FULBRIGHT
& Jaworski L.L.P.
Attorneys at Law

Fulbright Tower • 1301 McKinney, Suite 5100• Houston, Texas 77010-3095
gwatkins@fulbright.com • Direct: 713 651 5127 • Main: 713 651 5151 • Facsimile: 713 651 5246

October 5, 2012

Mr. John Anderson
Office of Fuels Programs, 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: Excelerate Liquefaction Solutions I, LLC
FE Docket No. 12- 146 LNG
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Mr. Anderson:

Enclosed for filing on behalf of Excelerate Liquefaction Solutions I, LLC ("ELS"), please find an original and three (3) copies of ELS's application for long-term, multi-contract authorization to engage in exports of domestically produced liquefied natural gas ("LNG") in an amount up to 10 million metric tons per year, which is equivalent to approximately 1.33 billion cubic feet of natural gas per day or approximately 502 million MMBtu per year. ELS seeks authorization for a 20-year term, commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted, to export LNG to any country with which the U.S. does not now, or during the term of the license requested herein will not, have a Free Trade Agreement requiring the national treatment for trade in natural gas and LNG that has, or in the future develops, the capacity to import LNG; and with which trade is not prohibited by U.S. law or policy.

A check in the amount of $50.00 is enclosed as payment of the applicable filing fee.

Please feel free to contact me at (713) 651-5127 if you have any questions regarding this application.

Respectfully submitted,

G. Gail Watkins

G. Gail Watkins
Fulbright & Jaworski L.L.P.
1301 McKinney, Suite 5100
Houston, Texas 77010
Counsel for Excelerate Liquefaction Solutions I, LLC

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In The Matter Of:	)	
	)	
EXCELERATE LIQUEFACTION	)	Docket No. 12 - 146 - LNG
SOLUTIONS I, LLC	)	
	)	

APPLICATION OF EXCELERATE LIQUEFACTION SOLUTIONS I, LLC FOR LONG-TERM, MULTI-CONTRACT AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS TO NON-FREE TRADE AGREEMENT COUNTRIES

Martin A. Hruska
Excelerate Liquefaction Solutions I, LLC
1450 Lake Robbins Drive, Suite 200
The Woodlands, Texas 77380
Telephone: (832) 813-7100
Facsimile: (832) 813-7103
Email: martin.hruska@excelerateenergy.com

G. Gail Watkins
Fulbright & Jaworski, L.L.P.
1301 McKinney, Suite 5100
Houston, Texas 77010
Telephone: (713) 651-5127
Facsimile: (713) 651-5246
Email: gwatkins@fulbright.com

TABLE OF CONTENTS

Page

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In The Matter Of:	)	
	)	
EXCELERATE LIQUEFACTION	)	Docket No. 12 - 146 - LNG
SOLUTIONS I, LLC	)	
	)	

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

Pursuant to Section 3 of the Natural Gas Act ("NGA")[1] and Part 590 of the regulations of the Department of Energy ("DOE"),[2] Excelerate Liquefaction Solutions I, LLC ("ELS") hereby requests that DOE, through its Office of Fossil Energy ("DOE/FE"), grant long-term, multi-contract authorization for ELS to engage in exports of domestically produced liquefied natural gas ("LNG") in an amount up to 10 million metric tons per annum ("MTPA") (equivalent to approximately 1.33 billion cubic feet per day ("Bcf/d")[3] or approximately 502 x 10^{12} British Thermal Units ("million MMBtu") per year)[4] for a 20-year period commencing the earlier of the date of first export or seven years from the date of issuance of the authorization requested herein. ELS is seeking authorization to export LNG from the proposed Excelerate Liquefaction Project to be located in Calhoun County, Texas ("ELS Project") to any country with which the United States of America ("U.S.") does not now, or during the term of the license requested herein will not, have a Free Trade Agreement ("FTA") requiring the national treatment for trade in natural gas; that has, or in the future develops, the capacity to import LNG; and with which trade is not

[1] Natural Gas Act, 15 U.S.C. § 717b (2012).
[2] 10 C.F.R. pt. 590 (2012).
[3] Based on 1 MTPA = 48.7 Bcf/yr. See, http://www.extension.iastate.edu/agdm/wholefarm/pdf/c6-89.pdf.
[4] The proposed maximum export quantity of 10 MTPA (502 million MMBtu per year) equates to a daily maximum export rate of approximately 1.33 Bcf/d.

prohibited by U.S. law or policy (taken together, a "non-FTA Country" or "non-FTA Countries"). ELS 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 represents the second part of ELS's two-part export authorization request. On May 25, 2012, ELS filed in DOE/FE Docket No. 12-61-LNG its application requesting long-term, multi-contract authorization to export up to 10 MTPA of domestically produced LNG for a 20-year period commencing the earlier of the date of first export or seven years from the date authorization is granted by DOE/FE. ELS requested that such long-term authorization provide for export to any country with which the U.S. currently has, or in the future may enter into, a FTA requiring national treatment for trade in natural gas, and which has, or in the future develops, the capacity to import LNG. ELS requested authorization to export LNG on its own behalf and also as agent for other parties who hold title to the LNG at the time of export. DOE/FE granted this authorization to ELS in Order No. 3128. If, in addition, this Application for authorization to export to non-FTA Countries is granted, the combined effect of the DOE/FE Order addressing this Application and Order No. 3128 will be to authorize ELS to export up to 10 MPTA (equivalent to approximately 1.33 Bcf/d or approximately 502 million MMBtu per year) of domestic natural gas as LNG to any country with which trade is not prohibited by U.S. law or policy.[5] As such, grant of this Application would not increase the total amount of natural gas that ELS would be entitled to export, it would only broaden the range of countries to which such natural gas could be exported.

[5] ELS has requested its engineers to design a facility that can export up to 10 MTPA. The Bcf/d and MMBtu figures are derivative numbers calculated by using conversion factors. In ELS's May 25, 2012 application, ELS sought and obtained authorization to export 1.38 Bcf/d or 504 Bcf/yr of natural gas based on a conversion factor of one (1) standard cubic foot of natural gas to 1.0×10^3 Btu, which is accurate to two digits. The current Application uses more significant digits in the conversion process and equates one (1) standard cubic foot of natural gas to 1,030 Btu. This results in an apparent reduction in the stated volumes of less than four percent. ELS also believes that 502 million MMBtu is a more accurate equivalent of 10 MTPA. ELS will not export natural gas in excess of the lowest measure stated in the relevant DOE/FE authorization order(s).

In support of this Application, ELS states as follows:

I. DESCRIPTION OF THE APPLICANT

The exact legal name of ELS is Excelerate Liquefaction Solutions I, LLC. ELS is a limited liability company organized under the laws of Delaware. Its principal place of business is 1450 Lake Robbins Drive, Suite 200, The Woodlands, Texas 77380. ELS is a wholly-owned subsidiary of Excelerate Liquefaction Solutions, LLC, which also is a limited liability company organized under the laws of Delaware. Excelerate Liquefaction Solutions, LLC is, in turn, a wholly-owned subsidiary of Excelerate Energy Limited Partnership, which is limited partnership organized under the laws of Delaware.[6] The general partner of Excelerate Energy Limited Partnership is Excelerate Energy, LLC – a limited liability company organized under the laws of Delaware. RWE Supply & Trading Participations Ltd., a UK company, and Mr. George B. Kaiser, an individual, each own 50% of Excelerate Energy, LLC. The limited partners of Excelerate Energy Limited Partnership are (a) RWE Supply & Trading Participations Ltd.; and (b) Excelerate Holdings LLC, a limited liability company organized under the laws of Oklahoma. RWE Supply & Trading Participations Ltd. is a wholly-owned subsidiary of RWE Supply & Trading GmbH, a German company, that is, in turn, ultimately owned by RWE, A.G., a widely-held and publicly-traded, German electric and gas company. Excelerate Holdings LLC is majority-owned and controlled by Mr. Kaiser. (No other entity owns more than 2.5% of Excelerate Holdings LLC.) ELS is authorized to do business in the State of Texas.

[6] This represents a correction in the description of the upstream ownership of ELS with respect to the information previously provided in DOE/FE Docket No. 12-61-LNG. There Excelerate Energy, LLC was identified as the direct owner of Excelerate Liquefaction Solutions, LLC, instead of the general partner of the direct owner of Excelerate Liquefaction Solutions, LLC. Additional information about upstream ownership is also provided.

II. COMMUNICATIONS AND CORRESPONDENCE

All correspondence and communications concerning this Application, including all service of pleadings and notices, should be directed to the following persons:[7]

Martin A. Hruska
Excelerate Liquefaction Solutions I, LLC
1450 Lake Robbins Drive, Suite 200
The Woodlands, Texas 77380
Telephone: (832) 813-7100
Facsimile: (832) 813-7103
Email: martin.hruska@excelerateenergy.com

G. Gail Watkins
Fulbright & Jaworski, L.L.P.
1301 McKinney, Suite 5100
Houston, Texas 77010
Telephone: (713) 651-5127
Facsimile: (713) 651-5246
Email: gwatkins@fulbright.com

Pursuant to Section 590.103(b) of the DOE regulations,[8] ELS hereby certifies that the persons listed above and the undersigned are the duly authorized representatives of ELS.

III. EXECUTIVE SUMMARY

ELS is herein seeking multi-contract, long-term authorization to export up to 10 MTPA of domestically produced LNG, which is equivalent to approximately 1.33 Bcf/d or approximately 502 million MMBtu per year, to any non-FTA Country. ELS requests this authorization for a 20-year term commencing the earlier of: (i) the date of first export, and (ii) seven years from the date of issuance of the authorization requested herein.

ELS will file an application with the Federal Energy Regulatory Commission ("FERC" or the "Commission") for authorization pursuant to Section 3(a) of the NGA to site, construct and operate the ELS Terminal facilities (the "ELS Terminal") and ELS will file an application with FERC pursuant to Section 7(c) of the NGA to construct, own and operate the ELS Pipeline ("ELS Pipeline") to connect the ELS Terminal to interstate and intrastate natural gas supplies and markets.[9] In connection therewith, DOE/FE would act as a cooperating agency in FERC's

[7] ELS requests waiver of Section 590.202(a) of DOE's regulations, 10 C.F.R. § 590.202(a), to the extent necessary to include outside counsel on the official service list in this proceeding.
[8] 10 C.F.R. § 590.103(b) (2012).
[9] In connection with these filings ELS will commence FERC's mandatory National Environmental Policy Act, 42 U.S.C. § 4321, *et seq.*, prefiling process for the ELS Project.

environmental review process for the ELS Project and in the preparation of an environmental assessment ("EA") or environmental impact statement ("EIS") to satisfy DOE/FE's National Environmental Policy Act ("NEPA") responsibilities.[10]

The ELS Terminal is designed to produce approximately 10 MTPA or approximately 502 million MMBtu per year of LNG. The ELS Pipeline, which is a proposed part of the ELS Project, is comprised of an approximately 27-mile long, 36-inch O.D. pipeline. ELS proposes to source natural gas to be used as feedstock for LNG production at the ELS Project from the interstate and intrastate pipeline grid utilizing up to nine (9) different interconnection points with the ELS Pipeline,[11] as necessary to provide ELS with the ability to source natural gas for the ELS Project from virtually any point on the U.S. interstate pipeline system through direct delivery or by displacement.

The ELS Project is motivated by the improved overall outlook for domestic natural gas production owing, in part, to drilling productivity gains that have enabled rapid growth in supplies in South Texas and elsewhere in the U.S.[12] The expectation that U.S. residential, commercial, industrial, and electric consumers will not increase consumption quickly enough to offset growth in production has contributed to projections for sustained low prices for natural gas in the U.S. Rapid growth in U.S. natural gas production has driven wellhead prices to

[10] *See FERC Notice of Intent to Prepare an Environmental Assessment for the Planned Corpus Christi LNG Terminal and Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Scoping*, Docket No. PF12-3-000, Accession No. 20120601-3015 (June 1, 2012) (noting that DOE/FE has agreed to participate as a cooperating agency in the NEPA process).

[11] Depending on the final interconnection arrangements, some of the potential interconnections may require additional short pipeline spurs/laterals branching off from the header to connect to pipelines located at a modest distance from the proposed header route.

[12] Domestic wellhead natural gas production in 2011 totaled 28.57 Tcf, the highest in U.S. history. *See* U.S. Energy Information Administration ("EIA"), *Natural Gas Gross Withdrawals and Production*, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

historically low levels,[13] resulting in decreased investment by the natural gas industry[14] and a reduction in associated economic activity. Low wellhead prices also have encouraged increased flaring of associated natural gas that otherwise could have been beneficially utilized.[15]

As described in this Application, the ELS Project presents numerous benefits to the public, including, but not limited to, improving the U.S. balance of payments, stimulating state, regional and national economies through job creation, increasing economic activity and tax revenues, enhancing competition in gas markets, increasing flexibility in gas supply, and improving security for the U.S. and its trading partners. ELS submits that the authorization sought herein is therefore consistent with the public interest.

The economic benefits of the ELS Project are quantified in the report ELS commissioned from Black & Veatch, entitled *Economic Impacts of the Lavaca Bay LNG Project – Estimates of the Construction and Operational Impacts on the Local, State and U.S. Economies* ("B&V Report").[16] With respect to such activity, the B&V Report estimates the ELS Project's construction expenditures to account for well in excess of $3.32 billion in total economic

[13] Henry Hub natural gas futures on the New York Mercantile Exchange ("NYMEX") have traded at times during 2012 at the lowest price levels seen since 2002. *See David Bird, US Gas: Futures Slip to Fourth-Straight New Decade Low on Glut*, Dow Jones Energy Service, Apr. 13, 2012.

[14] For example, earlier this year, Chesapeake Energy announced that, in response to low natural gas prices, it "plans to … reduce its operated dry gas drilling activity by 50%." It also stated that "Chesapeake's operated dry gas drilling capital expenditures in 2012, net of drilling carries, are expected to decrease to $0.9 billion, a decrease of approximately 70% from similar expenditures of $3.1 billion in 2011", http://www.chk.com/News/Articles/Pages/1651252.aspx.

[15] The EIA estimates that a total of 165.9 Bcf was vented or flared in 2010, an increase of 72.1% from vented and flared volumes of 96.4 Bcf in 2004. *See* EIA, *supra* note 12. At the same time, the World Bank-led Global Gas Flaring Reduction Partnership estimates that natural gas flaring in the U.S. increased to 7.1 billion cubic meters (equivalent to approximately 251 Bcf) in 2011 from 2.4 billion cubic meters in 2007, an increase of 222.7%. *See Press Release, World Bank Sees Warning Sign in Gas Flaring Increase* (July 3, 2012), http://www.worldbank.org/en/news/2012/07/03/world-bank-sees-warning-sign-gas-flaring-increase, and http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:22137498~menuPK:3077311~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html.

[16] Black & Veatch, *Economic Impacts of the Lavaca Bay LNG Project – Estimates of the Construction and Operational Impacts on the Local, State and U.S. Economies* (October 5, 2012). The B&V Report is attached hereto as Appendix E.

output.[17] Under current tax regimes, that economic output is estimated to generate more than $154 million in state and local taxes, as well as more than $242 million in total federal tax revenues. Moreover, the combined operations and maintenance expenditures are anticipated to result in an additional yearly total economic output of over $102 million and well over $3.7 million in state and local taxes, plus more than $6.0 million in total federal taxes each year.[18] With respect to job creation, construction of the ELS Project is projected to result in 21,367 new jobs during the three year construction period for Phase 1 (with additional jobs created by Phase 2 work over and above that amount), and the operations and maintenance expenditures are projected to support or create 696 jobs during the ELS Project's life.[19]

As supported by the attached documentation and the other sources referenced herein (including the study commissioned by the DOE and already released to the public[20]), the export of LNG from the ELS Project as proposed by ELS in this Application is consistent with the public interest. Accordingly, ELS requests that DOE/FE grant the authorization requested in this Application.

IV. <u>AUTHORIZATION REQUEST</u>

ELS requests long-term, multi-contract authorization to export up to 10 MTPA of domestically produced LNG, which is equivalent to approximately 1.33 Bcf/d or approximately

---

[17] *Id.* at 2. The specific amounts estimated in the B&V Report are based solely on the impacts of Phase I of the ELS Project. As noted in the B&V Report, the combined impacts of both Phase 1 and Phase 2 of the ELS Project are projected to be on the order of 166% of Phase 1 impacts alone. *Id.* at 1.
[18] *Id.* at 2.
[19] *Id.*
[20] EIA, *Effect of Increased Natural Gas Exports on Domestic Energy Markets* (January 2012), http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf. The EIA study projects, on average of all scenarios reviewed, end-use costs to U.S. natural gas customers from 2015 to 2035 will increase 3% to 9% over a comparable baseline case with no natural gas exports and electric costs will increase 3% or less. More than three-quarters of the exported natural gas would be offset by increased domestic natural gas production and imports from Canada, with the rest balanced by increased energy production from a variety of sources (including renewable) and modest conservation. Coal would substitute for a portion of the exported natural gas, but increases in carbon dioxide emissions would be on the order of 1% or less. While identifying public benefits outside of the energy markets was beyond the scope of the study, the study does reveal that many segments of the U.S. energy industry would benefit from the export of natural gas.

502 million MMBtu per year, from the ELS Project to non-FTA Countries.[21] ELS requests this authorization for a 20-year term commencing the earlier of the date of first export or seven years from the date of issuance of the authorization requested herein.

ELS is requesting this authorization both on its behalf and as agent for other parties who themselves hold title to the LNG at the time of export. To ensure that all exports are permitted and lawful under U.S. laws and policies, ELS will comply with all DOE/FE requirements for exporters and agents, including the registration requirements as first established in *Freeport LNG Development, L.P.*, DOE/FE Order No. 2913 and as set forth in Excelerate Liquefaction Solutions I, LLC, DOE/FE Order No. 3128.[22]

Therefore, when acting as agent, ELS will register with the DOE/FE each LNG title holder ELS seeks to export LNG on behalf of or as agent for, and will provide the DOE/FE with registration materials that include an acknowledgement and agreement by the LNG title holder to supply information necessary to permit ELS to register that person or entity with DOE/FE, including: (1) the LNG title holder's agreement to comply with any order issued by DOE/FE pursuant to this Application and all applicable requirements of DOE's regulations at 10 C.F.R. Part 590, including but not limited to destination restrictions; (2) the exact legal name of the LNG title holder, state/location of incorporation/registration, primary place of doing business, and the LNG title holder's ownership structure, including the ultimate parent entity if the registrant is a subsidiary or affiliate of another entity; (3) the name, title, mailing address, e-mail

[21] In any given year, ELS would export a maximum of 10 MTPA of LNG (or the equivalent of 1.33 Bcf/d) from the ELS Project. Such export may be to FTA Countries pursuant to the authorization granted in DOE/FE Order No. 3128 or to non-FTA Countries with which trade is not prohibited by U.S. law or policy pursuant to the authorization sought herein. In this regard, 10 MTPA is the maximum cumulative volume that will be exported from the ELS Project annually.

