines, which espouse a goal of "minimiz[ing] federal

---

12 15 U.S.C. § 717b(a) (emphasis added).

13 *See, e.g. Sierra Club v. U.S. Dep't of Energy*, 867 F.3d 189, 203 (D.C. Cir. 2017).

14 *See, e.g.,* Golden Pass at 11; *Lake Charles LNG Export Co., 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 at 14 (June 29, 2017) [hereinafter Lake Charles]; *Southern LNG Company, LLC*, DOE/FE Order No. 3956, DOE/FE Docket No. 12-100-LNG, Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Elba Island Terminal in Chatham County, Georgia to Non-Free Trade Agreement Nations at 10 (Dec. 16, 2016) [hereinafter Southern LNG].

15 *See* Golden Pass at 11; Lake Charles at 14-15; Southern LNG at 10-11.

control and involvement in energy markets" and "promot[ing] a balanced and mixed energy resource system."[16] The Policy Guidelines are premised on the notion that:

> The market, not government, should determine the price and other contract terms of imported [or exported] natural gas . . . The federal government's primary responsibility in authorizing imports [or exports] will 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.[17]

In identifying factors relevant to its review of Non-FTA export applications, DOE/FE has also looked to DOE Delegation Order No. 0204-111, which based the regulation of exports "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."[18] Although DOE Delegation Order No. 0204-111 is no longer in effect, DOE/FE continues to focus on the following factors in its review of export applications: (i) the domestic need for the natural gas 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 DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[19]

B. *Domestic Need for Natural Gas*

A comparison of estimated natural gas supplies and production against forecasted demand demonstrates that the requested exports will not adversely affect domestic need for natural gas. Moreover, any natural gas price increases attributable to exports from the Project

---

[16] *See* Golden Pass at 11 (citing New Policy Guidelines and Delegations Order Relating to Regulation of Imported Natural Gas, 49 Fed. Reg. 6684 (Feb. 22, 1984) [hereinafter Policy Guidelines]); *see also* Lake Charles at 15; Southern LNG at 11. DOE/FE has explained that while the Policy Guidelines are nominally applicable to natural gas import cases, that it has held them to be applicable to export applications. *See, e.g.,* Golden Pass at 12; Lake Charles at 15; Southern LNG at 11.

[17] Policy Guidelines at 6685.

[18] U.S. Department of Energy, Delegation Order No. 0204-111 at 1 (Feb. 22, 1984).

[19] *See, e.g.*, Golden Pass at 12; Lake Charles at 16; Southern LNG at 12.

would be minimal. Overall, the proposed exports would yield net benefits to the domestic economy and natural gas supply-demand balance.

1. Domestic Natural Gas Supply

Existing U.S. natural gas supplies are abundant and more than sufficient to satisfy both projected U.S. demand for natural gas and increased LNG exports, including the proposed exports from the Project. Technological advances over the past decade have facilitated a boom in natural gas production, particularly with respect to unconventional resources. These developments have permitted unprecedented volumes of U.S. natural gas to be produced economically and have paved the way for the United States to become a net exporter of natural gas. Growth in natural gas production is expected to continue over the requested term of Annova's proposed exports.

The U.S. Energy Information Administration ("EIA") estimates that natural gas production will increase and outpace natural gas consumption between the period 2017 through 2050.[20] Production growth is largely attributable to the development of shale gas and tight oil plays, which EIA predicts will account for more than three quarters of natural gas production by 2050.[21] The largest contributors to shale gas development are the Marcellus and Utica shale plays, followed by production from the Eagle Ford and Haynesville plays in the Gulf Coast region.[22] Additionally, the EIA predicts strong growth in associated gas production from tight oil production in the Permian basin over the 2017-2050 period.[23] As the EIA explains, "[c]ontinued technological advancements and improvements in industry practices are expected to

---

[20] U.S. Energy Information Administration, *Annual Energy Outlook 2018* at 61-62 (Feb. 6, 2018) [hereinafter AEO 2018], https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

[21] *Id.* at 65-66

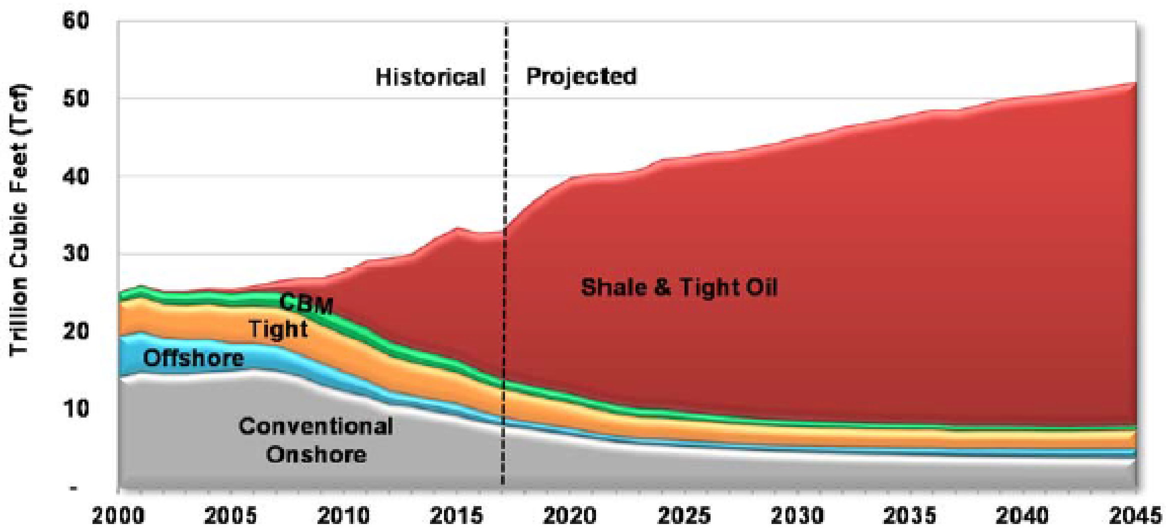
[22] *Id.* at 67-68.

[23] *Id.* at 68.

lower costs and to increase the volume of oil and natural gas recovery per well."[24] The EIA estimates technically recoverable dry natural gas resources in the United States to total 2,462.3 trillion cubic feet (Tcf), with 707.1 Tcf in the Gulf Coast region.[25] The EIA's assessment of unproved technically recoverable tight/shale oil and gas resources in the United States is approximately 1,228.1 Tcf.[26]

In a report commissioned by Annova, included herein as Appendix C, ICF analyzed the economic impacts of the proposed Project, including natural gas supply and demand trends.[27] As illustrated in Exhibit 1-2 of the ICF Report, the growth trend in natural gas production is

Exhibit 1-2: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q3 2018

---

[24] *Id.*

[25] U.S. Energy Information Administration, *Assumptions to Annual Energy Outlook 2018*, Oil and Gas Supply Module at 3 (Apr. 2018).

[26] *Id.* at 4.

[27] App. A, ICF, *Economic Impacts of the Proposed Annova Liquefaction Project: Information for DOE Non-FTA Permit Application* (Dec. 18, 2018) [hereinafter ICF Report].

expected to continue over the term of the requested authorization term, reaching 52 Tcf per year by 2045.[28] This constitutes a 19 Tcf per year increase over 2017 levels.[29]

As shown in Exhibit 3-8 of the ICF Report, ICF's current estimate of technically recoverable gas resources in the Lower 48 is 3,693 Tcf.[30]

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)

28 *Id.* at 7-8.

29 *Id.*

30 *Id.* at 25. ICF explains that its assessment of technically recoverable resources is significantly higher than EIA's, owing in part to the more comprehensive nature of ICF's analysis. *Id.* at 26. Even so, ICF notes that even the EIA's assessments of U.S. natural gas resource base have been growing by approximately 50 Tcf per year. *Id.* at 25.

According to ICF, a large portion of technically recoverable resources is economic at relatively low wellhead prices. ICF estimates that between 1,200 to 1,400 Tcf of U.S. and Canadian gas resources are available at gas prices between $3.50 and $4.000 per MMBtu.[31] These estimates are conservative, as they are based on current technology and do not factor in technological improvements and associated cost reductions that are likely to occur.[32] Assuming that recent technological advances continue into the future, ICF indicates that the amount of gas in the Lower 48 that would be economic at $5.00 per MMBtu could increase by as much as 76% (from 1,225 Tcf to 2,160 Tcf).[33] According to ICF, the total export volumes from the Project (7.9 Tcf over the period 2024-2045) represent only a small fraction of North American natural gas resources and total market demand, and would have only a minimal effect on U.S. supply availability.[34]

2. Domestic Natural Gas Demand

The EIA predicts that "production growth [will] outpace[e] natural gas consumption" over the 2017-2050 period.[35] ICF estimates that U.S. and Canadian gas consumption under the Base Case (which assumes no exports from the Project) will be over 52 Tcf by 2045.[36] Forty-five percent of the gas consumption growth will be fueled by increased gas-powered generation in the power sector (from 10 Tcf in 2017 to 19 Tcf in 2045), while consumption in the industrial sector accounts for sixteen percent of total growth.[37] ICF predicts that consumption will grow at

---

31 *Id.* at 17.

32 *Id.*

33 *Id.* at 21.

34 *Id.* at 9.

35 AEO 2018 at 62.

36 ICF Report at 27.

37 *Id.* at 28-29.

a slower pace in other sectors. For example, ICF explains that residential and commercial demand growth will be somewhat offset by energy efficiency gains, leading to lower per-customer gas consumption.[38] Furthermore, ICF notes that, under the Base Case, pipeline exports to Mexico are estimated to increase from 1.5 Tcf in 2017 to 2.7 Tcf by 2045, and U.S. LNG exports are expected to reach an annual volume of 6.1 Tcf by 2040.[39] As the ICF Report explains, the U.S. natural gas market rebalances to accommodate incremental increases in LNG exports by increasing natural gas production, contracting U.S. domestic natural gas consumption, and increasing net natural gas imports from Canada and Mexico.[40] The incremental LNG export volumes attributable to the Annova Project would only result in a small reduction of U.S. natural gas consumption of 0.11 Bcf/d in 2045, mostly as a result in gas use declines in the power sector.[41]

By comparison, EIA estimates that domestic natural gas consumption will reach 34.48 Tcf by 2050 (a 0.8% growth over 2017 consumption), with 11.44 Tcf attributable to electric power, 4.54 Tcf used in the residential sector, 3.94 Tcf used in the commercial sector, and 13.18 Tcf used in the industrial sector.[42] Under either the EIA's or ICF's estimates, technically recoverable resources greatly exceed forecasted natural gas demand (including exports from the Project) over the requested authorization term.

---

[38] *Id.* at 29.

[39] *Id.*

[40] *Id.* at 46.

[41] *Id.* at 50.

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

3. Effects on Natural Gas Prices

In 2012, the DOE/FE released a two-part study examining the effects of increased LNG exports. In the first part of the study, the EIA examined the effects on domestic energy markets of LNG exports at levels of 6 Bcf/d and 12 Bcf/d under various supply, demand, and price scenarios.[43] EIA's analysis was based on baseline scenarios from EIA's 2011 Annual Energy Outlook. EIA found that increased LNG exports would lead to a rise in domestic natural gas prices, increased natural gas production, lower domestic natural gas consumption, and minor additional imports from Canada.[44] EIA noted, however, that its study did not consider the macroeconomic impacts of increased LNG exports.[45] In the second part of the study, NERA Economic Consulting ("NERA") evaluated macroeconomic effects under a variety of global natural gas supply and demand scenarios, including unlimited LNG exports.[46] NERA concluded that under all scenarios analyzed, the U.S. would experience net economic benefits from higher LNG exports.[47] NERA found that U.S. economic welfare increased as the volume of LNG exports rose, including under scenarios in which there are unlimited exports.[48] According to NERA, while increased exports cause a rise in natural gas prices, the cost to consumers and producers of higher energy prices is more than offset by increases in real income and welfare resulting from the exports.[49]

---

43 U.S. Energy Information Administration, *Effect of Increased Natural Gas Exports on Domestic Energy Markets* (Jan. 2012), https://www.energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf.

44 *Id.* at 6.

45 *Id.* at 3.

46 NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (Dec. 2018), https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

47 *Id.* at 1.

48 *Id.* at 6.

49 *Id.*

In an updated 2014 study, the EIA assessed the effects on U.S. energy markets of higher levels of LNG exports, using baseline cases from the 2014 Annual Energy Outlook.[50] The EIA analyzed LNG exports at levels of 12 Bcf/d, 16 Bcf/d, and 20 Bcf/d under various economic scenarios. The EIA again concluded that LNG exports would result in increased natural gas prices, increased natural gas production and supply (with minor additional imports from Canada), and decreased natural gas consumption.[51] However, the EIA also found that increased energy production "spurs investment, which more than offsets the adverse impact of somewhat higher energy prices . . . ."[52] According to the EIA, U.S. gross domestic product ("GDP") would generally rise with the amount of additional LNG exports, with increases ranging from 0.05 to 0.17 percent.[53] The DOE/FE also commissioned an updated macroeconomic study, which was conducted by the Center for Energy Studies at Rice University's Baker Institute and Oxford Economics (the "2015 Study").[54] The 2015 Study analyzed LNG exports at levels of 12 Bcf/d and 20 Bcf/d based on different assumptions, including U.S. resource endowment, domestic natural gas demand, and international LNG market dynamics. The study found that a rise in LNG exports from 12 Bcf/d to 20 Bcf/d would cause GDP growth in the range of 0.03 to 0.07 percent annually (or $7-$20 billion) over the period 2026-2040.[55] According to the 2015 Study, the majority of the increased LNG exports is accommodated by increased domestic natural gas

---

[50] 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.

[51] *Id.* at 12.

[52] *Id.*

[53] *Id.*

[54] Center for Energy Studies at Rice University's 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.

