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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

Port Arthur LNG, LLC	)))	**FE Docket No. 15-96-LNG**

AMENDMENT TO APPLICATION OF PORT ARTHUR LNG, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT COUNTRIES

DESIGN INCREASE

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the United States Department of Energy's ("DOE") regulations,[2] Port Arthur LNG, LLC ("Port Arthur LNG") hereby files an amendment ("Amendment") to its application currently pending before the DOE's Office of Fossil Energy ("DOE/FE") in the above-captioned proceeding (the "Non-FTA Application").[3] The Non-FTA Application, filed on June 15, 2015, requested long-term, multi-contract authorization to export 517 billion cubic feet ("Bcf") per year of domestically produced liquefied natural gas ("LNG") (equivalent to approximately 10 million metric tons per annum of LNG ("MTPA")) to any country (i) with which the United States does not have a Free Trade Agreement ("FTA") requiring national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy. The Non-FTA Application requested a 20-year term commencing on the earlier of the date of first commercial export or a date seven years from

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1 15 U.S.C. § 717b (2012).

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

3 *Port Arthur LNG, LLC*, FE Docket No. 15-96-LNG, Application of Port Arthur LNG, LLC for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries (June 15, 2015).

the issuance of a final order granting the requested authorization. The Non-FTA Application requested authorization for Port Arthur LNG to export LNG on its behalf and as agent for other parties who will hold title to the LNG at the time of export.

As set forth in greater detail below, this Amendment increases the volumes requested in the Non-FTA Application by 181 Bcf per year (approximately 3.5 MTPA) for a total requested volume of up to 698 Bcf per year (approximately 13.5 MTPA).

In support of this Amendment, Port Arthur LNG states as follows:

I. COMMUNICATIONS AND CORRESPONDENCE

All communications and correspondence regarding the Non-FTA Application and this Amendment should be directed to:

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II. DESCRIPTION OF THE APPLICANT

The exact legal name of Port Arthur LNG is Port Arthur LNG, LLC. Port Arthur LNG is a limited liability company organized under the laws of Delaware. Port Arthur LNG is a wholly-owned, indirect subsidiary of Sempra Energy. The principal place of business of Port Arthur LNG is 2925 Briarpark Drive, Suite 900, Houston, Texas 77042.

Port Arthur LNG holds an authorization to export up to 517 Bcf per year of domestically produced LNG to any nation with which the United States has, or in the future enters into, an FTA requiring the national treatment for trade in natural gas. The DOE/FE granted Port Arthur LNG that authorization in Order No. 3698, dated August 20, 2015.[4] Port Arthur LNG is separately filing an application for authorization to export an additional 181 Bcf per year (approximately 3.5 MTPA) of LNG to FTA countries, which would permit Port Arthur LNG to export a total volume of 698 Bcf per year (approximately 13.5 MTPA) of LNG to FTA countries. Additionally, Port Arthur LNG filed the Non-FTA Application in the instant proceeding, requesting long-term, multi-contract authorization to export up to 517 Bcf per year of domestically produced LNG to Non-FTA countries. The Non-FTA Application is currently pending. This Amendment modifies the Non-FTA Application by requesting authorization to export LNG in an amended volume of 698 Bcf per year (approximately 13.5 MTPA).

III. BACKGROUND

In this proceeding, Port Arthur LNG seeks long-term authorization to export domestically produced LNG from liquefaction and export facilities it intends to construct and operate at a site in Port Arthur, Texas (the "Project").

As discussed above, the DOE/FE granted Port Arthur LNG authorization to export LNG from the Project to FTA nations on August 20, 2015. On June 15, 2015, Port Arthur LNG filed the Non-FTA Application in the instant proceeding, seeking authorization to export LNG from

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[4] *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).

the Project to Non-FTA Nations. The DOE/FE's Notice of Application regarding the Non-FTA Application was published in the *Federal Register* on August 26, 2015.[5]

On November 29, 2016, Port Arthur LNG and its affiliate PALNG Common Facilities Company, LLC filed with the Federal Energy Regulatory Commission ("FERC") an Application for Authorization under Section 3 of the Natural Gas Act to construct and operate the liquefaction and export facilities associated with Project ("FERC Application").[6] As reflected in the FERC Application, the Project will permit natural gas to be pre-treated, liquefied, stored, and loaded onto LNG vessels berthed at the Project's proposed marine facilities in order to be exported. The Project will include two liquefaction trains, each with a maximum capacity under optimal conditions of 6.73 MTPA, for an aggregate capacity of approximately 13.5 MTPA.[7]

IV. REQUESTED AMENDMENT

In this Amendment, Port Arthur LNG proposes to modify the volumes requested in the Non-FTA Application so that it may be authorized to export the Project's full maximum capacity at optimal conditions, as reflected in the FERC Application. The FERC Application demonstrates that under optimal conditions, the Project's maximum capacity is currently estimated to be approximately 13.5 MTPA. However, in the Non-FTA Application, Port Arthur LNG sought to export LNG in volumes up to 10 MTPA or 517 Bcf per year—*i.e.*, 3.5 MTPA less than the peak capacity of the Project facilities. This Amendment seeks to modify the volumes requested in the Non-FTA Application to account for this 3.5 MTPA increment. Port Arthur LNG hereby requests that the DOE/FE's order in this proceeding grant it an aggregate

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5 Notice of Application, *Port Arthur LNG, LLC,* 80 Fed. Reg. 51795 (Aug. 26, 2015).

6 Application of Port Arthur LNG, LLC and PALNG Common Facilities Company, LLC for Authorization under Section 3 of the Natural Gas Act, *Port Arthur LNG, LLC*, Docket No. CP17-20-000 (Nov. 29, 2016).

7 *Id.* at 4.

Non-FTA export authorization of 698 Bcf per year, which is equivalent to approximately 13.5 MTPA. This would enable Port Arthur LNG to export LNG at a volume equivalent to the Project's maximum capacity at optimal conditions, which FERC has determined is the appropriate measure of liquefaction capacity to be reflected in a FERC Section 3 authorization.[8]

In addition, this Amendment supplements the Non-FTA Application with an updated version of the ICF Report, which was included as Appendix A to the Non-FTA Application ("2015 ICF Report").[9] The 2015 ICF Report, dated June 5, 2015, was commissioned by Port Arthur LNG to assess the economic effects of the Project. An updated version of the report, dated November 11, 2016, was included as an exhibit to the FERC Application ("2016 ICF Report").[10] A copy of the 2016 ICF Report is included herewith as Appendix C.

Port Arthur LNG is seeking the authorizations requested in this proceeding, as amended herein, for a 20-year period commencing on the earlier of the date of first export or seven years from the date of issuance of the authorizations requested herein. Consistent with DOE/FE policy, Port Arthur LNG 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. Port Arthur further requests that it be permitted to continue exporting for a total of three years following the end of the 20-year non-FTA term requested in this proceeding, solely to export any make-up volume that Port Arthur LNG may be

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8 *Sabine Pass Liquefaction, LLC*, 146 FERC ¶ 61,117 at P 12 (2014) ("We recognize that an accurate calculation of the maximum or peak capacity at optimal conditions may not be possible at the time an initial application for construction is filed. However, we believe that it is appropriate for an ultimate authorization to reflect the maximum or peak capacity at optimal conditions as such a level represents the actual potential production of LNG.").

9 Non-FTA Application, Appendix A (ICF International, *Economic Impacts of the Port Arthur Liquefaction Project: Information for DOE Non-FTA Permit Application* (Jun. 5, 2015)).

10 FERC Application, Exhibit Z (ICF International, *Economic Impacts of the Port Arthur Liquefaction Project: Information for DOE Non-FTA Permit Application* (Nov. 11, 2016)).

unable to export during the original export periods.[11] Port Arthur LNG requests such export authorization on its own behalf and as agent for others. To ensure all exports are permitted and lawful under United States laws and policies, Port Arthur LNG will comply with all DOE/FE requirements for an exporter or agent, including any applicable requirements to register LNG title holders and to file relevant long-term commercial agreements under seal with the DOE/FE. Port Arthur LNG requests that the DOE/FE permit it to submit transaction-specific information identified in Section 590.202(b) of the DOE/FE's regulations at the time the applicable agreements are executed, consistent with DOE/FE precedent.[12]

V. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standard

The DOE/FE has the power to approve or deny applications to export natural gas pursuant to specific authorization in Section 3 of the NGA.[13] The general standard for review of applications to export to non-FTA countries is established by Section 3(a), 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,

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[11] *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).

[12] *See Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2833, FE Docket No. 10-85-LNG, Order Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Free Trade Nations (Sept. 7, 2010).

[13] 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-006.02 (Nov. 17, 2014).

> after opportunity for hearing, and for good cause shown, make such supplemental order in the premises as it may find necessary or appropriate.[14]

In applying this provision, the DOE/FE has consistently found that Section 3(a) of the NGA creates a rebuttable presumption that proposed exports of natural gas are in the public interest.[15] The DOE/FE must 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.[16]

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.[17] While nominally applicable to natural gas import cases, the DOE/FE has found these Policy Guidelines to be applicable to applications for the export of natural gas as well.[18] The goals of the Policy

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[14] 15 U.S.C. § 717b(a).

[15] *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).

[16] *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.

[17] 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. 6684 (Feb. 22, 1984) [hereinafter Policy Guidelines].

[18] *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.

Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system. The Policy Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas . . . The federal government's primary responsibility in authorizing imports [or exports] should be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[19]

Historically, the DOE/FE's review has also been guided by DOE Delegation Order No. 0204-111 ("Delegation Order").[20] 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."[21] Although the Delegation Order is no longer in effect, the DOE/FE's review of export applications continues to focus on: (i) the domestic need for natural gas proposed to be exported; (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies; (iii) whether the arrangement is consistent with the DOE/FE's policy of promoting market competition; and (iv) any other factors bearing on the public interest.[22]

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

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19 Policy Guidelines at 6685.

20 U.S. Department of Energy, Delegation Order No. 0204-111 (Feb. 22, 1982).

21 Delegation Order at para. (b).

22 *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).

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.[23]

As demonstrated below, the export of domestically produced LNG as proposed in the Non-FTA Application, as supplemented by this Amendment, satisfies each of these considerations.

B. Domestic Need for Natural Gas to be Exported

The Project is proposed in view of considerable growth in domestic natural gas resources and production. In particular, drilling productivity gains and extraction technology enhancements have enabled significant growth in supplies from unconventional gas-bearing shale formations in the United States. In addition, estimates of recoverable natural gas resources have increased by approximately 715 Tcf (41%) between 2007 and 2016.[24] In light of the substantial addition of resources and the comparatively minor increases in domestic natural gas demand, there are more than sufficient natural gas resources to accommodate both domestic demand and the exports proposed in this Application throughout the 20-year term of the requested authorization.

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

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[23] *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.

[24] *Compare* U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2018*, Oil and Gas Supply Module, tbl. 2 (Apr. 5, 2018) [hereinafter Assumptions to the AEO 2018), https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf *with* U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, tbl. 9.2 (Mar. 2009) [hereinafter Assumptions to the AEO 2009], http://www.eia.gov/forecasts/archive/aeo09/assumption/pdf/0554(2009).pdf.

MMBtu in 2008 to $2.99 per MMBtu in 2017.[25] In its most recently calculated reference case, the U.S. Energy Information Administration ("EIA") estimates that natural gas prices will remain relatively flat at approximately $5.00 per MMBtu between 2030 through 2050.[26] Prices for natural gas in the U.S. market are now significantly below those of most other major gas-consuming countries.[27] 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."[28] The EIA estimates that natural gas production over the 2017-2020 period will grow at 6% a year, greater than the 4% per year average growth rate from 2005 to 2015.[29] The EIA further estimates that U.S. dry gas production increased from 21 Tcf in 2010 to 27 Tcf in 2017.[30]

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

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

26 U.S. Energy Information Administration, *Annual Energy Outlook 2018*, at 63 (Feb. 6, 2018) [hereinafter AEO 2018], https://www.eia.gov/outlooks/aeo/data/browser/#/?id=14-AEO2018&cases=ref2018&sourcekey=0.

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

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

29 AEO 2018 at 62.

30 U.S. Energy Information Administration, *U.S. Dry Natural Gas Production* (Sept. 28, 2018), https://www.eia.gov/dnav/ng/hist/n9070us2A.htm.

between 2016 and 2050.[31] Much of the future natural gas production growth is expected to come from unconventional production of shale resources, including horizontal drilling and multi-stage hydraulic fracturing. Specifically, the EIA found that production from shale gas and associated gas from tight oil plays would be the largest contributor to natural gas production growth, comprising almost three-quarters of total U.S. production by 2040.[32] In its 2018 Annual Energy Outlook, the EIA has also significantly increased its estimates of shale gas production through 2035 as compared to its projections in the Annual Energy Outlook 2015. For example, the EIA revised its projection of shale gas production in 2030 from 17.85 Tcf to 26.87 Tcf and in 2035 from 18.85 Tcf to 28.24 Tcf.[33]

This growth in shale production has been accompanied by an increase in the overall volume of U.S. natural gas resources. The EIA's estimates of recoverable natural gas resources have increased by 715 Tcf (41%) between 2007 and 2016.[34] A large component of the technically recoverable resource is economic at relatively low wellhead prices. ICF estimates that 944 Tcf of this gas resource could economically be developed with gas prices at $5.00 per MMBtu using today's technology.[35] 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

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

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

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

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

[35] Appendix C, 2016 ICF Report at 17 [hereinafter 2016 ICF Report].

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 are economic at $5.00/MMBtu would increase by 55% to 1,465 Tcf by 2043.[36]

2. Domestic Natural Gas Demand

Although domestic demand for natural gas is anticipated to grow, the rate of demand increase will continue to be outpaced by the growth of available supply. For example, though demand for natural gas has increased since 2009, production of natural gas has increased faster due to the shale gas revolution.[37] According to data published by the EIA, U.S. natural gas consumption was only 16% higher in 2017 than in 2000.[38] In its Annual Energy Outlook 2018, the EIA estimates long-term annual U.S. demand growth of only 0.8%, with demand expected to reach 34.48 Tcf in 2050.[39] In contrast, total U.S. dry gas production during the same period is projected to grow at an annual rate of 1.4%, with dry gas production estimated to reach 42.98 Tcf in 2050, as compared to 26.94 Tcf in 2016.[40]

Growth in demand for natural gas through 2040 is expected to be primarily driven by the power sector due, in part, to environmental regulations.[41] ICF forecasts an increase in gas use in

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[36] *Id*. at 36.

[37] 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.

[38] U.S. Energy Information Administration, *U.S. Natural Gas Total Consumption* (Sept. 28, 2018), https://www.eia.gov/dnav/ng/hist/n9140us2a.htm.

[39] AEO 2018 at tbl. 13.

[40] *Id.* at tbl. 14.

[41] 2016 ICF Report at 25.

the power generation market from 32% of total consumption in 2015 to 41% by 2043.[42] Similarly, the EIA forecasts that energy consumption in the electric power sector will increase on average by 0.7% per year to 11.44 Tcf in 2050 from 9.97 Tcf in 2016 in the Reference case.[43] Relatively small growth is anticipated in the industrial sector's demand for natural gas, as reducing energy intensity, or energy input per unit of industrial output, remains a top priority for manufacturers.[44] The EIA estimates that energy consumption in the industrial sector will increase by an average of 1.0% per year to 13.18 Tcf in 2050 from 9.33 Tcf in 2016 in the Reference case.[45] Energy efficiency gains are expected to somewhat offset gas demand growth in the residential and commercial sectors.[46] Natural gas consumption in the commercial sector will increase only by 0.7% per year to 3.94 Tcf in 2050 from 3.11 Tcf in 2016 in the EIA Reference case.[47] The residential sector is forecasted to have only 0.1% growth in natural gas consumption to 4.54 Tcf in 2050 from 4.35 Tcf in 2016.[48] Under the ICF Base Case, which assumes no exports from the Project, U.S. and Canadian natural gas consumption in 2040 is expected to be over 50 Tcf (LNG and pipeline exports included).[49] Despite the projected growth in domestic demand through the forecast period of 2040, U.S. natural gas resources, especially unconventional supply from shale resources, are wholly adequate to satisfy domestic demand as

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42 *Id.*

43 AEO 2018 at tbl. 13.

44 2016 ICF Report at 26.

45 AEO 2018 at tbl. 13.

46 2016 ICF Report at 26.

47 AEO 2018 at tbl. 13.

48 *Id.*

49 2016 ICF Report at 25.

well as the added demand of LNG exports from the Project, even when other LNG exports are assumed.

3. Effects on Domestic Prices of Natural Gas

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

The first part of the 2012 studies consisted of an EIA report evaluating how LNG exports would affect domestic energy consumption, production, and prices under various scenarios involving either 6 Bcf per day or 12 Bcf per day (the "2012 EIA Study").[50] The 2012 EIA Study projected that natural gas prices would rise over time, even without additional LNG exports.[51] 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 demand scenarios, including scenarios with unlimited LNG exports ("2012 NERA Study").[52] In each of the scenarios analyzed, NERA found that the United States would experience net economic benefits from increased LNG exports.[53] With regard to the effect of natural gas prices,

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50 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.

51 *Id.* at 6.

52 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.

53 *Id.* at 6.

NERA further projected that "price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios."[54] NERA also indicated that the peak natural gas export levels and resulting price increases analyzed by the 2012 EIA Study are "not likely,"[55] namely because U.S. exports would fall far short of the levels of exports assumed in the 2012 EIA Study.[56] 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.[57] The 2012 NERA Study further found that the net positive economic results became greater with higher levels of exports.[58]

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").[59] 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.[60] The 2014 EIA Study projected that, under the Annual Energy Outlook 2014 Reference Case, the increased LNG export levels analyzed would lead to a 2% to 5% increase in residential natural gas prices between 2015 and

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54 *Id.* at 2.

55 *Id.* at 9.

56 *Id.* at 12.

57 *Id.* at 6.

58 *Id.* at 12.

59 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.

60 2014 EIA Study.

2040 compared to baseline projections.[61] 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.[62] 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.[63] That limitation notwithstanding, the EIA 2014 Study estimated that higher LNG exports would result in gross domestic product ("GDP") increases across all scenarios.[64]

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.[65] The 2015 LNG Export Study found that LNG exports would raise domestic prices and lower international prices.[66] 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).[67] Nevertheless, the 2015 LNG Export Study found that these potentially adverse outcomes would be offset by the overall net macroeconomic

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61 *Id.* at 12.

62 *Id.*

63 *Id.*

64 *Id.* at 24-25.

65 2015 LNG Export Study at 82.

66 *Id.* at 8.

67 *Id.*

benefits of increased LNG exports, finding that "[a]cross the domestic cases, the positive impacts of higher U.S. gas production, greater investment in the U.S. natural gas sector, and increased profitability of U.S. gas producers typically exceeds the negative impacts of higher domestic natural gas prices associated with increased LNG exports."[68] 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.[69] 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.[70] 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."[71]

Most recently, NERA published another study ("2018 NERA Study") examining the probability and macroeconomic impact of various lower-48 sourced LNG export scenarios.[72] 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

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68 *Id.* at 16.

69 *Id.* at 8.

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

71 *Id.* at 110.

72 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.

2050 time period. Specifically, the 2018 NERA Study develops 54 scenarios by identifying various assumptions for domestic and international supply and demand conditions to capture a wide range of uncertainty in the natural gas markets.[73] "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."[74] 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.[75]

In an independent analysis commissioned by Port Arthur LNG, ICF found that the price increases due to additional LNG exports produced by Port Arthur LNG 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 Port Arthur LNG.[76] Nevertheless, because unconventional production will increasingly be relied upon to offset declining conventional production,[77] and the cost of production of unconventional natural gas is estimated to be much lower on a per-unit basis than conventional sources,[78] the natural gas price

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73 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.

