Cameron LNG LLC

December 21, 2011

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Mr. John Anderson
Office of Fossil Energy
U.S. Department of Energy
Docket Room 3F-056, FE-50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Cameron LNG, LLC
FE Docket No. 11-162-LNG
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Mr. Anderson,

Cameron LNG, LLC ("Cameron LNG) hereby submits its application for long-term, multi-contract authorization to export liquefied natural gas ("LNG"). In this application, Cameron LNG is seeking authorization to export up to 12 million metric tons per year (equivalent to approximately 620 billion cubic feet) of LNG produced from domestic sources. The requested authorization is sought for a term of 20 years, commencing on the earlier of the date of first export or seven years from the date of issuance of the authorization.

As reflected in its application, Cameron LNG is requesting authority to export LNG from the Cameron LNG terminal in Cameron Parish, Louisiana to any country with which the United States does not have a free trade agreement requiring national treatment for trade in natural gas and with which trade is not prohibited by United States law or policy.

Cameron LNG also submits a check in the amount of $50.00 in payment of the applicable filing fee.

Please contact me if you have any questions regarding this application.

Respectfully submitted,

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

Cameron LNG, LLC	)))	**Docket No. 11- ___ -LNG**

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

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Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"),[2] Cameron LNG, LLC ("Cameron LNG") submits this application ("Application") for a long-term, multi-contract authorization to export up to 12 million metric tons per annum ("MTPA") of liquefied natural gas ("LNG") (equivalent to approximately 620 billion cubic feet ("Bcf") per year)[3] produced from domestic sources. Cameron LNG seeks this authorization for a 20-year period commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted.

In this Application, Cameron LNG seeks authorization to export LNG from the Cameron LNG terminal in Cameron Parish, Louisiana ("Cameron Terminal") to any country (i) with which the United States does not have a Free Trade Agreement ("FTA") requiring national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States

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[1] 15 U.S.C. § 717b (2010).

[2] 10 C.F.R. Part 590 (2011).

[3] The proposed export quantity of 12 MTPA of LNG is equivalent to approximately 1.7 billion cubic feet per day ("Bcfd") of LNG. The Liquefaction Project may also consume another 0.2 Bcfd of fuel, resulting in a total gas requirement of up to 1.9 Bcfd.

law or policy. Cameron LNG is requesting this authorization both on its own behalf and as agent for other parties who hold title to the LNG at the time of export.

This Application is the second part of Cameron LNG's planned two-part export authorization request. On November 10, 2011, Cameron LNG filed a separate application with the DOE Office of Fossil Energy ("DOE/FE") for a long-term authorization to export LNG to those countries with which the United States has an FTA. That request is presently pending with DOE/FE in Docket No. 11 - 145 - LNG.

In support of this Application, Cameron LNG respectfully states the following:

I. COMMUNICATIONS AND CORRESPONDENCE

Any notices, pleadings or other communications concerning this Application should be addressed to:

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II. DESCRIPTION OF THE APPLICANT

The exact legal name of Cameron LNG is Cameron LNG, LLC. Cameron LNG is a limited liability company organized under the laws of Delaware. Cameron LNG is a wholly-owned indirect subsidiary of Sempra Energy, a publicly-traded corporation. Cameron LNG's executive offices are located at 101 Ash Street, San Diego, California 92101. Cameron LNG is currently engaged in the business of owning and operating the Cameron Terminal in Cameron Parish, Louisiana.

Cameron LNG currently holds no import or export authorizations from DOE/FE. One of the affiliates of Cameron LNG, Sempra LNG Marketing, LLC ("SLNG"), has a blanket authorization to import LNG at the Cameron Terminal.[4] SLNG also has a blanket authorization to export previously imported (i.e., foreign sourced) LNG from the Cameron Terminal.[5] Nothing in this Application is intended to supersede or otherwise modify the blanket import and export authorizations granted by DOE/FE to SLNG.

III. DESCRIPTION OF CAMERON LNG TERMINAL

In this Application, Cameron LNG seeks a long-term authorization to export domestically produced LNG from the Cameron Terminal. The Federal Energy Regulatory Commission ("FERC") approved the construction and operation of the Cameron Terminal in an order issued in 2003.[6] In that order, FERC authorized the Cameron Terminal to send out up to 1.5 Bcfd of re-gasified LNG to domestic markets. In a subsequent order, issued in 2007, FERC authorized Cameron LNG to construct and operate additional facilities expanding the maximum send-out capacity to 1.8 Bcfd.[7]

Cameron LNG completed construction of the Cameron Terminal and placed it into service in July 2009. Initially, the Cameron Terminal was used for the sole purpose of receiving and storing foreign-sourced LNG, and re-gasifying such LNG and sending it out for delivery to domestic markets. In January 2011, FERC authorized Cameron LNG to operate the Cameron

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[4] *Sempra LNG Marketing, LLC*, DOE Order No. 2806 (2010).

[5] *Sempra LNG Marketing, LLC*, DOE Order No. 2885 (2010).

[6] *Cameron LNG, LLC*, 104 FERC ¶61,269 (2003).

[7] *Cameron LNG, LLC*, 118 FERC ¶61,019 (2007).

Terminal for the additional purpose of exporting previously imported (i.e., foreign sourced) LNG on behalf of its customers.[8]

The Cameron Terminal has an existing interconnection with Cameron Interstate Pipeline, LLC ("Cameron Interstate"). Cameron Interstate, an affiliate of Cameron LNG, is an interstate pipeline regulated by FERC. Cameron Interstate's facilities consist primarily of a 36.2 mile pipeline connecting the Cameron Terminal with five other interstate pipelines. Those interstate pipelines provide, directly or indirectly, access to all of the major gas producing basins in the Gulf Coast and Midcontinent regions of the United States, including recent discoveries of shale gas and other unconventional reserves.

IV. LIQUEFACTION PROJECT DESCRIPTION

Cameron LNG is finalizing the design of natural gas processing and liquefaction facilities to receive and liquefy domestic natural gas at the Cameron Terminal for export to foreign markets (the "Project"). The Project facilities will be integrated into the existing Cameron Terminal facilities. The Cameron Terminal presently consists of two marine berths, three full containment LNG storage tanks, LNG vaporization systems, and associated utilities. The new facilities proposed as part of the Project will include natural gas pre-treatment, liquefaction, and export facilities with a capacity of up to 12 MTPA of LNG, plus upgrades to the existing equipment and additional utilities.

The Project facilities will permit gas to be received by pipeline at the Cameron Terminal, to be liquefied, and to be loaded from the Cameron Terminal's storage tanks onto vessels berthed at the existing marine facility. The Project will be designed to allow Cameron LNG to provide bi-directional service. Thus, once the Project facilities are operational, the Cameron Terminal

[8] *Cameron LNG, LLC*, 134 FERC ¶61,049 (2011).

will have the capability to (i) liquefy domestically-produced gas for export, or (ii) import LNG and either re-gasify it for delivery to domestic markets or export it to foreign markets.

The Project will not result in an increase in the number of ship transits currently authorized for the Cameron Terminal. The total amount of LNG processed (whether through liquefaction of natural gas or re-gasifying LNG) would not exceed the current maximum authorized send-out rate of 1.8 Bcfd.

When gas prices are significantly higher overseas than in the United States, as they are currently, customers of the Project can be expected to liquefy and export LNG. If gas prices in the United States converge with those in other markets, the Project's customers may elect not to export their supplies of domestic gas. Further, Cameron LNG will continue to be able to receive cargoes of LNG and operate in vaporization and send-out mode to enable its customers to provide additional natural gas supply to the United States market, to the extent such supply is needed.[9]

Any modifications to the Cameron Terminal proposed as part of the Project would be subject to review and approval by FERC. Upon completion of initial facility planning and design, Cameron LNG will request that FERC initiate the mandatory pre-filing review process for the first phase of the Project. It is anticipated that this request will be made no later than the second quarter of 2012.

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[9] In addition, the domestic market for LNG itself may develop more fully during the 20-year term of the requested authorization. For example, LNG appears to be a promising option for transportation fuel. The LNG would be delivered by truck or other means of ground transportation to natural gas fueling stations, where it would be used as transportation fuel. This would be an additional option for the Project's customers, in lieu of re-gasifying LNG and sending it out of the Cameron Terminal via pipeline.

V. AUTHORIZATION REQUESTED

Cameron LNG requests long-term, multi-contract authorization to export up to 12 MTPA of domestically produced LNG from the Cameron Terminal. This authorization is requested for a 20-year term commencing on the earlier of the date of first export or seven years from the date on which authorization is granted by the DOE. Cameron LNG seeks authorization to export LNG to any country (i) with which the United States does not have an FTA requiring the national treatment for trade in natural gas, (ii) which has or will develop the capacity to import LNG delivered by ocean-going carrier, and (iii) with which trade is not prohibited by United States law or policy.

Cameron LNG requests authorization to export LNG on its own behalf (by holding title to the LNG at the time of export) or by acting as agent for others. In those instances in which Cameron LNG exports LNG on its own behalf, Cameron LNG will either take title to the gas at a point upstream of the Cameron Terminal or will purchase LNG from a customer of the Cameron Terminal prior to export. In other cases, Cameron LNG will act as agent for the customers of the Cameron Terminal without taking title to facilitate the export of the customer's LNG. To ensure that all exports are permitted and lawful under United States laws and policies, Cameron LNG will comply with all DOE/FE requirements for an exporter or agent.

In Order No. 2913,[10] DOE/FE approved a proposal by the applicant to register each LNG title holder for whom the applicant sought to export LNG as agent. The applicant also proposed that this registration include a written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included in its export authorization and to include those requirements in any subsequent purchase or sale agreement entered into by that title holder.

[10] *Freeport LNG Development, LP*, DOE Order No. 2913 (2011).

The applicant further stated that it would file under seal with DOE/FE any relevant long-term commercial agreements that it reached with the LNG title holders on whose behalf the exports were performed. The DOE found that this proposal was an acceptable alternative to the non-binding policy adopted in Order No. 2859,[11] which stated that title to all LNG authorized for export must be held by the authorization holder at the point of export. In approving this alternative approach, DOE/FE noted that it would ensure that the title holder was aware of all DOE/FE requirements applicable to the proposed export, and would provide DOE/FE with a record of all authorized exports and a point of contact with the title holder.

Therefore, when acting as agent, Cameron LNG will register with DOE/FE each LNG title holder for whom Cameron LNG seeks to export as agent, and will provide DOE/FE with a written statement by the title holder acknowledging and agreeing to (i) comply with all requirements in Cameron LNG's long-term export authorization, and (ii) include those requirements in any subsequent purchase or sale agreement entered into by the title holder. Cameron LNG will also file under seal with DOE/FE any relevant long-term commercial agreements that it enters into with the LNG title holders on whose behalf the exports are performed.

In recent orders granting long-term authorizations to export LNG, DOE/FE has found that the applicants were not required to submit with their applications transaction-specific information, pursuant to Section 590.202(b) of the DOE's regulations.[12] DOE/FE found that, given the stage of development for these projects, it was appropriate for the applicants to submit such information "when practicable" (i.e., when the contracts reflecting such information are

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[11] *Dow Chemical Company*, DOE Order No. 2859 (2010).

[12] *See, e.g.*, *Sabine Pass Liquefaction, LLC*, DOE Order No. 2833 (2010). The transaction-specific information described in the regulations includes long-term supply agreements and long-term export agreements.

executed). Cameron LNG requests that the DOE make the same finding in this case. As discussed below, abundant, reliable and economical supplies of domestic gas are available without the need to enter into long-term supply agreements. Presently, participants in the United States wholesale gas market do not typically enter into the types of long-term gas purchase and sales agreements that were prevalent at the time DOE/FE originally adopted this requirement. The wholesale gas market today is far more diverse and liquid and provides gas purchasers with many reliable and competitive short-term supply options. Thus, submittal of the transaction-specific information identified in Section 590.202(b) at the time the applicable agreements are executed is appropriate in light of current market conditions and contracting practices.

Cameron LNG further requests that DOE/FE issue an order authorizing the long-term export of LNG, subject to completion of the environmental review of the proposed modifications to the Cameron Terminal that FERC will conduct.[13] DOE/FE routinely grants conditional authorizations of this nature subject to the completion of a satisfactory environmental review by another agency.[14]

The long-term authorization requested in this application is necessary in order to permit Cameron LNG to incur the substantial costs of developing the Project and secure customer contracts. Terms for the use of the liquefaction and other facilities will be set forth in one or more long-term service or agency agreements with customers of the Project. These agreements are expected to be for terms of up to 20 years in length and will run concurrently with Cameron LNG's export authorization. Cameron LNG has not yet entered into such agreements; a long-term export authorization is required to finalize arrangements with prospective customers. As

[13] It is anticipated that FERC will act as the lead agency for purposes of the environmental review and DOE/FE will act as a cooperating agency.

[14] *Sabine Pass Liquefaction, LLC*, DOE Order No. 2961 (2011).

noted above, Cameron LNG intends to file these agreements with DOE under seal when they are executed.

VI. EXPORT SOURCES

Cameron LNG seeks authorization to export natural gas available through the United States natural gas supply and transmission network. As a result of the Cameron Terminal's access (through its existing interconnection with Cameron Interstate) to five major interstate pipelines, and indirect access to the entire national gas pipeline grid, the Project's customers will have a variety of stable and economical supply options from which to choose.

The sources of natural gas for the Project will include the vast supplies available from the Texas and Louisiana producing regions. In 2010, these regions collectively produced and made available to the national market 8.9 trillion cubic feet ("Tcf") (approximately 24.4 Bcfd) of natural gas, according to the United States Energy Information Administration ("EIA"), which was 40% of the United States total for that year.[15] According to the 2010 Report of the Potential Gas Committee, the United States Gulf Coast region is estimated to have traditional natural gas resources of 506 Tcf.[16] Other regional gas production basins such as Permian, Fort Worth and Anadarko are estimated to contain another 147 Tcf of traditional natural gas resources.[17]

Emerging unconventional supply areas, such as the Barnett, Haynesville, and Eagle Ford shale gas formations also represent very attractive sources of supply for the Project's customers. Technological improvements in natural gas exploration, drilling and production have resulted in significant reductions in the costs of developing shale resources, making shale gas production

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[15] Energy Information Administration, Natural Gas Marketed Production available at http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

[16] U.S. Potential Gas Committee 2010, "The Potential Supply of Natural Gas in the United States," available at http://www.potentialgas.org/PGC%20Press%20Conf%202011%20slides.pdf (Apr. 2011).