[55] *Id.* at 8.

production, instead of reductions in domestic demand.[56] Although an increase in LNG exports is predicted to generate small output declines in certain energy-intensive industries, the 2015 LNG Study found that these effects would be offset by positive effects on other industries.[57] Overall, the 2015 LNG Study concluded that higher LNG exports would lead to net positive economic effects.[58]

In June 2018, the DOE/FE issued an updated LNG export study conducted by NERA (the "2018 LNG Export Study").[59] As compared to the prior studies, the 2018 LNG Export Study analyzed a larger number of scenarios (54) to capture a wider range of uncertainty in the natural gas markets, examined "unconstrained" export volumes beyond the levels considered in the previous studies, evaluated the likelihood of the various scenarios, and provided macroeconomic projections associated with scenarios within the more likely range. While increased LNG exports were found to place an upward pressure on natural gas prices, the 2018 LNG Export Study reports several macroeconomic benefits. For example, the study finds that increased LNG exports leads to higher levels of GDP and consumer wellbeing.[60] This is because a large majority of the increase in exports is accommodated by greater domestic gas production (resulting in positive effects on labor income, output, and natural gas production sector profits), and higher world prices for natural gas (resulting in wealth transfer from the rest of the world to

---

[56] *Id*.

[57] *Id*.

[58] *Id*. at 16.

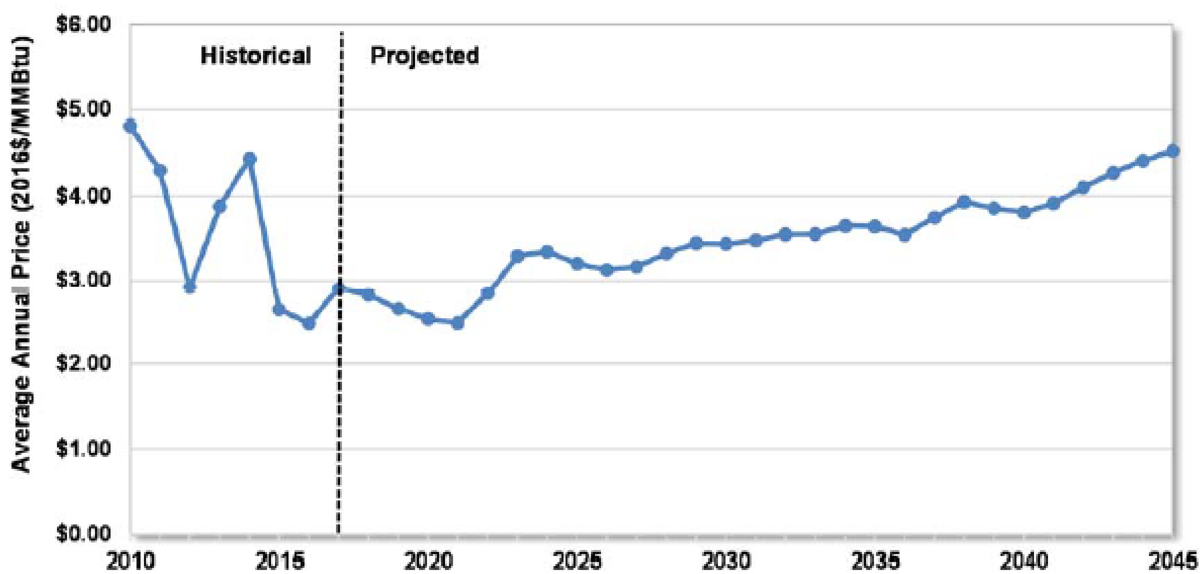
[59] NERA Economic Consulting, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports* (June 7, 2018), https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf.

[60] *Id.* at 18-21.

the United States).[61] According to NERA, these factors "more than make up for the dampening economic effects that are observed in these scenarios . . . [e]ven the most extreme scenarios of high LNG exports that are outside the more likely probability range . . . show higher overall economic performance in terms of GDP, household income, and consumer welfare than lower export levels associated with the same domestic supply scenarios."[62]

The ICF Report confirms that while natural gas prices are predicted to rise with increased LNG exports, domestic gas prices will remain moderate (as illustrated in Exhibit 3-13 of the ICF Report); moreover, increases attributable to exports from the Project will be minimal. According to ICF, the growth in gas prices at Henry Hub under the Base Case will be gradual from \$2.90/MMBtu in 2017 to \$4.54/MMBtu by 2045 (for an average price of \$3.50/MMBtu); this

Exhibit 3-13: GMM Average Annual Prices for Henry Hub



Source: ICF GMM® Q3 2018

61 *Id.* at 21.

62 *Id.*

"gradual increase in gas prices supports development of new sources of supply, but prices are not so high as to discourage demand growth."[63] ICF concludes that the exports from the Annova LNG facilities on average would only result in a \$0.06/MMBtu increase over the Base Case, reaching \$4.60/MMBtu by 2045 and resulting in an average price of \$3.69/MMBtu over the forecast period.[64]

As the ICF Report and DOE/FE LNG export studies demonstrate, increases in natural gas prices attributable to the exports requested herein are minimal. Moreover, any potential natural gas price increases would be offset by overall macroeconomic benefits to the U.S. economy.

C. *Other Public Interest Considerations*

1. *Benefits to Local, Regional, and U.S. Economies*

The proposed exports will have numerous local, regional, and national economic benefits. ICF estimates that construction and operation of the Annova LNG terminal will increase employment through direct, indirect, and induced employment. Specifically, the Project will add over 18,649 incremental jobs on average per year nationally over the Base Case, with an increase of 504,000 cumulative job-years over the forecast period.[65] In Texas, the Project is estimated to add roughly 6,383 jobs on an average annual basis compared to the Base Case, with a cumulative addition of 172,400 job-years over the forecast period.[66]

The Project will also result in an increase in federal, state, and local government revenues. ICF projects that the additional exports will result in an annual average of \$1.05 billion in government revenues, with a cumulative addition of \$28.4 billion in government

---

63 ICF Report at 33.

64 *Id.* at 51.

65 *Id.* at 53.

66 *Id.* at 57.

revenues over the forecast period.[67] On the state and local level, the Project will add an average $88 million increase in government revenues annually over the forecast period, with a cumulative impact of $2.4 billion.[68]

Nationally, LNG exports from the project will result in $3.2 billion annual incremental value added, for a cumulative value added of $86.7 billion over the forecast period.[69] Additionally, the Project will result in a $0.68 billion annual average increase to value added in Texas, for a cumulative value added of $18.5 billion from 2019-2045.[70]

2. *International Benefits*

The Project will also provide international benefits. Specifically, exports from the Annova facility will reduce the U.S. balance of trade deficit by $2.0 billion annually, or a total of $44.1 billion between 2024 and 2045.[71] Moreover, as the DOE/FE has determined, increased LNG exports reduce the need for the United States to import LNG, diversify global LNG supplies, and improve energy security for key U.S. allies and trading partners.[72]

VII. ENVIRONMENTAL IMPACTS

As noted above, Applicant filed an application to site, construct, and operate the Project with FERC on July 13, 2016. FERC released a draft EIS on December 14, 2018, and will issue the final EIS by April 19, 2019. As lead agency for purposes of review of the project under NEPA, FERC will evaluate the potential environmental effects of the Annova terminal and impose any applicable mitigation requirements as a condition to any authorization. DOE/FE has

---

67 *Id.* at 54.

68 *Id.* at 58.

69 *Id.* at 55.

70 *Id.* at 59.

71 *Id.* at 56.

72 *See, e.g.,* Golden Pass at 145; Lake Charles at 30; Southern LNG at 153-154.

confirmed its intention to act as a cooperating agency in FERC's NEPA review of the Project. In this capacity, DOE/FE will have the opportunity to cooperate with FERC in the development of the EIS. DOE/FE is responsible for conducting an independent review of FERC's NEPA review process, and may adopt FERC's EIS or supplement the record to the extent necessary to meet its statutory responsibilities under NGA section 3 and NEPA.

In addition to its obligations under NEPA, DOE/FE released two reports examining the environmental effects of increased natural gas exports. The first study, the *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States*, reviewed the potential environmental effects of unconventional natural gas exploration and production (the "Addendum").[73] In analyzing the report, the DOE/FE acknowledged that unconventional natural gas production raises potential environmental issues that require careful management, but concluded that these concerns do not establish that non-FTA exports are inconsistent with the public interest. Rather, DOE/FE has determined that "Section 3(a) of the NGA is too blunt an instrument to addresses these environmental concerns efficiently. A decision to prohibit exports of natural gas would cause the United States to forego entirely the economic and international benefits . . . but would have little more than a modest, incremental impact on . . . environmental issues."[74] The second report, *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States* ("LCA GHG Report"), compares the greenhouse gas ("GHG") emissions from power generation in Europe and Asia using U.S. LNG exports versus GHG emissions from alternative supplies (such as regional coal

---

73 U.S. Department of Energy, *Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States* (Aug. 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/Addendum.pdf.

74 Southern LNG at 156.

and other imported natural gas).[75] According to DOE/FE, the record for the LCA GHG Report "does not support the conclusion that U.S. LNG exports will increase global GHG emissions in a material or predictable way," and suggests that U.S. exports may in fact reduce emissions.[76]

VIII. APPENDICES

The following appendices are attached hereto:

Appendix A:	Verification
Appendix B:	Opinion of Counsel
Appendix C:	ICF, *Economic Impacts of the Proposed Annova Liquefaction Project: Information for DOE Non-FTA Permit Application*

---

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

76 Southern LNG at 163.

IX. CONCLUSION

For the foregoing reasons, Applicant respectfully requests that DOE/FE grant its request for long-term, multi-contract authorization to engage in exports of up to approximately 360 Bcf/y of natural gas in the form of LNG from the Annova LNG Project to Non-FTA Nations for a term of twenty (20) years commencing on the earlier of the date of first export or seven (7) years from the issuance of such authorization.

Respectfully submitted,

/s/ Brett A. Snyder

Brett A. Snyder
Mark R. Haskell
Lamiya Rahman
Blank Rome LLP
1825 Eye Street NW
Washington, DC 20006
(202) 420-2200
bsnyder@blankrome.com
mhaskell@blankrome.com
lrahman@blankrome.com

Counsel to Annova LNG Common Infrastructure, LLC

Dated: February 26, 2019

APPENDIX A

Verification

VERIFICATION

County of Baltimore)
)
State of Maryland)

BEFORE ME, the undersigned authority, on this day personally appeared Susan Bergles, who, having been by me first duly sworn, on oath says that she is legal counsel for Annova LNG Common Infrastructure, LLC, and is duly authorized to make this Verification on behalf of such company, that she has read the foregoing instrument, and that the facts therein stated are true and correct to the best of her knowledge, information and belief.

SWORN TO AND SUBSCRIBED before me on this 26 day of February, 2019.

MELISSA A KERCHNER
My Commission Expires
NOTARY PUBLIC
04-08-2022
HARFORD COUNTY, MD

Melissa A. Kerchner
Notary Public

APPENDIX B

Opinion of Counsel

OPINION OF COUNSEL

February 26, 2019

Ms. Amy Sweeney
Director, Division of Natural Gas Regulation
Office of Fossil Energy
U.S. Department of Energy
Room 3E-052
1000 Independence Ave S.W.
Washington, DC 20585

Re: ***Annova LNG Common Infrastructure, LLC***
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to 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) (2018). I am in house counsel to Annova LNG Common Infrastructure, LLC ("Annova").

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

Respectfully submitted,

Susan Berg

Susan B. Bergles
Assistant General Counsel
Exelon Corporation
1310 Point Street, 8th Floor,
Baltimore, MD 21231
Tel.: (410) 470-1553
Susan.Bergles @exeloncorp.com

APPENDIX C

ICF, ***Economic Impacts of the Proposed Annova Liquefaction Project: Information for DOE Non-FTA Permit Application***

Economic Impacts of the Proposed Annova Liquefaction Project:

Information for DOE Non-FTA Permit Application

December 18, 2018

Submitted to:
Annova LNG Common Infrastructure, LLC

COPYRIGHT © 2018 ICF, LLC All rights reserved.

Warranties and Representations. ICF endeavors to provide information and projections consistent with standard practices in a professional manner. ICF MAKES NO WARRANTIES, HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically but without limitation, ICF makes no warranty or guarantee regarding the accuracy of any forecasts, estimates, or analyses, or that such work products will be accepted by any legal or regulatory body.

Waivers. Those viewing this Material hereby waive any claim at any time, whether now or in the future, against ICF, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall ICF, its officers, directors, employees, or agents be liable to those viewing this Material.

Table of Contents

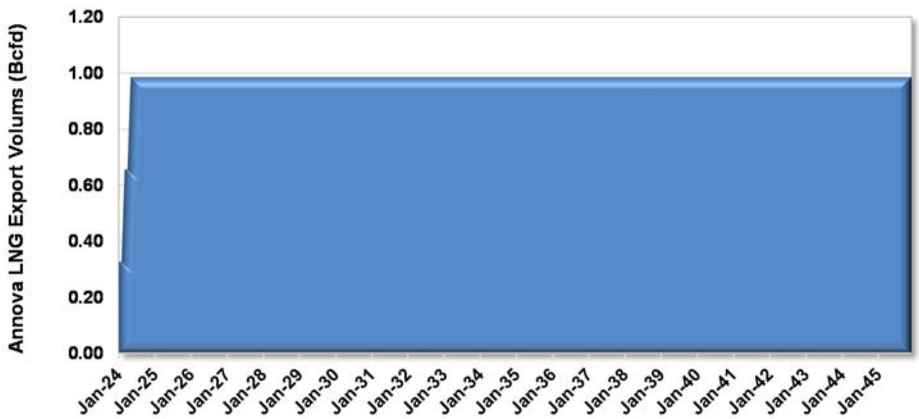
List of Exhibits

1. Executive Summary

1.1. Introduction

ICF conducted an analysis on behalf of Annova LNG Common Infrastructure, LLC (Annova), a company owned by Exelon, to assess the market and economic impacts of the proposed Annova Brownsville LNG export facility located in Cameron County, Texas to the U.S. economy. The Annova export facility is proposed to be developed with six trains with a total nameplate capacity of 6 MTPA and a total maximum output at optimal operating conditions of 6.95 MTPA, equivalent to 360[1] Bcf per year (0.986 Bcfd) of natural gas exported volumes (Exhibit 1-1), to come on-line in three stages in 2024. The facility will receive feed gas from a third-party intrastate pipeline.

Exhibit 1-1: Annova LNG Export Volumes



Source: Annova

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Annova 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 Annova export facility;
2) **Annova LNG Case** - Base Case with 0.986 Bcfd of additional export volumes from Annova.