[22] *Freeport LNG Development, L.P., Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Freeport LNG Terminal to Free Trade Nations*, FE Docket No. 10-160-LNG, DOE/FE Order No. 2913 (Feb. 10, 2011); *Errata Notice Correcting Footnote 9 in Order 2913 Issued 2/10/2009* (Feb. 17, 2011); *Excelerate Liquefaction Solutions I, LLC*, FE Docket No. 12-61-LNG, DOE/FE Order No. 3128 (Aug. 9, 2012).

address, and telephone number of a corporate officer or employee of the LNG title holder to whom inquiries may be directed; (4) within 30 days of execution, a copy, filed with DOE/FE under seal, of any long-term contracts, including processing agreements, that result in the export of LNG; and (5) within 30 days of execution by a person or entity required by the authorization requested herein to register a copy, filed with DOE/FE under seal, of any long-term contracts associated with the long-term supply of natural gas to the ELS Project with the intent to process this natural gas into LNG for export pursuant to the authorization requested herein.[23]

ELS has not yet entered into any long-term gas supply or long-term export contracts in conjunction with the LNG export authorization requested herein. Accordingly, ELS is not submitting transaction-specific information (*e.g.*, long-term supply agreements and long-term export agreements) at this time. As the DOE/FE stated in the context of Sabine Pass, "under section 590.202(b) [of its rules], the information in question is to be supplied 'to the extent applicable' and supported 'to the extent practicable'."[24] ELS recognizes that it will need to update the DOE/FE in order to comply with Section 590.202(b) of the DOE regulations[25] once ELS's supply and export arrangements become more concrete and the relevant information becomes available. ELS is cognizant of the DOE/FE Policy Guidelines (of 1984) and expects to enter into export transactions that are responsive to the relative level of natural gas prices in the U.S., in a manner similar to those entered into in connection with the Sabine Pass liquefaction

[23] *See Excelerate Liquefaction Solutions I, LLC*, FE Docket No. 12-61-LNG, DOE/FE Order No. 3128, at 8 (Aug. 9, 2012).

[24] In the May 20, 2011 order granting Sabine Pass Liquefaction, LLC ("Sabine Pass") long-term export authorization to non-FTA Countries, DOE/FE found that Sabine Pass was not required to submit with its application transaction-specific information pursuant to Section 590.202(b) of the DOE regulations. DOE/FE found that given the state of development for the proposed Sabine Pass export project, it was appropriate for Sabine Pass to submit such transaction-specific information when the contracts reflecting such information were executed. *See Sabine Pass Liquefaction, LLC, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, FE Docket No. 10-111-LNG, FE Order No. 2961, at 41 (May 20, 2011), hereinafter "*Sabine Pass*, DOE/FE Order No. 2961".

[25] 10 C.F.R. § 590.202(b) (2012).

and export project (DOE/FE Docket No. 10-111-LNG), thereby creating supply to mitigate price impacts if the U.S. market is in greater need of natural gas that would otherwise be exported.

Finally, ELS also requests that the DOE/FE recognize that the required environmental review will be conducted by the Commission in conjunction with the Commission's review of the request for authorization of the construction and operation of the ELS Project facilities that ELS will file. If necessary, pursuant to Section 590.402 of the DOE regulations,[26] the Assistant Secretary may issue a conditional order authorizing the export of domestically produced LNG, subject to completion of the environmental review of the ELS Project by FERC.[27] DOE routinely issues conditional orders subject to satisfactory environmental review in similar circumstances.[28]

V. <u>DESCRIPTION OF LIQUEFACTION PROJECT</u>

The ELS Project consists of a terminal, a pipeline and related facilities as described below.

A. <u>ELS Terminal</u>

The ELS Project will be located on a parcel of land owned by the Calhoun Port Authority (the "Port"). The Port and ELS have entered into an option to lease approximately 85 acres for the development of the ELS Project located on the South Peninsula of Point Comfort, Texas.[29]

---

[26] 10 C.F.R. § 590.402 (2012).

[27] In promulgating its regulations setting forth the administrative procedures for the import and export of natural gas, DOE indicated that issuance of a conditional decision is appropriate when the application at issue involves, for example, the importation of LNG into new terminal facilities. In such a case, DOE reviews the application to determine if the proposed importation is in the public interest based on the considerations within DOE's jurisdiction, while, concurrently, FERC must review other aspects of the proposed importation such as siting, construction and operation of the LNG receiving terminal facilities. *See Import and Export of Natural Gas*, 46 Fed. Reg. 44,696, 44,700 (Sept. 4, 1981).

[28] See, *e.g.*, *Sabine Pass*, DOE/FE Order No. 2961, *supra* note 24; *Rochester Gas and Elec. Corp*., FE Docket No. 90-05-NG, Order No. 503 (May 16, 1991).

[29] Included with this Application as Appendix C is a locator map showing the location and giving the latitude and longitude of the proposed ELS Terminal site. This is the same information as previously filed with the DOE/FE in Docket No. 12-61-LNG on July 19, 2012. The option to lease the site from the Port described in that filing remains

In this Application, ELS seeks a long-term, multi-contract authorization to export domestically produced LNG from the ELS Terminal that ELS intends to construct, own, and operate in Calhoun County, Texas, under the authorization of Section 3 of the NGA. The ELS Project consists of the ELS Terminal, with natural gas compression, gas treatment, gas liquefaction, and ancillary facilities as needed to receive and liquefy domestic natural gas at the ELS Terminal. ELS is currently finalizing the design of the ELS Project, but the ELS Project facilities will include two floating liquefaction, storage and offloading ("FLSO") units, each capable of producing up to 5 MTPA of LNG per year for a total capacity of 10 MTPA of LNG (equivalent to approximately 1.33 Bcf/d or 502 million MMBtu per year). In addition to liquefying natural gas, each FLSO unit will have an LNG storage capacity of about 250,000 m^3 and the ability to offload LNG to LNG carriers for export utilizing standard hard-arm technology and a ship-to-ship transfer process.

B. ELS Pipeline

The ELS Terminal will receive natural gas from the ELS Pipeline, an approximately 27-mile long, 36-inch O.D. natural gas pipeline that ELS will construct, or cause to be constructed. The ELS Pipeline will allow the ELS Terminal to connect to and access up to nine (9) natural gas pipelines,[30] including both interstate and intrastate systems, thereby providing indirect access to natural gas through displacement and transactions at market hubs, as well as direct access to gas in Texas. As a result, ELS Terminal users will have access to a wide variety of stable and economical supply options of natural gas from which to choose, including the vast supplies available from the Texas producing regions.

---

in effect and the information relevant thereto submitted in Docket No. 12-61-LNG is hereby incorporated by reference.

[30] These pipelines are identified at page 9 of the B&V Report. Depending on the final interconnection arrangements, some of the potential interconnections may require additional short pipeline spurs/laterals branching off from the header to connect to pipelines located at a modest distance from the proposed header route.

C. Permitting

Other than the authorization being sought herein, the permits/authorizations and consultations so far identified by ELS as necessary to site, construct, own and operate the ELS Terminal and ELS pipeline remain as described in ELS's prior application for authority to export LNG to FTA countries in Docket No. 12-61-LNG. This information is summarized in Appendix D to this Application.

VI. EXPORT SOURCES

ELS seeks authorization to export natural gas available from the U.S. natural gas supply and transmission network. As a result of the ELS Terminal's potential to access nine (9) major interstate and intrastate natural gas pipelines, and indirect access to the entire interconnected North American natural gas pipeline grid, the ELS Project's customers will have a wide variety of stable and economical supply options from which to choose. The sources of natural gas for the ELS Project will include the vast supplies available from the Texas producing regions, among them the recent discoveries of shale gas resources.

In addition to traditional production, emerging unconventional supply areas, such as the Barnett, Eagle Ford, Haynesville, and Bossier shale gas formations, represent very attractive sources of supply. 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 economically viable. Production from shale gas resources has contributed to a 24% increase in total U.S. gas production during the past five years[31] and shale gas production has increased from a nominal amount just five years ago (1 trillion cubic feet ("Tcf") in 2004) to 30% of total U.S. natural gas production in 2011 (6.6 Tcf of a total of 23

[31] The 24% increase is derived from EIA dry gas production information for 2006 and 2011. *See* EIA, *U.S. Dry Natural Gas Production*, http://www.eia.gov/dnav/ng/hist/n9070us2A.htm.

Tcf).[32] Furthermore, the EIA predicts that shale gas production will increase to 13.6 Tcf in 2035, making up 49% of total U.S. natural gas production.[33] Given the size of traditional natural gas resources in close proximity to the ELS Terminal, as well as rapid growth in emerging unconventional gas resources in the region, the ELS Project's customers will have a diverse and reliable choice of alternative gas supplies.

VII. DESCRIPTION OF EXPORT PROPOSAL; COMMERCIAL MATTERS

The ELS Project facilities will permit the ELS Terminal to receive natural gas from the ELS Pipeline. The natural gas will then be liquefied aboard the FLSO units and stored thereon. From the FLSO units' storage tanks, the LNG will be loaded onto LNG carriers berthed alongside. The long-term authorization requested in this Application is necessary to permit ELS to incur the substantial costs of developing the ELS Project and to secure customer contracts. Terms for the use of the liquefaction and other facilities will be set forth in agreements with customers of the ELS Project. These agreements are expected to be for terms of up to 20 years in length and will run concurrently with ELS's export authorization. ELS has not yet entered into such agreements given that a long-term export authorization is required to finalize arrangements with prospective customers. As discussed above, ELS will file any long-term gas supply or long-term export contracts with DOE/FE under seal pursuant to DOE/FE regulations.

VIII. APPLICABLE LEGAL STANDARD

Pursuant to Section 3 of the NGA, DOE/FE is required to authorize exports to a foreign country unless there is a finding that such exports "will not be consistent with the public interest."[34] Specifically, Section 3(a) of the NGA, states in its relevant part:

---

[32] EIA, *Annual Energy Outlook 2012 (Early Release) Data*, http://www.eia.gov/forecasts/aeo/er/excel/overview.fig02.data.xls.
[33] EIA, *Annual Energy Outlook 2012* (June 2012), at 3, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf, hereinafter "Annual Energy Outlook 2012".
[34] 15 U.S.C. § 717b(a) (2012).

> **(a) Mandatory authorization order**
> After six months from June 21, 1938, no person shall export any natural gas from the U.S. to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.[35]

This provision represents a statutory presumption in favor of approval of this Application, which opponents bear the burden of overcoming. Absent testimony that the proposed export is inconsistent with the public interest that outweighs any evidence to the contrary, DOE/FE has a statutory obligation to approve an application for export authorization.[36]

Furthermore, DOE issued a set of Policy Guidelines in 1984 delineating the criteria that DOE shall utilize in reviewing applications for natural gas imports,[37] and the agency has applied this criteria in its review of applications for natural gas exports as well.[38] The *Policy Guidelines* emphasize free market principles and promote limited government involvement in federal natural gas regulation:

> The market, not government, should determine the price and other contract terms for imported [and exported] gas. U.S. buyers [and sellers] should have full freedom - along with the responsibility - for negotiating the terms of trade arrangements with foreign sellers [and buyers].
>
> 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

---

[35] *Id.*
[36] *Sabine Pass,* DOE/FE Order No. 2961, at 28.
[37] *Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6,684 (Feb. 22, 1984), hereinafter "*Policy Guidelines*".
[38] *See Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, FE Docket No. 96-99-LNG, Order No. 1473, at 14 (Apr. 2, 1999) (citing *Yukon Pacific Corporation*, Order No. 350, 1 FE ¶ 70,259 (1989), at 71,128), hereinafter "*Phillips Alaska*, DOE/FE Order No. 1473".

> parties to structure more freely their trade arrangements, tailoring them to the markets served.[39]

The *Policy Guidelines* also provide some insight into the public interest standard for evaluating potential import and export applications. In this regard, the *Policy Guidelines* provide that the "policy cornerstone of the public interest standard is competition."[40] Competitive import/export arrangements are therefore an essential element of the public interest and, so long as the sales agreements are set in terms that are consistent with market demands, they should be considered to "largely" meet the public interest standard.[41] The *Policy Guidelines* further provide that "[t]his policy approach presumes that buyers and sellers, if allowed to negotiate free of constraining governmental limits, will construct competitive import [and export] agreements that will be responsive to market forces over time."[42]

Another consideration in determining whether an export would be inconsistent with the public interest is domestic need for the gas proposed to be exported. The DOE/FE has noted that its "review of export applications in decisions under current delegated authority [focuses] on the domestic need for the natural gas 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 of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements."[43] Previously, the other issues found to be appropriate to weigh into the public interest determination have included local interests, international effects and the environment.

---

[39] *Policy Guidelines*, *supra* note 37, at 6685 (references to "exports" inserted to reflect DOE policy that "the principles are applicable to exports as well" as enunciated in *Phillips Alaska*, DOE/FE Order No. 1473, *supra* note 38, at 14).
[40] *Id.* at 6687.
[41] *Id.*
[42] *Id.* (referencing "exports" inserted to reflect DOE policy that "the principles are applicable to exports as well" as enunciated in *Phillips Alaska*, DOE/FE Order No. 1473, *supra* note 38, at 14).
[43] *Sabine Pass*, DOE/FE Order No. 2961, *supra* note 24, at 29.

As discussed herein, all of the foregoing factors support grant of this Application. Of course, the projections are estimates of the future. Thus, the accuracy of the forecasting methodology, projections of supply, cost of supply, demand, and future technological innovation offered herein are estimates. Nonetheless, these projections represent the best measures available for determining whether a future export would be in the public interest or not.

To protect against the possibility that the projections diverge from future reality, ELS will ensure that its export contracts contain provisions that permit its customers to temporarily cancel or suspend the loading of cargoes of LNG for export if market price signals warrant. Such provisions will allow the export arrangements to respond to future market price signals reflecting conditions of supply and demand in the domestic market.

IX. PUBLIC INTEREST ANALYSIS

The ELS Project has been proposed, in part, due to the markedly improving outlook for domestic natural gas resources and production. Improved drilling techniques and extraction technologies have contributed to the rapid growth in new supplies from unconventional gas-bearing shale formations across the U.S. Such developments have completely changed the complexion of the U.S. natural gas industry and radically expanded our resource base.

U.S. export of LNG represents a market driven path toward deploying the country's vast energy reserves in a manner meaningfully contributing to the public interest in a variety of ways:

- Increased production capacity able to better adjust to varying domestic demand scenarios;
- Less volatile domestic natural gas prices;
- More jobs, greater tax revenues, and improvements to economic activity;
- New competitive supplies introduced into world gas markets, leading to improved economies among the U.S.'s trading partners, and, in turn, providing better opportunities to market U.S. products and services abroad;
- Promote greater national security through larger role in international energy markets, assisting our allies, and reducing dependency on foreign oil through co-production of oil and natural gas liquids that might otherwise be uneconomic;

- Improve the U.S. balance of payments by between $2.4 billion and $4.4 billion annually per terminal through the exportation of natural gas and the displacement of imports of other petroleum liquids;[44] and
- Increase economic trade and ties with foreign trading partners and hemispheric allies, and displace environmentally damaging fuels in those countries.

ELS submits that these and the other benefits enumerated in this Application compellingly demonstrate that the LNG exports that would result from the approval of this Application are in the public interest.

A. Analysis of Domestic Need for Gas to Be Exported

The ELS Project is in the public interest because it (i) would not impair the ability of domestic natural gas consumers to obtain adequate supplies at appropriate prices; (ii) would promote a stable domestic gas industry during times when domestic demand for natural gas is depressed; and (iii) would enhance domestic natural gas production capacity which can provide greater elasticity of supplies to meet domestic demand on short notice under a variety of conditions, in lieu of relying heavily on increases in domestic prices to bring demand in line with less elastic supplies.

Drilling productivity and extraction technology improvements have enabled rapid growth in the overall U.S. natural gas supply. Proven natural gas reserves have increased by 93.5 Tcf (44%) between 2006 and 2010.[45] As U.S. natural gas resources and production have increased, U.S. natural gas prices have fallen markedly. The monthly average Henry Hub price for natural gas fell from over $10.00 per MMBtu in late 2005 to under $3.57 per MMBtu in late 2011.[46] In its most recently calculated AEO 2012 reference case, the EIA projects that the annual average wellhead price for natural gas, stated in 2010 U.S. dollars, will remain under $5.00 per MMBtu

[44] B&V Report, *supra* note 16, at 12 (based on $1.2 - 2.2 billion for Phase I alone, exporting 4 MPTA). Other studies have found even greater benefits for individual LNG export terminals. *Id.* at 32-34.
[45] EIA, *Natural Gas Reserves Summary as of Dec. 31 ,2010*, http://www.eia.gov/dnav/ng/ng_enr_sum_a_epg0_r11_bcf_a.htm.
[46] EIA, *Henry Hub Gulf Coast Natural Gas Spot Price,* http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm.

through at least 2025, and rise to only $6.48 by 2035.[47] Prices for natural gas in the U.S. market are now substantially below those of most other major gas-consuming countries. While U.S. gas prices are now similar to or less than they were a decade ago, prices for LNG in other major gas consuming countries have mostly increased sharply over the past decade. 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 U.S. prices.

1. *National Supply – Overview*

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 U.S. dry natural gas production was 2.02 Tcf in July 2012, a 11% increase compared to July 2010 dry natural gas production of 1.82 Tcf.[48] 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.

