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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY AND CARBON MANAGEMENT

Cameron LNG, LLC	))))	**DOCKET NOS. 15-36-LNG & 15-90-LNG**

APPLICATION OF CAMERON LNG, LLC FOR COMMENCEMENT EXTENSION, TERM EXTENSION, AND PARTIAL VACATUR

Pursuant to section 3 of the Natural Gas Act ("NGA"),[1] part 590 of the regulations of the United States Department of Energy ("DOE"),[2] Cameron LNG, LLC ("Cameron LNG") hereby respectfully requests an extension of the export commencement deadlines applicable to the authorizations issued to Cameron LNG in Order Nos. 3680 ("FTA Authorization") and 3846 ("Non-FTA Authorization), each as amended, in FE Docket Nos. 15-36-LNG and 15-90-LNG.

Specifically, Cameron LNG requests that the DOE Office of Fossil Energy and Carbon Management ("DOE/FECM") (a) eliminate the specific start date for the authorization term under Order No. 3680 and set the term to begin on the date of first commercial export of liquefied natural gas ("LNG"); (b) extend the deadline for commercial export of LNG under Order No. 3846 to March 16, 2033; and (c) extended both authorization terms to the later of twenty years after the date of first commercial export or December 31, 2050, with an additional three-year make-up period.

1 15 U.S.C. § 717b.
2 10 C.F.R. Part 590.

Additionally, as set forth in greater detail below, Cameron LNG requests that DOE/FECM partially vacate the authorized export volumes under Order Nos. 3680 and 3846.

Cameron LNG submits that good cause exists to grant these requests and that the requests are not inconsistent with the public interest. **Cameron LNG respectfully asks that DOE/FECM act on these requests by January 21, 2026.**

In support hereof, Cameron LNG states as follows:

I. BACKGROUND

Cameron LNG owns and operates the Cameron LNG Terminal in Cameron and Calcasieu Parishes, Louisiana ("Cameron LNG Terminal"). On May 5, 2016, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued in Docket No. CP15-560-000 an order authorizing Cameron LNG to site, construct, and operate two liquefaction trains, Trains 4 and 5 (the "Expansion Project"), to provide additional natural gas processing, storage, and liquefaction capability at the site of the existing Cameron LNG Terminal, which includes Trains 1–3 and which is currently under commercial operation.[3] FERC's order required the Expansion Project to be constructed and made available for service by May 5, 2020.

On July 10, 2015, DOE/FECM issued Order No. 3680, granting Cameron LNG long-term, multi-contract authorization to export LNG from the Expansion Project to any country with which the United States currently has, or in the future will have, a free trade agreement requiring the national treatment for trade in natural gas. ("FTA Authorization").[4] The FTA Authorization permitted Cameron LNG to export LNG in volumes equivalent to 515 billion cubic feet per year

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[3] *Cameron LNG, LLC*, 155 FERC ¶ 61,141 (2016).

[4] *Cameron LNG, LLC*, DOE/FE Order No. 3680, FE Docket No. 15-36-LNG, Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Cameron LNG Terminal in Cameron and Calcasieu Parishes, Louisiana, to Free Trade Agreement Nations (July 10, 2015), *amended by* DOE/FE Order No. 3680-A (Nov. 2, 2020) (extending commencement deadline), *amended by* DOE/FE Order No. 3680-B (Dec. 30, 2020) (extending termination date of export authorization).

("Bcf/yr") of natural gas.[5] Ordering Paragraph (A) of the FTA Authorization required Cameron LNG to commence exports within seven years of the date of the order (i.e., by July 10, 2022).

On July 15, 2016, DOE/FECM issued Order No. 3846 granting Cameron LNG long-term, multi-contract authorization to export LNG from the Expansion Project, in volumes equivalent to 515 Bcf/yr of natural gas, to any country with which the United States does not have an FTA requiring national treatment for trade in natural gas ("Non-FTA Authorization" and together with the FTA Authorization, the "Expansion Project Authorizations").[6] Ordering Paragraph (D) of the Non-FTA Authorization required Cameron LNG to commence exports within seven years of the date of the order (i.e., by July 15, 2023).

On March 6, 2020, Cameron LNG filed with DOE/FECM a request to extend the deadlines to begin commercial export to May 5, 2026, under each of the Expansion Project Authorizations ("March 2020 Request").[7] In support of the extension request, Cameron LNG stated that it has proceeded expeditiously to advance the Expansion Project and had spent $50 million in costs related to the project. Cameron LNG also included information about conducting certain front-end engineering design (FEED) work, installing piping tie-ins to systems within the existing Cameron LNG Terminal, and beginning site preparation work including cut, fill, and soil stabilization. Cameron LNG also explained that it had obtained all federal, state, and local permits necessary at the time for the construction of the Expansion Project. Cameron LNG noted that

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[5] Order No. 3680 at ordering para. (A).

[6] *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 (July 15, 2016), *amended by* DOE/FE Order No. 3846-A (Nov. 2, 2020) (extending commencement deadline), *amended by* DOE/FE Order No. 3846-B (Dec. 30, 2020) (extending termination date of export authorization).

[7] *Cameron LNG, LLC*, Request for Extension of Time under Order Nos. 3680 and 3846, Docket Nos. 15-36-LNG & 15-90-LNG (March 6, 2020).

despite its diligence in pursuing the project, it had experienced changes in circumstances surrounding its joint-venture owners that affected the timing of the project.

On November 2, 2020, after considering Cameron LNG's request and the steps that Cameron LNG had taken, DOE/FECM issued Order Nos. 3680-A and 3846-A, extending Cameron LNG's deadlines to commence both commercial FTA and non-FTA exports to May 5, 2026.[8] In its order, DOE/FECM noted that the request was unopposed and that the requested extensions did not alter DOE/FECM's underlying public interest determination for the non-FTA exports, as no facts or requirements associated with the original authorization would be affected beyond the additional time period to commence exports.[9] DOE/FECM also pointed out that Cameron LNG had already completed construction and commenced commercial operations of Trains 1-3 at the Cameron LNG Terminal.[10]

On December 30, 2020, as it did for other long-term export authorizations, DOE/FECM issued an order extending the export terms for the Expansion Project Authorizations through December 31, 2050.[11]

In response to requests from its customers to increase the efficiency of the Expansion Project, Cameron LNG redesigned the project. Specifically, on January 18, 2022, Cameron LNG filed an application with FERC pursuant to section 3(a) of the NGA to amend its existing authorization for the Expansion Project.[12] The proposed amendments included several final design enhancements to increase the efficiency, reliability, and capacity of Train 4. Cameron LNG

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8 *Cameron LNG, LLC*, Order Nos. 3680-A & 3846-A, Docket Nos. 15-36-LNG & 15-90-LNG (Nov. 2, 2020).

9 *Id.* at 6.

10 *Id.*

11 *Cameron LNG, LLC*, DOE/FECM Order Nos. 3680-B & 3846-B *et al.*, Order Extending Export Term for Authorizations to Free Trade and Non-Free Trade Agreement Nations Through December 31, 2050 (Dec. 30, 2020).

12 *Cameron LNG, LLC*, Abbreviated Application of Cameron LNG, LLC to Amend Authorization under Section 3 of the Natural Gas Act, FERC Docket No. CP22-41-000 (Jan. 18, 2022).

proposed to eliminate Train 5 and the fifth LNG storage tank. Cameron LNG also proposed various modifications to the remaining train, including the replacement of gas turbine drives with electric drive ("e-drive") motors and the addition of tie-ins to allow the option to access future carbon capture and sequestration facilities that may be developed. With the removal of Train 5, the overall maximum production capacity of the Expansion Project would decrease from 9.97 million metric tonnes per annum ("MTPA") (equivalent to 515 Bcf/yr) to 6.75 MTPA (equivalent to 350 Bcf/yr), sourced exclusively from Train 4. On February 18, 2022, Cameron LNG notified the DOE/FECM of the filing of the Amendment Application with FERC.[13]

FERC issued an Environmental Assessment ("EA") evaluating Cameron LNG's proposed amendments in December 2022.[14] The EA concluded "approval of the proposed project amendment, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment."[15]

On March 16, 2023, FERC issued an order granting Cameron LNG's request to modify the Expansion Project, finding the redesigned Expansion Project "is not inconsistent with the public interest[.]" ("FERC Amendment Order").[16] Among other things, the FERC Amendment Order requires that "Cameron LNG's proposed facilities shall be constructed and made available for service within five years of the date of this order [i.e., March 16, 2028]."[17] The FERC Amendment Order also granted Cameron LNG's request to vacate its authorization to site, construct, and operate the previously authorized Train 5 and the fifth LNG storage tank.

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13 *Cameron LNG, LLC*, FE Docket Nos. 15-36-LNG & 15-90-LNG, Report Pursuant to 10 C.F.R. § 590.407 (Feb. 18, 2022).

14 *Cameron LNG, LLC*, Cameron LNG Amended Expansion Project, Environmental Assessment, FERC Docket No. CP22-41-000 (Dec. 2, 2022) ("FERC EA").

15 *Id.* at 1.

16 *Cameron LNG, LLC*, 182 FERC ¶ 61,173 (2023) ("FERC Amendment Order"). The Commission also agreed with the conclusions set forth in the EA.

17 *Id*. at ordering para. (B).

On October 21, 2025, Cameron LNG filed with FERC a request to extend the construction deadline in the FERC Amendment Order to March 16, 2033.[18]

II. REQUEST FOR COMMENCEMENT EXTENSION

In relevant part, ordering paragraph A of Order No. 3680-A sets the start date of the term of the FTA Authorization as beginning on the earlier of the date of first commercial export or May 5, 2026. Ordering paragraph B of Order No. 3864-A requires Cameron LNG to commence commercial exports under the Non-FTA Authorization no later than May 5, 2026.

Cameron LNG hereby respectfully requests that DOE/FECM amend ordering paragraph A of Order No. 3680-A to remove the deadline associated with Cameron LNG's FTA export authorization and to establish the commencement of the term as the date of first export, consistent with DOE/FECM precedent.[19] Cameron LNG further respectfully requests that the deadline for the commencement of service for Non-FTA exports pursuant to Order No 3864-A be changed to March 16, 2033, consistent with Cameron LNG's October 21, 2025 request filed with FERC to extend the construction deadline established in the FERC Amendment Order.

A. FTA Authorization (Order No. 3680 *et al.*)

With respect to its FTA Authorization in Order No. 3680, as amended, Cameron LNG requests that DOE/FECM grant the requested removal of the export commencement deadline without modification or delay.

Under section 3(c) of the NGA, an application for authorization to export natural gas, including LNG, to any "nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest,

[18] Cameron LNG, LLC Request for Extension of Time, *Cameron LNG, LLC*, FERC Docket No. CP22-41-001 (Oct. 21, 2025) (Accession No. 20251021-5136).

[19] *See, e.g.*, *Port Arthur LNG, LLC*, DOE/FECM Order No. 3698-C & 4372-B, Docket Nos. 15-53-LNG, 15-96-LNG, 18-162-LNG at 4-5 (Apr. 21, 2023).

and … shall be granted without modification or delay."[20] In light of this statutory obligation, DOE/FE has found that it need not engage in any analysis of factors affecting the public interest. Because this request as it pertains to the FTA Authorization falls within section 3(c), it should be processed and approved in accordance with this standard.

B. Non-FTA Authorization (Order No. 3846 *et al.*)

The portion of this request relating to Cameron LNG's Non-FTA Authorization in Order No. 3864, as amended, is governed by section 3(a) of the NGA.

Section 3(a) of the NGA provides:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.[21]

NGA section 3(a) creates a rebuttable presumption that a proposed export of natural gas is in the public interest.[22] DOE/FE has explained that it must grant an application requesting the export of natural gas unless the presumption favoring exports is overcome by an affirmative showing that the application is inconsistent with the public interest.[23] Although the NGA does not define "public interest," DOE/FE has identified several factors that it considers when reviewing Non-FTA export applications, including economic impacts, international impacts, security of natural gas supply, and environmental impacts.[24]

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20 15 U.S.C. §§ 717b(b)-(c).

21 15 U.S.C. § 717b(a).

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

23 *See, e.g.*, *Golden Pass Prods. LLC*, DOE/FE Order No. 3978, FE Docket No. 12-156-LNG, Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel From the Golden Pass LNG Terminal Located in Jefferson County, Texas, to Non-Free Trade Agreement Nations at 11 (Apr. 25, 2017).

24 *See, e.g., Venture Global Plaquemines LNG, LLC*, DOE/FE Order No. 4446, FE Docket No. 16-28-LNG, Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 19 (Oct. 16, 2019) [hereinafter *Venture Global*]; *Eagle LNG Partners Jacksonville LLC*, DOE/FE Order No. 4445, FE Docket No. 16-15-LNG, Opinion and Order Granting Long-Term Authorization to Export Liquefied

1. Good Cause Exists to Grant This Request

Consistent with NGA section 3(a), Cameron LNG submits that good cause exists to grant this request.

Since the issuance of the Expansion Project Authorizations, Cameron LNG has proceeded diligently to advance the Expansion Project. Cameron LNG's need for this requested extension arises primarily out of its customers' request for redesign of the Expansion Project. A significant driver of the redesign is to enhance the efficiency and reliability of the remaining train. The modifications to the design of Train 4 approved by FERC are consistent with this objective. Granting the requested extension will allow Cameron LNG to align the term of the Expansion Project Authorizations with the revised construction schedule requested by Cameron LNG at FERC. In so doing, the requested extension will allow Cameron LNG to realize the significant benefits of the redesigned Expansion Project.

Within the scope of a revised project, the approval of which was pending before FERC, Cameron LNG has commenced construction activities for the Expansion Project. To date, Cameron LNG has spent approximately $100 million in costs related to the project, which include development activities such as permitting, corporate structuring, negotiation of commercial agreements necessary for the Expansion Project, and financing.[25]

Cameron LNG conducted front-end engineering and design, as well as value engineering work to progress procurement of long lead items, specifically, the compressors, electric motors,

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Natural Gas to Non-Free Trade Agreement Nations at 19 (Oct. 3, 2019) [hereinafter *Eagle LNG*]; *Gulf LNG Liquefaction Co., LLC*, DOE/FE Order No. 4410, FE Docket No. 12-101-LNG, Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 19-20 (July 31, 2019) [hereinafter *Gulf LNG*].

[25] This reflects an increase of $50 million since Cameron LNG's March 2020 Request.

transformers, and main cryogenic heat exchanger; and to advance service requisition for site preparation activities including laydown areas/on-site parking and temporary facilities.

In addition, Cameron LNG has also taken important commercial steps in furtherance of the project. Cameron LNG has significantly progressed with both customers and lenders amendments to the existing Liquefaction and Regasification Tolling Agreements ("LRTAs") for Trains 1–3 as well as Liquefaction Tolling Agreements ("LTAs") for Train 4 that would allow integrated operations of the Cameron LNG Terminal. These LTAs represent 350 Bcf/yr, or 100% of the Amended Expansion Project's capacity. All customers of Trains 1–4 are affiliates of the joint-venture owners of Cameron LNG.

With the issuance of the FERC Amendment Order, Cameron LNG has obtained all necessary federal, state, and local permits for the construction of the amended Expansion Project including receipt of the Louisiana Department of Environmental Management (LDEQ) modified air permit. Cameron LNG filed a modification to the existing air permit that reduced all criteria air pollutants. Cameron LNG will continue taking steps to ensure that all such permits remain in full force and effect through the anticipated in-service date discussed in this request.

Finally, Cameron LNG further notes that it has successfully developed liquefaction and export facilities in the past, having commenced commercial operations for the Cameron LNG Terminal in 2019. Cameron LNG will bring its experience and proven track record to bear in diligently achieving commercial operation for the redesigned Expansion Project.

In the March 2020 Request, Cameron LNG explained the unforeseen delays that transpired due to circumstances surrounding its joint-venture owners.[26] As explained therein, Cameron LNG

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[26] *See* March 2020 Request at 3-4.

had no control over these circumstances, which delayed the project. Cameron LNG hereby incorporates by reference the March 2020 Request.

A significant aspect of Cameron LNG's redesign of the Expansion Project is the efficiency design modifications to Train 4 and the elimination of the fifth train and fifth storage tank. The modifications to the Expansion Project arose out of requests by Cameron LNG's customers that the Expansion Project be redesigned to enhance the efficiency and reliability of the remaining facilities. To address its customers' requests, Cameron LNG filed an application with FERC to amend the Expansion Project in January 2022. Cameron LNG's inability to meet its current export commencement deadline is due in significant measure to the regulatory process for seeking and obtaining FERC approval for the redesign of the Expansion Project, the completion of which Cameron LNG has little control over, despite proactive measures taken by Cameron LNG to shorten the process.

2. DOE/FECM's Previous Public Interest Determination and Environmental Review Are Unaffected

Granting Cameron LNG's requested extension will not disturb DOE/FECM's underlying public interest determinations regarding the Non-FTA Authorization. No facts or requirements associated with the Non-FTA Authorization would be affected by the requested extension beyond the additional time period to commence operations.[27]

Additionally, in support of its FERC amendment application, Cameron LNG filed an updated economic analysis with FERC detailing the economic and employment impacts of the amended Expansion Project between the test years 2027 and 2050 ("ICF Report").[28] The ICF

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27 *Port Arthur LNG, LLC*, DOE/FECM Order No. 3698-C & 4372-B, Docket Nos. 15-53-LNG, 15-96-LNG, 18-162-LNG at 13 (Apr. 21, 2023).

28 *Cameron LNG*, *LLC*, Updated Economic Analysis – ICF Report, FERC Docket No. CP22-41 (Nov. 16, 2022) (attached as Appendix C).

Report is appended here at Appendix C. This report demonstrated that additional LNG exports resulting from the amended Expansion Project will substantially benefit national, regional, and local economies. The ICF Report showed the amended Expansion Project could add $2.6 billion to the U.S. economy annually ($80.3 billion over the forecast period), including $318 million annually in Louisiana ($9.9 billion over the forecast period).[29] The ICF Report found that the amended Expansion Project would lead to tax revenues amounting to $26.4 billion throughout the United States and $1.3 billion within Louisiana between 2027 and 2050.[30] The ICF Report demonstrated that the added LNG export capacity is expected to create a cumulative impact through 2050 of approximately 399,000 U.S. job-years and 57,300 Louisiana job-years.[31] The ICF Report also estimated that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $1.5 billion annually or a cumulative value of $36.4 billion between 2027 and 2050.[32] Importantly, the ICF Report shows that exports from Train 4 would have a minimal impact on U.S. gas prices.[33]

3. Summary

As the foregoing demonstrates, there is good cause to grant this request, and granting the requested extension will not disturb DOE/FECM's prior determination that the non-FTA Authorization is not inconsistent with the public interest. On the other hand, Cameron LNG respectfully submits that denying the requested extension may unintentionally dissuade efforts by project developers, such as Cameron LNG, to proactively and voluntarily enhance their previously approved projects to align with its customers' evolving efficiency and environmental goals.

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29 *See* Appendix C, ICF Report at 9, 53, 58.
30 *Id*. at 10.
31 *Id*. at 9-10, 52, 55.
32 *Id*. at 54.
33 *Id*. at 9, 49.