[17] Potential Supply of Natural Gas - 2010, *Advance Summary* at pp. 18.

economically viable. The latest EIA estimate of shale gas resources in these three shale formations alone range from 139 to 260 Tcf.[18] Production from shale gas resources has contributed to a 20% increase in total United States gas production during the past five years.[19] Shale production has increased from a nominal amount just seven years ago (1.4 Bcfd in 2004)[20] to 23% of total United States production in 2010 (13.2 Bcfd).[21] Looking forward, the EIA projects that shale gas production will account for an estimated 47% of total domestic dry production by 2035.[22]

Given the size of traditional natural gas resources in close proximity to the Cameron Terminal, as well as rapid growth in emerging unconventional gas and oil resources in the region, the Project's customers will have a choice of diverse and reliable alternative gas supplies.

Natural gas to be exported will be purchased in a market that has sufficient liquidity and capacity to accommodate a wide range of sales arrangements beyond long-term physical sales. Natural gas markets are particularly liquid in the Gulf Coast region of Texas and Louisiana as a result of the key market centers in the area and the availability of readily accessible incremental gas supplies. In 2010, only 4.2 Tcf (38%) of the 11.2 Tcf of marketed gas production from Texas, Louisiana and the Gulf of Mexico was delivered to consumers in those two states.[23]

The Cameron Terminal, in particular, is ideally situated to take advantage of the abundant natural gas resources in this region. The Project's customers will be able to deliver natural gas

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[18] Energy Information Administration, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays* at p. 5, *available at* http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf (July 2011); Baker Institute, *Shale Gas and U.S. National Security* at p. 24 (July 2011).

[19] The 20% increase is derived from EIA dry gas production information for 2005 and 2010 available on the EIA website at the following link: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

[20] *See* Wood MacKenzie, *North American Natural Gas Long-Term View* (Apr. 2011).

[21] Energy Information Administration, *Annual Energy Outlook 2011* (Apr. 2011).

[22] *Id., p. 2*

[23] Energy Information Administration, *Natural Gas Monthly* (November 2011), Table 5 and Table 16.

supplies to the Cameron Terminal from five interstate pipelines (Florida Gas Transmission Company, Transcontinental Gas Pipeline Company, LLC, Texas Eastern Transmission Corporation, Tennessee Gas Pipeline Company, and Trunkline Gas Company) with significant capacity in southwestern Louisiana. These interstate pipelines are connected to recently-constructed transmission and gathering systems that have been developed to access new production in the major shale gas formations. This interconnected pipeline network will enable the Project's customers to access and deliver supplies from the recent and substantial shale gas discoveries in Texas and Louisiana.

Moreover, the Project's customers will not necessarily have to limit themselves to particular geographical supply areas when contracting for gas supply. The Cameron Terminal is in close proximity to the Henry Hub, one of the most liquid and transparent natural gas market centers in the world and the pricing point for the natural gas futures contract. In addition to the Henry Hub, there are 11 other market centers in Louisiana and Texas.[24] These market centers provide ample liquidity to accommodate a wide range of gas supply arrangements for each of the Project's customers. Therefore, in addition to purchasing gas supplies at or near the point of production, the Project's customers may elect to purchase supplies at a market center in proximity to the Cameron Terminal.

VII. PUBLIC INTEREST ANALYSIS

A. Applicable Legal Standard

The DOE/FE has the power to approve or deny applications to export LNG pursuant to specific authorization in Section 3 of the Natural Gas Act.25 The general standard for review of

[24] Energy Information Administration, *Natural Gas Market Centers: A 2008 Update* (Apr. 2009).

[25] 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for FE pursuant to Redelegation Order No. 00.002.04D (Nov. 6, 2007).

export applications to non-FTA countries is established by Section 3(a), which provides that:

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

In applying this statute, DOE/FE has consistently found that Section 3(a) creates a rebuttable presumption that proposed exports of natural gas are in the public interest. For that reason, DOE/FE must grant the export application unless opponents of an export authorization establish an affirmative showing based on evidence in the record that the export would be inconsistent with the public interest.[26]

DOE has issued a set of Policy Guidelines setting out the criteria that it employs in evaluating applications for natural gas imports.[27] While nominally applicable to natural gas import cases, the DOE has found that the same policies apply to natural gas export applications.[28] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and diverse energy resource system. The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] natural gas. The federal

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[26] Order No. 1473 at 13 n.42 (citing *Panhandle Producers and Royalty Owners Ass'n v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987)); *see also Sabine Pass Liquefaction, LLC*, DOE Order No. 2961 (2011).

[27] *Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6684 (Feb. 22, 1984) ("Policy Guidelines").

[28] *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE Order No. 1473 (1999).

> government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[29]

Historically, the DOE has also been guided by DOE Delegation Order No. 0204-111 ("Delegation Order"). The Delegation Order stated that exports of natural gas are to be regulated primarily "based on a consideration of the domestic need for the gas to be exported and such other matters [found] in the circumstances of a particular case to be appropriate."[30]

Both the Policy Guidelines and the principles underlying the Delegation Order presume that competitive markets largely free of governmentally-imposed restrictions will benefit the public:

> The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [and export] arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served.[31]

Although the Delegation Order is no longer in effect, DOE has noted in recent orders that its "review of export applications in decisions under current delegated authority has continued to focus on the domestic need for the natural gas proposed to be exported; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy

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[29] *Id.*

[30] *Department of Energy*, Delegation Order No. 0204-111 (Feb. 22, 1982).

[31] Policy Guidelines at 6685.

of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements."[32]

In granting recent authorizations, DOE has indicated that the following additional considerations are relevant in determining whether proposed exports are in the public interest: whether the exports will be beneficial for regional economies, the extent to which the exports will foster competition and mitigate trade imbalances with the foreign recipient nations, and the degree to which the exports would encourage efficient management of United States domestic natural resources.[33] As demonstrated below, the export of domestically produced LNG as proposed in this Application satisfies each of these considerations.

B. Domestic Need for Gas to be Exported

The Project is proposed in light of the recent, substantially improved outlook for domestic natural gas resources and production. Drilling productivity gains and extraction technology enhancements have enabled rapid growth in supplies from unconventional gas-bearing shale formations in the United States. Natural gas proved reserves have increased by 61 Tcf (29%) between 2006 and 2009 and estimates of recoverable natural gas resources have increased by 849 Tcf (64%) between 2006 and 2010.[34] In light of these substantial resource additions and the comparatively minor increases in domestic natural gas demand, there are more than sufficient natural gas resources to accommodate both domestic demand and the exports proposed in this Application throughout the 20-year term of the requested authorization.

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[32] *Sabine Pass Liquefaction, LLC*, Order No. 2961 (2011).

[33] *See, e.g., Sabine Pass Liquefaction, LLC*, Order No. 2961, at 34-38 (2011).

[34] Energy Information Administration, *Natural Gas Reserves Summary as of December 31, 2010, available at* http://www.eia.gov/dnav/ng/ng_enr_sum_a_EPG0_R11_BCF_a.htm.

As United States natural gas resources and production have increased, United States natural gas prices have fallen significantly. The annual average Henry Hub price for natural gas fell from $8.69 per MMBtu in 2005 to $4.37 in 2010.[35] In its most recently calculated reference case, the EIA estimates that the annual average wellhead price for natural gas, stated in 2009 dollars, will remain under $5.00 per MMBtu through at least 2020, and rise to only $6.26 by 2035.[36] Prices for natural gas in the United States market are now substantially below those of most other major gas-consuming countries. While United States gas prices have fallen, prices for LNG in other major gas consuming countries have actually increased sharply over the past decade, moving generally in line with world oil prices. The result is that domestic gas can be liquefied and exported to foreign markets on a very competitive basis. As discussed below, such exports can be expected to have only a nominal effect on United States prices.

1. <u>United States Natural Gas Supply</u>

Domestic gas production and reserves collectively provide for an abundant domestic supply of natural gas. Domestic gas production has been on a significant upward trend in recent years as rapid growth in supply from unconventional discoveries has more than compensated for declines in production from conventional onshore and offshore fields. The EIA estimates that United States dry gas production was 63.2 Bcfd in August 2011, a 6.2% increase compared to August 2010 dry production of 59.5 Bcfd.[37] Increased drilling productivity in certain prolific shale gas formations, including the Marcellus and Haynesville shales, has enabled domestic production to continue expanding despite a reduction in the number of wells drilled.

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[35] Energy Information Administration, *Natural Gas Spot and Futures Prices, available at* http://www.eia.gov/dnav/ng/ng_pri_fut_s1_a.htm.

[36] Energy Information Administration, *2011 Annual Energy Outlook, Reference Case* (Apr. 2011).

[37] Energy Information Administration *Natural Gas Gross Withdrawals and Production, available at* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

In its *Annual Energy Outlook 2011*, the EIA noted that United States shale gas production grew at an average annual rate of 17% between 2000 and 2006. The rate of growth accelerated substantially during the period 2006 to 2010, with the annual growth rate averaging 48%. The EIA expects this increase in shale gas production to continue through 2035, when it will make up an estimated 47% of total United States gas production, up considerably from a 16% share in 2009.

The EIA has significantly increased its estimate of shale gas production for 2015, 2020, 2025, 2030, and 2035 compared with EIA's projections in the *Annual Energy Outlook 2010*. For example, the EIA revised its projection of shale gas production for 2015 from 3.85 Tcf to 7.20 Tcf. Similarly, the EIA revised its projection of shale gas production for 2035 from 6.00 Tcf to 12.25 Tcf.[38]

The growth in shale gas production has been accompanied by an increase in the overall volume of United States natural gas resources. In 2011, the EIA substantially increased its estimate of technically recoverable natural gas resources in the United States to 2,543 Tcf.[39]

This growth in United States natural gas resources is reflected in other recent academic and industry evaluations. The Potential Gas Committee in April 2011 determined that the United States possesses future available gas supply of 2,170 Tcf, the highest resource evaluation in the group's 46-year history and enough to satisfy 90 years of domestic market needs, based on 2010 consumption. This assessment included 687 Tcf of shale gas resources, which is 32% of the total available supply.[40]

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[38] *See* Energy Information Administration, *Annual Energy Outlook 2011* at Table A-14, p 143 (Apr. 2011); Energy Information Administration, *Annual Energy Outlook 2010* at Table A-14, p 135 (Apr. 2010).

[39] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2011*, Table 9.2, *available at* http://www.eia.gov/forecasts/aeo/assumptions/pdf/oil_gas.pdf (2011).

[40] U.S. Potential Gas Committee 2010, "The Potential Supply of Natural Gas in the United States," *available at* http://www.potentialgas.org/PGC%20Press%20Conf%202011%20slides.pdf (Apr. 2011). The PGC consists of

In its recently published study, The Future of Natural Gas ("MIT Report"), the Massachusetts Institute of Technology estimates that the United States has a mean remaining resource base of approximately 2,100 Tcf. This estimate includes 650 Tcf of recoverable shale gas resources, "approximately 400 Tcf of which could be economically developed with a gas price at or below $6/MMbtu at the wellhead." [41]

According to the July 2011 report titled "Shale Gas and U.S. National Security" by the James A. Baker III Institute for Public Policy at Rice University, North America has mean technically recoverable shale gas resources of 937 Tcf, with 637 Tcf of that located in the United States. The report assigns a weighted mean break-even price for United States shale gas resources of $5.42/MMbtu.[42] This report indicates that the break-even price is the average price needed for development of up to 60 percent of the identified technically recoverable resource.[43]

In a July 2011 report commissioned by the EIA, an independent consultant estimates United States onshore lower 48 states shale gas resources to be 750 Tcf.[44] The 750 Tcf of shale gas resources in this report is a subset of the *Annual Energy Outlook 2011* onshore Lower 48 States natural gas shale technically recoverable resource estimate for shale gas of 862 Tcf. The *Annual Energy Outlook 2011* estimate includes an additional 35 Tcf of proved reserves reported

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members, advisors and representatives from the exploration, production, pipeline and distribution sectors of the natural gas industry, together with observers from various professional and industry trade associations, research organizations, and government agencies, and from Canada and Mexico. For the 2007-2008 assessment cycle, over ninety topic experts were involved. The PGC functions independently but with the guidance and administrative support of the Potential Gas Agency at the Colorado School of Mines.

[41] Massachusetts Institute of Technology, *Executive Summary*, at xii, *available at* http://web.mit.edu/mitei/research/studies/documents/natural-gas/natural-gas-summary.pdf (2011).

[42] The weighted mean break-even price for United States shale gas resources was calculated based on break-even price estimates presented in the MIT Report.

[43] Baker Institute, *Shale Gas and U.S. National Security* at pp. 24-25 (July 2011).

[44] Energy Information Administration, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays* at p. 5, *available at* http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf (July 2011).

to the United States Securities Exchange Commission and the EIA, 20 Tcf of reserves not included in the July 2011 report, and 56 Tcf of undiscovered resources estimated by the USGS.[45]

These studies and reports indicate that the United States has a 90- to an over 100-year inventory of recoverable natural gas resources. This inventory is expected to continue growing as further advancements in drilling technology are deployed to exploit additional shale gas development opportunities.

2. United States Natural Gas Demand

Over the past decade, there has been essentially no growth in the demand for natural gas in the United States. According to data published by the EIA, natural gas demand in 2010 was only 3.2% higher than in 2000.[46] In its *Annual Energy Outlook 2011*, the EIA estimated long-term annual United States demand growth of only 0.6%, with demand expected to reach 26.6 Tcf in 2035 (compared to 22.7 Tcf of actual demand in 2009).[47]

The table below presents a comparison of actual demand and prices in 2010 and forecasted demand and prices in the year 2025, based on information presented in the *Annual Energy Outlook 2011*.[48]

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[45] *Id.*

[46] Energy Information Administration, *Natural Gas Consumption by End Use available at*.http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[47] Energy Information Administration, *Annual Energy Outlook 2011*, Table A13.

[48] Energy Information Administration, *Annual Energy Outlook 2011*, Table 16, *available at* http://205.254.135.24/forecasts/aeo/excel/table16.xls. Volumes stated in Tcf per year in the *Annual Energy Outlook 2011* were converted to Bcf per day. In addition, 2009 volumes and prices were updated to 2010 actual volumes and prices, based on EIA Natural Gas Summary available at http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm

	2010	2025 Projection						
		AEO2011 Reference Case	IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
	Bcf/d							
Dry gas production	59	66	72	68	64	80	66	62
Consumption	66	69	79	70	70	83	72	68
Residential	14	13	13	14	15	14	19	13
Commercial	9	10	8	9	9	8		11
Industrial	18	22	18	21	18	20	19	22
Electricity generators	20	18	35	21	22	33	33	22
Other	5	5	6	6	6	7	0	
	2009 $ / Mcf							
L48 wellhead price	4.2	5.4	4.7	6.5	7.2	6.1		
End-use prices								
Residential	11.2	12.2	11.6			10.5		
Commercial	9.2	10.0	9.8			9.5		
Industrial	5.4	6.3	7.1			7.4		
Electricity generators	5.3	5.9	5.4			7.1		

The consensus of estimates by the EIA and academic and industry experts is that the United States has between 2,000 and 2,543 Tcf of recoverable natural gas resources. Even at 100% utilization, the Project would result in maximum natural gas requirements of 13.4 Tcf over the 20-year term of the requested authorization. This represents only 0.5% to 0.7% of total estimated recoverable United States natural gas resources.