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

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

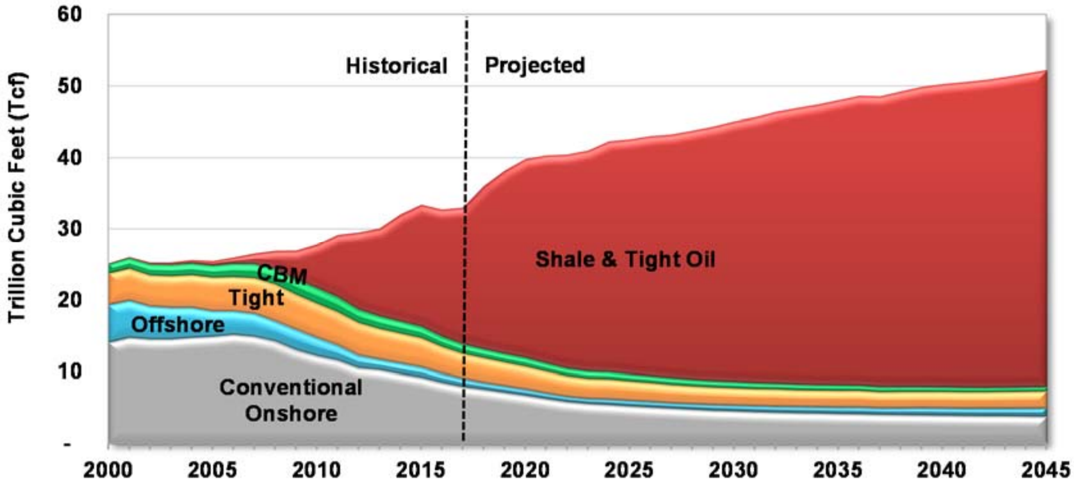
meet the additional natural gas supplies needed for Annova exports. GMM also solved for changes in natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins as a whole and from Texas were both estimated.

- **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 Annova LNG export facility's cost estimates, ICF assessed the annual capital and operating expenditures 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 Texas. 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 Annova exports on the national and Texas 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 continue with production reaching 52 Tcf per year (143 Bcfd) by 2045, an increase of 19 Tcf per year (53 Bcfd) over 2017's level. (see Exhibit 1-2: U.S. and Canadian Gas Supplies). Much of the future natural gas production growth comes from increases in gas-directed (non-associated) drilling, specifically horizontal drilling in the Marcellus and Utica shales, which will account for over half of the incremental production. In addition, Haynesville production appears to be resurging. Associated gas production from tight oil plays in the Permian Basin, Niobrara, and SCOOP and STACK will also be major drivers, with liquids prices playing a large role. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

Exhibit 1-2: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q3 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). About 45 percent of the growth comes from the power sector, which increases to 19 Tcf per year (51 Bcfd) by 2045. Feed gas deliveries for U.S. LNG exports are projected to reach 16.8 Bcfd by 2040, with volumes from the Gulf Coast expected to reach 15.8 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 Annova export volumes associated with this economic impact analysis. Mexican Exports grow to 2.7 Tcf (7.5 Bcfd) by 2040.

Increased demand growth will push gas prices above $3.00 per MMBtu[2] from 2023, with long-term prices expected to range between $3.25 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.

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

1.3. Key Study Results

ICF's analysis shows that the volume exported via the Annova LNG export facility has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.06/MMBtu (in real 2016 dollars) on average for the forecast period of 2024 to 2045, averaging $3.75/MMBtu, with the Annova export facility included in the scenario, compared with $3.69/MMBtu without the export facility in the scenario. The natural gas prices at Henry Hub are expected to reach $4.54/MMBtu in the Base Case and $4.60/MMBtu in the Annova LNG Case by 2045, indicating a price increase of $0.06/MMBtu attributable to the Annova LNG export volumes of 0.986 Bcfd.

The Annova 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 from 2024 to 2045 is 7.9 Tcf. This represents (a) roughly 0.6% of U.S. natural gas resources that can be produced with current technology at an 8% rate of return, Henry Hub price at less than $4.00/MMBtu, and crude at $75/Bbl; and (b) 1.1% of the total U.S. domestic natural gas consumption during the same period.

Exhibit 1-3: Natural Gas Price Impact of the Annova LNG Export Facility

Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Annova LNG Case	Annova LNG Case Change
2024	$ 3.35	$ 3.43	$ 0.08
2025	$ 3.21	$ 3.27	$ 0.06
2030	$ 3.44	$ 3.50	$ 0.06
2035	$ 3.65	$ 3.70	$ 0.05
2040	$ 3.81	$ 3.87	$ 0.06
2045	$ 4.54	$ 4.60	$ 0.06
2024-2045 Avg	**$ 3.69**	**$ 3.75**	**$ 0.06**

Source: ICF

ICF's analysis concluded that activity in the U.S. to support Annova LNG exports could lead to significant economic impacts, on average, creating roughly 18,700 jobs annually for the U.S. economy, and about 6,400 jobs in Texas from the starting of the construction in 2019 through 2045. This means a cumulative impact through 2045 of 504,000 job-years for the U.S. and 172,400 job-years in Texas. In addition, the project could add $3.2 billion to the U.S. economy annually ($86.7 billion over the forecast period), including $0.68 billion annually in Texas ($18.5 billion over the forecast period). The additional Annova LNG exports would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $1.05 billion annually; and Texas state and local tax revenues are expected to increase by about $88 million annually. Throughout the forecast period, the U.S. will receive $28.4 billion additional revenue from taxes and Texas will receive $2.4 billion.

Exhibit 1-4: Economic and Employment Impacts of the Annova LNG Export Facility

Region	2019-2045 Average Annual Impact			2019-2045 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.	18,649	$ 3,211	$ 1,051	503,524	$ 86,698	$ 28,388
Texas	6,383	$ 684	$ 88	172,328	$ 18,481	$ 2,364

Source: ICF

2. Introduction

Annova LNG Common Infrastructure, LLC tasked ICF with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Annova Brownsville LNG export facility located in Cameron County, Texas. The Annova export facility will consist of six trains with a total nameplate capacity of 6 MTPA and a total maximum output at optimal operating conditions of 6.95 MTPA, equivalent to 360 Bcf per year (0.986 Bcfd) of natural gas exported volumes, and will commence construction in 2019. The construction will use a modular approach, with fabrication and assembly of major equipment and plant components at offsite locations, to reduce activities at the main construction site. The completed modules will be delivered to the worksite and integrated into field operations.

The Annova export facility will come on-line in three stages in 2024. The export facility will receive feed gas from a third-party intrastate pipeline.

The export facility will use power from the electric grid primarily to power large electric motors for the six liquefaction compressors. The liquefaction operation will consume 360 megawatts of power during normal operation with a maximum of 405 megawatts. South Texas Electric Cooperatives (STEC) will deliver power to the facility through a new 138-kilovolot, 15-mile electric transmission line.

For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the 0.986 Bcfd Annova export facility and estimated the changes between the two scenarios for the total U.S. and Texas:

- 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, pipeline, electric power, and upstream capital and operating expenditures were inputted into the IMPLAN model to estimate the export facility's impacts on the U.S. and Texas 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) Annova LNG Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

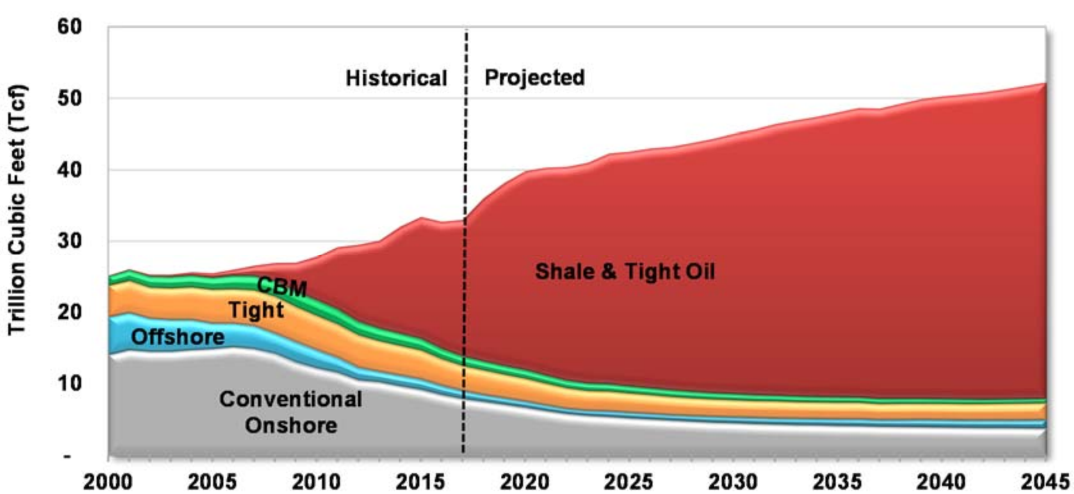
3. Base Case U.S. and Canadian Natural Gas Market Overview

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



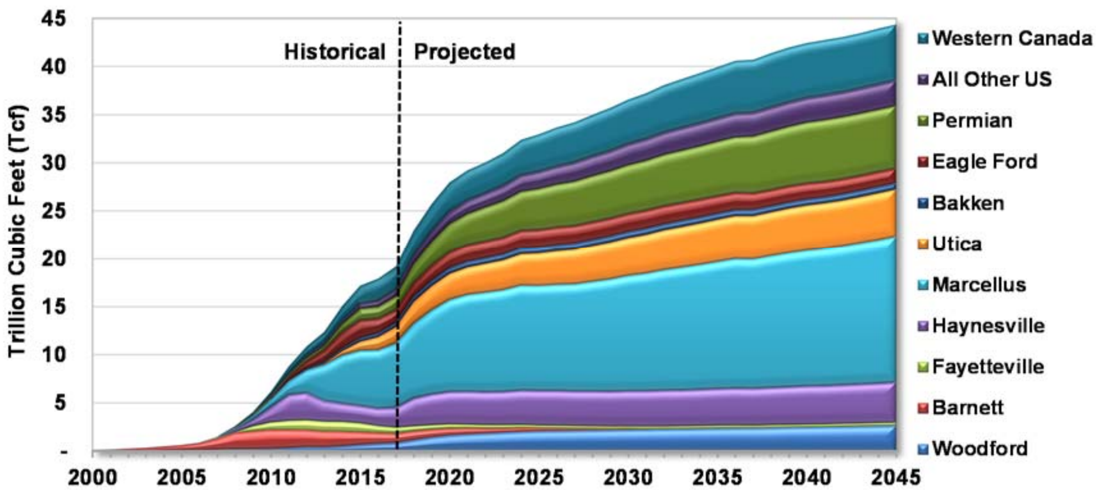
Source: ICF GMM® Q3 2018

Production from U.S. and Canadian shale formations will grow from 19.2 Tcf per year (52.6 Bcfd) in 2017 or 58 percent of total production to 44.4 Tcf per year (122 Bcfd) by 2045 or 85 percent of total production (see exhibit above). The projection assumes West Texas Intermediate (WTI) 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 Permian, Niobrara, and Bakken 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. Dry gas[3] production from the lower cost Permian basin will reach 7 Tcf per year (19 Bcfd) by 2045, mostly gas associated with tight oil, from about 2 Tcf (5.8 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



Source: ICF GMM® Q3 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.[4] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base in total. Even though their production costs are uncertain due the newness of the plays and considerable site-to-site variation in geology, , shale plays such as the Marcellus and Permian and other tight oil plays 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

---

[3] Dry gas is natural gas which remains after processing plant separation, also known as consumer-grade natural gas.
[4] Unconventional refers to production that requires some form of stimulation (such as hydraulic fracturing) within the well to produce gas economically. Conventional wells do not require stimulation.

the cost curves are all of the resources discussed above – proven reserves, growth, new fields, 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.[5,6,7] 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.

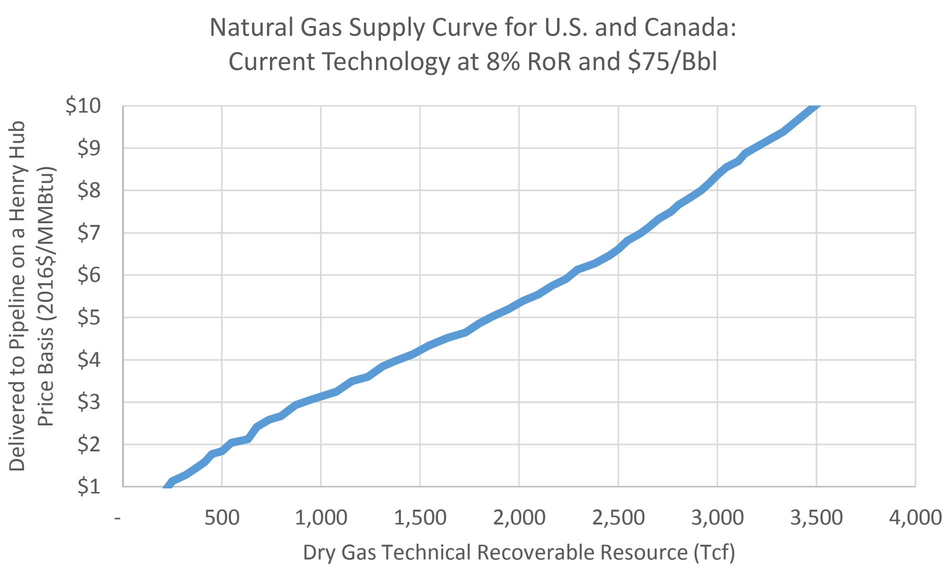
---

[5] American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.
[6] Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/
[7] 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.)

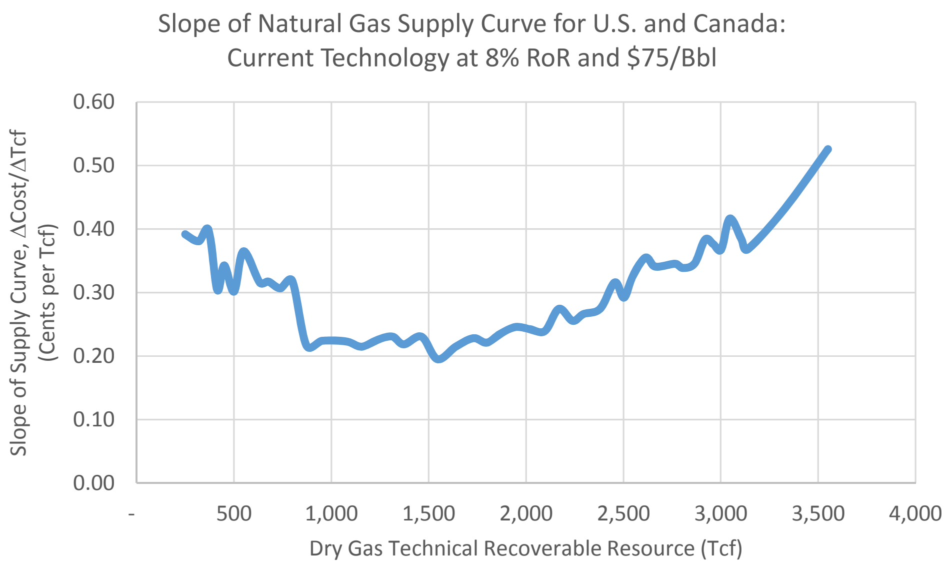
Exhibit 3-3: U.S. and Canada Natural Gas Supply Curves



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.[8]

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.