Cameron LNG has made significant efforts to advance the project as redesigned to increase the efficiency and reliability of the project. However, because the project's lenders require assurances that Cameron LNG has all necessary authorizations for the Expansion Project as amended, a grant of the extension requested herein is a prerequisite to reaching a positive final investment decision, to amending the LRTAs, and ultimately to successfully commercializing the Expansion Project. Accordingly, the denial or delay in issuance of the requested extension will create uncertainty for stakeholders and hinder the progress Cameron LNG has made to develop the redesigned Expansion Project.

Finally, DOE/FECM limits any comments on a request for extension to the extension itself and not to the underlying authorization.[34] Cameron LNG submits that DOE/FECM should do so here.

III. REQUEST FOR TERM EXTENSION AND MAKE-UP PERIOD

On December 30, 2020, as it did for other long-term export authorizations, DOE/FECM issued an order extending the export terms for the Expansion Project Authorizations through December 31, 2050.[35] If DOE/FERCM grants the commencement extension requested herein, it is likely that a term ending on December 31, 2050, would be less than 20 years, which is the industry standard for the long-term LNG sale and purchase agreements that support the financing of LNG export terminals such as the Cameron LNG Phase 2 project. Others in the industry have noted a concern with 2050 potentially limiting terms to less than 20 years, the accepted industry minimum.[36]

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[34] *Cameron LNG, LLC*, 85 Fed. Reg. 20993, 20994 (Apr. 15, 2020).

[35] *Cameron LNG, LLC*, DOE/FECM Order Nos. 3680-B & 3846-B, Order Extending Export Term for Authorizations to Free Trade and Non-Free Trade Agreement Nations Through December 31, 2050 (Dec. 30, 2020).

[36] *See, e.g.*, Amendment to Pending Application for Authorization to Export Liquefied Natural Gas to Non-Free-Trade Agreement Nations and Request for Amended Authorizations for Exports to Free Trade Agreement Nations, at 11–13, *Sabine Pass Liquefaction, LLC*, Docket No. 24-27-LNG (June 6, 2025).

Cameron LNG hereby requests that the term of each of the FTA Authorization and the Non-FTA Authorization be extended to the later of (a) December 31, 2050, or (b) 20 years after the date of first commercial export. Cameron LNG also hereby requests a three-year, post-term make-up period.[37]

In proposing the policy statement extending the terms of all long-term authorizations, DOE recognized that a <u>30-year export term</u> would better match the operational life of LNG export facilities, would enhance authorization holders' ability to finance their facilities, and would facilitate authorization holders' ability to enter into longer-term natural gas supply and export contracts.[38] Indeed, DOE/FE recognized that the longer export term would increase the competitiveness of U.S. gas exports vis-à-vis exports from other countries.[39] In the policy statement, DOE also noted that the five export studies through 2018 had all projected "consistently positive economic benefits from increased levels of U.S. LNG exports as measured by GDP."[40] DOE has subsequently determined that its 2024 export study continues to show a range of persistent positive economic and security benefits from increased levels of LNG exports.[41]

All these considerations hold just as true today. It is therefore not inconsistent with the public interest to grant the term extension for a minimum of 20 years with a three-year make-up period, as requested herein.

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37 *See* Order Amending Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 3-5, Order No. 5292-A, *Port Arthur LNG Phase II, LLC*, Docket No. 20-23-LNG (June 30, 2025).

38 *Extending Natural Gas Export Authorizations to Non-Free Trade Agreement Countries Through the Year 2050*, 85 Fed. Reg. 52237, 52240 (Aug. 25, 2020).

39 *Id.* at 52240-41.

40 *Id*. at 52241.

41 *See* Response to Comments at 46-50, *2024 LNG Export Study: Energy, Economic, and Environmental Assessment of U.S. LNG Exports* (May 2025).

IV. REQUEST FOR PARTIAL VACATUR

Cameron LNG also requests that DOE/FECM partially vacate the authorizations granted in the Expansion Project Authorizations. Under the FERC Amendment Order, the certificated capacity of the amended Expansion Project is 6.75 MTPA, or 350 Bcf/yr. It is no longer necessary under the revised Expansion Project to export the full 515 Bcf/yr of natural gas authorized in each of the Expansion Project Authorizations. Rather, Cameron LNG plans to export LNG up to a volume equivalent to the proposed production capacity of the amended Expansion Project facilities (i.e., 350 Bcf/yr). Cameron LNG requests that DOE/FECM (a) vacate 165 Bcf/yr of the volumes authorized for export in the FTA Authorization, such that Cameron LNG would be authorized to export 350 Bcf/yr of natural gas from the Expansion Project to FTA nations; and (b) vacate 165 Bcf/yr of the volumes authorized for export in the Non-FTA Authorization, such that Cameron LNG would be authorized to export 350 Bcf/yr of natural gas from the Expansion Project to Non-FTA nations.

V. APPENDICES

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

IV. CONCLUSION

Cameron LNG submits that the foregoing requests are not inconsistent with the public interest under section 3(a) of the NGA and that good cause exists to grant this application. Cameron LNG respectfully requests that that DOE/FECM act on this application by **January 21, 2026**, to ensure that Cameron LNG can expeditiously move forward with the redesigned Expansion Project.

/s/ Brett A. Snyder

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Counsel to Cameron LNG, LLC

Dated: October 23, 2025

Appendix A:

Verification

VERIFICATION

I, Blair Woodward, declare that I am Senior Vice President, Business Strategy and General Counsel of Cameron LNG, LLC; that I am duly authorized to make this Verification; that I have read the foregoing instrument and that the facts therein stated are true and correct to the best of my knowledge, information, and belief.

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

Executed in Houston, Texas, on October 23, 2025.

/s/ Blair Woodward

Appendix B:

Opinion of Counsel

October 23, 2025

Amy Sweeney
Director, Office of Regulation, Analysis and Engagement (FE-34)
Office of Fossil Energy and Carbon Management
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Re: **Cameron LNG, LLC**
FE Docket Nos. 15-36-LNG and 15-90-LNG
Application for Commencement Extension, Term Extension, and Partial Vacatur

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 ("DOE"), 10 C.F.R. § 590.202(c) (2023). I am counsel to Cameron LNG, LLC ("Cameron LNG").

I have reviewed the organizational and internal governance of Cameron LNG and it is my opinion that the Request for Extension of Time under Order Nos. 3680 and 3846 and for Partial Vacatur with the DOE Office of Fossil Energy and Carbon Management on October 23, 2025, is within the company powers of Cameron LNG.

Respectfully submitted,

/s/ Jerrod L. Harrison
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On Behalf of Cameron LNG, LLC.

Appendix C:

ICF Report

Economic Impacts of Cameron LNG Phase 2, Train 4 Project

November 1, 2022

Submitted to:
Cameron LNG Holdings, LLC
2825 Briarpark Drive, Suite 1000
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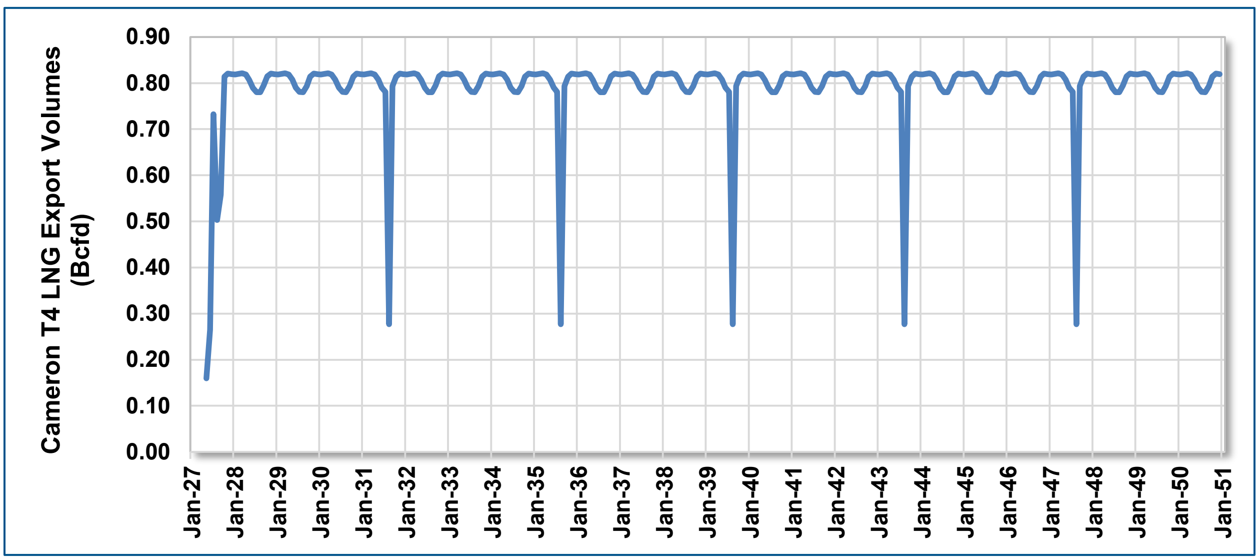
1. Executive Summary

1.1. Introduction

ICF conducted an analysis on behalf of Cameron LNG to assess the market and economic impacts of the proposed Cameron LNG Phase 2, Train 4 Project to add an electric drive train to its LNG export facility located in Hackberry, LA. Cameron LNG has proposed in an Amendment Application to implement several design modifications and enhancements to reduce the overall greenhouse gas ("GHG") emissions from the project, allow for Cameron LNG to gain access to carbon capture and storage ("CCS") facilities in the future, and to enhance the overall efficiency and production capacity of the Cameron LNG Phase 2, Train 4 Project.

Per the proposed amendment, Train 4 will have a maximum LNG production capacity of 6.75 MTPA with its own feed gas pretreatment facility. On a daily average basis, Train 4 is expected to take in 859,541 MMBtu of natural gas and produce 846,812 MMBtu of LNG and 1,396 MMBtu of gas liquids (ethane, propane, etc.). The plant itself would consume on an average day 5,363 MMBtu of natural gas and 6,930 megawatt-hours of electricity. For this economic analysis, the export volumes are assumed to begin in May 2027 and extend through the end of 2050 as shown in Exhibit 1-1. The up and down pattern of exports reflects shutdowns for scheduled maintenance.

Exhibit 1-1: Cameron Train 4 LNG Export Volumes



Source: Cameron LNG

ICF was tasked with assessing the energy market impacts, as well as the economic and employment impacts of the Cameron LNG Train 4 export facility. To assess the impacts on the energy market, ICF conducted two alternative scenario runs using its proprietary Gas Market Model (GMM):

1) **Base Case** – This is ICF's "expected" or "most likely" forecast of US natural gas markets, which includes Cameron LNG Trains 1 through 3 but no Cameron LNG Train 4 export facility (of any type or configuration).
2) **Cameron LNG Train 4 Case** – This has all the same national economic and energy market assumptions as the Base Case except that an average of 0.80 Bcfd of additional export volumes from Train 4 (as described in the Amended Expansion Project) is added to operate starting in May 2027 along with the first three trains at Cameron LNG.

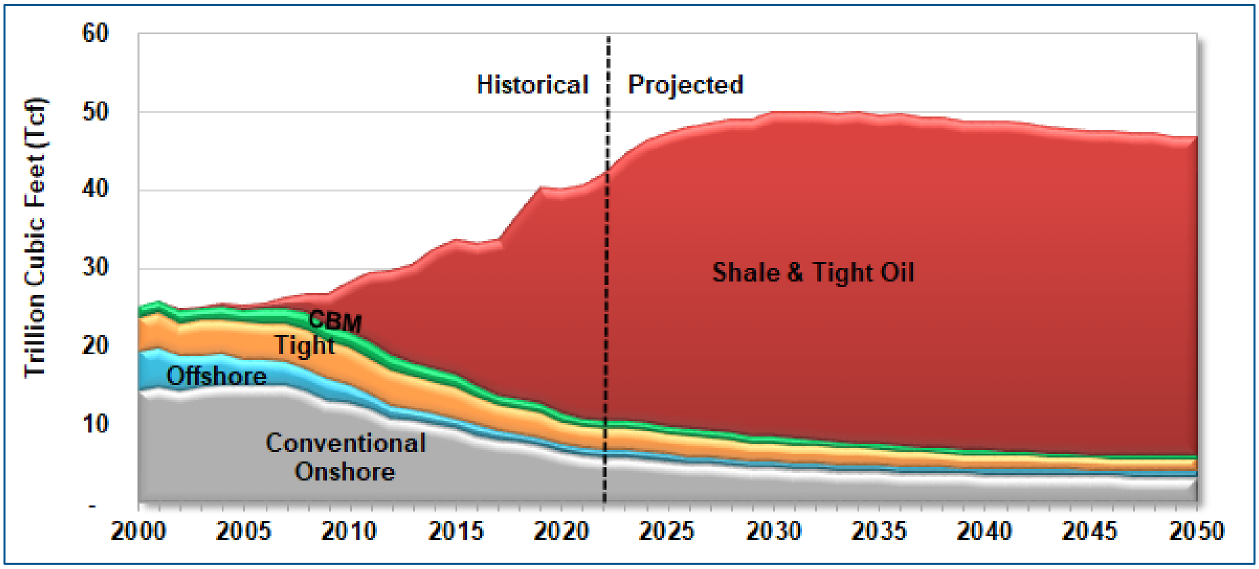
The changes of natural gas and liquids production value, investment, capital and operating expenditure between these two cases are inputs into IMPLAN, an input-output economic model for assessing the economic and employment impacts. Specifically, the analysis methodology consisted of the following steps:

- **Assess natural gas and liquids production changes:** From the GMM run results, we first estimated natural gas and liquids (including crude oil, condensate, and natural gas liquids (NGLs) – such as ethane, propane, butane, and pentanes plus) production changes to meet the additional natural gas supplies needed for Cameron LNG Train 4 exports. GMM also solved for changes in natural gas prices and demand levels. The incremental production volumes from the U.S. supply basins as a whole and from Louisiana were both estimated.
- **Quantify upstream and the plant capital and operating expenditures:** ICF translated the natural gas and liquids production changes from GMM into annual capital and operating expenditures that will be required for the additional production. In addition, based on Cameron LNG Train 4 export facility's cost estimates, ICF assessed the annual capital and operating expenditures to support the LNG exports at the facility.
- **Create IMPLAN input-output matrices:** ICF utilized the LNG plant and upstream expenditures as inputs to the IMPLAN input-output model to assess their economic impacts for the U.S. and Louisiana. 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 Cameron LNG exports on the national and Louisiana economies. The impacts include direct, indirect, and induced impacts on gross domestic product (GDP), employment, taxes, and international balance of trade.

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

U.S. and Canadian natural gas production has grown considerably over the past several years, led by unconventional production, especially from shale resources. The growth trend is expected to continue with production reaching over 50 Tcf per year by 2030, an increase of 10 Tcf per year over recent 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 horizontal drilling in the Marcellus and Utica shales, which will account for over half of the incremental production. In addition, Haynesville production is resurging. Associated gas production from tight oil plays in the Permian Basin, Niobrara, and SCOOP and STACK will also be major drivers, with liquids prices playing a large role. In Canada, essentially all incremental production growth comes from development of shale and other unconventional resources.

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



Source: ICF GMM® Q2 2022

Natural gas exports (LNG and pipeline gas to Mexico and Canada) are key drivers for near-term and long-term demand growth and account for about half of the overall demand growth over the next 25 years. Natural gas demand for power generation is expected to increase in the near term due to additional gas power plant builds and lower coal generation. In the long run, power generation gas demand is expected to decline due to higher renewable penetration, state level initiatives to pursue mandatory renewable portfolio standards and state/federal regulations that drive higher energy efficiency and incentivize energy storage. Natural gas demand in the industrial sector is expected to be up slightly in the long run as gas-intensive end uses such as petrochemicals and fertilizers continue to expand. In the transportation sector (where compressed natural gas and LNG are used in vehicles, rail locomotives, ships, and off-road equipment), ICF expects significant penetration of electric vehicle technologies (both on-road and off-road) starting in 2030.

Increased demand growth keep natural gas prices above $3.00 per MMBtu[1] even as Covid-19 and Ukrainian-Russian war impacts eventually fade. Prices will be high enough to foster sufficient supply development to meet growing demand, but not so high to throttle the demand

[1] All dollar figure results in this report are in 2021 real dollars, unless otherwise specified.

growth. Long-term demand growth will be shaped by future environmental policies and their impact on power sector gas demand.

1.3. Key Study Results

ICF's analysis shows that the volume exported via Cameron LNG Train 4 would have a minimal impact on the U.S. natural gas price. (See Exhibit 1-3.) The Henry Hub natural gas price is expected to increase by $0.05/MMBtu (in real 2021 dollars) on average for the forecast period of 2027 to 2050 when the Cameron LNG Train 4 export facility is included in the scenario, compared with to the Base Case without Cameron LNG Train 4. This small increase in expected prices is very similar across all years of the forecast.

Cameron LNG Train 4 is expected to have minimal impact on the U.S. supply availability and market price because the volume represents a small amount of the North American natural gas resources and total market demand. Total export volumes from the facility from 2027 to 2050 would be 6.8 Tcf. This represents roughly 0.5% of U.S. natural gas resources that can be produced assuming current technology, an 8% rate of return for gas producers, Henry Hub prices of $4.00/MMBtu, and a crude price of $75/bbl. The 6.8 Tcf to be exported from Cameron LNG Train 4 also represents just 1.0% of the total U.S. domestic natural gas consumption during the 2027-2050 period.

Exhibit 1-3: Natural Gas Price Impact of the Cameron LNG Train 4

Year	Henry Hub Natural Gas Price (2021$/MMBtu)		
	Base Case	Cameron T4 LNG Case	Cameron T4 LNG Case Change
2024	$ 3.34	$ 3.34	$ -
2025	$ 2.78	$ 2.78	$ -
2026	$ 2.78	$ 2.78	$ -
2027	$ 2.71	$ 2.75	$ 0.04
2028	$ 2.73	$ 2.78	$ 0.05
2029	$ 3.02	$ 3.07	$ 0.05
2030	$ 3.07	$ 3.11	$ 0.04
2035	$ 3.24	$ 3.29	$ 0.05
2040	$ 3.42	$ 3.47	$ 0.05
2045	$ 3.54	$ 3.59	$ 0.05
2050	$ 3.00	$ 3.05	$ 0.05
2027-2050 Avg	**$ 3.23**	**$ 3.28**	**$ 0.05**

Source: ICF estimates.

ICF's analysis concluded that activity in the U.S. to support Cameron LNG Train 4 exports could lead to significant economic impacts, on average, creating roughly 12,900 jobs annually for the U.S. economy, and about 1,800 jobs in Louisiana from the start of project planning in 2020 through 2050. (See Exhibit 1-4.) This means a cumulative impact through 2050 of 399,000 job-years for the U.S. and 57,300 job-years in Louisiana. In addition, the project could add $2.6 billion to the U.S. GDP annually ($80.3 billion over the forecast period), including $318 million annually in Louisiana ($9.9 billion over the forecast period). The additional Cameron LNG Train 4 exports would also increase tax revenues. In total, federal, state, and local governments are expected to receive an additional $852 million annually; and Louisiana state and local tax revenues are expected to increase by about $43 million annually. Throughout the forecast period, U.S. federal, state, and local governments will receive $26.4 billion additional revenue from taxes and Louisiana alone will receive $1.3 billion.