3. Impact on Domestic Gas Prices

Cameron LNG commissioned the independent consulting firm of Black & Veatch to assess the impact of the proposed LNG exports on United States delivered natural gas prices. As noted above, estimates of the available United States natural gas supply have increased dramatically over the past five years due to commercialization of vast shale gas resources and significant productivity improvements in shale gas development and production. Black & Veatch analyzed the underlying long-run supply and demand curves used in EIA's *Annual*

Energy Outlook 2011[49] as the basis for evaluating the impact of Cameron LNG's proposed LNG exports on United States delivered natural gas prices. This approach was used in order to take advantage of the latest market intelligence underlying the EIA's well known National Energy Modeling System ("NEMS") and to approximate the results of running the NEMS model using the EIA's *Annual Energy Outlook 2011* assumptions. The estimates of domestic supply and demand in EIA's *Annual Energy Outlook 2011* extend to 2035, allowing a long-term view of price impacts. This approach also allows the results to be compared to those of other demand and supply case studies published in EIA's *Annual Energy Outlook 2011*.

In the report attached as Appendix C, Black & Veatch first estimates the EIA's *Annual Energy Outlook 2011* natural gas supply and demand curves at five-year intervals using reference and sensitivity case results as reflected in the *Annual Energy Outlook 2011*. The 48 case study results were sorted into three groups, one in which the natural gas demand curve is held constant (10 cases), one in which the natural gas supply curve is held constant (29 cases), and a third group in which both the supply and demand curves are concurrently shifted (9 cases). After constructing the demand and supply curves, Black & Veatch calculated the reference price and quantity at the intersection of the supply and demand curves.

Black & Veatch next estimated the delivered price impacts of increasing the natural gas demand curve by 1.0 Bcfd, thereby simulating 1.0 Bcfd of gas needed for LNG exports. Black & Veatch found that an incremental 1.0 Bcfd increase in demand would increase United States average delivered natural gas prices by $0.085/Mcf in 2020, $0.088/Mcf in 2025, $0.078/Mcf in 2030, and $0.064/Mcf in 2035.[50] Based on the range of EIA's *Annual Energy Outlook 2011* sensitivity cases, Black & Veatch indicates that this analysis is accurate up to approximately 2.0

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[49] Energy Information Administration, *AEO 2011 with Projections to 2035* (Apr. 2011).

[50] Black & Veatch Management Consultants, Price Response to Incremental LNG Export Demand (2011).

Bcfd of incremental demand in 2020 and approximately 7.0 Bcfd of incremental demand in 2035, although there are indications that the supply curve begins to flatten out at a level well below 7.0 Bcfd (i.e., lower price impacts per Bcfd at higher volumes). A 12 MTPA LNG export operation (approximately equivalent to 620 Bcf per year) would create 1.9 Bcfd of incremental natural gas demand (consisting of 1.7 Bcfd of exports and 0.2 Bcfd of fuel consumption). Consequently, the effect on average delivered United States natural gas prices (in 2009 dollars) of a 12 MTPA LNG export facility as implied by the *Annual Energy Outlook 2011* model is $0.161/Mcf in 2020, $0.167/Mcf in 2025, $0.148/Mcf in 2030 and $0.122/Mcf in 2035.

The Black & Veatch analysis supports the conclusion that the exports proposed in this Application will have a minimal impact on domestic natural gas prices. Further, any upward pressure on prices due to increased demand for exports would likely be offset by a reduction in domestic price volatility. In recent years, low market prices have resulted in domestic producers deferring the drilling of new wells or completion of wells that have already been drilled. Exports of domestic LNG will provide an additional market for United States production, thereby encouraging exploration, development and production at times when domestic demand alone might not. Customers of the Project will have sufficient flexibility to reduce their exports and instead redirect gas to the domestic market if demand and market prices indicate a sufficient need for incremental supplies. The increased production and reserves are not, in other words, irrevocably dedicated to foreign destinations. To the contrary, market signals in the United States will play a key role in the determination of whether such gas will be consumed in the United States or delivered to a foreign market. Supplemental natural gas production initially expected to be liquefied and exported will likely reduce volatility in the United States natural gas market by sustaining robust levels of domestic exploration and production and providing an additional source of supply during periods of high domestic demand. This will serve to reduce the likelihood and magnitude of sudden and significant increases in domestic gas prices.

C. Other Public Interest Considerations

To assess and quantify the substantial public benefits that will result from the Project, Cameron LNG prepared an Economic Impact Assessment of the Project, which is attached as Appendix D to this Application ("Economic Assessment"). This Economic Assessment, which is derived from price forecasts from the EIA and regional input-output multipliers from the United States Bureau of Economic Analysis, finds that the Project will substantially benefit national, regional and local economies and improve the United States balance of trade.

1. Benefits to National, Regional and Local Economies

With an estimated capital cost in excess of $4 billion, and annual LNG exports averaging $8.6 billion, the Project will stimulate local, regional, and national economies through direct and indirect job creation, increased economic activity and tax revenues.

The design, engineering and construction of the Project will result in the creation of an average of over 1,300 on-site engineering and construction jobs over a four-year period. Hundreds of additional off-site jobs will be created to support the design, fabrication and construction of the Project facilities. During the peak 12-month construction period, an estimated 2,900 jobs will be directly created, with a total of 5,200 direct job-years created during construction.

There will also be substantial indirect economic impacts resulting from construction of the Project. Using the average of commonly accepted employment and demand output multiplier methods, the Economic Assessment estimates a total economy-wide impact of 63,000 job-years over the 48 month construction period. The Economic Assessment further calculates that the design, engineering and construction of the Project will result in a total economic impact of $7.6 billion, which will be spread over the 48-month construction period.

An even greater number of jobs, and far greater overall economic benefits, will result from the exploration and production of the 1.9 Bcfd of gas required for the Project. Some 4,600 jobs are expected in the natural gas industry. In addition, the exploration and production of natural gas has a very strong multiplier or "ripple" effect on job creation and other economic activity. Independent studies have examined the economic impact of shale gas development in Pennsylvania and West Virginia.[51] The studies measured the costs of natural gas development in these areas and estimated that, for every dollar spent by natural gas producers, at least one additional dollar of economic activity was generated within that state.[52] This, in turn, benefits local businesses and other vendors and suppliers.

For the United States economy as a whole, the Economic Assessment finds that the Project would generate, in addition to 63,000 job-years during construction, an average of 53,000 jobs during the ensuing 20-year operations period, resulting in a total impact during the periods of construction and operation of 1.1 million job-years. In order to verify the reasonableness of this result, the Economic Assessment identified three relevant studies that suggested economy-

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[51] *See, e.g.*, *Economic Impacts of Marcellus Shale in Pennsylvania: Employment and Income in 2009* (Aug. 2011), *available at* http://www.marcellus.psu.edu/resources/PDFs/Economic%20Impact%20of%20Marcellus%20Shale%202009.pdf; Pennsylvania State University, *An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play* (July 24, 2009), *available at* http://www.alleghenyconference.org/PDFs/PELMisc/PSUStudyMarcellusShale072409.pdf; National Energy Technology Laboratory, *Projecting the Economic Impact of Marcellus Shale Gas Development in West Virginia* (Mar. 31, 2010), *available at* http://www.netl.doe.gov/energy-analyses/pubs/WVMarcellusEconomics3.pdf; West Virginia University, *The Economic Impact of the Natural Gas Industry and the Marcellus Shale Development in West Virginia in 2009* (Dec. 2010), *available at* http://be.wvu.edu/bber/pdfs/BBER-2010-22.PDF; Report to the American Petroleum Institute, *The Economic Impacts of the Marcellus Shale: Implications for New York, Pennsylvania, and West Virginia* (July 14, 2010), *available at* http://www.api.org/policy/exploration/hydraulicfracturing/upload/API%20Economic%20Impacts%20Marcellus%20Shale.pdf.

[52] *Id.*

wide job gains from the Cameron facility ranging from 46,000 to 95,000 (i.e., 920,000 to 1,900,000 job-years over the term of the export permit).

As shown in Figure A-3 of the Economic Assessment, the total economic benefits of the Project to the United States economy are estimated to average $2 billion per year during the period of construction and $14 to $18 billion per year during the 20-year term of the requested authorization. The total increase in United States output is estimated at $336 billion over the 20-year term. This does not include the beneficial effects to the local, state and federal governments from the new tax revenue that will be generated from the economic activities associated with the Project.

2. Increased Exports and International Trade

Cameron LNG estimates that the Project's customers will export an average of approximately $8.6 billion of LNG per year.[53] In addition, associated oil and natural gas liquids production resulting from the Project is expected to average $2.2 billion per year, bringing the average total trade balance benefits to $10.8 billion per year in 2011 dollars. This will have a positive and significant impact on the balance of trade that the United States has with its international trading partners. In 2010, the United States trade deficit was $646 billion (reflecting imports of $1,935 billion and exports of $1,289 billion).[54] Over 40% of this trade imbalance was attributable to imports of petroleum products. While the Project alone will not eliminate this imbalance, it will make a significant contribution to reducing it for a sustained period of time.

[53] This assumes that the Project's customers will sell LNG at a price equal to 70% of the oil price forecasts in the AEO 2011, as stated in 2011 dollars.

[54] U.S. Department of Commerce Bureau of Economic Analysis, *International Data, available at* http://www.bea.gov/iTable/iTable.cfm?ReqID=6&step=1, Table 1. U.S. International Transactions.

Increasing exports to address the United States trade imbalance is a key element of President Obama's efforts to spur economic recovery. In his National Export Initiative, the President stated that a central goal of his administration is to "enhance and coordinate Federal efforts to facilitate the creation of jobs in the United States through the promotion of exports."[55] The President further noted that "[a] critical component of stimulating economic growth in the United States is ensuring that U.S. businesses can actively participate in international markets by increasing their exports."[56] Approval of this Application, which would result in $173 billion of new exports from the United States over the 20-year term of the requested authorization, plus $43 billion of displaced imports, would represent a significant step toward achieving the President's goal.

United States international trade law, general United States trade policy and DOE's longstanding policy that the public interest is best served by the principles of free trade all support exports of domestically produced LNG. In addition to having a beneficial impact on the United States trade deficit by leveling the balance of payments between the United States and the rest of the world, LNG exports also will enhance the diversity of global supply and contribute to the security interests of the United States and its allies.

The export of domestically produced LNG will promote liberalization of the global gas market by fostering increased liquidity and trade at prices established by market forces. LNG exports also will advance national security interests as well as the security interests of United States allies through the diversification of global natural gas supplies. The current international

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[55] *See* Executive Order – National Export Initiative (Mar. 11, 2010) *available at* http://www.whitehouse.gov/the-press-office/executive-order-national-export-initiative ("A critical component of stimulating economic growth in the United States is ensuring that U.S. businesses can actively participate in international markets by increasing their exports of goods, services, and agricultural products. Improved export performance will, in turn, create good high-paying jobs.").

[56] *Id.*

trade in natural gas centers around three primary markets: North America, Europe and Asia. There is substantial trade within these markets, but limited trade among the markets. The pricing structure within these markets is significantly different. In North America, natural gas is traded in a highly liquid and competitive market, and prices are very transparent. The European and Asian markets are dominated by natural gas price linkage to the valuation of competing crude oil products. LNG contracts for these markets also are predominantly indexed to crude oil.

Current global supply shortages of LNG are having adverse impacts for the United States' closest allies in Asia and Europe. For example, natural gas consumption and price forecasts by the EIA[57] and the Institute of Energy Economics, Japan ("IEEJ")[58] indicate that Japan's economy will be burdened by LNG imports with a cumulative price premium relative to United States gas prices of over one trillion United States dollars through 2035. By introducing market-based price structures, the Project reduces the premiums charged to economies which have few economic energy supply alternatives, and helps reduce gas price volatility around the world.

It would also be inconsistent with United States obligations under World Trade Organization ("WTO") Agreements to restrict exports of domestically-produced LNG to other WTO countries. The United States has undertaken commitments not to restrict such exports to other WTO countries, whether directly or indirectly, through quantitative measures or other administrative action.[59] It would be a further violation of the most-favored-nation obligations under the WTO Agreements for the United States to grant such applications for exports to

[57] Energy Information Administration, *Annual Energy Outlook 2011*, Figure 88, Figure 52.

[58] Institute of Energy Economics Japan, *Asia/World Energy Outlook 2010*, November 2010, slide 11.

[59] *See* Marrakesh Protocol to the General Agreement on Tariffs and Trade 1994, Schedule XX – United States of America, Part I, Section II, 54 at HTS 2711.11.00 "Liquefied Natural Gas."

countries with which the United States has separate FTAs while denying applications for exports to other WTO countries with which the United States does not have FTAs.

3. Environmental Benefits

The export of LNG from the United States provides consuming nations with access to low carbon natural gas as an alternative to higher CO_2 emitting fossil fuels such as coal and fuel oil. In many locations, LNG would be able to displace the current consumption of coal in power generation and deter the construction of additional coal-fired generation capacity. This would act as a bridge until some countries can develop their own unconventional natural gas resources. The potential reductions in global greenhouse gas emissions, and other undesirable byproducts of coal- or oil-fired generation,[60] are substantial.

An LNG supply volume of 1 Bcfd has the potential to replace almost 6400 MW of traditional coal-fired generation.[61] This would result in a reduction in combustion emissions of approximately 126 thousand tons of CO_2 per day.[62] Generating similar reductions in CO_2 emissions would require the construction of 11,800 wind turbines or 14 square miles of PV solar panels.[63]

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[60] Increased supplies of LNG can also be expected to reduce emissions of sulfur dioxide and particulate emissions.

[61] This is based on a gross heating value of 1030 Btu/Scf and a gas plant heat rate of 6719 Btu/kWh. Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results, Pace, pp 11 (February 3, 2009). This reflects a calculated value of 153,297 MWh per day of power generated converted to an equivalent capacity of 6387 MW at a 100% load factor.

[62] The reduction in emissions is calculated from emission rates for coal-powered generation and LNG powered generation contained in the document Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results, Pace, pp 11 (February 3, 2009).