74 *Id.* at 14.

75 *Id.* at 18, 20.

76 2016 ICF Report at 29.

77 *Id.* at 14.

78 *Id.* at 15.

increase resulting from increased demand will be minimal.[79] In the ICF Base Case, gas prices at Henry Hub are expected to increase gradually from approximately $2.61/MMBtu in 2015 to $5.88/MMBtu in 2043.[80] 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.[81]

The 2016 ICF Report supports the conclusion that the exports proposed in the Non-FTA Application will have a minimal adverse effect on domestic natural gas prices. According to ICF, by 2040, the increase in the Henry Hub natural gas price attributable to Port Arthur LNG is only $0.11/MMBtu, from an estimated 2040 price of $5.88/MMBtu (with some LNG exports, but not the Project) to a 2040 price with the Project of $5.99/MMBtu.[82]

C. Other Public Interest Considerations

1. <u>Local, Regional, and National Economic Benefits</u>

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

The construction and operation of the Project will result in significant employment benefits across a number of industries both locally and nationwide. Including direct, indirect, and induced employment, the Project will result in the creation of an average of nearly 41,000 jobs for the U.S. economy annually from 2019 through 2043.[83] Additionally, the Project is expected to result in approximately 5,700 jobs annually in Texas over the same forecast period.[84] ICF estimates that, as a result of this substantial job creation, the Project will lead to a

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79 *Id.* at 29.

80 *Id.*

81 *Id.*

82 *Id.* at 50.

83 *Id.* at 52.

84 *Id.* at 57.

cumulative increase of almost 1,067,000 job-years for the United States economy as a whole and 143,000 job-years for the Texas economy through 2043.[85]

Further, Port Arthur LNG exports will increase tax revenues on both the state and federal level. Total government revenues in Texas (including fees and taxes on personal income, corporate income, sales, property, oil and gas severance, and employment) are estimated to increase by $240 million annually through 2043 with the Project.[86] This equates to a cumulative increase in Texas government revenues of approximately $6.0 billion.[87] LNG exports from Port Arthur LNG are estimated to result in an increase in collective government revenues of $3.9 billion annually.[88] This translates to a cumulative increase of $102 billion in governmental revenue over the forecast period between 2019 and 2043.[89]

The Project will make a significant contribution to the national economy. The additional LNG volumes exported from Port Arthur LNG could add $11 billion to the U.S. economy annually over the period from 2019 through 2043, resulting in a cumulative contribution of $287 billion including the value of associated liquids produced with incremental natural gas and multiplier effects.[90] In Texas alone, the Project is expected to add $1.9 billion to the economy annually ($46.3 billion over the forecast period).[91]

The Project will result in substantial local, regional and national net economic benefits and will be an important source of new capital investment and job creation. The benefits of the

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85 *Id.* at 52, 57.

86 *Id.* at 58.

87 *Id.*

88 *Id.* at 54.

89 *Id.*

90 *Id.* at 55.

91 *Id.* at 59.

Project will first be realized prior to the commencement of construction (when orders for equipment and engineering and other services are placed) and will continue during construction and over the 20-year export term.

2. Increased Exports and International Trade

According to ICF, Port Arthur LNG will generate an expected cumulative value of approximately $137 billion of LNG exports between 2019 and 2043, which will favorably influence the balance of trade that the United States has with its international trading partners.[92] In 2017, the U.S. trade deficit increased to $566.3 billion, reflecting $2.3 trillion in exports and $2.9 trillion in imports.[93] According to ICF, the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $5.3 billion annually between 2019 and 2043, based on the value of LNG export volumes, liquids produced in association with incremental natural gas, and other trade effects.[94]

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 trading partners and allies. The export of domestically produced LNG will promote liberalization of the global gas market by fostering increased liquidity and trade at prices established by market forces. Though the price of LNG has recently been volatile, the price of LNG in Asian markets remains significantly higher than that of U.S. LNG.[95]

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[92] *Id.* at 56.

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

[94] 2016 ICF Report at 56.

[95] *See, e.g.,* The World Bank, *World Bank Commodities Price Data (The Pink Sheet)* (June 4, 2018), http://pubdocs.worldbank.org/en/799841528151608411/CMO-Pink-Sheet-June-2018.pdf (the average natural gas price in May 2018 was $2.78 per MMBtu in the United States, while the average LNG price was $9.40 per MMBtu

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

3. Environmental Benefits

LNG exports can have significant environmental benefits as natural gas is cleaner burning than other fossil fuels. For example, the DOE's Life Cycle Analysis Greenhouse Gas ("GHG") 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."[96] Many economies are looking to LNG to displace coal as a means of improving local air quality conditions and an increased supply of natural gas made possible through LNG exports can help position the United States as a leader in the move toward more diverse fuel supplies.

VI. REVIEW OF ENVIRONMENTAL EFFECTS

The construction and operation of the Project will be subject to authorization by FERC. On March 20, 2015, Port Arthur LNG submitted a request to initiate FERC's pre-filing process for the proposed Project facilities. FERC issued a letter approving this request on March 31, 2015. This constituted the initial step in a comprehensive and detailed environmental review by

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

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

FERC of the proposed Project under the National Environmental Policy Act ("NEPA")[97] prior to authorizing the construction of the Project facilities. Since then, Port Arthur LNG has held multiple open houses to explain the Project, identify interests, and resolve concerns of interested stakeholders early in the review process. On June 24, 2015, FERC issued a notice of intent to prepare an Environmental Impact Statement ("EIS") to evaluate the environmental effects of the Project. The notice also initiated a scoping process to gather input from the public and interested agencies on potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental effects of the Project. On July 13, 2015, FERC held a public scoping meeting on the Project in Port Arthur, Texas. The FERC Application was submitted on November 29, 2016. On September 28, 2018, the FERC announced the availability of a Draft EIS for the Project.[98] The Draft EIS was prepared assuming that the Project is capable of producing the full volume requested in this proceeding, as amended hereby.[99]

As required by NEPA and FERC's regulations, Port Arthur LNG will design the Project facilities to minimize or mitigate any potential adverse environmental effects. During the pre-filing process, Port Arthur LNG submitted thirteen publicly available draft resource reports to FERC assessing the effects of the Project on existing land, water, and air resources and discussing measures to mitigate potential adverse effects. Port Arthur LNG submitted revised versions of the resource reports as part of the FERC Application, which incorporated comments to the draft resource reports from FERC staff. The environmental effects for the Project are anticipated to be very similar to those analyzed and addressed in 2005 for the LNG import

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97 42 U.S.C. §§ 4321, et seq. (2012).

98 Draft Environmental Impact Statement for Port Arthur Liquefaction Project, Texas Connector Project, and Louisiana Connector Project, *Port Arthur LNG, LLC*, Docket No. CP17-20-000 (Sept. 28, 2018).

99 *Id*. § 1.2.2.4 ("The two liquefaction trains would be capable of producing a total of 13.5 MTPA of LNG . . .").

terminal,[100] where the site of the Project was found to be an acceptable location for siting an LNG facility and to have minimal adverse effects.[101] These known effects will be accounted for and addressed early while planning and developing the Project. In addition to the authorization from the DOE/FE sought in the Non-FTA Application (as supplemented by this Amendment) and the authorization from FERC, Port Arthur LNG will seek the necessary permits from, and conduct consultations with, other federal, state, and local agencies.

VII. APPENDICES

The following appendices are included with this Amendment:

Appendix A	Verification
Appendix B	Opinion of Counsel
Appendix C	2016 ICF Report

VIII. CONCLUSION

For the reasons set forth above, Port Arthur LNG respectfully submits this Amendment to the Non-FTA Application, and requests that the DOE/FE issue an order granting Port Arthur LNG authorization to export for a 20-year term on its own behalf and as agent for others, approximately 698 Bcf/year (equivalent to approximately 13.5 MTPA) of domestically produced LNG to any country (i) with which the United States does not have an FTA requiring national treatment for trade in natural gas (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy.

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100 *See Port Arthur LNG, LP*, 115 FERC ¶ 61,344 (2006).

101 *See* Final Environmental Impact Statement for the Port Arthur LNG Project, *Port Arthur LNG, LP*, Docket No. CP05-83-000 (Apr. 28, 2006).

Respectfully submitted,

/s/ _Jerrod L. Harrison_____

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Counsel for Port Arthur LNG, LLC

Dated: October 19, 2018

APPENDIX A

VERIFICATION

County of San Diego)
)
State of California)

BEFORE ME, the undersigned authority, on this day personally appeared E. Scott Chrisman, who, having been by me first duly sworn, on oath says that he is Vice President for Port Arthur LNG, LLC, and is duly authorized to make this Verification on behalf of such company, that he has read the foregoing instrument, and that the facts therein stated are true and correct to the best of his knowledge, information, and belief.

E. Scott Chrisman
Vice President, Port Arthur LNG, LLC

SWORN TO AND SUBSCRIBED before me on the ____ day of __________, 2018.

____
Notary Public Signature

SEAL:

see attached

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

STATE OF CALIFORNIA)
)
COUNTY OF SAN DIEGO)

Subscribed and sworn to (or affirmed) before me on this 19th day of October, 2018, by E. Scott Chrisman, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

B. Warbritton
Notary Public in and for said State

(SEAL)

B. WARBRITTON
COMM. #2091163
Notary Public - California
San Diego County
My Comm. Expires Nov. 23, 2018
NR01

APPENDIX B

October 19, 2018

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

RE: *Port Arthur LNG, LLC*
Amendment to Application of Port Arthur LNG, LLC for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Ms. Sweeney:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the United States Department of Energy, 10 C.F.R. § 590.202(c) (2017). I am counsel to Port Arthur LNG, LLC ("PALNG"). I have reviewed the organizational and internal governance documents of PALNG and it is my opinion that the proposed export of natural gas as described in the application filed by PALNG, to which this Opinion of Counsel is attached as Appendix B, is within the company powers of PALNG.

Respectfully submitted,

/s/ Jerrod L. Harrison
Jerrod L. Harrison
Counsel for Port Arthur LNG, LLC

APPENDIX C

Economic Impacts of the Port Arthur Liquefaction Project

Information for DOE Non-FTA Permit Application

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

November 11, 2016

Submitted by:
ICF

Contact:
Harry Vidas
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Andrew Griffith
Anthony Ciatto

Table of Contents

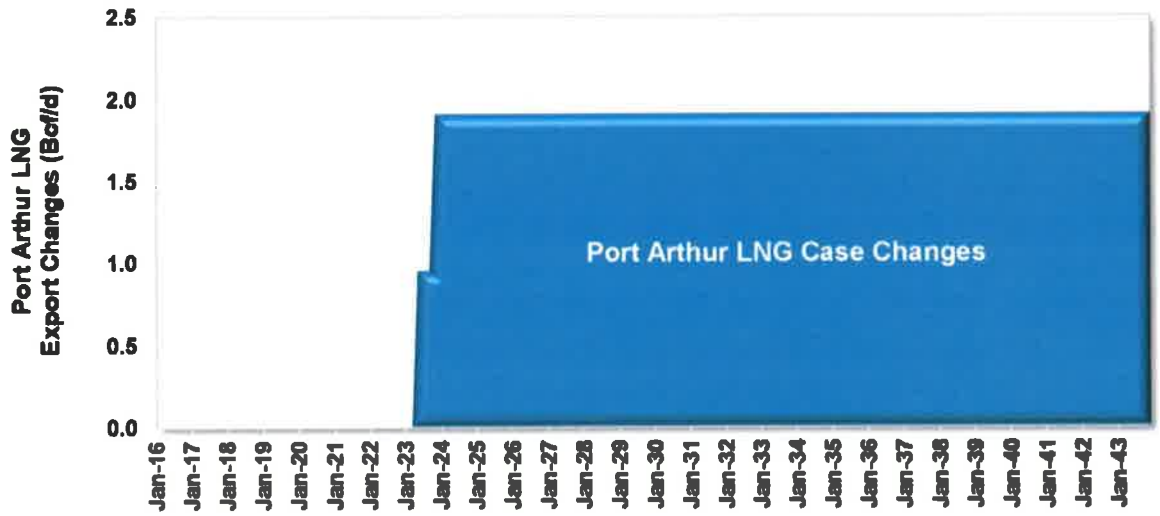
List of Exhibits

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 Port Arthur LNG export facility (Port Arthur), located in Port Arthur, Texas. The LNG export facility is proposed to come on-line in 2023, with proposed capacity of 698[1] Bcf per year (13.5 million metric tons per annum), or 1.91 Bcfd, as shown in Exhibit 1-1: Port Arthur LNG Export Volumes.

Exhibit 1-1: Port Arthur LNG Export Volumes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Port Arthur export facility. In order to assess these impacts, ICF conducted two alternative scenario runs using its proprietary Gas Market Model (GMM):

1) **Base Case** - no Port Arthur export facility;
2) **Port Arthur LNG Case** - Base Case with 1.91 Bcfd additional export volumes from Port Arthur.

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

[1] This volume does not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

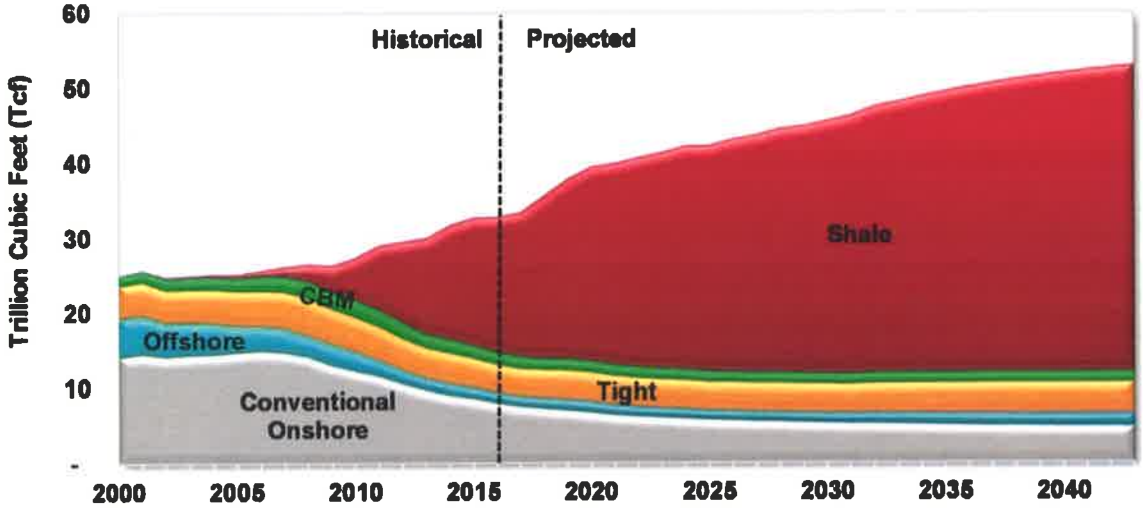
(NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for Port Arthur exports. GMM also solved for changes to natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins and from Texas were separately estimated.

- **Quantify upstream and the plant capital and operating expenditures:** ICF translated the natural gas and liquids production changes from GMM into annual capital and operating expenditures that will be required for the additional production. In addition, based on Port Arthur LNG's cost estimates, ICF assessed the annual capital and operating expenditures required to support the LNG exports at the facility.
- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant and upstream expenditures as inputs to the IMPLAN input-output model to assess their economic impacts for the U.S. and Texas. The model quantifies the economic stimulus impacts from capital and operational investments. For example, any amount of annual expenditures on drilling and completing new gas wells would support a certain number of direct employees (e.g., natural gas production employees), indirect employees (e.g., drilling equipment manufacturers), and induced employees (e.g., consumer industry employees).
- **Quantify the economic and employment impacts:** Results of IMPLAN allows ICF to estimate the impacts of the projected incremental expenditures from supporting Port Arthur exports on the national and Texas economies. The impacts include direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and international balance of trade.

1.2. Key U.S. and Canadian Natural Gas Market Trends

U.S. and Canadian natural gas production has grown considerably over the past several years, led by unconventional production, especially from shale resources. The growth trend is expected to continue over the next 30 years (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 gas-directed horizontal drilling in the Marcellus and Utica shales, which will account for over half of the incremental production. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

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



Source: ICF GMM® Q4 2016

In the long-term, the power sector presents the largest single source of incremental domestic gas consumption, though near-term gas market growth is driven by growth in export markets (LNG and Mexican exports). Significant power sector gas demand growth is expected after 2017, as natural gas capacity replaces coal capacity, with accelerated growth after 2020 when federal carbon regulation is expected to be initiated. After 2030, nuclear power plant retirements start a new round of growth in natural gas consumption.

Increased demand growth will push gas prices above $4 per MMBtu[2] after 2025, with long-term prices expected to range between $5 and $6 per MMBtu. Prices are high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand growth. Long-term demand growth will be shaped by future environmental policies and their impact on power sector gas demand.

U.S. LNG exports are projected to reach 10.5 Bcfd by 2028, with volumes from the Gulf Coast expected to reach 9.4 Bcfd, based on ICF's review of approved projects. These volumes do not include the additional Port Arthur export volumes associated with this economic impact analysis and include liquefaction fuel of 10% at the export facilities.

[2] All dollar figure results in this report are in 2015 real dollars, unless otherwise specified.

1.3. Key Study Results

ICF's analysis shows that the Port Arthur LNG export facility has minimal impact on the U.S. natural gas price. The Henry Hub natural gas price is expected to increase by $0.09/MMBtu on average for the forecast period of 2019 to 2043, averaging $4.77/MMBtu over the forecast period, with the Port Arthur export facility, compared with $4.68/MMBtu without the export facility, as shown in Exhibit 1-3. The Port Arthur LNG Case natural gas prices at Henry Hub are expected to reach $5.88/MMBtu in the Base Case and $5.99 in the Port Arthur LNG Case by 2043, indicating a price increase of $0.11/MMBtu attributable to the Port Arthur LNG export volumes of 1.91 Bcfd.

The Port Arthur LNG export facility is expected to have minimal impact on the U.S. supply availability and market price because the volume represents a small amount of the North American natural gas resources and total market demand. Total export volumes from the facility over the 20-year period from 2023 to 2043 is approximately 14.3 Tcf. This represents roughly 1.3% of Lower 48 and Canadian natural gas resources that can be produced with current technology at less than $5.00/MMBtu, and about 2.1% of the total U.S. domestic natural gas consumption during the same period.

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

Year	Henry Hub Natural Gas Price (2015$/MMBtu)		
	Base Case	Port Arthur LNG Case	Port Arthur LNG Case Change
2019	$ 3.71	$ 3.71	$ -
2023	$ 3.73	$ 3.86	$ 0.132
2025	$ 3.99	$ 4.11	$ 0.114
2030	$ 4.67	$ 4.76	$ 0.096
2035	$ 5.13	$ 5.24	$ 0.103
2040	$ 5.60	$ 5.71	$ 0.109
2043	$ 5.88	$ 5.99	$ 0.107
2019-2043 Avg	*$ 4.68*	*$ 4.77*	*$ 0.087*

Source: ICF

ICF's analysis concluded that Port Arthur LNG export volumes could lead to significant economic impacts, on average, creating 41,000 annual jobs for the U.S. economy, approximately 5,700 in Texas between 2019 and 2043. This means a cumulative impact through 2043 of over 1,000,000 job-years for the U.S. and 143,000 job-years for Texas. In addition, the project could add over $11 billion to the U.S. economy annually ($287 billion over the forecast period), and $1.85 billion annually in Texas ($46.3 billion over the forecast period). The additional Port Arthur LNG exports would also increase tax revenues. At the U.S. level, federal, state, and local governments are expected to receive an additional $3.9 billion annually; and Texas state and local taxes are expected to increase by $240 million annually. Throughout the 25-year forecast period, the U.S. will receive $102 billion additional revenue from taxes and Texas will receive $6 billion.