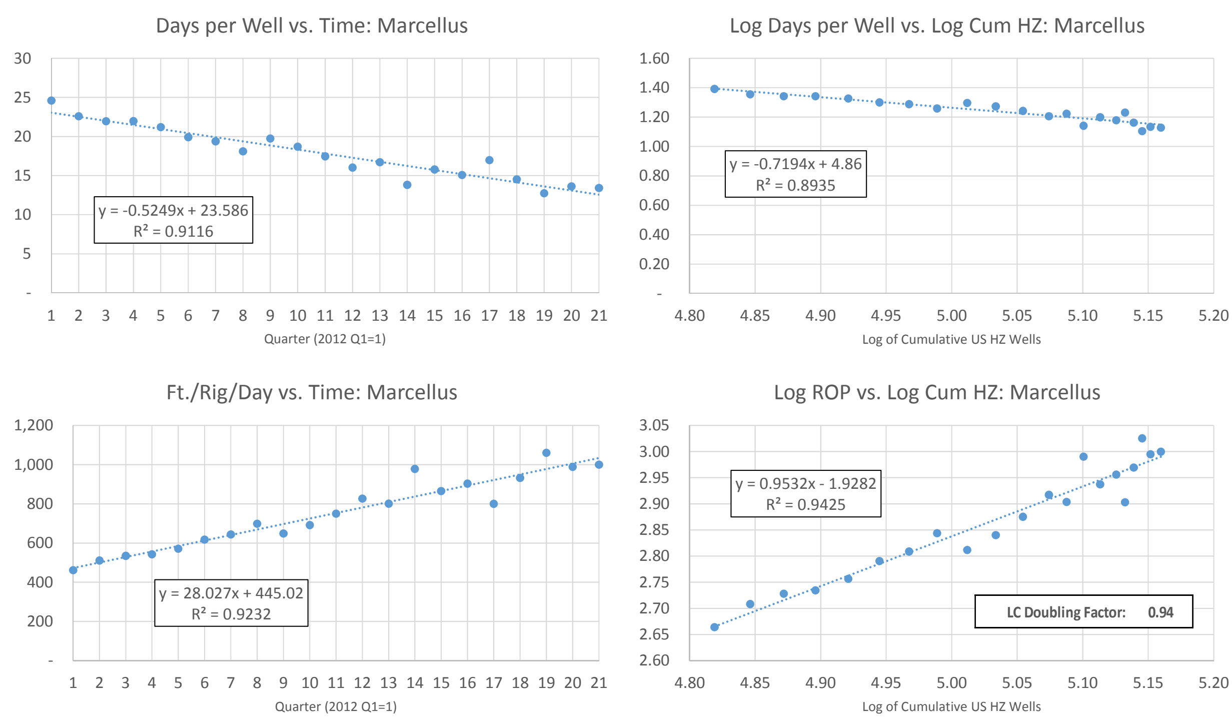
[8] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

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)



Source: ICF

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[9] 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

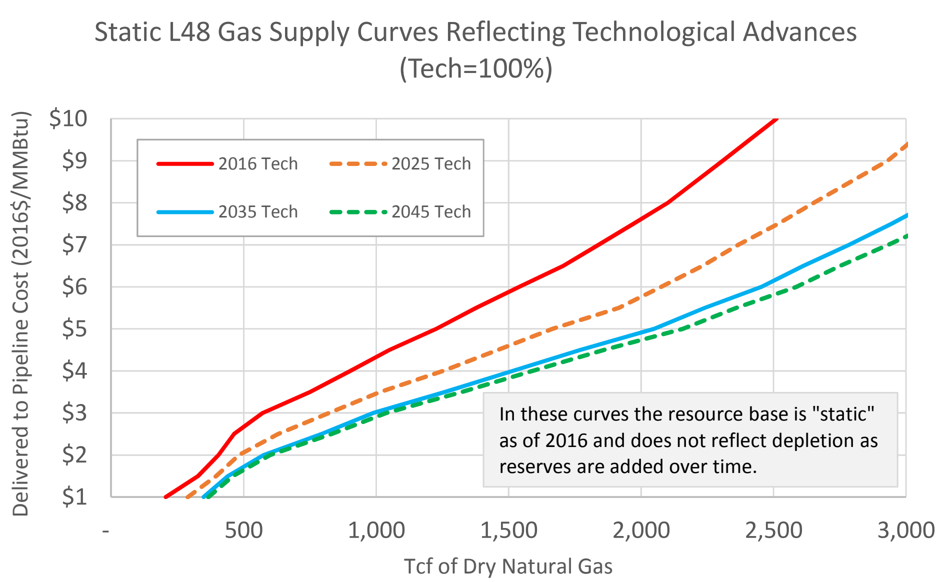
[9] Doubling factor = 2^C-1 where C is the regression slope coefficient.

cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well 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).

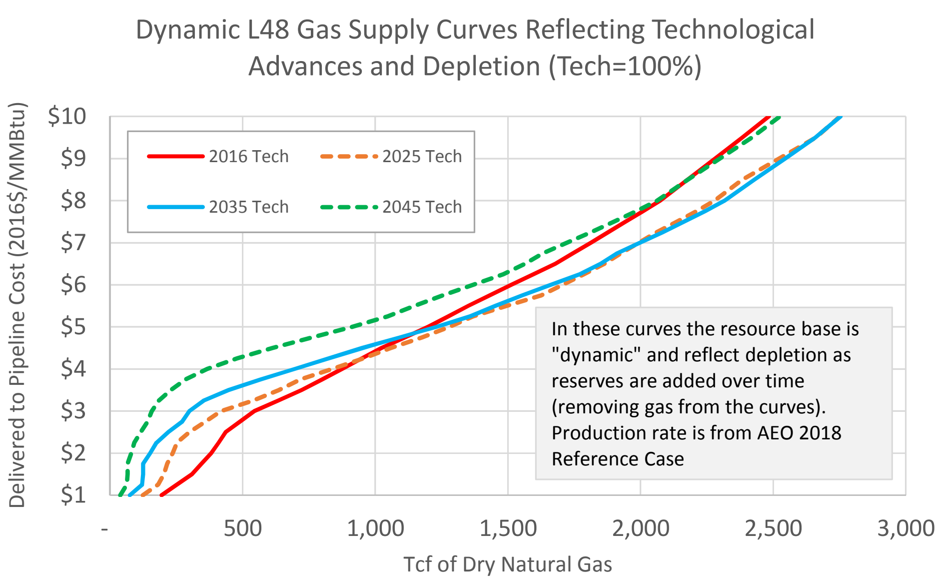
Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



Source: ICF

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)



Source: ICF

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[10].) 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.

[10] 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.[11]

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.[12]

---

[11] 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/

[12] 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.[13] 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.

[13] 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.

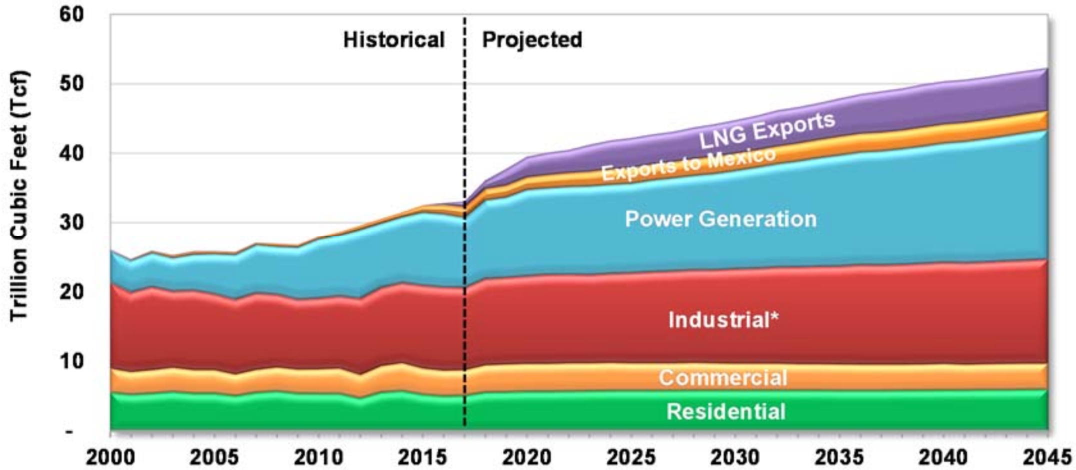
ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas assessment in order to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, 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 Annova facility, U.S. and Canadian natural gas consumption in 2045 is expected to be over 52 Tcf (LNG and pipeline exports included).

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



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q3 2018

Feed gas deliveries for U.S. LNG exports are projected to reach 6.1 Tcf per year (16.8 Bcfd) by 2040, with volumes from the Gulf Coast expected to reach 5.7 Tcf per year (15.8 Bcfd), based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy.

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. Gas use for power generation will increase from about 10 Tcf (28 Bcfd) in 2017 of total demand to 19 Tcf per year (51 Bcfd) by 2045. This represents about 45 percent of the total gas demand growth.

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 4,700 Terawatt-hours (TWh) per year by 2045, or growth nearing 25 percent over 2017 levels.

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 36 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 16 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.

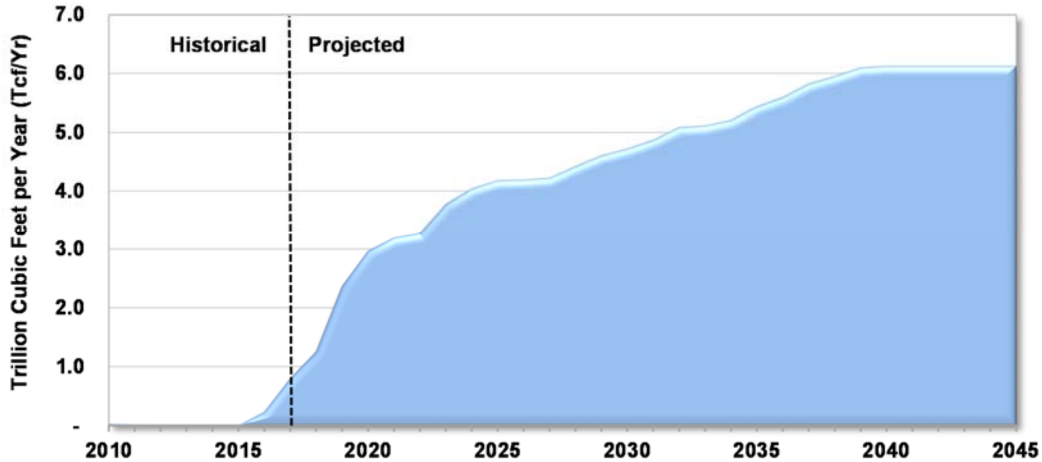
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the 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 2.7 Tcf (7.5 Bcfd) by 2045, up from 1.5 Tcf (4.2 Bcfd) in 2017.

3.2.1. LNG Export Trends

The U.S. Department of Energy (DOE) has 52 active or approved 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, 26 applications at 17 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 6.1 Tcf per year (16.8 Bcfd) by 2040. 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 over 8 Bcfd by 2020 and as oil prices increase, the export volume is projected to be about13 Bcfd by 2030 and 16.8 Bcfd by 2040 (see exhibit below).

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

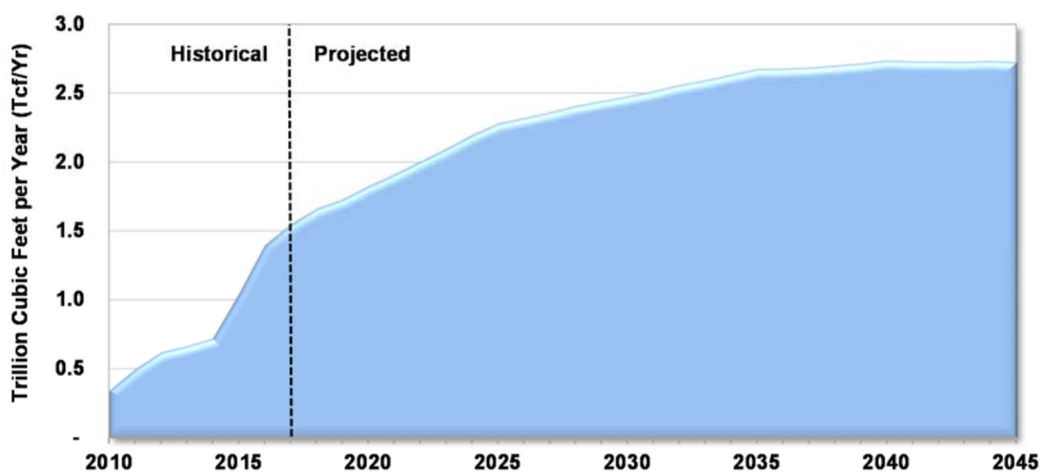


Source: ICF GMM® Q3 2018

3.2.2. Exports to Mexico

Natural gas exports to Mexico has grown more than doubled from 0.72 Tcf per year (2 Bcfd) in 2014 to 1.5 Tcf per year (4.2 Bcfd) in 2017, led by increased Mexican power generation gas markets that lie directly across the U.S.-Mexico border. The growth is expected to continue and the ICF Base Case projects the exports to increase to 2.3 Tcf per year (11.5 Bcfd) by 2025 and to 2.7 Tcf per year (7.5 Bcfd) from 2040.