[63] The calculation of the equivalent reduction required from wind turbines or solar panels is based on replacement of 106,557 MWh/Day of coal-fired generation with wind or PV solar. Capacity factors of 0.25 for wind and 0.17 for solar were derived from information in EIA Renewable Energy Trends in Consumption and Electricity 2008 Edition, Tables 1.11 & 1.12. The calculation further assumed a 1.5 MW wind turbine size and derived solar PV size of 8 acres per MW based on information from the Copper Mountain Solar Facility. See

The United States has a strong interest in encouraging the world's major energy consumers to take advantage of a global boom in natural gas to help ease oil dependency and reduce greenhouse gas emissions. The State Department has established a new Bureau of Energy Resources; one of the primary objectives of this agency is to promote environmentally sustainable forms of energy abroad.

VIII. REVIEW OF ENVIRONMENTAL IMPACTS

As noted above, Cameron LNG will, in the next several months, initiate the pre-filing review process at FERC for the proposed Project facilities. This will be the first step in a comprehensive and detailed environmental review by FERC of the Project. It is anticipated that, consistent with the requirements of the National Environmental Policy Act, FERC will act as the lead agency for environmental review, with the DOE/FE acting as a cooperating agency. Cameron LNG therefore respectfully requests that the DOE/FE issue an order approving this Application, with such approval conditioned upon completion by FERC of a satisfactory environmental review of the Project. Such conditional orders are routinely issued by DOE/FE, which may review an application to determine whether a proposed authorization is in the public interest concurrent with FERC's review of environmental impacts.

IX. REPORT CONTACT INFORMATION

The contact with respect to monthly reports submitted by Cameron LNG following the receipt of the authorization requested herein is:

Richard McElroy
101 Ash Street
San Diego, CA 92101
(619) 696-2734

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http://www.renewableenergyworld.com/rea/news/article/2010/12/americas-largest-pv-power-plant-is-now-live?cmpid=WNL-Wednesday-December8-2010

X. APPENDICES

The following appendices are included with this Application:

Appendix A	Verification
Appendix B	Opinion of Counsel
Appendix C	Black & Veatch Report
Appendix D	Economic Impact Assessment

XI. CONCLUSION

For the reasons set forth above, Cameron LNG respectfully requests that DOE/FE issue an order granting Cameron LNG authorization to export for a period of 20 years (commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted) up to 12 MTPA (equivalent to approximately 620 Bcf per year) of domestically produced LNG to any country with which the United States does not have an FTA and with which trade is not prohibited by United States law or policy.

Respectfully submitted,

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Dated: December 21, 2011

APPENDIX A

VERIFICATION

County of San Diego)
)
State of California)

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

William D Rapp
William D. Rapp

SWORN TO AND SUBSCRIBED before me on the 21st day of December, 2011.

EMMA CASTILLO
Commission # 1853090
Notary Public - California
San Diego County
My Comm. Expires Jun 18, 2013

Emma Castillo
Notary Public

APPENDIX B

OPINION OF COUNSEL

December 21, 2011

Mr. John A. Anderson
Office of Fossil Energy
U.S. Department of Energy
Docket Room 3F-056, FE 50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, DC 20585

RE: Cameron LNG, LLC Application for Long-Term Authorization to Export Liquefied Natural Gas to Free Trade Agreement Countries

Dear Mr. Anderson:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the U.S. Department of Energy, 10 C.F.R. § 590.202(c) (2011). I am counsel to Cameron LNG, LLC ("Cameron LNG"). I have reviewed the organizational and internal governance documents of Cameron LNG and it is my opinion that the proposed export of natural gas as described in the application filed by Cameron LNG, to which this Opinion of Counsel is attached as Appendix B, is within the company powers of Cameron LNG.

Respectfully submitted,

William D. Rapp

William D. Rapp
Counsel to Cameron LNG, LLC

APPENDIX C

REVISED FINAL

PRICE RESPONSE TO INCREMENTAL LNG EXPORT DEMAND (BASED ON DOE/EIA ANNUAL ENERGY OUTLOOK 2011 FORECASTS)

PREPARED FOR

Cameron LNG, LLC

01 DECEMBER 2011

BLACK & VEATCH
Building a world of difference.

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Executive Summary

Black & Veatch (B&V) was retained by Cameron LNG, LLC to evaluate a regression analysis methodology using DOE/EIA AEO2011 sensitivity analysis to determine the price effect from exporting incremental LNG volumes. This analysis is based on the DOE/EIA's 2011 Annual Energy Outlook (AEO2011).[1]

This approach was used to take advantage of the latest market intelligence underlying the EIA's well-documented and public National Energy Modeling System (NEMS). In addition to the thoroughness of EIA's methods and documentation, AEO2011, which extends to 2035, gives a long-term view of price impacts. This approach also allows the results to be compared to those of other case studies based on supply and demand that are published in AEO2011.

Black & Veatch's fuel team has extensive experience with industry leading gas price forecasting models including NARG™, GPCM™, and SAIC/NEMS used for EIA/DOE forecasting. The lead analysts assigned to this project worked as SAIC employees in its federal services division for two years. While there, they analyzed key market drivers for the petroleum market model, oil and gas supply model, and the natural gas transportation models within NEMS. They also analyzed full cycle (extraction to market) energy efficiency curves for the oil and gas sectors (as well as for the metal and non-metal mining sectors) of NEMS.

The approach used in this study was first to use published data on case studies from AEO2011 to estimate the underlying gas supply and demand curves. The intersection of these curves (the equilibrium point) serves as a baseline. The demand curve was then shifted to the right by one Bcf/d to simulate the impact of adding one Bcf/d of liquefaction capacity operating at 100% load factor. The difference between the adjusted and baseline equilibrium points indicates the expected increase in national average delivered prices in 2009 dollars. The price impact for this case of 1.0 Bcf/d increase was determined to range from a high of $0.088/Mcf in 2025 to a low of $0.064/Mcf in 2035.

The results of this analysis, based upon the described methodology and assumptions, are reasonable to provide a general and national overview of the price effect on the average U.S. delivered price of gas resulting from a generic incremental demand of 1.0 Bcf/d attributable to LNG exports.

The result for 1.0 Bcf/d is expected to be scalable up to approximately 2.0 Bcf/d, a volume associated with a generic liquefaction facility. These results are believed to be generally accurate within the range of the sensitivity scenarios conducted by DOE, especially in 2020 when the maximum increase evaluated by DOE along the supply curve was approximately 2.0 Bcf/d. The maximum increase evaluated by DOE was approximately 7.0 Bcf/d in 2035.

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[1] U.S. Energy Information Administration, "AEO 2011 with Projections to 2035, " DOE/EIA-0383(2011), April 2011.

Methodology

B&V was retained by Cameron LNG, LLC to evaluate a regression analysis methodology using DOE/EIA AEO2011 sensitivity analysis to determine the price effect from exporting incremental LNG volumes. This methodology is summarized below.

1. Categorize the forty five (45) published scenarios & national average delivered gas price (2009$) in AEO 2011:

    a. Dominantly affect gas demand and not gas supply (Table 1),
    b. Dominantly affect gas supply but not gas demand (Table 2), or
    c. Significantly affect both gas demand and gas supply (Table 3).

The sorting process and description is provided in the Section entitled "Sorting AEO 201 Cases".

In this analysis AEO2011 case study results were used rather than actual market data. As such, the analysis is an attempt to interpret and apply the supply and demand curves underlying the model used in developing the case studies. Therefore the results should be accurate to the extent that the AEO2011 model reflects real world market behavior, over the range of the scenarios analyzed.

Normally what economists call the "identification problem" means that one cannot easily use market data to estimate supply and demand curves. However, in this special case in which only the demand curve has shifted, as in Table 1, the before and after market clearing prices and quantities can be used to estimate the supply curve. Similarly, in the special case in which only the supply curve has shifted, as in Table 2, the quantities can be used to estimate the demand curve. The data in Table 3 were not used in the analysis because they would be subject to the identification problem.[2]

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[2] *Identification problem: The problem of estimating the parameters of *structural equations when only equilibrium positions can be observed. For example, in the market for a particular good, if demand conditions vary and supply conditions do not, comparing prices and quantities at different times allows us to determine the supply equation; if supply conditions vary and demand conditions do not, we can estimate the demand equation; but if both supply and demand conditions vary, regressing quantity on price tells us nothing. The identification problem can be resolved only if either theory or the results of other studies inform us that some explanatory variables affect one side of the market but not the other.*

Source: Black, John; Hashimzade, Nigar (2009-01-22). A Dictionary of Economics (Oxford Dictionary of Economics) (p. 210). Oxford University Press. Kindle Edition.

Cameron LNG, LLC | PRICE RESPONSE TO INCREMENTAL LNG EXPORT DEMAND **(Based on DOE/EIA Annual Energy Outlook 2011 Forecasts)**

Table 1: AEO 2011 Scenarios Selected That Impact Only the Demand Curve (2009$/Mcf, and All-Sector U.S. Demand in Bcf/d)

	2020		2025		2030		2035	
AEO2011 Case Study	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**
High technology	$6.63	66.4	$7.52	64.2	$7.92	65.5	$8.41	66.4
Low growth	$6.89	67.5	$7.66	65.5	$7.97	66.3	$8.42	66.7
Extended policies	$6.96	68.4	$7.71	66.4	$8.05	67.0	$8.56	67.5
Decreasing costs	$7.07	68.4	$8.01	67.9	$8.43	69.9	$8.90	70.5
Low coal cost	$7.03	68.4	$8.00	67.6	$8.50	70.0	$9.15	72.0
Low renewable cost	$7.08	69.0	$8.00	68.1	$8.43	69.8	$8.89	70.4
High renewable cost	$7.19	69.0	$8.10	68.6	$8.55	71.0	$9.25	73.0
Low E15	$7.08	69.1	$8.04	68.4	$8.49	70.7	$9.13	72.4
Low EOR	$7.19	69.1	$8.03	68.4	$8.50	70.8	$9.19	72.5
Low nuclear cost	$7.13	69.2	$8.03	68.5	$8.45	70.4	$8.95	71.0
HDV fuel economy standard	$7.12	69.3	$8.01	68.5	$8.49	70.8	$9.12	72.5
Low fossil cost	$7.20	69.3	$8.08	68.8	$8.49	70.8	$9.03	71.7
3% LDV fuel economy growth	$7.10	69.3	$8.01	68.3	$8.46	70.5	$9.13	72.2
No Sunset	$7.08	69.4	$7.97	68.5	$8.40	70.2	$8.93	71.3
Reference	$7.13	69.4	$8.01	68.7	$8.48	71.0	$9.14	72.7
Frozen costs	$7.18	69.5	$8.05	68.7	$8.52	71.0	$9.22	72.9
High fossil cost	$7.16	69.5	$8.07	68.7	$8.53	71.1	$9.19	72.8
6% LDV fuel economy growth	$7.10	69.5	$8.01	68.5	$8.50	70.8	$9.12	72.9
High nuclear cost	$7.18	69.5	$8.04	68.7	$8.49	70.9	$9.17	72.6
Low oil price	$6.94	69.6	$7.67	68.6	$8.24	70.0	$8.72	72.7
Traditional low oil price	$6.94	69.6	$7.67	68.6	$8.24	70.0	$8.72	72.7
High E15	$7.18	69.6	$8.01	68.6	$8.51	70.9	$9.16	72.7
Transport mercury MACT 20	$7.15	69.8	$8.11	69.5	$8.49	71.7	$9.16	73.5
High oil price	$7.28	70.0	$8.25	69.2	$8.71	71.2	$9.30	73.5
Traditional high oil price	$7.28	70.0	$8.25	69.2	$8.71	71.2	$9.30	73.5
High coal cost	$7.22	70.0	$8.15	69.8	$8.69	72.8	$9.38	75.7
Low technology	$7.28	70.5	$8.42	70.8	$8.84	74.2	$9.53	77.3
Transport mercury MACT 5	$7.26	70.5	$8.21	70.5	$8.59	72.5	$9.25	74.8
High growth	$7.42	71.2	$8.52	71.6	$9.12	76.1	$9.48	81.2

Table 2. AEO 2011 Scenarios Selected That Impact Only the Supply Curve (2009$/Mcf, and All-Sector U.S. Demand in Bcf/d)

	2020		2025		2030		2035	
AEO2011 Case Study	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**
Low shale recovery per well	$9.11	61.7	$10.59	61.6	$10.45	65.2	$11.39	66.1
Low shale recovery per play	$8.11	65.0	$9.45	64.0	$9.59	66.9	$10.23	69.5
Slow oil/gas technology	$7.76	66.5	$8.90	65.4	$9.46	67.7	$9.73	71.0
High OCS costs	$7.19	69.1	$8.07	68.3	$8.50	70.7	$9.19	72.3
High OCS resource	$7.10	69.2	$8.00	68.6	$8.45	71.1	$8.95	73.4
OCS access	$7.12	69.4	$8.05	68.6	$8.52	70.9	$9.18	72.4
Reference	$7.13	69.4	$8.01	68.7	$8.48	71.0	$9.14	72.7
Rapid oil/gas technology	$6.63	72.0	$7.38	71.0	$7.85	73.5	$8.51	75.2
High shale recovery per play	$6.46	73.0	$7.21	72.4	$7.62	74.9	$8.11	77.4
High shale recovery per well	$5.84	75.9	$6.50	76.1	$6.98	78.4	$7.42	81.2

Table 3. AEO 2011 Scenarios Selected That Impact Both Demand and Supply Curves (Excluded from Analysis) (2009$/Mcf, and All-Sector U.S. Demand in Bcf/d)

	2020		2025		2030		2035	
AEO2011 Case Study	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**	**Price**	**Demand**
AEO2010 Reference	$8.81	62.0	$9.13	64.6	$10.17	25.0	$11.00	68.1
Retrofit 20	$7.00	67.6	$7.95	67.8	$8.49	21.8	$9.20	73.2
Early release	$7.23	68.9	$8.08	68.4	$8.58	22.1	$9.26	72.5
Retrofit 5	$7.12	68.9	$8.27	69.9	$8.67	22.7	$9.28	75.8
No GHG concern	$7.13	69.2	$7.98	68.3	$8.40	21.9	$9.04	71.7
Low EOR - GHG price	$8.93	73.5	$10.03	74.9	$12.05	27.5	$13.12	81.2
GHG price	$8.95	73.6	$10.02	74.8	$12.05	27.5	$13.10	81.3
Retrofit 20, low gas price	$5.74	75.1	$6.36	75.7	$6.90	17.4	$7.33	81.7
Retrofit 5, low gas price	$5.81	76.6	$6.56	77.6	$7.08	18.0	$7.55	84.2

2. Run a regression analysis for the selected supply and demand scenarios

The supply curve resulting from the data in Table 1 is a positively sloping line (low supply when price is low, high supply stimulated when price is high). The 2020 supply curve price elasticity is approximately 0.7, meaning a 1.0% increase in price results in about a 0.7% increase in quantity supplied. By 2035 price elasticity is approximately 1.5 indicating that supply becomes more elastic to price.