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

Region	Average Annual Impact			Cumulative Impact		
	Jobs (Jobs)	Value Added (2021$ Million)	Government Revenues (2021$ Million)	Jobs (Job-years)	Value Added (2021$ Million)	Government Revenues (2021$ Million)
U.S.	12,863	$ 2,589	$ 852	398,741	$ 80,265	$ 26,401
Louisiana	1,848	$ 318	$ 43	57,289	$ 9,853	$ 1,319

Source: ICF estimates.

2. Introduction

ICF conducted an analysis on behalf of Cameron LNG to assess the market and economic impacts of the proposed Cameron LNG Phase 2, Train 4 Project to add an electric drive train to its LNG export facility located in Hackberry, LA. In an Amendment Application, Cameron LNG has proposed to implement several design modifications and enhancements to reduce the overall greenhouse gas ("GHG") emissions from the project, allow for Cameron LNG to gain access to carbon capture and storage ("CCS") facilities in the future, and to enhance the overall efficiency and production capacity of the Cameron LNG Phase 2, Train 4 Project.

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For this analysis, ICF ran its proprietary natural gas market fundamental GMM model with and without an average of 0.80 Bcfd of exports from the proposed Cameron LNG Train 4 export facility. For the U.S. as a whole and for Louisiana, ICF estimated the changes between the two scenarios for the following parameters:

- 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 natural gas and liquids production
- Upstream operating expenditure
- Natural gas consumption
- Henry Hub natural gas prices
- Natural gas and liquids production value.

The changes in LNG plant, pipeline, electric power, and upstream capital and operating expenditures were put into the IMPLAN model to estimate the export facility's impacts on the U.S. and Louisiana economy. The economic metrics estimated by the IMPLAN model include:

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

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) Cameron LNG Train 4 Energy Market and Economic Impact Results
6) Bibliography.

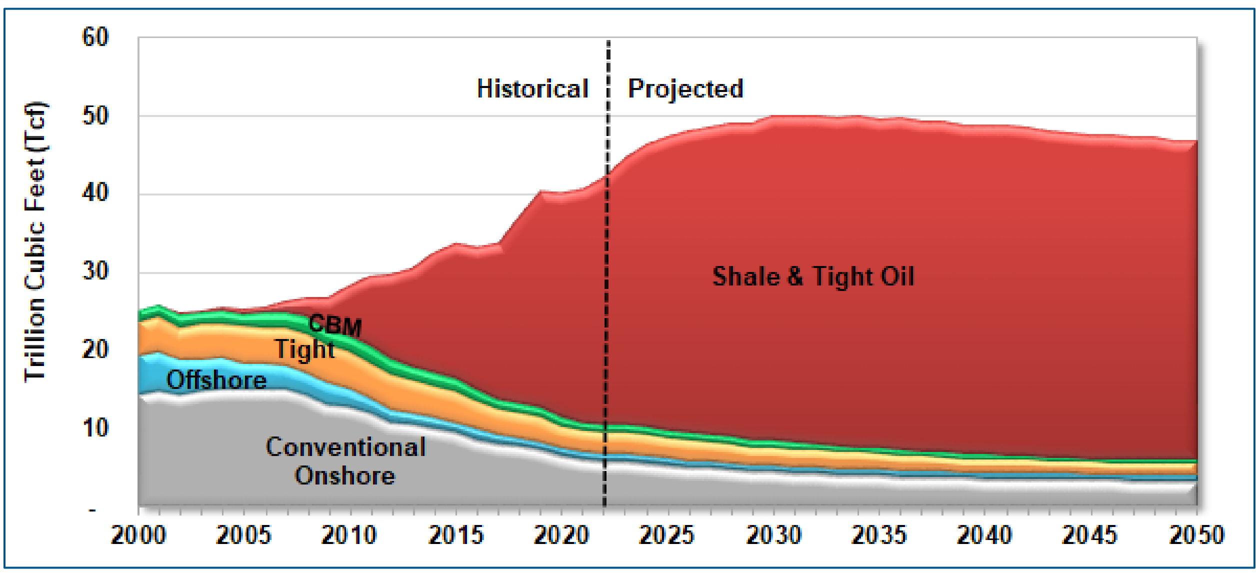
3. Base Case U.S. and Canadian Natural Gas Market Overview

This section discusses ICF's 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 2050, including pipeline construction and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

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

Over the past several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2030 and then is expected to remain relatively flat (see Exhibit 3-1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil production expected to far exceed declining conventional production. These production changes have incentivized significant infrastructure investments to create pathways between new supply sources and consumption markets.

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



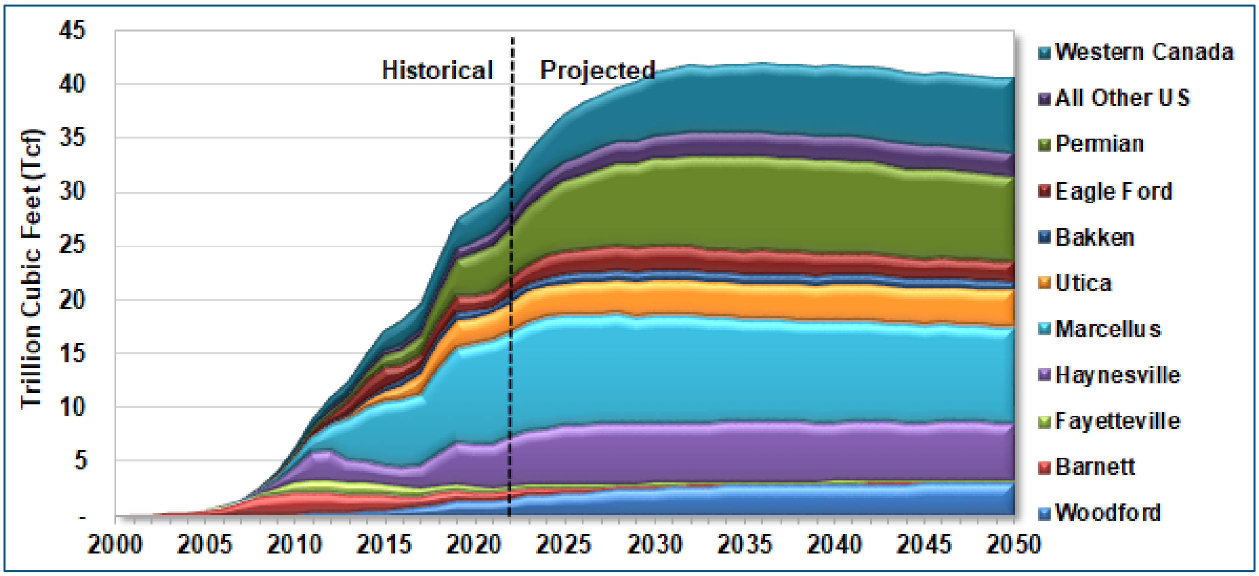
Source: ICF GMM® Q2 2022

Production from U.S. and Canadian shale formations will grow from 31.4 Tcf per year (86.1 Bcfd) in 2022 or 75 percent of total production to 40.6 Tcf per year (111.3 Bcfd) by 2050 or 87 percent of total production (see exhibit above). The projection assumes West Texas Intermediate (WTI) crude price of $70/bbl. ($2021).

The major shale formations in the U.S. and Canada are in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, and Haynesville), South Texas (Eagle Ford), and western Canada (Montney and Horn River). The Permian, Niobrara, and Bakken are primarily producing oil with associated natural gas volumes. As shown in Exhibit 3-2, associated gas production from the Permian, Niobrara, and Bakken is expected to grow significantly in the next 10 years. Dry gas[2] production (mostly gas associated with tight oil) from the lower cost Permian basin will reach 7.9 Tcf per year (21.5 Bcfd) by 2050, growing from about 4.7 Tcf (12.8 Bcfd) in 2022.

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

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



Source: ICF GMM® Q2 2022

3.1.1. Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane (CBM) will generally have much lower cost on a per-unit basis than conventional sources.[3] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base volume in total. Even though their production costs are uncertain due the newness of the plays and considerable site-to-site variation in geology, shale plays such as the Marcellus and Permian and other tight oil plays are proving to be among the least expensive (on a per-unit basis) natural gas sources.

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

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

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

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and transportation. Then, those cost factors are added to estimate costs at points farther downstream of the wellhead. Costs can be further adjusted to a "Henry Hub" basis by adding regional basis differentials for certain types of analysis that considers the locations of resources relative to markets.

Supply Costs of Conventional Oil and Gas

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

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

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies and have been subsequently refined and expanded. North American plays include all 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, technological improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study anticipates there will be more resources available in the future than indicated by a static supply curve based on current technology.

Aggregate Cost of Supply Curves

U.S. and Canadian supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in Exhibit 3-3. The supply curves were developed on an "oil-derived" basis. That is to say, the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas

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

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

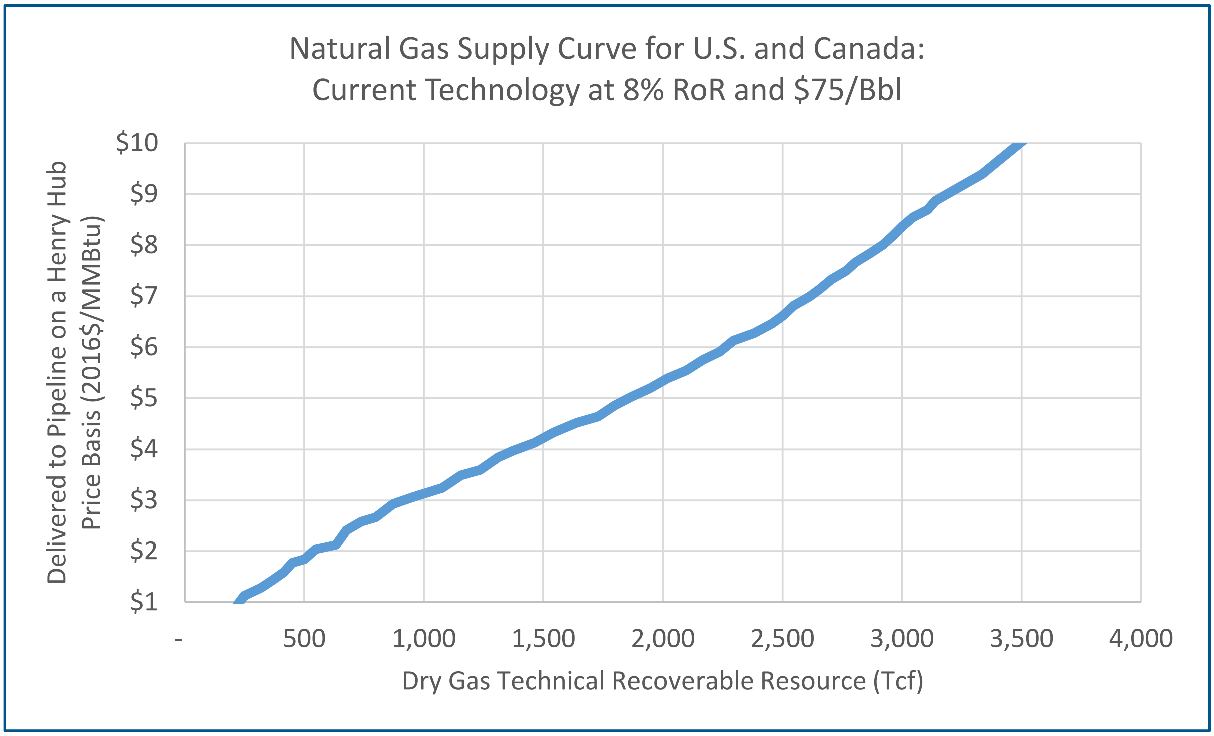
6 U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011 and various other years: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

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

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future. (See section 3.1.2 for discussion of technology trends assumed in this study.)

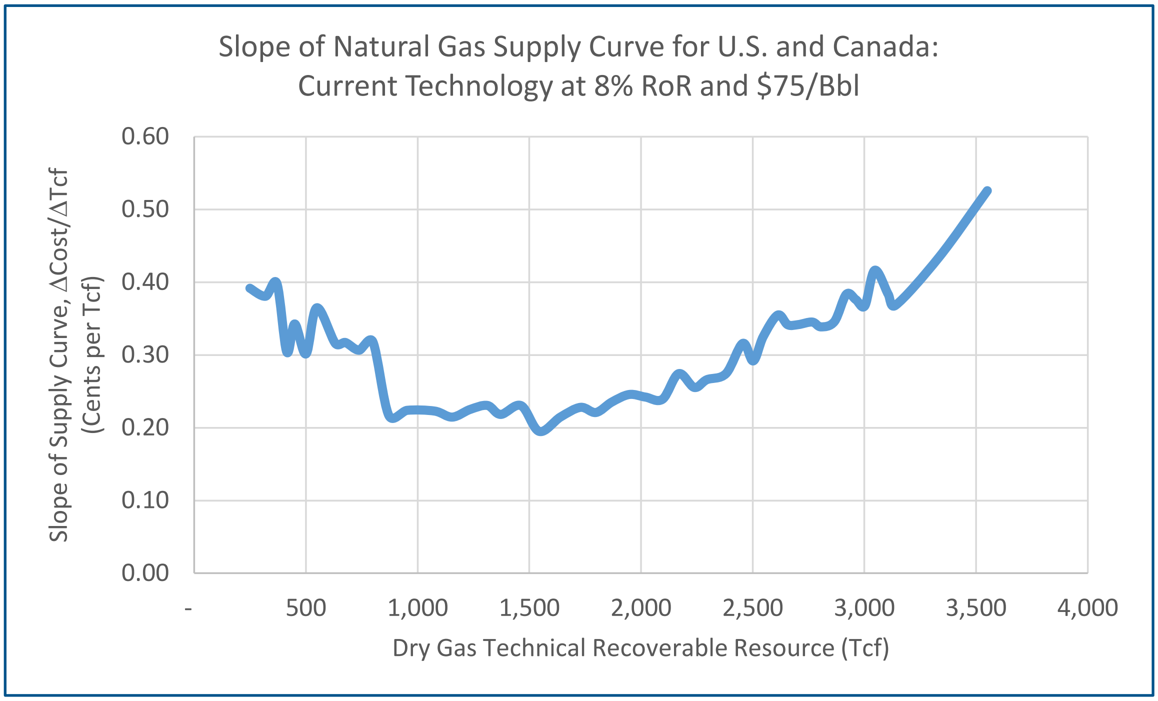
Exhibit 3-3: U.S. and Canada Natural Gas Supply Curves



Source: ICF

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

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



Source: ICF

3.1.2. Representation of Future Upstream Technology Improvements

Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the "current technology" gas supply curves.[7]

Technology advances in natural gas development in recent years have been related to the drilling of longer horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time micro-seismic and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. The percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, however, resulting in lower costs per unit of reserve additions.

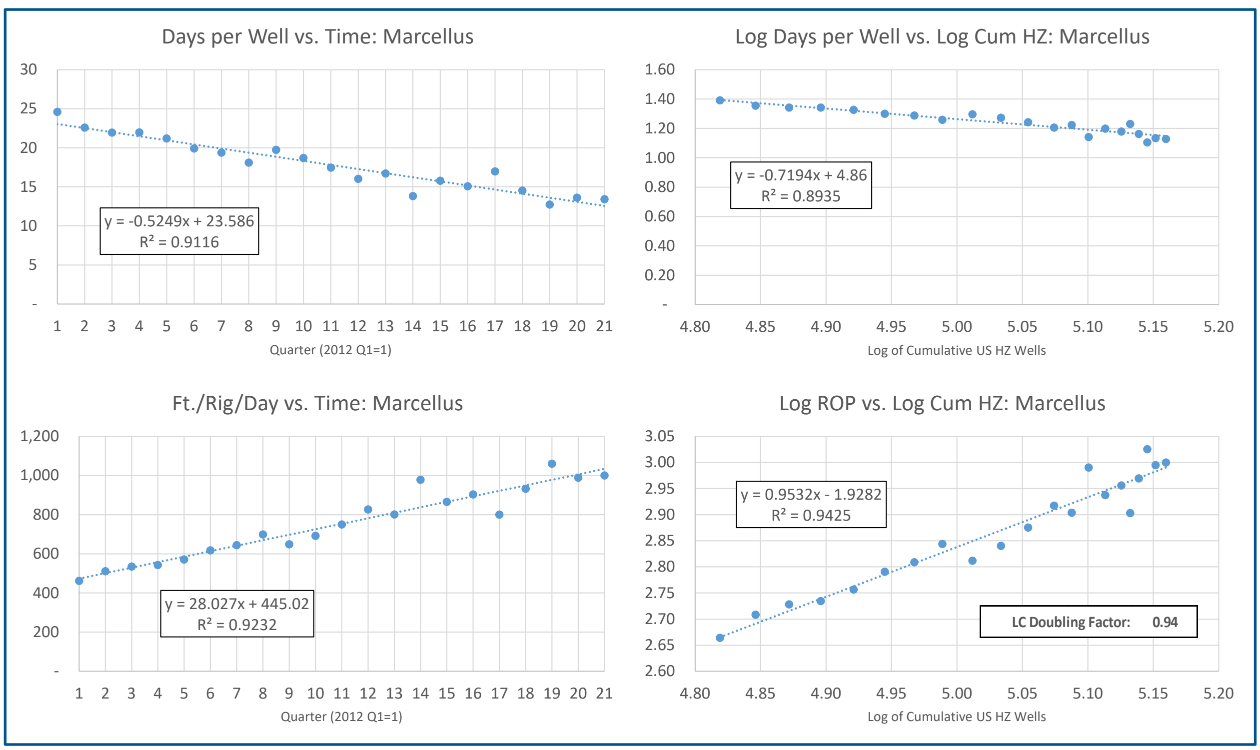
[7] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

Technology Advances in Rig Efficiency

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

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

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



Source: ICF

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

The two right-hand charts in Exhibit 3-5 show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[8] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What this means is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

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

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

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

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

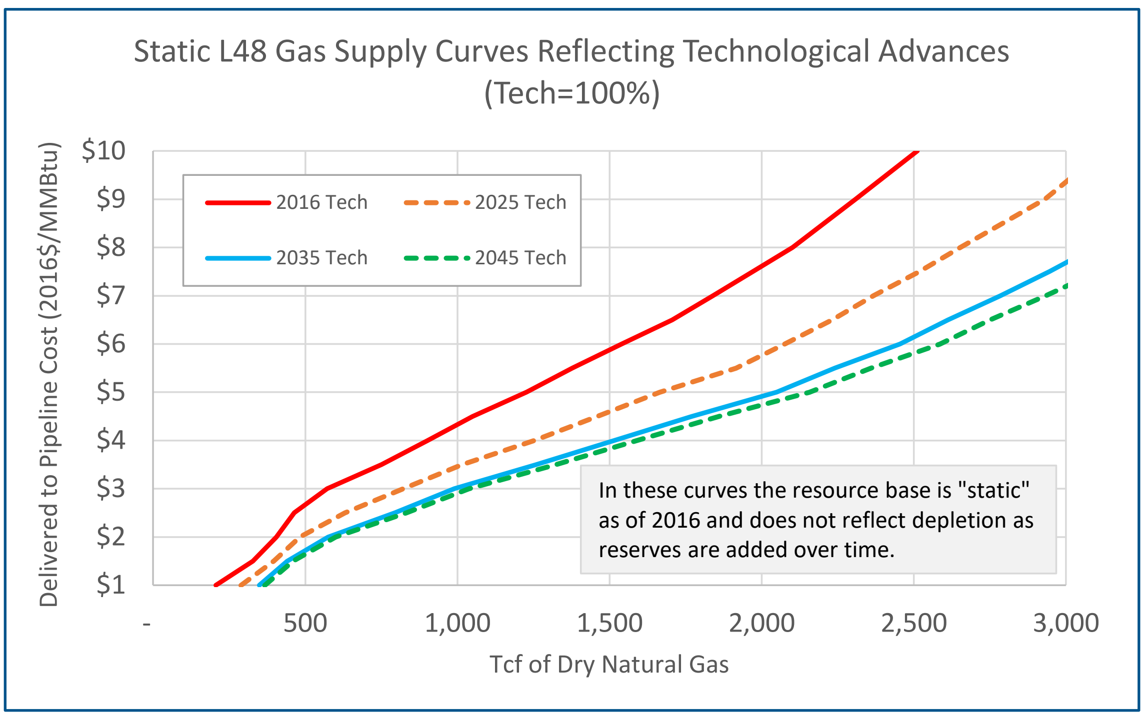
[8] Doubling factor = 2^C-1 where C is the regression slope coefficient.