Exhibit 3-11: Base Case Exports to Mexico Assumptions



Source: ICF GMM® Q3 2018

There is 10.3 Bcfd of U.S.-Mexico cross-border pipeline capacity currently online. Based on planned expansions and Presidential Permit applications authorized or pending before the Federal Energy Regulatory Commission, ICF expects there will be 14.2 Bcfd of cross-border capacity by 2020. Nearly all of the additional border-crossing capacity that ICF expected to be added is already under construction (3.6 Bcfd of the incremental capacity is accounted for by the Nueva Era Pipeline and the Valley Crossing Pipeline).

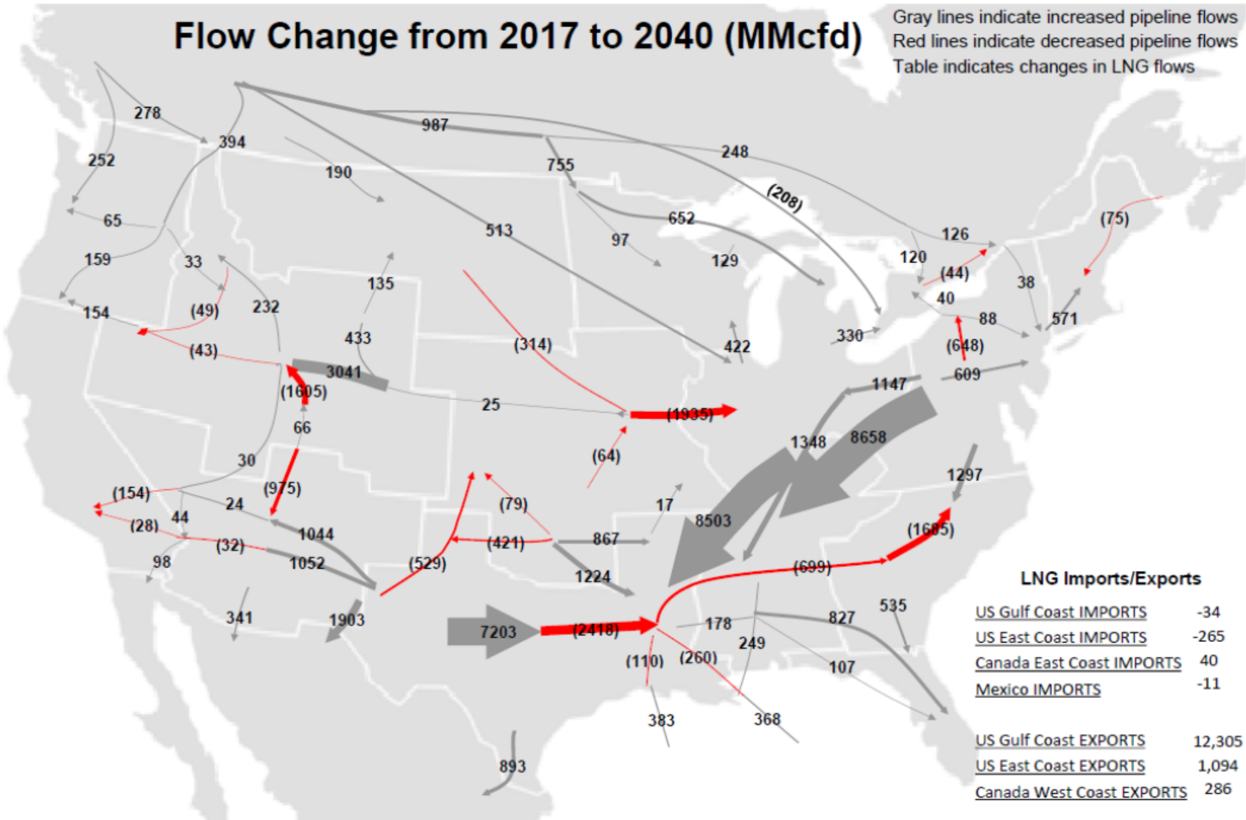
Mexican demand for natural gas will be influenced by many factors including the growth of the overall economy and its energy-intensive sectors, relative energy prices, and government policies encouraging the substitution of natural gas for coal in the power sector. Mexican natural gas supply will be 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.

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 3-12 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 3-12 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 grey arrows entering Canada, the Midwest (Ohio), and South Atlantic (North Carolina). In effect, the Mid-Atlantic Region becomes a major producer of gas and supplies gas to consumers throughout the East Coast, Midwest, and Gulf Coast. The red arrows from the Gulf Coast to the East Coast point towards a continuing trend of the economic Marcellus and Utica gas supplies displacing the traditional flows from the Gulf Coast towards Northeast.

Exhibit 3-12: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q3 2018

In addition, natural gas will be exported from the West South Central (Texas, Louisiana, and Arkansas) region via pipeline to Mexico and in the form of LNG exports that started from the Sabine Pass export facility in 2016. The Permian in west Texas becomes an increasingly important source of gas for the Gulf Coast.

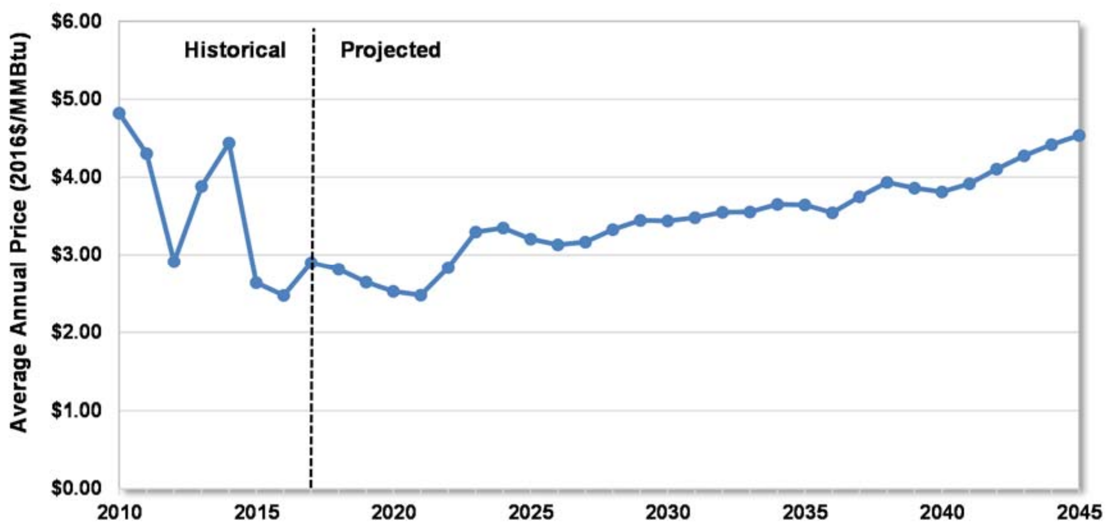
Eastward flows from western Canada will slightly increase. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong industrial 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 2022. Pipeline flows west out of the Rocky Mountains will decrease slightly to California as demand there decreases.

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 $2.90 per MMBtu in 2017 to $4.54 per MMBtu by 2045 with average of about $3.50 per MMBtu (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 3-13.

Exhibit 3-13: GMM Average Annual Prices for Henry Hub

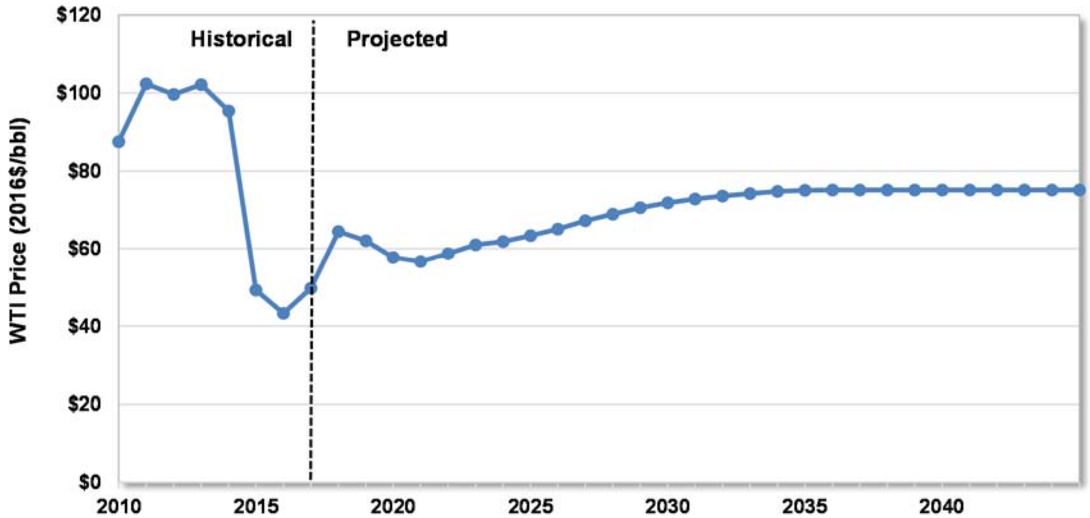


Source: ICF GMM® Q3 2018

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 2035 as shown in the exhibit below.

Exhibit 3-14: ICF Oil Price Assumptions



Source: ICF GMM® Q3 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.

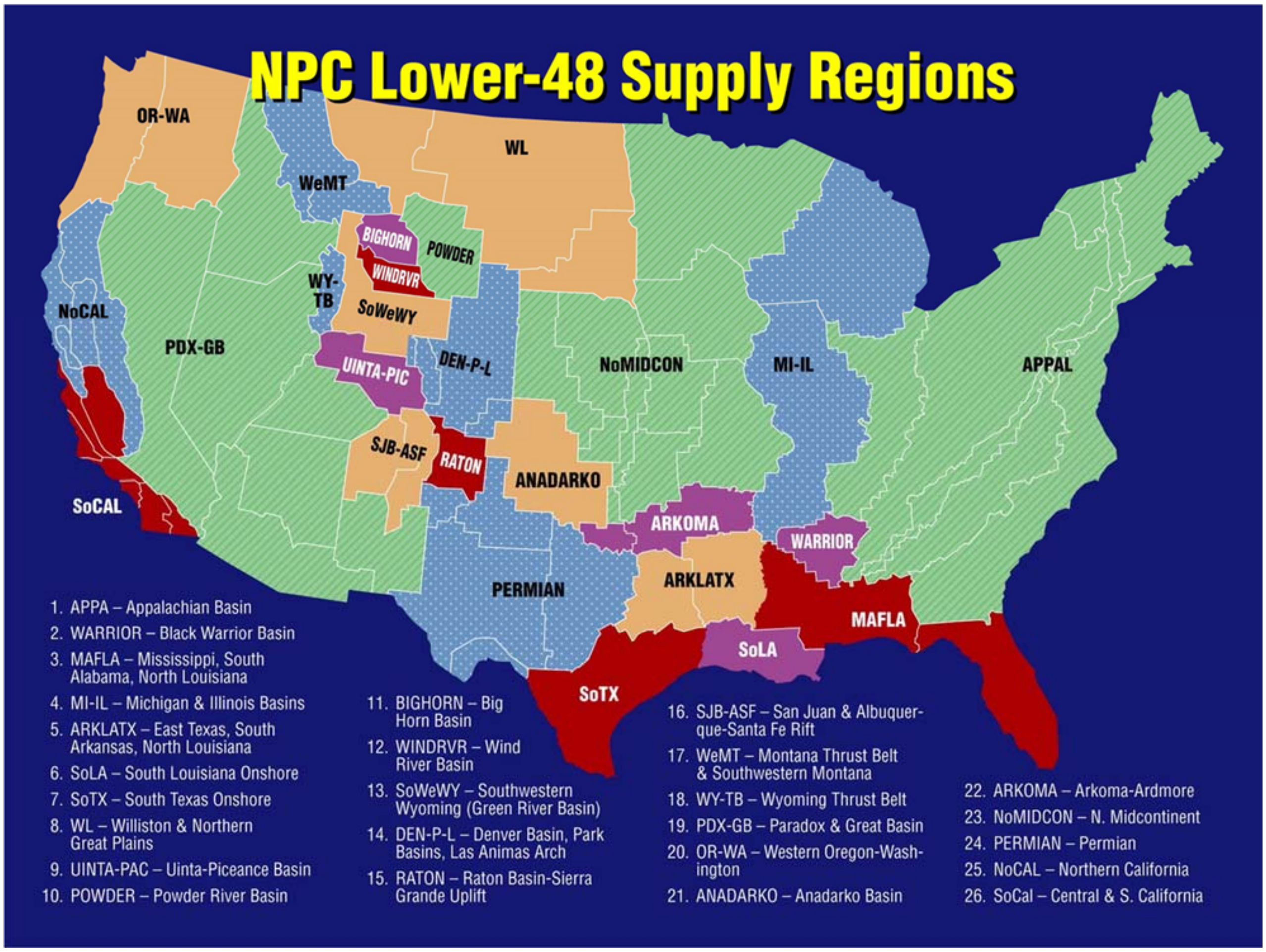
4.1.1. Conventional Undiscovered Fields

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.[14] Gas resources

[14] 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**	

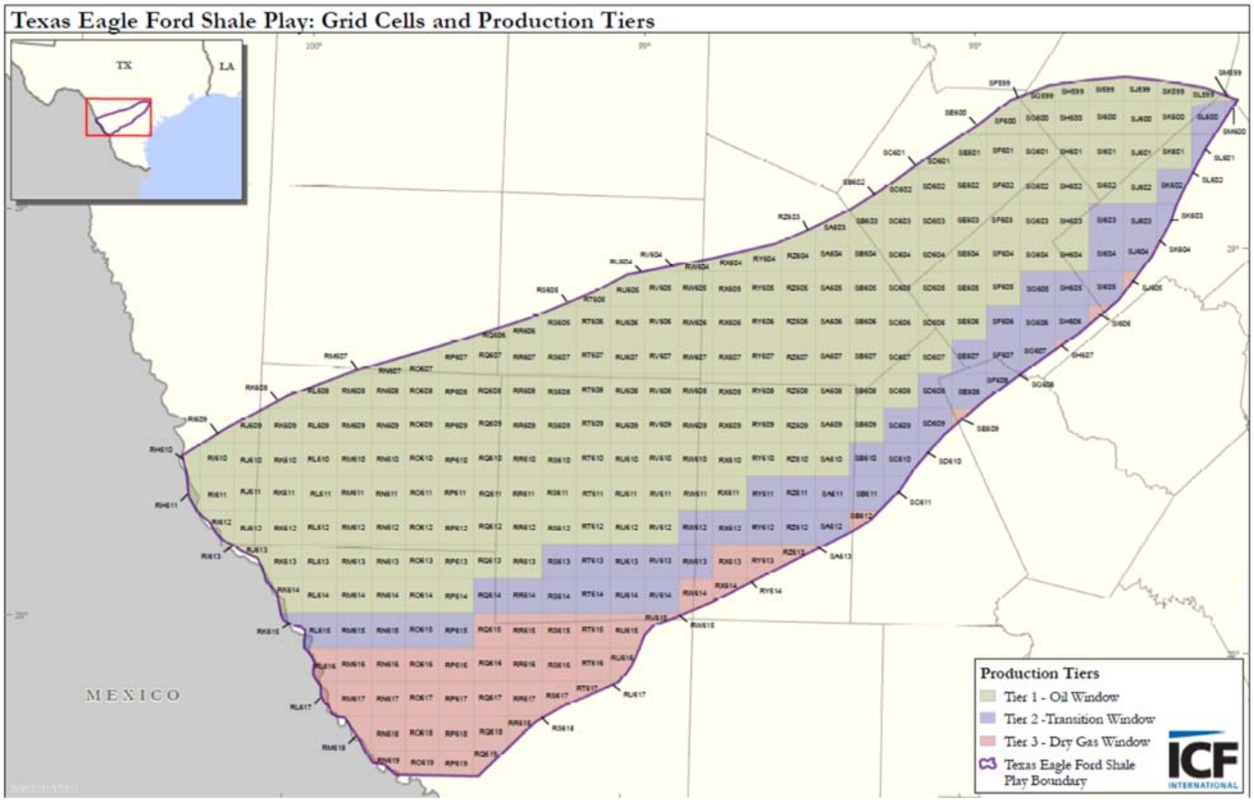
No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Coalbed Methane		
36	San Juan Fruitland	8,800	160
	L-48 GIS Assessed Coalbed Methane Total	**8,800**	
37	Horseshoe Canyon	24,740	80
38	Mannville	46,760	320
	Canada GIS Assessed Coalbed Methane Total	**71,500**	
	Tight Oil		
39	Anadarko Mississippi 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, Niobrara, 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

