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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
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Port Arthur LNG Phase II, LLC	)	**FE Docket No. 20-23-LNG**
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APPLICATION FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATIONS TO EXPORT LIQUEFIED NATURAL GAS FROM THE UNITED STATES TO FREE TRADE AGREEMENT AND NON-FREE TRADE AGREEMENT NATIONS

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Pursuant to section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"),[2] Port Arthur LNG Phase II, LLC ("PALNG Phase II") hereby submits this application ("Application") requesting that the DOE's Office of Fossil Energy ("DOE/FE") grant long-term, multi-contract authorizations for PALNG Phase II to engage in exports of up to 13.5 million tonnes per annum ("MTPA") of liquefied natural gas ("LNG"), the equivalent to 698 billion cubic feet ("Bcf") per year (1.91 Bcf/d) from the site of the proposed Port Arthur LNG terminal in Jefferson County, Texas, where PALNG Phase II is proposing to construct, own, and operate two new LNG trains, referred to as Trains 3 and 4 (the "Expansion Project") to (a) any nation that currently has or in the future develops the capacity to import LNG and with which the United States currently has, or in the future enters into, a free trade agreement ("FTA") requiring national treatment for trade in natural gas and LNG; and (b) any nation with which the United States does not have an FTA requiring the national treatment for trade in natural gas ("Non-FTA" nations) which has or will develop the capacity to import LNG and with which trade is not prohibited by United States law or policy.

[1] 15 U.S.C. § 717b (2018).
[2] 10 C.F.R. Part 590 (2019).

PALNG Phase II requests each of these authorizations for a term commencing on the earlier of the date of first export or seven years from the date of issuance of the authorizations requested herein, and terminating on the later of the date that is twenty years from the date of the commencement of the term or December 31, 2050.[3] Consistent with DOE/FE policy, PALNG Phase II requests that prior to the commencement of exports under its long-term agreements, it be permitted to export commissioning volumes under a short-term, blanket export application to be filed separately at a later date. PALNG Phase II further requests that it be permitted to continue exporting for a total of three years following the end of the FTA and non-FTA term requested in this Application, solely to export any make-up volume that PALNG Phase II may be unable to export during the original export periods.[4] PALNG Phase II requests this authorization both on its own behalf and as agent for other parties who hold title to the gas and/or LNG at the time of export.

The Expansion Project will be located entirely within the LNG export terminal (the "Base Project") proposed by PALNG Phase II's affiliate Port Arthur LNG, LLC ("Port Arthur LNG").[5]

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[3] PALNG Phase II's request regarding the end date of its term is consistent with the DOE/FE's recent policy statement regarding the terms of Non-FTA export authorizations. *See Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050*, 85 Fed. Reg. 7672 (Feb. 11, 2020) ("Proposed Policy Statement"). The "the December 31, 2050 date would be the end of the authorization period for all non-FTA exports, inclusive of any 'make-up' export periods." 85 Fed. Reg. at 7679.

[4] *See, e.g., Freeport LNG Expansion, L.P.*, DOE/FE Order Nos. 3282-B & 3357-A, FE Docket Nos. 10-161-LNG & 11-161-LNG, Order Amending DOE/FE Order Nos. 3282 and 3357, at 4-9 (June 6, 2014). The Proposed Policy Statement noted DOE/FE's proposal to extend the termination date of Non-FTA export authorizations to December 31, 2050 and that this "date would be the end of the authorization period for all non-FTA exports, inclusive of any 'make-up' export periods." 85 Fed. Reg. at 7679. Subject to DOE/FE's issuance of a final policy statement on the issue, PALNG Phase II requests that the DOE/FE grant it the longest combined primary term and make-up period DOE/FE determines to be permissible under its applicable policies.

[5] Port Arthur LNG sought and received from the DOE/FE authorization to export up to 13.5 MTPA of LNG from the initial project (Trains 1 and 2) to FTA countries in Docket No. 15-53-LNG, and to Non-FTA counties in Docket No. 15-96-LNG. *See Port Arthur LNG, LLC,* DOE/FE Order No. 3698, FE Docket No. 15-53-LNG, Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Proposed Port Arthur LNG Project in Port Arthur, Texas, to Free Trade Agreement Nations (Aug. 20, 2015)*, authorization amended*, DOE/FE Order No. 3698-A, FE Docket Nos. 15-53-LNG & 18-162-LNG, Order Amending Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Proposed Port Arthur LNG

PALNG Phase II currently anticipates commencing construction activities associated with the Expansion Project in the first part of 2021 and commencing commercial operations in 2026.

In support of its application, PALNG Phase II states as follows:

I. COMMUNICATIONS AND CORRESPONDENCE

All communications and correspondence regarding this Application, including all service of pleadings and notice, should be directed to the following persons:[6]

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II. DESCRIPTION OF THE APPLICANT

The exact legal name of the applicant is Port Arthur LNG Phase II, LLC. PALNG Phase II is a limited liability company organized and existing under the laws of the state of Delaware. PALNG Phase II is a wholly-owned, indirect subsidiary of Sempra Energy, a California corporation. An organizational chart reflecting the ownership structure of PALNG Phase II is attached to this Application as Appendix C.

The Expansion Project will be located on a project site within a 2,842-acre parcel of land owned in fee by an affiliate of Port Arthur LNG—Port Arthur LNG Holdings, LLC ("Port Arthur

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Project in Port Arthur, Texas, to Free Trade Agreement Nations (Nov. 20, 2018); *Port Arthur LNG, LLC,* DOE/FE Order No. 4372, FE Docket No. 15-96-LNG, Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations (May 2, 2019),

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

Holdings").[7] PALNG Phase II intends to lease or purchase the project site from Port Arthur Holdings. Port Arthur Holdings is a limited liability company formed under the laws of the state of Delaware and a wholly-owned, indirect subsidiary of Sempra Energy.

PALNG Phase II has its principal place of business at 2925 Briarpark Drive, Suite 900, Houston, TX 77042. Sempra Energy and Port Arthur Holdings each has its principal place of business at 488 8th Ave., San Diego, CA 92101.

III. EXECUTIVE SUMMARY

The Expansion Project is proposed for the purpose of liquefying surplus natural gas in the United States for export as LNG to foreign markets. PALNG Phase II expects the first LNG exports from the Expansion Project in 2026. The Expansion Project is proposed at the site of the Port Arthur LNG terminal previously permitted by the Federal Energy Regulatory Commission ("FERC") by order issued on April 18, 2019 in FERC Docket No. CP17-20-000.[8]

On June 14, 2019, PALNG Phase II's affiliate and predecessor in interest, Sempra PALNG Holdings, LLC filed a request to commence the FERC's National Environmental Policy Act ("NEPA") pre-filing process for the Expansion Project.[9] On June 25, 2019, the Director of the FERC's Office of Energy Projects issued a letter order in FERC Docket No. PF19-5-000, granting that request.[10] Following completion of the pre-filing process, on February 19, 2020, PALNG Phase II and its affiliate PALNG Common Facilities Company, LLC filed in FERC Docket No.

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[7] A copy of the deed for the site is included in the docket for Port Arthur LNG's FTA application, DOE/FE Docket No. 15-53-LNG, and is incorporated herein by reference. *See* Supplement to Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Free Trade Agreement Countries, FE Docket No. 15-53-LNG, at exh. 1 (Apr. 9, 2015).

[8] *Port Arthur LNG, LLC*, 167 FERC ¶ 61,052 (2019).

[9] Request to Initiate NEPA Pre-Filing Review Process, FERC Docket No. PF19-5-000 (June 14, 2019) (Accession No. 20190614-5192).

[10] Approval of Pre-Filing Request, FERC Docket No. PF19-5-000 (June 25, 2019) (Accession No. 20190625-30360.

CP20-55-000 an application with FERC under section 3 of the NGA for authorization to construct, own, and operate the Expansion Project facilities.[11] The February 19 application filed with FERC requested that the authorization be issued by February 1, 2021.

Abundant supplies of natural gas from the United States are available to serve both domestic natural gas needs and the needs of the Expansion Project for the proposed term. The use of domestically-sourced natural gas for Port Arthur LNG exports would not significantly reduce the volume of natural gas potentially available for domestic consumption. This is supported by forecasts issued by the U.S. Energy Information Administration ("EIA"), as well as the report prepared for this Application by ICF International ("ICF"), which is included as Appendix B to this Application ("ICF Report").[12] Both of these resources illustrate that there is abundant U.S. natural gas supply currently and during the Expansion Project's proposed timeframe for exports. The robust supply of natural gas, largely as a result of increased levels of production from unconventional resources, is forecasted to exceed demand. The ICF Report indicates that LNG exports from the Expansion Project will result in minimal impact on the price of natural gas for U.S. consumers over the analysis period of 2026 to 2046.[13]

The Expansion Project presents numerous benefits to the public, including increased U.S. economic activity, tax revenues, and job creation during both the construction and operation phases of the project. Through 2046, the estimated total economic gains associated with the Expansion Project are over $5.7 billion annually for the U.S. economy, including $1.1 billion annually for the

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[11] Application under Section 3 of the Natural Gas Act, FERC Docket No. CP20-55-000 (Feb. 19, 2020) (Accession Nos. 20200219-5157, 20200219-5158 & 20200219-5159).
[12] App. B, ICF International, *Economic Impacts of the Proposed Port Arthur Trains 3 and 4 Liquefaction Project: Information for DOE Non-FTA Permit Application* (Feb. 13, 2020) ("ICF Report").
[13] *Id.* at 9.

Texas economy.[14] These economic gains are measured in terms of increased net gross domestic product and state product including multiplier effects. In addition, the Expansion Project will add approximately 720,900 job-years for the U.S. economy as a whole, and 232,700 job-years for the Texas economy through 2046.[15]

On an international level, the Expansion Project will favorably influence the balance of trade that the United States has with its international trading partners. The Expansion Project will generate an expected cumulative value of approximately $77.3 billion of LNG exports over a projected 20-year export term, which will favorably influence the balance of trade that the United States has with its international trading partners.[16] Specifically, the expected value of the exports from the Expansion Project is estimated to reduce the U.S. balance of trade deficit by $3.7 billion annually between 2026 and 2046, based on the value of LNG export volumes and incremental associated liquids production.[17]

PALNG Phase II respectfully requests that the DOE/FE grant long-term, multi-contract authorizations for PALNG Phase II to engage in aggregate exports of up to 13.5 MTPA of LNG, which is the approximate equivalent of 698 Bcf/y of natural gas (or 1.91 Bcf/d of natural gas), produced from the Expansion Project facilities and exported from the marine facilities approved as part of the Base Project, to FTA and Non-FTA countries.

PALNG Phase II requests these authorizations for a minimum 20-year term commencing on the earlier of the date of first commercial export or a date seven years from the issuance of an order by the DOE/FE granting the requested authorizations. PALNG Phase II requests

[14] *Id*. at 10.
[15] *Id*.
[16] *Id*. at 55.
[17] *Id*.

authorization to export natural gas and LNG on its own behalf and as agent for other parties who will hold title to natural gas at the time it is exported from the Port Arthur LNG terminal for delivery to Non-FTA countries, as permitted by DOE/FE policy.[18] PALNG Phase II will comply with all DOE/FE requirements related to PALNG Phase II's exportation of LNG on behalf of others, including any applicable requirements to register LNG title holders or to file long-term commercial agreements under seal with the DOE/FE.

PALNG Phase II anticipates entering into one or more long-term export agreements with customers of the Expansion Project. Section 590.202(b) of DOE's regulations requires applicants to submit information regarding the terms of certain transactions, which includes long-term supply agreements and long-term export agreements.[19] PALNG Phase II has not currently entered into any export agreements or finalized supply arrangements for the Expansion Project, but will comply with the obligation to file such agreements after they have been executed and become binding, consistent with DOE/FE policy.[20]

Accordingly, PALNG Phase II respectfully requests that the DOE/FE issue an order granting the authorization requested herein to export LNG to FTA countries by June 1, 2020. PALNG Phase II further requests that the DOE/FE issue an order granting the authorization requested herein to export LNG to Non-FTA countries by April 1, 2021, consistent with the action

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18 *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).

19 10 C.F.R. § 590.202(b)(4).

20 PALNG Phase II notes that the DOE/FE has published a Proposed Interpretive Rule that proposed to clarify (1) the types of contracts and contractual amendments that are relevant to DOE/FE's public interest determination and therefore must be filed; and (2) when such relevant contracts and contractual amendments must be filed with DOE/FE to comply with the Part 590 regulations. *See Filing of Contracts and Purchase Agreements Associated With the Export of Natural Gas*, Proposed Interpretive Rule, 83 Fed. Reg. 65,111 (Dec. 19, 2018). An affiliate of PALNG Phase II, Sempra LNG & Midstream, LLC, filed comments in that proceeding, along with several other parties. The Proposed Interpretive Rule is currently pending before the DOE/FE.

date requested in its related FERC application, which will allow PALNG Phase II to finalize the commercial development, financing, and contracting of the Expansion Project.

IV. DESCRIPTION OF THE EXPANSION PROJECT

A. Expansion Project Facilities

The Expansion Project will be located on approximately 900 acres located near the City of Port Arthur and entirely within the jurisdictional boundary of Jefferson County, Texas. The Expansion Project facilities will be located on the property authorized for use for the Base Project. The Expansion Project will include two liquefaction trains, each capable of producing under optimal conditions 6.73 MTPA of LNG or approximately 13.5 MTPA in the aggregate.[21] Each train will consist of a feed gas pre-treatment unit, a heavy hydrocarbon removal unit, and a natural gas liquefaction unit. The Expansion Project does not include any new marine facilities or LNG storage tanks, as LNG produced from Trains 3 and 4 will be stored and exported using storage tanks and marine facilities approved as part of the Base Project.[22] The Expansion Project will not require a change in the size or quantity of LNG ships currently authorized by the U.S. Coast Guard in the Waterway Suitability Assessment for the Base Project. Purchased power will be utilized for the Expansion Project.

PALNG Phase II expects to initiate construction of the Expansion Project in the second quarter of 2021. There will be an approximately seven-month lag between the completion dates of the two liquefaction trains. Accordingly, the Applicants expect Train 3 to be completed and in

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[21] Once constructed, the Expansion Project facilities will, under optimal conditions, increase LNG production capacity from Trains 1-4 up to 27 MTPA in the aggregate.

[22] As approved by FERC, the Base Project includes: (1) two liquefaction trains (Trains 1 and 2), each with its own gas treatment facilities and capable of producing 6.73 MTPA under optimal conditions; (2) condensate and refrigerant storage areas; (3) a marine facility, including up to two LNG berths, with two LNG loading arms and two hybrid arms; (4) condensate loading and refrigerant unloading truck facilities; (5) a construction and materials loading/unloading dock; and (6) three full containment LNG storage tanks each with a net working capacity of 160,000 m^3.

service in the second quarter of 2026, and Train 4 to be completed and in service in the fourth quarter of 2026.

B. Natural Gas Transportation and Supply

Natural gas that will be exported by the Expansion Project will be transported by facilities on the extensive U.S. interstate and intrastate natural gas pipeline grid and delivered to the project by the facilities to be owned and operated by Port Arthur Pipeline, LLC ("Port Arthur Pipeline"), an affiliate of PALNG Phase II, which were approved by the FERC in its April 18, 2019 order.[23] Through these pipeline interconnections, PALNG Phase II will have economical access to the national natural gas supply and pipeline system. This will enable the Expansion Project to access major natural gas supply basins in the United States.

Abundant supplies of natural gas in the United States are available to serve domestic natural gas needs as well as the proposed Project.[24] Natural gas for the proposed exports can be sourced from basins throughout the United States, including the Appalachian, Gulf Coast, Mid-Continent, and Rocky Mountain regions, providing the Expansion Project with supply diversity and optionality for the benefit of its customers. Given the size of traditional natural gas resources in close proximity to the Expansion Project, as well as the rapid growth in emerging unconventional gas and oil resources throughout the United States, the Expansion Project will have a choice of diverse and reliable alternative gas supplies.

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[23] Port Arthur Pipeline is a limited liability company formed under the laws of Delaware and a wholly-owned indirect subsidiary of Sempra Energy. Its principal place of business is 488 8th Ave., San Diego, California 92101. As certificated by the FERC, each of the two separate, independent segments of Port Arthur Pipeline's system will be capable of transporting up to 2.0 Bcf/d of natural gas to the approved LNG facility, which is equivalent to the maximum productive capacity of the facilities to be owned by Port Arthur LNG (Trains 1 and 2) and the facilities proposed by PALNG Phase II (Trains 3 and 4). Accordingly, no new pipeline construction was proposed in connection with the February 19, 2020 application PALNG Phase II filed with the FERC.

[24] ICF Report at 7, 13-14.