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

The Effect of Technology Advances on the Gas Supply Curves

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

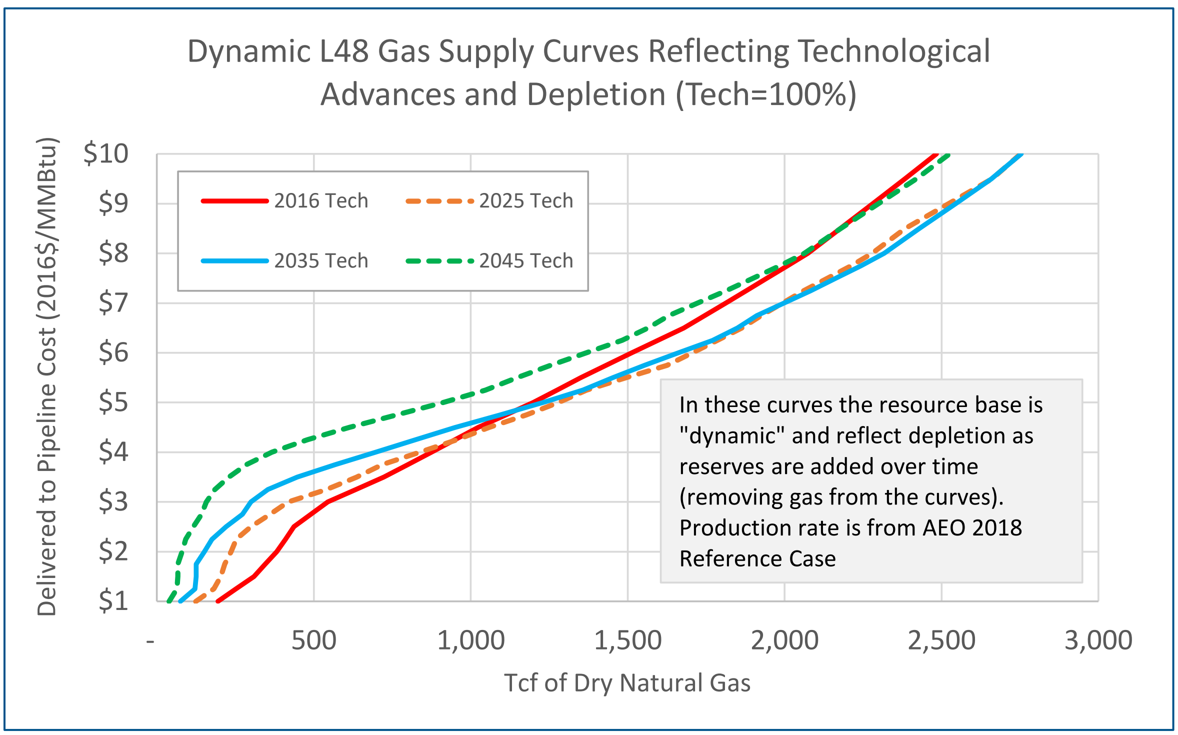
Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



Source: ICF

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

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



Source: ICF

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

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

This means that the estimates provided here for the market impacts of any given amount of LNG exports could be proven in time to be overstated or understated. In reviewing the trends of economic impact studies performed over the last serval years with regard to U.S. LNG exports, we see that the more recent studies show lower impacts in terms of cents per MMBtu of natural gas price increases per 1 Bcfd of exports compared to the older studies. (See ICF's updated report to API on the impact of LNG exports on the U.S. economy[9].) This indicates that the forecasts have tended to:

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

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

3.1.3. ICF Resource Base Estimates

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

The following resource categories have been evaluated:

Proven reserves – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

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

Reserve appreciation – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[10]

Enhanced oil recovery (EOR) – defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane – defined as the remaining recoverable volumes of gas from the development of coal seams. Exhibit 3-8 summarizes the current ICF gas and crude oil assessments for the U.S. and Canada.

Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The current assessment temporal basis is the start of 2016. The current assessment is 3,693 Tcf. As shown in the exhibit below, almost 65 percent of the gas resources is from shale gas and tight oil plays. A large portion of the resources is in the Marcellus, Utica, and Haynesville shale gas plays. The largest tight oil gas resource is in the Permian basin. It accounts for almost 30% of the gas resource from tight oil plays.

Exhibit 3-8: ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of 2016; Excludes Canadian and U.S. Oil Sands)

Lower 48	Total Gas Tcf	Crude and Cond. Billion barrels
Proved reserves	320	33
Reserve appreciation and low Btu	161	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	361	71

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

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

Sources: ICF, EIA (proved reserves)

3.1.4. Resource Base Estimate Comparisons

The ICF natural gas resource base assessment for the U.S. Lower 48 states is historically higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or are associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and are added to the upper end of the natural gas supply curves. Such resources may eventually be exploited if natural gas prices increase substantially or if upstream technological advances improve recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2045.

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

- More plays are included. ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.
- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.
- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.

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

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although ICF did not include shale gas reservoirs with a net thickness of less than 50 feet.

ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas assessment to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, the well spacing assumptions differ from current practices. EIA is using a modified version of the USGS Marcellus that is still low compared to ICF evaluation. The relatively high ICF Barnett Shale assessment is the result of our including a large fringe area of low-quality resource. The great majority of this fringe area is uneconomic, so the comparison is not for an equivalent play area.

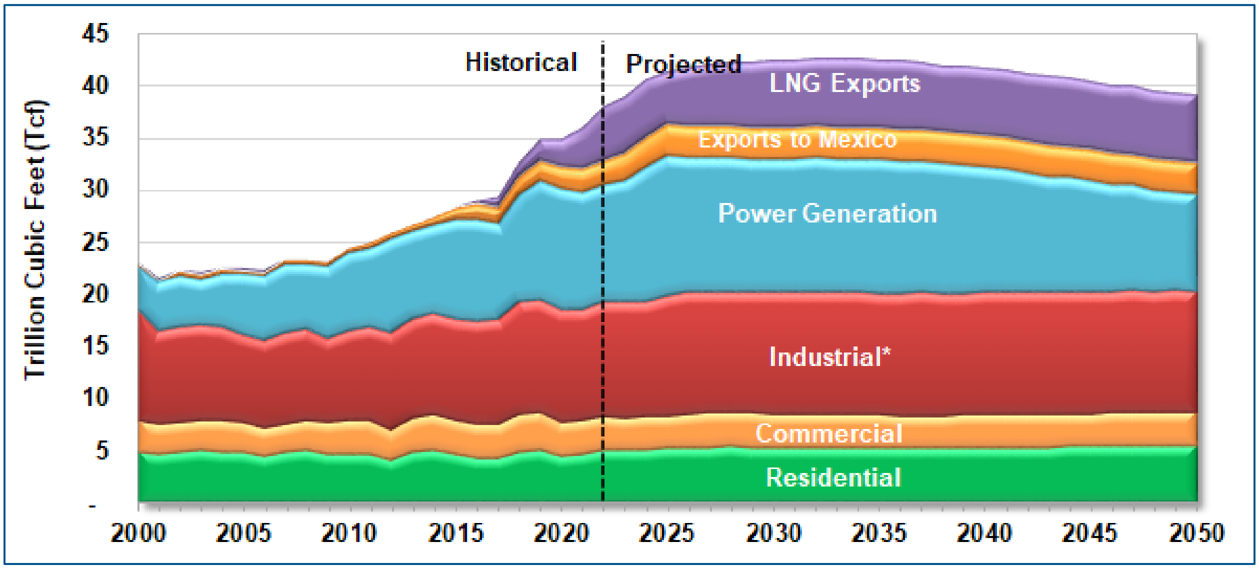
The ICF assessment of tight oil associated gas is much higher than that of other assessments. The difference reflects our inclusion of more plays and entire play areas. It also reflects our methodology, which generally assesses recoverable resources through determination of resource in-place, with an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

3.2. U.S. Natural Gas Demand Trends

Natural gas exports (LNG and Mexico) are key drivers for near-term and long-term demand growth and account for about half of the overall demand growth over the next 25 years. Natural gas demand for power generation is expected to increase in the near term due to additional gas power plant builds and lower coal generation. In the long run, power generation gas demand is expected to decline due to higher renewable penetration, state level initiatives to pursue mandatory renewable portfolio standards and state/federal regulations that drive higher energy efficiency and incentivize energy storage. Natural gas demand in the industrial sector is expected to be up slightly in the long run as gas-intensive end uses such as petrochemicals and fertilizers. In the transportation sector (compressed natural gas and LNG used in vehicles and off-road equipment), ICF expects significant penetration of electric vehicle technologies (both on road and off road) starting 2030.

Exhibit 3-9 shows ICF's U.S. consumption forecast by sector. Under the base case, ICF assumes that 12 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada, Woodfibre, Calcasieu Pass, Costa Azul, and Driftwood LNG.

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



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q2 2022

Feed gas deliveries for U.S. LNG exports are projected to reach 6.5 Tcf per year (17.9 Bcfd) by 2050, with volumes from the Gulf Coast expected to reach 6.1 Tcf per year (16.8 Bcfd), based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy.

Incremental power sector gas use between 2022 and 2050 is expected to decline over the period, with renewable power generation expected to increase significantly over time. Gas use for power generation will decrease from about 11.2 Tcf (30.6 Bcfd) in 2022 to 9.3 Tcf per year (25.5 Bcfd) by 2050.

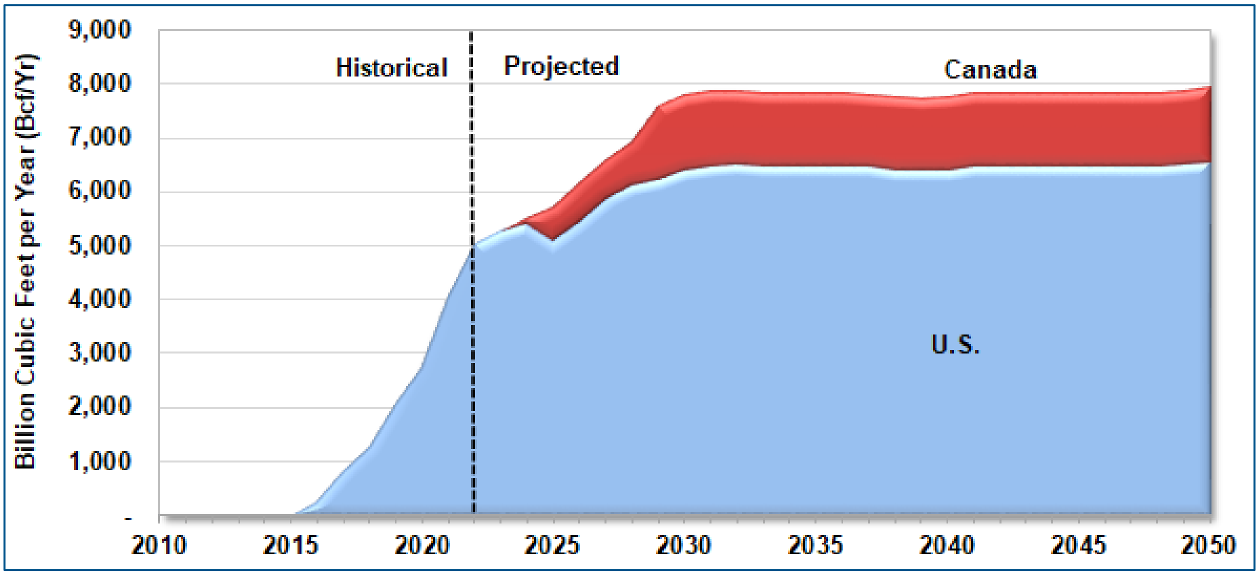
Several factors are expected to lead to growth of gas demand for power generation in the near term. Currently, about 600 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada. Much of that capacity is underutilized and readily available to satisfy incremental electric load growth. U.S. electric load growth is based on the latest available projections from ISOs as well as forecasts from NERC. Electricity demand is projected to average 0.69% per year from 2022-2050 across the U.S., which is driven by the ISO's expected levels of demand change, including the impacts of electrification of the transportation and other sectors, as well as offsetting changes in energy efficiency adoption. ICF assumes that by 2023, consistent with Moody's estimate of economic impacts, there will be a full recovery to the forecasted demand to pre-pandemic levels. Updates to firm generation capacity additions and retirements based on announcements are as of April 2022. The ICF Base Case includes regional carbon control programs in California and for the Regional Greenhouse Gas Initiative (RGGI) states, as well as a probability-weighted national CO2 charge that is representative of federal carbon policies that may take effect between now and 2050. ICF's Base Case also reflects EPA rules governing power plants, including the Mercury & Air Toxics Standards Rule (MATS), the Cross-State Air Pollution Rule (CSAPR), and rules governing water intake structures under Clean Water Act 316(b), and coal combustion residuals (CCR, or ash).

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 2.8 Tcf (7.9 Bcfd) by 2050, up from 2.3 Tcf (6.3 Bcfd) in 2022.

3.2.1. LNG Export Trends

With an increased reliance on US LNG exports by the European Union to move away from Russian supplies, the U.S. export facilities are currently running at full capacity. Europe is seeking an additional 2-15 Bcfd of exports demand from across the globe. There is about 14.5 Bcfd of U.S. LNG export capacity currently in-service with another 2.5 Bcfd planned by 2025. The U.S. has an additional 30 Bcfd of export capacity that is FERC approved, which is double the potential additional demand required by Europe. However, ICF's Q2 2022 base case did not include any additional greenfield facilities since these projects were missing long-term contracting and final investment decisions (FIDs). Based on our assessment of world LNG demand and other international sources of LNG supply, the Base Case of this study assumes that the U.S. and Canadian LNG exports reach 7.9 Tcf per year (21.8 Bcfd) by 2050. (See Exhibit 3-10.) Global LNG prices are heavily influenced by oil prices. Given the current global economic climate and high oil price environment, U.S. and Canadian export volumes are projected to be about 5 Tcf per year (13.7 Bcfd) in 2022 (see exhibit below).

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

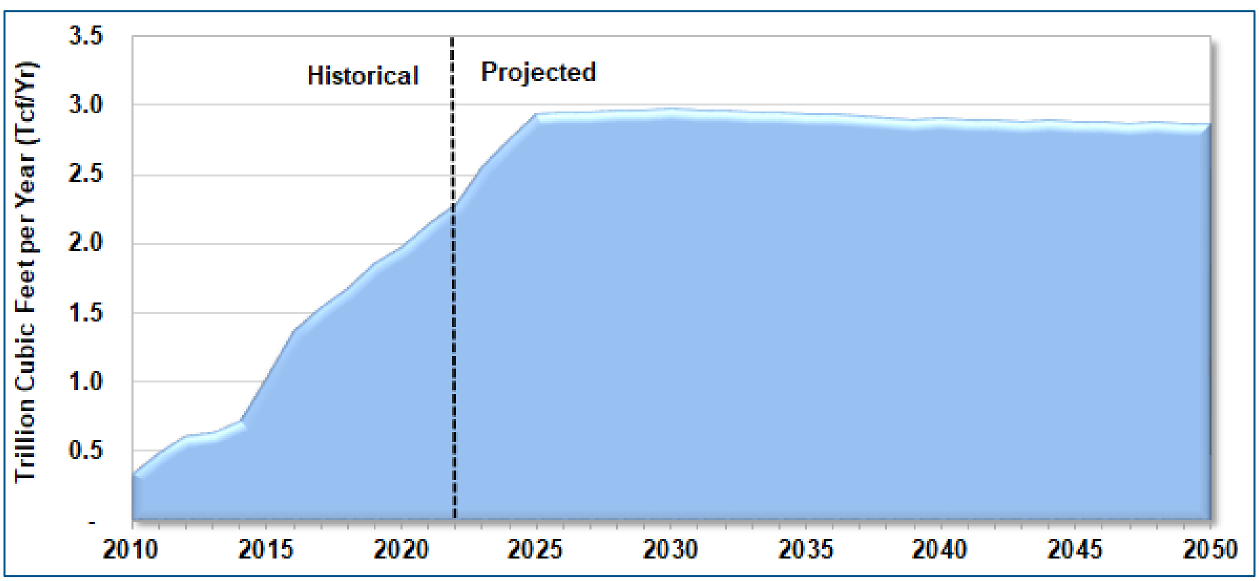


Source: ICF GMM® Q2 2022

3.2.2. Exports to Mexico

Mexico's demand for natural gas continues to rise, while its domestic production has been declining. Since 2015, Mexico's imports of U.S. gas have undergone a 118% increase, reaching 6.3 Bcfd in 2022. As Mexico continues to add gas-fired generation and sponsor new pipelines from the U.S., exports are expected to continue to grow, reaching 8.2 Bcfd by 2030 and then level off. (See Exhibit 3-11.)