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

Region	2019-2043 Average Annual Impact			2019-2043 Cumulative Impact		
	Jobs (Jobs)	Value Added (2015$ Million)	Government Revenues (2015$ Million)	Jobs (Job-years)	Value Added (2015$ Million)	Government Revenues (2015$ Million)
U.S.	41,071	$ 11,034.3	$ 3,924.3	1,067,162	$ 286,828.2	$ 102,009.7
Texas	**5,720**	**$ 1,852.8**	**$ 240.3**	**143,011**	**$ 46,319.9**	**$ 6,007.8**

Source: ICF

2. Introduction

Port Arthur LNG tasked ICF with assessing the economic and employment impacts of additional liquefied natural gas (LNG) exports from its Port Arthur, TX LNG export facility.

Exhibit 2-1 and Exhibit 2-2 show Port Arthur's location and preliminary layout, respectively.

Exhibit 2-1: Port Arthur LNG Location Map

Exhibit 2-2: Port Arthur LNG Preliminary Layout

For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without the 1.91 Bcfd export facility and estimated the changes between the two scenarios for the total U.S. and Texas:

- Natural gas production
- Liquids production, including oil, condensate, and natural gas liquids (NGLs), including ethane, propane, butane, and pentanes plus
- LNG plant capital expenditures
- LNG plant operating expenditures
- Upstream capital expenditures to support the natural gas and liquids production
- Upstream operating expenditures
- Natural gas consumption
- Henry Hub natural gas prices
- Natural gas and liquids production value.

The changes in LNG plant capital and operating expenditure and upstream capital and operating expenditures were inputted into the IMPLAN model to estimate the export facility's impacts on the U.S. and 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) Port Arthur LNG Energy Market and Economic Impact Results
6) Bibliography
7) Appendices

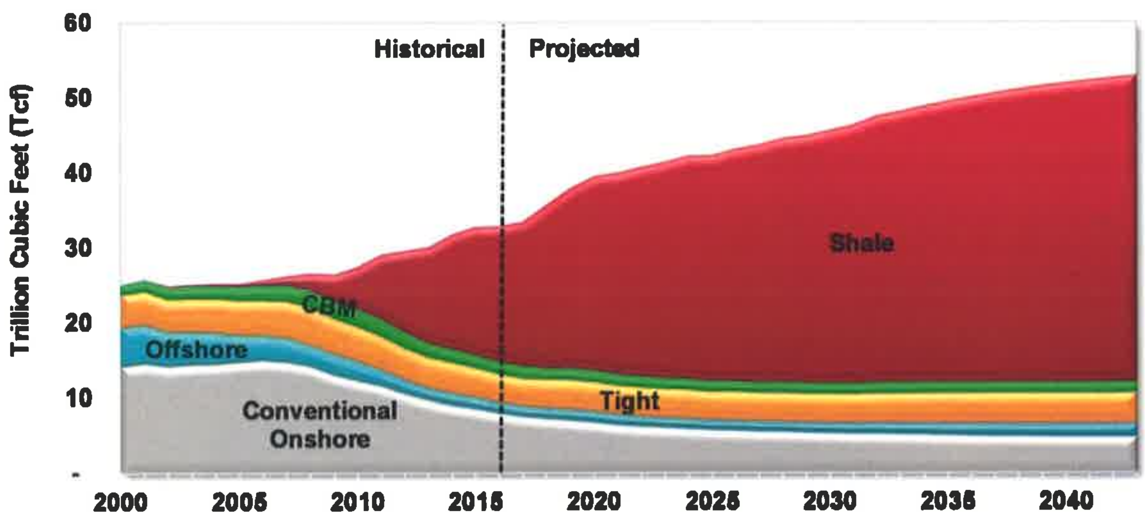
3. Base Case U.S. and Canadian Natural Gas Market Overview

This section discusses U.S. and Canadian Base Case natural gas market forecasts, starting with natural gas supply trends, including ICF's resource base assessment and comparisons with other assessments. The section then discusses trends in U.S. and Canadian demand through 2043, including pipeline and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

3.1. U.S. and Canadian Natural Gas Supply Trends

Over the past seven years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production, and is expected to grow further through 2043 and beyond (see Exhibit 3-1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional 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.

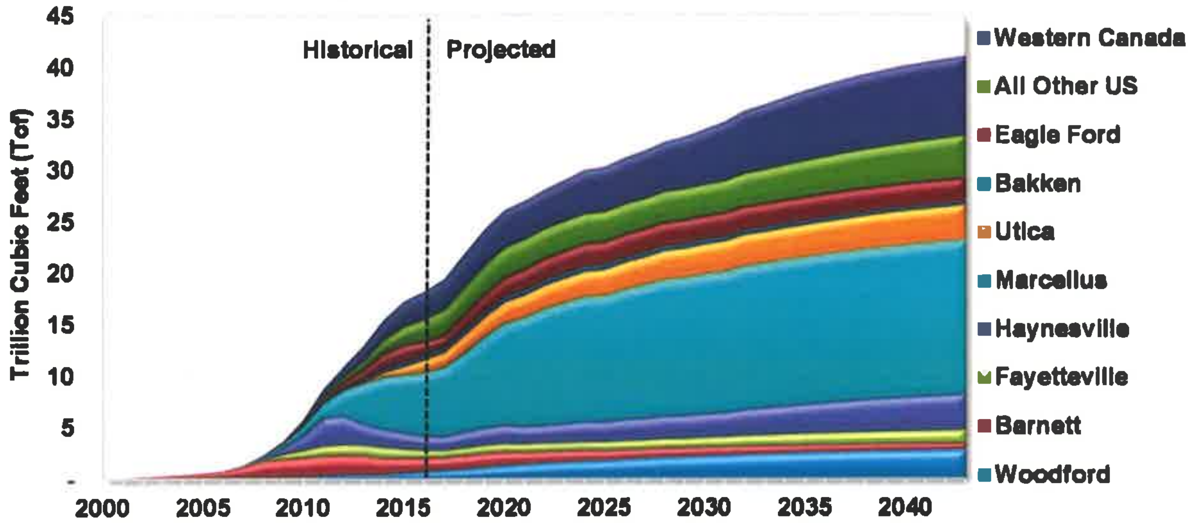
Exhibit 3-1: U.S. and Canadian Gas Supplies



Source: ICF GMM® Q4 2016

Production from U.S. and Canadian shale formations will grow from about 5.8 Tcf (15.9 Bcfd) in 2010 to nearly 41 Tcf (112 Bcfd) by 2043 (see exhibit above). The major shale formations in the U.S. and Canada are located in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, and Haynesville), South Texas (Eagle Ford), and west Canada (Montney and Horn River). The Bakken Shale, which in the U.S. spans parts of North Dakota and Montana, is primarily an oil formation with natural gas volumes. ICF did not include potential shale formations in the U.S. that have not yet been evaluated or developed for gas production.

Exhibit 3-2: U.S. and Canadian Shale Gas Production



Note: Haynesville production includes production from other shales in the vicinity (e.g., the Bossier Shale).

Source: ICF GMM® Q4 2016

3.1.1. Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane (CBM)) will generally be much lower cost on a per-unit basis than conventional sources.[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. While the emerging stage of shale gas production, as well as the site-specific nature of unconventional production costs, mean uncertain production costs, shale plays such as the Marcellus are proving to be among the least expensive (on a per-unit basis) natural gas sources.

ICF has developed resource cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the curve are all of the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The unconventional GIS plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas is almost all development drilling. Offshore undiscovered conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and transportation. Then, those cost factors are added to allow costing at points

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

farther downstream of the wellhead. Costs can be adjusted to a "Henry Hub" basis for certain type of analysis that considers the remoteness of the resource.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies, and have been subsequently refined and expanded. North American plays include all of the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration

(EIA) is a source for operating and equipment costs.[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

North American supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in Exhibit 3-3. The supply curves were developed on an "oil-derived" basis. That is to say that the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

For the Lower-48, 2,244 Tcf of gas resource is available at $10.00 per MMBtu or less. For Canada there is 481 Tcf at $10.00 per MMBtu or less. At $5.00 per MMBtu, 944 Tcf is available in the Lower-48 and approximately 149 Tcf is available in Canada.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact,

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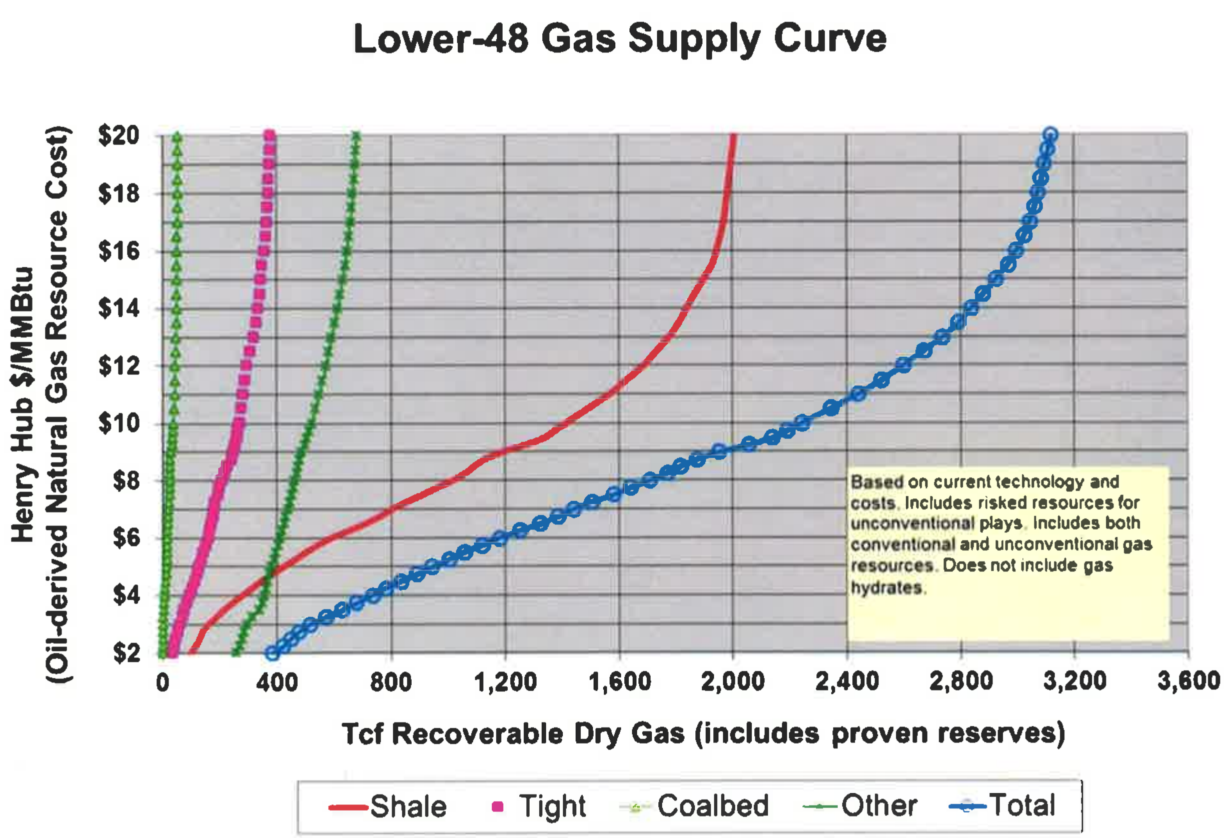
4 American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.
5 Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/
6 U.S. Energy Information Administration.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

large improvements in these areas have been made historically and are expected in the future. (See section 4.1.3 for discussion of technology trends assumed in this study.)

Exhibit 3-3: U.S. Lower-48 Gas Supply Curves



Source: ICF

3.1.2. ICF Resource Base Estimates

ICF has assessed conventional and unconventional North American oil and gas resources and resource economics. ICF's analysis is bolstered by the extensive work we have done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system (GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays. Resource assessments are derived either from credible public sources or are generated in-house using ICF's GIS-based models.

The following resource categories have been evaluated:

> ***Proven reserves*** – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.
>
> ***Reserve appreciation*** – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's

approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[7]

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 3-4 and Exhibit 3-5 on the following page, summarize the current ICF gas and crude oil assessments for the U.S. and Canada. Resources shown are “technically recoverable resources.” This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The assessment basis is year-end 2013 (as this is the latest date for published proved reserves).

[7] 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/

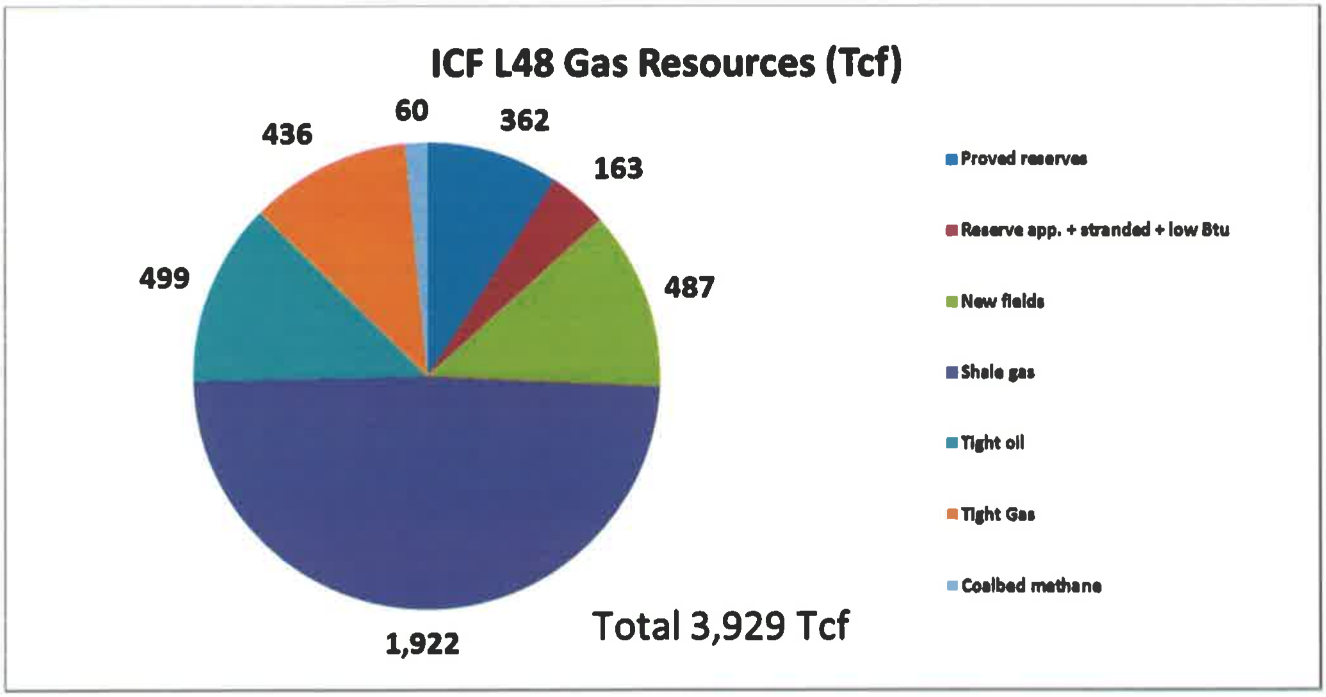
Exhibit 3-4: ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of year-end 2014; excludes Canadian and U.S. oil sands)

Lower 48	Dry Total Gas Tcf	Crude and Cond. Bn. bbls
Proved reserves	362	37
Reserve appreciation and low Btu	163	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	487	71
Shale gas and condensate	1,922	36
Tight oil (excl. shale gas resource)	499	118
Tight gas	436	4
Coalbed methane	60	0
Lower 48 Total	**3,929**	**325**
Canada		
Proved reserves	71	4.6
Reserve appreciation and low Btu	29	2.9
Stranded frontier	40	0.0
Enhanced oil recovery	0	3.0
New fields	219	11.8
Shale gas and condensate	546	0.2
Tight oil (excl. shale gas resource)	119	26.2
Tight gas (with conventional)	0	0.0
Coalbed methane	75	0.0
Canada Total	**1,099**	**49**
Lower-48 and Canada Total	**5,028**	**374**

Sources: ICF, EIA (proved reserves)

Exhibit 3-5: Lower-48 Gas Resources



Source: ICF

3.1.3. Resource Base Estimate Comparisons

The ICF gas resource base is significantly higher than most published assessments. A comparison of Lower-48 resources by category is shown in Exhibit 3-6. For example, the ICF Lower-48 shale gas assessment of 1,922 Tcf can be compared to the EIA's 500 Tcf or the Potential Gas Committee's 1,253 Tcf.

The ICF natural gas resource base assessment for the U.S. lower 48 states is higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and get added to the upper end of the natural gas supply curves. Such resources may eventually get exploited if natural gas prices increase substantially or if upstream technological advances improve well recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2043.

There are several other reasons for the magnitude of the differences:

- More plays are included. ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the

Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.

- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.
- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.
- ICF looks at infill drilling (or new technologies that can substitute for infill wells) that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas. ICF shale resources are based upon the first level of infill drilling, with primary spacing based upon current practices. In other words, if the current practice is 120 acres and 1,000 feet spacing between horizontal well laterals, our assessment assumes an ultimate spacing can be (if justified by economics) 60 acres and 500 feet spacing between laterals.
- For conventional new fields, ICF includes areas of the Outer Continental Shelf (OCS) that are currently off-limits, such as the Atlantic and Pacific OCS.
- ICF evaluates all hydrocarbons at the same time (i.e., dry gas, NGLs, and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.
- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

Exhibit 3-6: Comparison of Published Lower-48 Gas Resource Assessments

ICF, October 2016
TCF of technically recoverable gas; excludes proved reserves of 362 Tcf as of year end 2014

Group	Shale Gas	Tight Oil	Tight Gas	Coalbed	Conventional	Unproved Total	Including Proved
ICF, 2016	**1,922**	**499**	**436**	**60**	**650**	**3,567**	**3,929**
ICF, 2015	1,922	350	436	60	650	3,418	---
ICF, 2014	1,964	172	438	66	707	3,347	---
EIA AEO, 2015	500	94	355	120	628	1,697	---
EIA AEO, 2014	489	49	365	120	637	1,660	---
USGS and BOEM (current)	384	14	200	73	481	1,152	---
Potential Gas Committee, 2015	1,253	---	(with conv.)	101	919	2,273	---
Potential Gas Committee, 2013	1,073	---	(with conv.)	101	955	2,129	---
Advanced Resources Inc., 2012	1,219	---	561	124	730	2,634	---
EIA AEO, 2011	827	---	369	117	703	2,016	---
Potential Gas Committee, 2011	687	---	(with conv.)	102	858	1,647	---
MIT, 2011	631	---	173	115	951	1,870	---

Source: ICF

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although we generally did not include shale gas reservoirs with a net thickness of less than 50 feet. A detailed comparison of the ICF, EIA, and U.S. Geological Survey (USGS) shale gas assessments by region is presented in Exhibit 3-7. The exhibit provides a better understanding of the differences in the major assessments. Most of the difference is with the Marcellus, Utica, Haynesville, Eagle Ford, and Fort Worth Barnett Shale plays. Another area of difference relates to plays such as the Utah Paradox Basin, Appalachian Basin Huron Shale, and Louisiana Bossier Shale that ICF has assessed but the other groups generally do not.

ICF has evaluated the 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 very low. 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. Our recoverable resource of 499 Tcf can be compared to the EIA assessment of 94 Tcf. 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.