The demand curve resulting from the data in Table 2 is a negative sloping line (low price stimulates high demand; high price results in low demand). The 2020 and 2035 demand curve price elasticity is approximately -0.5, meaning a 1.0% increase in price results in about a 0.5% reduction in quantity demanded. The demand curve price elasticity is approximately the same over this 15-year period.

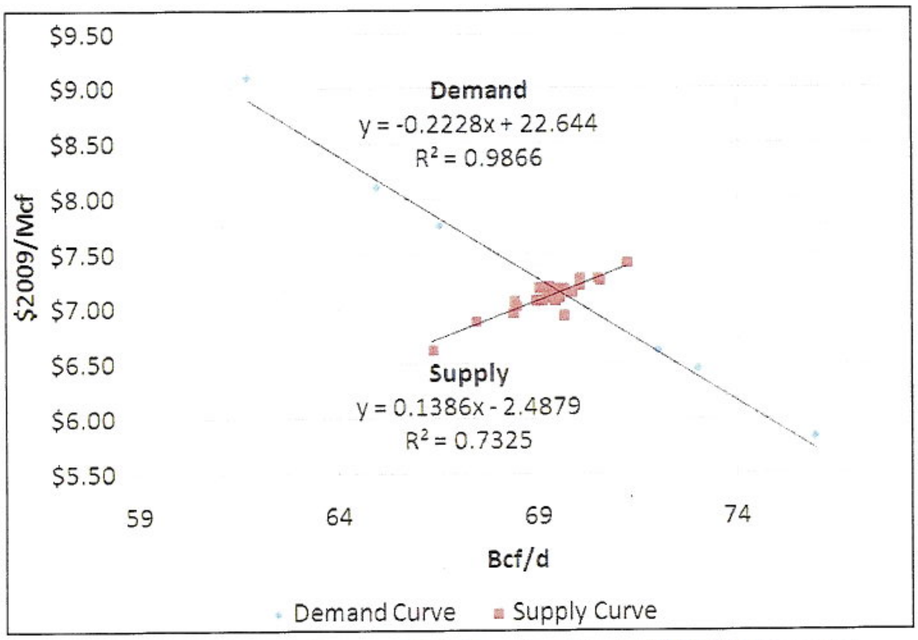


Figure 1:Demand and Supply Curves – 2020, Based on Selected AEO 2011 Scenarios

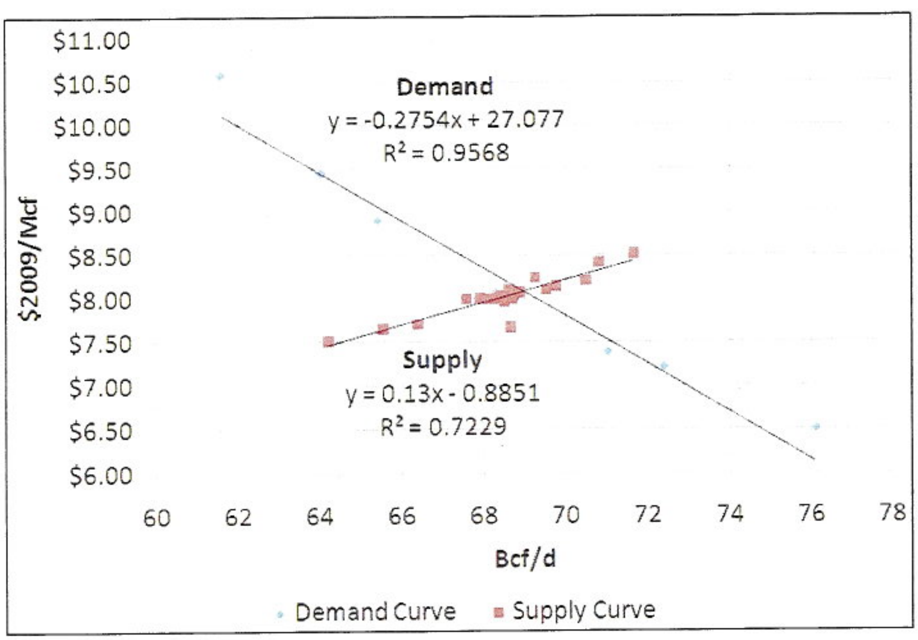


Figure 2.Demand and Supply Curves – 2025, Based on Selected AEO 2011 Scenarios

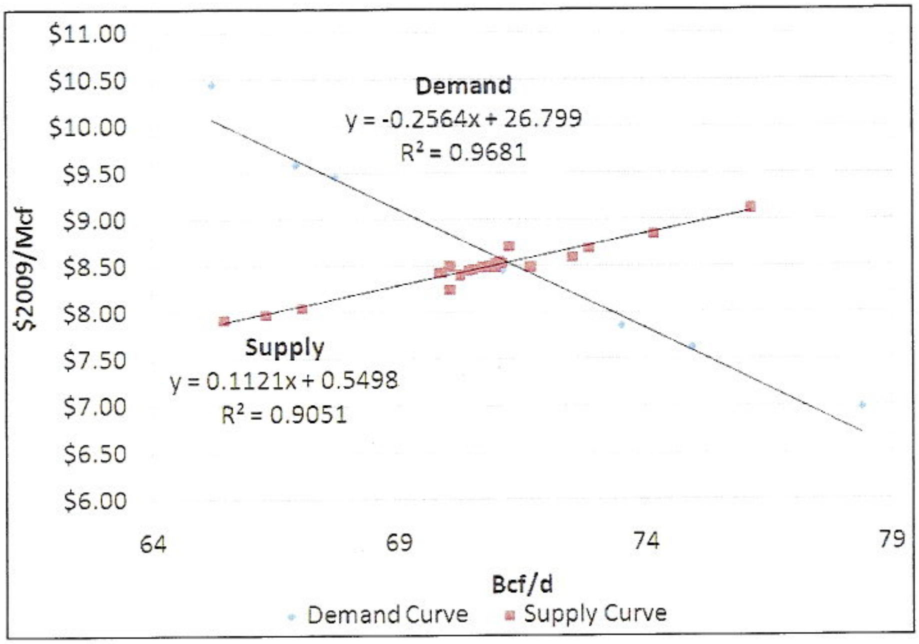


Figure 3.Demand and Supply Curves – 2030, , Based on Selected AEO 2011 Scenarios

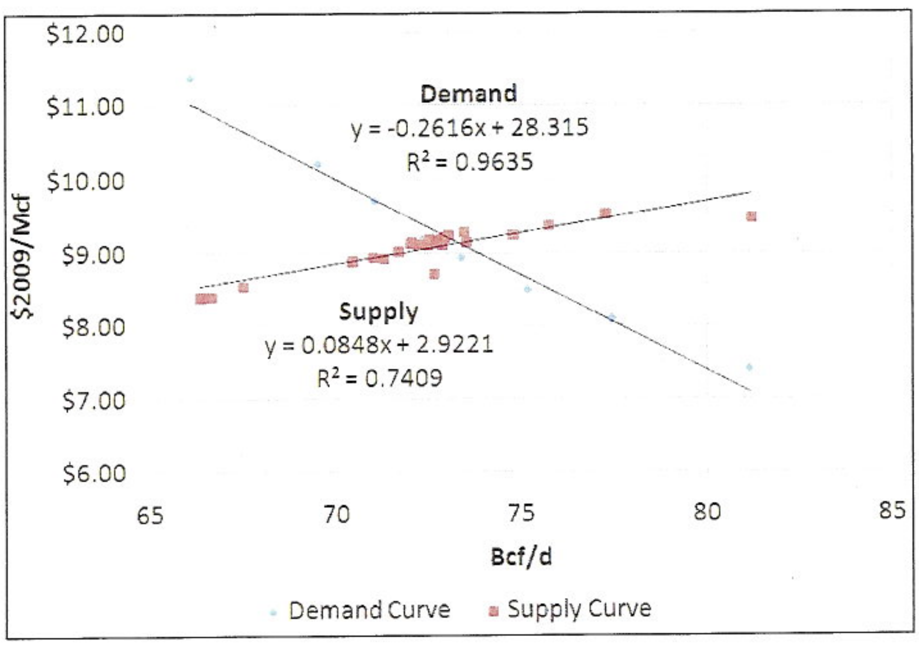


Figure 4. Demand and Supply Curves – 2035, Based on Selected AEO 2011 Scenarios

3. Where the supply curve and the demand curve intersect is the annual equilibrium point where price is balanced between demand and supply. This equilibrium price for four designated periods (Figures 1-4) is summarized below and is close to the DOE's average national delivered price (2009$) for their Reference Case.

Table 4. Comparison of Equilibrium Price Based on Selected Methodology with DOE AEO 2011 Reference Case Average Delivered Price (2009$/Mcf)

	EQUILIBRIUM PRICE	DOE AVERAGE DELIVERED PRICE
2020	7.150	7.13
2025	8.082	8.01
2030	8.535	8.48
2035	9.138	9.14

The addition of liquefaction demand would have the effect of increasing the demand for gas without affecting the shape of the demand curve. Therefore, the estimated demand and supply curves and their equilibrium point were used to calculate that effect of increasing demand (negative slope) by 1.0 Bcf/d. This is accomplished by shifting the demand line 1.0 Bcf/d to the right while keeping the supply curve unchanged (Figure 5).

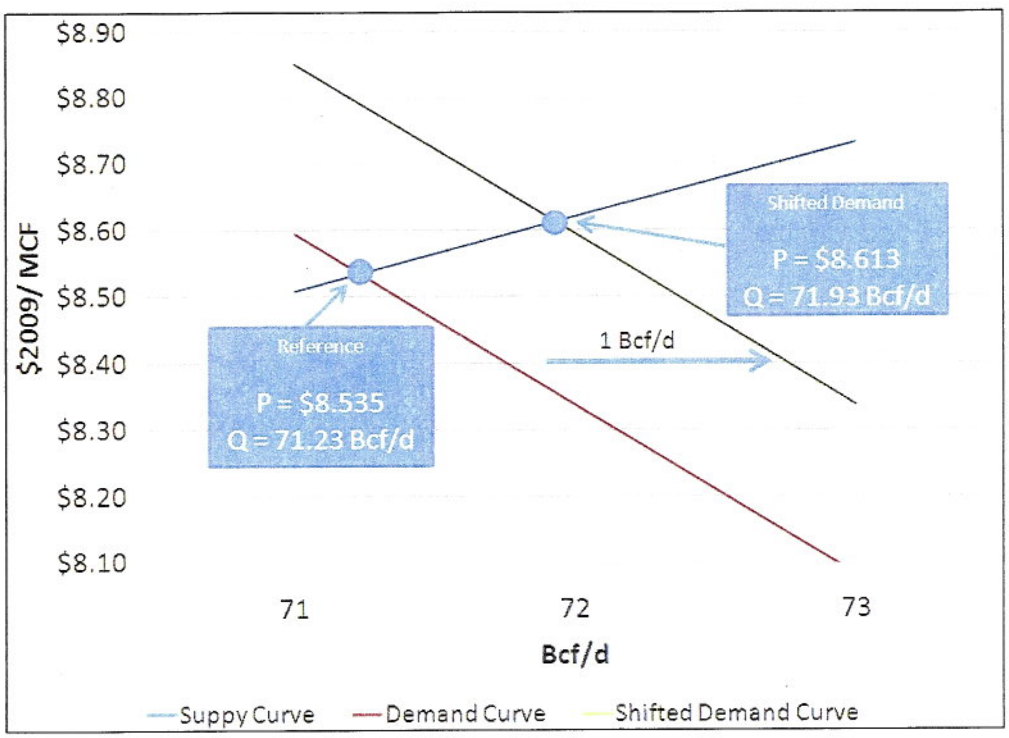


Figure 5. Shifting Demand Curve by 1.0 Bcf/d in 2030

Results

The results are shown below in Table 5 for a 1.0 Bcf/d demand curve shift.

Table 5. Price and Supply Response as Result of 1.0 Bcf/d Demand Increase

	EQUILIBRIUM PRICE RESPONSE 2009$/MCF			NET SUPPLY RESPONSE (BCF/D)		
	Equilibrium Price	Demand Shift Price	Difference	Equilibrium Demand	Demand Shift	Difference
2020	7.150	7.235	0.085	69.540	70.156	0.616
2025	8.082	8.170	0.088	68.975	69.653	0.678
2030	8.535	8.613	0.078	71.233	71.928	0.695
2035	9.138	9.202	0.064	73.305	74.060	0.755

These results indicate that a 1.0 Bcf/d change in total U.S. demand in 2020, due to new liquefaction load, would result in an estimated $0.085 increase per Mcf in U.S. average delivered gas price. This same 1.0 Bcf/d change would result in increases of $0.088 per Mcf in 2025, $0.078 per Mcf in 2030, and $0.064 per Mcf in 2035.

The results of this analysis, based upon the described methodology and assumptions, are reasonable to provide a general and national overview of the price effect on the average U.S. delivered price of gas resulting from a generic incremental demand of 1.0 Bcf/d attributable to LNG exports.

Limitations

- The results are accurate only to the extent that the DOE models used in AEO2011 reflect real world market behavior for a 1.0 Bcf/d demand increase and scalable up to about 2.0 Bcf/d related to a generic U.S. liquefaction facility.
- Some "affect demand only" points near the intersection of the demand and supply curves may also have small supply impacts, although the effect if any on the supply curve regression coefficients is believed to be minimal.
- The progressive flattening of the supply curve as indicated by their coefficients (approximately 0.14 in 2020 to 0.08 in 2035 as shown in Figures 1-4) is believed to reflect the flattening of the long run marginal cost of supply due to gains in technology efficiency and other factors incorporated in the DOE analyses.
- The results are believed to be accurate within the range of the sensitivity scenarios conducted by DOE. In 2020 the maximum increase evaluated by DOE along the supply curve was about 1.7 Bcf/d. By 2035 the maximum increase evaluated was approximately 7 Bcf/d, although there is some indication that the supply curve had begun to flatten out at a level lower than 7 Bcf/d, as can be seen in Figure 4.

Sorting AEO 2011 Cases

This section sorts the 45 cases with available gas and price data into one of three categories:

- Gas supply-only
- Combined gas supply and demand
- Gas demand-only

Two other reported cases, the AEO2010 Reference case and the 2011 Early Release case were based on other models and therefore were not used.