In its *Annual Energy Outlook 2011,* the EIA noted that U.S. shale gas production grew at an average rate of 17% between 2000 and 2006.[49] The rate of growth accelerated substantially during the period of 2006 and 2010, with the annual growth rate averaging 48%. The EIA expects this increase in shale gas production to continue through 2035, when shale gas will make

[47] Annual Energy Outlook 2012, *supra* note 33, at 131.
[48] EIA, *Natural Gas Gross Withdrawals and Production*, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_nus_m.htm.
[49] EIA, *Annual Energy Outlook 2011* (April 2011), at 2, http://electricdrive.org/index.php?ht=a/GetDocumentAction/id/27843, hereinafter "Annual Energy Outlook 2011".

up an estimated 49% of total U.S. natural gas production, up considerably from a 16% share in 2009.[50]

For 2012, the EIA has significantly increased its estimate of shale gas production for 2015, 2020, 2025, 2030, and 2035 compared with the EIA's projections in its *Annual Energy Outlook 2011.* For example, the EIA revised its projection of onshore shale gas production for the lower 48 states in 2015 from 7.20 Tcf to 8.24 Tcf.[51] Similarly, the EIA revised its projection of shale gas production for 2035 from 12.25 Tcf to 13.63 Tcf.[52]

The growth in shale gas production has been accompanied by an increase in the overall volume of U.S. natural gas resources. In 2012, the EIA estimated technically recoverable natural gas resources in the U.S. to be 2,203 Tcf.[53]

This growth in U.S. natural gas resources is reflected in other recent academic and industry evaluations. In April 2011, the Potential Gas Committee of the Colorado School of Mines determined that the U.S. possesses a future available natural 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.[54] In its recently published study, The Future of Natural Gas, the Massachusetts Institute of Technology estimates that the U.S. has a mean remaining resource base of approximately 2,150 Tcf of natural gas.[55] This estimate includes approximately 1,000 Tcf of recoverable shale gas resources,[56] and approximately 400

---

[50] *Id.* at *2;* Annual Energy Outlook 2012, *supra* note 33, at 3.
[51] Annual Energy Outlook 2012, *supra* note 32, at Table A-14; Annual Energy Outlook 2011, *supra* note 49, at Table A-14.
[52] *Id.*
[53] EIA, *Assumptions to the Annual Energy Outlook 2012* (August 2012), Table 9.2, http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf.
[54] Potential Gas Committee, "Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee" (Dec 31,2010), http://www.potentialgas.org/PGC%20Press%20Conf%202011%20slides.pdf.
[55] Massachusetts Institute of Technology(2011), *The Future of Natural Gas*, at 24 (Fig. 2.8), http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Report.pdf.
[56] *Id*.

Tcf of this could be economically developed with a gas price at or below $6/MMBtu at the well-head.[57]

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 a mean technical recoverable shale gas resources of 937 Tcf, with 637 Tcf of that located in the U.S.[58] This report indicates that breakeven prices for some of the more prolific shales in the U.S. are as low as $3, with a large majority of the resources accessible at below $6, which is a significant cost decrease from ten years ago.[59] (The report defines the break-even price as the average price needed for development of up to 60 percent of the identified technical recoverable resource.[60])

In a July 2011 report commissioned by the EIA, an independent consultant estimates U.S. onshore lower 48 states shale gas resources to be 750 Tcf.[61] The 750 Tcf of shale gas resources in this report is a subset of the estimated 862 TCF of onshore lower 48 States natural gas shale technically recoverable resources in the EIA's *Annual Energy Outlook 2011*. The *Annual Energy Outlook 2011* estimate includes an additional 35 Tcf of proven reserves reported to the U.S. 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 U.S. Geological Survey.[62]

These studies and reports indicate that the U.S. 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.

---

[57] *Id*. at 31 (Fig. 2.14(b)).
[58] James A. Baker III Institute for Public Policy, *"Shale Gas and U.S. National Security"* (July 2011) at 23, http://www.bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.
[59] *Id.*
[60] *Id.* at 24-25.
[61] EIA, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, at 5, http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf (July 2011).
[62] *Id.*

2. *Regional Supply*

As described in the attached B&V Report, the proposed ELS terminal will be located in an area with robust access to natural gas supplies thanks to the highly integrated and well developed natural gas pipeline system. ELS expects to directly interconnect with interstate pipelines with existing capacity of at least 3.80 Bcf per day and up to approximately 4.96 Bcf per day.[63] The wealth of pipelines in the region demonstrates the ability of the industry to build new, and expand the capacity of existing, infrastructure as needed to ensure adequate regional supplies. In addition to substantial existing gas transportation capacity in the region, the area is blessed with large quantities of natural gas resources in the ground. The Deloitte MarketPoint *Analysis of Economic Impact of LNG Exports from the United States* (the "Deloitte MarketPoint Analysis") projects that all of the natural gas used as feedstock to produce 1.33 Bcf/d of exports from the ELS Project will come from Texas production.[64] Despite this, the increased demand represented associated with the ELS Project is not expected to result in an especially large increase in production by the shale deposits in South Texas because these deposits are of sufficient quality to be developed regardless of the entry of the ELS Project. Instead, most of the demand associated with operation of the ELS Terminal will be satisfied through displacement with only about one-third of the needed supply coming from incremental production within Texas.[65]

3. *National Natural Gas Demand*

Over the past decade, there has been essentially no growth in the demand for natural gas in the U.S. According to data published by the EIA, natural gas consumption in 2011 was only

---

[63] B&V Report, *supra* note 16, at 9.
[64] Deloitte MarketPoint, *Analysis of Economic Impact of LNG Exports from the United States*, at 14, hereinafter "Deloitte MarketPoint Analysis". The Deloitte MarketPoint Analysis is attached hereto as Appendix E.
[65] *Id.*

4.2% higher than in 2000.[66] In its *Annual Energy Outlook 2012,* the EIA estimated long-term annual U.S. consumption growth of only 0.4%, with consumption expected to reach 26.6 Tcf in 2035 (compared to 22.8 Tcf of actual demand in 2009).[67]

The table below presents a comparison of actual consumption and prices in 2011 and forecasted demand and prices in the year 2020, based on information presented in the *Annual Energy Outlook 2012.*[68]

	2011	**2020**
Natural Gas Demand (Bcf/day)	67.2	69.8
Henry Hub Spot Price ($/MMBtu)	3.94	4.58
Average Lower 48 Wellhead Price ($/MMBtu)	3.72	4.10

The consensus of estimates by the EIA and academic and industry experts is that the U.S. has between 2,000 and 2,543 Tcf of recoverable natural gas resources. Even at 100% utilization, the ELS Project would result in maximum natural gas requirements of 10.7 Tcf over the 20-year term of the requested authorization.[69] This represents only 0.42% to 0.53% of total estimated recoverable U.S. natural gas resources.

4. *Supply-Demand Balance Demonstrates the Lack of National and Regional Need*

As discussed above, the enormous available domestic supply of natural gas dwarfs current U.S. demand, and, even under the extreme case of operating at 100% utilization, the natural gas to be exported from the ELS Terminal is substantially less than 1% of the available resources. The current low prices of natural gas are a consequence of a buyer's market owing to

---

[66] EIA, *Natural Gas Consumption by End Use*, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm..
[67] Annual Energy Outlook 2012, *supra* note 32, at Table A13.
[68] EIA, *Annual Energy Outlook 2012 Table 13*, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=0-AEO2012&table=13-AEO2012&region=0-0&cases=ref2012-d020112c. Volumes stated in Tcf per year in the *Annual Energy Outlook 2012* were converted to Bcf per day. In addition, 2010 volumes and prices were updated to 2011 actual volumes and prices, based on EIA, *Natural Gas Summary*, http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
[69] This number was calculated by multiplying 1.33 Bcf/d by 365 days/year times 20 years and increasing the result by 10% to allow for losses and gas to operate the ELS Terminal.

plentiful supply and limited domestic needs. The interest in exporting gas from the U.S. despite the billions of dollars of investment to develop a single LNG export terminal is a reflection of these market conditions.

As more fully described in the Deloitte MarketPoint Analysis, the issue is not merely one of volume, but also of price impact. "In a free market economy, price is one of the best measures of scarcity, and if price is not significantly affected, then scarcity and shortage of supply typically do not occur… A key determinant to the estimated price impact is the supply response to increased demand including LNG exports."[70] The Deloitte MarketPoint Analysis's modeling approach accounts for this supply-demand dynamic and considers how producers will change their production in response to demand, rather than simply assuming that supply will be brought into equilibrium with increase demand through a change in price.[71] The result of this modeling "indicates that the projected level of exports is not likely to induce scarcity on domestic markets."[72]

5. *Price Impacts – Natural Gas*

Both of the studies commissioned by ELS in conjunction with this Application deal with the subject of price impacts related to the export of natural gas from the U.S. via the ELS terminal. The Deloitte MarketPoint Analysis considers LNG exports ranging from 1.33 Bcf/d (ELS Terminal exports only) to 12 Bcf/d (ELS Terminal plus 9.67 additional Bcf/d of exports from other Gulf of Mexico terminals plus 1 Bcf/d of Cove Point exports).[73] The potential impact of LNG exports on U.S. natural gas prices as set forth in Figure 2 of the Deloitte MarketPoint Analysis are reproduced below:

---

[70] Deloitte MarketPoint Analysis, *supra* note 64, at 1.
[71] *Id*. at 2
[72] *Id*. at 4
[73] *Id*. at 3.

Export Case	U.S. Citygate	Henry Hub	New York
1.33 Bcf/d	0.4%	0.4%	0.3%
3 Bcf/d	1.0%	1.7%	0.9%
6 Bcf/d	2.2%	4.0%	1.9%
9 Bcf/d	3.2%	5.5%	3.2%
12 Bcf/d	4.3%	7.7%	4.1%

In no case did the impacts on average U.S. Citygate prices for the assumed years of operation of the ELS terminal (2018-2037) reach even 5% and Henry Hub, which experiences a greater impact due to its proximity to the modeled location of most of the exports, is expected to have only a 7.7% increase. This equates to a maximum price increase of 30 cents per MMBtu at U.S. Citygate and 50 cents at Henry Hub – a change smaller than that frequently experienced by the natural gas industry due to other causes.[74] The Deloitte MarketPoint Analysis also notes the buffering effect of a flattening supply curve, which is believed to exist for the domestic natural gas market. In short, as the price of natural gas rises the industry is able to produce more natural gas than had to be consumed to cause the first increment of price increase. Thus, natural gas becomes more abundant and, for so long as the curve continues to flatten, it takes ever larger jumps in demand to produce additional price increases of a similar magnitude, thereby muting the price impacts of changing demand.[75]

[74] For example, as reported by the EIA, the average monthly Henry Hub spot price for natural gas in 2011 ranged from $3.17 to $4.54 per MMBtu (a change of $1.37 per MMBtu) and the average January Henry Hub spot price during the period 2008 to 2012 ranged from $2.67 to $7.99 per MMBtu (a change of $5.32 per MMBtu). EIA, *Henry Hun Gulf Coast Natural Gas Spot Price*, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[75] Deloitte MarketPoint Analysis, *supra* note 64, at p. 8.

6. *Price Impacts – Other*

Recognizing that natural gas is an important fuel for the electric industry, the Deloitte MarketPoint Analysis also examined to what extent natural gas exports would affect the price of electricity. The projected average impact on electric prices in the area overseen by the Electric Reliability Council of Texas (which includes the ELS Terminal site and much of the rest of Texas) during the study period was less than one percent under the six Bcf/d export scenario.[76] For other power markets the effect is much lower.[77]

B. <u>Other Public Interest Considerations</u>

1. *Promote Long-Term Stability in Natural Gas Markets*

Lower U.S. natural gas prices has led to decreased capital spending on natural gas drilling and development activities.[78] Exporting natural gas would create increased demand for domestically produced gas, and, as noted above, contribute to a small increase in domestic natural gas prices. Both of these factors would help encourage investment and, thereby, help to stabilize the natural gas industry.[79] Of broader importance is the stabilizing affect increased exports would have on both the price and availability of natural gas for domestic uses. The stabilizing effects would stem from several causes.

---

[76] *Id*. at 12.
[77] *Id.*
[78] *See, e.g.*, *The American Shale Gas Revolutions: Fundamental Winners and Losers,* by Marcus V. McGregor, in Asset Management Viewpoint, Volume 16, #2 (April 2012), https://www.conning.com/uploadedFiles/Asset_Management/Point_of_View/Viewpoint/04-2012%20Shale%20Gas%20Revolution%20FINAL.pdf (noting: "Operators have been allocating more capital to exploration and production of liquids in order to mitigate the recent decline in natural gas spot prices ….) Chesapeake Energy operated 100 natural gas rigs and 22 oil and natural gas liquids rigs in January of 2010 and as of August 2012 its natural gas rig count was 10 and its oil and natural gas liquids rig count was 111. This complete reversal in 30 months was due to low natural gas prices. *Chesapeake Energy September 2012 Investor Presentation*, http://www.chk.com/investors/documents/latest_ir_presentation.pdf.
[79] In the February 2012 issue (Vol. 233 No. 2) of World Oil Online James C. West, Anthony Walker, Zachary Sadow and Rachel Nabatoan of Barclays Capital reported on the results of a survey of 351 oil and gas operating companies. "Roughly 27% of companies surveyed plan on increasing spending [on natural gas exploration and production activities] if natural gas prices average $4.50/MMbtu in 2012, and 70% would do so if they average $5.00/MMbtu. Nearly half of surveyed companies would cut back spending if gas averaged $3.50/MMbtu, while $3.00/MMbtu was the most popular threshold for companies to reduce budgets." http://www.worldoil.com/February-2012-EP-spending-to-reach-record-600-billion.html.

First, simply by increasing the size and diversity of the demand for natural gas to include consumers in other nations, the volatility in demand decreases, which will contribute to more stable prices in the U.S.

Second, a greater domestic production base and upgraded gas transmission capabilities present an opportunity for rapid, voluntary diversion of gas supply to domestic purposes should domestic demand change rapidly. For example, consider the possibilities if the U.S. were to have a catastrophic event at a U.S. nuclear generating plant, leading to the shutdown of a large portion of the U.S. nuclear generating fleet. In such a situation, an expanded U.S. natural gas industry could respond quickly through a global least cost solution. Exporters could chose to cancel export shipments and divert gas for use in domestic natural gas generating facilities, while foreign counter parties were made economically whole under the terms of their contracts. In contrast, a smaller U.S. natural gas industry would not have the option to redeploy foreign bound gas and production and transportation capabilities would be more limited. Simply producing more gas immediately would not be an option, and trying to expedite the drilling of new wells on an emergency basis would increase the level of environmental risk. The only immediately available course of action would involve establishing a new short-term equilibrium in a domestic-only market with fewer options, leading to much higher prices and a greater potential for scarcity of both natural gas and electricity.

Finally, as stated in Section IX.A.5. above, in the natural gas industry, increased production moves production to a flatter part of the supply curve. Such a situation means that future increases (or decreases) in demand of a given increment result in smaller changes in price and increased amounts of available supply relative to a steeper supply curve. In such an environment, both supply and prices are less volatile.

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

The construction and operation of the ELS Project will stimulate the local, regional, and national economies through job creation, increased economic activity and tax revenues. Much of the technology, equipment, and material needed to construct the ELS Project will be obtained from U.S. sources. Moreover, the national economy will benefit from the ELS Project's role in supporting the exploration and production value chain for natural gas extraction. This stimulus will have a marked multiplier effect due to the wages, taxes and lease payments involved in the natural gas supply chain.

The economic benefits of the ELS Project are quantified in the B&V Report, broken down into the primary and secondary economic impacts of the construction and operation of the first phase of the ELS Project on the local ELS Project area, the remainder of Texas, and on the remainder of the U.S. [80]

a. *Primary Economic Impacts*

The ELS Project will provide a significant source of employment, economic activity and tax revenues to the regional and national economies. The B&V Report estimates Phase 1 direct expenditures in the U.S. to be $1.36 Billion, with $319 million of that amount occurring within the "Primary Impact Area" (a defined region around the ELS Terminal), an additional $493 million of those expenditures going to other parts of Texas, and $522 million going to the remainder of the U.S.[81]

b. *Secondary Economic Impacts*

As described in the B&V Report, the benefits of the ELS Project will not be limited to the primary impacts discussed above because the direct expenditures ripple through the economy.

---

[80] B&V Report, *supra* note 16.
[81] B&V Report, *supra* note 16, at 18-19 (providing estimates of the construction and operational impacts on the local, state, and U.S. economies).

For example, the primary impact area construction expenditures are estimated to account for more than $526 million in total production from all industries impacted by those expenditures (total economic output) and generate $17.2 million in state and local taxes, as well as $32.2 million in total federal tax revenues,[82] while the operational impacts over the first 20 years of operation are estimated to account for more than $870 million (in 2012 dollars) in total economic output, generate $26 million in state and local taxes, and contribute an additional $40 million in federal taxes.[83]

Estimated positive impacts for the U.S. as a whole are considerably greater. The ELS Project's construction related contribution to total economic output in the U.S. (including the Primary Impact Area, the rest of TX and the remainder of the U.S.) is projected to be nearly $3.32 billion, with taxes revenues for state and local authorities of more than $154 million and federal tax revenues of nearly $242 million.[84] Similarly, the ELS Project's first 20 years of operations related contribution to total economic output in the U.S. is estimated to exceed $2.04 billion, with state and local tax revenues in excess of $74 million and federal taxes of nearly $120 million.[85] As noted previously, these estimates are just for Phase 1. For both Phase 1 and Phase 2 of the ELS Project, the impacts will be roughly two-thirds greater.[86]

c. *Jobs*

Unemployment is a huge concern at present, and the B&V Report considers the positive impacts the ELS Project will have on the job market. Construction of Phase 1 of the ELS Project is projected to support the employment of an average of 7,122 workers each year for three

---

[82] *Id.* at 24.
[83] *Id.* at 29.
[84] *Id.* at 25.
[85] *Id.* at 29.
[86] *Id.* at 1.

years.[87] The construction of Phase 2 would increase the total number of jobs created in certain years, as well as extend the period of job creation. A mix of skilled and unskilled labor would be required, resulting in an average labor income associated with each of these 7,122 jobs of $64,163.[88] The operation of the ELS Project is anticipated to result in the employment of an additional 696 workers each year over the entire life of the ELS Project.[89] The average wages and benefits associated with the portion of these jobs falling in the Primary Impact Area are even higher than the construction related work – $75,833/job.[90]

3. *International Considerations*

Recent world events, such as the continuing weakness of certain European Community member country economies, have served as ample reminders that the welfare of U.S. citizens is interdependent on the health of the world economy. In May 2012, the Brookings Institution's Energy Security Initiative released its Policy Brief 12-01, titled "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas" ("Brookings Study"), and in analyzing the international implications of LNG exports, the Brookings Study's authors broke the subject down into three components: pricing, geopolitics, and the environment.[91]

With respect to pricing, the Brookings Study observes: "LNG exports will help to sustain market liquidity in what looks to be an increasingly tight LNG market beyond 2015."[92] Looser or more liquid markets help place downward pressure on the pricing terms of oil-linked contracts, which are common in the world markets for LNG. This has resulted, in turn on the

---

[87] *Id.* at 2.
[88] *Id.*
[89] *Id.*
[90] *Id.* at 29. Operational jobs associated with the ELS Project over the entirety of the U.S. have a similar per job value of $71521. ($49,786,098 of labor income/696.1 jobs.) *Id.* at 31.
[91] Charles Ebinger, Kevin Massy and Govinda Avasarala, Brookings Institution Energy Security Initiative, *Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas*, Policy Brief 12-01, May 2012, http://www.brookings.edu/~/media/research/files/papers/2012/1/natural%20gas%20ebinger/natural_gas_ebinger.pdf , hereinafter "Brookings Study".
[92] *Id.* at 39.

renegotiation of some contracts particularly in Europe.[93] Of course, lower prices for energy in Europe and elsewhere can contribute to an uptick in the world economy, fueling increased trade with the U.S.