Exhibit 3-7: Play-level Shale Gas Comparison

Technically Recoverable Resource, Tcf
ICF October 2016

		ICF	AEO 2015	USGS Current
Appalachia				
Marcellus		689	149	84
Huron		42	0	0
Other Devonian		15	24	10
Utica (OHWVPA)		445	53	38
NY Utica (moratorium)		56	--	--
	subtotal	1,247	226	132
Midcontinent				
Arkoma Fayetteville		32	20	13
Arkoma Caney		20	3	1
Arkoma Woodford		38	6	11
Anadarko Woodford (CANA)		36	12	16
	subtotal	126	41	41
Gulf Coast and Permian				
Haynesville		278	73	60
Bossier Shale		49	0	0
Fort Worth Barnett		46	18	26
Eagle Ford		90	48	52
Gulf Coast Pearsall		0	5	9
W. Texas Barnett/Woodford		23	12	35
Floyd/Conasauga		0	4	2
	subtotal	486	160	184
Rockies				
Green River Hilliard, etc		10	11	0
Uinta Mancos		0	9	0
San Juan Lewis		0	10	0
Paradox Basin		34	0	0
	subtotal	44	30	0
Michigan and Illinois		10	42	11
Other Lower- 48		9	1	16
Total		**1,922**	**500**	**384**

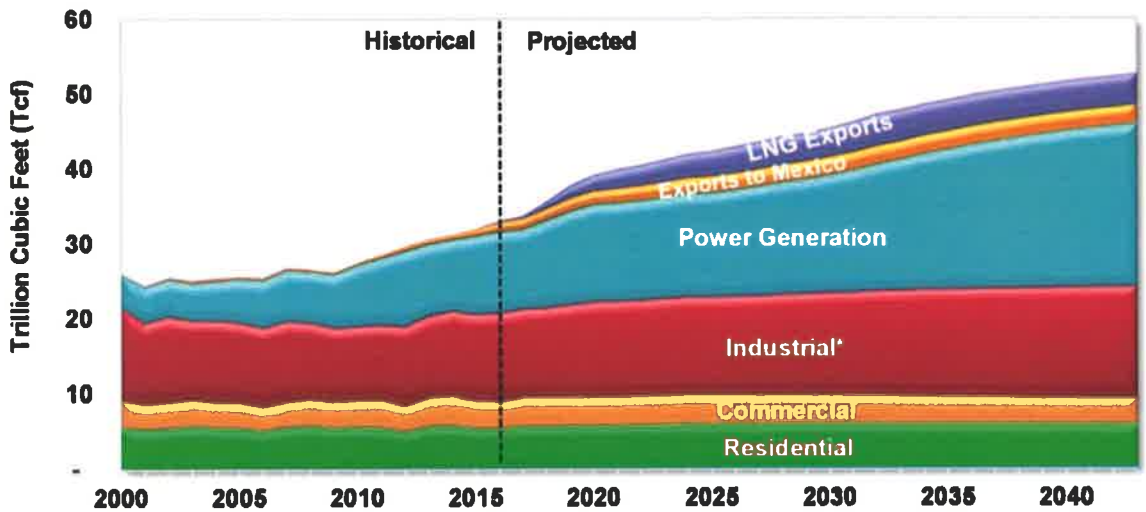
Source: Various compiled by ICF

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

While new LNG export facilities in the U.S. just started production early this year, power generation will see the bulk of incremental natural gas consumption growth over the foreseeable future, along with some growth in the industry sector, led by gas-intensive end uses such as petrochemicals, fertilizers, and transportation (compressed natural gas and LNG used in vehicles and off-road equipment). Exhibit 3-8 below shows ICF's U.S. and Canadian consumption forecast by sector.

Incremental power sector gas use between 2016 and 2043 is expected to comprise the largest share of total *incremental* U.S. and Canadian gas growth over the period, with gas-fired power generation expected to increase significantly over time. Growth in gas demand for power generation is driven by a number of factors. Currently, about 470 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada, and much of that capacity is underutilized and readily available to satisfy incremental electric load growth. Electricity demand has historically been linked to Gross Domestic Product (GDP). Prior to the 2007-2008 global recession, demand for electricity was growing at about two percent per year. Over the next twenty years, although GDP is forecast to grow at 2.6 percent annually from 2017 onward, electricity load growth is expected to average only about 0.9 percent per year, mainly due to implementation of energy efficiency measures. Even at this lower growth rate, annual electricity sales are expected to increase to nearly 4,100 Terawatt-hours (TWh) per year by 2021, or growth nearing 11 percent over 2010 levels (3,700 TWh annually).

Exhibit 3-8: U.S. and Canadian Gas Consumption by Sector and Exports



Source: ICF GMM® Q4 2016

* Includes pipeline fuel and lease & plant

The expanding use of natural gas in the power sector is driven in part by environmental regulations, primarily in the United States. ICF's Base Case reflects EPA's current rules for Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes Cross-State Air Pollution Rule (CSAPR), which was reinstated in January 2015. CSAPR has replaced the CAIR program, imposing regional and state caps on emissions of NO_X and SO_2. It also includes a charge on CO_2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO_2 to be implemented. The case generally leads to retirement and replacement of some coal-generating capacity with gas-based capacity. ICF also assumes that all current state renewable portfolio standards are met and other forms of generation are fairly flat. We also assume existing nuclear units have a maximum lifespan of 60 years, which results in over 27 GW of nuclear retirements by 2035. The Base Case forecasts an increase in gas use in the power generation market from 32 percent of total demand in 2015 to 41 percent by 2043. This growth in gas-fired generation and the accompanying growth in gas consumption is the primary driver of gas demand growth throughout the forecast period.

Industrial demand accounts for 16 percent of total gas use growth in U.S. and Canada during the 2015-2043 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.

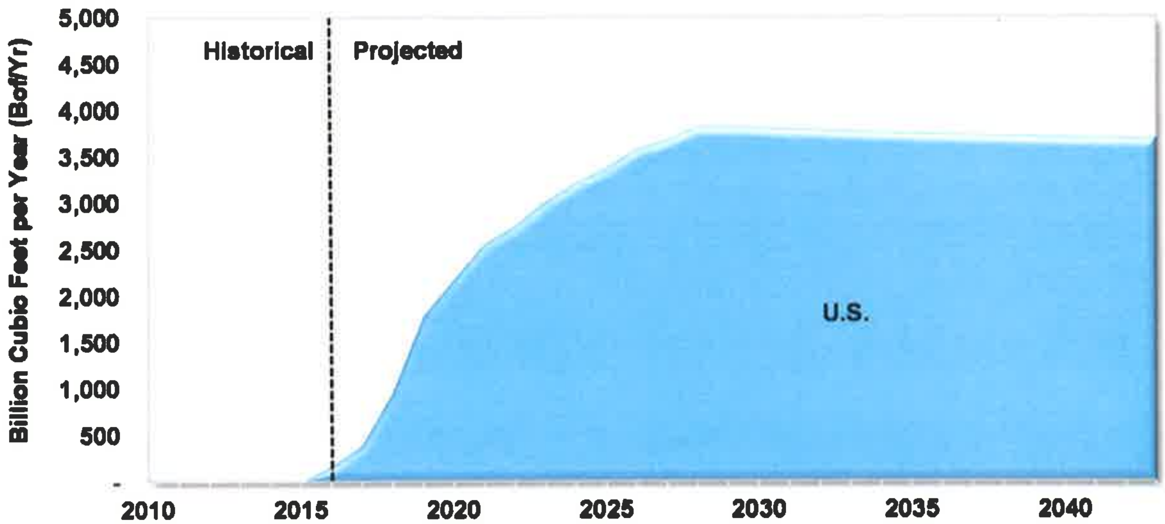
Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the 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 2.5 Tcf (7 Bcfd) by 2043, up from 1.0 Tcf (2.8 Bcfd) in 2015.

3.2.1. LNG Export Trends

The U.S. Department of Energy (DOE) has received 49 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, nineteen applications at eleven 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 6 U.S. LNG export facilities will be built: Sabine Pass, Freeport, Cove Point, Cameron LNG, Corpus Christi, and Elba Island. 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 approach 6 Bcfd with a utilization of less than 60% by 2020. As oil prices firm, U.S. LNG exports are projected to approach 9.3 Bcfd by 2025 (see exhibit below) and capacity utilization increases to about 80%. The U.S. LNG exports are expected to peak at about 10.5 Bcfd in 2029, as the increase in U.S. natural gas prices make U.S. LNG less competitive for new liquefaction capacity.

Exhibit 3-9: U.S. LNG Export Assumptions



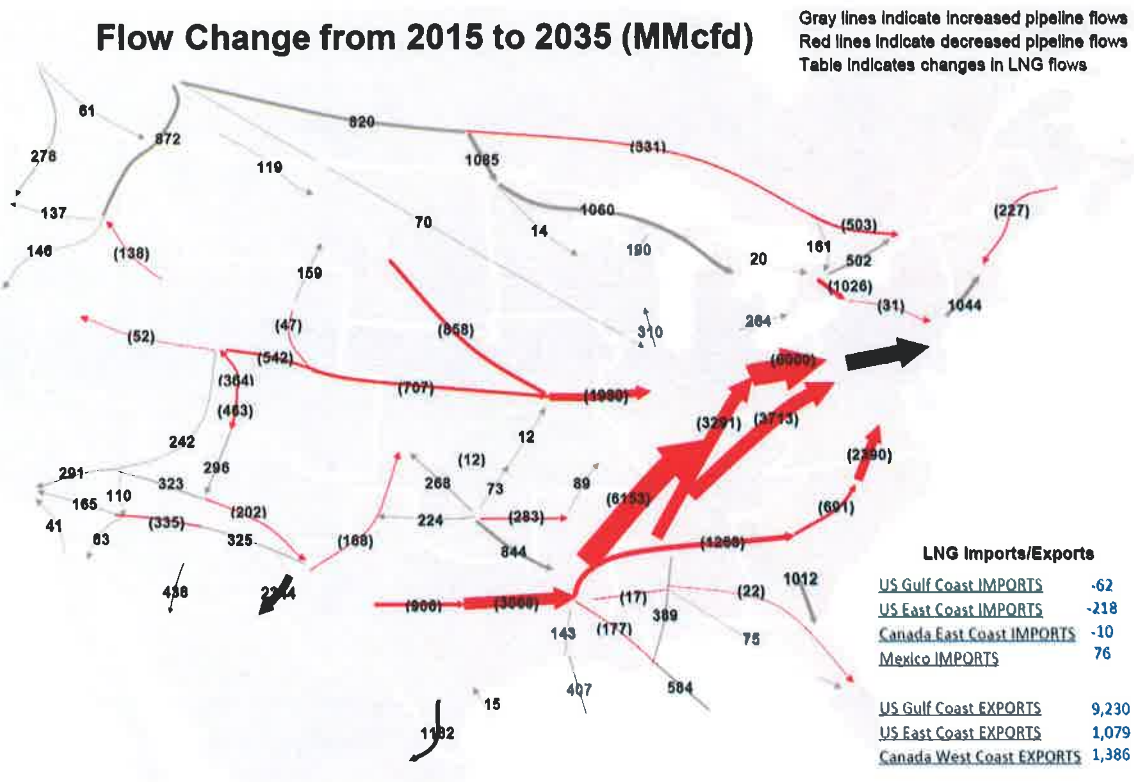
Source: ICF GMM® Q4 2016

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

As regional gas supply and demand continue to shift over time, there are likely to be significant changes in interregional pipeline flows. Exhibit 3-10 shows the projected changes in interregional pipeline flows from 2015 to 2035 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2015 and 2035, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit 3-10 illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. The growth in Marcellus Shale gas production in the Mid-Atlantic Region will displace gas that once was imported into that region, hence the red arrows entering the Mid-Atlantic Region from points north (Canada), Midwest (Ohio), and South Atlantic (North Carolina). In effect, the Mid-Atlantic Region becomes a major producer of gas and supplies gas to consumers throughout the East Coast. The flow of natural gas from Alberta through eastern Canada to the eastern U.S. will decline as Marcellus production displaces both imports from Canada and flows from the U.S. Gulf Coast. The red arrows from the Gulf Coast to the U.S. Northeast point towards a continuing trend of the economic Marcellus and Utica gas supplies displacing the traditional flows from the Gulf Coast towards Northeast.

Exhibit 3-10: Projected Change in Interregional Pipeline Flows



Source: ICF GMM® Q4 2016

The large increases in flows eastward from the West South Central Region (Texas, Louisiana, and Arkansas) are due to growing shale gas production in the region. However, most of this gas is consumed in the South Atlantic Region (Florida to North Carolina) where demand is growing. In addition, natural gas will be exported from the West South Central region via pipeline to Mexico and in the form of LNG exports that started from Sabine Pass export facility in 2016. The growing Marcellus gas production in the Mid-Atlantic Region will also displace gas flows from the West South Central Census Region to the South Atlantic states.

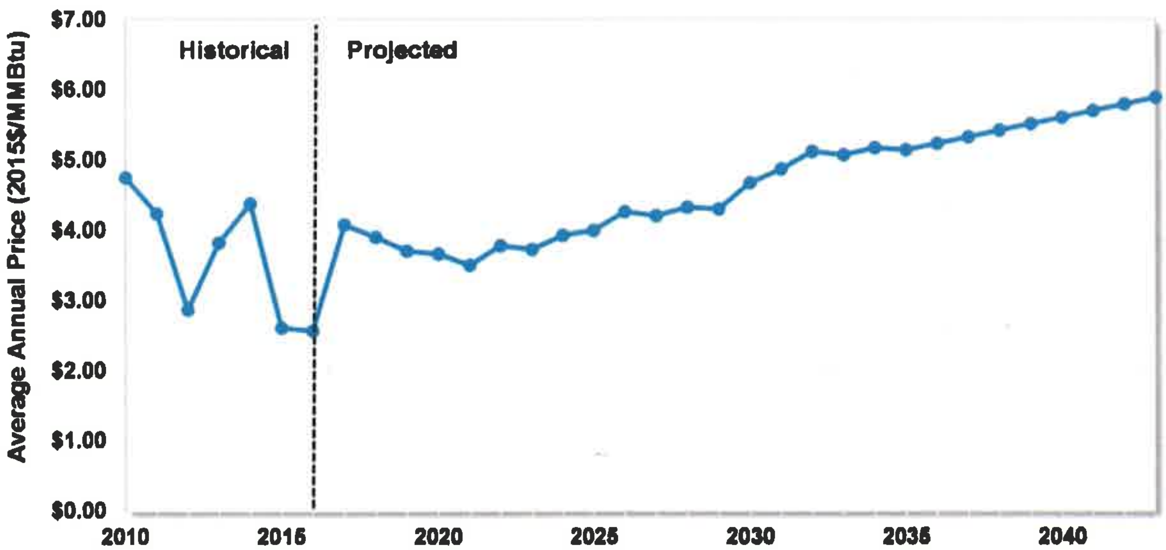
Eastward flows out of western Canada are projected to decline. Growth in production from shale gas resources in British Columbia (BC) and Alberta will be more than offset by declines in conventional gas production in Alberta until 2020, as well as growth in natural gas demand in western Canada. Strong industrial demand growth in western Canada for producing oil from oil sands will keep more gas in the western provinces. The planned LNG export facilities in British Columbia will also draw off gas supply once exports of LNG begin in 2030. Pipeline flows west out of the Rocky Mountains will increase to California. The completion of the Ruby Pipeline in 2011 allowed Rocky Mountain gas to displace gas coming from Alberta on Gas Transmission Northwest.

3.4. Natural Gas Price Trends

With growing gas demand and increased reliance on new sources of supply, the Base Case forecasts higher gas prices from current levels. Nevertheless, the cost of producing shale gas moderates the price increase. In the Base Case, gas prices at Henry Hub are expected to increase gradually, climbing from approximately $2.61 per MMBtu in 2015 to $5.88 per MMBtu in 2043 (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 3-11.

Exhibit 3-11: GMM Average Annual Prices for Henry Hub

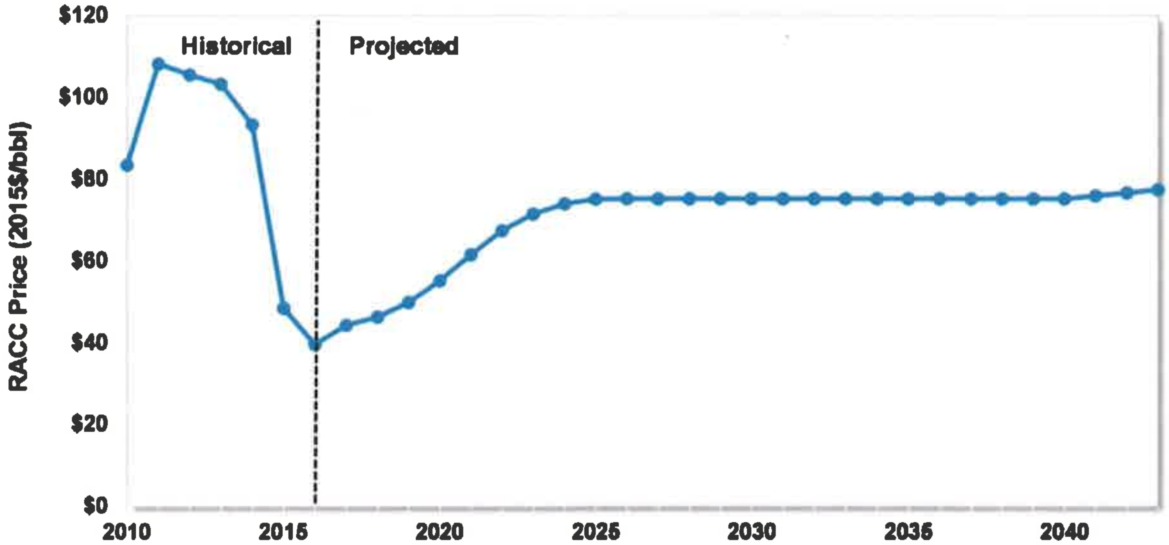


Source: ICF GMM® Q4 2016

3.5. Oil Price Trends

In the wake of recent market declines, ICF has revised its near-term oil price assumption downward to average below $40/bbl in 2016 due to the ongoing global supply surplus. ICF assumes that oil prices will follow a trajectory starting with recent spot prices and will rise to a constant real level reflecting a liquid traded mid-term price in the futures market of approximately $75/bbl (2015 dollars) after 2025 through 2040 and rise slightly thereafter as shown in the exhibit below.

Exhibit 3-12: ICF Oil Price Assumptions



Source: ICF GMM® Q4 2016

4. Study Methodology

This section describes ICF's methodologies in assessing U.S. and Canadian natural gas market dynamics, resource base assessments, and energy and economic impact modeling.

4.1. Resource Assessment Methodology

ICF assessments combine components of publicly available assessments by the USGS and the Bureau of Ocean Energy Management (BOEM/formerly the Mineral Management Service, MMS), industry assessments such as that of the National Petroleum Council, and our own proprietary work. As described in the previous section, in recent years, ICF has done extensive work to evaluate shale gas, tight gas, and coalbed methane using engineering-based geographic information system (GIS) approaches. This has resulted in the most comprehensive and detailed assessment of North America gas and oil resources available. It includes GIS analysis of over 30 unconventional gas plays.

On the resource cost side, ICF uses discounted cash flow analysis at various levels of granularity, depending upon the category of resource. For undiscovered fields, the analysis is done by field size class and depth interval, while for unconventional plays, DCF analysis is generally done on each 36-square-mile unit of play area. Exhibit 4-1 is a map of the U.S. Lower-48 ICF oil and gas supply regions.