The supply-only cases are believed to shift the supply curve and not affect the demand curve. The equilibrium price and quantity points in these cases are used to trace out the demand curve. The demand-only cases are believed to shift only the demand curve and not affect the supply curve. The equilibrium price and quantity points in these cases are used to trace out the supply curve.

The cases believed to affect both the supply and demand curve were not used in the analysis.

GAS SUPPLY-ONLY CASES

Introduction

The gas supply-only cases are believed to make no changes to the demand for natural gas that would impact the natural gas demand curve. As the starting point, the Reference Case is applicable as both a gas demand-only case and a gas supply-only case. AEO2011 included four cases that made changes to the recovery per shale gas well and or the required number of wells in each gas play is changed.

Following is a brief description of each case for which gas price and quantity forecasts are available.

AEO 2011 Gas Supply-only Cases

Reference Case

- **Reference case:** Current laws and regulations affecting the energy sector remain unchanged and current sunset dates do not change. Economic output as measured by real GDP increases by 2.7 percent per year from 2009 through 2035. Oil prices of $125 per barrel (2009 dollars) in 2035. Capital cost of greenhouse gas intensive technologies increased by 3 percentage points.

Oil and Gas Supply Cases

- **Low Shale EUR case:** Estimated ultimately recovery (EUR) per shale gas well is assumed to be 50 percent lower than in the Reference case., increasing the per-unit cost of developing the resource.
- **High Shale EUR case:** Estimated ultimate recovery (EUR) per shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource.
- **Low Shale Recovery case:** Total unproved technically recoverable shale gas resource base is the same as in the Low Shale Estimate Ultimate Recovery case (423 trillion cubic feet), but instead of decreasing the EUR per well, the estimate of the number of wells that need to be drilled to fully recover the shale gas in each play is assumed to be 50 percent lower than in the

Reference case. This means that the per-unit cost of developing the resource is the same as in the Reference case.

- **High Shale Recovery case:** Total unproved technically recoverable shale gas resource base is the same as in the High Shale Estimated Ultimate Recovery case (1,230 trillion cubic feet), but instead of increasing the EUR per well, the estimate of the number of wells that need to be drilled to fully recover the shale gas in each play is assumed to be 50 percent higher than in the Reference case. This means that the per-unit cost of developing the resource is the same as in the Reference case.
- **Slow Oil and Gas Technology case**: Parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for conventional and unconventional oil and natural gas drilling are 50 percent less optimistic than those in the Reference case.
- **Rapid Oil and Gas Technology case:** Parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for conventional and unconventional oil and natural gas drilling in the Reference case are improved by 50 percent.
- **Reduced OCS Access case:** No new oil or gas lease sales occur in the Eastern Gulf of Mexico, Pacific, Atlantic, and Alaska OCS through 2035.
- **High OCS Resource case:** Oil and natural gas resources in undeveloped areas of the OCS (namely the Pacific, Eastern Gulf of Mexico, Atlantic, and Alaska) are assumed to be 3 times higher than in the Reference case.
- **High OCS Costs case:** Costs of exploration and development of oil and natural gas resources in the OCS are assumed to be 30 percent higher than in the Reference case.

COMBINED GAS DEMAND AND SUPPLY CASES

Introduction

Combined cases are believed to have at least some impact on both the natural gas supply curve and the natural gas demand curve.

- In the electricity sector the cases combine retrofit cases, which impact the gas demand curve through fuel substitution, with lower gas prices, which implies a shifted supply curve.
- The oil and gas supply cases modify the supply of oil, which impacts the gas demand curve through fuel substitution and the costs or access to gas, which modifies the gas supply curve.
- The greenhouse (GHG) scenarios impact the relative costs of other energy sources, which impacts the gas demand curve, and the cost of gas directly through carbon taxes, which impacts the gas supply curve.

Following is a brief description of each case for which gas price and quantity forecasts are available.

AEO 2011 Combined Cases

Electricity Sector Cases

- **Retrofit Required 5 case:** Represents stringent requirements for reductions in airborne emissions from coal-fired power plants. Investments in retrofits are assumed to be recovered over a 5-year period.
- **Retrofit Required 20 case:** Same requirements as above, but investments in retrofits are assumed to be recovered over a 20-year period.
- **Low Gas Price Retrofit Required 5 case:** Identical to the Retrofit Required 5 case but adds an assumption of increased availability domestic shale availability and utilization rate, as in the High Shale EUR case.
- **Low Gas Price Retrofit Required 20 case:** Identical to the Low Gas Price Retrofit Required 5 case, but investments in retrofits are assumed to be recovered over a 20-year period.

Cross-cutting Integrated Cases

- **GHG Price Economywide case:** Economy-wide carbon allowance greenhouse gas (GHG) price is examined.
- **No GHG Concern case:** Run without any adjustment for concern about potential greenhouse gas (GHG) regulations.
- **Low EOR - GHG Price Economywide case:** *Low Lo*C Low Combines the assumptions of the low enhanced oil recover (EOR) and the green house gas price economywide cases. Enhanced oil recoveryCO2 availability is reduced and a carbon price exists that provides incentives for emitters to install carbon capture capabilities.

GAS DEMAND-ONLY CASES

Introduction

The gas demand-only cases are believed to make no changes to the price or availability of natural gas that would impact the natural gas supply curve. Once all cases that impact on the gas supply curve have been removed the remaining cases should impact only the demand curve, although in some cases that impact may be small. As the starting point, the Reference Case is applicable as both a gas demand-only case and a gas supply-only case.

Following is a brief description of each case for which gas price and quantity forecasts are available.

AEO 2011 Gas Demand-only Cases

Reference Case

- **Reference case:** Current laws and regulations affecting the energy sector remain unchanged and current sunset dates for laws do not change. Economic output as measured by real GDP increases by 2.7 percent per year from 2009 through 2035. Oil prices of $125 per barrel (2009 dollars) in 2035. Capital cost of greenhouse gas intensive technologies increased by 3 percentage points.

Macroeconomic Growth Cases

- **Low Economic Growth case:** *E*conomic output as measured by real GDP increases by 2.1 percent per year from 2009 through 2035.

- **High Economic Growth case:** Economic output as measured by real GDP grows at 3.2 percent per year from 2009 through 2035.

Oil Price Cases

- **High Oil Price case:** World oil prices reach about $200 per barrel (2009 dollars) in 2035.
- **Low Oil Price case (primary low price case):** world crude oil prices are only $50 per barrel (2009 dollars) in 2035.
- **Traditional High Oil Price case:** OPEC countries are assumed to reduce their production from the current rate.
- **Traditional Low Oil Price case:** OPEC countries increase their conventional oil production to obtain a 52-percent share of total world liquids production.

Industrial Sector Cases

- **Frozen Plant Capital Cost case:** Holds the energy efficiency of new plant and equipment constant at the 2010 level over the projection period.
- **Decreasing Plant Capital Cost case:** Earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes.

Transportation Sector Cases

- **CAFE 3% Growth case**: Examines the impact of increasing corporate average fuel economy (CAFE) fuel economy standards by 3% annually through 2025.
- **CAFE 6% Growth case**: Examines the impact of increasing corporate average fuel economy (CAFE) fuel economy standards by 6% annually through 2025.
- **Heavy-Duty Vehicle Fuel Economy Standards case:** Simulates the expected fuel economy impact of the fuel economy standards for heavy-duty vehicles for model years 2014 through 2018.

Electricity Sector Cases

- **Low Nuclear Cost case:** Reflects a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2011, falling to 40 percent below the Reference case in 2035.
- **High Nuclear Cost case:** Capital costs for advanced nuclear technology remain fixed at the 2011 levels.
- **Low Fossil Technology Cost case:** Capital costs and operating costs for all coal- and natural-gas-fired generating technologies start 20 percent lower than Reference case levels and fall to 40 percent lower than Reference case levels in 2035.
- **High Fossil Technology Cost case:** Capital costs for all coal- and natural-gas-fired generating technologies remain fixed at the 2011.
- **Transport Rule Mercury MACT 5 case:** Air Transport Rule limits on SO2 and NOx and a 90-percent mercury MACT (maximum achievable control technology) are enacted. A 5-year recovery period for investments in environmental control projects is assumed.
- **Transport Rule Mercury MACT 20 case:** Same rules as above, but a 20-year recovery period for investments in environmental control projects is assumed.

Renewable Fuels Cases

- **Low Renewable Technology Cost case:** Levelized costs of energy resources for generating technologies using renewable resources are assumed to start at 20 percent below Reference case assumptions in 2011 and decline to 40 percent below the Reference case costs for the same resources in 2035.

- **High Renewable Technology Cost case:** Capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, geothermal, and renewable liquid fuel technologies are assumed to remain constant at 2011 levels through 2035.

Coal Market Cases

- **Low Coal Cost case:** Average annual growth rates for coal mining productivity are higher than those in the Reference case and are applied at the supply curve level.
- **High Coal Cost case:** Average annual productivity growth rates for coal mining are lower than those in the Reference case.

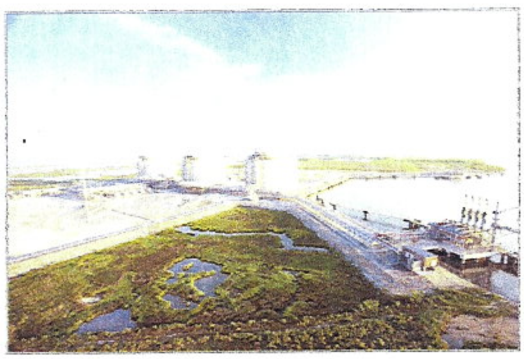
Cross-Cutting Integrated Cases

- **Integrated Low Technology case:** *C*ombines the assumptions from the Residential, Commercial, and Industrial 2010 Technology cases and the Electricity High Fossil Technology Cost, High Renewable Technology Cost, and High Nuclear Cost cases.
- **Integrated High Technology case:** *C*ombines the assumptions from the Residential, Commercial, and Industrial High Technology cases and the Electricity Low Fossil Technology Cost, Low Renewable Technology Cost, and Low Nuclear Cost cases.
- **Low EOR case:** Industrial CO2 available from coal-to-liquids and biomass to liquids plants is reduced by 50 percent from the Reference case due to low enhanced oil recovery (EOR).
- **No Sunset case:** Selected policies with sunset provisions like the PTC, ITC, and tax credits for energy-efficient residential, commercial, industrial, refinery, and renewables equipment in the buildings and industrial sectors will be extended indefinitely rather than allowed to sunset.
- **Extended Policies case:** Existing policies are extended as in the No Sunset Case, plus new standards and tax credits are added or extended.
- **Low E15 Penetration case:** Infrastructure and regulatory barriers to 15% ethanol (E15) adoption are more pronounced, and penetration of E15 in all demand regions grows at a slower rate.
- **High E15 Penetration case:** 15% ethanol (E15) adoption occurs at a faster rate and reaches a higher overall level than in the Reference case.

APPENDIX D

Economic Impact Assessment

LNG Exports from Cameron Terminal



Cameron LNG, LLC

December 2011

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1. Introduction

The objective of this analysis is to provide an assessment of the economic impact that the production and export of liquefied natural gas (LNG) from Cameron LNG would have on the U.S. economy, including:

- Improved national balance of trade
- Increase in national output
- Increase in employment
- Increase in employee wages

Key assumptions include:

- The Cameron LNG liquefaction plant will make use of existing facilities at the site, including marine facilities, loading and unloading facilities, storage tanks and control buildings.
- LNG exports will average 12 mtpa of LNG (approximately 1.7 Bcfd) over the plant's 20-year project life,[1] with an additional 0.2 Bcfd required for its operation.[2]
- The liquefaction plant is assumed to be operational from 2017 to 2036.

This analysis is derived from the latest publicly available forecasts, data and analyses. These include: (1) energy prices from the Energy Information Administration's 2011 Annual Energy Outlook (AEO2011), (2) employment and other economic statistics from the 2007 Economic Census by the U.S. Census Bureau, and (3) multipliers developed by the Bureau of Economic Analysis (BEA) from its Regional Input-Output Modeling System (RIMS II)[3].

2. Summary

Key findings of this analysis include:

- U.S. balance of trade over the project's lifetime will be improved by $166 billion in 2011 dollars for LNG priced at 50% of oil parity to $265 billion in 2011 dollars for LNG priced at 90% of oil parity.

- U.S. national output is expected to increase $253 billion to $403 billion in 2011 dollars over the project life.

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[1] For purposes of this analysis the project operating life is assumed to be the same as the anticipated 20 year export license.

[2] Actual liquefaction volumes and related economic impacts may vary depending on customer requirements in response to relative world gas prices.

[3] RIMS II multipliers produced for Cameron LNG, LLC by the Regional Product Division of the Bureau of Economic Analysis on 10/16/2011.

- Direct employment in the gas industry is expected to increase by approximately 2,900 jobs during the peak 12-month construction period and by 98,000 job-years over the project life.
- Total employment in the U.S. economy, including the gas industry, is expected to increase by an estimated 63,000 job-years over the 48-month construction period and 53,000 jobs per year over the 20-year period of plant operation, totaling almost 1.1 million job-years over the project's lifetime.
- Total economy-wide wage gains are estimated to average $717 million per year in 2007 dollars during the 48-month period of plant construction, and $2.1 billion per year in 2007 dollars during the period of plant operation. The total economy-wide wage gain impact over the project's life is estimated to be $45 billion in 2007 dollars.

3. Analysis

The following are details related to the development of these key findings.

a) Improved National Balance of Trade

The improvement in U.S. balance of trade resulting from Cameron LNG's liquefaction and LNG exports was examined as an important component of economic goals.[4] As illustrated in Chart 1, the seemingly unsustainable U.S. trade deficit has been a lingering problem, with petroleum product imports becoming an increasingly important factor. LNG exports from a liquefaction plant at Cameron LNG can contribute toward offsetting petroleum product imports and helping reduce the overall trade deficit.

[4] When combined with other U.S. LNG export facilities one result may be reduced world-wide LNG prices, which would in turn increase LNG demand, particularly through conversion from coal for economic and environmental reasons. This may reduce the balance of trade impacts towards the lower end of the 50% to 90% of oil price parity price range considered here.