Annova tasked ICF with assessing the economic and employment impacts of LNG exports from its Annova LNG export facility. This study analyzed two cases[15]:

1) **Base Case** with the assumption of no Annova LNG export volumes.
2) **Annova LNG Case** with the assumption of 360 Bcf per year, or 0.986 Bcfd higher than the Base Case due to the new construction at Annova.

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 Texas level.

Step 2 – LNG plant capital and operating expenditures: Based on Annova LNG export facility’s cost estimates, ICF determined the annual capital and operating expenditures that will be required to support the LNG exports.

Step 3 – Upstream capital and operating expenditures: ICF then translated the natural gas and liquids production changes from the GMM into annual capital and operating expenditures that will be required to support the additional production.

Step 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 Texas. For instance, if the model found that $100 million in a particular category of expenditures generated 390 direct employees, 140 indirect employees, and 190 induced employees (i.e., employees related to consumer goods and services), then we would apply those proportions to forecasted expenditure changes. If forecasted expenditure changes totaled $10 million one year, according to the model proportions, that would generate 39 direct, 14 indirect, and 19 induced employees in the year the expenditures were made.

---

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

Step 5 – Economic impacts: ICF assessed the impact of LNG exports for the national and Texas levels. 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:

- Annova 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: Annova LNG Export Volume Assumptions and LNG Plant Capital and Operating Expenditures

Year	The Annova LNG Case Changes		
	LNG Export Volume Assumptions (Bcfd)	LNG Capital Costs (2016$ MM)	LNG Operating Costs (2016$ MM)
2019	-	$94	-
2020	-	$920	-
2021	-	$1,262	-
2022	-	$1,148	-
2023	-	$519	-
2024	0.824	$85	$128
2025	0.986	-	$128
2026	0.986	-	$128
2027	0.986	-	$128
2028	0.986	-	$128
2029	0.986	-	$128
2030	0.986	-	$128
2031	0.986	-	$128
2032	0.986	-	$128
2033	0.986	-	$128
2034	0.986	-	$128
2035	0.986	-	$128
2036	0.986	-	$128
2037	0.986	-	$128
2038	0.986	-	$128
2039	0.986	-	$128
2040	0.986	-	$128
2041	0.986	-	$128
2042	0.986	-	$128
2043	0.986	-	$128
2044	0.986	-	$128
2045	0.986	-	$128

Note: LNG export volumes do not include liquefaction fuel or losses of about 0.02 Bcfd.

Source: Annova, ICF

Exhibit 4-6: Additional Capital and Operating Expenditures Associated with New Pipeline and Electric Transmission Line

Year	The Annova LNG Case Changes	
	Pipeline and Electric Transmission Line Capital Costs (2016$ MM)	Pipeline and Electric Transmission Line Operating Costs (2016$ MM)
2019	-	-
2020	-	-
2021	-	-
2022	$407	-
2023	$421	-
2024	-	$21
2025	-	$21
2026	-	$21
2027	-	$21
2028	-	$21
2029	-	$21
2030	-	$21
2031	-	$21
2032	-	$21
2033	-	$21
2034	-	$21
2035	-	$21
2036	-	$21
2037	-	$21
2038	-	$21
2039	-	$21
2040	-	$21
2041	-	$21
2042	-	$21
2043	-	$21
2044	-	$21
2045	-	$21

Note: ICF assumes: (1) 130-mile, 36-inch pipeline and a 20,000-HP compressor station with construction costs of $162,000 per inch-mile and $2,800 per horsepower, (2) $900,000 per mile for electric transmission line capital expenditures, and (3) annual operating costs at 2.5% of total capital expenditures.

Source: Annova, ICF

Exhibit 4-7: Assumed Federal, State, and Local Tax Rates

Year	Federal Tax Rate on GDP (%)	Weighted Average State and Local Tax Rate on GDP (% of own-source) (%)	Texas and Local Own Taxes as % of State Income (%)
2015	18.1%	14.6%	12.8%
2016	17.7%	14.6%	12.8%
2017	17.3%	14.6%	12.8%
2018	16.7%	14.6%	12.8%
2019	16.3%	14.6%	12.8%
2020	16.4%	14.6%	12.8%
2021	16.5%	14.6%	12.8%
2022	16.8%	14.6%	12.8%
2023	17.1%	14.6%	12.8%
2024	17.2%	14.6%	12.8%
2025	17.3%	14.6%	12.8%
2026	17.4%	14.6%	12.8%
2027	17.5%	14.6%	12.8%
2028	17.6%	14.6%	12.8%
2029	17.7%	14.6%	12.8%
2030	17.8%	14.6%	12.8%
2031	17.9%	14.6%	12.8%
2032	18.0%	14.6%	12.8%
2033	18.1%	14.6%	12.8%
2034	18.2%	14.6%	12.8%
2035	18.3%	14.6%	12.8%
2036	18.4%	14.6%	12.8%
2037	18.5%	14.6%	12.8%
2038	18.6%	14.6%	12.8%
2039	18.7%	14.6%	12.8%
2040	18.8%	14.6%	12.8%
2041	18.9%	14.6%	12.8%
2042	19.0%	14.6%	12.8%
2043	19.1%	14.6%	12.8%
2044	19.2%	14.6%	12.8%
2045	19.3%	14.6%	12.8%

Source: ICF extrapolations from Tax Policy Center historical figures.

Exhibit 4-8: Liquids Price Assumptions

Year	WTI 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	$ 43	$ 41	$ 14	$ 20	$ 28	$ 37
2017	$ 50	$ 50	$ 15	$ 22	$ 34	$ 45
2018	$ 64	$ 64	$ 16	$ 23	$ 43	$ 58
2019	$ 62	$ 61	$ 18	$ 24	$ 41	$ 55
2020	$ 58	$ 57	$ 17	$ 27	$ 38	$ 52
2021	$ 57	$ 56	$ 16	$ 29	$ 38	$ 51
2022	$ 59	$ 57	$ 17	$ 30	$ 39	$ 52
2023	$ 61	$ 60	$ 18	$ 32	$ 40	$ 54
2024	$ 62	$ 60	$ 18	$ 32	$ 41	$ 55
2025	$ 63	$ 61	$ 18	$ 32	$ 42	$ 56
2026	$ 65	$ 62	$ 18	$ 33	$ 42	$ 57
2027	$ 67	$ 64	$ 19	$ 34	$ 43	$ 58
2028	$ 69	$ 65	$ 19	$ 35	$ 44	$ 60
2029	$ 71	$ 67	$ 20	$ 35	$ 45	$ 61
2030	$ 72	$ 68	$ 20	$ 36	$ 46	$ 62
2031	$ 73	$ 69	$ 20	$ 36	$ 46	$ 63
2032	$ 74	$ 69	$ 20	$ 37	$ 47	$ 63
2033	$ 74	$ 70	$ 21	$ 37	$ 47	$ 63
2034	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2035	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2036	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2037	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2038	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2039	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2040	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2041	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2042	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2043	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2044	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64
2045	$ 75	$ 70	$ 21	$ 37	$ 47	$ 64

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Texas
Upstream Capital Costs ($MM/Well)	$7.7	$7.7
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	17.0%
LNG Tanker Capacity (Bcf/Ship)		3.30
U.S. Port Fee ($/Port Visit)		$100,000

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. Annova LNG Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the Annova LNG Case. Specifically, differentials between the two cases result from an additional 0.986 Bcfd in LNG exports assumed from Annova.

5.1. Energy Market and Economic Impacts

This section discusses the impacts of LNG exports in the Base Case and the Annova 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 0.986 Bcfd, the market also must rebalance for liquefaction and fuel losses, estimated at 8 percent of incremental net gas pipeline import volumes. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below.

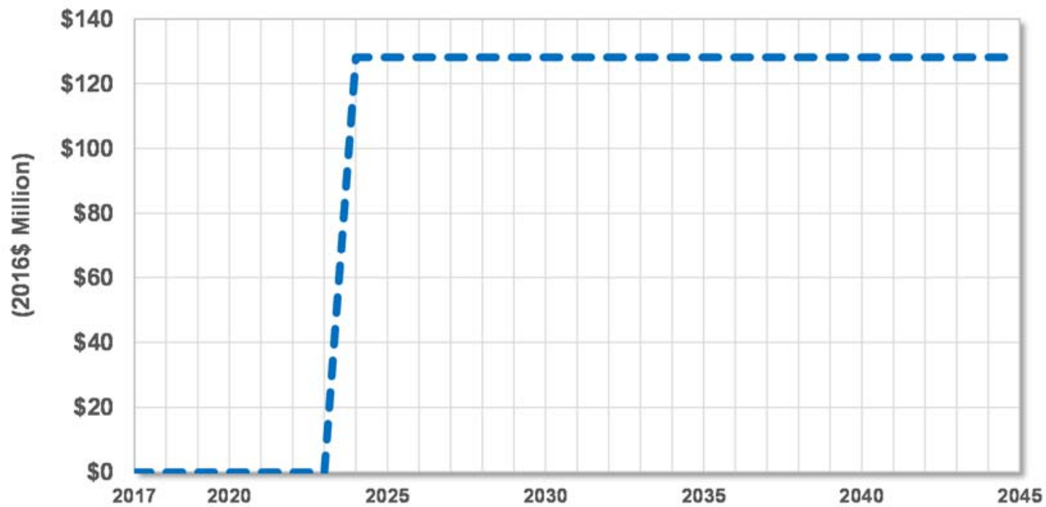
Exhibit 5-1: U.S. Flow Impact Contribution to LNG Exports

2024-2045 Average Supply Sources			
Production Increase	**Demand Decrease**	**Net Gas Pipeline Imports**	**Total Share of LNG Exports**
91% 0.90 Bcfd	11% 0.11 Bcfd	8% 0.08 Bcfd	110% 1.08 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 and electrical but including employee costs, materials, maintenance, insurance, and property taxes). Over the export period of 2024 and 2045, there is a total cumulative impact on operating expenditures in the U.S. of $2.8 billion (in real 2016$) for the Annova LNG Case. During that period, LNG plant operating expenditures in the U.S. average $128 million annually.

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

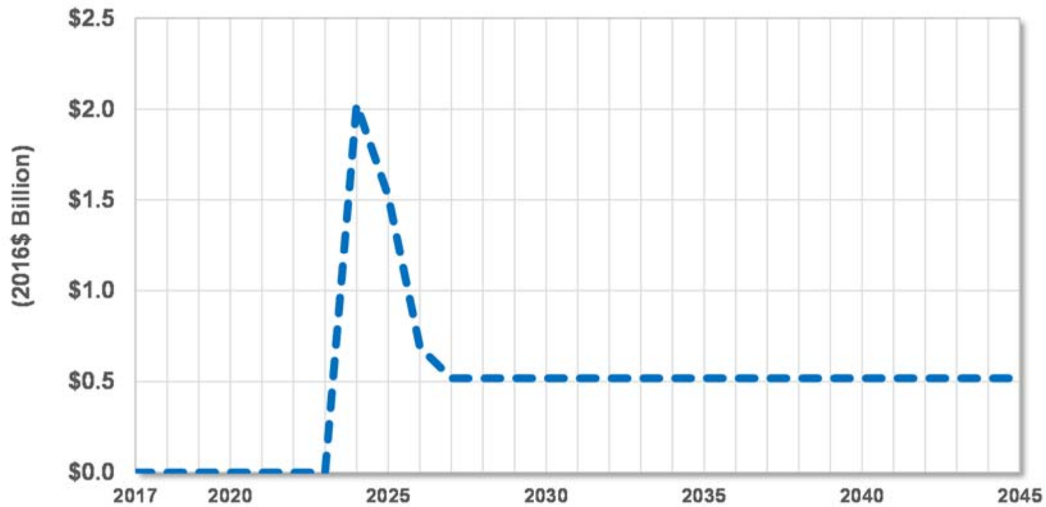


Year	LNG Facility Operating Expenditures (2016$ Million)
2019	$ -
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ 128
2025	$ 128
2030	$ 128
2035	$ 128
2040	$ 128
2045	$ 128
2019-2045 Avg	**$ 128**
2019-2045 Sum	**$ 2,820**

Source: Annova, 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 export period of 2024 and 2045, the cumulative impact on U.S. upstream capital expenditures totals $14.1 billion in the Annova LNG Case as compared to the Base Case. U.S. upstream capital expenditures average $0.64 billion higher annually in the Annova LNG Case than in the Base Case.