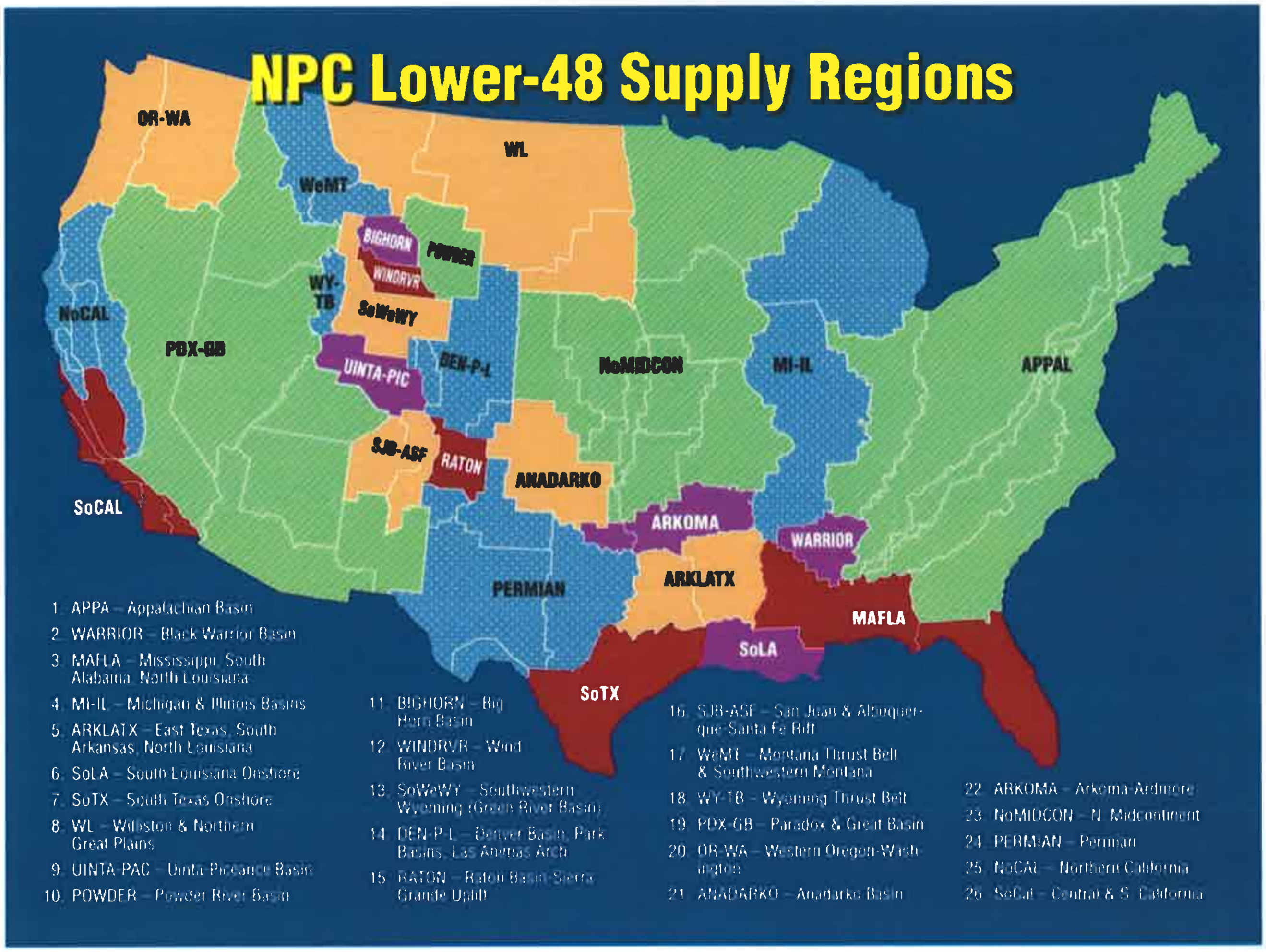
4.1.1. Conventional Undiscovered Fields

Undiscovered fields are assessed by 5,000-foot drilling depth intervals and a distribution of remaining fields by USGS "size class." Hydrocarbon ratios are applied to convert barrel of oil equivalent (BOE) per size class into quantities of recoverable oil, gas, and NGLs. U.S. and Canadian conventional resources are based largely on USGS and BOEM (formerly MMS) (and various agencies in Canada) assessments made over the past 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, both in terms of recoverable resources and their impact on economics.

The ICF unconventional gas GIS model is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about porosity, pressure gradient, and other information. The unit of analysis for gas-in-place and recoverable resources is a 6-by-6 mile or 36-square-mile grid unit. Gas-in-place is determined for free gas, adsorbed gas, and gas dissolved in liquids, and well recovery is modeled using a reservoir simulator.[8] Gas resources

[8] 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.	Assess-ment well spacing (acres)
	Shale		
1	Appalachian Marcellus Shale	39,100	40
2	Appalachian Huron Shale	22,941	80
3	NY Utica Shale	14,280	80
4	Ft. Worth Barnett Shale	26,300	40
5	Gulf Coast Haynesville Shale	7,400	40
6	Gulf Coast Bossier Shale	2,830	40
7	Texas Eagle Ford Shale	9,097	60
8	West Texas Barnett Shale	4,500	40
9	West Texas Woodford Shale	4,500	40
10	Arkoma Fayetteville Shale	2,600	60
11	Arkoma Woodford Shale	1,863	40
12	Arkoma Moorefield Shale	520	80
13	Arkoma Caney Shale	6,340	80
14	Anadarko Woodford Shale	1,776	40
15	Uinta Mancos Shale	7,100	20
16	Paradox Gothic Shale	1,350	80
17	Paradox Cane Creek Shale	3,110	40
18	Green River Vermillion Baxter Shale	180	20
19	Green River Hilliard Shale	4,350	20
	L-48 GIS- assessed shale total	**160,137**	

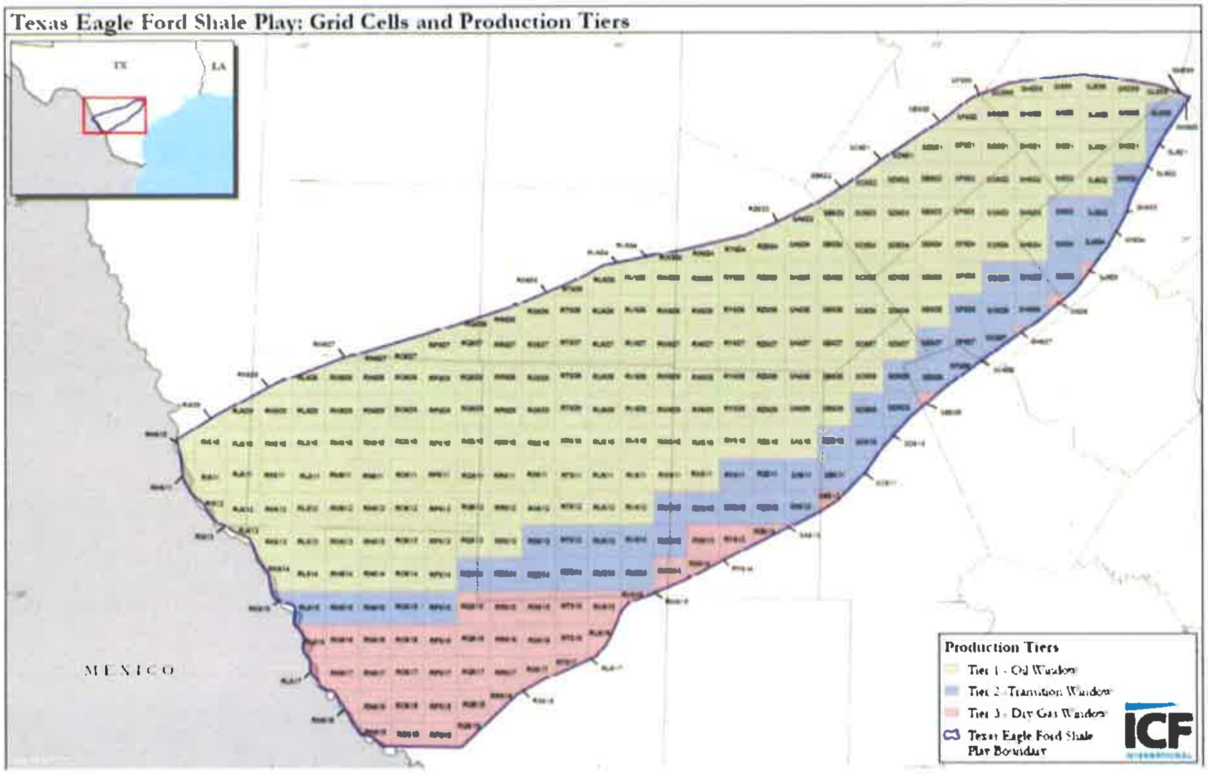
no.	Play	Play Area Sq. Mi.	Assess-ment well spacing (acres)
20	WCSB Montney Siltstone	13,700	40
21	WCSB Horn River Muskwa/Evie Shale	5,100	80
22	WCSB Cordova Embayment Shale	1,544	160
23	Quebec Utica Shale	1,600	80
24	New Brunswick Frederick Brook Sh.	120	80
	Canada GIS-assessed shale total	**22,064**	
	Tight Gas		
25	Anadarko Granite Wash Tight	3,533	213
26	Uinta Mesaverde Tight	4,721	10
27	Uinta Wasatch Tight	2,045	10
28	Green River Lance Tight	16,200	5
29	Green River Mesaverde/Almond Tight	13,400	20
	L-48 GIS-assessed tight total	**39,899**	
	Coalbed Methane		
30	**San Juan Fruitland CBM (L-48 GIS total)**	**6,599**	**160**
31	WCSB Horseshoe Canyon CBM	24,730	80
32	WCSB Mannville CBM	46,758	320
	Canada GIS-assessed CBM total	**71,488**	

Source: ICF

Exhibit 4-3 shows an example of the granularity of analysis for a specific play. This map shows the six-mile grid base and oil and gas production windows for the Eagle Ford play in South Texas. Economic analysis is also performed on a 36-square-mile unit basis and is based upon discounted cash flow analysis of a typical well within that area. Model outputs include risked and unrisked gas-in-place, recoverable resources as a function of spacing, and supply versus cost curves.

One of the key aspects of the analysis is the calibration of the model with actual well recoveries in each play. These data are derived from ICF analysis of a commercial well-level production database. The actual well recoveries are compared with the model results in each 36-square-mile model cell to calibrate the model. Thus, results are not just theoretical, but are ground-truthed to actual well results.

Exhibit 4-3: Eagle Ford Play Six-Mile Grids and Production Tiers (Oil, Wet Gas, Dry Gas)



Source: ICF

Tight Oil

Tight oil production is oil production from shale and other low-permeability formations including sandstone, siltstone, and carbonates. The tight oil resource has emerged as a result of horizontal drilling and multi-stage fracturing technology. Tight oil production in both the U.S. and Canada is surging. Production in 2015 was 4.6 million barrels per day (MMbpd) in the U.S., up from almost zero in 2007, and 384,000 bpd in Canada. U.S. tight oil production is dominated by the Bakken, Eagle Ford, several plays in the Permian Basin, and increasingly, the Anadarko Basin, including the SCOOP and STACK plays. Eagle Ford volumes include a large amount of lease condensate.

Tight oil production impacts both oil and gas markets. Tight oil contains a large amount of associated gas, which affects the North American price of natural gas. Growing associated gas production has resulted in the need for a great deal of midstream infrastructure expansion.

Tight oil resources may be represented by previously undeveloped plays, such as the Bakken shale, and in other cases may be present on the fringes of old oil fields, as is the case in western Canada. ICF assessments are based upon map areas or "cells" with averaged values of depth, thickness, maturity, and organics. The model takes this information, along with assumptions about porosity, pressure, oil gravity, and other factors to estimate original oil and gas-in-place, recovery per well, and risked recoverable resources of oil and gas. The results are compared to actual well recovery estimates. A discounted cash flow model is used to develop a cost of supply curve for each play.

4.1.3. Technology and Cost Assumptions

An important aspect of the resource assessment is the underlying assumptions about technology. The basic ICF economic resource assessment and gas supply curves are based upon existing technology. This is a conservative assumption, as has been demonstrated by the very rapid technology growth in shale gas and tight oil development in just the last five years.

In recent years, there have been great gains in technology related to the drilling of long horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time microseismic monitoring. In general, lateral lengths and the number of stimulation stages are increasing in most plays. This increases the cost per well over prior configurations. However, the gas recovery is much greater than the increased cost, resulting in lower costs per unit of production.

ICF expects that drilling costs will continue to be reduced largely due to increased efficiency and the higher rate of penetration. In some cases, the number of rig days to drill a well is a fraction of what it was several years ago. Rig day rates and other service industry costs have declined due to reduced drilling activity 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 prices.

ICF examines trends in estimated ultimate recovery (EUR) 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. To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" concept says that we can describe the aggregate influence of learning and technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or EUR per well) for each doubling of cumulative output volume of other measure of maturity.

The most technologically immature resources, wherein technologies advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells, 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 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 20 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 14 percent per doubling of cumulative wells. In other words about one-third of the observed total 20% improvement in EUR per well doubling 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 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." The amount of the shift depends on what price point and future year are being estimated and which forecast case is being examined. The forecasted pace of drilling affects the cumulative learning impact in any given year as more drilling leads to faster technology advances as the effect is estimated based on cumulative wells drilled. As an example, for the two forecast cases examined here (the ICF Base Case and the Port Arthur LNG Case) the upstream technology effects through 2043 add approximately 521 Tcf of Lower 48 gas supplies that are economic at $5.00/MMBtu (1,465 Tcf with 2043 technology compared to 944 Tcf with 2014 technology). Generally speaking, by 2043 the upstream technology assumptions used in the GMM add roughly 50 percent to 60 percent to economic resources in the $5.00 to $7.00/MMBtu price range of the Lower 48 gas supply curve.

4.2. Energy and Economic Impacts Methodology

Port Arthur LNG tasked ICF with assessing the economic and employment impacts of additional LNG exports from its Port Arthur, TX LNG export facility. This study analyzed two cases[9]:

1) **Base Case** with the assumption of no Port Arthur LNG export volumes.
2) **Port Arthur LNG Case** with the assumption of an additional 698 Bcf per year, or 1.91 Bcfd higher than the Base Case due to the new construction of Trains 1 and 2 at Port Arthur.

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

Step 1 – Natural gas and liquids production: We first ran the ICF Gas Market Model to determine supply, demand, and price changes in the natural gas market. The natural gas and liquids production changes required to support the additional LNG exports were assessed on both a national and Texas level.

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

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

Step 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

[9] These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

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.

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:

- Port Arthur 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: Port Arthur LNG Export Volume Assumptions (Bcfd)

Year	Base Case	Train 1	Train 2	Port Arthur LNG Total
2023	-	0.68	0.20	**0.88**
2024	-	0.96	0.96	**1.91**
2025	-	0.96	0.96	**1.91**
2026	-	0.96	0.96	**1.91**
2027	-	0.96	0.96	**1.91**
2028	-	0.96	0.96	**1.91**
2029	-	0.96	0.96	**1.91**
2030	-	0.96	0.96	**1.91**
2031	-	0.96	0.96	**1.91**
2032	-	0.96	0.96	**1.91**
2033	-	0.96	0.96	**1.91**
2034	-	0.96	0.96	**1.91**
2035	-	0.96	0.96	**1.91**
2036	-	0.96	0.96	**1.91**
2037	-	0.96	0.96	**1.91**
2038	-	0.96	0.96	**1.91**
2039	-	0.96	0.96	**1.91**
2040	-	0.96	0.96	**1.91**
2041	-	0.96	0.96	**1.91**
2042	-	0.96	0.96	**1.91**
2043	-	0.96	0.96	**1.91**

Note: LNG export volumes do not include liquefaction fuel or losses.

Source: Port Arthur LNG, ICF

Exhibit 4-6: Port Arthur LNG Plant Capital and Operating Expenditures

Year	The Port Arthur LNG Case Changes	
	LNG Capital Costs (2015$ MM)	LNG Operating Costs (2015$ MM)
2015	$0	$0
2016	$0	$0
2017	$0	$0
2018	$47	$0
2019	$1,304	$0
2020	$1,304	$0
2021	$1,304	$0
2022	$1,304	$0
2023	$1,304	$86
2024	$6	$171
2025	$0	$171
2026	$0	$171
2027	$0	$171
2028	$0	$171
2029	$0	$171
2030	$0	$171
2031	$0	$171
2032	$0	$171
2033	$0	$171
2034	$0	$171
2035	$0	$171
2036	$0	$171
2037	$0	$171
2038	$0	$171
2039	$0	$171
2040	$0	$171
2041	$0	$171
2042	$0	$171
2043	$0	$171

Source: Port Arthur LNG, ICF

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

Year	Federal Tax Rate on GDP (%)	Weighted Average State and Local Tax Rate on GDP (% of own-source) (%)	Texas State and Local Own Taxes as % of State Income (%)
2010	14.6%	15.1%	13.4%
2011	15.0%	14.9%	12.8%
2012	15.3%	14.5%	12.6%
2013	16.7%	15.0%	13.0%
2014	17.5%	15.0%	13.0%
2015	17.7%	15.0%	13.0%
2016	18.7%	15.0%	13.0%
2017	19.1%	15.0%	13.0%
2018	19.1%	15.0%	13.0%
2019	19.2%	15.0%	13.0%
2020	19.3%	15.0%	13.0%
2021	19.4%	15.0%	13.0%
2022	19.5%	15.0%	13.0%
2023	19.6%	15.0%	13.0%
2024	19.7%	15.0%	13.0%
2025	19.8%	15.0%	13.0%
2026	19.9%	15.0%	13.0%
2027	20.0%	15.0%	13.0%
2028	20.1%	15.0%	13.0%
2029	20.2%	15.0%	13.0%
2030	20.3%	15.0%	13.0%
2031	20.4%	15.0%	13.0%
2032	20.5%	15.0%	13.0%
2033	20.6%	15.0%	13.0%
2034	20.7%	15.0%	13.0%
2035	20.8%	15.0%	13.0%
2036	20.9%	15.0%	13.0%
2037	21.0%	15.0%	13.0%
2038	21.1%	15.0%	13.0%
2039	21.2%	15.0%	13.0%
2040	21.3%	15.0%	13.0%
2041	21.4%	15.0%	13.0%
2042	21.5%	15.0%	13.0%
2043	21.6%	15.0%	13.0%

Source: ICF extrapolations from Tax Policy Center historical figures

Exhibit 4-8: Liquids Price Assumptions

Year	RACC Price (2015$/bbl)	Condensate Price (2015$/bbl)	Ethane Price (2015$/bbl)	MB Propane Price (2015$/bbl)	Butane Price (2015$/bbl)	Pentanes Plus (2015$/bbl)
2010	$ 83	$ 83	$ 28	$ 49	$ 56	$ 76
2011	$ 108	$ 108	$ 25	$ 61	$ 73	$ 99
2012	$ 105	$ 105	$ 17	$ 42	$ 71	$ 96
2013	$ 103	$ 103	$ 22	$ 42	$ 70	$ 94
2014	$ 93	$ 93	$ 25	$ 44	$ 63	$ 85
2015	$ 48	$ 48	$ 15	$ 19	$ 33	$ 44
2016	$ 39	$ 39	$ 15	$ 20	$ 27	$ 36
2017	$ 44	$ 44	$ 15	$ 21	$ 30	$ 40
2018	$ 46	$ 46	$ 15	$ 22	$ 31	$ 42
2019	$ 50	$ 50	$ 15	$ 24	$ 34	$ 45
2020	$ 55	$ 55	$ 16	$ 27	$ 37	$ 50
2021	$ 61	$ 61	$ 18	$ 30	$ 42	$ 56
2022	$ 67	$ 67	$ 20	$ 33	$ 46	$ 61
2023	$ 71	$ 71	$ 21	$ 36	$ 48	$ 65
2024	$ 74	$ 74	$ 22	$ 37	$ 50	$ 67
2025	$ 75	$ 75	$ 22	$ 38	$ 51	$ 68
2026	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2027	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2028	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2029	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2030	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2031	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2032	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2033	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2034	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2035	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2036	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2037	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2038	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2039	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2040	$ 75	$ 75	$ 22	$ 40	$ 51	$ 68
2041	$ 76	$ 76	$ 22	$ 40	$ 51	$ 69
2042	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70
2043	$ 77	$ 77	$ 23	$ 41	$ 52	$ 70

Source: ICF

Exhibit 4-9: Other Key Model Assumptions

Assumption	U.S.	Texas
Upstream Capital Costs ($MM/Well)	$7.7	$7.7
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$3.19	$3.19
Royalty Payment (%)	16.7%	17.0%
LNG Tanker Capacity (Bcf/Ship)		3.60
U.S. Port Fee ($/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 to those directly involved in the activity, 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.