The primary sources of natural gas for the Expansion Project will include vast supplies available from the Permian Basin and Gulf Coast producing regions. The Permian Basin in West Texas and New Mexico is becoming an increasingly important source of gas for the Gulf Coast. Dry gas production from the low cost Permian basin will reach 9.2 Tcf per year (25 Bcfd) by 2045, mostly gas associated with tight oil, from about 2.5 Tcf (6.7 Bcfd) in 2018.[25] Associated gas production from tight oil plays in the Permian Basin also represents about 30% of the gas resource from tight oil plays.[26] Mid-continent assessments in the Potential Gas Committees 2018 year-end assessment increased by 245 Tcf (66%) from the 2016 year-end assessment, "reflecting intensive developments of conventional, tight and shale reservoirs in the Permian Basin."[27] According to the EIA's most recent estimates, unproved technically recoverable tight/shale gas resources in the Permian Basin amount to 289.3 Tcf.[28]

The EIA reports that, in 2018, the Gulf Coast region collectively produced and made available to the national market 11.6 trillion cubic feet ("Tcf") of natural gas, which was 35% of the United States total for that year.[29] According to the 2018 Report of the Potential Gas Committee, the United States Gulf Coast region is estimated to have traditional gas resources of 515 Tcf.[30] Emerging unconventional supply areas, such as the Barnett, Haynesville, Eagle Ford, Fayetteville and Woodford shale gas formations, represent attractive sources of supply for the

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25 *Id.* at 14.
26 *Id.* at 24.
27 U.S. Potential Gas Committee 2018, "The Potential Supply of Natural Gas in the United States," available at http://www.potentialgas.org.
28 U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2020*, Oil and Gas Supply Module, tbl.3 (Jan 29. 2020) [hereinafter Assumptions to the AEO 2020], https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf.
29 U.S. Energy Information Administration, Natural Gas Gross Withdrawals and Production (Jan. 31, 2020), https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm. For purposes of calculating total marketed production from the Gulf Coast region, EIA's data has been aggregated for the following categories: TX, LA, and Federal Offshore Gulf of Mexico.
30 *See supra* note 27.

Expansion Project. Technological improvements in natural gas exploration, drilling, and production have resulted in significant reductions in the costs of developing shale resources and making shale gas production economically viable. The latest EIA estimate of technically recoverable gas resources in the Barnett, Haynesville and Eagle Ford formations alone is approximately 248 Tcf.[31] Natural gas production from shale gas and tight oil plays accounted for 66% (22.32 Tcf) of total U.S. dry production in 2019 (33.81 Tcf).[32] Looking forward, the EIA projects that U.S. dry natural gas production will increase as a result of continued development of tight and shale resources, "which account for more than 90% of dry natural gas production in 2050 in the Reference case."[33]

Abundant supplies of natural gas in regions outside of the Permian and Gulf Coast are also available to serve domestic natural gas needs, as well as the needs of the Expansion Project. The Appalachian Basin, which encompasses both the Marcellus and Utica supply regions, represents one of the most extensive potential sources of natural gas supply in the United States. According to the EIA, Eastern U.S. production of natural gas from shale resources leads growth in the Reference Case, with total U.S. gas production across most cases being driven by the continued development of the Marcellus and Utica shale plays.[34] The EIA estimates total technically recoverable dry natural gas resources in the East alone at 821.4 Tcf.[35] In response to the increased production in the Appalachian Basin region, the natural gas industry is building new interstate pipeline projects to transport production out of the Marcellus and Utica Shale Plays, as well as

[31] Assumptions to the AEO 2020, Oil and Gas Supply Module at tbl. 3.
[32] U.S. Energy Information Administration, *Annual Energy Outlook 2020*, tbl. D7 (Jan. 29, 2020) [hereinafter AEO 2020], https://www.eia.gov/outlooks/aeo/pdf/appd.pdf.
[33] *Id.* at 49-50, https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf.
[34] *Id.* at 51-52.
[35] Assumptions to the AEO 2020, Oil and Gas Supply Module at tbl. 2.

modifying existing systems to allow pipelines originally built and used to move gas into the Northeast to now provide new markets for excess gas out of the Northeast.[36] Gas production in the Permian Basin, Gulf Coast, and Appalachian Basin is therefore well situated to satisfy domestic requirements for natural gas.

When these new resources are added to conventional producing formations, it is evident that the United States has more than sufficient supply to serve domestic needs and accommodate the proposed exports from the Expansion Project. In 2020, the EIA estimated total technically recoverable natural gas resources in the United States at 2,828.8 Tcf.[37] This growth in U.S. natural gas resources is reflected in other recent academic and industry evaluations. In its year-end 2018 assessment, the Potential Gas Committee determined that the United States possesses future available gas supply (reserves and resources) of 3,838 Tcf, which is an increase of approximately 697 Tcf (+22%) from the Potential Gas Committee's projections in 2016.[38]

The Expansion Project is well-positioned to access natural gas supplies from the numerous pipelines that are in proximity to the Expansion Project. Natural gas to be exported from the Expansion Project will be purchased in a market that has sufficient liquidity and capacity to accommodate a variety of purchase arrangements, including spot market transactions and long-term supply arrangements. Natural gas markets are particularly liquid in the Gulf Coast regions as a result of the key market centers in the area and the availability of readily accessible incremental gas supplies. In 2018, only 3 Tcf (26%) of the 11.6 Tcf of marketed gas production

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

37 Assumptions to the AEO 2020, Oil and Gas Supply Module, at tbl. 2.

38 U.S. Potential Gas Committee, *supra* note 27.

from Texas Louisiana, and the Gulf of Mexico was delivered to consumers in those two states.[39] Moreover, the Expansion Project will not be limited to particular geographical supply areas when contracting for gas supply. The Expansion Project will have access to market centers providing ample liquidity to accommodate a wide and geographically diverse range of gas supply arrangements. There are multiple major natural gas market centers in Louisiana and Texas.[40] These market centers provide ample liquidity to accommodate a wide and geographically diverse range of gas supply arrangements.

This access to multiple supply options means that the Expansion Project will be able to respond to shifts in the economics and production profiles of different gas production areas, which may vary significantly over the term of the requested authorizations. Thus, given the integrated nature of the U.S. pipeline system, which yields a broad range of supply and transportation options that the Expansion Project currently has at its disposal, it is uncertain where the gas used by the Expansion Project will originate.

C. Commercial Structure

PALNG Phase II currently anticipates that it will sell LNG to customers on an FOB basis at the terminal under LNG sales and purchase agreements. However, it is in discussions with customers regarding other proposed structures, such as the provisions of liquefaction services under tolling agreements. As noted above, PALNG Phase II has not yet entered into long-term export contracts in connection with the export authorizations requested herein or finalized gas supply arrangements for the Expansion Project. However, once executed, PALNG Phase II will file any such contracts with the DOE/FE in accordance with the DOE/FE's filing requirements.

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39 Energy Information Administration, *Natural Gas Monthly* (Jan. 31, 2020), tbls. 7 and 16 *available at* http://www.eia.gov/naturalgas/monthly/.

40 Energy Information Administration, *Natural Gas Market Centers: A 2008 Update* (April 2009) *available at* https://www.eia.gov/naturalgas/archive/ngmarketcenter.pdf.

V. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standards

Pursuant to sections 301(b) and 402 of the Department of Energy Organization Act,[41] and delegations of authority issued thereunder, the DOE/FE is responsible for evaluating applications to export natural gas and LNG from the United States under section 3 of the NGA.[42] As discussed below, to the extent that this Application requests authority to export LNG to FTA nations, that request should be deemed in the public interest and granted without modification or delay, as required by NGA section 3(c).[43] The applicable legal standard for the portion of the Application that requests authorization to export LNG to Non-FTA countries is set forth in section 3(a) of the NGA.[44]

1. Exports to FTA Countries

Section 3(c) was added to the NGA by section 201 of the Energy Policy Act of 1992.[45] That section provides in relevant part that applications to the DOE/FE requesting authority for the export of natural gas, including LNG, to a nation with which there is in effect a FTA requiring national treatment for trade in natural gas shall be deemed consistent with the public interest and granted without modification or delay.[46] Accordingly, the portion of this Application requesting authority to export LNG to FTA countries is deemed by statute to be consistent with the public interest and must be approved without modification or delay.

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41 42 U.S.C. §§ 7151(b), 7172 (2018).

42 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04G (June 4, 2019).

43 15 U.S.C. § 717b(c).

44 *Id.* § 717b(a).

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

46 15 U.S.C. § 717b(c).

2. Exports to Non-FTA Countries

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

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary] authorizing it to do so. The [Secretary] shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate, and may from time to time, after opportunity for hearing, and for good cause shown, make such supplemental order in the premises as it may find necessary or appropriate.[47]

In applying this provision, the DOE/FE has consistently found that section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[48] The DOE/FE will grant a Non-FTA export application unless opponents of the application make an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[49]

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47 *Id*. § 717b(a).

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

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

The DOE/FE's prior decisions have looked to the 1984 Policy Guidelines setting out the criteria to be employed in evaluating applications for natural gas imports.[50] While nominally applicable to natural gas import cases, the DOE/FE has found these Policy Guidelines applicable to natural gas export applications, as well.[51] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource systems. The Policy Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas. . . . The federal government's primary responsibility in authorizing imports [or exports] should be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[52]

The DOE/FE's analysis has also been guided by DOE Delegation Order No. 0204-111.[53] According to the Delegation Order, exports of natural gas are to be regulated primarily "based on a consideration of the domestic need for the gas to be exported and such other matters [found] in the circumstances of a particular case to be appropriate."[54] Although the Delegation Order is no longer in effect, the DOE/FE's review of export applications continues to focus on: (i) the domestic need for natural gas proposed to be exported; (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies; (iii) whether the arrangement is consistent with the

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

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

[52] Policy Guidelines at 6,685.

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

[54] Delegation Order at para. (b).

DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[55]

The DOE/FE has indicated that the following additional considerations are relevant in determining whether proposed exports are in the public interest: whether the exports will be beneficial for regional economies, the extent to which the exports will foster competition and mitigate trade imbalances with the foreign recipient nations, and the degree to which the exports would encourage efficient management of U.S. domestic natural resources.[56]

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

B. Domestic Need for the Gas to be Exported

The Expansion Project is being proposed in light of the rapid growth in U.S. natural gas resources and production. In particular, drilling productivity gains and extraction technology enhancements have enabled significant growth in supplies from unconventional gas-bearing shale formations in the United States. In addition, estimates of recoverable natural gas resources have increased by approximately 1,081 Tcf (62%) between 2009 and 2020.[57] In light of the substantial addition of resources and the comparatively minor increases in domestic natural gas demand, there

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

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

57 *Compare* Assumptions to the AEO 2020, Oil and Gas Supply Module, at tbl. 2 *with* U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, tbl. 9.2 (Mar. 2009) [hereinafter Assumptions to the AEO 2009], http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.

are more than sufficient natural gas resources to accommodate both domestic demand and the exports proposed in this Application throughout the term of the requested authorization.

As U.S. natural gas resources and production have increased, U.S. natural gas prices have fallen significantly. The annual average Henry Hub spot price for natural gas fell from $8.86 per MMBtu in 2008 to $2.56 per MMBtu in 2019.[58] In its most recently calculated reference case, the EIA estimates that Henry Hub prices will remain lower than $4 per MMBtu throughout the projection period.[59] Prices for natural gas in the U.S. market are now significantly below those of most other major gas-consuming countries.[60] The result is that domestic gas can be exported, liquefied, and re-exported to foreign markets on a competitive basis. As discussed below, such exports can be expected to have only a nominal effect on U.S. prices.

1. Domestic Natural Gas Supply

As the EIA has noted, domestic "[n]atural gas production from tight and shale gas formations has grown rapidly in recent years."[61] The EIA estimates that natural gas production over the 2020-2025 period will grow at 1.9% a year, and will outpace consumption in most cases.[62] The EIA further estimates that U.S. dry gas production increased from 21.3 Tcf in 2010 to 30.6 Tcf in 2018.[63]

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58 U.S. Energy Information Administration, *Henry Hub Natural Gas Spot Price* (Feb. 20, 2020, https://www.eia.gov/dnav/ng/hist/rngwhhda.htm.
59 AEO 2020 at 48.
60 *See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (Feb 4, 2020), http://pubdocs.worldbank.org/en/596831580311438199/CMO-Pink-Sheet-February-2020.pdf (the average natural gas price in January 2020 was $2.03 per MMBtu in the United States, while the average price in Europe was $3.63 per MMBtu and the average LNG price was $10.08 per MMBtu in Japan).
61 U.S. Energy Information Administration, *Annual Energy Outlook 2016,* at IF-29 (Aug. 2016), https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.
62 AEO 2020 at 45-46.
63 U.S. Energy Information Administration, *U.S. Dry Natural Gas Production* (Jan. 31, 2020), https://www.eia.gov/dnav/ng/hist/n9070us2A.htm.

This growth trend is expected to continue over the next several decades. Total U.S. dry gas production is projected to grow to 45 Tcf by 2050, with a 0.9% annual growth rate between 2019 and 2050.[64] Much of the future natural gas production growth is expected to come from unconventional production of shale resources, including horizontal drilling and multi-stage hydraulic fracturing. Specifically, the EIA found that production from shale gas and associated gas from tight oil plays would be the largest contributor to natural gas production growth, comprising over three-quarters of total U.S. production by 2050.[65] In its 2020 Annual Energy Outlook, the EIA has also significantly increased its estimates of shale gas production through 2050 as compared to its projections in prior years. For example, the EIA revised its projection of shale gas production in 2040 from 32.54 in its 2020 Annual Energy Outlook, up from 19.58 Tcf in its 2015 Annual Energy Outlook.[66]

This growth in shale production has been accompanied by an increase in the overall volume of U.S. natural gas resources. The EIA's estimates of recoverable natural gas resources have increased by 1,081 Tcf (62%) between 2009 and 2020.[67] According to ICF—the independent consulting firm commissioned by PALNG Phase II to assess the domestic market and economic effects of the proposed Expansion Project—there were 3,693 Tcf of technically recoverable gas in the lower-48 U.S. states as of 2016, 2,133 Tcf of which was attributable to shale gas.[68] A large

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64 AEO 2020 at tbl. 13, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2020&cases=ref2020&sourcekey=0

65 AEO 2020 at tbl. 14, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2020&cases=ref2020&sourcekey=0.

66 *Compare* AEO 2020 at tbl. 14, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2020&cases=ref2020&sourcekey=0 *with* U.S. Energy Information Administration, *Annual Energy Outlook 2015*, at tbl. A14 (Apr. 2015), https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf.

67 *Compare* Assumptions to the AEO 2020, Oil and Gas Supply Module at tbl. 2 *with* Assumptions to the AEO 2009 at tbl. 9.2.

68 ICF Report at 25.

component of the technically recoverable resource is economic at relatively low wellhead prices.[69] ICF estimates that between 1,200 and 1,400 Tcf of gas resources in the United States and Canada could economically be developed with gas prices at between $3.50 and $4.00 per MMBtu using today's technology.[70] This "current technology" assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction while, in fact, large improvements in these areas have been made historically and are expected in the future. With the advancement in drilling technology that will exploit additional shale gas development opportunities, further increases are anticipated in the amount of the technically recoverable resource that can be economically developed. ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that is economic at $5/MMBtu would increase from 1,225 Tcf to 2,160 Tcf, a 76% increase.[71]

2. <u>Domestic Natural Gas Demand</u>

Although domestic demand for natural gas is anticipated to grow, the rate of demand increase will continue to be outpaced by the growth of available supply. For example, though demand for natural gas has increased since 2009, production of natural gas has increased faster due to the shale gas revolution.[72] According to data published by the EIA, U.S. natural gas consumption was only 29% higher in 2008 than in 2018.[73] In its Annual Energy Outlook 2020, the EIA estimates long-term annual U.S. demand growth of only 0.5%, with demand expected to

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[69] *Id.* at 17.
[70] *Id.*
[71] *Id.* at 21.
[72] The Brattle Group, Understanding Natural Gas Markets, at 3 (Sep. 2014), https://www.api.org/~/media/Files/Oil-and-Natural-Gas/Natural-Gas-primer/Understanding-Natural-Gas-Markets-Primer-High.pdf.
[73] U.S. Energy Information Administration, *U.S. Natural Gas Total Consumption* (Jan. 31, 2020), https://www.eia.gov/dnav/ng/hist/n9140us2a.htm.

reach 36.50 Tcf in 2050.[74] In contrast, total U.S. dry gas production during the same period is projected to grow at an annual rate of 0.9%, with dry gas production estimated to reach 45 Tcf in 2050, as compared to 33.81 Tcf in 2019.[75]

Growth in demand for natural gas through 2045 is expected to be primarily driven by the power sector due, in part, to environmental regulations.[76] ICF forecasts an increase of 40% in gas use in the power generation market from 2018 to 2045.[77] The EIA forecasts that energy consumption in the electric power sector will increase to 12.20 Tcf in 2050 from 11.40 Tcf in 2019 in the Reference case.[78] Relatively small growth is anticipated in the industrial sector's demand for natural gas, driven by reductions in energy intensity, or energy input per unit of industrial output, which remain a top priority for manufacturers.[79] The EIA estimates that energy consumption in the industrial sector will increase by an average of 1.1% per year to 14.70 Tcf in 2050 from 10.35 Tcf in 2019 in the Reference case.[80] Energy efficiency gains are expected to somewhat offset gas demand growth in the residential and commercial sectors.[81] Natural gas consumption in the commercial sector will increase only by 0.2% per year to 3.74 Tcf in 2050 from 3.50 Tcf in 2019 in the EIA Reference case.[82] The residential sector is forecasted to experience a decrease in consumption, with a -0.3% growth in natural gas consumption down to 4.55 Tcf in 2050 from 5.03 Tcf in 2019.[83] Under the ICF Base Case, which assumes no exports from the Expansion Project, U.S. and Canadian natural gas consumption in 2045 is expected to be

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74 AEO 2020 at tbl. 13.
75 *Id.* at tbl. 14.
76 ICF Report at 27-28.
77 *Id.* at 28.
78 AEO 2020 at tbl. 13.
79 ICF Report at 29.
80 AEO 2020 at tbl. 13.
81 ICF Report at 29.
82 AEO 2020 at tbl. 13.
83 *Id.*

over 41 Tcf (LNG and pipeline exports included). This Base Case projection assumes feed gas deliveries for U.S. LNG exports in a total amount of 6.4 Bcf/d per year by 2040.[84] Despite the projected growth in domestic demand through the forecast period of 2045, U.S. natural gas resources, especially unconventional supply from shale resources, are wholly adequate to satisfy domestic demand as well as the added demand of LNG exports from the Expansion Project, even when other LNG exports are assumed.