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

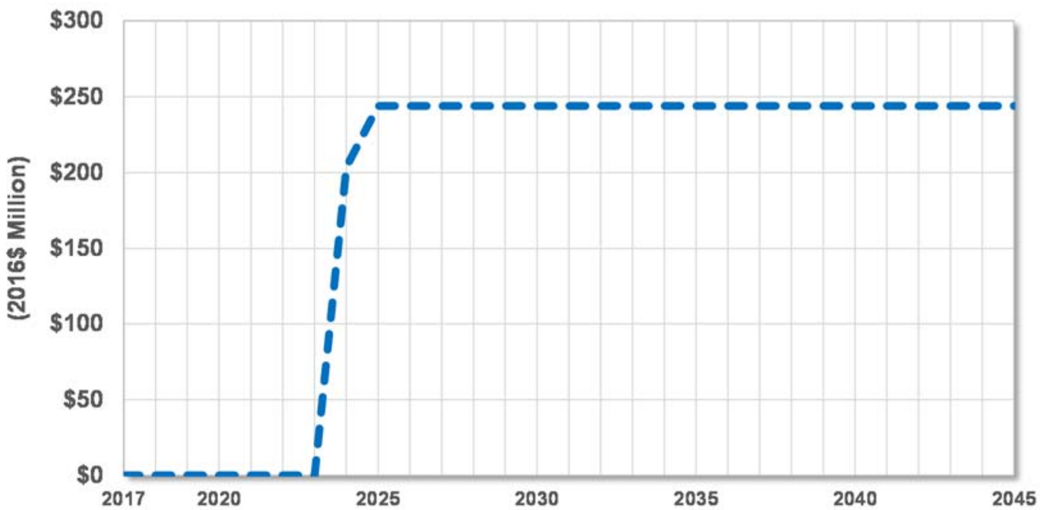


Year	Upstream Capital Expenditures (2016$ Billion)	
2019	$	-
2020	$	-
2021	$	-
2022	$	-
2023	$	-
2024	$	2.03
2025	$	1.52
2030	$	0.52
2035	$	0.52
2040	$	0.52
2045	$	0.52
2019-2045 Avg	**$**	**0.64**
2019-2045 Sum	**$**	**14.06**

Source: ICF

As shown below (Exhibit 5-4), U.S. upstream operating expenditures increase $5.3 billion on a cumulative basis, or on average $242 million annually in the Annova LNG Case as compared to the Base Case between 2024 and 2045 export period.

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



Year	Upstream Operating Expenditures (2016$ Million)
2019	$ -
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ 204
2025	$ 244
2030	$ 244
2035	$ 244
2040	$ 244
2045	$ 244
2019-2045 Avg	**$ 242**
2019-2045 Sum	**$ 5,326**

Source: ICF

The table below (Exhibit 5-5) shows U.S. natural gas consumption in the Base Case and in the Annova LNG Case. The additional LNG export volumes of 0.986 Bcfd are expected to result in only a small reduction in U.S. natural gas consumption of 0.11 Bcfd in 2045, mostly from a decline in gas use in the power sector.

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

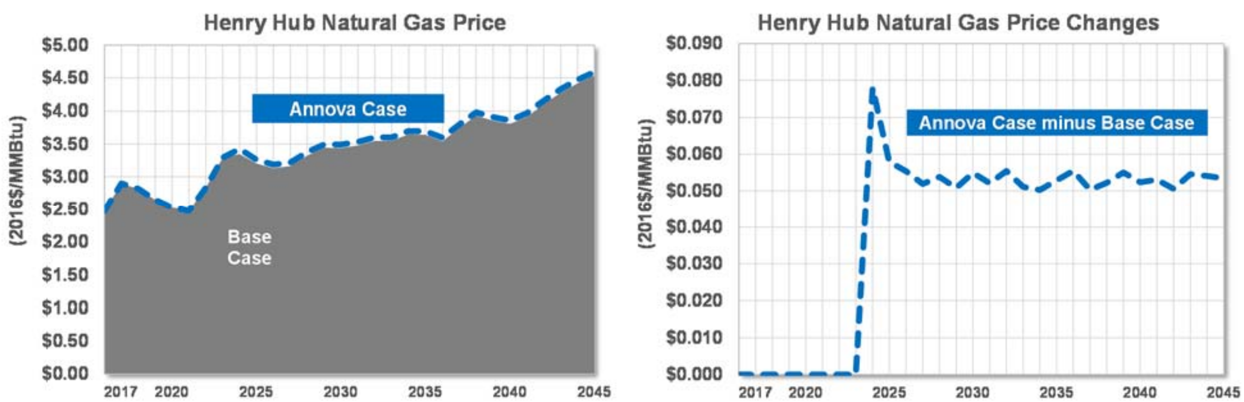
Year	U.S. Domestic Natural Gas Consumption (Bcfd)		
	Base Case	Annova LNG Case	Annova LNG Case Change
2019	73.9	73.9	-
2020	76.3	76.3	-
2021	77.2	77.2	-
2022	77.5	77.5	-
2023	77.4	77.4	-
2024	77.7	77.6	(0.09)
2025	78.2	78.1	(0.11)
2030	82.0	81.9	(0.11)
2035	87.0	86.8	(0.11)
2040	90.5	90.3	(0.11)
2045	94.3	94.2	(0.11)
2019-2045 Avg	**84.3**	**84.2**	**(0.11)**
2019-2045 Sum	**2,275.0**	**2,272.6**	**(2.37)**

Note: Charts above do not include exports, liquefaction fuel, pipeline fuel, and lease & plant gas use.

Source: ICF

The Henry Hub natural gas price in the Annova LNG Case (averaging $3.75/MMBtu from 2024 to 2045) is expected to be on average $0.06/MMBtu higher compared to the Base Case (averaging $3.69/MMBtu), as shown in Exhibit 5-6. The natural gas prices at Henry Hub are expected to reach $4.54/MMBtu in the Base Case and $4.60 in the Annova LNG Case by 2045, indicating a natural gas price increase of $0.06/MMBtu attributable to the Annova LNG export volumes of 0.986 Bcfd.

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

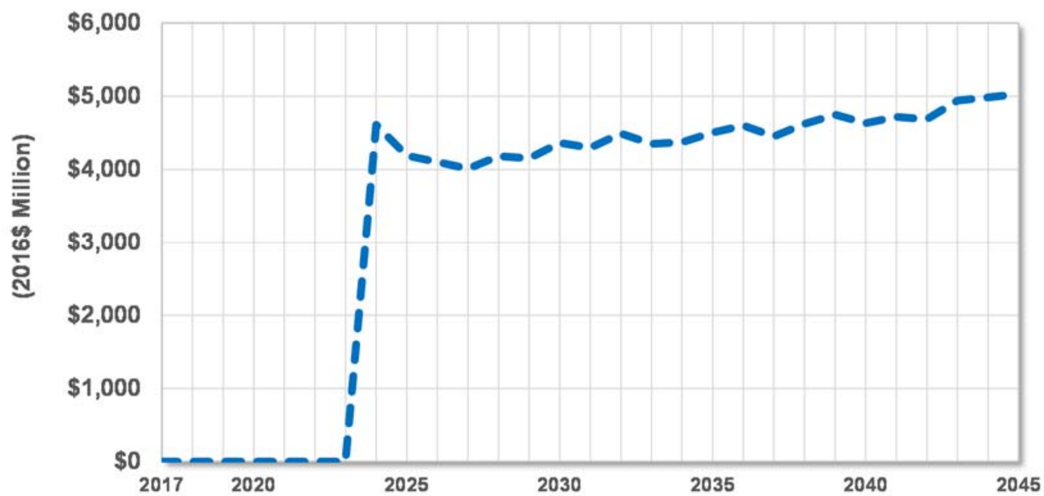


Year	Henry Hub Natural Gas Price (2016$/MMBtu)		
	Base Case	Annova LNG Case	Annova LNG Case Change
2024	$ 3.35	$ 3.43	$ 0.08
2025	$ 3.21	$ 3.27	$ 0.06
2030	$ 3.44	$ 3.50	$ 0.06
2035	$ 3.65	$ 3.70	$ 0.05
2040	$ 3.81	$ 3.87	$ 0.06
2045	$ 4.54	$ 4.60	$ 0.06
2024-2045 Avg	**$ 3.69**	**$ 3.75**	**$ 0.06**

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 Annova LNG Case (see Exhibit 5-7). Over the 2024 and 2045 export period, the cumulative impact on natural gas and liquids production value in the Annova LNG Case is approximately $99 billion. This represents an average increase of about $4.5 billion per year in the Annova LNG Case as compared to the Base Case.

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



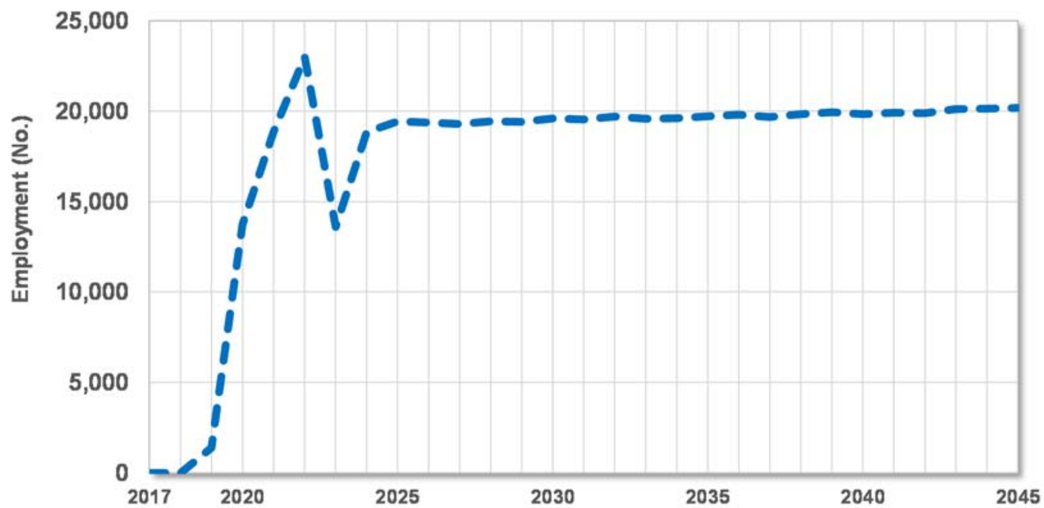
Year	Natural Gas and Liquids Production Value (2016$ Million)
2019	$ -
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ 4,610
2025	$ 4,189
2030	$ 4,364
2035	$ 4,506
2040	$ 4,633
2045	$ 5,031
2019-2045 Avg	**$ 4,503**
2019-2045 Sum	**$ 99,075**

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.[16] 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.)
2019	1,403
2020	13,739
2021	18,839
2022	22,996
2023	13,608
2024	18,837
2025	19,445
2030	19,596
2035	19,725
2040	19,842
2045	20,189
2019-2045 Avg	**18,649**
2019-2045 Sum	**503,524**

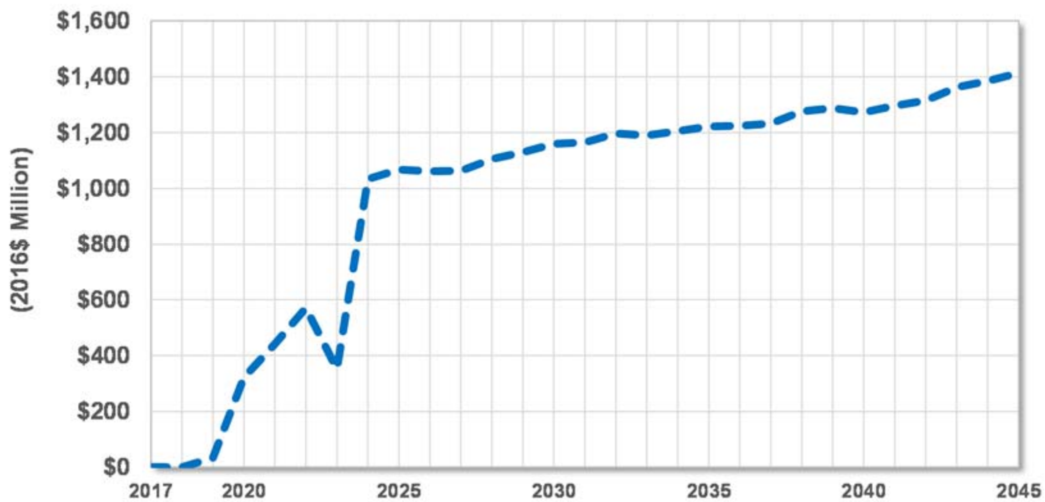
Source: ICF

The construction and operation of the Annova LNG export facility will likely increase employment through direct, indirect and induced employment that totals 18,700 of incremental jobs on average between 2019 and 2045. Over the forecast period the added LNG export facilities are expected to increase job-years relative to the Base Case by 504,000 cumulative job-years.

[16] 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 $1.05 billion annually as a result of the Annova LNG export facility. This translates to a cumulative impact of $28.4 billion over the forecast period between 2019 and 2045.

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



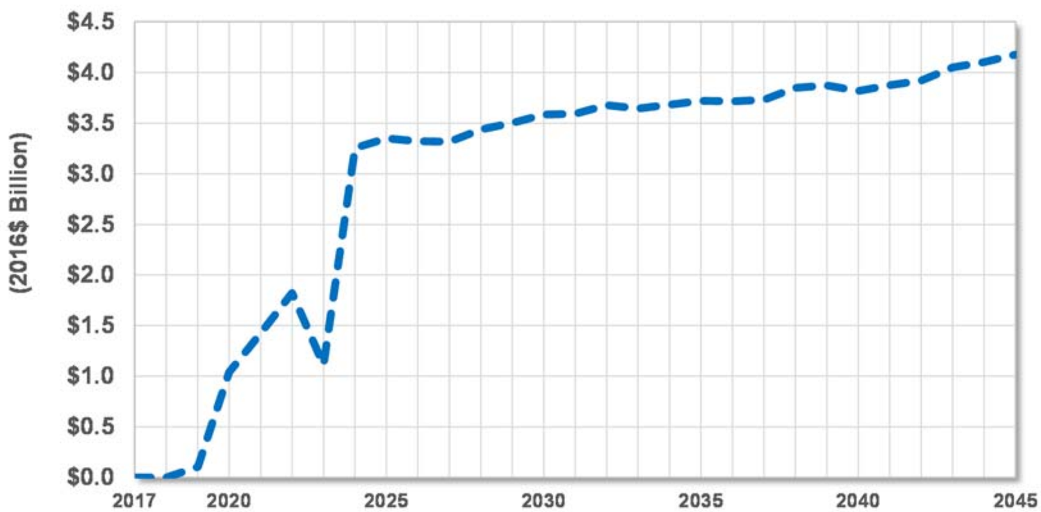
Year	Government Revenues (2016$ Million)	
2019	$	33
2020	$	322
2021	$	442
2022	$	571
2023	$	352
2024	$	1,034
2025	$	1,067
2030	$	1,160
2035	$	1,222
2040	$	1,273
2045	$	1,414
2019-2045 Avg	**$**	**1,051**
2019-2045 Sum	**$**	**28,388**

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 Annova LNG Case. This activity results in a $3.2 billion annual incremental value added between 2019 and 2045. The cumulative value added over the period between the Base Case and the Annova LNG Case totals $86.7 billion.