With respect to geopolitics, the Brookings Study concludes: "A large increase in U.S. LNG exports would have the potential to increase U.S. foreign policy interests in both the Atlantic and Pacific basins."[94] "[T]he addition of a large, market-based producer [*i.e.*, the U.S.] will indirectly serve to increase gas supply diversity in Europe, thereby providing European consumers with increased flexibility and market power. *** Increased LNG exports will provide similar assistance to strategic U.S. allies in the Pacific Basin. By adding supply volumes to the global LNG market, the U.S. will help Japan, Korea, India, and other import-dependent countries in South and East Asia to meet their energy needs. *** As U.S. foreign policy undergoes a 'pivot to Asia,' the ability of the U.S. to provide a degree of increased energy security and pricing relief to LNG importers in the region will be an important economic and strategic asset."[95]

Finally, as to the environment, the Brooking Study states:

> "According to the [International Energy Agency], natural gas in general has the potential to reduce carbon dioxide emissions by 740 million tonnes in 2035, nearly half of which could be achieved by the displacement of coal in China's power-generation portfolio. Natural gas – in the form of LNG – also has the potential to displace more carbon-intensive fuels in other major energy users, including across the EU and in Japan, which is being forced to burn more coal and oil-based fuels to make up for the nuclear generation capacity lost in the wake of the Fukushima [nuclear] disaster. In addition to its relatively lower carbon-dioxide footprint, natural gas produces lower emissions of pollutants such as sulfur dioxide nitrogen oxide and other particulates than coal and oil."[96]

---

[93] *Id.* at 38.
[94] *Id.* at p. 41.
[95] *Id.* at p. 43.
[96] *Id.* at p. 44.

The Brookings Study also notes that some have expressed concern that lower gas prices may lead to increased carbon dioxide emissions due to the displacement of nuclear and renewable energy by cheap natural gas.[97] ELS asserts that such concerns are misplaced. First, as the Brookings Study concludes, the export of U.S. natural gas would not make a substantial impact on the need for other energy sources to generate electricity.[98] Second, U.S. LNG exports are driven by the price differential between the destination markets and the U.S. natural gas market. Destination markets must command a significant price premium in order to cover the cost of liquefaction, transportation and regasification. Such considerations all favor the use of nuclear and renewable energy sources overseas relative to their competitiveness against natural gas in the U.S. Moreover, any tendency on the part of LNG exports to raise the cost of U.S. domestic gas supplies, not only tends to reduce the volume of exports, it also contributes to the increased use of alternative forms of generation in the U.S., making nuclear and renewable energy relatively more cost-effective. Thus, any loss of competitiveness of such generating technologies abroad would be at least partially mitigated by increased competitiveness of these technologies in the U.S.

The B&V Report points to yet another area in which exports of LNG will be beneficial to the U.S. The export of LNG from the U.S. directly improves the U.S. balance of trade. B&V calculates:

> "Even at a market natural gas price of $3/Mbtu and 80 percent utilization, the [ELS Project] will result in added exports in the range of $1.35 billion each year when including a tolling and project pipeline transport fee of approximately $3.5/Mbtu. This annual impact increases to approximately $1.78 billion at a natural

---

[97] *Id.*
[98] *Id.*

> gas price of $5/Mbtu and approximately $2.2 billion at a market price of $7/Mbtu."[99]

These statistics are for just Phase 1. Exports are expected to double under Phase 2 and so would the balance of trade benefits.

X. ENVIRONMENTAL IMPACT

As noted in Section XI., ELS intends to file an application with FERC for authorization to site, construct, own and operate the ELS Project. As part of the FERC's authorization process, the potential environmental impacts of the ELS Project will be reviewed by the FERC under NEPA. ELS anticipates that DOE/FE will act as a cooperating agency in the FERC's environmental review process for the ELS Project, including the preparation of an EA or EIS, to satisfy DOE/FE's NEPA responsibilities in authorizing LNG exports as proposed in this Application.[100]

ELS requests that if necessary, the Assistant Secretary issue an order authorizing the export of LNG, conditioned on completion of the environmental review of the ELS Project by FERC. If the authorization sought herein is conditioned on the completion of such environmental review, ELS requests that, upon issuance of an EA or EIS by the FERC for the ELS Project, DOE/FE adopt the FERC EA or EIS if DOE/FE concludes that its comments and suggestions have been satisfied. To the extent it reaches such conclusion, ELS also requests that DOE/FE promptly complete its NEPA obligations by issuing a Finding of No Significant Impact or Record of Decision, as applicable, thereby finalizing any conditional order.

---

[99] B&V Report, *supra* note 16, at 35.

[100] In connection with these filings, ELS will commence FERC's mandatory NEPA prefiling process for the ELS Project.

XI. RELATED AUTHORIZATIONS

The siting, construction and operation of the ELS Terminal is subject to approval by FERC pursuant to Section 3 of the NGA. As a prelude to the formal FERC application process, ELS intends to commence the FERC's mandatory prefiling process later this year and file its final application with FERC for Section 3 authorization in the first half of 2013. In concert with the FERC processes related to the ELS Terminal, ELS also will pursue authorization from the FERC under Section 7(c) of the NGA to construct, own and operate a pipeline to connect the ELS Terminal facilities to interstate and intrastate natural gas supplies and markets in 2012.

Additional permitting requirements are identified in Appendix D.

XII. REPORT CONTACT INFORMATION

The contact for any reports required in connection with the requested authorization is as follows:

Martin A. Hruska
Excelerate Liquefaction Solutions I, LLC
1450 Lake Robbins Drive, Suite 200
The Woodlands, Texas 77380
Telephone: (832) 813-7100
Facsimile: (832) 813-7103
Email: martin.hruska@excelerateenergy.com

XIII. APPENDICES

The following appendices are attached hereto and incorporated by reference herein:

Appendix A:	Verification
Appendix B:	Opinion of Counsel
Appendix C:	Locator Map and Project Location Information
Appendix D:	Permitting Information
Appendix E:	B&V Report
Appendix F:	Deloitte MarketPoint Analysis

XIV. CONCLUSION

For the foregoing reasons, ELS respectfully requests that DOE/FE grant ELS's request for long-term, multi-contract authorization to engage in exports of domestically-produced LNG in an amount up to 10 MTPA of domestically produced LNG, which is equivalent to approximately 1.33 Bcf/d or approximately 502 million MMBtu per year, from the ELS Project to those countries that: (i) do not now or during the term of the license requested herein will not, have an FTA requiring the national treatment for trade in natural gas and LNG, (ii) which have, or in the future develop, the capacity to import LNG and (iii) with which trade is not prohibited by U.S. law or policy, for a 20-year term commencing the earlier of the date of first export or seven years from the date of issuance of such authorization.

Respectfully submitted,

G. Gail Watkins
Attorney for
Excelerate Liquefaction Solutions I, LLC

Fulbright & Jaworski L.L.P.
1301 McKinney, Suite 5100
Houston, Texas 77010
(713) 651-5127

Dated: October 5, 2012

APPENDIX A – VERIFICATION

UNITED STATES OF AMERICA DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

VERIFICATION

Edward Scott, first being sworn, states that he is Senior Vice President of Development for Excelerate Energy L.P.; that he is duly authorized to execute this Verification; that he has read the foregoing filing and is familiar with the contents thereof; and that all of the statements of fact therein contained are true and correct to the best of his knowledge and belief.

Edward Scott
On behalf of
Excelerate Energy, L.P. & Excelerate Liquefaction Solutions I, LLC

STATE OF TEXAS)

COUNTY OF CALHOUN)

Subscribed and sworn to before me on this 4th day of October 2012, by Edward Scott proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Christina Samples

NOTARY PUBLIC SIGNATURE

NOTARY PUBLIC
STATE OF TEXAS
CHRISTINA SAMPLES
My Commission Expires
October 6, 2016

NOTARY PUBLIC SEAL

APPENDIX B – OPINION OF COUNSEL

FREDERIC DORWART
LAWYERS
OLD CITY HALL
124 EAST FOURTH STREET
TULSA, OKLAHOMA 74103-5010

H. STEVEN WALTON
Also Licensed in Texas and Kansas
Direct (918) 583-9920
Email: swalton@fdlaw.com

Main (918) 583-9922
Facsimile (918) 584-2729

October 4, 2012

Mr. John Anderson
Office of Fuels Programs, 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: Excelerate Liquefaction Solutions I, LLC
FE Docket No. 12-__ - LNG
Application for Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries

Dear Mr. Anderson:

This opinion of counsel is provided in accordance with the requirements of Section 590.202(c) of the U.S. Department of Energy's regulations, 10 C.F.R. § 590.202(c) (2012). I have examined the organizational and governance documents of Excelerate Liquefaction Solutions I, LLC ("ELS"), and other documents and authorities as necessary. It is my opinion that the proposed long-term, multi-contract export of liquefied natural gas by ELS, as described in the above-referenced application, is within the limited liability company powers of ELS.

Respectfully submitted,

FREDERIC DORWART, LAWYERS

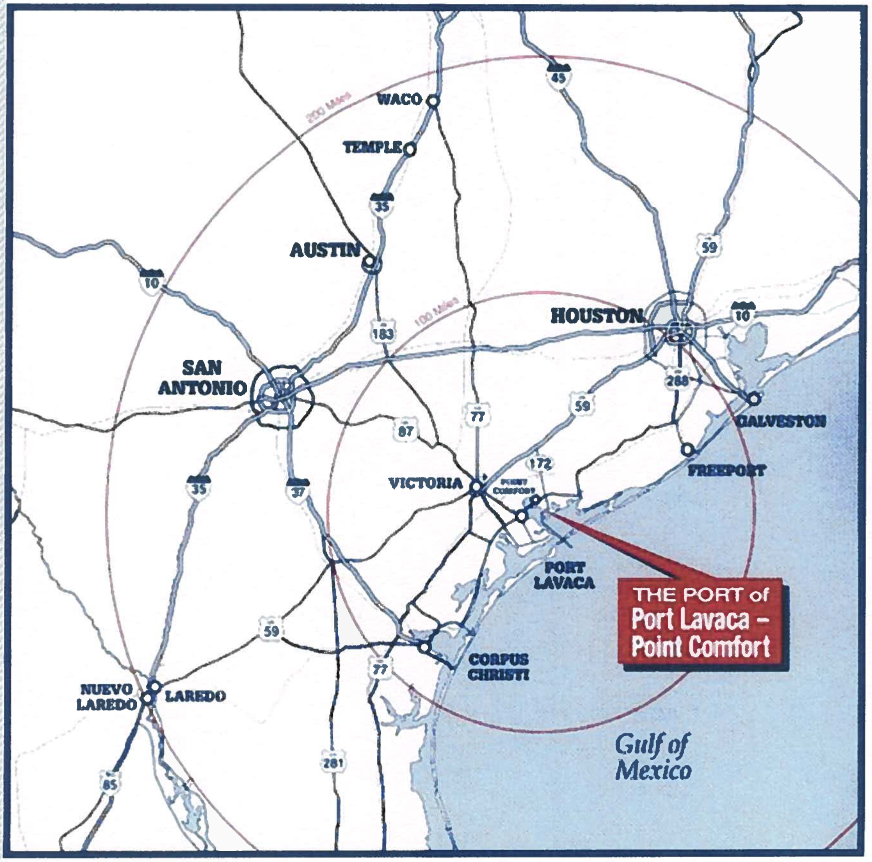
H. Steven Walton
Old City Hall
124 East Fourth Street
Tulsa, Oklahoma 74103
Tele: (918) 583-9922
Fax: (918) 583-9937
Counsel for Excelerate Liquefaction Solutions I, LLC

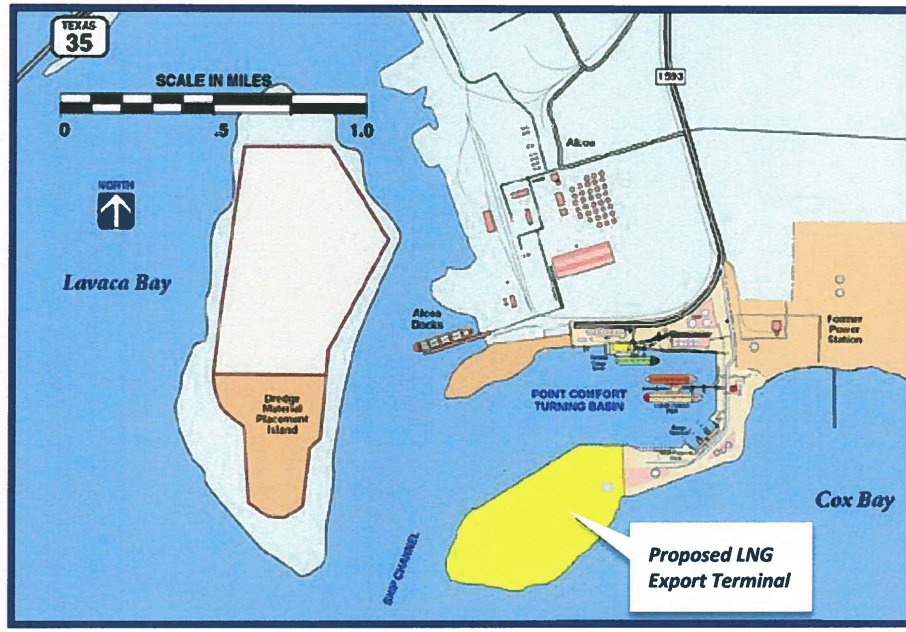
APPENDIX C – LOCATOR MAP AND PROJECT LOCATION INFORMATION

excelerate energy
ENERGY FAST FORWARD.™

Lavaca Bay LNG Project

map of proposed site





ELS 1 proposes to construct and operate a new LNG export, storage, and offloading terminal on the South Peninsula of Point Comfort, Texas with an approximate location of 28° 37' 56.32" N, 96° 33' 44.55" W.

APPENDIX D – PERMITTING INFORMATION

Table 1 Probable Permits and Approvals		
Agency	**Permit/Approvals/Consultations**	**Agency Action**
FEDERAL		
Federal Energy Regulatory Commission	Section 3 and 7 of the Natural Gas Act	Approval of Export Terminal and Pipeline.
U.S. Department of Energy (DOE)	Section 3 of the Natural Gas Act	Authorization to export natural gas.
Advisory Council on Historic Preservation	Section 106 of the NHPA	Opportunity to comment on the project
U.S. Department of Agriculture, Natural Resources Conservation Service – Farmland Protection Policy Act	Farmland Protection Policy Act	Determine that construction of the pipeline would not be a permanent conversion of important farmland.
U.S. Environmental Protection Agency (EPA)	Spill Prevention, Control, and Countermeasure Plan (Clean Water Act [CWA], 33 U.S.C.§1321(j))	Approval of Plan for responding to spills to prevent significant and substantial threat to the environment.
	NPDES permits for various discharges during construction and operations (CWA, (33 USC § 1342).	
	Prevention of Significant Deterioration (PSD) pre-construction review	PSD permit issued if Port is determined to be a major source of air emissions. If not a major source based on total annual emissions from the Port, a minor source construction permit is needed.
	Title V Operating Permit	Permit issued based on actual equipment installed and operations.
U.S. Army Corps of Engineers (USACOE)	Nationwide Permit No. 6 – Survey Activities	Geotechnical and geophysical surveys may be authorized under NWP No. 6.
	Section 404 (CWA)	Approval of floating LNG regasification facility and associated dredging requirements.
	Section 10 (Rivers and Harbors Act)	Permit for placement of structures in, or affecting, navigable waters (e.g., LNG import terminal).
U.S. Coast Guard (USCG)	Letter of Recommendation (33 CFR Part 127)	Captain of the Port issues Letter of Recommendation to operator in accordance with a Waterway Suitability Report
	Permission to establish Aids to Navigation required under 33 CFR Part 66	Coast Guard must be notified and give permission to establish any navigational aids (buoys) associated with the LNG import terminal.
	Spill Prevention and Spill Response Plan (CWA, 33 U.S.C.§1321(j))	Plan for responding to spills from ships.
U.S. Department of Transportation (DOT)	Petition for Approval (49 CFR Part 193) Federal Safety Standards	Must demonstrate that new LNG facility meets standards governing siting, design, installation, personnel qualifications and training.