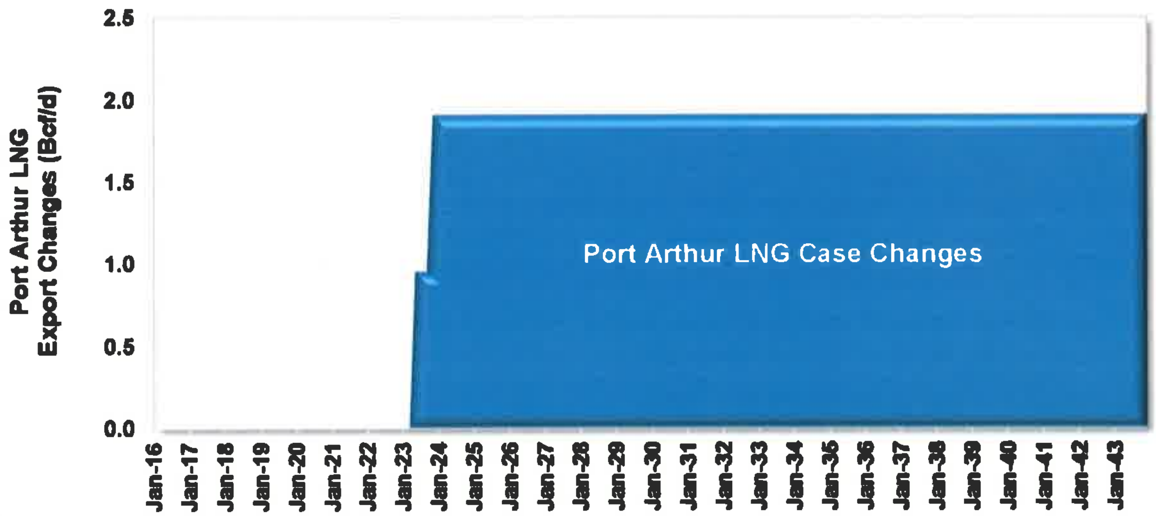
Direct, Indirect, and Induced Economic Impacts

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. Port Arthur LNG Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the Port Arthur LNG Case. Specifically, differentials between the two cases result from an additional 1.91 Bcfd (see exhibit below) in LNG exports assumed from Port Arthur LNG from Trains 1 and 2.

Exhibit 5-1: Port Arthur LNG Export Changes



Note: These volumes do not include 10 percent liquefaction fuel use or lease and plant and pipeline fuel use.

Source: ICF

5.1. Energy Market and Economic Impacts

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

Overall, in order to accommodate the incremental increases in LNG exports, the U.S. natural gas market rebalances through three sources: increasing U.S. natural gas production, a contraction in U.S. domestic natural gas consumption, and an increase in net natural gas pipeline imports from Canada and Mexico (see Exhibit 5-2). In addition to the incremental LNG export volumes of 1.91 Bcfd, the market also must rebalance for liquefaction and fuel losses, estimated at 10 percent of incremental export volumes. Thus, the market will rebalance to 110 percent of incremental export volumes, as shown in the exhibit below.

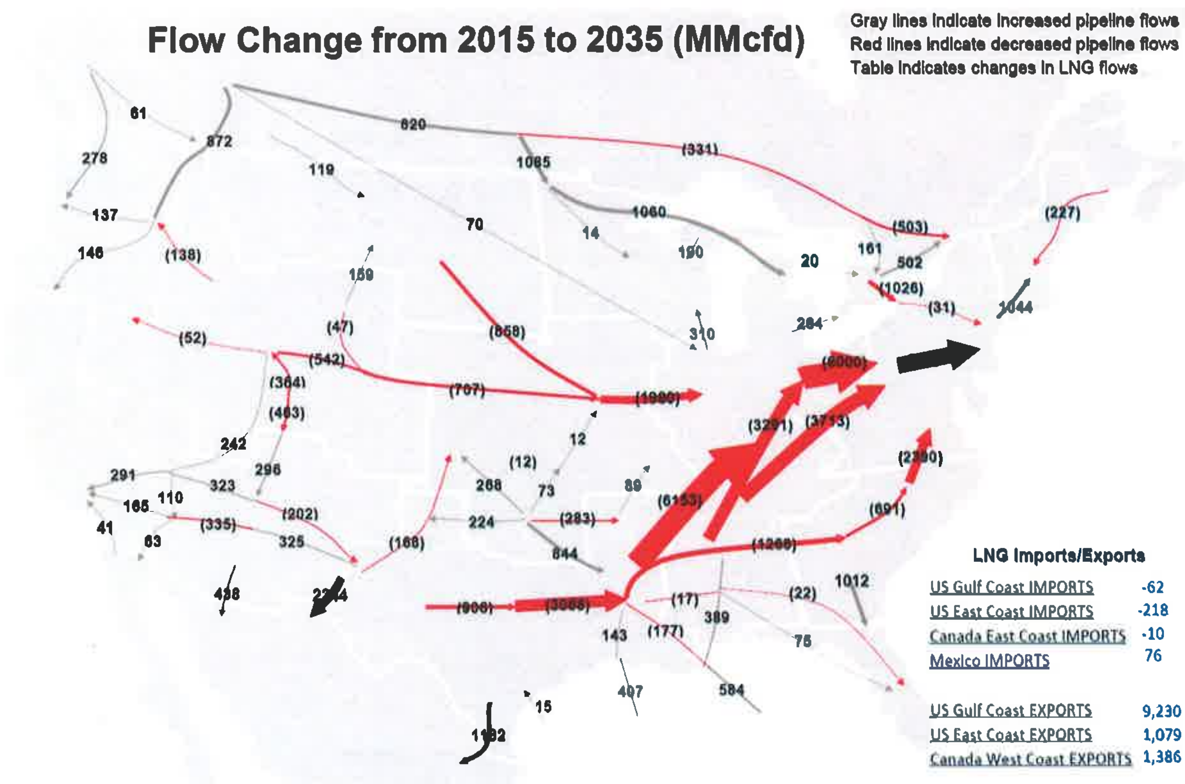
Exhibit 5-2: U.S. Flow Impact Contribution to LNG Exports

2023-2043 Average Supply Sources (%)			
Production Increase	Demand Decrease	Net Gas Pipeline Imports	Total Share of LNG Exports
92%	11%	7%	110%

Source: ICF

As mentioned in the previous section, the map below shows Base Case natural gas market flows, with Texas LNG export volumes of 3.8 Bcfd (1.9 Bcfd in East Texas and 1.9 Bcfd in South Texas).

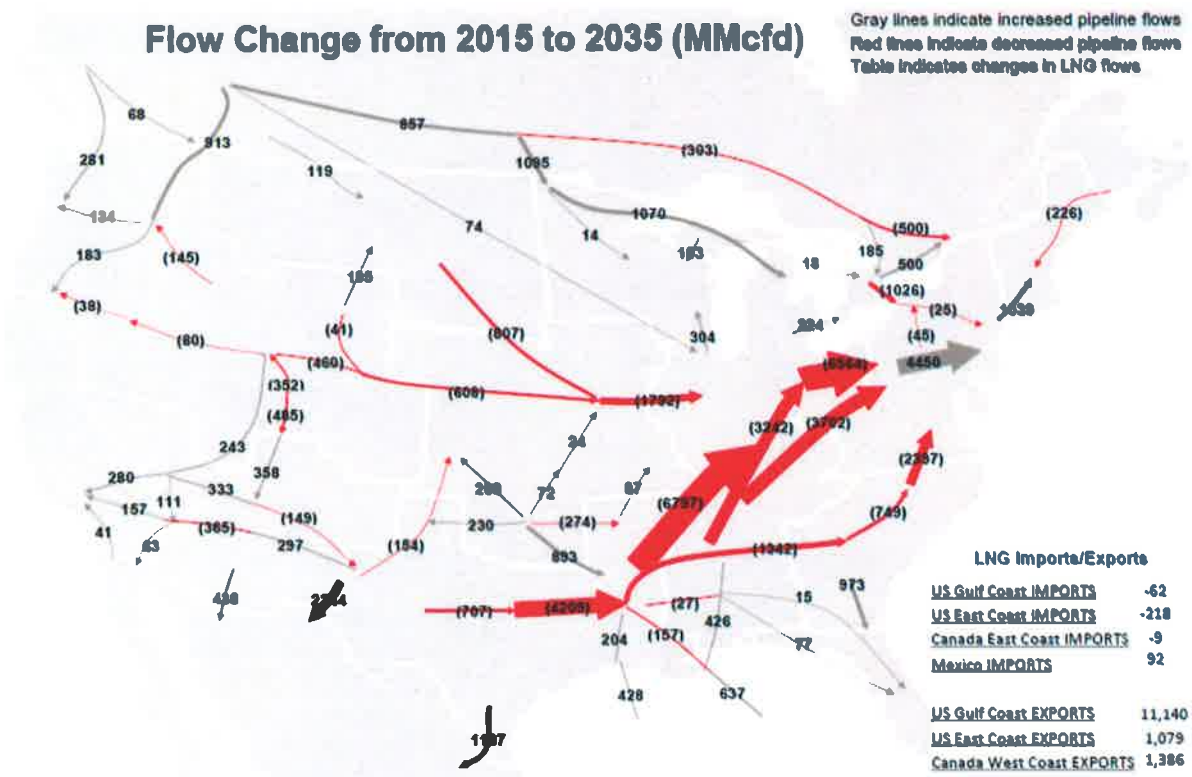
Exhibit 5-3: Base Case U.S. Natural Gas Market Flow Changes



Source: ICF GMM® Q4 2016

The map below shows the Port Arthur LNG Case U.S. natural gas flows which overall are similar to Base Case Flows. However, Texas export volumes are 5.71 Bcfd in the Port Arthur LNG Case, compared to 3.8 Bcfd in the Base Case. Total U.S. Gulf Coast LNG export flow changes are 11.14 Bcfd, compared to 9.23 Bcfd in the Base Case.

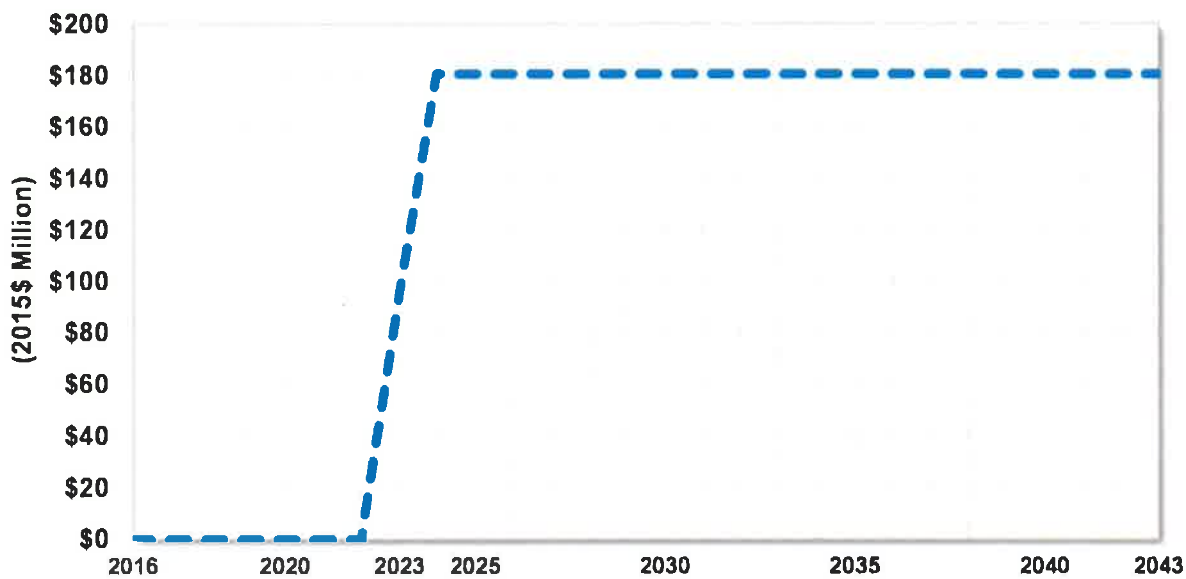
Exhibit 5-4: The Port Arthur LNG Expansion Case U.S. Natural Gas Market Flow Changes



Source: ICF

The exhibit below (Exhibit 5-5) shows the impact on LNG export facility operating expenditures (excluding the cost of natural gas feedstock but including employee costs, materials, maintenance, insurance, and property taxes). Port fees paid by the shipper during the tanker loading process are also included here. Over the study period of 2019 to 2043, there is a total cumulative impact on operating expenditures of $3.7 billion in the Port Arthur LNG Case as compared to the Base Case. During that period, LNG plant operating expenditures average $142.5 million higher annually in the Port Arthur LNG Case, as compared to the Base Case. Adding in pipeline O&M brings that total difference to $180.5 million per year.

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

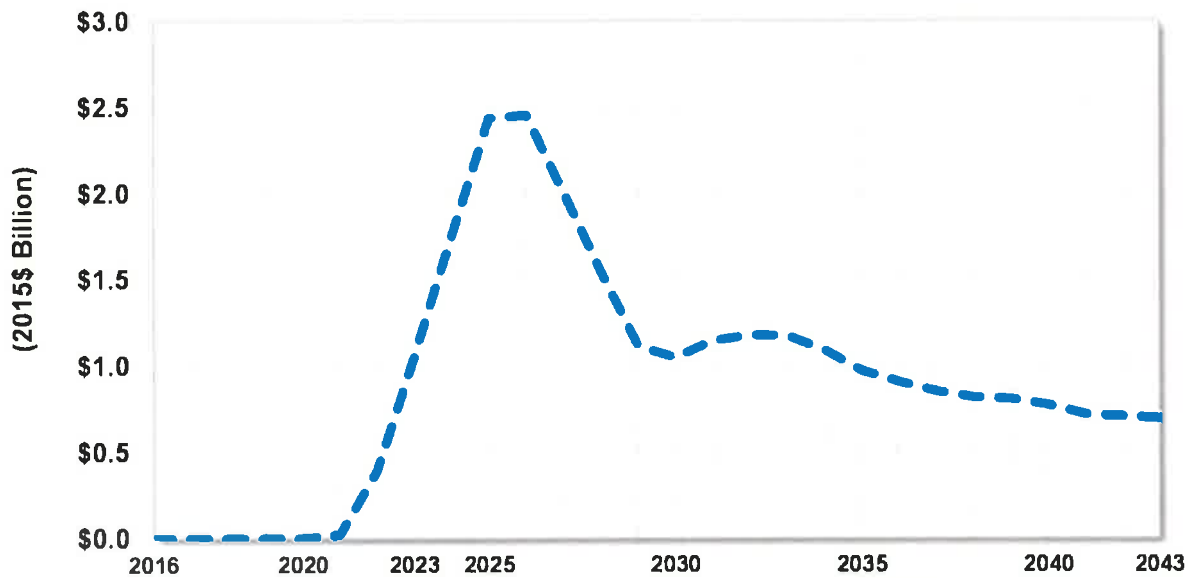


Year	LNG Facility Operating Expenditures (2015$ Million)
	Port Arthur LNG Case Change
2019	$ -
2023	$ 94.8
2025	$ 180.5
2030	$ 180.5
2035	$ 180.5
2040	$ 180.5
2043	$ 180.5
2019-2043 Avg	*$ 142.5*
2019-2043 Sum	**3,704.8**

Note: LNG plant operating expenditures include incremental pipeline O&M.
Source: ICF

The exhibit below (Exhibit 5-6) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. Investment peaks in the early years as more new wells are drilled to add the extra deliverability needed as LNG production ramps up. Once full LNG production is reached, fewer new wells are required to sustain production. Over the forecast period of 2019 to 2043, the cumulative impact on U.S. upstream capital expenditures totals near $25.7 billion in the Port Arthur LNG Case as compared to the Base Case. U.S. upstream capital expenditures average $1 billion higher annually in the Port Arthur LNG Case than in the Base Case.

Exhibit 5-6: U.S. Upstream Capital Expenditure Changes

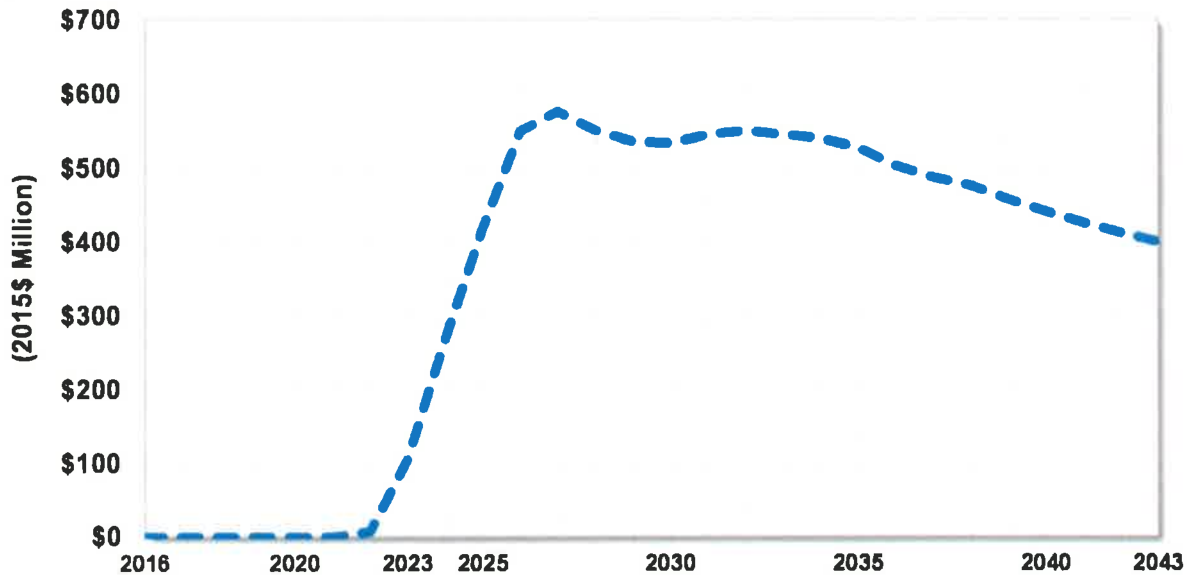


Year	Upstream Capital Expenditures (2015$ Billion)
	Port Arthur LNG Case Change
2019	$ -
2023	$ 1.06
2025	$ 2.43
2030	$ 1.05
2035	$ 0.97
2040	$ 0.78
2043	$ 0.70
2019-2043 Avg	*$ 0.99*
2019-2043 Sum	**$ 25.69**

Source: ICF

As shown below (Exhibit 5-7), U.S. upstream operating expenditures increase $9.8 billion on a cumulative basis, or on average $379 million annually in the Port Arthur LNG Case as compared to the Base Case between 2019 and 2043.