3. Effects on Domestic Prices of Natural Gas

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

The first part of the 2012 studies consisted of an EIA report evaluating how LNG exports would affect domestic energy consumption, production, and prices under various scenarios involving either 6 Bcf per day or 12 Bcf per day (the "2012 EIA Study").[85] The 2012 EIA Study projected that natural gas prices would rise over time, even without additional LNG exports.[86] In the second part of the 2012 studies, NERA Economic Consulting ("NERA") assessed the macroeconomic effects of increased LNG exports under a range of global natural gas supply and

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84 ICF Report at 27.

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

86 *Id.* at 6.

demand scenarios, including scenarios with unlimited LNG exports ("2012 NERA Study").[87] In each of the scenarios analyzed, NERA found that the United States would experience net economic benefits from increased LNG exports.[88] With regard to the effect of natural gas prices, NERA further projected that "price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios."[89] NERA also indicated that the peak natural gas export levels and resulting price increases analyzed by the 2012 EIA Study are "not likely,"[90] namely because U.S. exports would fall far short of the levels of exports assumed in the 2012 EIA Study.[91] Even in the export scenarios that led to the most significant theoretical price increases projected by the 2012 EIA Study, the 2012 NERA Study found net benefits to U.S. consumers.[92] The 2012 NERA Study further found that the net positive economic results became greater with higher levels of exports.[93]

The DOE/FE's updated studies consisted of a 2014 domestic market analysis by EIA ("2014 EIA Study"), and a 2015 macroeconomic analysis conducted by the Center for Energy Studies at Rice University's Baker Institute and Oxford Economics ("2015 LNG Export Study").[94] The 2014 EIA Study evaluated the effects on U.S. energy markets of increased LNG exports, ranging from 12 Bcf per day to 20 Bcf per day.[95] The 2014 EIA Study projected that, under the

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87 NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (Dec. 2012), https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.
88 *Id.* at 6.
89 *Id.* at 2.
90 *Id.* at 9.
91 *Id.* at 12.
92 *Id.* at 6.
93 *Id.* at 12.
94 U.S. Energy Information Administration, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (Oct. 2014), https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf; Center for Energy Studies at Rice University Baker Institute and Oxford Economics, *The Macroeconomic Impact of Increasing U.S. LNG Exports* (Oct. 29, 2015), https://www.energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf.
95 2014 EIA Study.

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

The 2015 LNG Export Study similarly evaluated the macroeconomic effects of LNG exports ranging from 12 Bcf per day to 20 Bcf per day, and confirmed that increased LNG exports would yield net positive macroeconomic results.[100] The 2015 LNG Export Study found that LNG exports would raise domestic prices and lower international prices.[101] The 2015 LNG Export Study also found that increased exports would lead to small declines in output at the margin for some energy-intensive industries (albeit declines that are offset by positive effects to industries that benefit from increased exports).[102] Nevertheless, the 2015 LNG Export Study found that these potentially adverse outcomes would be offset by the overall net macroeconomic benefits of

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[96] *Id.* at 12.
[97] *Id.*
[98] *Id.*
[99] *Id.* at 24-25.
[100] 2015 LNG Export Study at 82.
[101] *Id.* at 8.
[102] *Id.*

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

Most recently, NERA published another study ("2018 NERA Study") examining the probability and macroeconomic impact of various lower-48 sourced LNG export scenarios.[107] Like the prior studies the DOE/FE has commissioned, the 2018 NERA Study examines the impacts of varying levels of LNG exports on domestic energy markets. However, the 2018 NERA Study also assesses the likelihood of different levels of "unconstrained" LNG exports (defined as market determined levels of exports) and analyzes the outcomes of different LNG export levels on the U.S. natural gas markets and the U.S. economy as a whole, over the 2020 to 2050 time period. Specifically, the 2018 NERA Study develops 54 scenarios by identifying various

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103 *Id.* at 16.
104 *Id.* at 8.
105 *See Cameron LNG*, DOE/FE Order No. 3846, at 109-10.
106 *Id.* at 110.
107 NERA Economic Consulting, *Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports*, at 14 (June 7, 2018), https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf. The DOE/FE submitted the 2018 NERA Study for public comment, and the comment period has now closed.

assumptions for domestic and international supply and demand conditions to capture a wide range of uncertainty in the natural gas markets.[108] "Throughout the entire range of scenarios, [the 2018 NERA Study found] that overall U.S. economic output is higher whenever global markets call for higher levels of LNG exports, assuming that exports are allowed to be determined by market demand."[109] Further, the 2018 NERA Study found that "[f]or each of the supply scenarios, higher levels of LNG exports in response to international demand consistently lead to higher levels of GDP. . . . Consumer welfare, expressed in dollar terms, is also higher when there is greater domestic oil and gas supply" and higher levels of LNG exports.[110]

In an independent analysis commissioned by PALNG Phase II, ICF found that the price increases due to additional LNG exports produced by the Expansion Project will be minimal. As a consequence of growing gas demand and increased reliance on new sources of supply, gas prices are expected to increase in the future, even without any exports from the Expansion Project.[111] Nevertheless, because unconventional production will increasingly be relied upon to offset declining conventional production,[112] and the cost of production of unconventional natural gas is estimated to be much lower on a per-unit basis than that of conventional sources,[113] the natural gas price increase resulting from increased demand will be minimal.[114] In the ICF Base Case, gas prices at Henry Hub are expected to increase gradually from approximately $2.48/MMBtu in 2019

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

109 *Id.* at 14.

110 *Id*. at 18, 20.

111 ICF Report at 33.

112 *Id.* at 13.

113 *Id.* at 14.

114 *Id.* at 33.

to $4.04/MMBtu in 2045.[115] As a result, prices will be high enough to foster sufficient supply development to meet growing demand, but not so high as to discourage the demand growth.[116]

The ICF Report supports the conclusion that the exports proposed in the Non-FTA portion of this Application will have a minimal adverse effect on domestic natural gas prices. According to ICF, by 2046, the average increase in the Henry Hub natural gas price attributable to the Expansion Project is only approximately $0.10/MMBtu, from an estimated 2046 price of $4.19/MMBtu (with some LNG exports, but not the Expansion Project) to a 2046 price with the Expansion Project of $4.29/MMBtu.[117]

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

C. Other Public Interest Considerations

1. Local, Regional, and National Economic Benefits

The Expansion Project will have a positive impact on the local, regional, and national economies through increased economic activity, tax revenues, and job creation during both construction and operation.[118] The ICF Report finds that the construction and operation of the

[115] *Id.*
[116] *Id.*
[117] *Id.* at 49.
[118] In addition to the local, regional, and national economic benefits that will result from construction and operation of the Expansion Project, PALNG Phase II's resource reports analyze the economic and environmental benefits resulting from increased natural gas exports from the Expansion Project.

Expansion Project will result in significant employment impacts across a number of industries, both locally and nationwide.[119]

Through 2046, the estimated total economic gains associated with the Expansion Project are over $5.7 billion annually for the U.S. economy, including $1.1 billion annually for the Texas economy.[120] On an annual basis, the Expansion Project will create an average of nearly 27,700 jobs for the U.S. economy per year from 2021 through 2046.[121] The Expansion Project is expected to result in approximately 9,000 jobs annually in Texas over the same forecast period.[122] As a result of this substantial job creation, the Expansion Project will lead to a cumulative impact of over 720,900 job-years for the U.S. economy as a whole, and 232,700 job-years for the Texas economy through 2046.[123]

Further, the Expansion Project will increase tax revenues on both the state and federal level. Total government revenues in Texas are estimated to increase by $140.2 million annually through 2046[124] as a result of the Expansion Project.[125] This equates to a cumulative impact on Texas government revenues of approximately $3.6 billion.[126] Exports from the Expansion Project are estimated to result in an increase in collective government revenues of $1.9 billion annually.[127] This translates to a cumulative impact of 49.0 billion of governmental revenue over the forecast period between 2021 and 2046.[128]

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[119] ICF Report at 10.
[120] *Id.*
[121] *Id.*
[122] *Id.*
[123] *Id.*
[124] These revenues do not reflect tax abatements for the which the Expansion Project may qualify.
[125] ICF Report at 57.
[126] *Id.*
[127] *Id.* at 53.
[128] *Id.*

2. Increased Exports and International Trade

According to ICF, The Expansion Project will generate an expected cumulative value of approximately $77.3 billion of LNG exports over a projected 20-year export term, which will favorably influence the balance of trade that the United States has with its international trading partners.[129] In 2019, the U.S. trade deficit increased to $48.9 billion, reflecting $209.6 billion in exports and $258.5 billion in imports.[130] The expected value of the exports from the Expansion Project is estimated to reduce the U.S. balance of trade deficit by $3.7 billion annually between 2026 and 2046, based on the value of LNG export volumes, liquids produced in association with incremental gas and other trade effects.[131]

LNG exports will increasingly diversify the global supply of energy resources, which will support the geopolitical security interests of the United States by providing energy supply alternatives to its allies. The export of domestically produced LNG will promote liberalization of the global gas market by fostering increased liquidity and trade at prices established by market forces. Though the price of LNG has recently been volatile, the price of LNG in Asian markets remains higher than that of U.S. LNG.[132]

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[129] *Id*. at 55.

[130] U.S. Department of Commerce Bureau of Economic Analysis, *U.S. International Trade in Goods and Services* (Feb.5, 2020), https://www.bea.gov/index.php/news/2020/us-international-trade-goods-and-services-december-2019.

[131] ICF Report at 55.

[132] *See, e.g., See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (Feb 4, 2020), http://pubdocs.worldbank.org/en/596831580311438199/CMO-Pink-Sheet-February-2020.pdf (the average natural gas price in January 2020 was $2.03 per MMBtu in the United States, while the average price was $10.08 per MMBtu in Japan)); *see also* Federal Energy Regulatory Commission Market Oversight, *World LNG Estimated Landed Prices* (Dec. 2019), https://www.ferc.gov/market-assessments/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf (average estimated LNG landed price of $5.22 in India, $5.42 in Korea, and $5.42 in China as of December 2019).

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

3. Environmental Benefits

LNG exports can have significant environmental benefits as natural gas is cleaner burning than other fossil fuels. For example, the DOE's Life Cycle Analysis Greenhouse Gas ("GHG") Report ("2014 GHG Report") noted that under most scenarios analyzed in the report, "generation of power from imported natural gas [into both Europe and Asia] has lower life cycle GHG emissions than power generation from regional coal."[133] In 2018, the Department of Energy commissioned an update to its 2014 GHG Report, entitled Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas From the United States: 2019 Update ("2019 GHG Report Update").[134] As with the 2014 GHG Report, the 2019 GHG Report Update compared life cycle GHG emissions of exports of domestically produced LNG to Europe and Asia, compared with alternative fuel sources (such as regional coal and other imported natural gas) for electric power generation in the destination countries. The 2019 GHG Report Update demonstrated that the conclusions of the 2014 GHG Report remained the same – *i.e.*, that the use of U.S. LNG exports for power production in European and Asian markets will not increase global GHG emissions from a life cycle perspective, when compared to regional coal extraction and consumption for power production.[135] Accordingly, an increased supply of natural gas made possible through LNG exports can help countries move away from less environmentally friendly fuels by displacing the

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

[134] Nat'l Energy Tech. Lab., Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update (DOE/NETL 2019/2041) (Sept. 12, 2019).

[135] *See id*. at 78, 85.

current consumption of coal in power generation and deterring the construction of additional coal-fired generation capacity.

VI. ENVIRONMENTAL IMPACTS

The construction and operation of the Expansion Project will be subject to authorization by FERC. As discussed above, the Expansion Project has undergone the mandatory six-month FERC pre-filing process that is the first step in the comprehensive and detailed environmental review of the project that will be conducted by FERC in compliance with NEPA prior to authorizing the construction of the Expansion Project facilities. The pre-filing process culminated in PALNG Phase II's filing of its application with FERC on February 19, 2020, in which PALNG Phase II included 13 publicly available resource reports that assess the impacts of the Expansion Project on existing land, water, and air resources and discuss measures to mitigate potential impacts.

As required by NEPA and the FERC's regulations, PALNG Phase II will design and construct the Expansion Project facilities to minimize or mitigate any adverse environmental impacts. The environmental impacts for the Expansion Project are similar in character and less in degree than those analyzed and addressed as part of the Base Project in the FERC's April 18, 2019 order, where the site was found to be an acceptable location for siting a LNG facility and to have minimal adverse impacts.[136] These known impacts have been identified and addressed early in the planning and development of the Expansion Project.

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[136] *See* Final Environmental Impact Statement for the Port Arthur LNG, LLC's Port Arthur Liquefaction Project, FERC Docket No. CP17-20-000 (Jan. 31, 2019) (Accession No. 20190131-3023).

In addition to the authorizations from the DOE/FE sought in this Application and the authorizations from the FERC, PALNG Phase II will seek the necessary permits from, and consultations with, other federal, state, and local agencies.

VII. APPENDICES

The following attachments and appendices are included with this Application:

Verification

Appendix A: Opinion of Counsel

Appendix B: ICF Report

Appendix C: PALNG Phase II Ownership Structure

VIII. CONCLUSION

For the reasons set forth above, PALNG Phase II respectfully requests that the DOE/FE issue an order granting PALNG Phase II authorization to export, on its own behalf and as agent for others the equivalent of 698 Bcf/y (approximately 1.9 Bcf/d) as LNG from the United States to FTA and Non-FTA countries, as described herein. PALNG Phase II requests each of these authorizations for the term specified herein commencing on the earlier of the date of first export or seven years from the date the requested authorizations are granted.

Respectfully submitted,

/s/ Jerrod L. Harrison_____

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/s/ Brett A Snyder_____

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Counsel for Port Arthur Phase II, LLC

Dated February 28, 2020

VERIFICATION

I, Glen A. Donovan, declare that I am Vice President – Finance for Port Arthur LNG Phase II, LLC and am duly authorized to make this Verification; that I have read the foregoing instrument and that the facts therein stated are true and correct to the best of my knowledge, information and belief.

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

Executed in San Diego, California on February 27, 2020.

Glen A. Donovan
Vice President – Finance
Port Arthur LNG Phase II, LLC
488 8th Avenue
San Diego, CA 92101

APPENDIX A

Opinion of Counsel

OPINION OF COUNSEL

February 28, 2020

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

RE: *Port Arthur LNG Phase II, LLC*
Application for Long-Term, Multi-Contract Authorizations to Export Liquefied Natural Gas from the United States to Free Trade Agreement and Non-Free Trade Agreement Nations

Dear Ms. Sweeney:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the United States Department of Energy, 10 C.F.R. $ 590.202(c) (2019). I am counsel to Port Arthur LNG Phase II, LLC ("PALNG Phase II").

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

Respectfully submitted,

/s/ Jerrod L. Harrison
Senior Counsel
488 8th Avenue
San Diego, CA 92101
619-696-2987
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On Behalf of Port Arthur LNG Phase II, LLC

APPENDIX B

ICF Report

Economic Impacts of the Proposed Port Arthur Trains 3 & 4 Liquefaction Project:
Information for DOE Non-FTA Permit Application

February 13, 2020

Submitted by: ICF

Contact:
Harry Vidas
(703) 218-2745
Harry.Vidas@icf.com

Submitted to:

Port Arthur LNG
2925 Briarpark Drive, Suite 900
Houston, TX 77042

Table of Contents

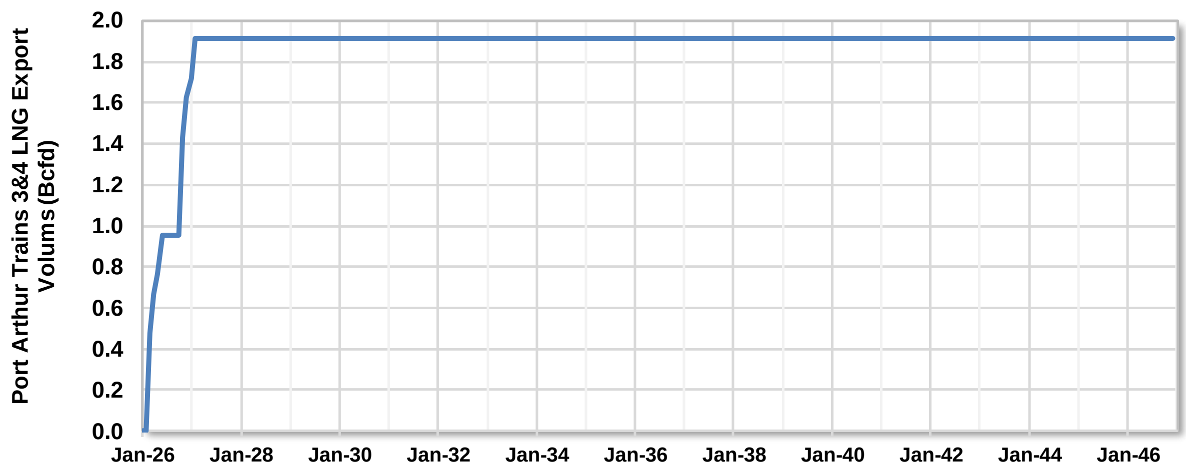
List of Exhibits

1. Executive Summary

1.1. Introduction

ICF conducted an analysis on behalf of Port Arthur LNG to assess the market and economic impacts of the proposed expansion of Port Arthur LNG export facility to add Trains 3 and 4 (Port Arthur T3 & T4). This facility is located in Port Arthur, Texas. The two new LNG trains are proposed to come on-line in the first (T3) and fourth (T4) quarters of 2026, with a combined export capacity of 673 billion cubic feet (Bcf) per year (13.5 million metric tons per annum), or 1.84 billion cubic feet per day (Bcfd), as shown in Exhibit 1-1: Port Arthur LNG T3 & T4 Export Volumes.