U.S. Fish and Wildlife Service (USFWS)	Section 7 of Endangered Species Act	Provide biological opinion on species of wildlife and plants that are federally listed as threatened or endangered. Issue incidental take permit as necessary.
	Migratory Bird Treaty Act (16 U.S.C. 703 et seq.)	Consult on potential to impact migratory birds covered under the MBTA.
NOAA National Marine Fisheries Service (NMFS)	Section 7 of Endangered Species Act and Marine Mammal Protection Act (MMPA) Letter of Authorization (LOA) or Incidental Harassment Authorization (IHA)	Provide biological opinion and conservation recommendations on marine species of wildlife that are federally listed as threatened or endangered; issue incidental take permit as necessary. Agency consultation and review of application including a detailed description of the Project, a list of potentially affected species, potential mitigation measures, and suggested means for monitoring and reporting impacts.
	Magnuson-Stevens Fishery Management and Conservation Act (Essential Fish Habitat (EFH))	Provide opinion on managed fisheries. Oversight of marine facilities construction.
U.S. Department of Defense	Section 311 of EPACT2005	Consult regarding affects on military installations.
Federal Emergency Management Administration	Clean Water Act Section 404 Permit Consultation	Consult regarding floodplain protection.
STATE OF TEXAS		
Texas Commission of Environmental Quality (TCEQ)	Texas Clean Air Act; CAA: 40 CFR 50-99	
Railroad Commission of Texas (TRRC)	Temporary Water Use Permit; Section 401 Water Quality Certification; Stormwater Pollution Prevention, and Sedimentation Plans.	
	TAC Title 16 Part 1 Chapter 3 Issue NPDES stormwater permit and pipeline construction permit, hydrostatic test water discharge permit	
Texas General Land Office/TRRC	Section 307 of the CZMA.	Determine coastal zone management consistency
Texas Parks and Wildlife Department	Review of biological survey reports. Review of Section 10 and Section 404 permits through the Fish and Wildlife Coordination Act.	
Texas Department of Transportation	Issue permit for crossing any state highways	
Texas State Historic Preservation Office	Section 106 of the National Historic Preservation Act	Consultation regarding NRHP eligibility

LOCAL		
Calhoun and Jackson County Road Commission	Conduct permit review for road crossings.	
Calhoun and Jackson County Drainage District	Permit to cross drainage districts.	
Calhoun and Jackson County	Building Permits	

APPENDIX E – B&V REPORT

FINAL REPORT

ECONOMIC IMPACTS OF THE LAVACA BAY LNG PROJECT

Estimates of the Construction and Operational Impacts on the Local, State, and US Economies

BLACK & VEATCH PROJECT NO. 177581

PREPARED FOR

Excelerate Energy

5 OCTOBER 2012

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1 Executive Summary

This study evaluates the economic impact of the construction and operation of Excelerate Energy's proposed Lavaca Bay LNG Project. While the project will consist of two phases, the analysis in this report focuses on the primary and secondary impacts of Phase 1 in the local project area, the remainder of Texas, and on the remainder of the US. The IMPLAN impact analysis model was used in the study to estimate project benefits in the areas of employment, income, value added, wages, federal taxes, and state and local taxes.

The Lavaca Bay LNG Project will consist of Floating Liquefaction Storage Offloading (FLSO) vessels to be located on the Gulf Coast in Port Lavaca, Texas. The FLSO vessels will be added in two phases. The first phase will consist of one FLSO vessel with a storage capacity of 250,000 cubic meters of LNG and a liquefaction capacity of up to 5 million tons per annum (MTPA), or the equivalent of 0.665 billion cubic feet per of natural gas per day (Bcf/day). The Phase 2 FLSO vessel will be similar in size, and will bring the total project liquefaction capacity up to 10 MTPA, or 1.33 Bcf/day. The Phase 1 project is expected to become operational by the end of 2017 and will involve total construction expenditures of more than $2.1 billion, of which $1.3 billion will be for the LNG vessel that will be built in South Korea (all figures are in 2012 dollars). The project will have annual operation and maintenance (O&M) costs of approximately $45 million during the operating life. These Phase 1 expenditures are broken down further in Table ES-1. The Phase 2 expenditures will be able to take advantage of some common facilities and Phase 1 expenditures, but will be on the order of an additional two-thirds of the Phase 1 construction and O&M expenditures shown in the table.

Table ES-1 Phase 1 Direct Construction and Operational Expenditures on the Lavaca Bay LNG Project

Phase 1 Direct Expenditures for the Port Lavaca LNG Facility during Construction and Operation (2012 Dollars)

CONSTRUCTION PHASE		OPERATIONAL PHASE (YEARLY EXPENDITURES)	
FLSO Vessel*	$1,300 million	Supervisors/engineering/ terminal labor & expenses	$12.2 million
Pipeline	$170 million	Operations	$8.6 million
On-Shore and Dredging Expenditures		FLSO maintenance	$3.1 million
Jetty/Site structures and processing	$275 million	On-shore facility maintenance	$7.5 million
Dredging	$400 million	Administration & General	$10.1 million
		Other O&M	$3.3 million
Total	**$2,145 million**	**Total**	**$44.8 million**

***Includes $13.5 million for front end engineering and $12 million in permitting costs.**

The Phase 1 analysis further divided construction and O&M expenditures according to the assumed sector of expenditure and according to the geographic region in which expenditures were expected to occur. Geographical areas in the study include several counties near the project site (called the Primary Impact Area), the state of Texas (other than the Primary Impact Area counties) and the US (other than Texas and the Primary Impact Area). Economic impacts were estimated for each of these areas and combined to derive the cumulative impact of the project. The cumulative impact of the Phase 1 construction includes:

- The construction expenditures are projected to support or create 21,367 jobs or an average of 7,122 jobs per year during the three year construction period expenditures.
- The construction expenditures are estimated to create more than $1.37 billion in labor income at an average of $64,163 per job across all impacted industries.
- The construction expenditures are estimated to contribute more than $2.06 billion in value added.
- The construction expenditures are estimated to account for nearly $3.32 billion in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The construction expenditures are projected to generate more than $154 million in state and local taxes and nearly $242 million in total federal tax revenues.

The Phase 1 operational expenditures will also generate economic benefits, and these impacts will be long-term in nature. This study focused primarily on the economic impacts of O&M expenditures (estimated to be nearly $45 million per year) during the operational period and found the impacts from these expenditures to be significant. The expected total Phase 1 impacts during each year of operation are projected to include the following:

- The O&M expenditures are projected to support or create 696 jobs.
- The O&M expenditures are estimated to create nearly $50 million in labor income.
- The O&M expenditures are estimated to contribute nearly $66 million in value added.
- The O&M expenditures are estimated to account for more than $102 million in total economic output.
- The O&M expenditures are projected to generate more than $3.7 million in state and local taxes each year and nearly $6.0 million in total federal tax revenues.

The construction and operational impacts on the three geographical areas are shown in Table ES-2 and ES-3, respectively.

In addition to these O&M-related impacts, the project will provide significant upstream benefits that will arise from expenditures on natural gas. These expenditures will support additional jobs and income related to drilling natural gas wells, operating the wells, and processing and transporting the natural gas to the project pipeline and site. Analysis of these impacts indicates that, even if it is conservatively assumed that the Phase 1 project operates at an 80 percent capacity factor (4 MTPA out of the maximum 5 MTPA is produced) the upstream impact of natural gas expenditures will support nearly 3,900 jobs each year, generate more than $286 million in labor income, account for nearly $600 million in value added, and more than $1.2 billion in output each year. These impacts are calculated based on a conservative price assumption of $3/Mbtu.

While not directly measured in the IMPLAN modeling of the project, there will also be significant benefits to the US economy in the form of an improved balance of trade. Even at a market natural gas price of $3/Mbtu, the project will result in added exports of more than $1.3 billion each year during operation when including a tolling and project-associated natural gas transmission fee of approximately $3.5/Mbtu. This impact would increase to more than $1.8 billion per year at a $5/Mbtu natural gas price and more than $2.2 billion per year at a $7/Mbtu natural gas price.

There could be many additional benefits arising from the Lavaca Bay LNG project that were not directly included in the Phase 1 impact analysis. In addition to the Phase 2 benefits arising from expenditures that will be approximately two-thirds of the Phase 1 expenditures, additional benefits may include:

- The benefits that will be associated with expenditures of project revenues for interest payments and return on equity.
- The added benefits that could arise if excess power is sold to the grid.
- The possible significant economic benefits associated with added economic activity at the Port of Lavaca that could resulting from the deepening of the channel, land reclamation (both resulting from the project) and the expansion of the Panama Canal.
- The benefits associated with shipping costs and wages that would arise if US vessels and staff are used to deliver LNG to its final destination.

Table ES-2 Phase 1 Impacts of Construction in the Three Multi-Regional IMPLAN Models

Total Impacts From Construction Expenditures						
Primary Impact Area						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	2,550	$ 220,243,892	$ 237,125,274	$ 317,016,000		
Indirect Effect	260	$ 15,891,886	$ 27,813,530	$ 48,006,720		
Induced Effect	1,402	$ 45,593,857	$ 98,322,494	$ 161,497,874		
Total Effect	4,213	$ 281,729,635	$ 363,261,298	$ 526,520,594	$ 17,251,886	$ 33,174,197
The Rest of Texas Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	3,158	$ 277,546,425	$ 323,687,355	$ 492,547,500		
Indirect Effect	1,072	$ 64,241,430	$ 105,066,017	$ 182,313,067		
Induced Effect	3,015	$ 136,613,802	$ 250,077,851	$ 403,512,732		
Total Effect	7,245	$ 478,401,657	$ 678,831,223	$ 1,078,373,299	$ 39,290,881	$ 74,435,421
The Rest of the US Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	2,769	$ 234,510,720	$ 374,358,336	$ 551,765,000		
Indirect Effect	2,261	$ 143,525,846	$ 235,093,393	$ 444,286,560		
Induced Effect	4,878	$ 232,770,024	$ 413,151,695	$ 715,384,640		
Total Effect	9,908	$ 610,806,590	$ 1,022,603,424	$ 1,711,436,200	$ 97,810,455	$ 134,243,221
Totals, All Regions						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	8,477	$ 732,301,037	$ 935,170,965	$ 1,361,328,500		
Indirect Effect	3,594	$ 223,659,162	$ 367,972,940	$ 674,606,347		
Induced Effect	9,295	$ 414,977,683	$ 761,552,040	$ 1,280,395,246		
Total Effect	21,367	$ 1,370,937,882	$ 2,064,695,945	$ 3,316,330,093	$ 154,353,222	$ 241,852,839

Table ES—3 Phase 1 Operational Economic Impacts by Region and Category

Operational Totals						
Primary Impact Area						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	181	19,361,889	19,542,373	26,923,660		
Indirect Effect	23.7	1,007,856	1,821,401	3,737,316		
Induced Effect	115.1	3,881,637	7,917,407	12,880,528		
Total Effect	319.8	24,251,382	29,281,181	43,541,504	$1,309,510	$2,045,104
The Rest of Texas Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	92.3	10,293,102	10,399,311	13,501,890		
Indirect Effect	35.9	2,281,612	3,792,398	6,910,977		
Induced Effect	133.3	6,009,874	11,136,429	18,037,912		
Total Effect	261.5	18,584,588	25,328,138	38,450,779	$1,489,271	$2,388,146
The Rest of US Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	8.5	1,020,153	1,078,624	2,115,000		
Indirect Effect	34.8	2,292,975	3,642,131	7,427,823		
Induced Effect	71.5	3,637,000	6,318,634	11,357,995		
Total Effect	114.8	6,950,128	11,039,389	20,900,818	$974,929	$1,517,239
Operation Totals						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	281.8	30,675,144	31,020,308	42,540,550		
Indirect Effect	94.4	5,582,443	9,255,930	18,076,116		
Induced Effect	319.9	13,528,511	25,372,470	42,276,435		
Total Effect	696.1	49,786,098	65,648,708	102,893,101	$3,773,710	$5,950,489

2 Introduction

Black & Veatch was retained to conduct an economic impact analysis of the construction and operational expenditures associated with Phase 1 of Excelerate Energy's two phase Lavaca Bay LNG Project. The analysis in this report estimates the primary and secondary impacts of the Phase 1 project on three different geographic regions: the multi-county study region that includes the project site, the remainder of the state of Texas, and the remainder of the US. Impacts are estimated in the areas of employment, income, value added, wages, federal taxes, and state and local taxes. To derive these estimates, use has been made of data provided by Excelerate Energy and the IMPLAN impact analysis model, which is widely used in the energy industry.

3 Project Description

The Lavaca Bay LNG Project will be a Floating Liquefaction Storage Offloading (FLSO) vessel project to be located on the Gulf Coast in Port Lavaca, Texas in two phases. The first phase of the project will consist of one FLSO vessel with a storage capacity of 250,000 cubic meters of LNG and a liquefaction capacity of up to 5 million tons per annum (MTPA) or the equivalent of 0.665 billion cubic feet per day (Bcf/day) of natural gas. That is, the facility will be capable of converting natural gas to LNG and able to produce up to 5 million tons of LNG per year. The Phase 1 project will have feed gas requirements of approximately 600 million cubic feet per day (MMcf/d), including the gas required for power generation. Phase 1 has a target commercial operation date of the fourth quarter of 2017.

The Phase 2 project, which will add a second FLSO vessel, will essentially double the production and feedstock requirements listed above. The present analysis evaluates only the benefits from the Phase 1 expenditures and conservatively assumes that the Phase 1 plant operates at 80 percent of its production capacity.

Excelerate Energy's FSLO vessel concept involves the design of a vessel that is small enough to fit into a standard shipyard slot. The FLSO vessel has an expected overall length of 338 meters, a breadth of 62 meters, a depth of 33.4 meters, and a designed draft of 15 meters. The vessel's deadweight will be nearly 171,000 tons and the full load displacement will be nearly 282,000 tons. The vessel will be built in South Korea and will be designed to accommodate a 100 person crew. There will be an estimated 133 full time equivalent workers on the site, not including any pipeline employees.

The location of the project is strategic in that it will allow shipments to reach international markets efficiently. For example, shipments can be made to Brazil in 10 days, to England in 13 days, and to East Asian markets through the Panama Canal in 24 to 26 days. The 85 acre project site has been previously permitted by FERC as an LNG import terminal and lies in an already industrialized area. Considerable dredging will be required, and this activity will create significant primary economic impacts. Likewise, the project will involve the construction of a 27-mile natural gas pipeline lateral that will allow the transport of natural gas from several existing pipelines having a combined transport capacity of approximately 5 billion cubic feet per day. Other Phase I impacts will include the construction of the jetty for the first FLSO vessel and on-shore support facilities. Phase 2 will require the construction of a second jetty and FLSO vessel, but will utilize the project pipeline and dredging activities performed for Phase 1.

The timeline for project development includes detailed site assessment work, approvals for exports (with the Department of Energy), front end engineering and design work, agreements and permits for pipeline interconnection, and the FERC permitting and approval process. These activities are currently expected to be completed by the second quarter of 2014, with detailed design to then begin, followed by dredging activities at the start of 2015 and construction of the jetty and pipeline in the second quarter of 2015. Commercial operation is expected to occur late in the fourth quarter of 2017; thus, 2018 will be the first full year of commercial operation.

Excelerate Energy envisions a flexible operating model whereby it can sell LNG through a number of different commercial arrangements that may include:

- a *tolling agreement*—whereby a customer sources its own natural gas and enters into a take-or-pay liquefaction agreement with Excelerate Energy

- a *delivered capacity agreement*—whereby a customer sources its own natural gas and pays Excelerate Energy for take-or-pay liquefaction and shipping transport charges;
- or through a *FOB LNG Supply Agreement*—whereby a customer purchases LNG from Excelerate Energy either at the terminal or on a delivered basis and Excelerate Energy supplies natural gas at a price tied to Henry Hub plus a fee for fuel transport and conversion.

In this analysis, it is assumed that the sales would occur through a tolling agreement whereby Excelerate Energy earns a conversion or tolling fee.

4 Modeling Phase 1 Economic Impacts

4.1 PROJECTED PROJECT EXPENDITURES

Modeling the economic impacts of the Lavaca Bay LNG Project requires multiple inputs and assumptions that will ultimately flow into the impact analysis model. Foremost among these inputs are the expected costs and cost categories of the project during the construction and operational phases.

The project investment can be divided into its three main components: 1) the interconnection pipeline, 2) the FLSO vessel, and 3) the on-shore infrastructure plus off-shore dredging work. These components are described below and their costs are summarized in Table 4-1.

The pipeline interconnection will allow the transport of natural gas from any of nine nearby natural gas pipelines having a total carrying capacity of approximately 5,000 MMcf/d. These pipelines and their carrying capacity are:

- Probable Interconnects[1]:
  - Channel/HPL JV Pipeline; 600 MMcf/d
  - Florida Gas Transmission; 300 MMcf/d
  - Kinder Morgan-Tejas Pipeline; 800 MMcf/d
  - Natural Gas Pipeline of America; 700 MMcf/d
  - Transco Pipeline; 500 MMcf/d
  - Houston Pipeline; 230 MMcf/d[2]
  - Tennessee Gas Pipeline; 700 MMcf/d
- Possible Interconnects:
  - Texas Eastern Transmission; 750 MMcf/d[3]
  - Boardwalk Field Services (formerly Gulf South); 380 MMcf/d

The purchases of natural gas from these pipelines will result in significant upstream impacts in the natural gas production and transportation sectors. The interconnection pipeline will be a 27-mile pipeline segment having a diameter of 36 inches. The pipeline will also have associated compression and metering stations. It is expected that the FERC approval for this pipeline will be obtained and construction will begin in the first quarter of 2014. The budgeted cost of this component is $170 million in 2012 dollars.

The Phase 1 FLSO vessel is anticipated to have a processing capacity of up to 5 million tons per annum (MTPA). The vessel will utilize the PRICO liquefaction process developed by Black & Veatch. The vessel will also have 250,000 cubic feet of storage capacity that will utilize the GTT Mark III membrane containment system. The cargo tanks will have a 5 x 2 arrangement that will provide a total of ten 25,000 cubic feet tanks. The FLSO vessel will be built by Samsung Heavy Industries and the vessel will be constructed in South Korea, although some related expenditures will occur in the US, such as the $13.5 million expected for the FLSO front end engineering design and $12 million in permitting expenses. The anticipated total cost of the FLSO vessel is $1.3 billion in 2012 dollars.

[1] Source: Calhoun LNG FERC filing CP05-380, CP05-381, CP05-382, and Calhoun LNG web site; http://www.calhounlng.com/pipeline.htm
[2] Source: EIA state to state pipeline capacity - http://www.eia.gov/naturalgas/data.cfm
[3] Source: EIA state to state pipeline capacity - http://www.eia.gov/naturalgas/data.cfm

The third major expenditure category includes the on-site structures and processing equipment, the jetty, and the dredging work. A considerable amount of dredging activity will occur to allow the FLSO vessel and other vessels to reach the site in Lavaca Bay. The dredging will occur over a 24-mile stretch from Point Comfort in the port of Port Lavaca through the Matagorda Ship Channel and on to the open Gulf of Mexico. At the project site, dredging will include work to allow two FLSO vessel berthing pockets plus a turning basin. Dredging activities are budgeted to be $400 million in 2012 dollars.