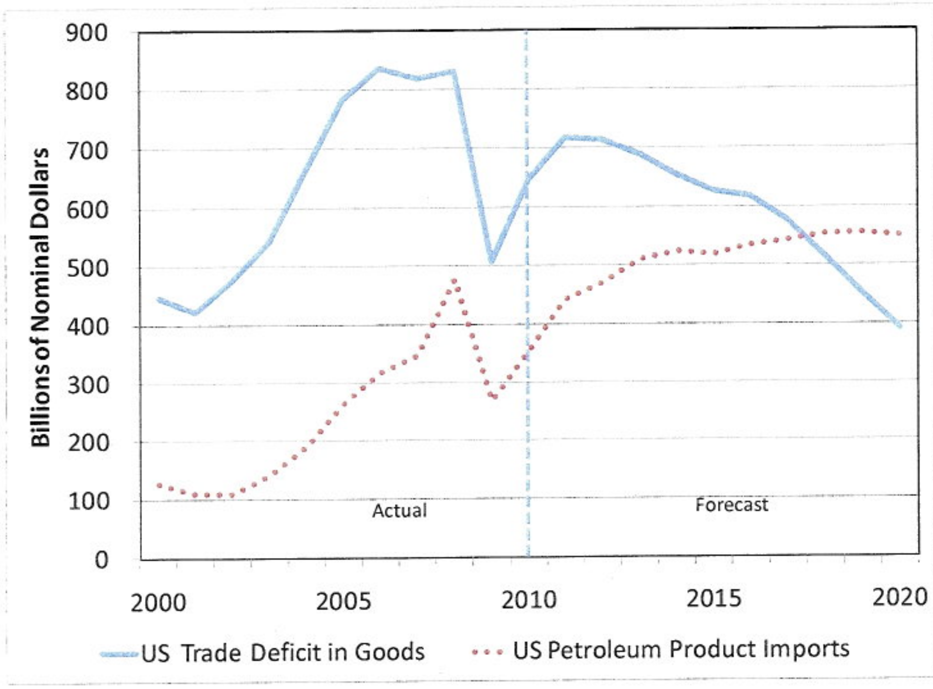

Chart 1: Trade Deficit and Petroleum Product Imports with Forecasts by IHS Global Insight[5]

Since the full output of the liquefaction plant will be exported, the total sale price of the LNG will appear as an improvement in the U.S. balance of trade (not considering shipping costs). In addition, oil and condensate (C&C) and NGL recovered during natural gas production will largely be used in the U.S. market and displace imports, also contributing toward an improved balance of trade. The total cumulative improvement in U.S. balance of trade over the project's 20-year life is estimated to be between $166 billion to $265 billion in 2011 dollars, depending on the sales price of LNG. The mid-range

[5] Historic data from the US Bureau of Economic Analysis. August 2011 forecasts by IHS Global Insight used with permission.

estimate over the life of the project is $215 billion, as shown in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
2020	$9.95	$15.15	46,931	$1.9
2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
2025	$10.83	$16.49	51,093	$2.1
2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
2029	$11.27	$17.16	53,157	$2.2
2030	$11.33	$17.26	53,461	$2.2
2031	$11.38	$17.32	53,663	$2.2
2032	$11.40	$17.36	53,766	$2.2
2033	$11.42	$17.39	53,879	$2.2
2034	$11.44	$17.42	53,962	$2.2
2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3.

The 2011 to 2035 oil price reference case forecast contained in the AEO2011 is the basis for the estimate, with increases in oil prices after 2035 extrapolated at approximately 0.15% per year in real dollars, as detailed in Figure A- 1 in the Appendix. Depending on market conditions and market region, LNG export prices are expected to range between 50% and 90% of the equivalent amount of oil on an energy basis (i.e., 50% to 90% of oil parity). In Northeast Asia, the common historical long-term contract price is 86% of oil price parity.[6] In Europe, oil-indexed gas prices have historically been lower, averaging 65% to 70% of oil price parity.[7]

Chart 2 illustrates the annual improvement in balance of trade, assuming a price of exported LNG at 70% of oil price parity.

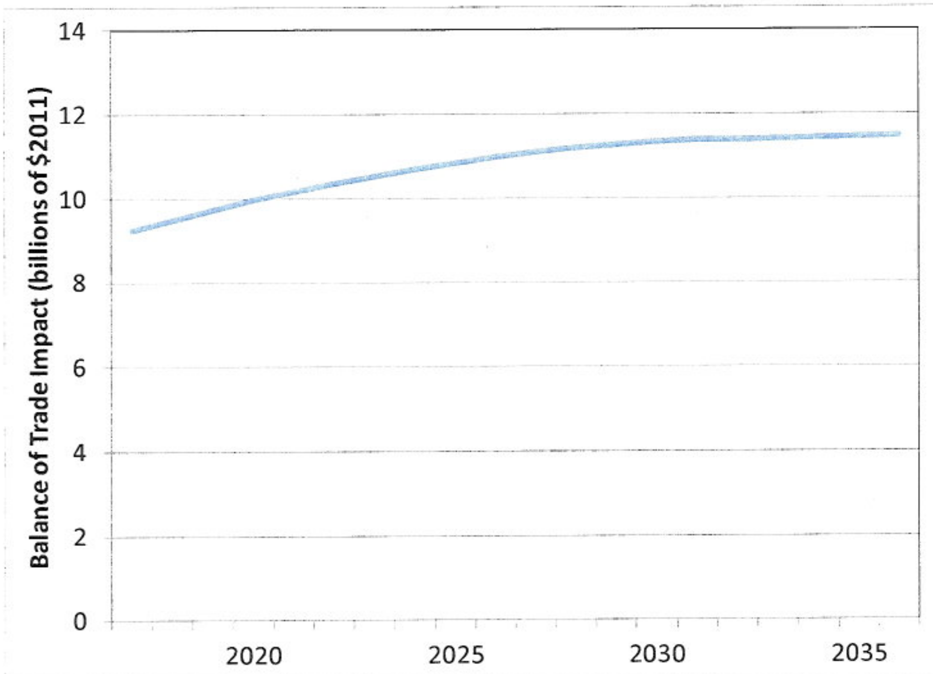

Chart 2: Balance of Trade Impact of Cameron Facility

b) Increase in National Output

Direct Output Impact of Cameron LNG Liquefaction Plant Construction

During construction, the direct output impact of the Cameron LNG liquefaction plant will equal the construction cost, which, for the limited purposes of this analysis, is estimated to be $4.2 billion, assuming a 12 mtpa plant and a cost of $350 per tonne of LNG capacity per annum.

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[6] Energy Charter Secretariat, "Developments in LNG Trade and Pricing," pg. 33, 2009, based on the common multiplier per MMBtu of gas of 0.1485 times the price of crude oil per barrel.

[7] Oxford Institute for Energy Studies, "LNG Trade-flows in the Atlantic Basin: Trends and Discontinuities," figures 18 and 19, March 2010.

Economy-wide Output Impacts

The final demand output multiplier for construction is 1.8106, which is applied to the plant construction cost of $4.2 billion to result in a total output impact of $7.6 billion spread over the 48-month construction period.

With all the LNG output exported, the impact of output on the gas industry during the period of plant operation will equal the balance of trade benefits in addition to the impacts on the gas pipeline sector and on the Cameron LNG facility. The direct output impact on the gas extraction industry is estimated to be between $166 billion and $265 billion in 2011 dollars over the life of the project, matching the trade balance improvements shown in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
2020	$9.95	$15.15	46,931	$1.9
2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
2025	$10.83	$16.49	51,093	$2.1
2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
2029	$11.27	$17.16	53,157	$2.2
2030	$11.33	$17.26	53,461	$2.2
2031	$11.38	$17.32	53,663	$2.2
2032	$11.40	$17.36	53,766	$2.2
2033	$11.42	$17.39	53,879	$2.2
2034	$11.44	$17.42	53,962	$2.2
2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3.

The final demand output multiplier for the oil and gas extraction sector is 1.5228, which results in a total economy-wide impact on output ranging from $253 billion to $403 billion in 2011 dollars over the period of plant operation.

As shown in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
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2021	$10.16	$15.47	47,925	$2.0
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2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
2025	$10.83	$16.49	51,093	$2.1
2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
2029	$11.27	$17.16	53,157	$2.2
2030	$11.33	$17.26	53,461	$2.2
2031	$11.38	$17.32	53,663	$2.2
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2033	$11.42	$17.39	53,879	$2.2
2034	$11.44	$17.42	53,962	$2.2
2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3, the total mid-range estimate is $328 billion over the life of the project, including the periods of construction and operation.

c) Increase in Employment

The resulting increase in employment includes direct and identified employment changes in addition to indirect effects on the economy captured through employment multipliers. The BEA developed a method for estimating regional input-output (I-O) multipliers using its Regional Industrial Multiplier

System (RIMS).[8] To aid in this analysis, Cameron LNG, LLC purchased a customized set of multipliers from the BEA for a region in Louisiana that includes the parishes of Allen, Beauregard, Calcasieu, Cameron and Jefferson Davis.[9]

Gas Industry Only Employment Impacts

The employment impacts of the Cameron LNG liquefaction facility can generally be divided in two: impacts during construction and impacts during operation.

Figure A- 2 in the Appendix illustrates a typical work force schedule for a liquefaction plant similar to the one proposed for Cameron LNG. The employment average over the peak 12-month construction period is approximately 2,900 jobs, and total employment on-site over the full 48-month construction period, including the periods of project ramp-up and final commissioning, is estimated to be 5,209 job-years.[10]

During plant operation, the primary direct impact on employment is expected to be in the exploration, production, gathering, processing and transmission of natural gas. Other direct jobs in the natural gas industry will be in the operation of the Cameron LNG liquefaction facility. According to the 2007 Economic Census, there were 150,443 jobs in oil and gas extraction (NAICS code 211). The reported product shipments indicate that 65.3% of the energy value was for natural gas, so the number of jobs was reduced to 98,262, which is 65.3% of 150,443. An additional 24,519 jobs in gas pipelines (NAICS code 4862) brings the total number of jobs to 122,781. This number divided by the average gas production of 51.6 Bcfd, as reported in the Economic Census,[11] results in an average of 2,400 natural gas industry jobs per Bcfd of produced natural gas. Based on this, a 1.9 Bcfd input plant would produce 4,600 jobs.

Given the incremental Cameron LNG operations employment of 65, the direct natural gas industry impact of a 1.9 Bcfd input plant is 98,000 cumulative job-years over the project's lifetime.[12]

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[8] U.S. Department of Commerce, "Regional Multipliers – A User Handbook for the Regional Input-Output Modeling System (RIMS II)," Third Edition, March 1997.

[9] Multipliers vary somewhat from region to region, and may differ from those of the Lake Charles area depending on the sources of the gas delivered to the Cameron facility.

[10] Cameron's construction employment forecast is based on full-time equivalent (FTE) employees, while the employment multipliers are based on the total of full- and part-time jobs. This suggests that the resulting job impacts estimates are conservatively low.

[11] Dry gas production in 2007 is reported by the EIA to have averaged 52.8 Bcfd. However, the somewhat lower value reported in the 2007 Economic Census is used here for internal consistency.

[12] Calculation detail: 5,209 job-years during construction plus 4,700 jobs per year over the period of operation (4,600 oil and gas extraction jobs plus 65 Cameron LNG jobs) equals 98,000 job-years after rounding.

Economy-wide Employment Impacts

The BEA describes two primary approaches for estimating economy-wide employment impacts. The first approach applies a multiplier to the number of jobs created in the industry sector directly affected. The second approach applies a final demand multiplier to the dollar output of the industry sector directly affected. In theory, these approaches should produce similar results. However, the large investment per construction employee and the large increase in expected LNG prices in relation to gas prices at the time of the 2007 Economic Census ($5.11 per Mcf) causes a significant difference between the results based on direct employment and the results based on output value or purchases. The approach using a final demand multiplier was selected as better reflecting the ultimate impact on the U.S. economy, including the direct and indirect impacts from equipment manufacturing and from increased investments in the economy resulting from export and reduced import revenues.

During Construction

The final demand employment multiplier for construction, as developed by the BEA for the region that includes Cameron LNG, is 15.0994 jobs per million dollars of output. This results in direct and indirect employment impacts of 63,000 job-years when applied to the plant construction cost of $4.2 billion. As a check on the reasonableness of this result, it is noted that the multiplier of 15.0994 jobs per million dollars of output means that each $66,000 of plant construction creates one job for one year somewhere in the U.S. economy.

During Plant Operation

The final regional demand employment multiplier is 4.7172 jobs per million dollars of output value in the oil and gas extraction sector (i.e., $211,000 per job in the U.S. economy) . Assuming LNG at 70% of crude oil parity in 2030 (see Figure A- 1), the average net export value is $11.3 billion. Therefore, the economy-wide impact results in approximately 53,000 jobs. This approach may be inaccurate to the extent that the added value of the LNG is invested in ways that vary from input-output flows in 2008. However, it is to be noted that the final-demand employment multiplier of 4.7172 for the oil and gas extraction sector is one of the lowest of 62 sectors, which have a median multiplier of 10.6 jobs per million dollars of output. This suggests that if future investment patterns vary from those of the past, the effect is likely to increase the impact beyond 53,000 full- and part-time economy-wide jobs resulting from the 1.9 Bcfd input plant.

Discussion

One study, which covers all 50 states and most business sectors, addressed the issue of multipliers, and found that foreign export employment multipliers are significantly greater than domestic multipliers. As a result the impacts may be more than estimated here. Specifically, the study notes that:

> This article attempts to show that foreign exports have a more dramatic impact on a state's employment than do domestic exports. Empirical testing revealed that in the aggregate the foreign export employment multiplier was almost five times larger than the domestic export multiplier.[13]

Another relevant analysis is the finding by the U.S. Department of Agriculture that each $1 billion of U.S. agricultural exports in 2009 required 8,400 U.S. workers engaged in both direct and indirect supporting activities.[14] When this multiplier is applied to the $11.3 billion LNG export estimate of the Cameron LNG facility, the result is an economy-wide impact of approximately 95,000 jobs.

The U.S. International Trade Administration also examined the impact of exports on jobs and found that in 2008, 10.3 million U.S. jobs were supported by exports, with each $165,000 of exports resulting in one U.S. job. For a 1.9 Bcfd plant, using this multiplier would result in an economy-wide impact of 69,000 jobs.[15]

Finally, a recent study by Wood Mackenzie for the American Petroleum Institute[16] focused on the job impacts resulting from increased oil and gas production in the U.S., finding that 1.4 million jobs could be created by 2030. Adjusting that finding to the size of the Cameron facility would result in an increase of 46,000 jobs.[17]

Considering the available evidence, the estimated impact on economy-wide employment during plant operation is, reasonably and perhaps conservatively, 53,000 jobs in 2030, assuming LNG pricing at 70% of oil price parity in 2030.

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[13] Elaine Webster, Mathis and Zech, "The Case for State-Level Export Promotion Assistance: A Comparison of Foreign and Domestic Export Employment Multipliers," Economic Development Quarterly, Sage Publications, Aug 1, 1990.

[14] USDA Economic Research Service, "Agricultural Trade Multipliers: Effects of Trade on the U.S. Economy," 2009.

[15] U.S. Department of Commerce, International Trade Administration, "Exports Support American Jobs," International Trade Research Report no. 1, April 2010.