Exhibit 1-1: Port Arthur LNG T3 & T4 LNG Export Volumes



Source: Port Arthur LNG

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Port Arthur T3 & T4 expansion. 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 expansion of Port Arthur export facility;
2) **Impact Case** - Base Case with 1.84 Bcfd of additional export volumes from the Port Arthur T3 & T4 expansion.

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

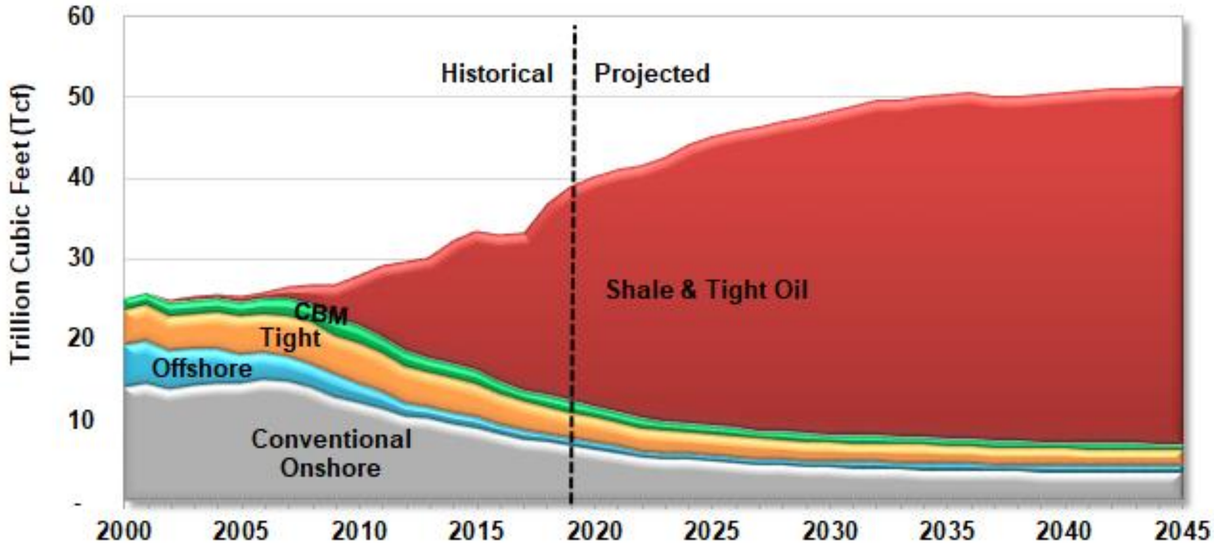
- **Assess natural gas and liquids production changes:** From the GMM run results, we first estimated natural gas and liquids (including oil, condensate, and natural gas liquids (NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for the Port Arthur T3 & T4 expansion. 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 upstream capital and operating expenditures that will be required for the additional production. In addition, based on cost estimates for the Port Arthur T3 & T4 expansion and other data, ICF estimated the incremental midstream and downstream annual capital and operating expenditures to support the expansion of LNG exports at the Port Arthur facility.
- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant, midstream 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 capital and operating expenditures and changes in hydrocarbon and LNG liquefaction outputs 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 to continue with production reaching 51 Tcf per year (140 Bcfd) by 2045, an increase of 15 Tcf per year (40 Bcfd) over 2018’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



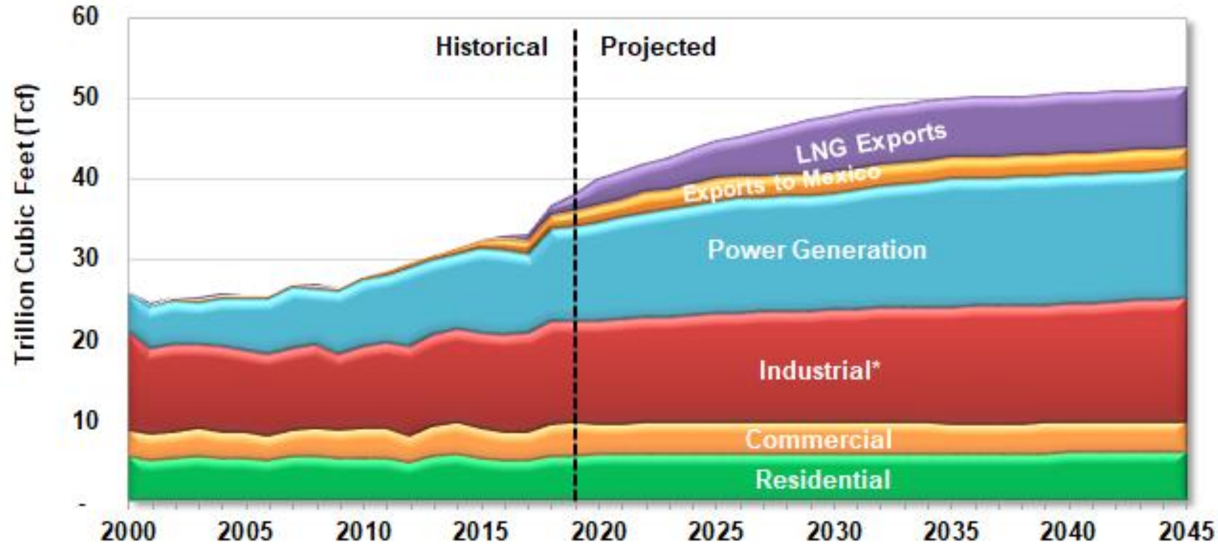
Source: ICF GMM® Q3 2019

In the long-term, the power sector presents the largest single source of incremental domestic U.S. and Canadian gas consumption, though near-term gas market growth is driven by growth in export markets (LNG and pipeline exports to Mexico). About 62 percent of the domestic growth comes from the power sector, which increases from 11 Tcf in 2018 to 16 Tcf per year (44 Bcfd) by 2045. Base Case feed gas deliveries for U.S. LNG exports are projected to reach 17.5 Bcfd by 2040, with volumes from the Gulf Coast expected to reach 16.3 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 Port Arthur T3 & T4 expansion volumes associated with this economic impact analysis. Mexican Exports grow to 2.6 Tcf (7.2 Bcfd) by 2040.

Exhibit 1-3 shows ICF's Base Case U.S. and Canadian consumption forecast by sector. Assuming no exports from Port Arthur T3 & T4, U.S. and Canadian natural gas consumption in 2045 is expected to be over 41 Tcf, including all Base Case LNG and pipeline exports. This increased demand growth will push the Henry Hub gas price above $3.00 per MMBtu[1] by 2028, with long-term prices expected to range between $3.00 and $4.00 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.

[1] All dollar figure results in this report are in 2018 real dollars, unless otherwise specified.

Exhibit 1-3: U.S. and Canadian Gas Consumption by Sector and Exports



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q3 2019

1.3. Key Study Results

ICF's analysis shows that the volume exported via the Port Arthur T3 & T4 expansion has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.10/MMBtu (in real 2018 dollars) on an annual average basis for the forecast period of 2026 to 2046, averaging $3.69/MMBtu, with the export expansion included in the scenario, compared with $3.59/MMBtu without the export facility in the scenario. The natural gas prices at Henry Hub are expected to reach $4.19/MMBtu in the Base Case and $4.29/MMBtu in the expansion case by 2046, indicating a price increase of $0.10/MMBtu attributable to the 1.84 Bcfd higher export volumes in the last year of analysis.

The Port Arthur T3 & T4 expansion 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 2026 to 2046 are 13.8 Tcf. This represents (a) roughly 1.0% 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) 2.1% of the total U.S. domestic natural gas consumption during the same 20-year period.

Exhibit 1-4: Natural Gas Price Impact of the Port Arthur T3 & T4 Expansion

Year	Henry Hub Natural Gas Price (2018$/MMBtu)		
	Base Case	Impact Case	Impact Case Change
2025	$ 2.85	$ 2.85	$ -
2026	$ 2.88	$ 2.96	$ 0.08
2031	$ 3.48	$ 3.59	$ 0.10
2036	$ 3.31	$ 3.43	$ 0.11
2041	$ 3.99	$ 4.10	$ 0.10
2046	$ 4.19	$ 4.29	$ 0.10
2026-2046 Avg	**$ 3.59**	**$ 3.69**	**$ 0.10**

Source: ICF

ICF's analysis concluded that activity in the U.S. to support Port Arthur T3 & T4 expansion could lead to significant economic impacts, on average, creating roughly 27,700 jobs annually for the U.S. economy, and about 9,000 jobs in Texas from the start of the construction in 2021 through 2046. This means a cumulative impact through 2046 of 720,900 job-years for the U.S. and about 232,700 job-years in Texas. In addition, the project could add $5.7 billion to the U.S. economy annually ($148.6 billion over the forecast period), including $1.1 billion annually in Texas ($28.5 billion over the forecast period). The additional LNG exports from the expansion would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $1.9 billion annually; and Texas state and local tax revenues are expected to increase by about $140 million annually. Throughout the forecast period, the U.S. will receive $49.0 billion additional revenue from taxes and Texas will receive $3.6 billion.

Exhibit 1-5: Economic and Employment Impacts of the Port Arthur T3 & T4 Expansion

Region	2021-2046 Average Annual Impact			2021-2046 Cumulative Impact		
	Jobs (Jobs)	Value Added (2018$ Million)	Government Revenues (2018$ Million)	Jobs (Job-years)	Value Added (2018$ Million)	Government Revenues (2018$ Million)
U.S.	27,728	$ 5,716	$ 1,884	720,930	$ 148,621	$ 48,972
Texas	8,951	$ 1,096	$ 140	232,729	$ 28,501	$ 3,646

Source: ICF

2. Introduction

Port Arthur LNG tasked ICF with assessing the economic and employment impacts of expanding liquefied natural gas (LNG) exports from its Port Arthur, Texas LNG export facility. Exhibit 2-1 shows Port Arthur's location.

Exhibit 2-1: Port Arthur LNG Location Map

The proposed expansion of Port Arthur LNG export facility would add Trains 3 and 4. The first of the two new LNG trains is proposed to come on-line in the first quarter of 2026 and the second in the last quarter of 2026. The two new trains will have a combined export capacity of 673 billion cubic feet (Bcf) per year (13.5 million metric tons per annum), or 1.84 billion cubic feet per day (Bcfd). Trains 3 and 4 are "twins" of Trains 1 and 2, and would, thus, double the capacity of the facility.

For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the Port Arthur expansion 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) Energy Market and Economic Impacts of the Port Arthur Expansion
6) Bibliography
7) Appendices

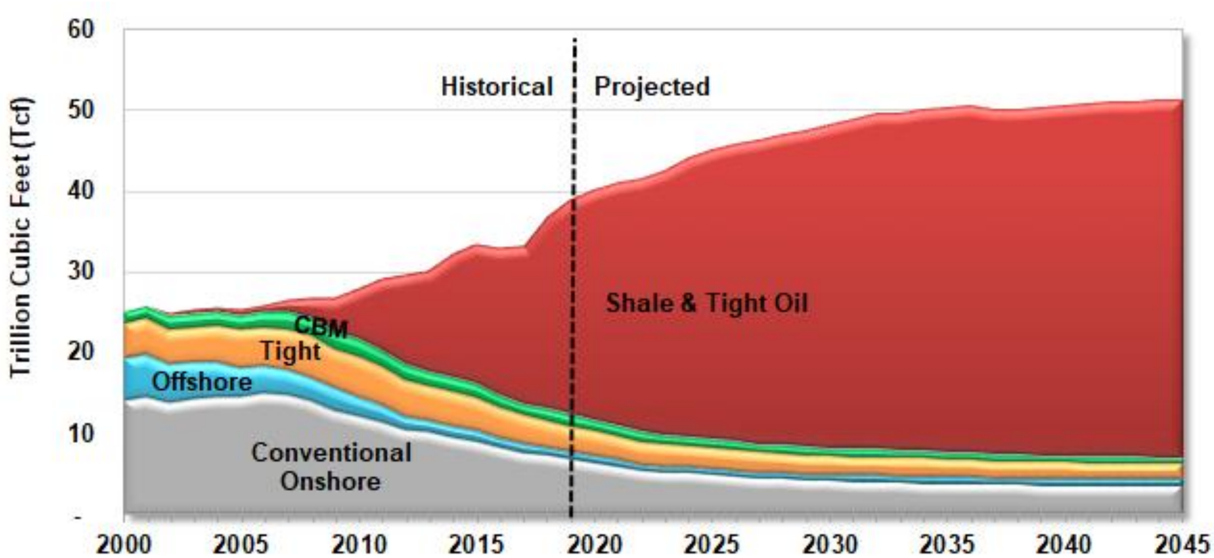
3. Base Case U.S. and Canadian Natural Gas Market Overview

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 with 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



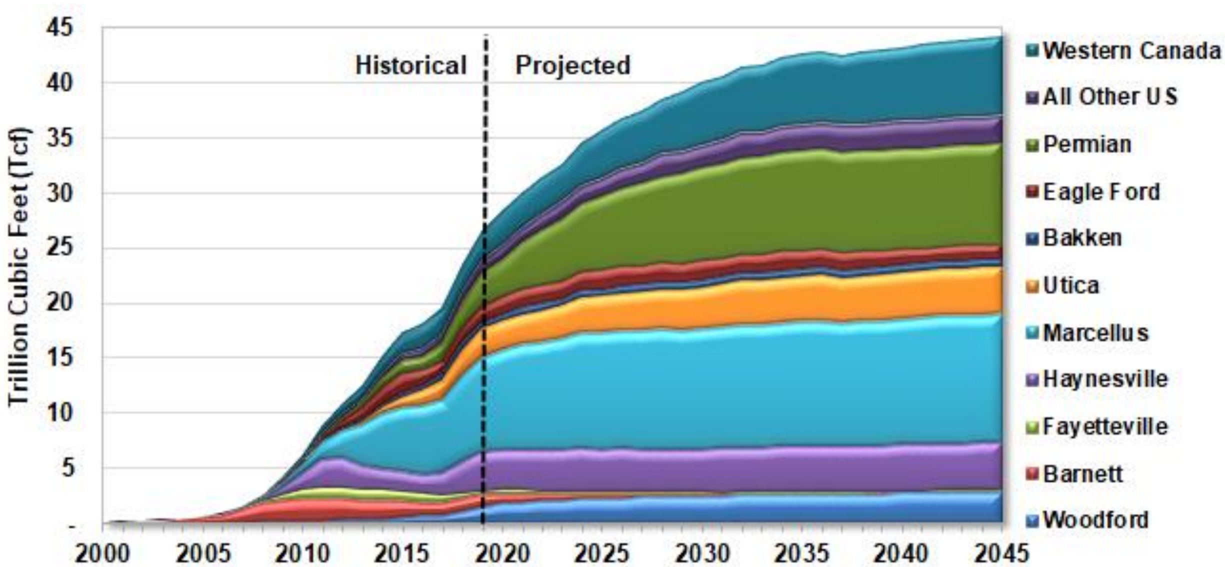
Source: ICF GMM® Q3 2019

Production from U.S. and Canadian shale formations will grow from 23.5 Tcf per year (64.4 Bcfd) in 2018 or 64 percent of total production to 44.2 Tcf per year (121 Bcfd) by 2045 or 86 percent of total production (see exhibit above). The projection assumes West Texas Intermediate (WTI) crude price of $75/bbl. ($2018).

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[2] production from the lower cost Permian basin will reach 9.2 Tcf per year (25 Bcfd) by 2045, mostly gas associated with tight oil, from about 2.5 Tcf (6.7 Bcfd) in 2018.

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 2019

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.[3] 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.

[2] Dry gas is natural gas which remains after processing plant separation, also known as consumer-grade natural gas.
[3] 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.

ICF has developed resource cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the cost curves are all of the resources discussed above – proven reserves, growth, new fields, 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.[4,5,6] 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

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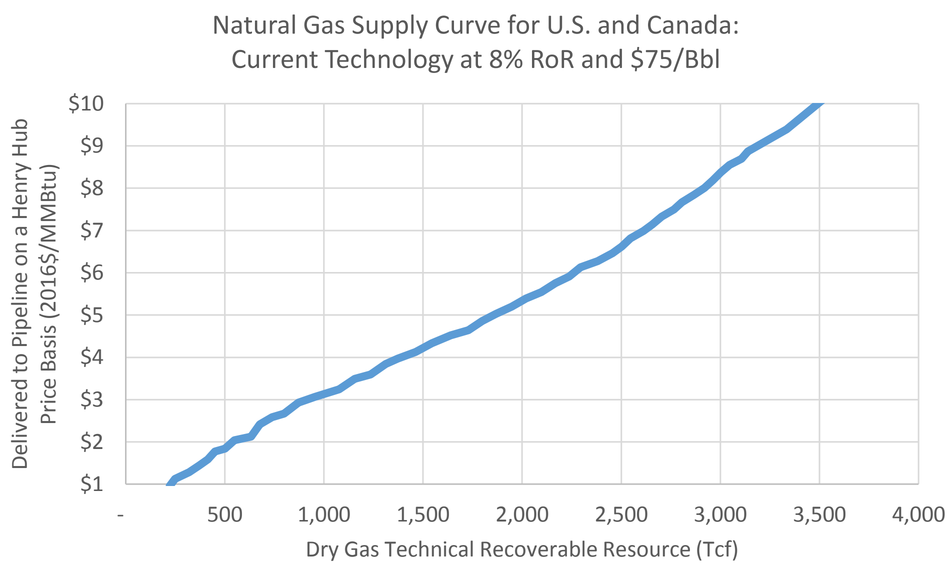
[4] American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.
[5] Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/
[6] U.S. Energy Information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

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.