Additional site work includes the jetty construction and structures to be located on the 85 acre site. The site is a green field area but has been previously permitted by FERC for location of an LNG import terminal. Various structures and buildings will be located on the site, with construction anticipated to begin the first quarter of 2014. Completion of the site works is expected by the second quarter of 2017. The budgeted cost of the jetty and site work is $275 million in 2012 dollars.

As shown in Table 4-1, the resulting total development and construction cost of the project is estimated to be approximately $2.15 billion. This total cost is in 2012 dollars.

During the LNG operational phase, there will be significant operations and maintenance (O&M) expenditures associated with the project, and these expenditures are estimated to total approximately $45 million in 2012 dollars. These O&M expenditures include approximately $12.2 million for supervisor, engineering, and terminal labor costs; $8.6 million for operations; $3.1 million for FLSO maintenance; $7.5 million for maintenance of the on-shore process facilities; $10.1 million for administration and general expenses; and $3.3 million for other O&M expenditures. These costs are listed shown in Table 4-1.

Table 4-1 Phase 1 Direct Construction and Operational Expenditures on the Lavaca Bay LNG Project

Direct Expenditures for the Port Lavaca LNG Facility during Construction and Operation (2012 Dollars)

CONSTRUCTION PHASE		OPERATIONAL PHASE (YEARLY EXPENDITURES)	
FLSO Vessel*	$1,300 million	Supervisors/engineering/ terminal labor & expenses	$12.2 million
Pipeline	$170 million	Operations	$8.6 million
On-Shore and Dredging Expenditures		FLSO maintenance	$3.1 million
Jetty/Site structures and processing	$275 million	On-shore facility maintenance	$7.5 million
Dredging	$400 million	Administration & General	$10.1 million
		Other O&M	$3.3 million
Total	**$2,145 million**	**Total**	**$44.8 million**

***Includes $13.5 million for front end engineering and $12 million in permitting costs.**

4.2 EXPENDITURES NOT INCLUDED

For purposes of this study, a conservative approach was taken and it was assumed that the tolling arrangement would be utilized for the sale of LNG. Thus, the economic impacts measured essentially end with the liquefaction process and do not account for additional benefits that would arise if

Excelerate shipped the LNG or if shipments occur in vessels owned and registered in the US or that have US crew members. To the degree that US ships and crew are involved in the delivery of the LNG product to the final destination, additional economic impacts would arise.

The analysis also assumes that no excess power produced from the facility power generation equipment is sold to the local grid. Should an arrangement occur in which excess power is sold, an additional category of impacts would be created.

This analysis assesses only the Phase 1 impacts, which are linked to the use of a single FLSO vessel. The Phase 2 project would add additional significant benefits not captured in this analysis.

For the operating period, the primary impacts measured are those arising from the operating and maintenance expenditures (O&M expenditures, from Table 4-1) of the project. The analysis conservatively assumes operation at 80 percent of full production capacity; in other words, it conservatively assumes that of the Phase 1 production capability of 5 MTPA, 4 MTPA is actually produced.

The MTPA production is only a portion of the actual impacts that will arise from operation, which could produce tolling fees and project pipeline transport fees in excess of $700 million per year assuming a tolling fee of $3.5/Mbtu and 4 MTPA of LNG shipped.[4] From this revenue, O&M expenses will be subtracted, debt service will be paid, income taxes will be incurred, and investors will earn a return on investment. While it is common to include interest on debt as part of economic impact assessments, the amount of interest generated will depend on the final cost of the facility, on the debt/equity ratio, and on the cost of debt. Since this information has not been finally determined or released, the impacts of expenditures in this category are not included in the analysis. The impact of the return on investment has similarly not been included, nor have the incomes taxes paid directly by the project been considered as these amounts depend on the profitability of the project during the long-term operation period. Thus, the operational impacts determined by modeling O&M expenditures in the operating period can be considered very conservative.

There will also be upstream impacts associated with the purchase of natural gas supplies for the project. These impacts will include the employment and earnings benefits associated with on-going well drilling, operation, and transport of natural gas to the project pipeline and project site. These impacts are evaluated separately below.

Other impacts that could arise from the project are price impacts on natural gas and additional natural gas pipeline construction that could arise if natural gas pipeline companies and natural gas producers in the region area see additional opportunities as a result of the Lavaca Bay LNG project. Note, however, that a natural gas price impact study has been performed by Black & Veatch as part of a separate assignment.

The project will also generate significant US exports and will improve the balance of trade with other countries. The total value of exports during operation will depend on the market price of natural gas

[4] Based on a the relationship of 1 ton of LNG containing 52 Mbtu, the production of 4 million tons of LNG per year would contain 208,000,000 Mbtu that, when applied to a tolling and project pipeline fee of $3.5/Mbtu yields $728 million in total conversion fees, and this export value would increase to $1.35 billion ($1.78 billion) with a $3/Mbtu ($5/Mbtu) price of natural gas is included. The upstream impacts of the natural gas purchases are evaluated below.

and the particular contracting method. A conservative estimate assuming a market natural gas price of \$3/Mbtu and a \$3.5/Mbtu tolling plus project pipeline fee would put the total value of exports at more than \$1.2 billion per year during operation if 4 MTPA out of the 5 MTPA Phase 1 capacity were produced and sold. At a market price of \$5/Mbtu, the value of exports and improvement to the US balance of payments would be more than \$1.6 billion per year when the tolling fee is included. This balance of payments impact would exceed \$2.2 billion per year assuming an average price of \$7/Mbtu for the natural gas.

Additional economic benefits could arise if the dredging and operational activities attract additional industries to the Lavaca Bay area, and this is possibility is increased due to the widening of the Panama Canal, which makes the Lavaca Bay a strategic location for global exporters.

5 Phase 1 Multiplier Impacts and the IMPLAN Model

The approximate $2.1 billion in direct construction investment and the annual O&M budget of approximately $45 million (all in 2012 dollars) will have a large and direct impact on the local area, state of Texas, and US economy. In addition to the primary or direct investment and expenditure impacts, there are also secondary impacts in the form of indirect and induced benefits.

To capture the total economic impact of the project investment and operating expenditures, it would be necessary to follow these expenditures as they worked their way through the economy over a period of a few years after expenditures are first made. For example, firms that perform the dredging operations will purchase materials and services from their suppliers and these may include purchases from a diverse set of companies offering products or services such as catering, fuel, specialized dredging equipment, sonar, financing, plus legal and environmental services. As these suppliers provide output to the dredging firm, the suppliers will spend their revenue to pay employees and to purchase their own inputs that will be turned into products for sale. This process arising from the business to business purchases continues through many rounds of spending in the economy and will create a total economic impact that is a multiple of the original purchase of material and service inputs by the dredging company. This type of effect is called the "indirect effect."

Similarly, a significant portion of the direct expenditure on dredging will be paid to workers who perform the dredging near the site and along the 24-mile route to the open Gulf of Mexico. Through what is called the "induced effect," these workers take their disposable earned income and spend it on goods and services such as clothing, rent, car payments, food, vacations, and savings. Establishments that receive the worker income in exchange for goods and services will, in turn, spend the revenue received to pay their own workers, to purchase supplies needed to provide additional goods and services, etc. This process will continue through multiple rounds of spending in the economy and will create a total economic impact that is a multiple of the original wages received by the dredging workers. Generally, through each round of spending, the impact will lessen because not all of the income is spent in the areas of study due to the purchase of imports, worker savings, taxes, etc. Thus, just as a stone thrown into water creates waves that lessen with time and distance, there will be an economic "ripple effect" with project expenditures that will lessen with time, as the successive rounds of spending work through the economy.

While envisioning the successive rounds of spending in an economy is intuitive, in reality, it is enormously difficult and expensive to trace the actual spending patterns of even a single construction project. Fortunately, there are mathematical methods for estimating the economic impact of an investment on the economy using complex economic models, commonly referred to as input-output models, first developed in the 1930s by Dr. Wassily Leontief. In recent decades, input-output models have been transformed into computerized commercial software that can generate impact estimates for employment, income, value added, output and taxes that arise due to a new investment or other change in economic activity. These models are built upon detailed databases, including survey data that tracks the historical economic interrelationship and expenditure patterns among industries and households. Two widely used input-output models are the RIMS II Input-Output model developed by the US Bureau of Economic Analysis, and the IMPLAN (Impact analysis for Planning) model, which is probably the most widely used model for large investment studies. IMPLAN was used in this analysis due to its widespread use and its multi-regional modeling capabilities.

The IMPLAN model has its roots in the 1970s and was developed initially by the US Forest Service, which wanted to determine the impacts of certain forestry policy and management decisions. In the mid-1980s, the US Forest Service contracted with the University of Minnesota to support and further develop the model data sets. In 1993, Minnesota IMPLAN Group, Inc. (MIG) was founded as an independent organization through a technology transfer agreement with the University of Minnesota, and MIG was given rights to all future IMPLAN development. In 1995, MIG began to develop the first Microsoft windows version and the following year IMPLAN Version 1 was released. This was followed by Version 2 in 1999 and Version 3 in 2009.[5] Version 3 has the ability to perform multi-regional impact analysis, which was used in the current study.

5.1 IDENTIFICATION OF THE PROJECT STUDY AREAS

One of the initial assumptions required in establishing an economic impact model is to determine the study area or areas to be evaluated. For the present analysis, it is beneficial to view impacts at the local, state, and federal level as the impacts will be the most significant at the local and state level, yet there will also be federal policy decisions and approvals required that will depend, in part, on a view of the project's national impacts. To assess the impacts of the project in each area a multi-regional modeling approach was used within IMPLAN. This approach allows the tracking of impacts from local expenditures on the project area, but it also allows tracking of local expenditure impacts on the state and US economies. Similarly, those expenditures made at the state level (not including those counties in local study area) will impact the local study area and US economies; and expenditures outside of Texas will impact the local study area and the remaining counties in the state.

Concerning the local study area, the analysis requires identification of the county or counties that will be identified as the Primary Impact Area going forward. The Primary Impact Area may, and in this study does, differ during the construction and operational phases.

While the most straightforward approach would be simply to equate the Primary Impact Area with the county containing the site (Calhoun County, Texas), this approach would tend to understate the impact of the project on other local communities and counties. An alternative approach in selecting the Primary Impact Area for the construction and operational phase is to identify the likely commuting distance that local workers may be willing to travel to reach the site. Thus, workers living in a nearby county and who are employed at the site during construction or operation will help generate economic benefits in their home counties and these counties should be included in the analysis as workers tend to spend most of their income in areas where they reside.

Studies of large construction projects have indicated that craft and specialized workers will be willing to commute, one way, up to 100 miles to work for extended periods of time lasting a year or more. For operational workers, the distance workers are willing to travel is less than temporary construction workers, and 60 miles is a reasonable limit to assume. To account for indirect transportation routes to the site, the decision was to include in the construction Primary Impact Area, those counties lying wholly or substantially within an 80-mile radius of the plant site. The exception was that Nueces County is also included in the construction Primary Impact Area because, while most of the county lies beyond the 80 mile radius, the county's largest population center of Corpus Christi is within the selected radius.

[5] IMPLAN Version 3.0 Training DVD, available from IMPLAN at IMPLAN.com

The Primary Impact Area for the construction phase is shown in Figure 5-1, and the counties in this area are listed in Table 5-4.

The operational Primary Impact Area was identified as those counties lying wholly or substantially within a 60 mile radius of the site. The resulting six county Primary Impact Area for the operational phase is shown in Figure 5-2, and the counties in this area are listed in Table 5-1.

Table 5-1 Primary Impact Area Counties for the Phase 1 Construction and Operational Analysis

CONSTRUCTION PHASE		OPERATIONAL PHASE
1. Calhoun	10. Goliad	1. Calhoun
2. Refugio	11. Karnes	2. Refugio
3. Victoria	12. DeWitt	3. Victoria
4. Jackson	13. Gonzales	4. Jackson
5. Matagorda	14. Lavaca	5. Matagorda
6. Aransas	15. Wharton	6. Aransas
7. San Patricio	16. Colorado	
8. Nueces	17. Brazoria	
9. Bee	18. Fort Bend	

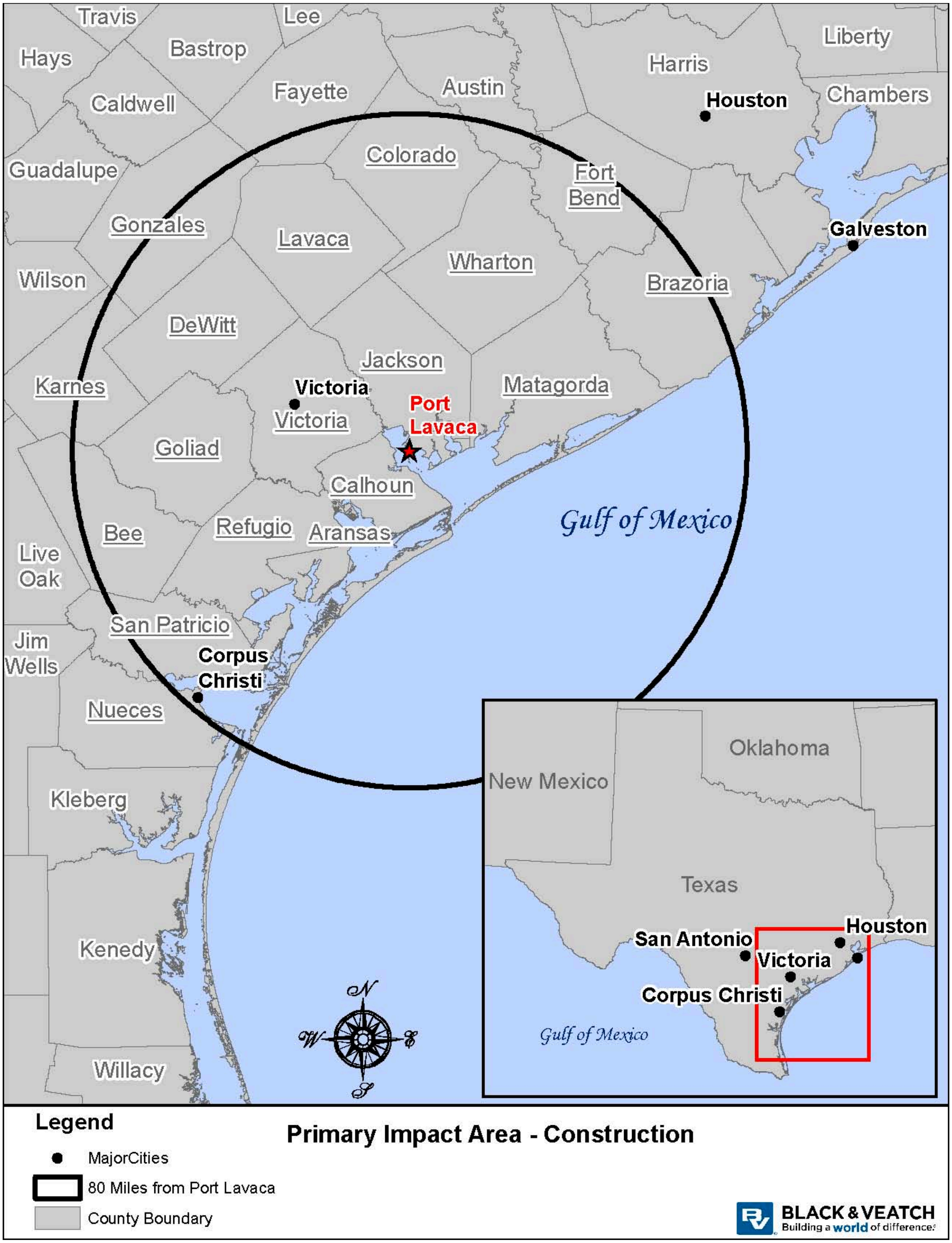


Figure 5-1 The Primary Impact Area During Construction

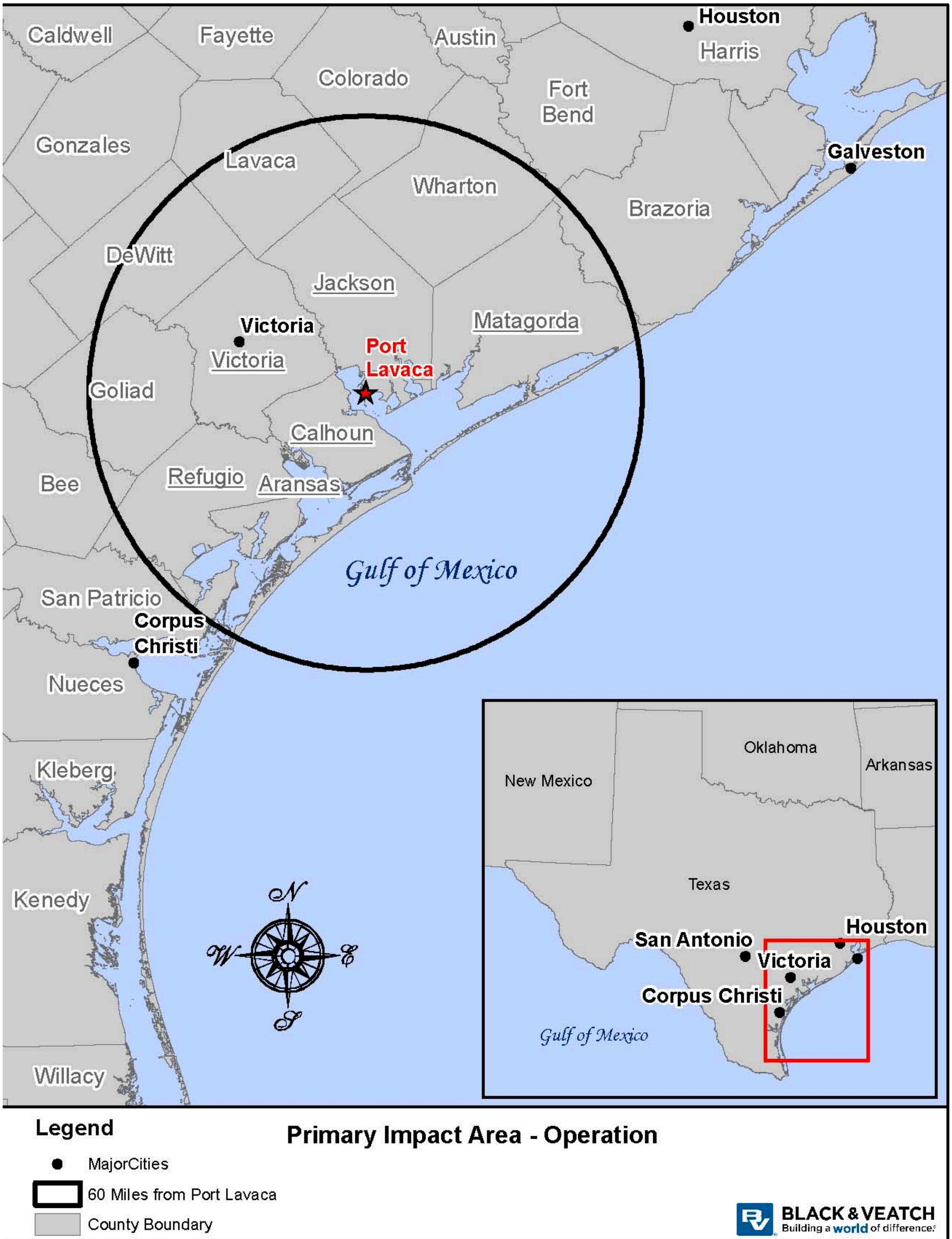


Figure 5-2 The Primary Impact Area During Operation

6 Phase 1 Economic Impacts of Facility Construction

6.1 INDUSTRY ALLOCATION OF CONSTRUCTION EXPENDITURES

The $2.1 billion of expenditures for the construction of the Phase 1 Lavaca Bay LNG Project was listed in Table 4-1 and arranged according to the three primary investment categories: the pipeline expenditures, the FLSO vessel and associated expenditures, and the dredging/on-site expenditures.