Exhibit 3-11: Base Case Exports to Mexico Assumptions



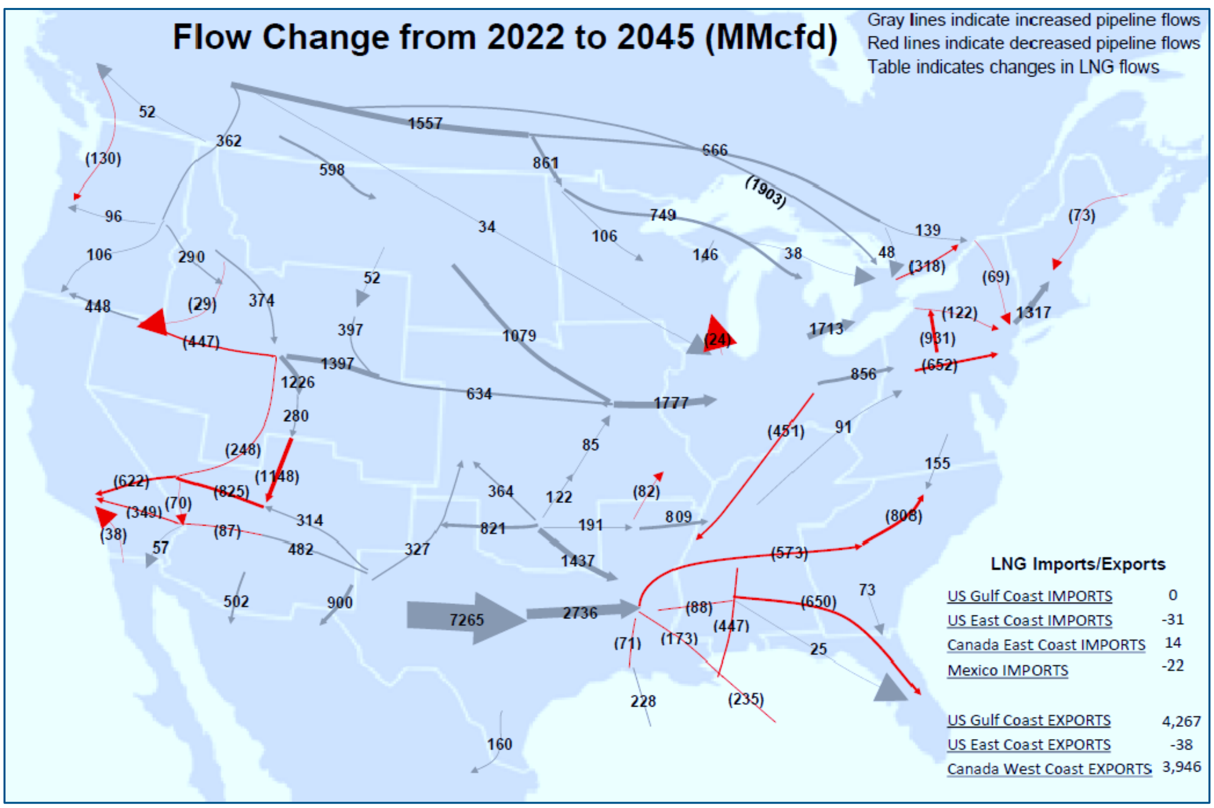
Source: ICF GMM® Q2 2022

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

As regional gas supply and demand continue to shift over time, there will likely be significant changes in interregional pipeline flows. Exhibit 3-12 shows the projected changes in interregional pipeline flows from 2022 to 2045 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 2022 and 2045, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit 3-12 illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. Marcellus gas production growth continues to reverse flows, pushing gas toward the west and south. New developments in Midcontinent unconventional plays will increasingly flow to the Gulf Coast region. Rocky Mountain production will increasingly move westward and serve local demand. Longer term Permian production will primarily be directed to the Gulf Coast. Eastward flows out of Western Canada will continue to remain relatively low as incremental gas supplies are consumed locally or exported off of the West Coast of Canada.

Exhibit 3-12: Projected Change in Interregional Pipeline Flows



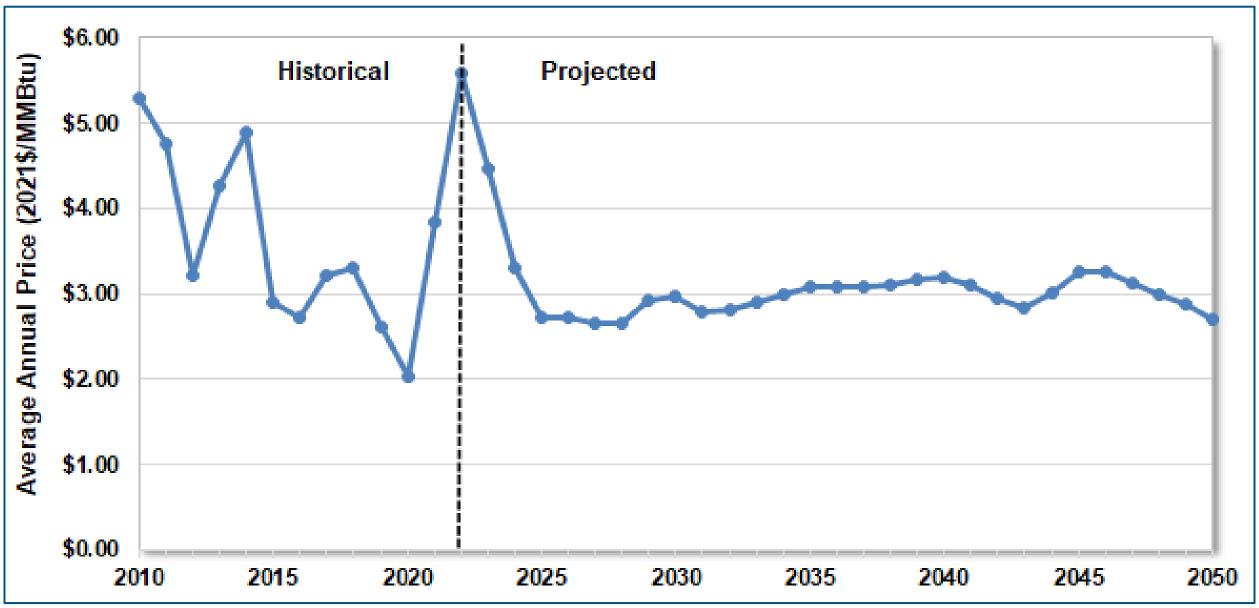
Source: ICF GMM® Q2 2022

3.4. Natural Gas Price Trends

Natural gas prices at the major market hubs in North America are forecasted to be higher in 2022 than they were in 2021 due to a significant rise in LNG exports demand, low levels of natural gas in storage, production gains slower than expected and the fluctuating weather. The Henry Hub price is projected to average $5.57/MMBtu (in real 2021$) in 2022 compared to $3.82/MMBtu in 2021. The average annual price at Henry Hub is projected to be $4.47/MMBtu in 2023, $3.29/MMBtu in 2024 and $2.73/MMBtu in 2025 (in real 2021$), under normal weather conditions, as natural gas markets rebalance with increased drilling and production activities. The natural gas price at Henry Hub is projected to average under $3.2/MMBtu in real 2021$ over the next 25 years and are never expected to be below the 2020 prices under normal weather conditions.

Gas prices throughout the U.S. are expected to remain moderate, as shown in Exhibit 3-13.

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

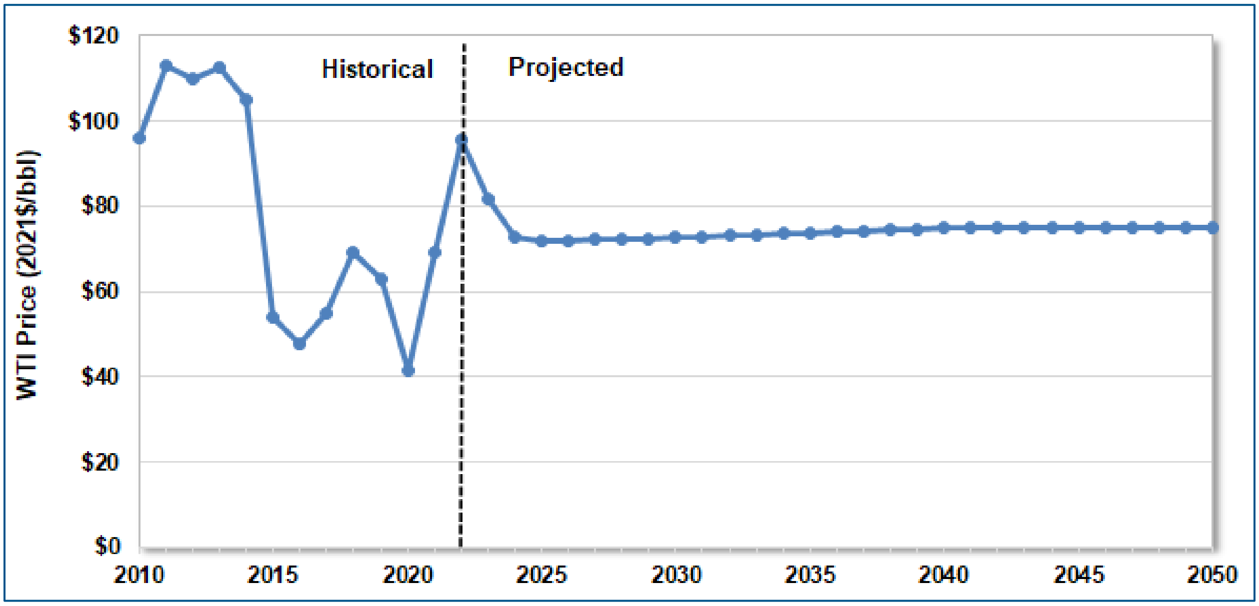


Source: ICF GMM® Q2 2022

3.5. Oil Price Trends

ICF's crude oil price forecast uses futures prices for 2022 and a blend of futures and our fundamental forecast for 2022-2025. As shown in Exhibit 3-14, ICF assumes an equilibrium marginal production cost of $70/bbl. (in real 2021$) for the long-term. Oil prices are higher in 2022 compared to the last 7 years. European Union continues to push for a ban on Russian oil imports. This would tighten global oil supply amid expectation of higher demand from easing of China's COVID lockdowns.

Exhibit 3-14: ICF Oil Price Assumptions



Source: ICF GMM® Q2 2022

4. Study Methodology

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

4.1. Resource Assessment Methodology

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

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

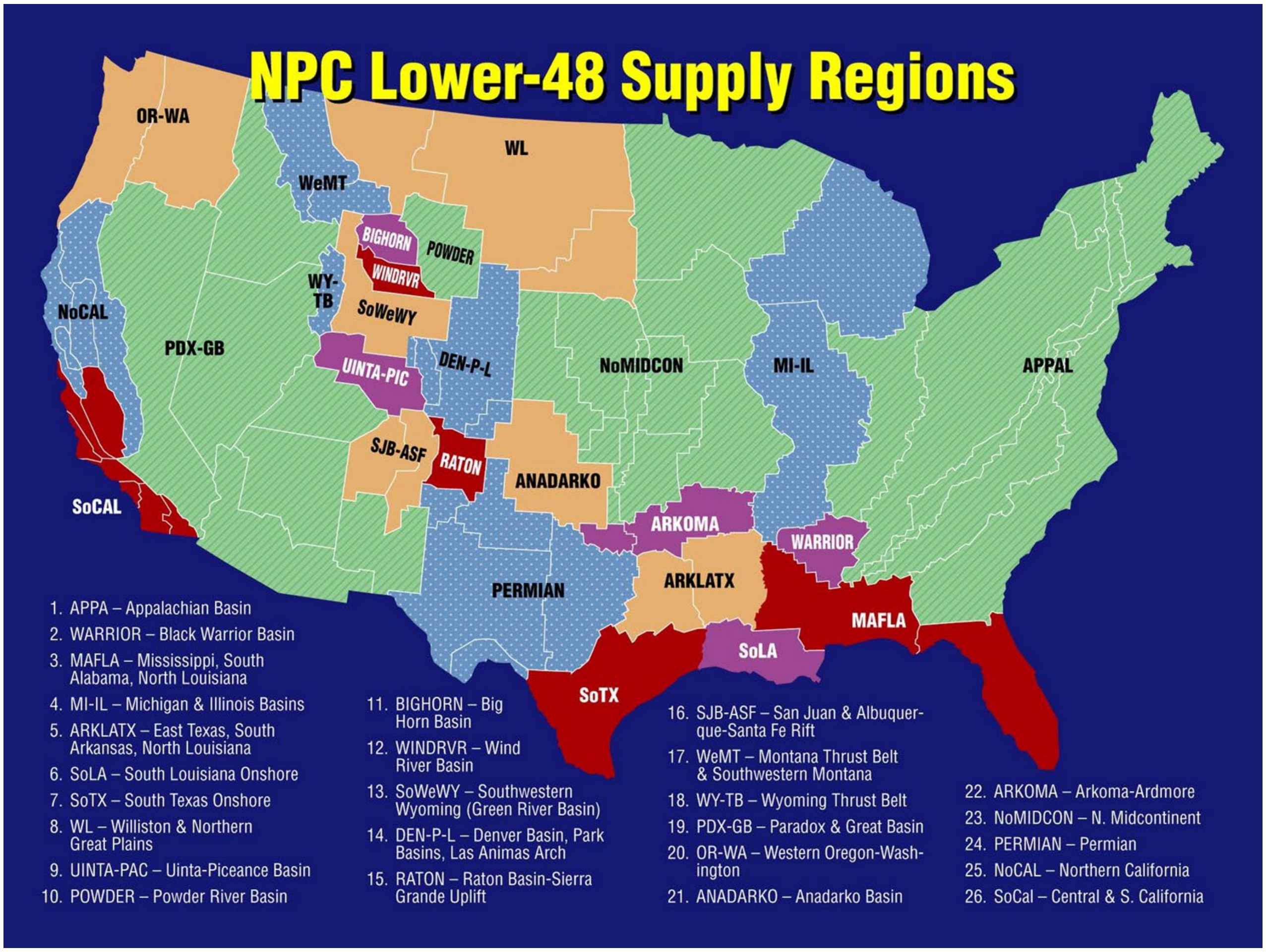
4.1.1. Conventional Undiscovered Fields

Undiscovered fields are assessed by 5,000-foot drilling depth intervals and a distribution of remaining fields by USGS "size class." Hydrocarbon ratios are applied to convert barrel of oil equivalent (BOE) per size class into quantities of recoverable oil, gas, and NGLs. U.S. and Canadian conventional resources are based largely on USGS and BOEM (formerly MMS) (and various agencies in Canada) assessments made over the past 25 years. The USGS provides information on discovered and undiscovered oil and gas and the number of fields by field size class. The ICF assessments were reviewed by oil and gas producing industry representatives in the U.S. and Canada as part of the 1992, 1998, 2003 and 2010 National Petroleum Council studies and have been updated periodically by ICF as part of work conducted for several clients.

4.1.2. Unconventional Oil and Gas

Unconventional oil and gas is defined as continuous deposits in low-permeability reservoirs that typically require some form of well stimulation such as hydraulic fracturing and/or horizontal drilling. ICF has assessed future North America unconventional gas and liquids potential, represented by **shale gas, tight oil, tight sands, and coalbed methane**. Prior to the shale gas revolution, ICF relied upon a range of sources for our assessed volumes, including USGS, the National Petroleum Council studies, and in-house work for various clients. In recent years, we developed our GIS method of assessing shale and other unconventional resources. The current assessment is a hybrid assessment, using the GIS-derived data where we have it.

Exhibit 4-1: ICF Oil and Gas Supply Region Map



Source: ICF and NPC

ICF developed a GIS-based analysis system covering 32 major North American unconventional gas plays. The GIS approach incorporates information on the geologic, engineering, and economic aspects of the resource. Models were developed to work with GIS data on a 36-square-mile unit basis to estimate unrisked and risked gas-in-place, recoverable resources, well recovery and resource costs at a specified rate of return. The GIS analysis focuses on gas and NGLs and addresses the issue of lease condensate and gas plant liquids in terms of both recoverable resources and their impact on economics.

The ICF unconventional gas GIS model is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about porosity, pressure gradient, and other information. The unit of analysis for gas-in-place and recoverable resources is a 6-by-6 mile or 36-square-mile grid unit. Gas-in-place is determined for free gas, adsorbed gas, and gas dissolved in liquids, and well recovery is modeled using a reservoir simulator.[11] Gas resources

[11] Free gas is gas within the pores of the rock, while adsorbed gas is gas that is bound to the organic matter of the shale and must be desorbed to produce.

and recovery per well are estimated as a function of well spacing. Exhibit 4-2 is a listing of the GIS plays in the model.

Exhibit 4-2: ICF Unconventional Plays Assessed Using GIS Methods

No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Shale		
1	Anadarko Woodford	1,780	40
2	Arkoma Caney	5,300	80
3	Arkoma Moorefield	520	80
4	Arkoma Woodford	1,870	40
5	Barnett	26,320	40
6	Bossier	2,840	40
7	Eagle Ford	10,500	60
8	Fayetteville	2,610	60
9	Green River Hilliard	4,350	20
10	Haynesville	7,420	40
11	Lower Huron	19,530	80
12	Marcellus	39,140	40
13	NY Utica	14,290	80
14	OHPAWV Utica	58,970	40
15	Paradox Cane Creek	3,110	40
16	Paradox Gothic	1,350	80
17	Uinta Mancos	7,080	20
18	Vermillion Baxter	180	20
19	West Texas Barnett	4,500	40
20	West Texas Woodford	4,500	40
	L-48 GIS Assessed Shale Total	**216,160**	
21	Cordova Embayment	1,550	80
22	Frederick Brook	130	80
23	Horn River	9,050	80
24	Montney	13,700	80
25	Quebec Utica	2,210	80
	Canada GIS Assessed Shale Total	**26,640**	
	Tight Gas		
26	Granite Wash	3,540	160
27	GRB Dakota	19,680	10
28	GRB Frontier	19,700	10
29	GRB Lance	13,570	10
30	GRB Lewis	6,820	10
31	GRB Lower Mesaverde	12,660	10
32	GRB MV/Almond	11,820	40
33	GRB MV/Ericson	12,680	10
34	Uinta Mesaverde	4,730	20
35	Uinta Wasatch	2,050	20
	L-48 GIS Assessed Tight Gas Total	**107,250**	

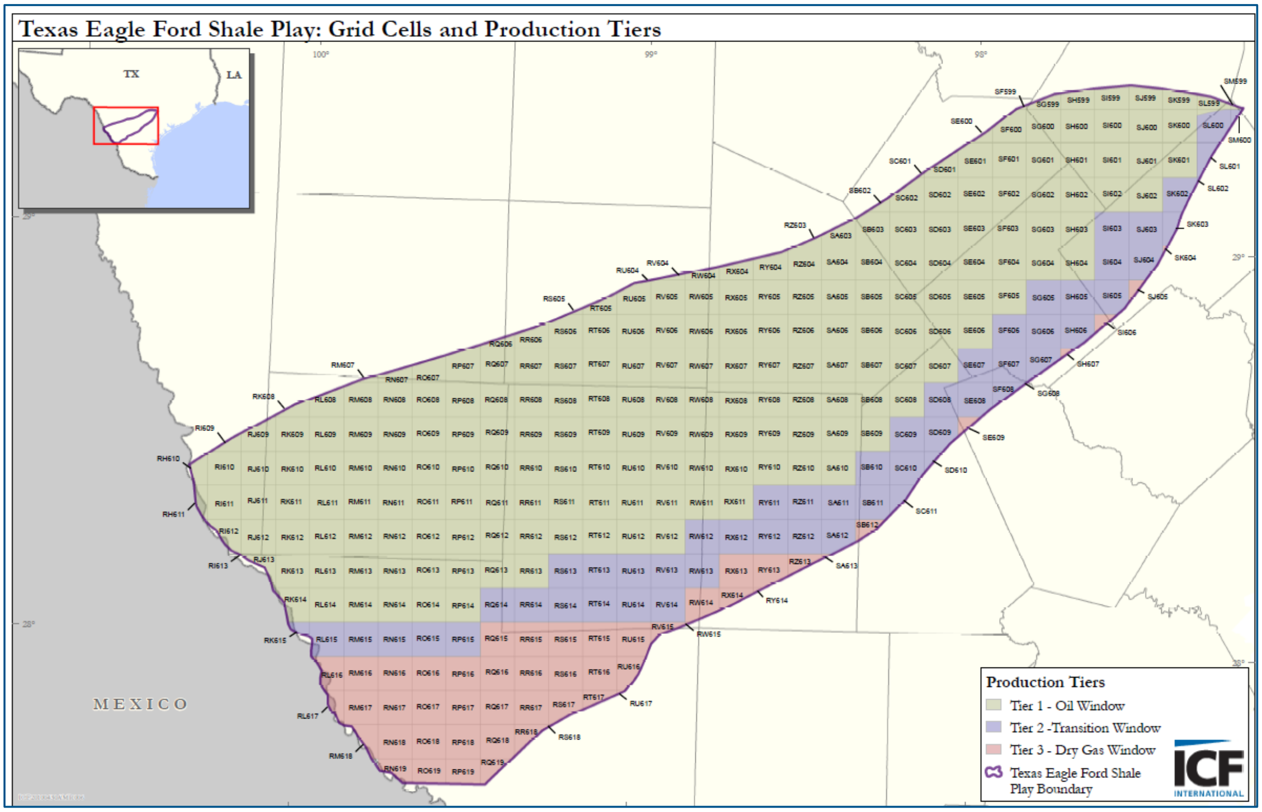
No.	Play	Play Area Sq. Mi.	Assessment Well Spacing (acres)
	Coalbed Methane		
36	San Juan Fruitland	8,800	160
	L-48 GIS Assessed Coalbed Methane Total	**8,800**	
37	Horseshoe Canyon	24,740	80
38	Mannville	46,760	320
	Canada GIS Assessed Coalbed Methane Total	**71,500**	
	Tight Oil		
39	Anadarko Mississippi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

Source: ICF

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

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

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



Source: ICF

Tight Oil

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

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

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

4.2. Energy and Economic Impacts Methodology

Cameron LNG tasked ICF with assessing the economic and employment impacts of LNG exports from its proposed Cameron LNG Phase 2, Train 4 Project. This study analyzed two cases[12]:

1) **Base Case** – This is ICF’s “expected” or “most likely” forecast of US natural gas markets. This case includes Cameron LNG Trains 1 through 3 but no Cameron LNG Train 4 export facility (of any type or configuration).
2) **Cameron LNG Train 4 Case** – This has all the same national economic and energy market assumptions as the Base Case except that an average of 0.80 Bcfd of export volumes from Cameron LNG Train 4 are added starting in May 2027.