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.)

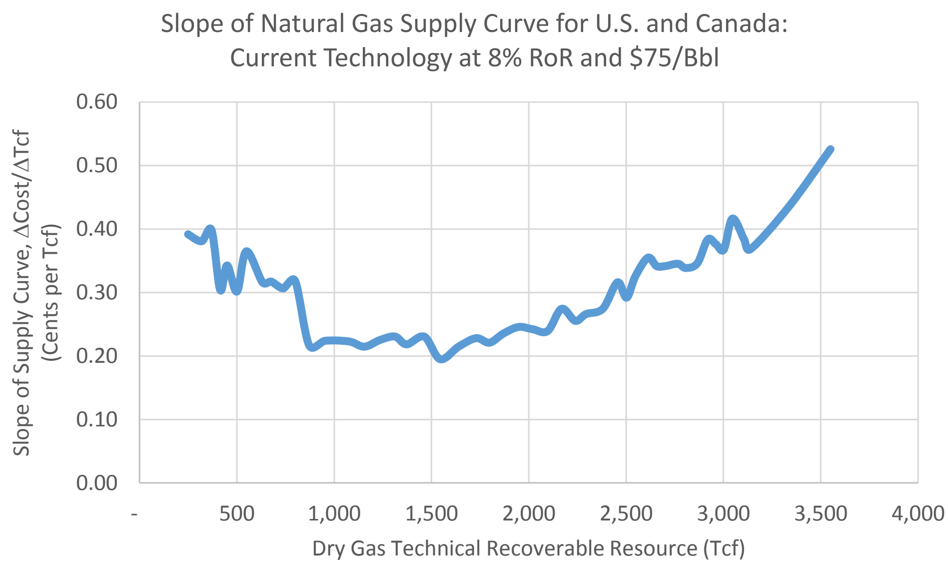
Exhibit 3-3: U.S. and Canada Natural Gas Supply Curves



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 gas 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.[7]

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.

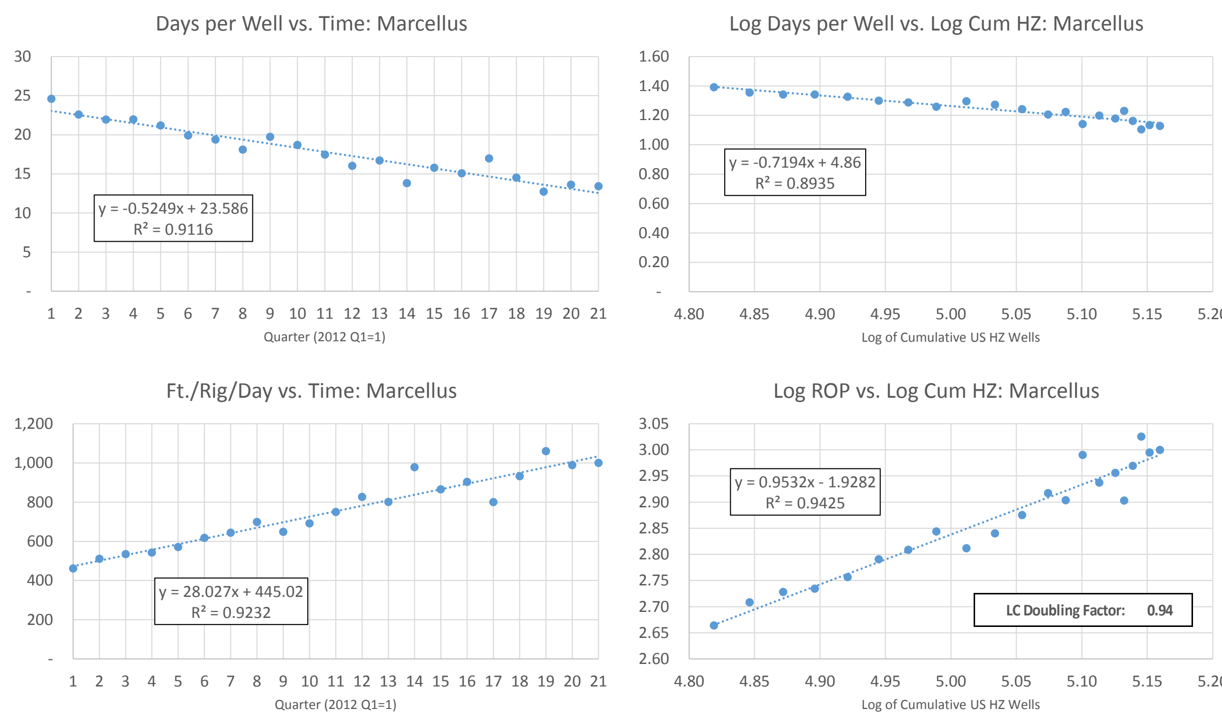
[7] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

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 (1st quarter 2012 to 1st 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[8] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What these mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

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

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

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

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

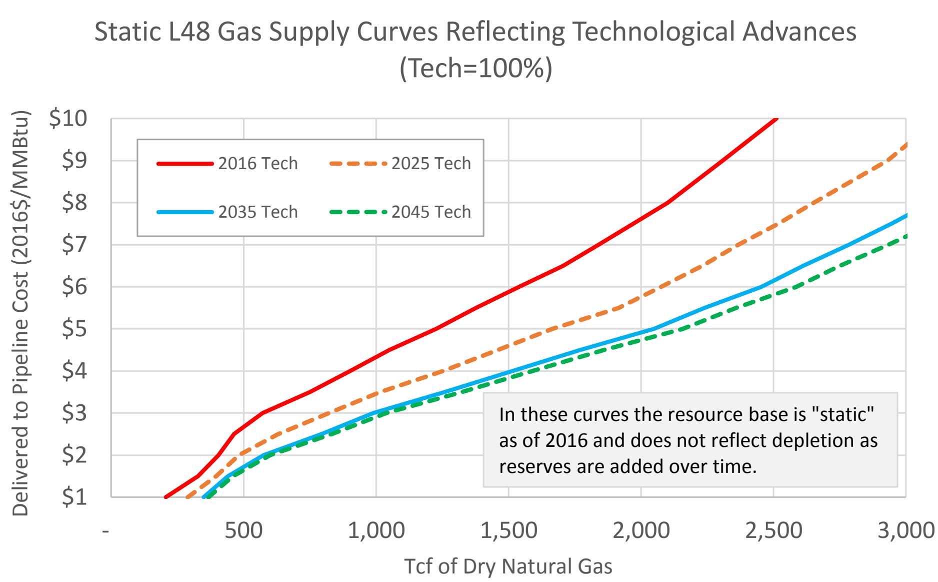
[8] Doubling factor = 2^C-1 where C is the regression slope coefficient.

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 resources 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 percent per year net reduction in cost per unit of production).

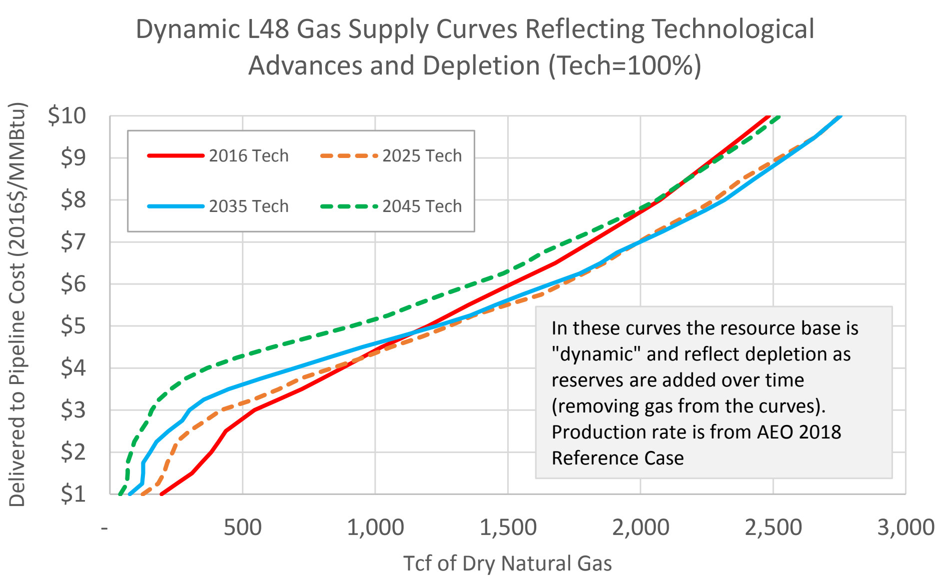
Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



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 updated report to API on the impact of LNG exports on the U.S. economy[9].) 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.

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.

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[9] 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

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.[10]

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 estimate published in July 2017 was 3,141 Tcf (including proven reserves) which was 10% greater than its estimate published two years earlier.[11] In 2019 the Potential Gas Agency assessment grew another 22% to 3,838 Tcf. This means that over this four-year period the PGC assessments grew at an annual rate of 246 Tcf per year.

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[10] 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/
[11] 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.[12] 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 246 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.

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

3.1.4. Resource Base Estimate Comparisons

The ICF gas resource base is higher than many published assessments. As noted above, the ICF Lower-48 gas assessment of 3,693 Tcf is greater than the EIA's 2,462 Tcf assumption but slightly lower than PGC's latest 3,838 Tcf assessment.

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.

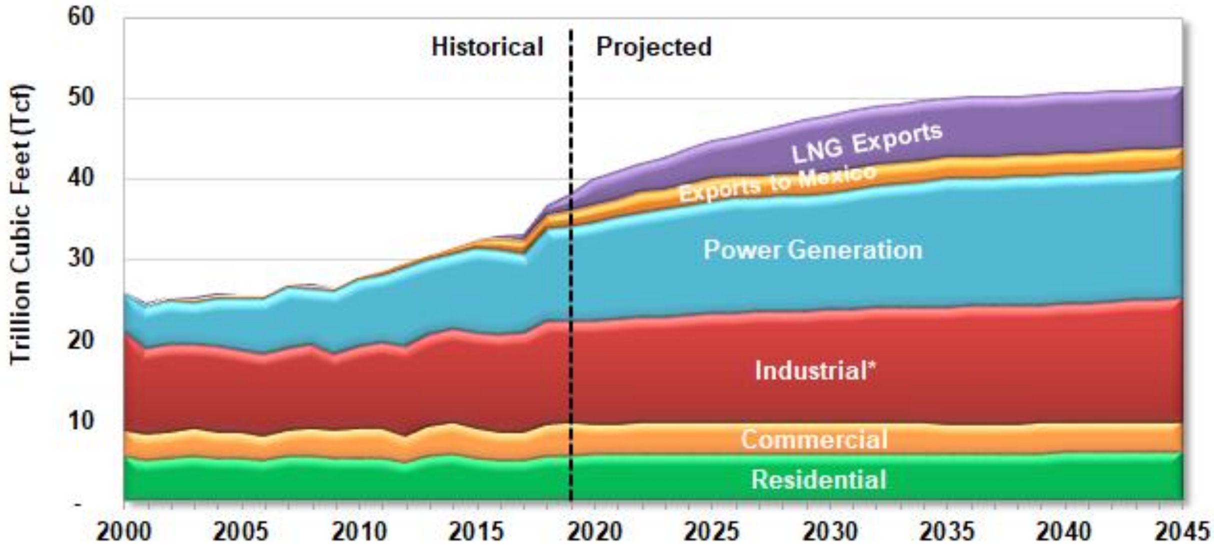
3.2. U.S. and Canadian Natural Gas Demand Trends

While new LNG export facilities in the U.S. started production in 2016, 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 Port Arthur T3 & T4, U.S. and Canadian natural gas consumption in 2045 is expected to be over 41 Tcf (LNG and pipeline exports included).

Feed gas deliveries for U.S. LNG exports are projected to reach 6.4 Tcf per year (17.5 Bcfd) by 2040, with volumes from the Gulf Coast expected to reach 6.0 Tcf per year (16.3 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 2018 and 2045 is expected to comprise the largest share of total incremental U.S. and Canadian gas demand growth over the period, with gas-fired power generation expected to increase significantly over time. Gas use for power generation will increase from about 11 Tcf (31 Bcfd) in 2018 of total demand to 16 Tcf per year (44 Bcfd) by 2045. This represents about 31 percent of the total gas demand growth.

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



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q3 2019

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 2020 onward. Electricity load growth is expected to average only about 0.67 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 5,400 Terawatt-hours (TWh) (4,700 TWh in the U.S.) per year by 2045, or growth nearing 16 percent over 2018 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 of 40 percent in gas use in the power generation market from 2018 to 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.

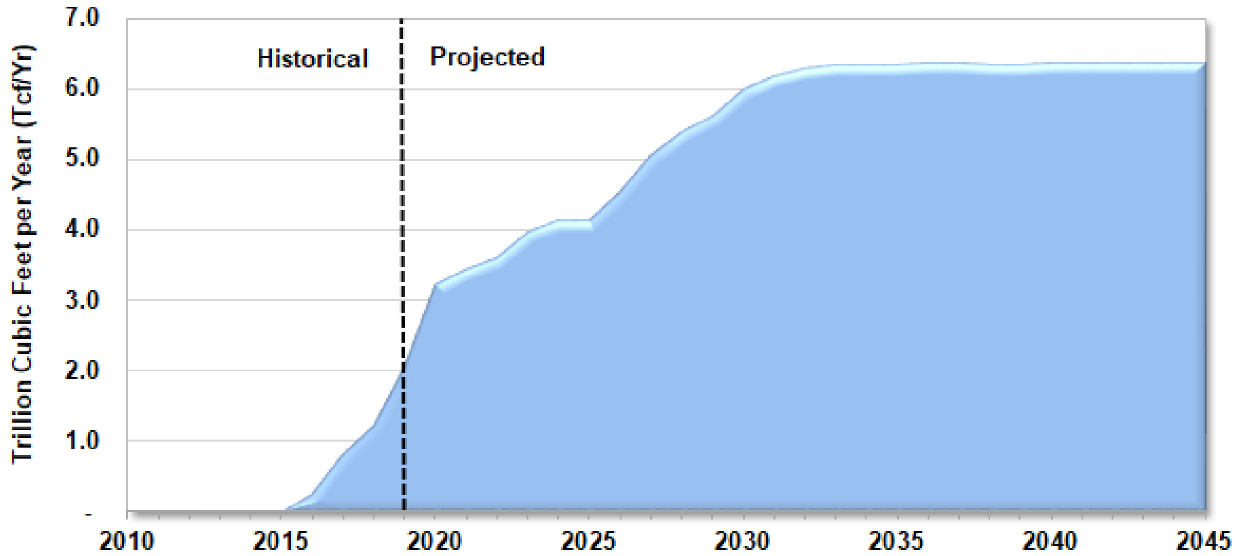
Industrial demand accounts for 34 percent of total gas demand growth in U.S. and Canada during the 2018-2045 period. A large share of the industrial gas demand increase is from development of the western Canadian oil sands. Excluding natural gas use for oil sands, the growth in industrial sector gas demand in the Base Case is relatively small, as reducing energy intensity (i.e., energy input per unit of industrial output) remains a top priority for manufacturers.

Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the residential and commercial sectors, which lead to lower per-customer gas consumption. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The Base Case assumes that the growth of NGVs is primarily in fleet vehicles (e.g., urban buses), and vehicular gas consumption is not a major contributor to total demand growth. In addition, pipeline exports to Mexico are expected to increase to over 2.6 Tcf (7.3 Bcfd) by 2045, up from 1.7 Tcf (4.6 Bcfd) in 2018.

3.2.1. LNG Export Trends

The U.S. Department of Energy (DOE) has received 55 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, 38 applications at 22 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 6.3 Tcf per year (17.5 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 about 8.9 Bcfd by 2020 and as oil prices increase, the export volume is projected to be about 16.4 Bcfd by 2030 and 17.5 Bcfd by 2040 (see exhibit below).

Exhibit 3-10: U.S. Base Case LNG Exports

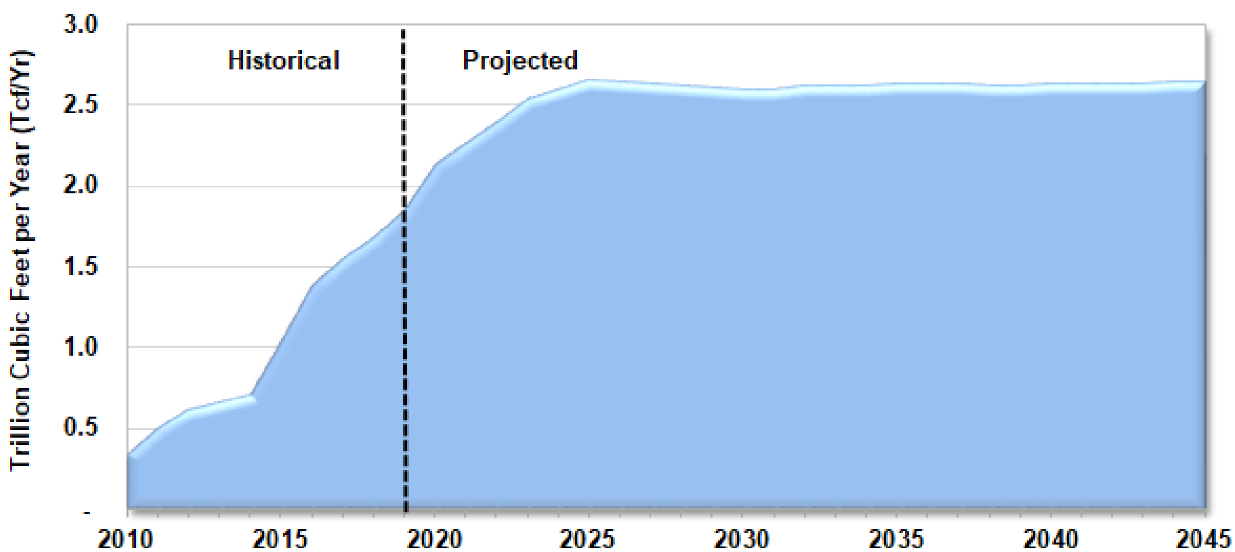


Source: ICF GMM® Q3 2019

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 1.7 Tcf per year (4.6 Bcfd) in 2018, led by increased demand from Mexican power generation gas markets. The growth is expected to continue and the ICF Base Case projects the exports to reach 2.7 Tcf per year (7.3 Bcfd) by 2025 and then level off until 2040.