To construct the economic impact model using IMPLAN, the next step was to develop more specific expenditure assumptions for each of the three investment categories. While it is possible to use the general IMPLAN construction category (sector 36) to model midstream investments, this sector is widely defined and would also include, for instance, power plant and airport construction. Thus, the method chosen for this analysis was to follow a “bill of goods” method, also called an “analysis by parts” approach in IMPLAN. This approach involves identifying the sectors or industries in which the project investment expenditures will be made.

Expenditure patterns were developed by consulting engineers familiar with the design of the Lavaca Bay LNG Project and by leveraging information gathered for previous Black & Veatch studies of natural gas transmission pipeline economic impacts. Table 6-1 shows the derivation of the assumed sector expenditures for the pipeline, FLSO vessel, and dredging/on-shore expenditure categories; it also lists the corresponding IMPLAN industry code used in the impact analysis. The associated percents indicate the assumed portion of total project costs that will be spent in a given sector. Percent expenditures are also broken down into expenditures made within the US, the state of Texas, and the Primary Impact Area. Funds not spent in one of these three areas are assumed to be spent internationally. For example, since the FLSO vessel will be constructed in South Korea, the direct expenditures for this large investment in the three study regions will be relatively small in most IMPLAN industries. Given the large pipeline industry in the US and Texas, on the other hand, a high percentage of pipeline expenditures will likely occur in the three study regions, as will expenditures for many of the items in the jetty/dredging/on-shore processing category.

In Table 6-1, the derivation of the expenditures that were entered into the three IMPLAN models is shown in color. For the US model, shown in green shading, the first entry column lists the percent of total project expenditures in an industry that are assumed to occur in the US. The second entry (the second green-shaded column) lists the resulting total dollar expenditures assumed to occur in the US and the third entry (the third green-shaded column) lists the dollar expenditure amount entered for this industry in the IMPLAN US model. To avoid double counting of expenditures, the third entry subtracts out expenditures in the industry assumed to occur in the Primary Impact Area or in the rest of Texas since the US model is essentially a “rest of the US” model and does not include expenditures in the Primary Impact Area or in the rest of Texas. Thus, it is the amount in the third entry (the third green-shaded column) that was entered into the IMPLAN model for US expenditures. In a similar manner, the Texas model expenditures entered into the IMPLAN model for Texas (which is a “rest of Texas” model that does not include Primary Impact Area expenditures) is equal to the total expenditures for Texas less the expenditures assumed to occur in the Primary Impact Area.

In total, direct expenditures entered into the US model for the project are approximately $552 million; the Texas model reflects approximately $493 million of expenditures; and the Primary Impact Area reflects approximately $319 million in direct expenditures. In total, then, of the estimated direct project cost of approximately $2.1 billion, an estimated $1.36 billion will occur in the US and will be allocated between the Primary Impact Area, the rest of Texas, and the rest of the US. This domestic expenditure occurs because, even though the FLSO vessel (costing $1.3 billion) will be constructed in South Korea, the US will nevertheless benefit from the provision of design, financing, and certain components associated with the FLSO vessel.

Table 6-1 Development of Expenditure Sectors for Phase 1 Construction of the Lavaca Bay LNG Project

Pipeline (Costs in $000s)

Expenditure Categories	Assumed % by Category	$000s	Further Breakdown by Expenditure Category	IMPLAN Industry	Percent of Total Project Cost Assumed Spent in IMPLAN Industry	Dollar Total in Industry	Percent Domestic	US Expenditures	Input into Model 3 (US-Texas)	Percent of US Expenditures in State	State Expenditures	Inputs into Model 2 (Texas - PIA)	Percent of US Expenditures in Local Study Area	Study Area Expenditures, IMPLAN Entry	Inputs into Model 1 (PIA)
Misc. / Owner's Costs	28.0%	$47,600	Financing / Insterest During Construction	355 Nondepository credit intermediation and related activities	7.00%	$ 11,900	100%	$ 11,900	$ 5,950	50%	$ 5,950	$ 5,950	0%	$ -	$ -
			Engineering/ Design/ Construction Monitoring	369 Architectural, engineering and related services	8.00%	$ 13,600	100%	$ 13,600	$ 6,800	50%	$ 6,800	$ 6,800	0%	$ -	$ -
			Regulatory Approvals/ FERC Fees	355 Nondepository credit intermediation and related activities	2.00%	$ 3,400	100%	$ 3,400	$ 1,700	50%	$ 1,700	$ 1,530	5%	$ 170	$ 170
			Insurance	359 Insurance Carriers	2.00%	$ 3,400	100%	$ 3,400	$ 1,700	50%	$ 1,700	$ 1,530	5%	$ 170	$ 170
			Legal Fees	367 Legal Services	2.00%	$ 3,400	100%	$ 3,400	$ 1,700	50%	$ 1,700	$ 1,530	5%	$ 170	$ 170
			Survey	369 Architectural, engineering and related services	2.00%	$ 3,400	100%	$ 3,400	$ 850	75%	$ 2,550	$ 1,870	20%	$ 680	$ 680
			GA/office	29 Support activities for oil and gas operations	5.00%	$ 8,500	100%	$ 8,500	$ 425	95%	$ 8,075	$ 7,650	5%	$ 425	$ 425
ROW	7.0%	$11,900	Payments for Land	10006 Household 50-75k	4.50%	$ 7,650	25%	$ 1,913	$ -	25%	$ 1,913	$ 191	23%	$ 1,721	$ 1,721
			ROW Restoration	29 Support activities for oil and gas operations	2.50%	$ 4,250	100%	$ 4,250	$ -	100%	$ 4,250	$ 425	90%	$ 3,825	$ 3,825
Materials	31.0%	$52,700	Coated Pipe	170 Iron and steel mills and ferroalloy manufacturing	21.00%	$ 35,700	90%	$ 32,130	$ 17,850	40%	$ 14,280	$ 14,280	0%	$ -	$ -
			Valves/fittings/ casings	198 Valve and fittings other than plumbing manufacturing	2.00%	$ 3,400	90%	$ 3,060	$ 2,040	30%	$ 1,020	$ 1,020	0%	$ -	$ -
			Transportation	335 Truck Transportation	2.00%	$ 3,400	100%	$ 3,400	$ 1,700	50%	$ 1,700	$ 1,360	10%	$ 340	$ 340
			Compression	227 Air and gas compressor manufacturing	6.00%	$ 10,200	95%	$ 9,690	$ 5,610	40%	$ 4,080	$ 4,080	0%	$ -	$ -
Labor/ Installation	34.0%	$57,800	Installlation (Local)		32.00%	$ 54,400	100%	$ 54,400	$ 5,440	90%	$ 48,960	$ 19,040	50%	$ 27,200	$ 27,200
			Installation (Commuters)	Labor Income Change							$ -	$ -	5%	$ 2,720	$ 2,720
			Inspect/Testing	technical services	2.00%	$ 3,400	100%	$ 3,400	$ 680	80%	$ 2,720	$ 2,550	5%	$ 170	$ 170
Total	100%	$170,000			100.00%	$ 170,000		$ 159,843	$ 52,445		$ 107,398	$ 69,806		$ 37,591	$ 37,591

FLSO Vessels (Costs in $000s)

Expenditure Categories	Assumed % by Category	$000s	Further Breakdown by Expenditure Category	IMPLAN Industry	Percent of Total Project Cost Assumed Spent in IMPLAN Industry	Dollar Total in Industry	Percent Domestic	US Expenditures	Input into Model 3 (US-Texas)	Percent of US Expenditures in State	State Expenditures	Inputs into Model 2 (Texas - PIA)	Percent of US Expenditures in Local Study Area	Study Area Expenditures, IMPLAN Entry	Inputs into Model 1 (PIA)
Topside (Process, Power, Generation)	42.0%	$546,000	Material/Equipment	31 Electric Power Generation, Distribution, Transmission	19.00%	$ 247,000	80%	$ 197,600	$ 172,900	10%	$ 24,700	$ 24,700	0%	$ -	$ -
			Engineering/ Design/ Construction Monitoring	369 Architectural, engineering and related services	4.00%	$ 52,000	100%	$ 52,000	$ 52,000	0%	$ -	$ -	0%	$ -	$ -
			Module Fabriacation	NA	15.00%	$ 195,000	0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
			Installlation (Local)	NA	4.00%	$ 52,000	0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
			Installation (Commuters)				0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
Vessel (Hull, LNG Containment, Cargo Piping, Offloading, Flare,	39.0%	$507,000	Material/Equipment	NA	15.00%	$ 195,000	0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
			Engineering/ Design/ Construction Monitoring	NA	2.00%	$ 26,000	0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
			Hull Fabrication	NA	18.00%	$ 234,000	0%	$ -	$ -	0%	$ -	$ -	0%	$ -	$ -
			Installation (Local)		4.00%	$ 52,000	90%	$ 46,800	$ 20,800	50%	$ 26,000	$ 21,320	0%	$ -	$ -
			Installation (Commuters)	Labor Income Change			1%	$ 520	$ 520				9%	$ 4,680	$ 4,680
Site Hook up	4.0%	$52,000	Installation (Local)		4.00%	$ 52,000	100%	$ 52,000	$ -	100%	$ 52,000	$ 23,400	50%	$ 26,000	$ 26,000
			Installation (Commuters)	Labor Income Change							$ -		5%	$ 2,600	$ 2,600
Owners Cost	15.0%	$195,000	Financing / Insterest During	355 Nondepository credit intermediation	5.00%	$ 65,000	100%	$ 65,000	$ 32,500	50%	$ 32,500	$ 32,500	0%	$ -	$ -
			Engineering/ Design/	369 Architectural, engineering and related	5.00%	$ 65,000	100%	$ 65,000	$ 32,500	50%	$ 32,500	$ 32,500	0%	$ -	$ -
			Regulatory Approvals/FERC	355 Nondepository credit intermediation	1.00%	$ 13,000	100%	$ 13,000	$ 6,500	50%	$ 6,500	$ 5,850	5%	$ 650	$ 650
			Insurance	359 Insurance Carriers	1.00%	$ 13,000	100%	$ 13,000	$ 6,500	50%	$ 6,500	$ 5,850	5%	$ 650	$ 650
			Legal Fees	367 Legal Services	1.00%	$ 13,000	100%	$ 13,000	$ 6,500	50%	$ 6,500	$ 5,850	5%	$ 650	$ 650
			Survey	369 Architectural, engineering and related	1.00%	$ 13,000	100%	$ 13,000	$ 3,250	75%	$ 9,750	$ 7,150	20%	$ 2,600	$ 2,600
			GA/office	29 Support activities for oil and gas operations	1.00%	$ 13,000	100%	$ 13,000	$ 650	95%	$ 12,350	$ 11,700	5%	$ 650	$ 650
Total	100%	$1,300,000			100.00%	$ 1,300,000		$ 543,920	$ 334,620		$ 209,300	$ 170,820		$ 38,480	$ 38,480

Jetty, Dredging/Processing/Site (On-Shore Infrastructure, Costs in $000s)

Expenditure Categories	Assumed % by Category	$000s	Further Breakdown by Expenditure Category	IMPLAN Industry	Percent of Total Project Cost Assumed Spent in IMPLAN Industry	Dollar Total in Industry	Percent Domestic	US Expenditures	Input into Model 3 (US-Texas)	Percent of US Expenditures in State	State Expenditures	Inputs into Model 2 (Texas - PIA)	Percent of US Expenditures in Local Study Area	Study Area Expenditures	Inputs into Model 1 (PIA)
Jetty (Mooring/ Breasting Dolphins, Testles,	14.0%	$94,500.00	Material/Equipment	206 Mining and oil and gas field machinery	3.00%	$ 20,250	80%	$ 16,200	$ 1,013	75%	$ 15,188	$ 14,175	5%	$ 1,013	$ 1,013
			Engineering/ Design/ Construction Monitoring	369 Architectural, engineering and related services	2.00%	$ 13,500	75%	$ 10,125	$ 7,425	20%	$ 2,700	$ 2,700		$ -	$ -
			Installation (Local)			$ 60,750	100%	$ 60,750	$ -	100%	$ 60,750	$ 27,337.50	50%	$ 30,375	$ 30,375
			Installation (Commuters)	Labor Income Change	9.00%								5%	$ 3,038	$ 3,038
Dredging	50.0%	$337,500.00	Dredging	26 Mining and Quarrying sand, gravel, and c	50.00%	$ 337,500	100%	$ 337,500	$ 67,500	80%	$ 270,000	$ 101,250	50%	$ 168,750	$ 168,750
Process (Gas Compression, Gas Pretreatment, Gas	23.0%	$155,250.00	Material/Equipment	227 Air and gas compressor manufacturing	12.00%	$ 81,000	90%	$ 72,900	$ 32,400	50%	$ 40,500	$ 36,450	5%	$ 4,050	$ 4,050
			Engineering/ Design/ Construction Monitoring	369 Architectural, engineering and related services	3.00%	$ 20,250	100%	$ 20,250	$ 17,213	15%	$ 3,038	$ -	15%	$ 3,038	$ 3,038
			Installation (Local)		8.00%	$ 54,000	100%	$ 54,000	$ -	100%	$ 54,000	$ 24,300.0	50%	$ 27,000	$ 27,000
			Installation (Commuters)	Labor Income Change									5%	$ 2,700	$ 2,700
Owner's Cost	13.0%	$87,750.00	Financing / Insterest During	355 Nondepository credit intermediation	4.00%	$ 27,000	100%	$ 27,000	$ 13,500	50%	$ 13,500	$ 13,500	0%	$ -	$ -
			Engineering/ Design/	369 Architectural, engineering and related	4.00%	$ 27,000	100%	$ 27,000	$ 13,500	50%	$ 13,500	$ 13,500	0%	$ -	$ -
			Regulatory Approvals/FERC	355 Nondepository credit intermediation	1.00%	$ 6,750	100%	$ 6,750	$ 3,375	50%	$ 3,375	$ 3,038	5%	$ 338	$ 338
			Insurance	359 Insurance Carriers	1.00%	$ 6,750	100%	$ 6,750	$ 3,375	50%	$ 3,375	$ 3,038	5%	$ 338	$ 338
			Legal Fees	367 Legal Services	1.00%	$ 6,750	100%	$ 6,750	$ 3,375	50%	$ 3,375	$ 3,038	5%	$ 338	$ 338
			Survey	369 Architectural, engineering and related	1.00%	$ 6,750	100%	$ 6,750	$ 1,688	75%	$ 5,063	$ 3,713	20%	$ 1,350	$ 1,350
			GA/office	operations	1.00%	$ 6,750	100%	$ 6,750	$ 338	95%	$ 6,413	$ 6,075	5%	$ 338	$ 338
Total	100%	$675,000.00			100.00%	$ 675,000		$ 659,475	$ 164,700		$ 494,775	$ 252,113		$ 242,663	$ 242,663
Total Project Expenditures, Total US Expenditures, and Total Expenditures Entered in to the Three Regional Models						**$ 2,145,000**		**$ 1,363,238**	**$ 551,765**			**$ 492,739**			**$ 318,734**

Following the allocation of expenditures by sector, multi-regional IMPLAN models were constructed and linked such that interregional secondary effects could be captured. As an example, the Primary Impact Area model was also linked to the Texas model (that included the rest of Texas, or all Texas counties outside the Primary Impact Area) and the US model (that included the rest of the US, or all states (plus Washington D.C.) other than Texas and the Primary Impact Area counties). Similarly, the Texas model was linked to the Primary Impact Area and US models; and the US model was linked to the Texas model and Primary Impact Area model. The three regional models and their interactive relationship are illustrated in Figure 6-1.

Once the models were established, IMPLAN was run and produced the direct, indirect and induced impacts of investments in the categories of employment, income, value added and output. In addition, IMPLAN tracked federal plus state and local taxes in the economy. The results of these simulations have been condensed and are presented below.