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

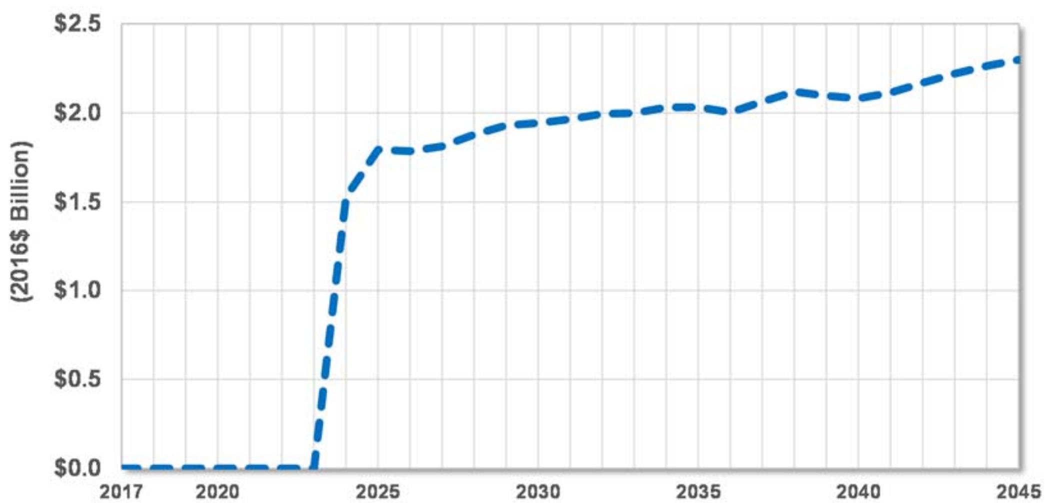


Year	Total Value Added (2016$ Billion)	
2019	$	0.1
2020	$	1.0
2021	$	1.4
2022	$	1.8
2023	$	1.1
2024	$	3.3
2025	$	3.4
2030	$	3.6
2035	$	3.7
2040	$	3.8
2045	$	4.2
2019-2045 Avg	**$**	**3.2**
2019-2045 Sum	**$**	**86.7**

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 $2.0 billion annually or a cumulative value of $44.1 billion between 2024 and 2045, based on the value of LNG export volumes and incremental associated liquids production. The improved balance of trade effects begin in 2024 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)	
2019	$	-
2020	$	-
2021	$	-
2022	$	-
2023	$	-
2024	$	1.5
2025	$	1.8
2030	$	1.9
2035	$	2.0
2040	$	2.1
2045	$	2.3
2019-2045 Avg	**$**	**2.0**
2019-2045 Sum	**$**	**44.1**

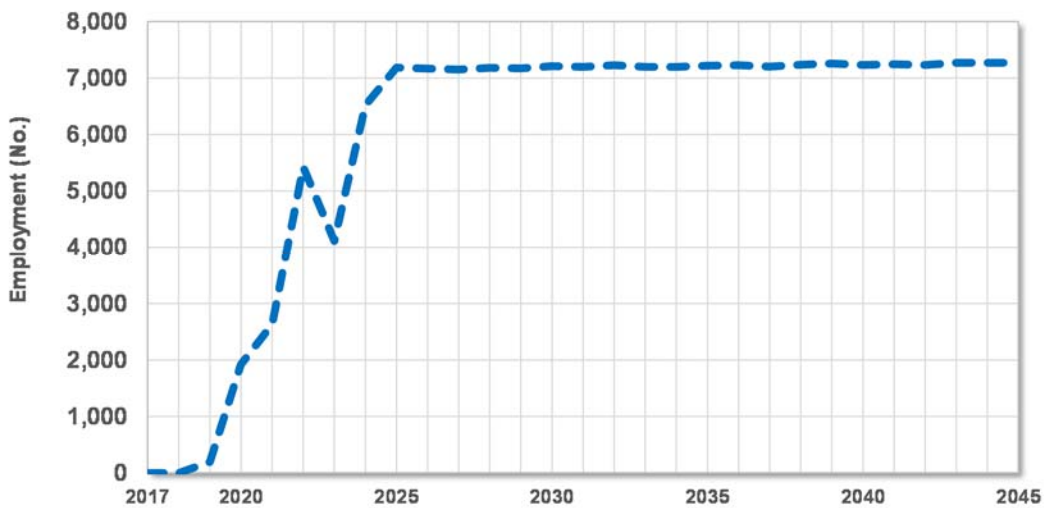
Source: ICF

5.2. Texas Impacts

The exhibits below describe the energy market and economic impacts of the LNG export cases in Texas.

Exhibit 5-12 shows the impacts of LNG export volumes in Texas 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 state and in other states to which Texas companies offer support services. The Annova LNG Case exhibits an increase of roughly 6,400 jobs on an average annual basis from 2019 to 2045 as compared to the Base Case. This equates to a cumulative impact of 172,400 job-years in Texas over the forecast period through 2045.

Exhibit 5-12: Texas Total Employment Changes

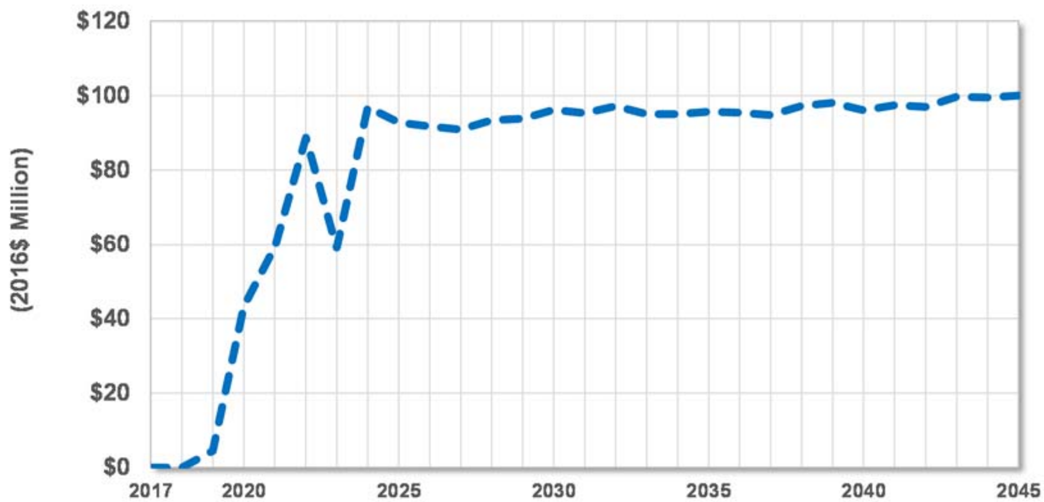


Year	Employment (No.)
2019	196
2020	1,919
2021	2,632
2022	5,424
2023	4,113
2024	6,518
2025	7,184
2030	7,211
2035	7,216
2040	7,229
2045	7,270
2019-2045 Avg	**6,383**
2019-2045 Sum	**172,328**

Source: ICF

Exhibit 5-13 shows the impacts of LNG export volumes on Texas state and local government revenues. Total Texas 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 Annova LNG Case results in a $88 million average annual increase to local and state Texas government revenues throughout forecast period through 2045, or a cumulative impact of about $2.4 billion.

Exhibit 5-13: Texas Government Revenue Changes

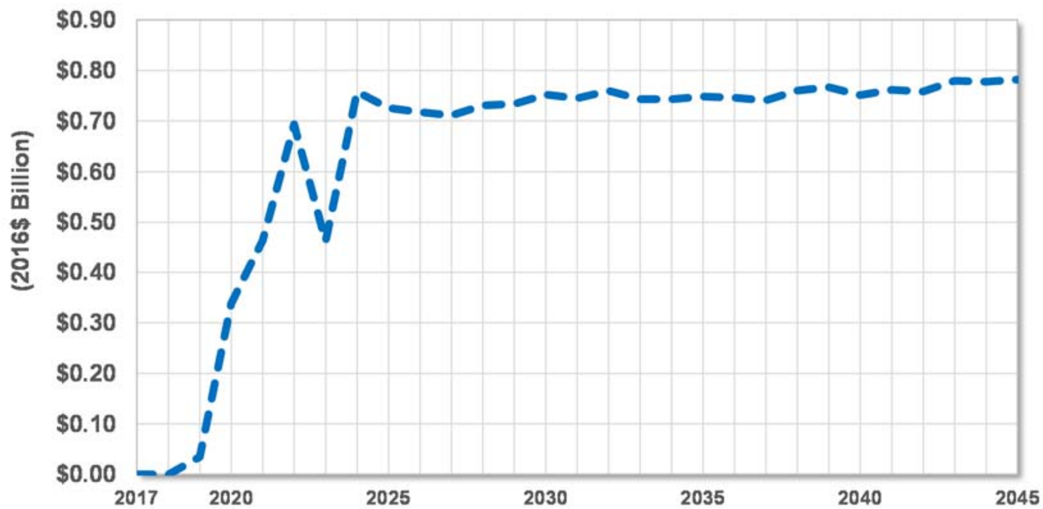


Year	Government Revenues (2016$ Million)	
2019	$	4.4
2020	$	43.2
2021	$	59.3
2022	$	88.7
2023	$	59.1
2024	$	96.9
2025	$	92.8
2030	$	96.2
2035	$	95.7
2040	$	96.0
2045	$	100.0
2019-2045 Avg	**$**	**87.6**
2019-2045 Sum	**$**	**2,364.2**

Source: ICF

Exhibit 5-14 shows the impacts of LNG export volumes on total Texas value added (also called gross state product or GSP). Texas value added increases as a result of the additional LNG export volumes assumed in the Annova LNG Case. Throughout the study period 2019 to 2045 the plant construction and the additional LNG volumes in the Annova LNG Case result in a $0.68 billion annual average increase to value added, relative to the Base Case. The total differential of value added to Texas over the study period between the Base Case and the Annova LNG Case is $18.5 billion.

Exhibit 5-14: Total Texas Value Added Changes



Year	Total Value Added (2016$ Billion)	
2019	$	0.03
2020	$	0.34
2021	$	0.46
2022	$	0.69
2023	$	0.46
2024	$	0.76
2025	$	0.73
2030	$	0.75
2035	$	0.75
2040	$	0.75
2045	$	0.78
2019-2045 Avg	**$**	**0.68**
2019-2045 Sum	**$**	**18.48**

Source: ICF

1. Bibliography

Annual Energy Outlook 2018, with Projection to 2050, U.S. Energy Information Administration (EIA), Feb 6, 2018. Available at: https://www.eia.gov/outlooks/aeo/

Centro Nacional de Control del Gas Natural (CENAGAS). “Resultados del Proceso de Consulta Publica CENAGAS 2017”. CENAGAS, October 2017: Mexico City, Mexico. Available at: https://www.gob.mx/cms/uploads/attachment/file/268281/Consulta_P_blica_Resultados_v6.pdf

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

American Petroleum Institute. “2012 Joint Association Survey of Drilling Costs”. API, various years: Washington, DC.

U.S. 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

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

Federal Energy Regulatory Commission (FERC). “Impacts on the Bulk Power System,” Item No: A-4 (6), 16 January 2014. Available at: http://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf

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

NERA Economic Consulting. “Macroeconomic Impacts of LNG Exports from the United States”. NERA, December 3, 2012: Washington, DC. Available at: http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf

NERA 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

Petroleum Services Association of Canada (PSAC). “2009 Well Cost Study”. PSAC, 2009. Available at: http://www.psac.ca/

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

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

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

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/

2. Appendices

2.1. 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[17] 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.[18] 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

[17] 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

[18] 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

prices by $0.32 to $1.02 (in 2010 dollars) on average during the 2016-2035 period. GDP and employment see net positive gains from LNG exports, as employment changes reach up to 665,000 annual jobs by 2035 while GDP gains could reach $78-115 billion in 2035. Different sectors feel varying effects from LNG exports. In the power sector, electricity prices are expected to increase moderately with gas prices. The petrochemicals industry benefit from the incremental 138,000-555,000 bpd of NGL production due to the drilling boost fueled by higher gas demand.

NERA's December 2012 study for the EIA looked at four LNG export cases from 6 Bcfd to unconstrained LNG exports using four EIA Annual Energy Outlook (AEO) 2011 scenarios.[19] 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.[20] 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.[21] 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

[19] 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

[20] 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

[21] 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

January 2012 study.[22] Relative to the January 2012 study, LNG exports further increase average gas prices by 8 to 11 percent depending on the case, and boosts natural gas production by 61 percent to 84 percent of the LNG export level. Imports from Canada increase slightly while domestic consumption declines by less than 2 Bcfd on average mostly in power generation and industrial consumption. The overall impact on the economy is positive, with GDP increased by 0.05 percent. Consumer spending on gas and electricity increases by “modest” levels, about 1-8 percent for gas and 0-3 percent for electricity compared to the January 2012 results.

Charles River Associates (CRA) released a study on LNG export impacts for Dow Chemical Company in February 2013 with different methodologies and conclusions from the studies mentioned above.[23] 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.

[22] 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

[23] 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

This page intentionally left blank

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	Employ ment 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	
Annova LNG (ICF 2018)	Annova LNG export of 0.986 Bcfd	0.986 Bcfd LNG Export	$0.05	$0.055	91%	11%	8%	110%	1.51	18,908	$172,183	Annova 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 supplement al 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									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.