Exhibit 3-11: Base Case Exports to Mexico



Source: ICF GMM® Q3 2019

There is 14 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 2021.

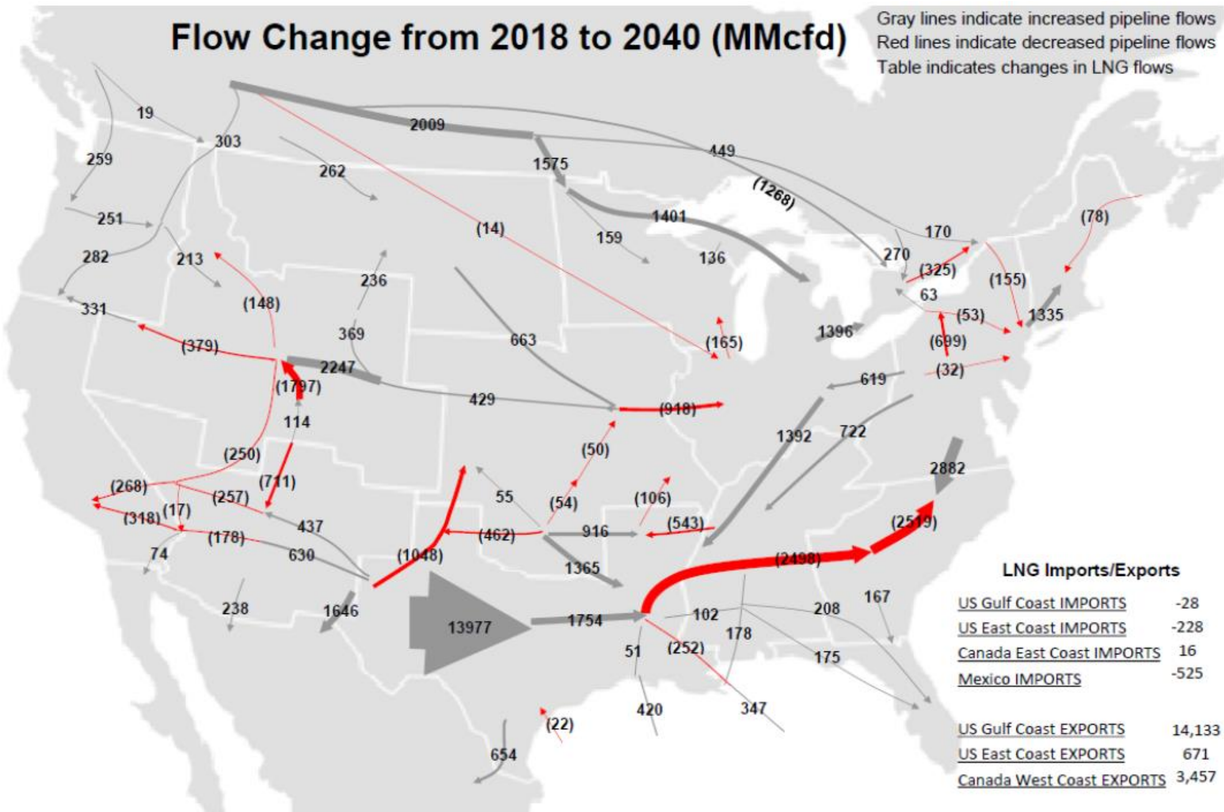
Mexican demand for natural gas will be influenced by many factors including the growth of the overall economy and its energy-intensive sectors, relative energy prices, and government policies encouraging the substitution of natural gas for coal in the power sector. Mexican natural gas supply will be 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 2018 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 2018 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 (ICF Base Case)



Source: ICF GMM® Q3 2019

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 and New Mexico becomes an increasingly important source of gas for the Gulf Coast.

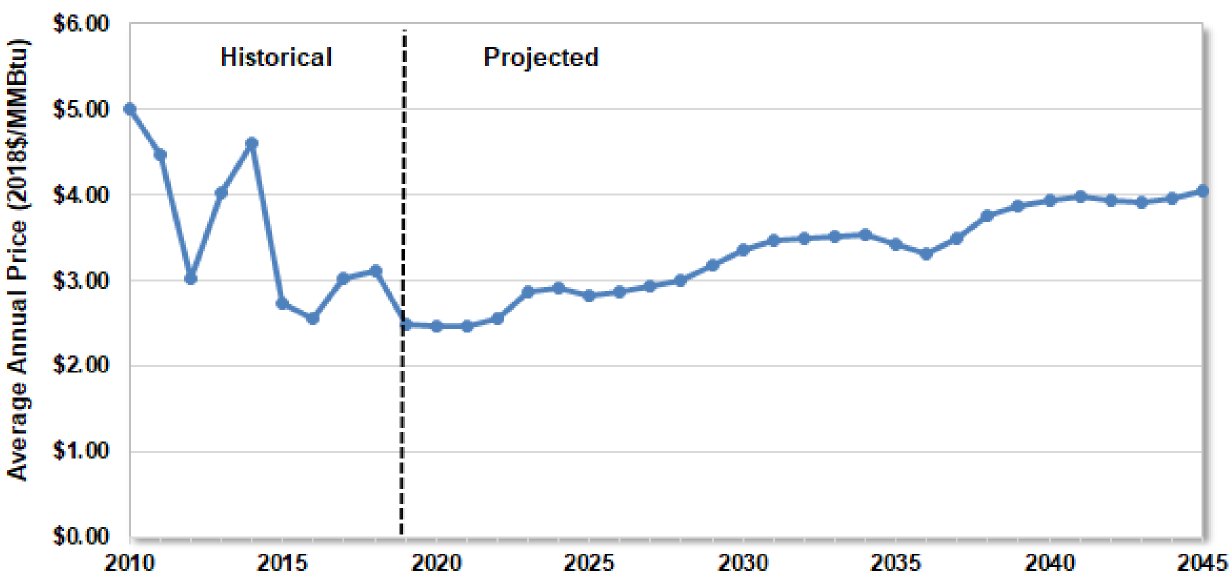
Eastward flows from western Canada will slightly increase. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong industrial 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 2023. 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 $2.48 per MMBtu in 2019 to $4.04 per MMBtu by 2045 with average of about $3.32 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 Base Case Prices for Henry Hub

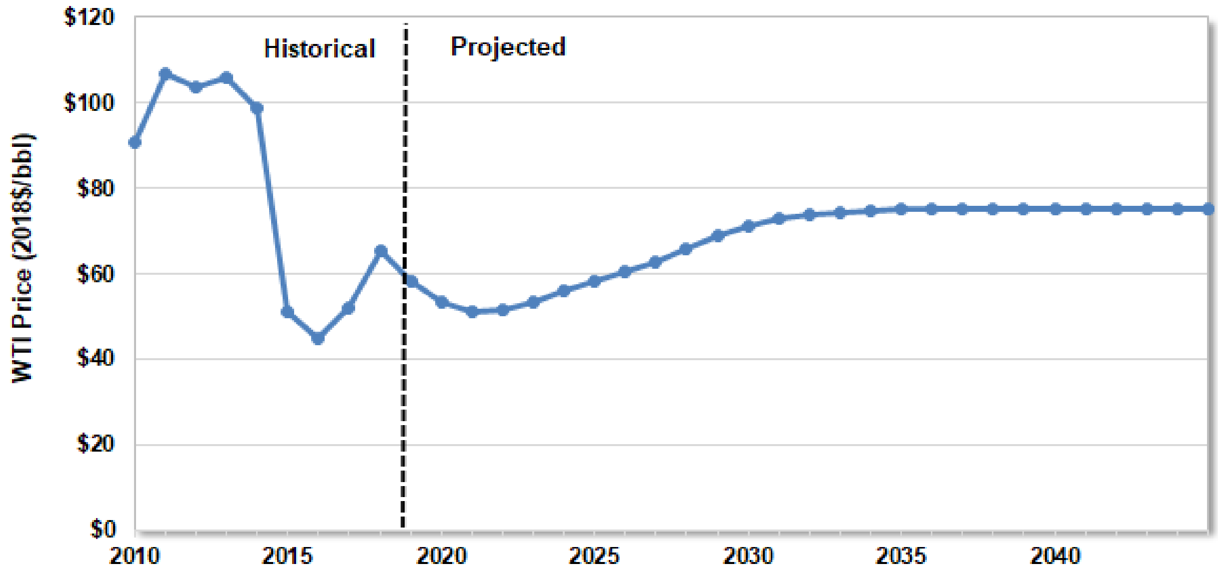


Source: ICF GMM® Q3 2019

3.5. Oil Price Trends

ICF assumes that crude 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. (2018 dollars) after 2035 as shown in the exhibit below.

Exhibit 3-14: ICF WTI Oil Price Assumptions



Source: ICF GMM® Q3 2019

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.

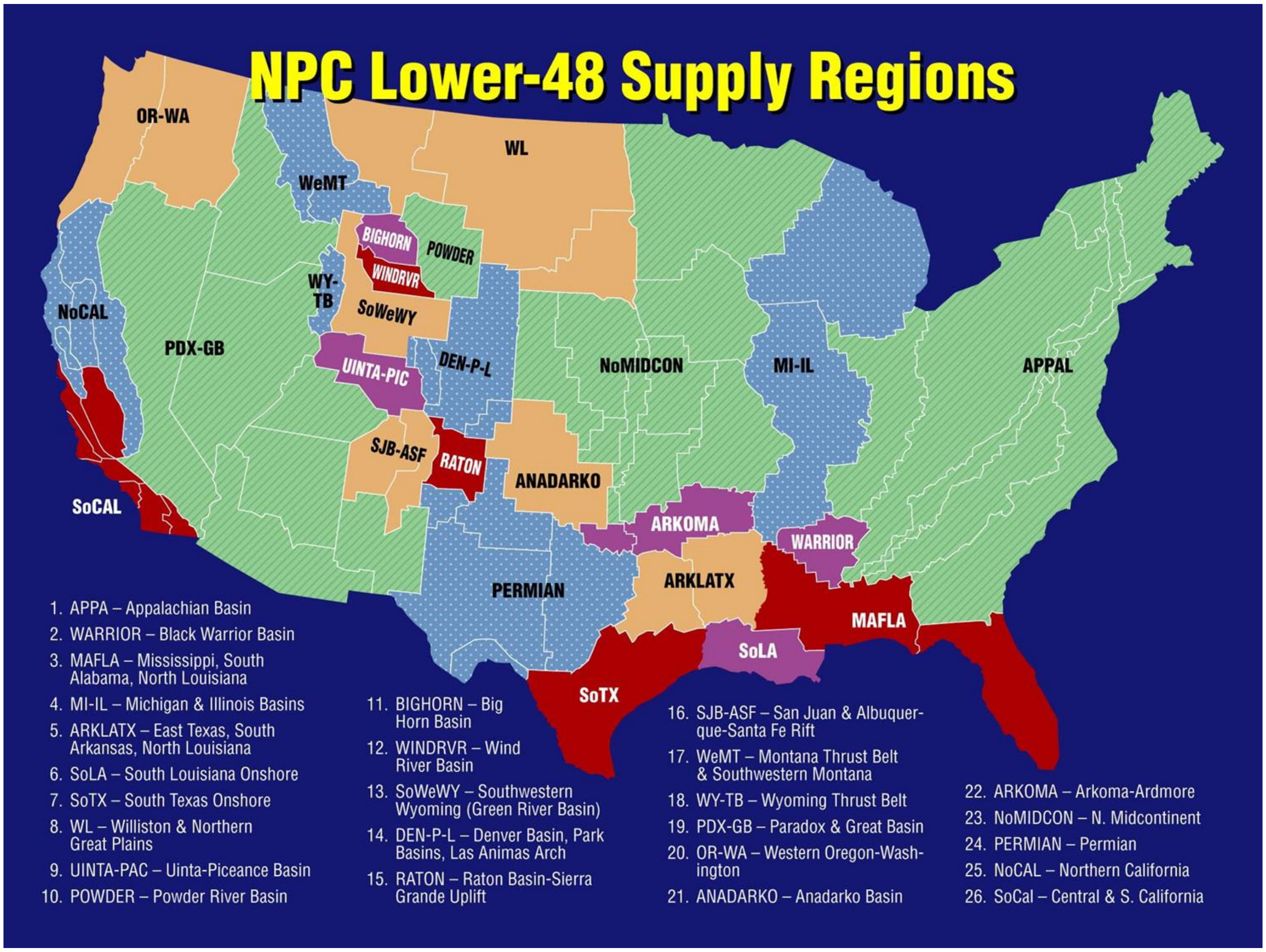
4.1.1. Conventional Undiscovered Fields

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.[13] Gas resources

[13] 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**	

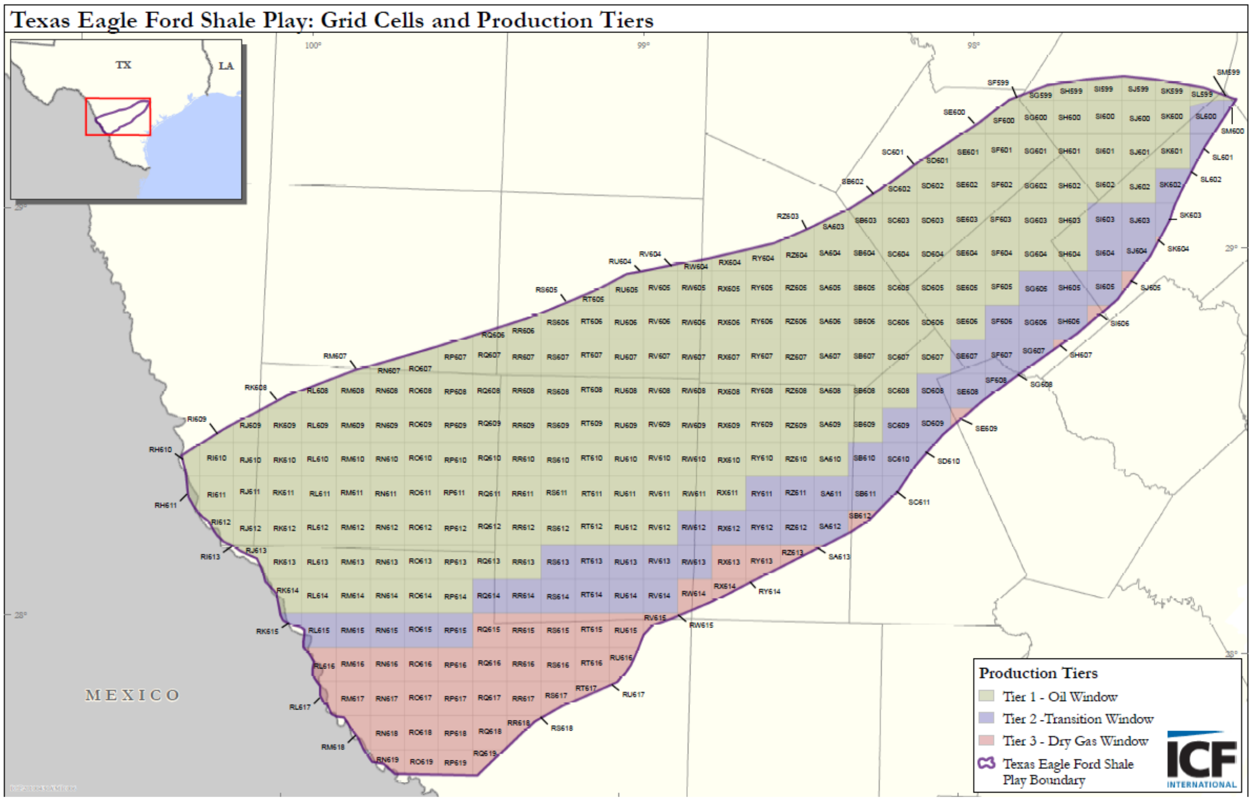
No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Coalbed Methane		
36	San Juan Fruitland	8,800	160
	L-48 GIS Assessed Coalbed Methane Total	**8,800**	
37	Horseshoe Canyon	24,740	80
38	Mannville	46,760	320
	Canada GIS Assessed Coalbed Methane Total	**71,500**	
	Tight Oil		
39	Anadarko Mississippi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

Port Arthur LNG tasked ICF with assessing the economic and employment impacts of LNG exports from its proposed expansion. This study analyzed two cases[14]:

1) **Base Case** with the assumption of no expansion.
2) **Impact Case** with the assumption of 673 Bcf per year, or 1.84 Bcfd higher than the Base Case due to the construction of Port Arthur Trains 3 and 4.