[16] Wood Mackenzie, prepared for the American Petroleum Institute, "U.S. Supply Forecast and Potential Jobs and Economic Impacts (2012-2030)," Sep 7, 2011.

[17] Calculation: Convert 10,371 mboed of increased production to 58.1 Bcfd of gas equivalent. Adjust 1.403 million jobs by the ratio of 1.9 Bcfd at the Cameron facility to 58.1 Bcfd.

Total employment impact over the life of the plant, including construction, is estimated to be 1.1 million job-years, as shown in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
2020	$9.95	$15.15	46,931	$1.9
2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
2025	$10.83	$16.49	51,093	$2.1
2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
2029	$11.27	$17.16	53,157	$2.2
2030	$11.33	$17.26	53,461	$2.2
2031	$11.38	$17.32	53,663	$2.2
2032	$11.40	$17.36	53,766	$2.2
2033	$11.42	$17.39	53,879	$2.2
2034	$11.44	$17.42	53,962	$2.2
2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3.

Chart 3 illustrates the resulting incremental job impacts over the periods of Cameron plant construction (2013 through 2016) and operation (2017 through 2036).

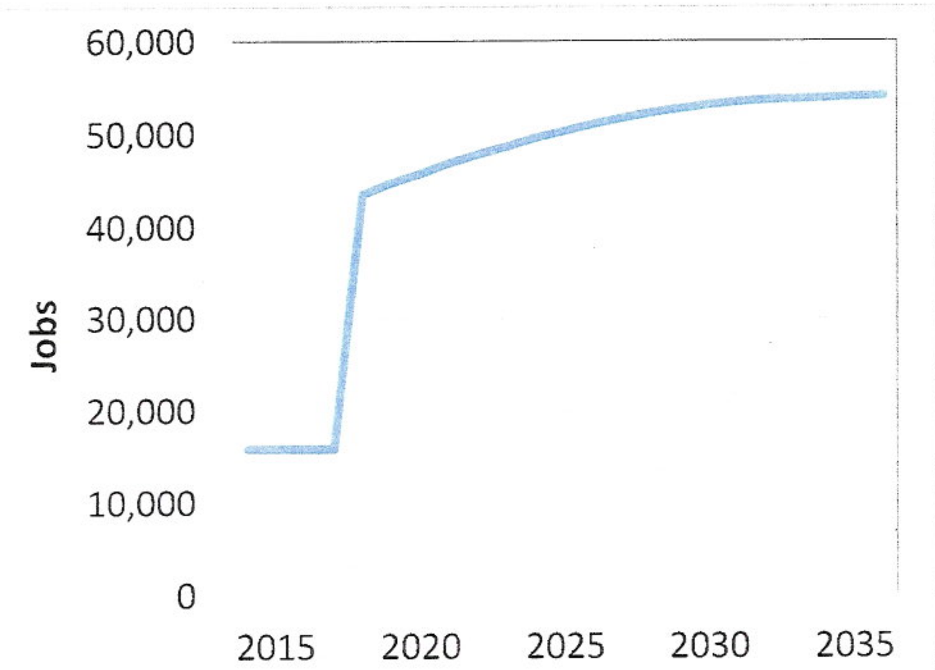

Chart 3: Economy-wide Job Impact of Cameron Facility

d) Increase in Employee Wages

Gas Industry Only Wage Impacts

Based on the 2007 Economic Census, employee wages in the combined oil and gas extraction and gas pipeline sectors totaled $8.4 billion. Based on the 122,781 employees in the sector, this averages $68,029 per employee, and $162 million per Bcfd based on the 51.6 Bcfd of gas production reported by the Economic Census. Therefore, for 1.9 Bcfd, the wage impact equals $307 million per year in 2007 dollars for direct wages in the oil and gas extraction and gas pipeline sectors.

Economy-wide Wage Impacts

Economy-wide employee wage impacts make use of the employment estimates, assuming that wages during construction are equal to the national average for construction, as reported in the 2007 Economic Census, and wages during plant operation are equal to the national average for all industries. Average economy-wide wages during construction are estimated at $717 million per year, and average economy-wide wages over the period of operation are estimated at $2.1 billion per year. The total economy-wide wage impact over the life of the project is estimated at $45 billion, as shown in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
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2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
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2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3.

4. Yearly Summary

Estimated impacts are reported in

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
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2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
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2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
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2030	$11.33	$17.26	53,461	$2.2
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2033	$11.42	$17.39	53,879	$2.2
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2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3 in the Appendix.

5. Technical Terms

BBL: barrel containing 42 gallons of liquid

Bcfd: billion cubic feet of gas per day

Btu: British thermal units

C&C: crude oil and condensate

LNG: liquified natural gas

Mboed: million barrels of oil equivalent per day

Mcf: thousand cubic feet of gas

MTPA: million metric tonne per annum

NAICS: North American Industry Classification System

NGL: natural gas liquids

Tcf: trillion cubic feet of gas

Appendix

	Price of Imported Crude Oil ($/bbl)		Value of Incidental Oil+NGL Production ($Billions)		LNG sold at 50% of Oil Parity ($Billions)		LNG sold at 70% of Oil Parity ($Billions)		LNG sold at 90% of Oil Parity ($Billions)		Balance of Trade Impact (50% of Oil Parity) ($Billions)		Balance of Trade Impact (70% of Oil Parity) ($Billions)		Balance of Trade Impact (90% of Oil Parity) ($Billions)	
	2009$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal	2011$	Nominal
2011	80.3	82.1														
2012	80.7	83.4														
2013	82.9	87.1														
2014	85.1	91.0														
2015	86.8	94.8														
2016	89.0	99.0														
2017	91.6	104.0	1.8	2.0	5.3	5.7	7.4	8.0	9.5	10.3	7.1	7.7	9.2	10.0	11.3	12.3
2018	94.0	109.1	1.9	2.1	5.4	6.0	7.6	8.4	9.8	10.8	7.3	8.1	9.5	10.5	11.7	12.9
2019	96.4	114.2	1.9	2.2	5.6	6.3	7.8	8.8	10.0	11.3	7.5	8.4	9.7	11.0	11.9	13.5
2020	98.6	119.2	2.0	2.3	5.7	6.5	8.0	9.2	10.2	11.8	7.7	8.8	9.9	11.4	12.2	14.1
2021	100.7	124.0	2.0	2.4	5.8	6.8	8.1	9.5	10.5	12.3	7.8	9.2	10.2	11.9	12.5	14.6
2022	102.5	128.5	2.1	2.5	5.9	7.1	8.3	9.9	10.6	12.7	8.0	9.5	10.3	12.3	12.7	15.2
2023	104.3	133.0	2.1	2.5	6.0	7.3	8.4	10.2	10.8	13.1	8.1	9.8	10.5	12.8	12.9	15.7
2024	105.9	137.6	2.1	2.6	6.1	7.6	8.6	10.6	11.0	13.6	8.2	10.2	10.7	13.2	13.1	16.2
2025	107.4	142.1	2.2	2.7	6.2	7.8	8.7	10.9	11.2	14.0	8.4	10.5	10.8	13.6	13.3	16.8
2026	108.8	146.5	2.2	2.8	6.3	8.0	8.8	11.3	11.3	14.5	8.5	10.8	11.0	14.1	13.5	17.3
2027	110.0	150.9	2.2	2.9	6.3	8.3	8.9	11.6	11.4	14.9	8.6	11.2	11.1	14.5	13.6	17.8
2028	110.9	155.0	2.2	3.0	6.4	8.5	9.0	11.9	11.5	15.3	8.6	11.5	11.2	14.9	13.7	18.3
2029	111.7	159.1	2.2	3.0	6.4	8.7	9.0	12.2	11.6	15.7	8.7	11.8	11.3	15.3	13.8	18.8
2030	112.4	162.9	2.3	3.1	6.5	8.9	9.1	12.5	11.7	16.1	8.7	12.1	11.3	15.6	13.9	19.2
2031	112.8	166.6	2.3	3.2	6.5	9.1	9.1	12.8	11.7	16.5	8.8	12.3	11.4	16.0	14.0	19.6
2032	113.0	170.1	2.3	3.3	6.5	9.3	9.1	13.1	11.7	16.8	8.8	12.6	11.4	16.3	14.0	20.1
2033	113.3	173.8	2.3	3.3	6.5	9.5	9.1	13.4	11.8	17.2	8.8	12.9	11.4	16.7	14.0	20.5
2034	113.4	177.5	2.3	3.4	6.5	9.7	9.2	13.6	11.8	17.5	8.8	13.1	11.4	17.0	14.1	20.9
2035	113.7	181.4	2.3	3.5	6.6	10.0	9.2	13.9	11.8	17.9	8.8	13.4	11.5	17.4	14.1	21.4
2036	113.9	185.4	2.3	3.5	6.6	10.2	9.2	14.2	11.8	18.3	8.9	13.7	11.5	17.8	14.1	21.9
Total			43	56	123	161	172	226	222	291	166	218	215	282	265	347

Figure A- 1: Balance of Trade Impact

Assumptions:

- Natural gas heating value = 1030 Btu/cf
- Oil to gas conversion = 5.82 Mcf per barrel
- Average NGL yield for non-associated gas = 35 bbl/MMcf
- Average crude oil and condensate (C&C) yield for non-associated gas = 9 bbl/MMcf
- Total incidental NGL + C&C production = (35 + 9) x 1,900 MMcf/d = 84,000 bbl/day
- NGL pricing = 50% of Brent oil parity

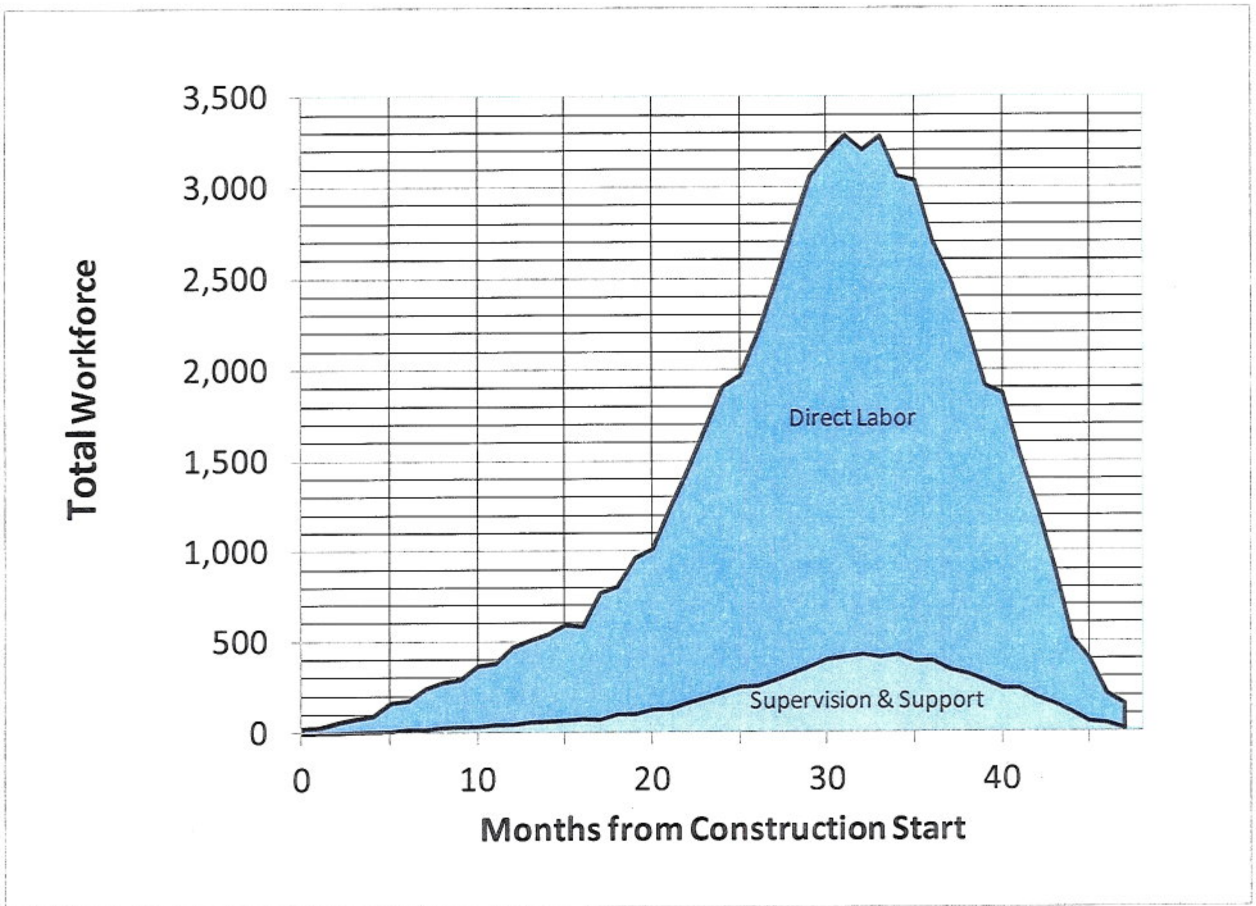

Figure A- 2: Estimated Cameron Construction Employment Schedule

	Improvement in Balance of Trade (Billions of $2011)	Increased US Output (Billions of $2011)	Increase in Number of Jobs	Wages Gains (billions $2007)
2013	$0.00	$1.90	15,854	$0.7
2014	$0.00	$1.90	15,854	$0.7
2015	$0.00	$1.90	15,854	$0.7
2016	$0.00	$1.90	15,854	$0.7
2017	$9.23	$14.06	43,559	$1.8
2018	$9.48	$14.44	44,739	$1.8
2019	$9.72	$14.81	45,872	$1.9
2020	$9.95	$15.15	46,931	$1.9
2021	$10.16	$15.47	47,925	$2.0
2022	$10.34	$15.74	48,758	$2.0
2023	$10.51	$16.01	49,597	$2.0
2024	$10.68	$16.26	50,372	$2.1
2025	$10.83	$16.49	51,093	$2.1
2026	$10.97	$16.71	51,760	$2.1
2027	$11.09	$16.89	52,321	$2.2
2028	$11.19	$17.04	52,773	$2.2
2029	$11.27	$17.16	53,157	$2.2
2030	$11.33	$17.26	53,461	$2.2
2031	$11.38	$17.32	53,663	$2.2
2032	$11.40	$17.36	53,766	$2.2
2033	$11.42	$17.39	53,879	$2.2
2034	$11.44	$17.42	53,962	$2.2
2035	$11.47	$17.46	54,088	$2.2
2036	$11.49	$17.49	54,186	$2.2
Total	$215	$336	1,079,278	$44.8

Figure A- 3: Economy-wide Economic Impacts – Yearly Detail