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 Louisiana level.

Step 2 – LNG plant capital and operating expenditures: Based on Cameron LNG Train 4 export facility’s cost estimates, ICF determined the annual capital and operating expenditures that will be required to support the LNG exports.

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

Step 4 – IMPLAN input-output matrices: ICF entered both LNG plant and upstream expenditures into the IMPLAN input-output model to assess the economic impacts for the U.S. and Louisiana. For instance, if the model found that $100 million in a particular category of expenditures generated 390 direct employees, 140 indirect employees, and 190 induced employees (i.e., employees related to consumer goods and services), then we would apply those proportions to forecasted expenditure changes. If forecasted expenditure changes totaled

[12] These volumes do not include liquefaction fuel use or pipeline fuel use.

$10 million one year, according to the model proportions, that would generate 39 direct, 14 indirect, and 19 induced employees in the year the expenditures were made.

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

Exhibit 4-4: Economic Impact Definitions

<u>Classification of Impact Types</u>

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.

<u>Definitions of Impact Measures</u>

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 data from Cameron LNG and ICF analysis, and include:

- Cameron LNG Train 4 LNG export volumes (see Exhibit 4-5)
- LNG plant capital and operating expenditures (see Exhibit 4-5)
- Tax rates (see Exhibit 4-6)
- Prices for crude oil and other liquids (see Exhibit 4-7)
- Per-well upstream capital costs (see Exhibit 4-8)
- Fixed and variable upstream operating costs per well (see Exhibit 4-8)

The following set of exhibits show the key model assumptions.

Exhibit 4-5: Cameron LNG Train 4 LNG Export Volume Assumptions and LNG Plant Capital and Operating Expenditures

Year	The Cameron T4 LNG Case Changes		
	LNG Export Volume Assumptions (Bcfd)	LNG Capital Costs (2021$ MM)	LNG Operating Costs (2021$ MM)
2020	-	$1	-
2021	-	$16	-
2022	-	$84	-
2023	-	$758	-
2024	-	$880	-
2025	-	$987	-
2026	-	$943	-
2027	0.392	$565	$47
2028	0.807	-	$71
2029	0.807	-	$71
2030	0.807	-	$71
2031	0.764	-	$71
2032	0.807	-	$71
2033	0.807	-	$71
2034	0.807	-	$71
2035	0.764	-	$71
2036	0.807	-	$71
2037	0.807	-	$71
2038	0.807	-	$71
2039	0.764	-	$71
2040	0.807	-	$71
2041	0.807	-	$71
2042	0.807	-	$71
2043	0.764	-	$71
2044	0.807	-	$71
2045	0.807	-	$71
2046	0.807	-	$71
2047	0.764	-	$71
2048	0.807	-	$71
2049	0.807	-	$71
2050	0.807	-	$71
2020-2050 Sum	**6,844**	**$4,235**	**$1,679**

Note: LNG export volumes do not include liquefaction fuel or losses, pipeline fuel, or the additional natural gas that might be used to supply some of the electricity for the facility. These additional uses of natural gas are expected to add approximately 7.0% to this gas volume. Source: Cameron LNG, ICF estimates.

Exhibit 4-6: Assumed Federal, State, and Local Tax Rates

Year	Federal Tax Rate on GDP (%)	Weighted Average State and Local Tax Rate on GDP (% of own-source) (%)	LA and Local Own Taxes as % of State Income (%)
2015	17.9%	14.4%	13.9%
2016	17.6%	14.4%	13.8%
2017	17.2%	14.3%	14.1%
2018	16.3%	14.5%	13.7%
2019	16.3%	14.7%	13.8%
2020	16.3%	13.8%	12.7%
2021	18.1%	14.3%	13.4%
2022	18.3%	14.3%	13.4%
2023	18.1%	14.3%	13.4%
2024	18.3%	14.3%	13.4%
2025	18.3%	14.3%	13.4%
2026	18.7%	14.3%	13.4%
2027	18.9%	14.3%	13.4%
2028	18.6%	14.3%	13.4%
2029	18.6%	14.3%	13.4%
2030	18.6%	14.3%	13.4%
2031	18.6%	14.3%	13.4%
2032	18.6%	14.3%	13.4%
2033	18.6%	14.3%	13.4%
2034	18.6%	14.3%	13.4%
2035	18.6%	14.3%	13.4%
2036	18.6%	14.3%	13.4%
2037	18.6%	14.3%	13.4%
2038	18.6%	14.3%	13.4%
2039	18.6%	14.3%	13.4%
2040	18.6%	14.3%	13.4%
2041	18.6%	14.3%	13.4%
2042	18.6%	14.3%	13.4%
2043	18.6%	14.3%	13.4%
2044	18.6%	14.3%	13.4%
2045	18.6%	14.3%	13.4%
2046	18.6%	14.3%	13.4%
2047	18.6%	14.3%	13.4%
2048	18.6%	14.3%	13.4%
2049	18.6%	14.3%	13.4%
2050	18.6%	14.3%	13.4%

Source: https://www.taxpolicycenter.org/statistics/source-revenue-share-gdp

Source: ICF extrapolations from Tax Policy Center historical figures.

Exhibit 4-7: Liquids Price Assumptions

Year	WTI Price (2021$/bbl)	RACC Price (2021$/bbl)	Condensate Price (2021$/bbl)	Ethane Price (2021$/bbl)	Propane Price (2021$/bbl)	Butane Price (2021$/bbl)	Pentanes Plus (2021$/bbl)
2015	$55	$55	$55	$17	$22	$37	$50
2016	$48	$45	$45	$16	$22	$31	$41
2017	$56	$56	$56	$19	$24	$38	$51
2018	$70	$69	$69	$19	$37	$47	$63
2019	$60	$63	$63	$15	$33	$42	$57
2020	$41	$41	$41	$12	$22	$28	$37
2021	$68	$67	$67	$22	$36	$46	$61
2022	$92	$92	$92	$27	$49	$62	$84
2023	$81	$80	$80	$24	$42	$54	$73
2024	$73	$72	$72	$21	$38	$49	$66
2025	$71	$70	$70	$21	$37	$48	$64
2026	$71	$70	$70	$21	$37	$48	$64
2027	$71	$71	$71	$21	$37	$48	$64
2028	$72	$71	$71	$21	$38	$48	$65
2029	$72	$71	$71	$21	$38	$48	$65
2030	$72	$71	$71	$21	$38	$48	$65
2031	$72	$72	$72	$21	$38	$48	$65
2032	$73	$72	$72	$21	$38	$49	$65
2033	$73	$72	$72	$21	$38	$49	$66
2034	$73	$72	$72	$21	$38	$49	$66
2035	$73	$72	$72	$21	$38	$49	$66
2036	$74	$73	$73	$21	$39	$49	$66
2037	$74	$73	$73	$22	$39	$49	$67
2038	$74	$73	$73	$22	$39	$50	$67
2039	$74	$73	$73	$22	$39	$50	$67
2040	$75	$74	$74	$22	$39	$50	$67
2041	$75	$74	$74	$22	$39	$50	$67
2042	$75	$74	$74	$22	$39	$50	$68
2043	$75	$74	$74	$22	$39	$50	$68
2044	$76	$75	$75	$22	$40	$51	$68
2045	$76	$75	$75	$22	$40	$51	$68
2046	$76	$75	$75	$22	$40	$51	$68
2047	$76	$75	$75	$22	$40	$51	$69
2048	$77	$76	$76	$22	$40	$51	$69
2049	$77	$76	$76	$22	$40	$51	$69
2050	$77	$76	$76	$22	$40	$52	$69

Source: ICF forecast. Historical data from EIA and other sources.

Exhibit 4-8: Other Key Model Assumptions

Assumption	U.S.	Louisiana
Upstream Capital Costs ($MM/Well)	$9.5	$13.7
Upstream Operating Costs ($/barrel of oil equivalent, BOE)	$2.25	$1.60
Royalty Payment (%)	16.7%	21.9%
LNG Tanker Capacity (Bcf/Ship)		3.20
U.S. Port Fee ($/Port Visit)		$100,000

Source: Various compiled or estimated by ICF

4.3. IMPLAN Description

The IMPLAN model is an input-output model based on a social accounting matrix that incorporates all flows within an economy. The IMPLAN model includes detailed flow information for hundreds of industries. By tracing purchases between sectors, it is possible to estimate the economic impact of an industry's output (such as the goods and services purchased by the oil and gas upstream sector) to impacts on related industries.

From a change in industry spending, IMPLAN generates estimates of the direct, indirect, and induced economic impacts. Direct impacts refer to the response of the economy to the change in the final demand of a given industry, for example, the direct expenditures associated with an incremental drilled well. Indirect impacts (or supplier impacts) refer to the response of the economy to the change in the final demand of the industries that are dependent on the direct spending of industries for their input. Induced impacts refer to the response of the economy to changes in household expenditure as a result of labor income generated by the direct and indirect effects.

After identifying the direct expenditure components associated with LNG plant and upstream development, the direct expenditure cost components (identified by their associated North American Industry Classification System (NAICS) code) are then used as inputs into the IMPLAN model to estimate the total indirect and induced economic impacts of each direct cost component.

Direct, Indirect, and Induced Economic Impacts

ICF assessed the economic impact of LNG exports on three levels: direct, indirect, and induced impacts. Direct industry expenditures (e.g., natural gas drilling and completion expenditures) produce a domino effect on other industries and aggregate economic activity, as component industries' revenues (e.g., cement and steel manufacturers needed for well construction) are stimulated along with the direct industries. Such secondary economic impacts are defined as "indirect." In addition, further economic activity, classified as "induced," is generated in the economy at large through consumer spending by employees and business owners in direct and indirect industries.

5. Cameron LNG Train 4 Energy Market and Economic Impact Results

This section describes the economic and employment impacts between the Base Case and the Cameron LNG Train 4 Case. Specifically, differentials between the two cases result from an average 0.80 Bcfd of additional LNG exports assumed from Cameron LNG Train 4.

5.1. Energy Market and Economic Impacts

This section discusses the impacts of LNG exports in the Base Case and the Cameron LNG Train 4 Case in terms of changes in production volumes, capital and operating expenditures, economic and employment impacts, government revenues, and balance of trade.

Overall, in order to accommodate the incremental increases in LNG exports, the U.S. natural gas market rebalances through three sources: increasing U.S. natural gas production, a contraction in U.S. domestic natural gas consumption, and an increase in net natural gas pipeline imports from Canada and Mexico. See Exhibit 5-1, which shows the market will rebalance to 107 percent of incremental export volumes.

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

	2027-2050 Average Supply Sources				
	LNG Exports	US Production Increase	Demand Decreases	Net Gas Pipeline Imports	Sum of Sources
As % of Exports	100.0%	89.3%	10.2%	7.6%	107.0%
In bcfd	0.80	0.71	0.08	0.06	0.85

Source: ICF

As shown in Exhibit 5-2, the gas volumes above the export quantities that are needed for the market to rebalance are made up of pipeline fuel consumption (assumed to be 1.0% of export volume which is consistent with a gas transmission distance of 250 miles), liquefaction and fuel losses of 1.3%, and about 4.7% to generate additional electricity for the plant. The estimate for gas use for incremental electricity is based on the 2022 EIA Annual Energy Outlook forecast for the Midcontinent South Region which shows slightly more than 78.2% of electricity generation through the year 2050 will be from natural gas. The other energy sources expected to be used to make electricity for the grid in this region are wind/solar (16.9%), coal (3.6%) and nuclear power (1.3%).

Exhibit 5-2: Uses of Natural Gas per 1 Unit of LNG Exports

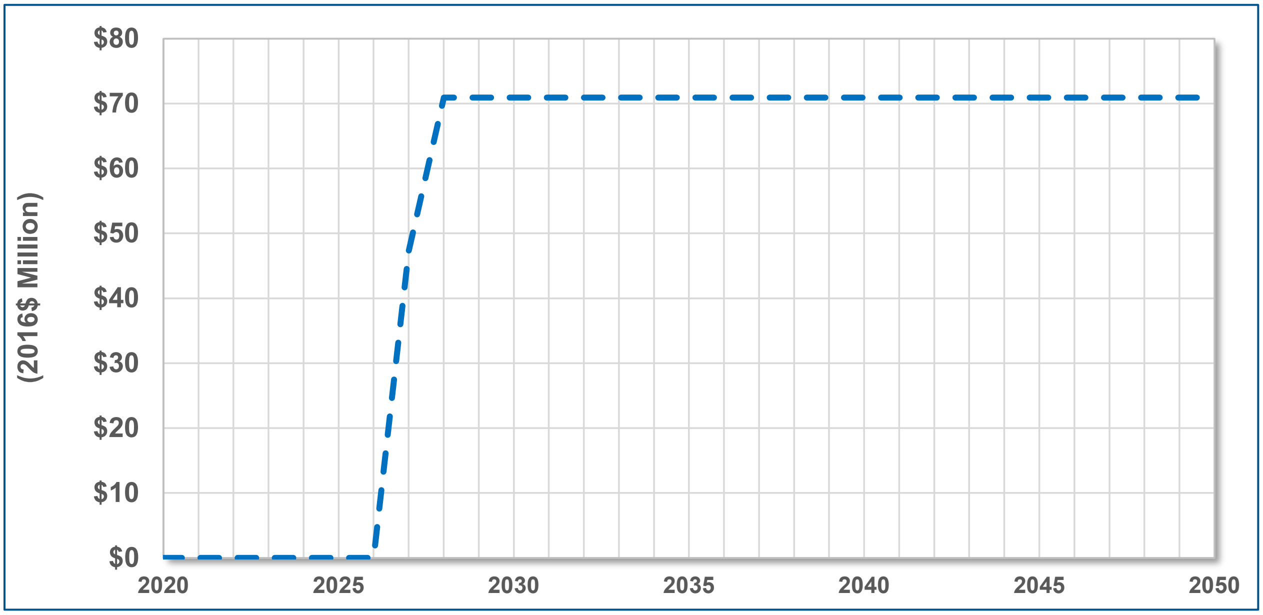
	Pipeline	Liquefaction Fuel & Losses	Electricity	Feedstock	Sum
Gas Drive Turbines	0.010	0.090	-	1.000	1.100
Electric Drive	0.010	0.013	0.047	1.000	1.070

Note: Pipeline distance is approximately 250 miles. Gas use for power generation assumes 2022 AEO generation mix of 78% natural gas in Midcontinent / South Region averaged through 2050..

Note that the overall balancing factor of 107 percent (total gas needed versus export volume) applies to electric drive liquefaction facilities, while a higher value of 110 percent would be appropriate for facilities powered by gas-fired turbines. Note also, that the 107 percent factor is based on a region-wide average mix of energy sources forecasted to be used to make electricity. A procurement strategy aimed at buying more or less electricity from gas-fired generators could change that value.

The exhibit below (Exhibit 5-3) shows the impact on LNG export facility operating expenditures. These exclude the cost of natural gas feedstock and electricity but include annual employee costs ($15.8 million), materials and maintenance ($39.5 million), and insurance ($6.5 million). Also included are $9.1 million of port-related expenditures that would be paid annually by the shippers of the LNG. Over the export period of 2027 and 2050, there is a total cumulative impact on operating expenditures in the U.S. of $1.68 billion (in real 2021$) for the Cameron LNG Train 4 Case. During that period, LNG plant operating expenditures in the U.S. will average slightly above $70 million annually.

Exhibit 5-3: U.S. LNG Export Facility Operating Expenditure Changes

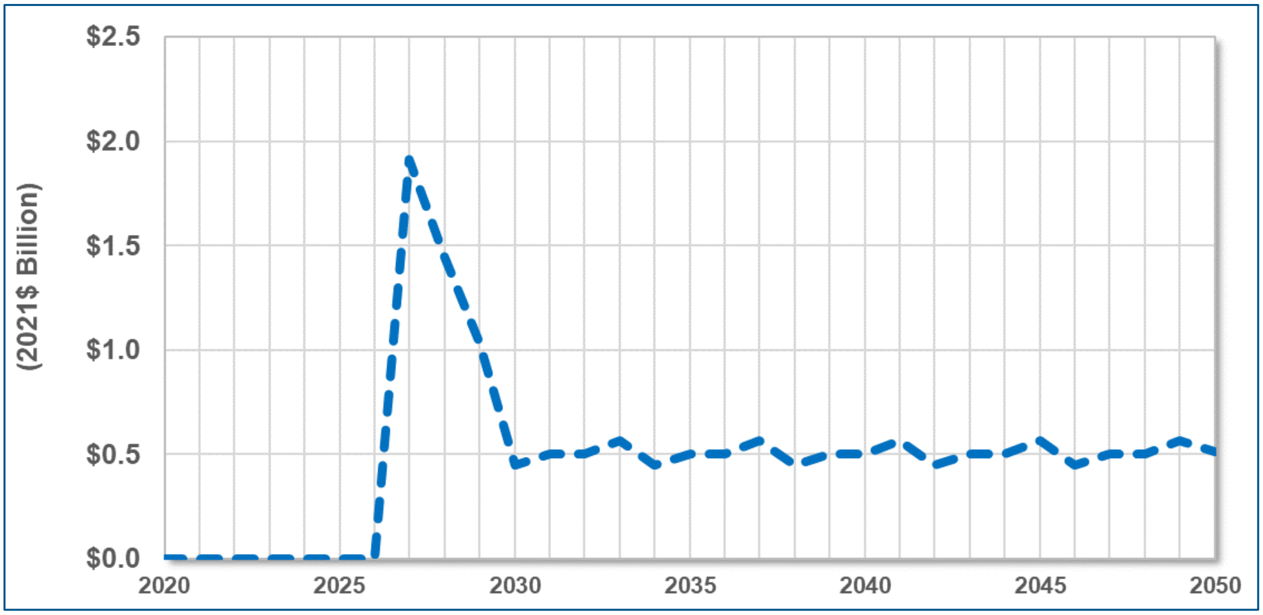


Year	LNG Facility Operating Expenditures (2021$ Million)
2024	$ -
2025	$ -
2026	$ -
2027	$ 47
2028	$ 71
2029	$ 71
2030	$ 71
2035	$ 71
2040	$ 71
2045	$ 71
2050	$ 71
Avg. non-zero yrs	**$ 70**
2027-2050 Sum	**$ 1,679**

Source: Cameron LNG, ICF estimates. Include labor costs, materials and maintenance, insurance, and port fees. Excludes the cost of feedstock natural gas (expected to be about $1,014 million per year) and electricity consumed by the plant (expected to be about $149 million per year). The facility is exempt from property taxes for the first 10 years of operation but will pay property tax thereafter at whatever will be the then applicable rate. Such property tax is not shown in this table.