The results in this report show the changes between the Base Case and Impact 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 and pipeline capital and operating expenditures: Based on the expansion’s cost estimates and other data, ICF determined the annual midstream and downstream 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 upstream 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.

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.

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

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:

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

Year	Impact Case Changes		
	LNG Export Volume Assumptions (Bcfd)	LNG Capital Costs (2018$ MM)	LNG Operating Costs (2018$ MM)
2018	-	-	-
2019	-	-	-
2020	-	-	-
2021	-	$39	-
2022	-	$1,059	-
2023	-	$1,066	-
2024	-	$1,130	-
2025	-	$1,134	-
2026	0.79	$975	$144
2027	1.83	-	$173
2028	1.84	-	$173
2029	1.84	-	$173
2030	1.84	-	$173
2031	1.84	-	$173
2032	1.84	-	$173
2033	1.84	-	$173
2034	1.84	-	$173
2035	1.84	-	$173
2036	1.84	-	$173
2037	1.84	-	$173
2038	1.84	-	$173
2039	1.84	-	$173
2040	1.84	-	$173
2041	1.84	-	$173
2042	1.84	-	$173
2043	1.84	-	$173
2044	1.84	-	$173
2045	1.84	-	$173
2046	1.84	-	$173

Note: LNG export volumes do not include liquefaction plant or pipeline fuel use.
Source: Port Arthur LNG, ICF

Exhibit 4-6: Additional Capital and Operating Expenditures Associated with New Pipeline Investments

Year	Impact Case Changes	
	Pipeline Capital Costs (2018$ MM)	Pipeline Operating Costs (2018$ MM)
2018	-	-
2019	-	-
2020	-	-
2021	-	-
2022	-	-
2023	-	-
2024	-	-
2025	$45	-
2026	$45	$2
2027	-	$2
2028	-	$2
2029	-	$2
2030	-	$2
2031	-	$2
2032	-	$2
2033	-	$2
2034	-	$2
2035	-	$2
2036	-	$2
2037	-	$2
2038	-	$2
2039	-	$2
2040	-	$2
2041	-	$2
2042	-	$2
2043	-	$2
2044	-	$2
2045	-	$2
2046	-	$2

Note: ICF assumes no new pipeline are built but 31,000 HP of additional compression would be needed on various system to accommodate higher flow volumes.
Source: ICF

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

Year	Federal Tax Rate (% of GDP)	Weighted Average State and Local Tax Rate (own-source as % of GSP)	Texas and Local Own Taxes (own-source as % of GSP)
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%
2046	19.4%	14.6%	12.8%

Source: ICF extrapolations from Tax Policy Center historical figures.

Exhibit 4-8: Liquids Price Assumptions

Year	WTI Price (2018$/bbl)	RACC Price (2018$/bbl)	Condensate Price (2018$/bbl)	Ethane Price (2018$/bbl)	MB Propane Price (2018$/bbl)	Butane Price (2018$/bbl)	Pentanes Plus (2018$/bbl)	Liquids Weighted Avg Price (2018$/bbl)
2010	$91	$88	$88	$29	$52	$59	$80	$77
2011	$107	$115	$115	$26	$65	$78	$104	$98
2012	$104	$111	$111	$18	$45	$75	$101	$94
2013	$106	$109	$109	$23	$44	$74	$99	$94
2014	$99	$98	$98	$27	$46	$66	$89	$85
2015	$51	$51	$51	$16	$20	$34	$46	$44
2016	$45	$42	$42	$15	$21	$29	$38	$36
2017	$52	$52	$52	$15	$22	$35	$47	$44
2018	$66	$64	$64	$16	$24	$44	$59	$54
2019	$58	$57	$57	$17	$25	$39	$52	$48
2020	$53	$52	$52	$15	$28	$35	$47	$45
2021	$51	$50	$50	$15	$26	$34	$45	$42
2022	$52	$50	$50	$15	$26	$34	$45	$42
2023	$53	$51	$51	$15	$27	$35	$47	$44
2024	$56	$54	$54	$16	$29	$36	$49	$46
2025	$58	$56	$56	$17	$30	$38	$51	$47
2026	$60	$58	$58	$17	$31	$39	$52	$49
2027	$63	$60	$60	$18	$32	$41	$55	$51
2028	$66	$63	$63	$19	$33	$43	$57	$53
2029	$69	$65	$65	$19	$35	$44	$60	$55
2030	$71	$67	$67	$20	$36	$46	$61	$57
2031	$73	$69	$69	$20	$36	$47	$63	$58
2032	$74	$69	$69	$20	$37	$47	$63	$59
2033	$74	$70	$70	$21	$37	$47	$64	$59
2034	$75	$70	$70	$21	$37	$47	$64	$59
2035	$75	$70	$70	$21	$37	$47	$64	$59
2036	$75	$70	$70	$21	$37	$48	$64	$59
2037	$75	$70	$70	$21	$37	$48	$64	$59
2038	$75	$70	$70	$21	$37	$48	$64	$59
2039	$75	$70	$70	$21	$37	$48	$64	$59
2040	$75	$70	$70	$21	$37	$48	$64	$59
2041	$75	$70	$70	$21	$37	$48	$64	$59
2042	$75	$70	$70	$21	$37	$48	$64	$59
2043	$75	$70	$70	$21	$37	$48	$64	$59
2044	$75	$70	$70	$21	$37	$48	$64	$59
2045	$75	$70	$70	$21	$37	$48	$64	$59
2046	$75	$70	$70	$21	$37	$48	$64	$59

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Texas
Upstream Capital Costs ($MM/Well)	$8.1	$8.1
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.33	$3.33
Royalty Payment (%)	16.7%	17.0%
LNG Tanker Capacity (Bcf/Ship)		3.40
U.S. Port Fee ($/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. Energy Market and Economic Impacts of Port Arthur Expansion

This section describes the economic and employment impacts between the Base Case and the Impact Case, which assumes that the Port Arthur facilities are expanded by adding Trains 3 and 4. Specifically, an additional 1.84 Bcfd in LNG exports are assumed to result from the expansion.

5.1. Energy Market and Economic Impacts

This section discusses the Base Case and the Impact Case (including Port Arthur T3 & T4) in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade.

Overall, in order to accommodate the incremental increases in LNG exports, the U.S. natural gas market rebalances through three sources: increasing U.S. natural gas production, a contraction in U.S. domestic natural gas consumption, and an increase in net natural gas pipeline imports from Canada and Mexico (see **Exhibit 5-1**). In addition to the incremental LNG export volumes of 1.84 Bcfd, the market also must rebalance for liquefaction and fuel losses, estimated at 10 percent of LNG export volumes. Thus, the market will rebalance to accommodate 110 percent of incremental export volumes or 2.03 Bcfd, as shown in the exhibit below.

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

2026-2046 Average Supply Sources			
Production Increase (% and Bcfd)	Demand Decrease (% and Bcfd)	Gas Pipeline Imports (% and Bcfd)	Total Share of LNG Exports (% and Bcfd)
92%	11%	7%	110%
1.69	0.20	0.14	2.03

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 2026 and 2046, there is a total cumulative impact on operating expenditures in the U.S. of $3.6 billion (in real 2018$) for Port Arthur T3 & T4. During that period, LNG plant operating expenditures in the U.S. average $171 million annually.

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

Year	LNG Facility Operating Expenditures (2018$ Million)	
2020	$	-
2021	$	-
2022	$	-
2023	$	-
2024	$	-
2025	$	-
2026	$	144
2031	$	173
2036	$	173
2041	$	173
2046	$	173
2021-2046 Avg	**$**	**171**
2021-2046 Sum	**$**	**3,596**

Source: Port Arthur LNG, 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 2026 and 2046, the cumulative impact on U.S. upstream capital expenditures totals $26.9 billion in the Impact Case as compared to the Base Case. U.S. upstream capital expenditures average $1.3 billion higher annually due to the Port Arthur T3 & T4 expansion.

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

Year	Upstream Capital Expenditures (2018$ Billion)	
2020	$	-
2021	$	-
2022	$	-
2023	$	-
2024	$	-
2025	$	-
2026	$	3.71
2031	$	1.01
2036	$	1.01
2041	$	1.01
2046	$	1.01
2021-2046 Avg	**$**	**1.28**
2021-2046 Sum	**$**	**26.86**

Source: ICF

As shown below (**Exhibit 5-4**), U.S. upstream operating expenditures increase $9.7 billion on a cumulative basis, or on average $462 million annually in the Impact Case as compared to the Base Case in the 2026 and 2046 export period.

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

Year	Upstream Operating Expenditures (2018$ Million)	
2020	$	-
2021	$	-
2022	$	-
2023	$	-
2024	$	-
2025	$	-
2026	$	203
2031	$	475
2036	$	475
2041	$	475
2046	$	475
2021-2046 Avg	**$**	**462**
2021-2046 Sum	**$**	**9,706**

Source: ICF

The table below (**Exhibit 5-5**) shows U.S. natural gas consumption in the Base Case and in the Impact Case with Port Arthur T3 & T4 expansion. The additional LNG export volumes of 1.84 Bcfd are expected to result in only a small reduction in U.S. natural gas consumption of roughly 0.20 Bcfd in most years, 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	Impact Case	Impact Case Change
2020	76.4	76.4	-
2021	77.7	77.7	-
2022	79.4	79.4	-
2023	79.7	79.7	-
2024	81.0	81.0	-
2025	82.1	82.1	-
2026	82.4	82.3	(0.09)
2031	84.1	83.9	(0.20)
2036	87.3	87.1	(0.20)
2041	87.6	87.4	(0.20)
2046	88.4	88.2	(0.20)
2021-2046 Avg	**84.9**	**84.7**	**(0.20)**

Note: Charts above includes only domestic end-use consumption and does not include exports, liquefaction fuel, pipeline fuel, and lease & plant gas use.

Source: ICF

The Henry Hub natural gas price in the Impact Case (averaging $3.69/MMBtu from 2026 to 2046) is expected to be on average $0.10/MMBtu higher compared to the Base Case (averaging $3.59/MMBtu), as shown in **Exhibit 5-6**. The natural gas prices at Henry Hub are expected to reach $4.19/MMBtu in the Base Case and $4.29 in the Impact Case by 2046, indicating a natural gas price increase of $0.10/MMBtu attributable to the higher export volumes of 1.84 Bcfd in the last year of analysis.

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

Year	Henry Hub Natural Gas Price (2018$/MMBtu)		
	Base Case	Impact Case	Impact Case Change
2025	$ 2.85	$ 2.85	$ -
2026	$ 2.88	$ 2.96	$ 0.08
2031	$ 3.48	$ 3.59	$ 0.10
2036	$ 3.31	$ 3.43	$ 0.11
2041	$ 3.99	$ 4.10	$ 0.10
2046	$ 4.19	$ 4.29	$ 0.10
2026-2046 Avg	**$ 3.59**	**$ 3.69**	**$ 0.10**

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 Impact Case including the Port Arthur T3 & T4 expansion (see **Exhibit 5-7**). Over the 2026 and 2046 export period, the cumulative impact on natural gas and liquids production value in the Impact Case is approximately $178.3 billion. This represents an average increase of about $8.5 billion per year 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 (2018$ Million)
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ -
2025	$ -
2026	$ 4,587
2031	$ 8,456
2036	$ 8,779
2041	$ 8,980
2046	$ 9,155
2021-2046 Avg	**$ 8,491**
2021-2046 Sum	**$ 178,316**

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

Source: ICF

Exhibit 5-8 shows the impacts of additional LNG export volumes on total U.S. employment.[15] 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	Total Employment Impact (no. of job-years)
2020	-
2021	555
2022	15,170
2023	15,273
2024	16,177
2025	16,870
2026	28,085
2031	31,244
2036	31,523
2041	31,702
2046	31,861
2021-2046 Avg	**27,728**
2021-2046 Sum	**720,930**

Source: ICF

The construction and operation of the expanded will likely increase employment through direct, indirect and induced employment that totals 27,700 of incremental jobs on average between 2021 and 2046. Over the forecast period the added LNG export facilities are expected to increase job-years relative to the Base Case by 720,900 cumulative job-years.

[15] 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 $1.9 billion annually as a result of the Port Arthur T3 & T4 expansion. This translates to a cumulative impact of $49.0 billion over the forecast period between 2021 and 2046.

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

Year	Government Revenues (2018$ Million) Impact Case Change
2020	$ -
2021	$ 14
2022	$ 375
2023	$ 381
2024	$ 405
2025	$ 426
2026	$ 1,318
2031	$ 2,233
2036	$ 2,262
2041	$ 2,441
2046	$ 2,530
2021-2046 Avg	**$ 1,884**
2021-2046 Sum	**$ 48,972**

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 Impact Case with the Port Arthur T3 & T4 expansion. This activity results in a $5.7 billion annual incremental value added between 2021 and 2046. The cumulative value added by the expansion over the period totals $148.6 billion.

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

Year	Total Value Added
	Impact Case Change
2020	$ -
2021	$ 0.0
2022	$ 1.2
2023	$ 1.2
2024	$ 1.3
2025	$ 1.3
2026	$ 4.1
2031	$ 6.9
2036	$ 6.9
2041	$ 7.3
2046	$ 7.5
2021-2046 Avg	**$ 5.7**
2021-2046 Sum	**$ 148.6**

Source: ICF

Exhibit 5-11 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $3.7 billion annually or a cumulative value of $77.3 billion between 2026 and 2046, based on the value of LNG export volumes and incremental associated liquids production. The improved balance of trade effects begin in 2026 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 fees) 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 (2018$ Billion)
	Impact Case Change
2020	$ -
2021	$ -
2022	$ -
2023	$ -
2024	$ -
2025	$ -
2026	$ 1.3
2031	$ 3.7
2036	$ 3.6
2041	$ 4.0
2046	$ 4.5
2021-2046 Avg	**$ 3.7**
2021-2046 Sum	**$ 77.3**

Source: ICF

5.2. Texas Impacts

The exhibits below describe the energy market and economic impacts of the Port Arthur T3 & T4 expansion in Texas. The Texas impacts are a portion (that is, a subset) of the national impacts already discussed above.

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 Impact Case exhibits an increase of roughly 8,900 jobs on an average annual basis from 2021 to 2046 as compared to the Base Case. This equates to a cumulative impact of 232,700 job-years in Texas over the forecast period through 2046.

Exhibit 5-12: Texas Total Employment Changes

Year	Texas Employment (no. of job-years)
2020	-
2021	78
2022	2,119
2023	2,134
2024	2,260
2025	2,594
2026	6,753
2031	10,777
2036	10,834
2041	10,934
2046	10,963
2021-2046 Avg	**8,951**
2021-2046 Sum	**232,729**

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 Impact Case results in a $140.2 million average annual increase to local and state Texas government revenues throughout forecast period through 2046, or a cumulative impact of about $3.6 billion.

Exhibit 5-13: Texas Government Revenue Changes

Year	Texas Government Revenues (2018$ Million)
2020	$ -
2021	$ 1.8
2022	$ 49.8
2023	$ 50.1
2024	$ 53.1
2025	$ 57.2
2026	$ 132.8
2031	$ 161.3
2036	$ 161.3
2041	$ 173.8
2046	$ 175.7
2021-2046 Avg	**$ 140.2**
2021-2046 Sum	**$ 3,646.0**

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 Impact Case. Throughout the study period 2021 to 2046 the plant construction and the additional LNG volumes in the Impact Case result in a $1.1 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 Impact Case including the Port Arthur T3 & T4 expansion is $28.5 billion.

Exhibit 5-14: Total Texas Value Added Changes

Year	Texas Total Value Added (2018$ Billion)
2020	$ -
2021	$ 0.01
2022	$ 0.39
2023	$ 0.39
2024	$ 0.41
2025	$ 0.45
2026	$ 1.04
2031	$ 1.26
2036	$ 1.26
2041	$ 1.36
2046	$ 1.37
2021-2046 Avg	**$ 1.10**
2021-2046 Sum	**$ 28.50**

Source: ICF

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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.

<u>Reports Sponsored by U.S. DOE</u>

The most recent of five DOE sponsored reports on LNG exports was entitled "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports."[16] This was prepared by NERA Economic Consulting and published in June 2018. That study examined a wide range of scenarios for future U.S. LNG exports wherein U.S. LNG exports were not constrained by regulations but depended on natural gas market conditions in the U.S. and the rest of the world over the 2020 to 2040 time period. The 2018 NERA Study developed 54 scenarios based on various assumptions for natural gas resource endowment and technologies, economic growth, alternative fuel prices, etc. to capture a wide range of uncertainty in the natural gas markets.

The first key results of these scenarios was that "For each of the supply scenarios, higher levels of LNG exports in response to international demand consistently lead to higher levels of GDP." The second key conclusion was that "Consumer welfare is a present value measure of the standard of living of all households over the entire period from 2020 to 2040… As in the case of GDP, consumer welfare within supply case is higher, the higher the level of LNG exports."

The study authors concluded:

> *There are several reasons for these consistently positive relationships between LNG exports and measures of economic performance.*
>
> - *About 80% of the increase in LNG exports is satisfied by increased U.S. production of natural gas, with positive effects on labor income, output, and profits in the natural gas production sector.*
> - *The higher world prices that bring forth those supplies improve U.S. terms of trade, so that there is a wealth transfer to the U.S. from the rest of the world*

[16] NERA, "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports," June 2018. Available at: https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf

equal to the increase in prices received for LNG exports times the quantity exported. The transfers from natural gas related activity to the U.S. economy improve the average consumer's ability to demand more goods and services leading to higher economic activity.

These two factors more than make up for the dampening economic effects that are observed in these scenarios, including slightly slower output growth of some natural gas intensive industries, costs of substituting other fuels for a small fraction of natural gas use in power generation, and infinitesimal reductions in natural gas use by households and other industries.