Exhibit 5-7: U.S. Upstream Operating Expenditure Changes

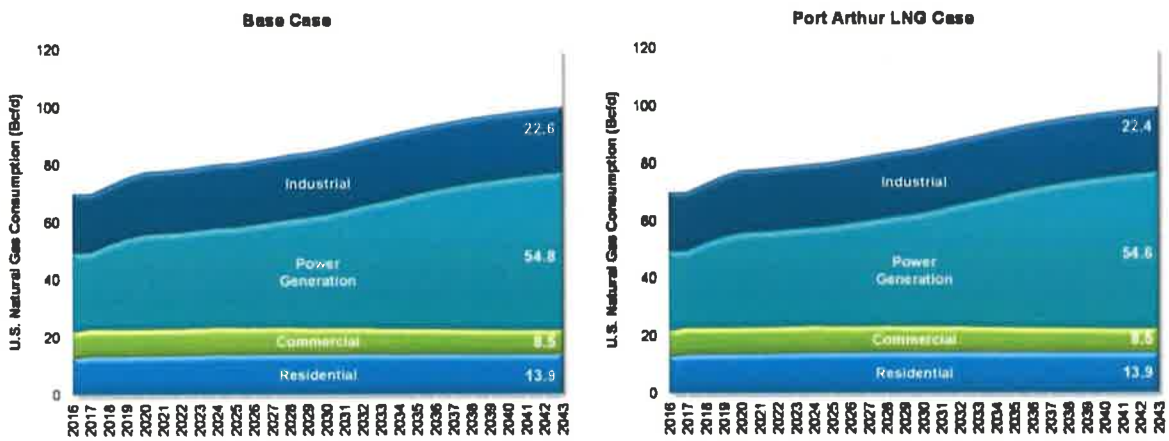


Year	Upstream Operating Expenditures (2015$ Million)	
	Port Arthur LNG Case Change	
2019	$	-
2023	$	106
2025	$	419
2030	$	533
2035	$	527
2040	$	441
2043	$	399
2019-2043 Avg	*$*	*379*
2019-2043 Sum	**$**	**9,849**

Source: ICF

The charts below (Exhibit 5-8) shows the Base Case and the Port Arthur LNG Case U.S. natural gas consumption. The additional LNG export volumes of 1.91 Bcfd (plus liquefaction fuel use of 10 percent, thus totaling 2.1 Bcfd) are expected to only result in a small reduction in U.S. natural gas consumption of 0.37 Bcfd in 2043. Most of this reduction comes from power sector gas use decline followed by industrial sector, and slight declines in residential and commercial gas use. This contraction in U.S. domestic natural gas consumption is the equivalent to 11% percent of the Port Arthur LNG incremental export volumes. Additional U.S. natural gas production and net natural gas imports over the forecast period in the Port Arthur LNG Case equal 99% of the export volumes of Port Arthur LNG.

Exhibit 5-8: U.S. Domestic Natural Gas Consumption by Sector



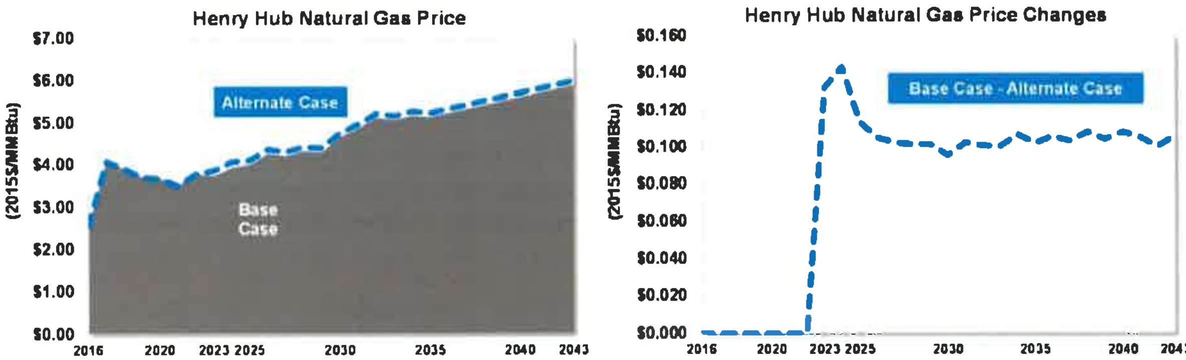
* Industrial demand does not includes pipeline fuel and lease & plant

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

Source: ICF

The Henry Hub natural gas price is expected to increase by $0.09/MMBtu on average over the forecast period through 2043, averaging $4.77/MMBtu over the forecast period, compared with $4.68/MMBtu in the Base Case, as shown in Exhibit 5-9. The Port Arthur LNG Case natural gas prices at Henry Hub are expected to reach $5.88/MMBtu in the Base Case and $5.99 in the Port Arthur LNG Case by 2043, indicating a natural gas price increase of $0.11/MMBtu attributable to the Port Arthur LNG export volumes of 1.91 Bcfd.

Exhibit 5-9: Annual Average Henry Hub Natural Gas Price Changes

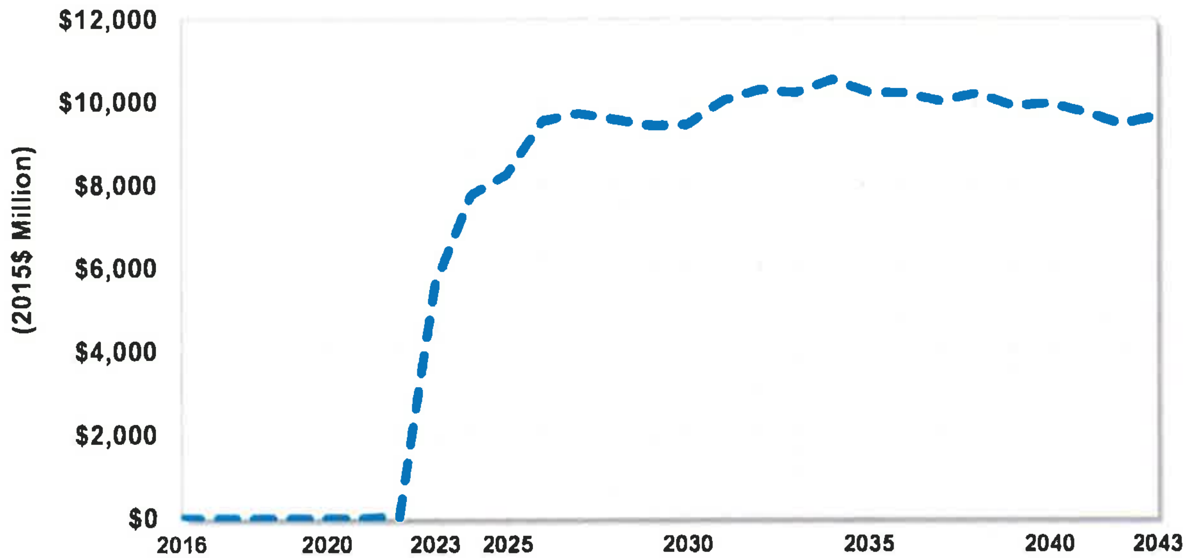


Year	Henry Hub Natural Gas Price (2015$/MMBtu)		
	Base Case	Port Arthur LNG Case	Port Arthur LNG Case Change
2019	$ 3.71	$ 3.71	$ -
2023	$ 3.73	$ 3.86	$ 0.132
2025	$ 3.99	$ 4.11	$ 0.114
2030	$ 4.67	$ 4.76	$ 0.096
2035	$ 5.13	$ 5.24	$ 0.103
2040	$ 5.60	$ 5.71	$ 0.109
2043	$ 5.88	$ 5.99	$ 0.107
2019-2043 Avg	*$ 4.68*	*$ 4.77*	*$ 0.087*

Source: ICF

U.S. natural gas and liquids production value increases as a result of additional LNG export volumes and higher prices as seen in the Port Arthur LNG Case (see Exhibit 5-10). Over the forecast period 2019 to 2043, the cumulative impact on natural gas and liquids production value in the Port Arthur LNG Case is approximately $200 billion. This represents an average increase of $7.7 billion per year in the Port Arthur LNG Case as compared to the Base Case between 2019 and 2043.

Exhibit 5-10: U.S. Natural Gas and Liquids Production Value Changes



Year	Natural Gas and Liquids Production Value (2015$ Million)	
	Port Arthur LNG Case Change	
2019	$	-
2023	$	5,625.3
2025	$	8,267.5
2030	$	9,459.5
2035	$	10,228.2
2040	$	9,948.4
2043	$	9,646.8
2019-2043 Avg	*$*	*7,687.0*
2019-2043 Sum	**$**	**199,861.0**

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

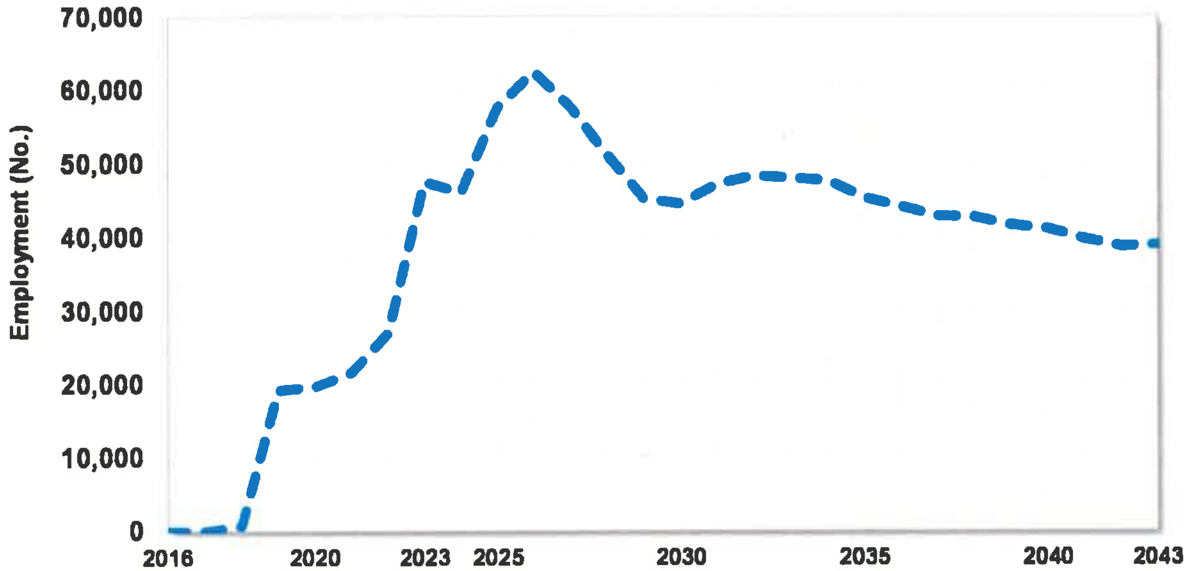
Source: ICF

Exhibit 5-11 shows the impacts of additional volumes on total U.S. employment.[10] The employment impacts are across all industries nationwide, and include direct, indirect, and induced employment. For example, the employment changes include direct and indirect jobs related to additional oil and gas production (such as drilling wells, drilling equipment, trucks to and from the drilling sites, construction workers), as well as induced jobs. Induced jobs are created when direct and indirect employment increases, and direct and indirect workers spend their higher incomes, creating induced impacts throughout the economy.

The construction and operation of Port Arthur LNG will likely increase employment through direct, indirect and induced employment impacts. Average annual job increase between 2019 and 2043 is 41,000 jobs. Over the forecast period the added LNG export facilities are expected to increase job-years relative to the Base Case by 1,067,000 job-years cumulative.

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

Exhibit 5-11: Total U.S. Total Employment Changes

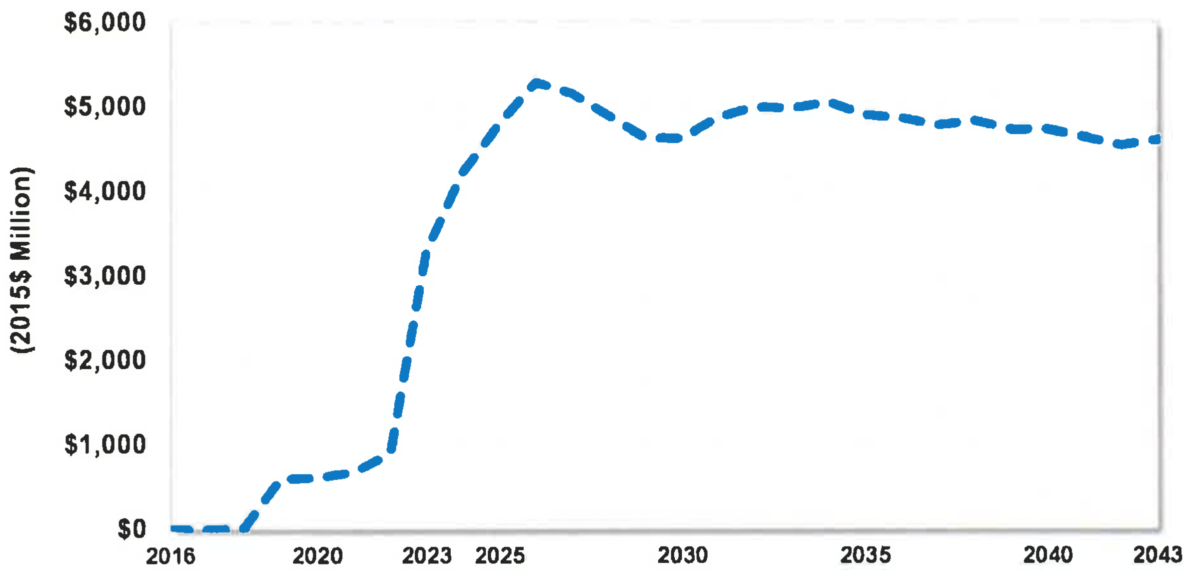


Year	Employment (No.)
	Port Arthur LNG Case Change
2019	19,194
2023	47,625
2025	57,532
2030	44,549
2035	45,368
2040	41,160
2043	38,977
2019-2043 Avg	*41,071*
2019-2043 Sum	**1,067,162**

Source: ICF

Exhibit 5-12 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective government revenues increase $3.9 billion annually as a result of the Port Arthur LNG Case additional LNG export trains. This translates to a cumulative impact of $102 billion over the forecast period between 2019 and 2043.

Exhibit 5-12: U.S. Federal, State, and Local Government Revenue Changes



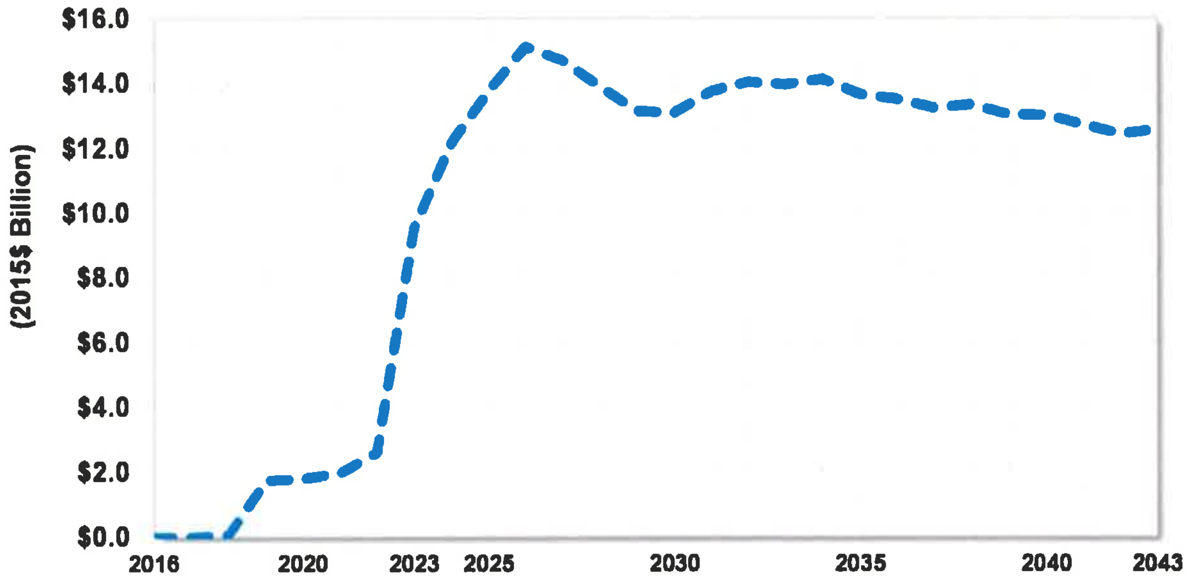
Year	Government Revenues (2015$ Million)	
	Port Arthur LNG Case Change	
2019	$	595.8
2023	$	3,293.7
2025	$	4,782.3
2030	$	4,616.5
2035	$	4,890.3
2040	$	4,721.8
2043	$	4,600.4
2019-2043 Avg	*$*	*3,924.3*
2019-2043 Sum	**$**	**102,009.7**

Source: ICF

Exhibit 5-13 shows the impacts of additional LNG export on total U.S. value added (that is, additions to U.S. GDP). The value added is the total U.S. output changes attributable to the incremental LNG exports minus purchases of imported intermediate goods and services. Based on U.S. historical averages across all industries, about 16 percent of output is made of imported goods and services. The value for imports used in the ICF analysis differs by industry and is computed from the IMPLAN matrices.

Total value added increases substantially as a result of the additional LNG export volumes assumed in the Port Arthur LNG Case. The additional LNG volumes in the Port Arthur LNG Case result in a $11 billion annual average increase of value added between 2019 and 2043. The cumulative value added over the period between the Base Case and the Port Arthur LNG Case Volumes Case totals $287 billion.

Exhibit 5-13: Total U.S. Value Added Changes

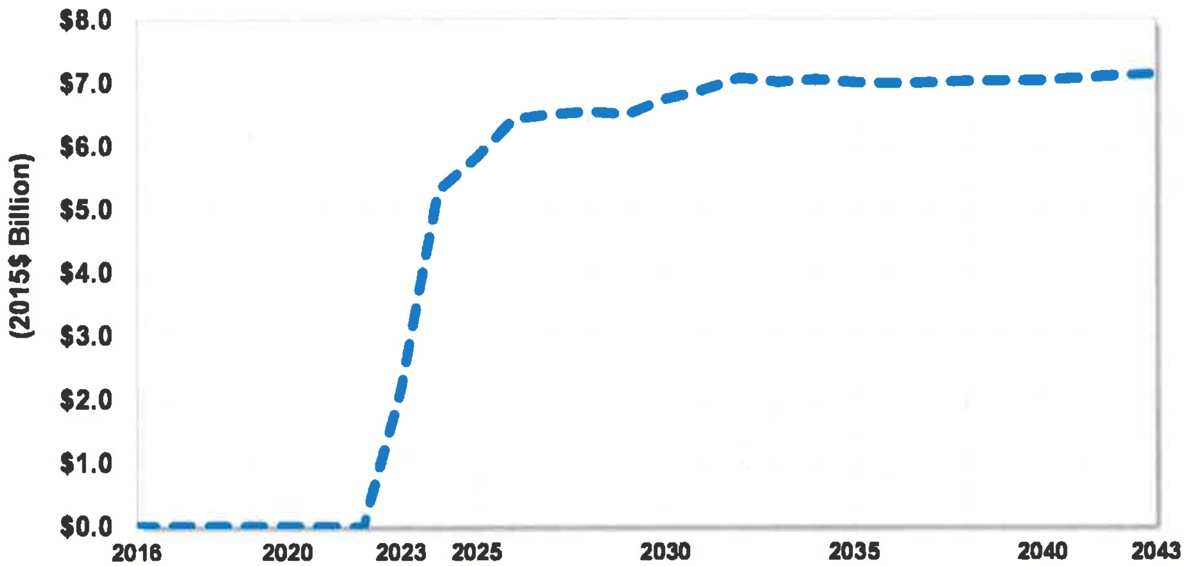


Year	Total Value Added (2015$ Billion)	
	Port Arthur LNG Case Change	
2019	$	1.7
2023	$	9.5
2025	$	13.7
2030	$	13.1
2035	$	13.7
2040	$	13.0
2043	$	12.6
2019-2043 Avg	*$*	*11.0*
2019-2043 Sum	**$**	**286.8**

Source: ICF

Exhibit 5-14 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $5.3 billion annually between 2019 and 2043, based on the value of LNG export volumes and incremental associated liquids production, or a cumulative value of $137 billion. The improved balance of trade effects begin in 2023 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, the LNG liquefaction process and the port services) and the additional hydrocarbon liquids production which is assumed to either substitute for imported liquids or be exported.