The exhibit below (Exhibit 5-4) illustrates the impacts of the additional LNG export volumes on U.S. upstream capital expenditures. Investment peaks in the early years as more new wells are drilled to add the extra deliverability needed as LNG production ramps up. Once full LNG production is reached, fewer new wells are required to sustain production. Over the export period of 2027 and 2050, the cumulative impact on U.S. upstream capital expenditures totals $14.98 billion in the Cameron LNG Train 4 Case as compared to the Base Case. U.S. upstream capital expenditures average $0.62 billion higher annually in the Cameron LNG Train 4 Case than in the Base Case.

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

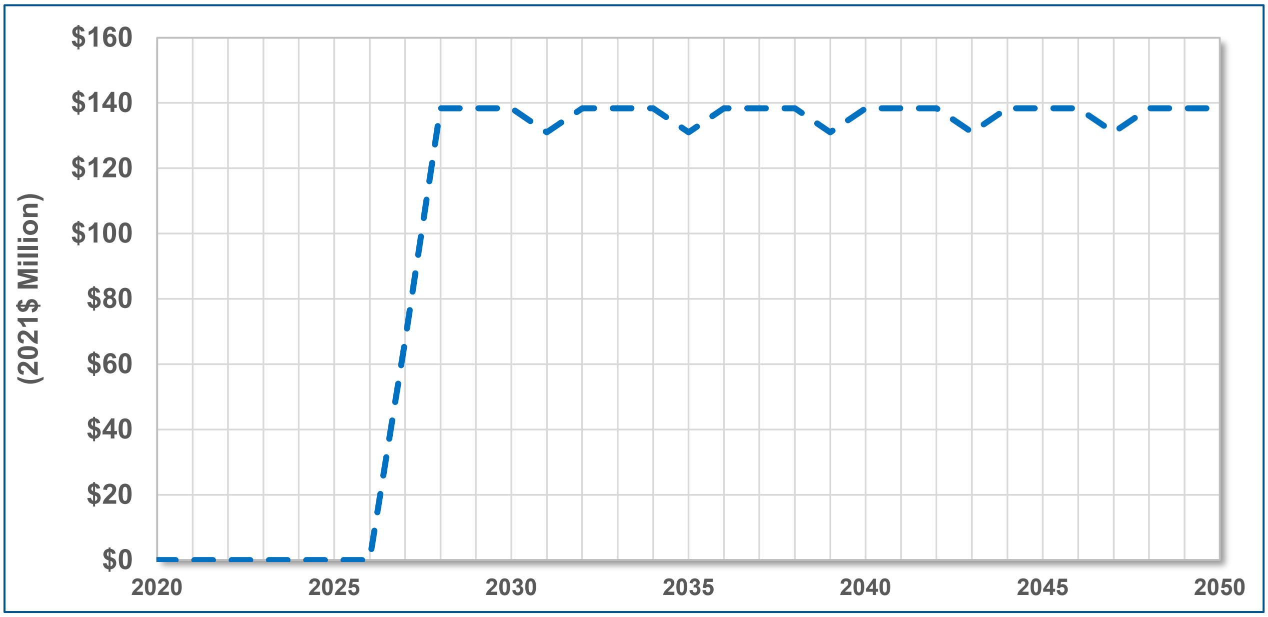


Year	Upstream Capital Expenditures (2021$ Billion)	
2024	$	-
2025	$	-
2026	$	-
2027	$	1.91
2028	$	1.44
2029	$	1.04
2030	$	0.45
2035	$	0.50
2040	$	0.50
2045	$	0.56
2050	$	0.51
Avg. non-zero yrs	**$**	**0.62**
2027-2050 Sum	**$**	**14.98**

Source: Cameron LNG and ICF estimates.

As shown below (Exhibit 5-5), U.S. upstream operating expenditures increase $3.21 billion on a cumulative basis, or on average of $134 million annually in the Cameron LNG Train 4 Case as compared to the Base Case between 2027 and 2050 export period.

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



Year	Upstream Operating Expenditures (2021$ Million)
2024	$ -
2025	$ -
2026	$ -
2027	$ 67
2028	$ 138
2029	$ 138
2030	$ 138
2035	$ 131
2040	$ 138
2045	$ 138
2050	$ 138
Avg. non-zero yrs	**$ 134**
2027-2050 Sum	**$ 3,212**

Source: ICF estimates.

The table below (Exhibit 5-6) shows U.S. natural gas consumption in the Base Case and in the Cameron LNG Train 4 Case. The additional LNG export volumes of 0.80 Bcfd are expected to result in only a small reduction in U.S. natural gas consumption of 0.08 Bcfd, mostly from a decline in gas use in the power sector.

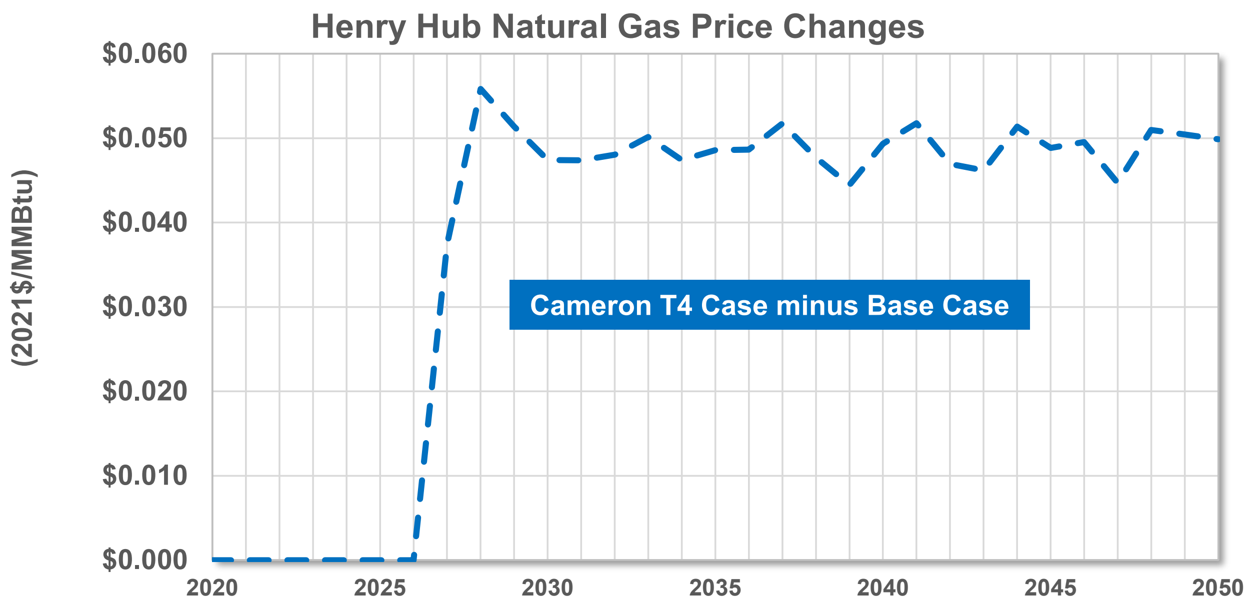
Exhibit 5-6: U.S. Domestic Natural Gas Consumption

Year	U.S. Domestic Natural Gas Consumption (Bcfd)		
	Base Case	Cameron T4 LNG Case	Cameron T4 LNG Case Change
2024	80.37	80.37	-
2025	83.26	83.26	-
2026	82.93	82.93	-
2027	82.64	82.60	(0.04)
2028	82.42	82.34	(0.08)
2029	82.18	82.10	(0.08)
2030	82.08	82.00	(0.08)
2035	82.04	81.96	(0.08)
2040	80.33	80.25	(0.08)
2045	77.03	76.94	(0.08)
2050	74.17	74.09	(0.08)
Avr. 2027-50	**79.05**	**78.97**	**(0.08)**

Source: ICF estimates. Table and charts above do not include exports, liquefaction fuel, pipeline fuel, and lease & plant gas use.

As shown in Exhibit 5-7, the Henry Hub natural gas price in the Cameron LNG Train 4 Case is expected to be on average $0.05/MMBtu higher compared to the Base Case. There are only small variations around this value in any forecast year.

Exhibit 5-7: Annual Average Henry Hub Natural Gas Price Changes

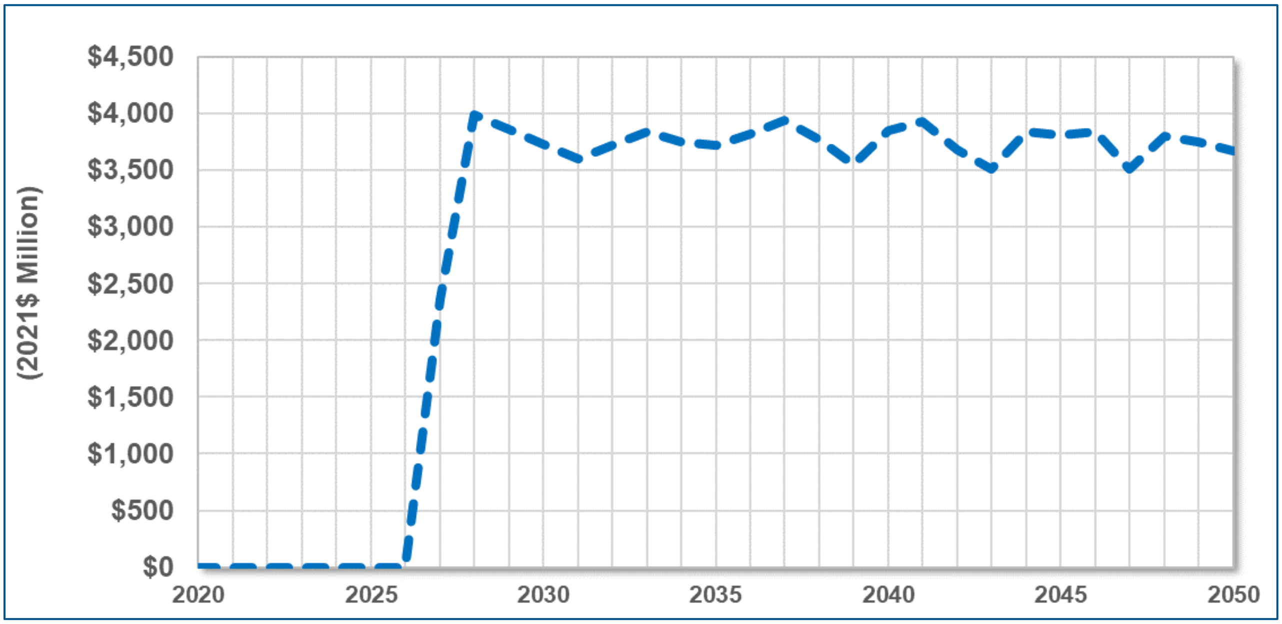


Year	Henry Hub Natural Gas Price (2021$/MMBtu)		
	Base Case	Cameron T4 LNG Case	Cameron T4 LNG Case Change
2024	$ 3.34	$ 3.34	$ -
2025	$ 2.78	$ 2.78	$ -
2026	$ 2.78	$ 2.78	$ -
2027	$ 2.71	$ 2.75	$ 0.04
2028	$ 2.73	$ 2.78	$ 0.05
2029	$ 3.02	$ 3.07	$ 0.05
2030	$ 3.07	$ 3.11	$ 0.04
2035	$ 3.24	$ 3.29	$ 0.05
2040	$ 3.42	$ 3.47	$ 0.05
2045	$ 3.54	$ 3.59	$ 0.05
2050	$ 3.00	$ 3.05	$ 0.05
2027-2050 Avg	**$ 3.23**	**$ 3.28**	**$ 0.05**

Source: ICF

U.S. natural gas and liquids production increases as a result of additional LNG export volumes and higher prices as seen in the Cameron LNG Train 4 Case (see Exhibit 5-8). Over the 2027 to 2050 export period, the cumulative impact on natural gas and liquids production value in the Cameron LNG Train 4 Case is approximately $88.8 billion. This represents an average increase of about $3.7 billion per year in the Cameron LNG Train 4 Case as compared to the Base Case.

Exhibit 5-8: U.S. Natural Gas and Liquids Production Value Changes

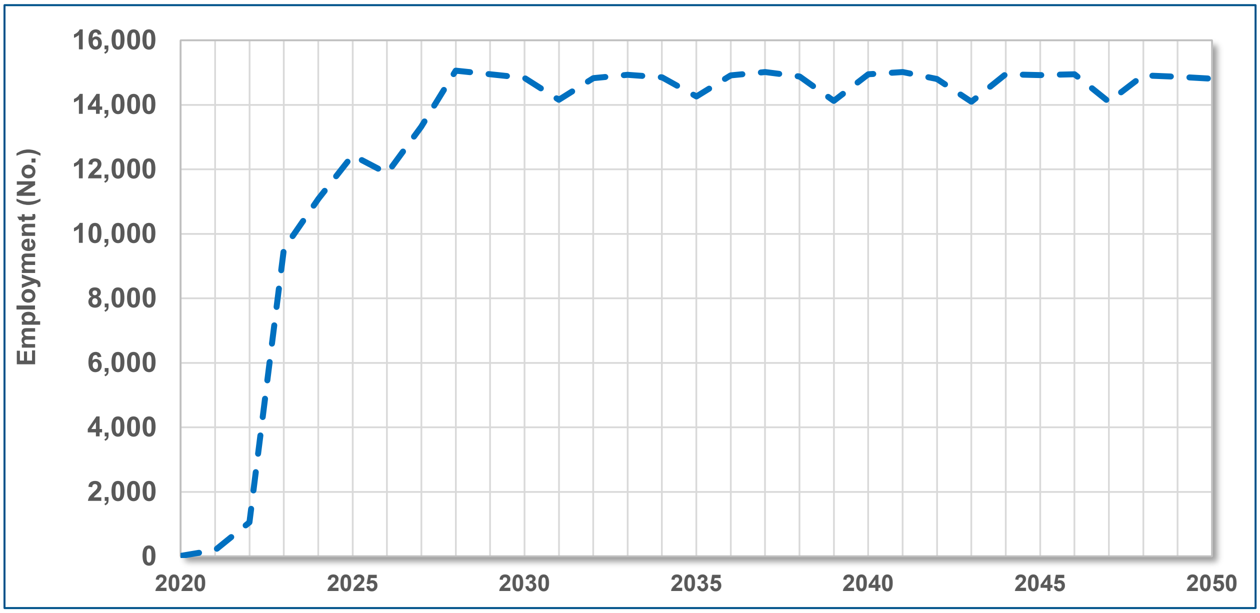


Year	Natural Gas and Liquids Production Value (2021$ Million)
2024	$ -
2025	$ -
2026	$ -
2027	$ 2,359
2028	$ 3,992
2029	$ 3,860
2030	$ 3,731
2035	$ 3,720
2040	$ 3,853
2045	$ 3,810
2050	$ 3,671
Avg. non-zero yrs	**$ 3,702**
2027-2050 Sum	**$ 88,837**

Source: ICF estimates. Note: liquids includes natural gas liquids (NGLs), oil, and condensate.

Exhibit 5-9 shows the impacts of additional LNG export volumes on total U.S. employment.[13] The employment impacts are across all industries nationwide, and include direct, indirect, and induced employment effects. For example, the employment changes include direct and indirect jobs related to additional oil and gas production (such as drilling wells, drilling equipment, trucks to and from the drilling sites, construction workers), as well as induced jobs. Induced jobs are created when incremental employment from direct and indirect impact leads to increased spending in the economy, creating induced impacts throughout the economy.

Exhibit 5-9: Total U.S. Total Employment Changes



Year	Change in Employment (No.)
2020	15
2021	201
2022	1,056
2023	9,543
2024	11,089
2025	12,437
2026	11,881
2027	13,321
2030	14,838
2045	14,920
2050	14,808
Avg. non-zero yrs	**12,863**
2020-2050 Sum	**398,741**

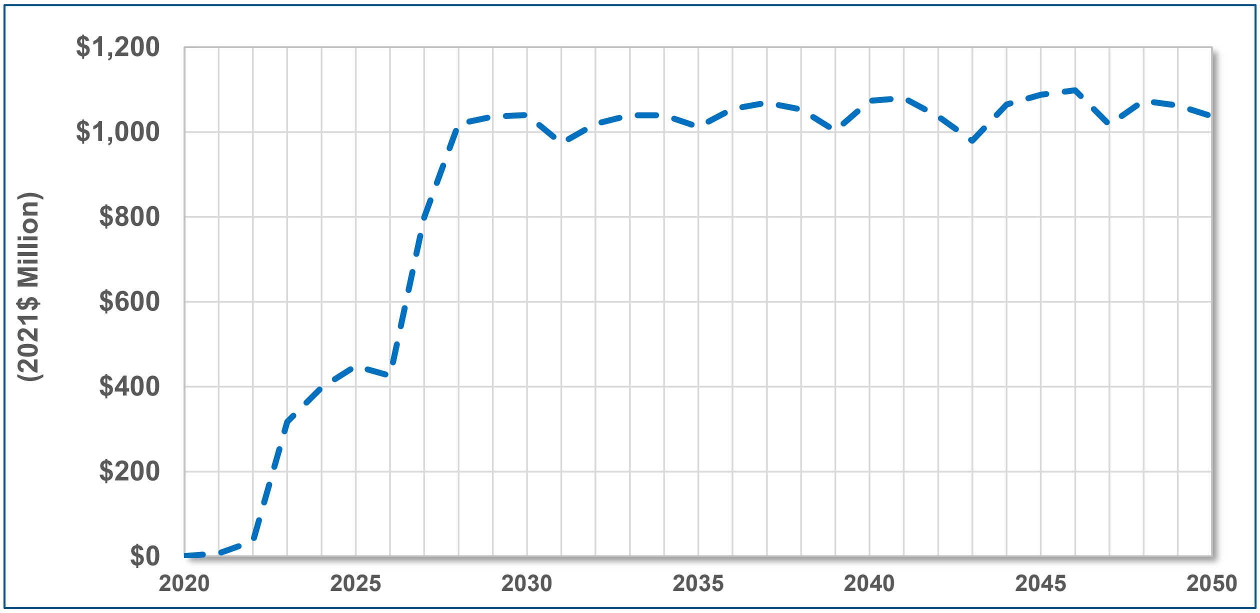
Source: ICF estimates. Include direct, indirect and induced employment effects related to the construction and operation of Cameron LNG Train 4 including supplying natural gas, electricity and other goods and materials.