Even the most extreme scenarios of high LNG exports that are outside the more likely probability range, which exhibit a combined probability of less than 3%, 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.

It is also important to note that our analysis also shows that the chemicals subsectors that rely heavily on natural gas for energy and as a feedstock continue to exhibit robust growth even at higher LNG export levels and is only insignificantly slower than cases with lower LNG export levels.

Another DOE-sponsored 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.

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 earlier January 2012 study.[18] 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

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[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] 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

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.

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.

The earliest EIA study of LNG export impacts on energy markets was released in January 2012 and looked at four export scenarios from 6 to 12 Bcfd based on AEO 2011 case assumptions.[20] 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 subject covered by the NERA report published in December of 2012).

Other Reports

ICF International's May 2013 study for the American Petroleum Institute looked at impacts of LNG exports on natural gas markets, GDP, employment, government revenue and balance of trade.[21] The four cases considered include no exports compared to 4, 8, and 16 Bcfd of exports. LNG exports are expected to increase domestic gas prices in all cases, raising Henry Hub prices by $0.32 to $1.02 (in 2010 dollars) on average during the 2016-2035 period. GDP and employment see net positive gains from LNG exports, as employment changes reach up to 665,000 annual jobs by 2035 while GDP gains could reach $78-115 billion in 2035. Different 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.

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[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

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[21] ICF International. "U.S. LNG Exports: Impacts on Energy Markets and the Economy". ICF International, May 15, 2013: Fairfax, VA. Available at: http://www.api.org/~/media/Files/Policy/LNG-Exports/API-LNG-Export-Report-by-ICF.pdf

NERA provided an update to its December 2012 DOE study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[22] 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.

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 on these and other studies.

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[22] 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

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Facility / Study	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	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	
Port Arthur LNG T3 & T4 (ICF 2020)	Port Arthur LNG export of 1.91 Bcfd	1.84 Bcfd export	$0.10	$0.053	92%	11%	7%	110%	1.51	15,037	$206,151	Port Arthur LNG T3 & T4 development increases US GDP and employment.
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.
Port Arthur LNG T1 & T2 (ICF-2016 update)	Port Arthur LNG export of 1.91 Bcfd	1.91 Bcfd incremental increase in LNG exports	$0.11	$0.06	92%	11%	7%	110%	1.6	21,488	$268,777	Port Arthur LNG development leads to positive impact on the 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/ΔJobs	
Jordan Cove (Navigant)	7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd	2.9 Bcfd [0.9 Bcfd incremental LNG exports from Jordan Cove (in addition to 2 Bcfd assumed in the base case)]	$0.03 (0.9 Bcfd)	$0.03	14%	7%	95%	0%	N/A	Construction: 1768 direct, 1530 indirect, 1838 induced (5136 total or 6188 per Bcfd) Operation: 99 direct, 404 indirect, 182 induced (736 total or 887 per Bcfd) Upstream: 20359 average, 27806 through 2035, 39366 through 2045 (in attached ECONorthwest study or 33501 per Bcfd through 2035)	N/A (separate reports on GDP impact attributed to regional, trade, upstream but no total)	Gas price impacts of Jordan Cove are "negligible". Jordan Cove creates positive economic and employment benefits for Oregon and Washington states.
		5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to Base Case Bcfd and 0.9 Bcfd incremental)]	$0.38 (3.9 Bcfd)	$0.10	80%	11%	12%	116%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Freeport (Deloitte)	Single scenario, with and without	6 Bcfd LNG exports	$0.12 citygate national average, $0.22 at HH (2016-2035)	$0.02 (citygate) $0.04 (HH)	63%	17%	20%	80%	1.34-1.90 (based on GDP)	Construction: more than 3000 Operation: 20 - 30 permanent Indirect: 2015-2040 avg: M.E. = 1.34: 18,211 (or 12,141 per Bcfd) 2015-2040 avg: M.E. = 1.55: 20,929 (or 13,953 per Bcfd) 2015-2040 avg: M.E. = 1.90: 16,852 (or 11,235 per Bcfd) (attached Altos study). 1.5 Bcfd project	2015-2040 avg: M.E. = 1.34: $200,000 2015-2040 avg: M.E. = 1.55: $201,300 2015-2040 avg: M.E. = 1.90: $306,432	Freeport has "minimal" gas price impacts. The project creates 17,000-21,000 new jobs and contributes $3.6-$5.2 billion for the economy.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
EIA (NEMS Modeling)	Total of 16 cases with 4 export scenarios examining impacts of either 6 or 12 Bcfd of exports phased in at a rate of 1 Bcfd per year or 3 Bcfd per year	5.3 Bcfd - 11.2 Bcfd (AEO Ref)	$0.55-$1.22	$0.10-$0.12	61%-64%	36%-39%	2%-3%	103%	N/A	N/A	N/A	Gas price impacts vary depending on the level of exports and pace of export ramp-up and moderate over time in all cases. Drilling and production get a boost while power and industrial gas use decline somewhat.
		5.3 Bcfd - 11.2 Bcfd (High Shale)	$0.38-$0.87	$0.07-$0.12	61%-64%	34%-37%	5%	103%	N/A	N/A	N/A	
		5.3 Bcfd - 11.2 Bcfd (Low Shale)	$0.77-$1.65	$0.15-$0.17	55%-60%	32%-37%	11%-12%	104%	N/A	N/A	N/A	
		5.3 Bcfd - 11.2 Bcfd (High GDP)	$0.55-$1.26	$0.10-$0.12	71%-72%	29%-30%	2%-3%	103%	N/A	N/A	N/A	
EIA (NERA)	8 cases examining different levels of U.S. demand and LNG export ranging from 3.75 to 15.75 Bcfd	6 Bcfd (Reference)	$0.34-$0.60	$0.09 to $0.10	51%	49%	0%	100%	N/A	Not likely to affect overall employment	N/A	LNG export leads to higher gas prices, with impacts ranging from $0.14 to $1.61/Mcf. The economy reaps positive benefits from LNG exports across all cases.
		12 Bcfd (Reference)	$1.20		51%	49%	0%	100%	N/A			
		Unlimited Bcfd (Reference)	$1.58		50%	50%	0%	100%	N/A			
	7 cases examining different levels of U.S. demand and LNG exports ranging from 6 to 23 Bcfd	6 Bcfd (High EUR)	$0.42	$0.07	50%	50%	0%	107%	N/A			
		12 Bcfd (High EUR)	$0.84		49%	51%	0%	100%	N/A			
		Unlimited Bcfd (High EUR)	$1.08 - $1.61		46%	54%	0%	100%	N/A			
	Single scenario with LNG exports reaching 1.42 Bcfd	6 Bcfd (Low EUR)	$0.14 (1 Bcfd)	$0.14	51%	49%	0%	115%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
EIA (2014 Update)	5 export cases with supply and demand assumptions based on AEO 2014 and DOE	Reference	$0.30 - $0.50	N/A	61-84%	10-18%	N/A	N/A	N/A	Change in nonfarm employment less than 0.1 million, representing up to 0.1% increase relative to the baseline	N/A	LNG exports result in positive economic benefits, enough to overcome the impact of higher gas prices.
		High Oil and Gas Resource	0 - $0.20	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		Low Oil and Gas Resource	$0.90 - $1.40	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		High Macroeconomic Growth	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
		Accelerated Coal and Nuclear	$0.30 - $0.60	N/A	61-84%	10-18%	N/A	N/A	N/A		N/A	
NERA (2014 Update)	5 cases with export ranging from 6 to unlimited	6 Bcfd (Reference)	$0.43/MMBtu by 2038	$0.07	61%	38-39%	0%	99-100%	N/A	LNG Exports could reduce unemployment by 45,000 before the economy returns to full employment by 2018.	N/A	LNG export leads to gas price increases. It also leads to gains in GDP, employment, and the chemical sectors.
		Unlimited Bcfd (Reference)	$0.36-$1.33	$0.02-$0.03	63%	36-104%	0%	99-167%	N/A			
	7 cases with export ranging from 6 to unlimited	6 Bcfd (High Oil and Gas Resource)	$0.16	$0.03	65-168%	33-34%	0%	98-202%	N/A			
		12 Bcfd (High Oil and Gas Resource)	$0.30-$0.34	$0.03	65-67%	33-35%	0%	98-102%	N/A			
		Unlimited Bcfd (High Oil and Gas)	$0.96-$1.38	$0.96	68%	32%	0%	100%	N/A			
	2 cases with	6 Bcfd (Low Oil and Gas)	$0.90	$0.15	59%	41%	0%	100%	N/A			
		Unlimited Bcfd (Low Oil and Gas)	$1.78	$0.03	58%	42%	0%	100%	N/A			

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Dow Chemical (CRA)	3 export scenarios with CRA Base Demand (adjusted AEO 2013 for industrial demand)	4 Bcfd LNG export (AEO export), CRA Base Demand	$0.90 (2013-2030)	$0.23 (using 4 Bcfd)	N/A	N/A	N/A	N/A	GDP-based M.E. not given. Indirect value not estimated. Employment-based M.E.: 30 (each direct job leads to 30 jobs along the supply chain)	N/A	N/A	LNG export increases gas prices significantly. Gas use in manufacturing yields higher benefits than in LNG exports. Impacts on gas and NGL production and the economy are not given.
		9 Bcfd LNG exports by 2025 and 20 Bcfd by 2030 layered on CRA Base Demand	$2.50 (2013-2030)	$0.13 (using 20 Bcfd)	N/A	N/A	N/A	N/A		N/A	N/A	
		20 Bcfd LNG exports by 2025 and 35 Bcfd by 2030 layered on CRA Base Demand	$4.00 (2013-2030)	$0.11(using 35 Bcfd)	N/A	N/A	N/A	N/A		N/A	N/A	
RBAC, REMI	2 export scenarios: 3 Bcfd and 6 Bcfd relative to a no export scenario	3 Bcfd	About $0.60 (2012-2025)	$0.20	N/A	N/A	N/A	N/A	N/A	2012-2025 avg: 41,768 per Bcfd. Multiplier not given.	2012-2025 avg: $35,357/job in 2011 dollars	LNG exports have mixed impacts on the economy, peaking in the earlier years due to infrastructure investments. Gas price impacts range from $0.60-$2.00/MMBtu.
		6 Bcfd	About $2.00 (2012-2025)	$0.33	N/A	N/A	N/A	N/A	N/A	2012-2025 avg: 67,236 per Bcfd. Multiplier not given.	2012-2025 avg: $46,349/job in 2011 dollars	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
API (ICF, 2012)	ICF Base Case	4 Bcfd	$0.35	$0.10	88%	21%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 17,800, M.E. = 1.9: 35,200	2015-2035 avg: M.E. = 1.3: $208,600, M.E. = 1.9: $150,900	LNG exports have moderate gas price impacts. Depending on the scenario LNG exports increase employment by up to 452,300 and GDP by $73.6 billion by on average during 2016-2035.
	Middle Exports Case	8 Bcfd	$1.19	0.11	82%	26%	7%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,700, M.E. = 1.9: 28,000	2015-2035 avg: M.E. = 1.3: $207,100, M.E. = 1.9: $149,300	
	High Exports Case	12 Bcfd	$1.33	$0.10	79%	27%	8%	115%	1.3; 1.9 (based on GDP)	2015-2035 avg: M.E. = 1.3: 13,400, M.E. = 1.9: 27,400	2015-2035 avg: M.E. = 1.3: $208,800, M.E. = 1.9: $150,200	

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Golden Pass (Perryman Group)	Refer to Deloitte's Mkt Point report for price impacts	N/A	N/A	N/A	N/A	N/A	N/A	N/A		3,860 permanent jobs for 2bcfd export	1.9 billion in 2012 dollars avg for all jobs	The project generate over $31 billion GDP and 324,000 job-years over the project life.
Southern LNG (Navigant)	3 North America LNG cases and 2 demand cases	Base Case (3.7 Bcfd)	N/A	N/A	N/A	N/A	N/A	N/A	RIMS II multipliers			North American gas resources can support the SLNG export facility. LNG exports have minimal gas price impacts and improve price stability.
		SLNG Export Case (base + 0.5)	$0.14/MM Btu by 2025	$0.28	60%	0%	N/A	N/A		during operation: 8933 avg	$145,136 .01	
		Aggregate Export Case (base + 3.5)	$0.39/MM Btu by 2025	$0.10	60%	15%	N/A	N/A				
		High Demand Base Case	$0.59/MM Btu	$0.20			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$0.23			N/A	N/A				
Pangea LNG (Black & Veatch for price and Perryman for economic impacts)	4 demand cases	Base Case			N/A	N/A	N/A	N/A				The project has limited impact on U.S. gas prices and bring significant economic benefits, including $1.4 billion in GDP and 17,230 person-years of employment.
		Pangea Export Case	$0.17/MM Btu (2018-27)	$0.14	N/A	100%	N/A	N/A		29860 permanent jobs in total	2.7 billion in total	
		High LNG Export	$0.26/MM Btu	0.09	N/A	100%	N/A	N/A				
		High LNG Export + Pangea	$0.37/MM Btu	0.09	N/A	N/A	N/A	N/A				

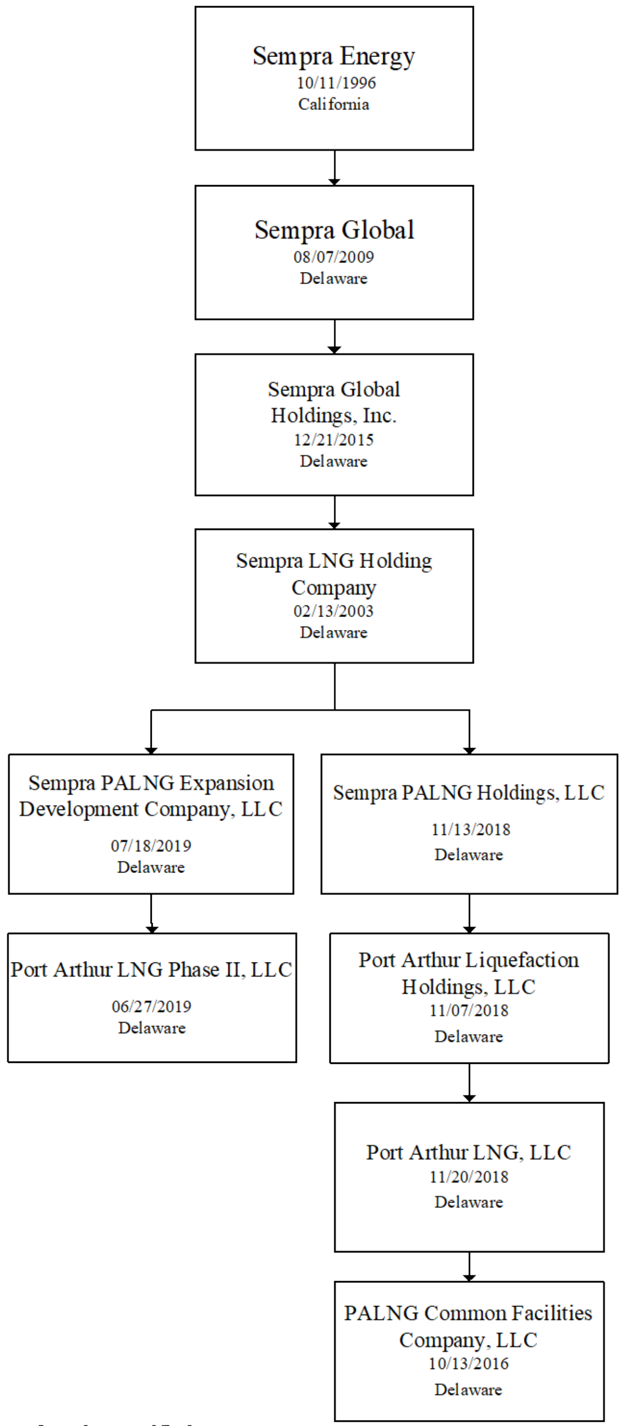
Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Base Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect of GDP	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Net Gas Pipeline Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Magnolia LNG (Berkeley Research Group)	6 gas market cases	Reference Case (4.6 Bcfd)										Project has negligible market and price impacts. Impacts increase with higher LNG and demand levels.
		Magnolia Scenario (5.7 Bcfd)	$0.14/MM Btu by 2035	$0.13	45%	18%	9%	73%	N/A	N/A	N/A	
		Moderate LNG Scenario (9.9 Bcfd)	$0.49/MM Btu	$0.09	77%	15%	6%	98%	N/A	N/A	N/A	
		High LNG Scenario (13.9 Bcfd)	$0.90/MM Btu	$0.10	69%	16%	1%	86%	N/A	N/A	N/A	
		High Demand/ Moderate LNG (9.9 Bcfd)	$0.93/MM Btu	$0.18	138%	53%	0%	191%	N/A	N/A	N/A	
		High Demand/ High LNG (13.9 Bcfd)	$1.40/MM Btu	$0.15	109%	22%	0%	130%	N/A	N/A	N/A	
Downeast LNG (Resource Report by ICF, Market Impacts by Concentric Energy Advisors, Economic Impacts by Todd Gabe)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	County-level multiplier: 1.25 (output), 2.00 (employment) State-level multiplier: 1.59 (output), 2.73 (employment)	3525 jobs statewide during construction, 310 jobs statewide during operations	N/A	Downeast unlikely to have material impacts on North American prices or in the Northeast region. The project would have positive impacts on employment and the economy.

APPENDIX C

PALNG Phase II Ownership Structure

Port Arthur LNG Phase II, LLC

Organizational Chart as of February 13, 2020



*ownership is 100% unless otherwise specified