Exhibit 5-14: U.S. Balance of Trade Changes



Year	Balance of Trade (2015$ Billion)	
	Port Arthur LNG Case Change	
2019	$	-
2023	$	2.2
2025	$	5.8
2030	$	6.7
2035	$	7.0
2040	$	7.0
2043	$	7.1
2019-2043 Avg	*$*	*5.3*
2019-2043 Sum	**$**	**137.2**

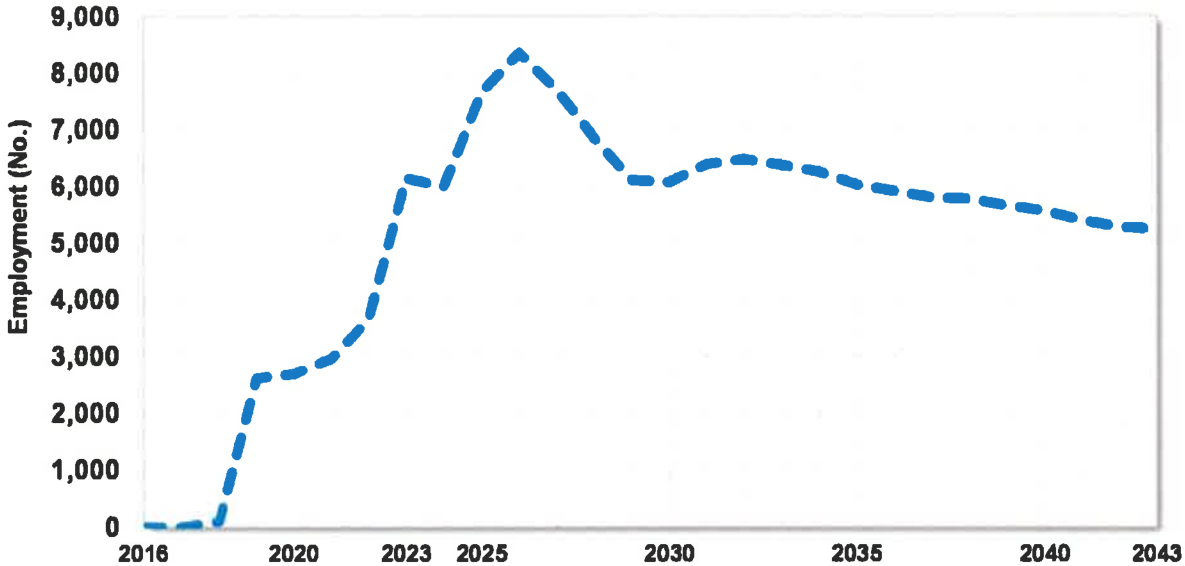
Source: ICF

5.2. Texas Impacts

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

Exhibit 5-15 shows the impacts of LNG export volumes on 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 added LNG trains 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 Port Arthur LNG Case exhibits an increase of 5,700 jobs on an average annual basis from 2019 to 2043 as compared to the Base Case. This equates to a cumulative impact of 143,000 Texas job-years over the 25-year forecast period through 2043.

Exhibit 5-15: Texas Total Employment Changes

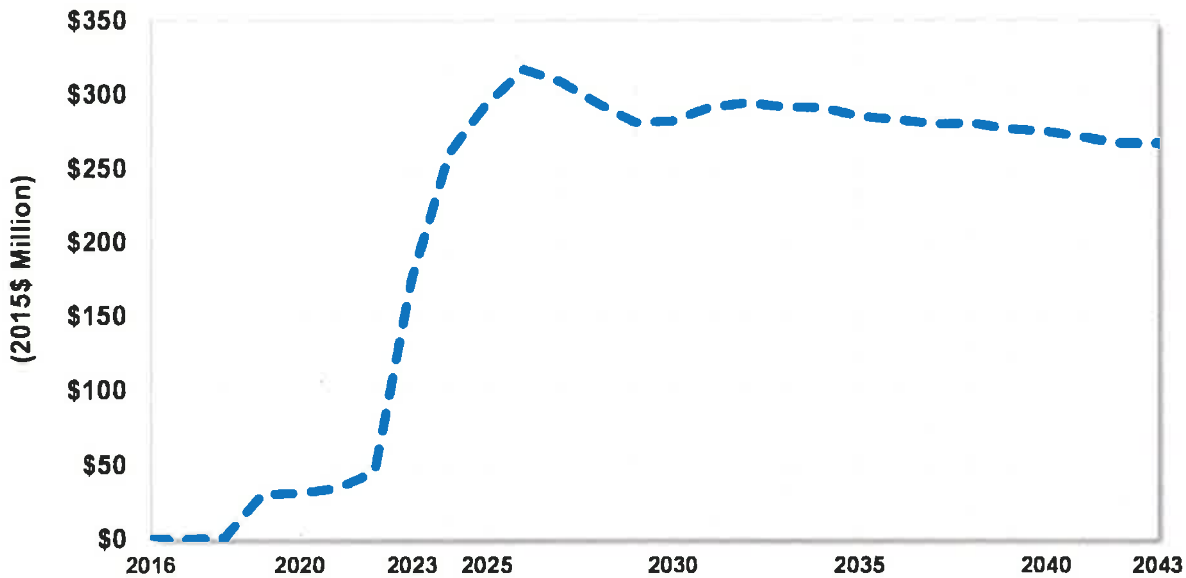


Year	Employment (No.)
	Port Arthur LNG Case Change
2019	2,621
2023	6,149
2025	7,641
2030	6,077
2035	6,030
2040	5,567
2043	5,246
2019-2043 Avg	*5,720*
2019-2043 Sum	**143,011**

Source: ICF

Exhibit 5-16 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 additional LNG volumes in the Port Arthur LNG Case result in a $240 million average annual increase to local and state Texas government revenues throughout the 25-year forecast period through 2043, or a cumulative impact of $6 billion.

Exhibit 5-16: Texas Government Revenue Changes

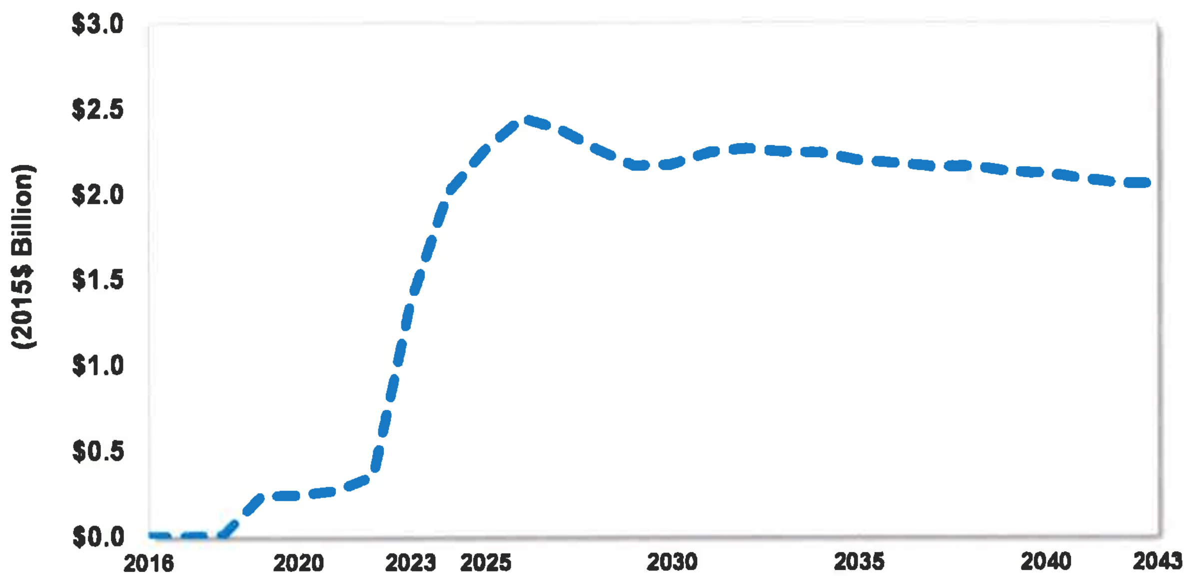


Year	Government Revenues (2015$ Million) Port Arthur LNG Case Change
2019	$ 30.5
2023	$ 175.8
2025	$ 293.3
2030	$ 281.9
2035	$ 285.2
2040	$ 275.1
2043	$ 267.3
2019-2043 Avg	*$ 240.3*
2019-2043 Sum	**$ 6,007.8**

Source: ICF

Exhibit 5-17 shows the impacts of LNG export volumes on total Texas value added (also called gross state product or GSP). Texas value added increases substantially as a result of the additional LNG export volumes assumed in the Port Arthur LNG Case. Throughout the study period 2019 to 2043 the additional LNG volumes in the Port Arthur LNG Case result in a $1.9 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 Port Arthur LNG Expansion Case is $46.3 billion.

Exhibit 5-17: Total Texas Value Added Changes



Year	Total Value Added (2015$ Billion) Port Arthur LNG Case Change
2019	$ 0.2
2023	$ 1.4
2025	$ 2.3
2030	$ 2.2
2035	$ 2.2
2040	$ 2.1
2043	$ 2.1
2019-2043 Avg	*$ 1.9*
2019-2043 Sum	**$ 46.3**

Source: ICF

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7. Appendices

7.1. Appendix A: LNG Economic Impact Study Comparisons

This section explores ICF's assessment of LNG export impacts on the U.S. economy versus previous studies performed by ICF and others. This study differs from previous ICF studies in that productivity of new wells has improved due to upstream technology advances. This means that fewer wells need to be drilled and less upstream expenditures are needed per Bcfd of LNG exports than calculated in past ICF analyses. The lower expenditures translate into few upstream job gains. In addition, GDP gains per Bcfd of LNG exports are lower relative to past studies, largely due to lower assumed crude oil, condensate and natural gas liquids prices, which reduce the value of liquids produced along with the gas used as a feedstock and fuel in the liquefaction plants. In addition, due to higher well productivity rates (driven by upstream technology advances) this study finds that U.S. gas production is more elastic and thus a smaller reduction in gas consumption is needed to rebalance the market to accommodate LNG exports.

The most recent industry wide study[11] assessing the impact of LNG exports on the US 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 US LNG Exports ranged from 12 to 20 Bcfd, and a range of US 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, however the study finds that the positive impacts to the US economy largely outweigh this increase in consumer gas prices. As a result of increased US 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 which benefit from the production increase.

ICF International's May 2013 study for the American Petroleum Institute looked at impacts of LNG exports on natural gas markets, GDP, employment, government revenue and balance of trade.[12] 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

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[11] 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

[12] 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

incremental 138,000-555,000 bpd of NGL production due to the drilling boost fueled by higher gas demand.

NERA's December 2012 study for the EIA looked at four LNG export cases from 6 Bcfd to unconstrained LNG exports using four EIA Annual Energy Outlook (AEO) 2011 scenarios.[13] In the unconstrained LNG export scenario, the study found that the U.S. can support up to 22.9 Bcfd of LNG exports. Gas price impacts range from zero to $0.33 per thousand cubic feet (Mcf) (in 2010 dollars), peaking in the earlier years and are higher in high production cases. Overall, LNG exports have positive impacts on the economy, boosting the GDP by up to 0.26 percent by 2020 and do not change total employment levels. According to NERA, sectors likely to suffer from gas price increases due to intensive gas use will experience only small output and employment losses.

NERA provided an update to its December 2012 study in March 2014 for Cheniere, using the AEO and International Energy Outlook (IEO) 2013 scenarios.[14] The report examined various export cases from no exports to 53.4 Bcfd in the High Oil and Gas Resource Case with no export constraints. The U.S. continues to maintain a low natural gas price advantage even when exports are not constrained. GDP gains could reach as much as $10-$86 billion by 2038 and are positive across all cases. LNG exports also lower the number of unemployed by 45,000 between 2013 and 2018. NERA's March 2014 report acknowledged the contribution of LNG exports to increasing NGL production and thus lowering feedstock prices for the petrochemicals industry. Electric sector growth will likely slow somewhat, however, compared to the No Exports Case.

The EIA released its first study of LNG export impacts on energy markets in January 2012, looking at four export scenarios from 6 to 12 Bcfd based on AEO 2011 case assumptions.[15] The study found that LNG exports lead to gas price increases by up to $1.58/Mcf by 2018 while boosting gas production by 60 to 70 percent of LNG export levels. Within the power sector, gas-fired generation sees the most dramatic decline while coal and renewable generation show small increases. This study did not look at economic impacts of LNG exports.

The EIA's October 2014 study revisited five AEO 2014 cases with elevated levels of LNG exports between 12 and 20 Bcfd, a sharp increase from the range considered in the EIA's January 2012 study.[16] Relative to the January 2012 study, LNG exports further increase average gas prices by 8 to 11 percent depending on the case, and boosts natural gas production by 61 percent to 84 percent of the LNG export level. Imports from Canada increase slightly while domestic consumption declines by less than 2 Bcfd on average mostly in power generation and industrial consumption. The overall impact on the economy is positive, with GDP increased by 0.05 percent. Consumer spending on gas and electricity increases by "modest"

[13] 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
[14] 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
[15] U.S. Energy Information Administration. "Effect of Increased Natural Gas Exports on Domestic Energy Markets". EIA, January 2012: Washington, DC. Available at: http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[16] 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

levels, about 1-8 percent for gas and 0-3 percent for electricity compared to the January 2012 results.

Charles River Associates (CRA) released a study on LNG export impacts for Dow Chemical Company in February 2013 with different methodologies and conclusions from the studies mentioned above.[17] Examining export cases from 20 Bcfd to 30 Bcfd by 2030, CRA argued that LNG export can raise gas prices to between $8.80 to $10.30/MMBtu by 2030, significantly above the reference price of $6.30/MMBtu. Electricity price impacts are also much greater than other studies, about 60 percent to 170 percent above the No Exports Case. CRA also compared economic values of gas use in manufacturing versus in LNG exports, finding that manufacturing creates much higher output and more jobs than do LNG exports.

See the exhibit on the next page for more details by study.

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

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Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employ ment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/Δ Jobs	
Port Arthur LNG (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.
Port Arthur LNG (ICF 2015)	Port Arthur LNG export of 1.42 Bcfd	1.42 Bcfd export	$0.07	$0.05	95%	7%	8%	110%	1.5	24,166	$282,649	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 Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES)	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for US 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 Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
DOE 2015 (Oxford Economics & Rice CES) cont'd	Multiple scenarios compared to Reference case which assumed 12 Bcfd of International Demand for US 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 Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/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	

<table>
<tr><th rowspan="3">Facility</th><th rowspan="3">Summary of Analysis</th><th rowspan="3">Case</th><th colspan="9">Impact LNG Exports</th><th rowspan="3">Main Conclusions</th></tr>
<tr><th colspan="2">Henry Hub Price Change Relative to Reference Case</th><th colspan="4">Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)</th><th>Multiplier Effect</th><th>Employment Impact</th><th>GDP Impact</th></tr>
<tr><th>$/MMBtu</th><th>$/MMBtu per 1 Bcfd</th><th>Production Increase (%)</th><th>Demand Decrease (%)</th><th>Canadian Gas Imports (%)</th><th>Total Share of LNG Exports (%)</th><th>Multiplier</th><th>Jobs per Bcfd</th><th>ΔGDP/Δ Jobs</th></tr>
<tr><td rowspan="2">Jordan Cove (Navigant)</td><td rowspan="2">7 cases examining different levels of U.S. demand and LNG exports ranging from 2.7 to 7.1 Bcfd</td><td>2.9 Bcfd [0.9 Bcfd incremental LNG exports from Jordan Cove (in addition to 2 Bcfd assumed in the base case)]</td><td>$0.03 (0.9 Bcfd)</td><td>$0.03</td><td>14%</td><td>7%</td><td>95%</td><td>0%</td><td>N/A</td><td rowspan="2">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)</td><td rowspan="2">N/A (separate reports on GDP impact attributed to regional, trade, upstream but no total)</td><td rowspan="2">Gas price impacts of Jordan Cove are "negligible". Jordan Cove creates positive economic and employment benefits for Oregon and Washington states.</td></tr>
<tr><td>5.9 Bcfd [3 Bcfd incremental LNG exports (in addition to Base Case Bcfd and 0.9 Bcfd incremental)]</td><td>$0.38 (3.9 Bcfd)</td><td>$0.10</td><td>80%</td><td>11%</td><td>12%</td><td>116%</td><td>N/A</td></tr>
</table>

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

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

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

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

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

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
Port Arthur LNG (Black & Veatch)	1 Bcfd demand curve shift relative to EIA cases	Various	$0.088/Mcf by 2025		67.8% (by 2025)		N/A		from RIMS II (Department of Commerce)	construction: 63,000; operation:53000	$211,000 /job	Gas price impacts are small, between $0.064 and $0.088/Mcf. Export facility generates 1.1 million job-years and $45 billion economic value over project lifetime.

Facility	Summary of Analysis	Case	Impact LNG Exports									Main Conclusions
			Henry Hub Price Change Relative to Reference Case		Flow Impact Contribution to LNG Exports (flows add to 1 Bcfd)				Multiplier Effect	Employment Impact	GDP Impact	
			$/MMBtu	$/MMBtu per 1 Bcfd	Production Increase (%)	Demand Decrease (%)	Canadian Gas Imports (%)	Total Share of LNG Exports (%)	Multiplier	Jobs per Bcfd	ΔGDP/ΔJobs	
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	$1.18			N/A	N/A				
		High Demand Base Case + SLNG	$0.82/MM Btu	$1.64			N/A	N/A				
Pangea LNG (Black & Veatch for price and Perryman for economic impacts)	4 demand cases	Base Case			N/A	N/A	N/A	N/A				The project has limited impact on U.S. gas prices and bring significant economic benefits, including $1.4 billion in GDP and 17,230 person-years of employment.
		Pangea Export Case	$0.17/MM Btu (2018-27)	$0.14	N/A	100%	N/A	N/A		29860 permanent jobs in total	2.7 billion in total	
		High LNG Export	$0.26/MM Btu	0.09	N/A	100%	N/A	N/A				
		High LNG Export + Pangea	$0.37/MM Btu	0.09	N/A	N/A	N/A	N/A				

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

ICF

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled in this proceeding.

Dated this 19th day of October, 2018.

/s/_Lamiya Rahman____

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