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

The construction and operation of the Cameron LNG Train 4 LNG export facility will likely support employment through direct, indirect and induced effects that total 12,900 jobs on average through 2050. Over the forecast period, Cameron LNG Train 4 is expected to support 399,000 cumulative job-years.

Exhibit 5-10 shows the impact of the additional LNG exports on U.S. federal, state, and local government revenues. Collective incremental government revenues average $852 million annually as a result of the Cameron LNG Train 4 LNG export facility. This translates to a cumulative impact of $26.4 billion over the forecast period to 2050.

Exhibit 5-10: U.S. Federal, State, and Local Government Revenue Changes



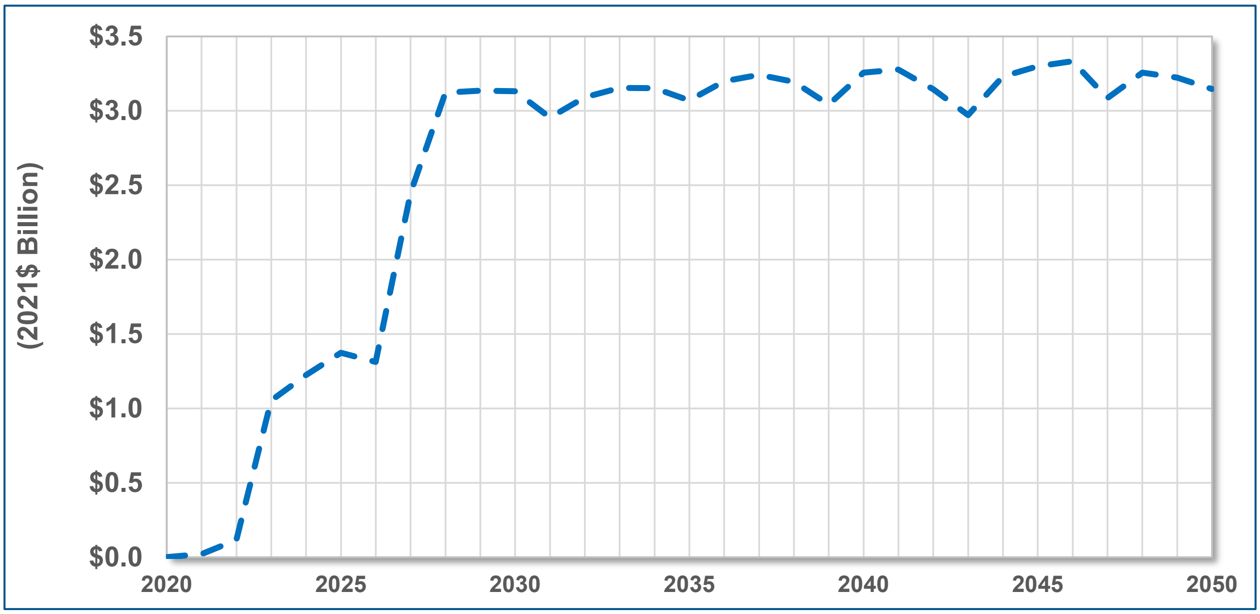
Year	Government Revenues (2021$ Million)	
2024	$	397
2025	$	448
2026	$	426
2027	$	800
2028	$	1,019
2029	$	1,036
2030	$	1,040
2035	$	1,012
2040	$	1,073
2045	$	1,088
2050	$	1,037
Avg. non-zero yrs	**$**	**852**
2020-2050 Sum	**$**	**26,401**

Source: ICF estimates for federal, state and local revenues.

Exhibit 5-11 shows the impacts of additional LNG export on total U.S. value added (that is, additions to U.S. GDP). The value added is the total U.S. output changes attributable to the incremental LNG exports minus purchases of imported intermediate goods and services. Based on U.S. historical averages across all industries, about 16 percent of output is made of imported goods and services. The value for imports used in the ICF analysis differs by industry and is computed from the IMPLAN matrices.

Total value added is substantially higher as a result of the the construction and the additional LNG export volumes assumed in the Cameron LNG Train 4 Case. This activity results in a $2.6 billion annual incremental value added between 2020 and 2050. The cumulative value added over the period between the Base Case and the Cameron LNG Train 4 Case totals $80.3 billion. About 42% of these value added amounts can be attributed to oil and gas production supply chains, 21% can be attributed to value added from liquefaction and port services and the remaining 37% is the induced effects.

Exhibit 5-11: Total U.S. Value Added Changes

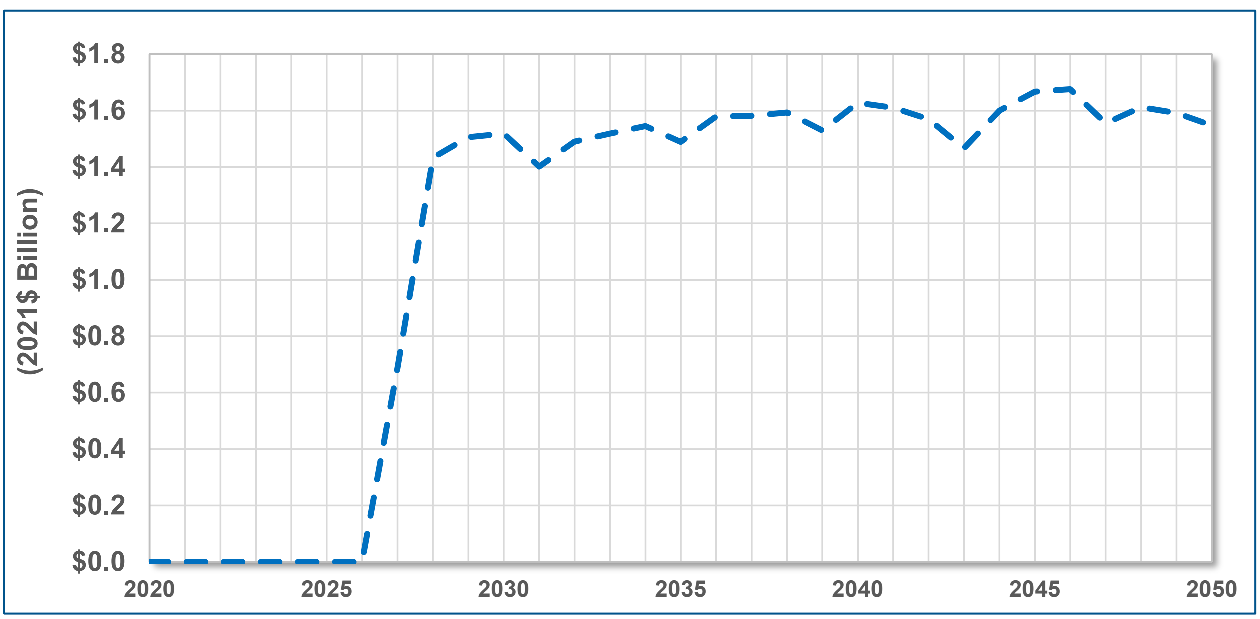


Year	Total Value Added (2021$ Billion)	
2024	$	1.2
2025	$	1.4
2026	$	1.3
2027	$	2.5
2028	$	3.1
2029	$	3.1
2030	$	3.1
2035	$	3.1
2040	$	3.3
2045	$	3.3
2050	$	3.1
Avg. non-zero yrs	**$**	**2.6**
2020-2050 Sum	**$**	**80.3**

Source: ICF estimates.

Exhibit 5-12 shows that the expected value of the exports from the facility is estimated to reduce the U.S. balance of trade deficit by $1.5 billion annually or a cumulative value of $36.4 billion between 2027 and 2050. The improved balance of trade effects begin in 2027 when the plant starts operating and are primarily a result of the LNG exports themselves (encompassing the natural gas feedstock used to make the LNG and the LNG liquefaction process) and the additional hydrocarbon liquids production which is assumed to either substitute for imported liquids or be exported. The positive blance of trade effects are reduced to some degree by higher imports of goods and services related to building and operating the liquefaction train and supply it with natural gas.

Exhibit 5-12: U.S. Balance of Trade Changes



Year	Balance of Trade (2021$ Billion)	
2024	$	-
2025	$	-
2026	$	-
2027	$	0.7
2028	$	1.4
2029	$	1.5
2030	$	1.5
2035	$	1.5
2040	$	1.6
2045	$	1.7
2050	$	1.5
Avg. non-zero yrs	**$**	**1.5**
2027-2050 Sum	**$**	**36.4**

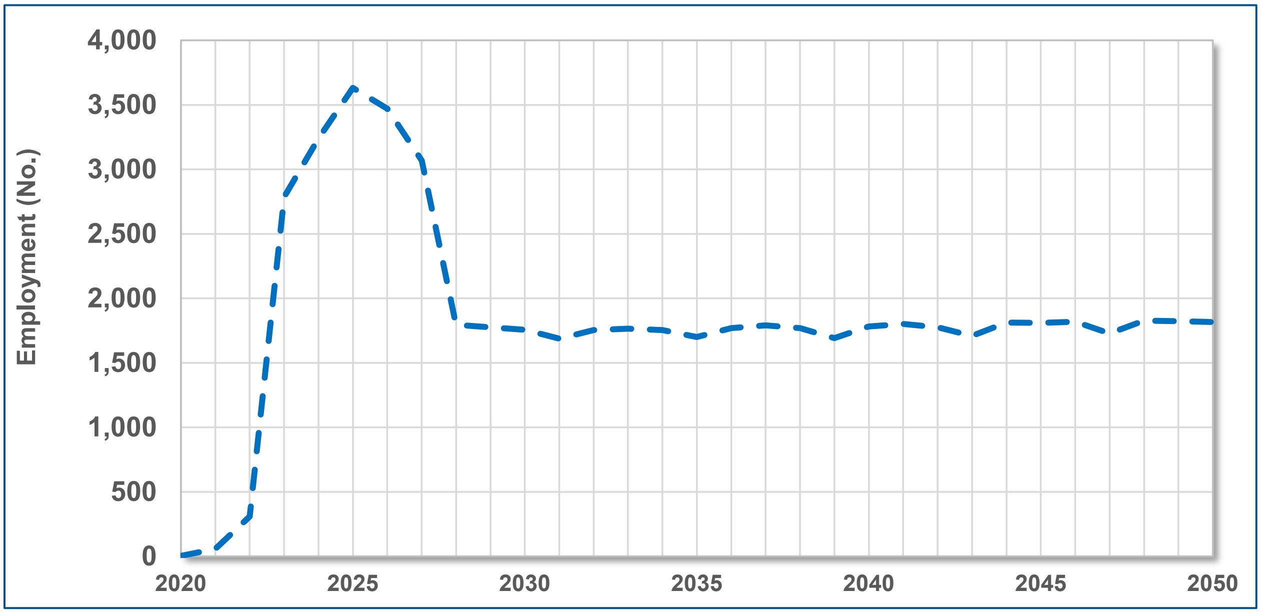
Source: ICF estimates.

5.2. Louisiana Impacts

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

Exhibit 5-13 shows the impacts of LNG export volumes in Louisiana total employment, including direct, indirect, and induced jobs. Employment numbers increase as a result of additional LNG export volumes and can be attributed to the construction and operation of the LNG export facility and to the added natural gas production that will take place in the state and in other states and the federal offshore to which Louisiana companies offer support services. The Cameron LNG Train 4 Case exhibits an increase of roughly 1,800 jobs on an average annual basis from 2020 to 2050 as compared to the Base Case. This equates to a cumulative impact of 57,300 job-years in Louisiana over the forecast period through 2050.

Exhibit 5-13: Louisiana Total Employment Changes

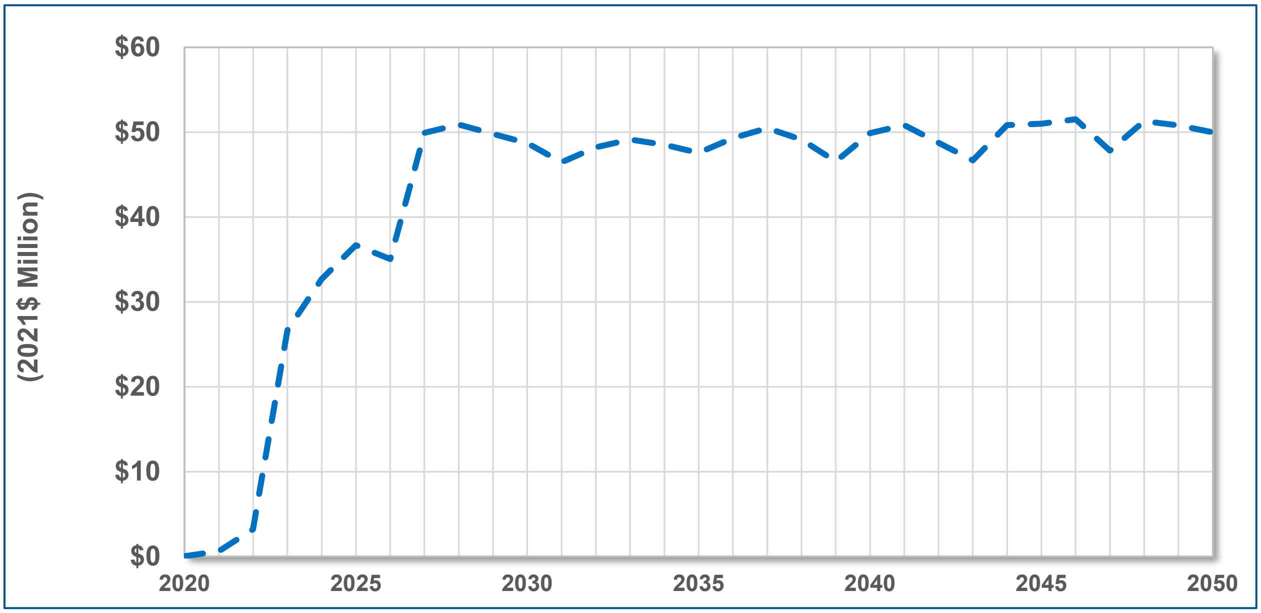


Year	Change in Employment (No.)
2020	4
2021	59
2022	309
2023	2,787
2024	3,239
2025	3,633
2026	3,470
2027	3,069
2030	1,757
2045	1,810
2050	1,816
Avg. non-zero yrs	**1,848**
2020-2050 Sum	**57,289**

Source: ICF estimates.

Exhibit 5-14 shows the impacts of LNG export volumes on Louisiana state and local government revenues. Total Louisiana 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 Cameron LNG Train 4 Case results in a $42.5 million average annual increase to local and state Louisiana government revenues throughout forecast period through 2050, or a cumulative impact of about $1.3 billion.

Exhibit 5-14: Louisiana Government Revenue Changes

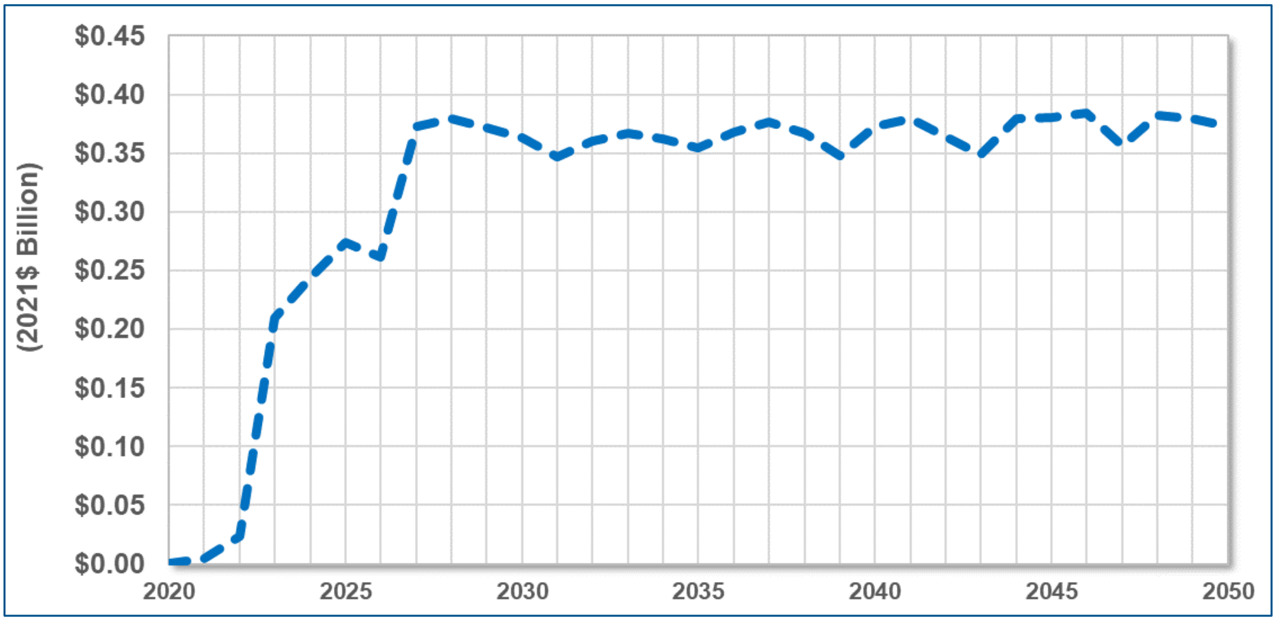


Year	Government Revenues (2021$ Million)	
2024	$	32.7
2025	$	36.7
2026	$	35.0
2027	$	49.9
2028	$	50.9
2029	$	49.8
2030	$	48.7
2035	$	47.6
2040	$	49.9
2045	$	51.0
2050	$	50.0
Avg. non-zero yrs	**$**	**42.5**
2020-2050 Sum	**$**	**1,318.9**

Source: ICF estimates.

Exhibit 5-15 shows the impacts of LNG export volumes on total Louisiana value added (also called gross state product or GSP). Louisiana value added increases as a result of the additional LNG export volumes assumed in the Cameron LNG Train 4 Case. Throughout the study period 2020 to 2050 the plant construction and the additional LNG volumes in the Cameron LNG Train 4 Case result in a $0.32 billion annual average increase to value added, relative to the Base Case. The total differential of value added to Louisiana over the study period between the Base Case and the Cameron LNG Train 4 Case is $9.85 billion.

Exhibit 5-15: Total Louisiana Value Added Changes



Source: ICF estimates.

Year	Total Value Added (2021$ Billion)	
2024	$	0.24
2025	$	0.27
2026	$	0.26
2027	$	0.37
2028	$	0.38
2029	$	0.37
2030	$	0.36
2035	$	0.35
2040	$	0.37
2045	$	0.38
2050	$	0.37
Avg. non-zero yrs	**$**	**0.32**
2020-2050 Sum	**$**	**9.85**

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CERTIFICATE OF SERVICE

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

Dated at Washington, D.C., this 23rd day of October 2025.

/s/ Emily Childress

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