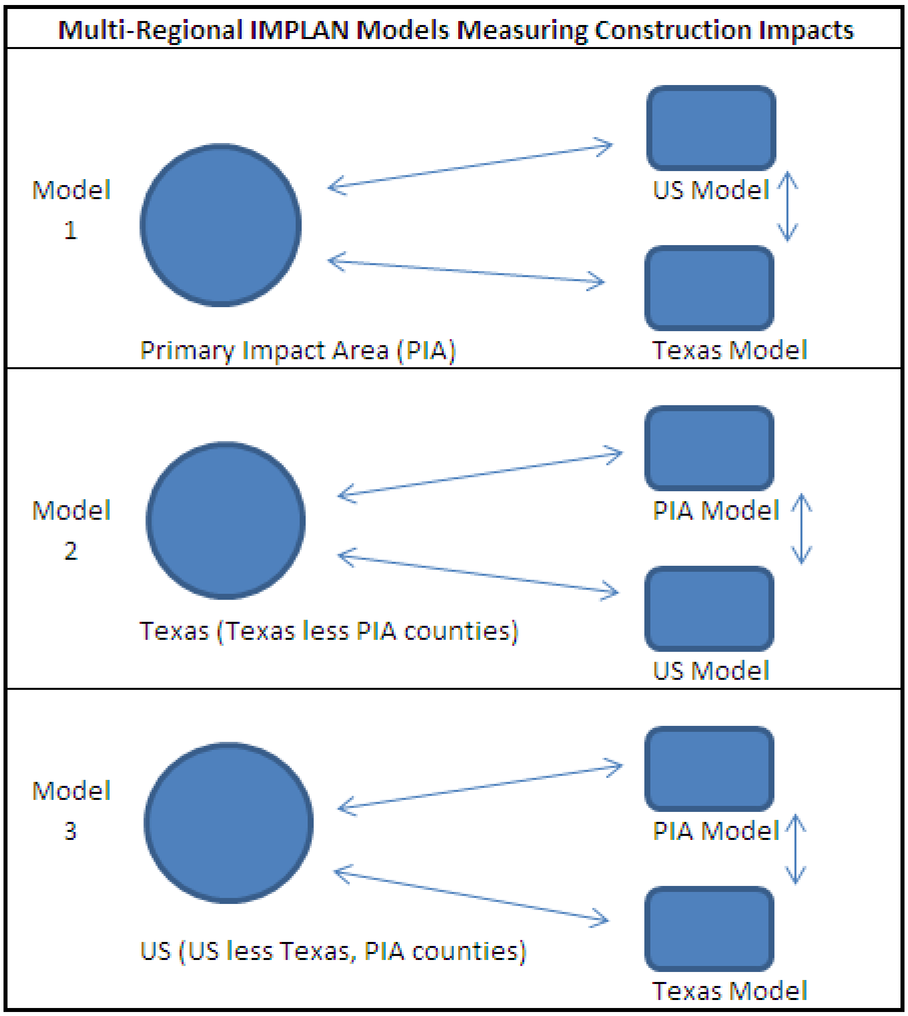


Figure 6-1 Multi-Regional IMPLAN Models Used to Estimate Construction Impacts

6.2 IMPACT RESULTS

Table 6-2 presents a summarized version of the IMPLAN modeling results for the Primary Impact Area model, the Texas model, and the US model. Results are arranged by impact category and type of effect. The results are explained below starting with the Primary Impact Area model results.

Table 6-1 indicates that the Primary Impact Area will experience an estimated $273 million in direct construction expenditures. These expenditures are projected to have the following impacts:

- The Primary Impact Area construction expenditures are estimated to support or create a total of approximately 4,213 jobs including those arising from direct, indirect, and induced effects. These employment numbers should be viewed as total job-years supported or created by expenditures during the study period.[6]
- The Primary Impact Area construction expenditures are estimated to create $282 million in labor income (which includes wages and benefits) at an average of $66,872 per job across all impacted industries. Labor income includes all forms of employment income, including employee compensation (wages and benefits) and proprietor income.
- The Primary Impact Area construction expenditures are estimated to contribute more than $363 million in value added. Value added for a firm is their sales revenue less the costs of goods and services purchased. The sum of value added in all industries is the gross domestic product (GDP), or the total value of all final goods and services produced in the nation.[7]
- The Primary Impact Area construction expenditures are estimated to account for more than $526 million in total economic output, which is the total value of production from all industries impacted by the investment expenditures. Virtually all industries will be impacted by direct expenditures; some will directly supply equipment and materials while other industries as workers spend their income on goods and services. [8]
- The Primary Impact Area construction expenditures are projected to generate $17.2 million in state and local taxes and $33.2 million in total federal tax revenues.

Table 6-1 indicates that the rest of Texas (all counties in the state except those in the Primary Impact Area) will experience an estimated $437 million in direct construction expenditures. These expenditures are projected to have the following impact:

- The rest of Texas construction expenditures are estimated to support or create 7,245 jobs, or an average of 2,415 jobs per year during the three year construction period expenditures.
- The rest of Texas construction expenditures are estimated to create $478 million in labor income at an average of $66,028 per job across all impacted industries.

[6] IMPLAN's glossary of terms defines a "job" as "the annual average of monthly jobs in that industry" but also points out that this can be "1 job lasting 12 months" or"2 jobs lasting 6 months each" or "3 jobs lasting 4 months each" and also explains that "a job can be either full-time or part-time."

[7] The IMPLAN glossary defines "value added" as "The difference between an industry's or an establishments total output and the cost of its intermediate inputs. It equals gross output (sales or receipts and other operating income, plus inventory change) minus intermediate inputs (consumption of goods and services purchased from other industries or imported)." As a simplified example, if a pipeline manufacturer purchased a steel plate for $10,000 then transformed this into a pipeline segment that was then sold for $50,000 then the value added would be $40,000 (ignoring other intermediate inputs and their costs).

[8] The IMPLAN glossary defines "output" as "the value of industry production…in producer prices. For manufacturers this would be sales plus/minus change in inventory. For service sectors production = sales…."

- The rest of Texas construction expenditures are estimated to contribute nearly $679 million in value added.
- The rest of Texas construction expenditures are estimated to account for more than $1.07 billion in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The rest of Texas construction expenditures are projected to generate $39.3 million in state and local taxes and $74.4 million in total federal tax revenues.

Table 6-1 indicates that the rest of the US (all states except Texas and the Primary Impact Area counties) will experience an estimated $552 million in direct construction expenditures. These expenditures are projected to have the following impact:

- The rest of the US construction expenditures are estimated to support or create 9,908 jobs, or an average of 3,303 jobs per year during the three year construction period expenditures.
- The rest of the US construction expenditures are estimated to create nearly $611 million in labor income at an average of $61,646 per job across all impacted industries.
- The rest of the US construction expenditures are estimated to contribute more than $1.02 billion in value added.
- The rest of the US construction expenditures are estimated to account for more than $1.71 billion in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The rest of the US construction expenditures are projected to generate nearly $98 million in state and local taxes and more than $134 million in total federal tax revenues.

Combining the impacts of all three models, the $1.36 billion in direct US construction expenditures are projected to generate the following:

- The combined expenditures are projected to support or create 21,367 jobs or an average of 7,122 jobs per year during the three year construction period expenditures.
- The combined expenditures are estimated to create more than $1.37 billion in labor income at an average of $64,163 per job across all impacted industries.
- The combined expenditures are estimated to contribute more than $2.06 billion in value added.
- The combined expenditures are estimated to account for nearly $3.32 billion in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The combined construction expenditures are projected to generate more than $154 million in state and local taxes and nearly $242 million in total federal tax revenues.

Table 6-2 Phase 1 Impacts of Construction in the Three Multi-Regional IMPLAN Models

Total Impacts From Construction Expenditures						
Primary Impact Area						
Impact Type	Employment	Labor Income	Value Added	Output	State and Local Taxes	Federal Taxes
Direct Effect	2,550	$ 220,243,892	$ 237,125,274	$ 317,016,000		
Indirect Effect	260	$ 15,891,886	$ 27,813,530	$ 48,006,720		
Induced Effect	1,402	$ 45,593,857	$ 98,322,494	$ 161,497,874		
Total Effect	4,213	$ 281,729,635	$ 363,261,298	$ 526,520,594	$ 17,251,886	$ 33,174,197
The Rest of Texas Impacts						
Impact Type	Employment	Labor Income	Value Added	Output	State and Local Taxes	Federal Taxes
Direct Effect	3,158	$ 277,546,425	$ 323,687,355	$ 492,547,500		
Indirect Effect	1,072	$ 64,241,430	$ 105,066,017	$ 182,313,067		
Induced Effect	3,015	$ 136,613,802	$ 250,077,851	$ 403,512,732		
Total Effect	7,245	$ 478,401,657	$ 678,831,223	$ 1,078,373,299	$ 39,290,881	$ 74,435,421
The Rest of the US Impacts						
Impact Type	Employment	Labor Income	Value Added	Output	State and Local Taxes	Federal Taxes
Direct Effect	2,769	$ 234,510,720	$ 374,358,336	$ 551,765,000		
Indirect Effect	2,261	$ 143,525,846	$ 235,093,393	$ 444,286,560		
Induced Effect	4,878	$ 232,770,024	$ 413,151,695	$ 715,384,640		
Total Effect	9,908	$ 610,806,590	$ 1,022,603,424	$ 1,711,436,200	$ 97,810,455	$ 134,243,221
Totals, All Regions						
Impact Type	Employment	Labor Income	Value Added	Output	State and Local Taxes	Federal Taxes
Direct Effect	8,477	$ 732,301,037	$ 935,170,965	$ 1,361,328,500		
Indirect Effect	3,594	$ 223,659,162	$ 367,972,940	$ 674,606,347		
Induced Effect	9,295	$ 414,977,683	$ 761,552,040	$ 1,280,395,246		
Total Effect	21,367	$ 1,370,937,882	$ 2,064,695,945	$ 3,316,330,093	$ 154,353,222	$ 241,852,839

7 Phase 1 Economic Impacts of Facility Operation

7.1 INDUSTRY ALLOCATION OF OPERATIONAL EXPENDITURES

In Table 6-1, the annual O&M expenditures were estimated to be $44.8 million (2012 dollars). Table 7-1 further divides these expenditures into industries and allocates these expenditures to the Primary Impact Area, the rest of Texas, and the rest of the US.

Of the $44.8 million in expected annual O&M expenditures, most is expected to be spent domestically, as reflected in the $42.5 million figure in the column labeled 'US Expenditures'. Of the total domestic expenditures, more than $40 million is expected to be spent in the state of Texas and this is divided into a projected $26.9 million that will be spent in the Primary Impact Area and $13.5 million that will be spent in the rest of Texas. During the operational phase, the percent accounted for by the state and Primary Impact Area is high because the largest expenditure components are for wages paid to staff working directly at the site or to general and administrative staff assumed to be located in Texas.

Table 7-1 O&M Expenditure Allocation by Industry and Region

Annual Operations and Maintenance												
Expenditure Categories	IMPLAN Industry	% of Total Project Cost Assumed Spent in IMPLAN Industry	Dollar Total in IMPLAN Industry	Percent Domestic	US Expenditure, IMPLAN Entry	Input into Model 3 (US-Texas)	Percent of US Expenditures in State	Expenditures, IMPLAN Entry	Inputs into Model 2 (Texas -PIA)	Expenditures in Local Study Area	Study Area Expenditures, IMPLAN Entry	Inputs into Model 1 (PIA)
Supervisor/Engineering salaries plus Terminal Labor & Expenses	Labor Income Change	27.18%	$ 12,183.55	100%	$ 12,184	$ -	100%	$ 12,183.55	$ -	100%	$ 12,183.55	$ 12,183.55
Operations	29 Support Activites for oil and gas operations	19.29%	$ 8,645.50	100%	$ 8,646	$ -	100%	$ 8,645.50	$ -	100%	$ 8,645.50	$ 8,645.50
Maintenance	417 Commercial and industrial machinery and equipment and repair and maintenance	6.86%	$ 3,076.00	50%	$ 1,538	$ 615	30%	$ 922.80	$ 769.00	5%	$ 153.80	$ 153.80
	337 Transport by Pipeline	16.73%	$ 7,500.00	90%	$ 6,750	$ 1,500	70%	$ 5,250.00	$ 3,000.00	30%	$ 2,250.00	$ 2,250.00
Administration & General Salaries	Labor Income Change	22.48%	$ 10,074.71	100%	$ 10,075	$ -	100%	$ 10,074.71	$ 7,052.29	30%	$ 3,022.41	$ 3,022.41
Other A&G	29 Support Activites for oil and gas operations	7.46%	$ 3,342.00	100%	$ 3,342	$ -	100%	$ 3,342.00	$ 2,673.60	20%	$ 668.40	$ 668.40
Total		100.00%	$ 44,821.76		$ 42,534	$ 2,115		$ -	$ 13,494.89	15%	$ 6,380.06	$ 26,923.66

7.2 IMPACT RESULTS

The anticipated $44.8 million in direct annual O&M expenditures associated with the Lavaca Bay LNG Project will produce significant benefits to the Primary Impact Area, to the rest of Texas, and to the rest of the US. As opposed to the construction impacts, which will largely be realized over a three to five year period, the annual operating impacts will be long-term in nature and will be generated for the duration of the project operational life. If it is conservatively assumed that the project will have a 20-year operating life, the results summarized below can be multiplied by 20 to arrive at the total operational impacts (all in 2012 dollars).

The results of the IMPLAN modeling indicate that the annual O&M impacts on these three regions are listed in Table 7-2 and include the following:

- The Primary Impact Area O&M expenditures are estimated to support or create 320 jobs on an ongoing, long-term basis. These employment numbers should be viewed as total job-years supported or created by expenditures during each year of the operational phase.
- The Primary Impact Area O&M expenditures are estimated to create $24.3 million in labor income (which includes wages and benefits) at an average of $75,833 per job across all impacted industries.
- The Primary Impact Area O&M expenditures are estimated to contribute more than $29.2 million in value added. Value added for a firm is their sales revenue less the costs of goods and services purchased. The sum of value added in all industries is the gross domestic product (GDP), or the total value of all final goods and services produced in the nation.
- The Primary Impact Area O&M expenditures are estimated to account for more than $43.5 million in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The Primary Impact Area O&M expenditures are projected to generate more than $1.3 million in state and local taxes and more than $2.0 million in total federal tax revenues each year of operation.

The O&M expenditures in the rest of Texas (all counties in the state except those in the Primary Impact Area) are projected to have the following annual impacts:

- The rest of Texas O&M expenditures are estimated to support or create 262 jobs during the operational phase.
- The rest of Texas O&M expenditures are estimated to create $18.6 million in labor income across all impacted industries.
- The rest of Texas O&M expenditures are estimated to contribute more than $25 million in value added each year.
- The rest of Texas O&M expenditures are estimated to account for nearly $38.5 million in total economic output each year, which is the total value of production from all industries impacted by the expenditures.
- The rest of Texas O&M expenditures are projected to generate nearly $1.5 million in state and local taxes and $2.4 million in total federal tax revenues each year.

The O&M expenditures in the rest of the US will be relatively small, since most of the project workers will live in the Primary Impact Area or the rest of Texas. Impacts in the rest of the US include an estimated 115 jobs each year, plus $7.0 million in labor income, $11.0 million in value added, and nearly $21 million in output.

Combining the impacts of all three models, the $38.2 million in direct O&M expenditures are projected to generate the following annual impacts:

- The combined O&M expenditures are projected to support or create 696 jobs.
- The combined O&M expenditures are estimated to create nearly $50 million in labor income.
- The combined O&M expenditures are estimated to contribute more than $65million in value added.
- The combined O&M expenditures are estimated to account for more than $102 million in total economic output.
- The combined construction expenditures are projected to generate nearly $3.8 million in state and local taxes each year and nearly $6.0 million in total federal tax revenues.

In addition to the economic benefits arising from direct O&M expenditures, there will be economic impacts associated with the upstream expenditures on natural gas. As natural gas is purchased for delivery to the project pipeline and site, these expenditures will support upstream activities including drilling for, putting in place, and operating natural gas wells, plus processing and transporting natural gas. Conservatively assuming that gas is priced at $3/Mbtu and that Phase 1 production is at 80 percent of full capacity, approximately $625 million in natural gas expenditures will be associated with upstream purchases. This annual expenditure was evaluated in the IMPLAN model and the resulting impacts indicate that, on an annual basis, these expenditures will support 3,872 jobs, will generate $286 million in labor income, $600 million in value added, $1.23 billion in output, $82 million in state and local taxes, and $73 million in federal taxes.

Table 7-2 Operational Economic Impacts by Region and Category

Operational Totals						
Primary Impact Area						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	181	19,361,889	19,542,373	26,923,660		
Indirect Effect	23.7	1,007,856	1,821,401	3,737,316		
Induced Effect	115.1	3,881,637	7,917,407	12,880,528		
Total Effect	319.8	24,251,382	29,281,181	43,541,504	$1,309,510	$2,045,104
The Rest of Texas Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	92.3	10,293,102	10,399,311	13,501,890		
Indirect Effect	35.9	2,281,612	3,792,398	6,910,977		
Induced Effect	133.3	6,009,874	11,136,429	18,037,912		
Total Effect	261.5	18,584,588	25,328,138	38,450,779	$1,489,271	$2,388,146
The Rest of US Impacts						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	8.5	1,020,153	1,078,624	2,115,000		
Indirect Effect	34.8	2,292,975	3,642,131	7,427,823		
Induced Effect	71.5	3,637,000	6,318,634	11,357,995		
Total Effect	114.8	6,950,128	11,039,389	20,900,818	$974,929	$1,517,239
Operation Totals						
Impact Type	**Employment**	**Labor Income**	**Value Added**	**Output**	**State and Local Taxes**	**Federal Taxes**
Direct Effect	281.8	30,675,144	31,020,308	42,540,550		
Indirect Effect	94.4	5,582,443	9,255,930	18,076,116		
Induced Effect	319.9	13,528,511	25,372,470	42,276,435		
Total Effect	696.1	49,786,098	65,648,708	102,893,101	$3,773,710	$5,950,489

8 Other Study Results

Other studies of proposed LNG facilities have also concluded that significant economic benefits will be generated through the construction and operation of facilities to import or export LNG. A number of these studies have been performed in conjunction with applications to the Department of Energy (DOE) for authorization to export LNG.[9] Several such studies are summarized below.

The *Gulf Coast LNG Exports, LLC* application to the DOE for export authorization dated January 10, 2012 would involve the export of an equivalent of 1,022 billion cubic feet per year for a 25 year period.[10] Direct expenditures are estimated to be $12 billion and construction is projected to involve over 3,000 design and construction jobs. The project will be phased into operation between 2018 and 2020 and will have a permanent staff of more than 250 employees. The application estimates that providing the natural gas for the project will involve expenditures of $5.4 billion per year for exploration, drilling, and production. Assuming that 6.2 to 7.7 jobs are created for every $1 million spent, the application estimates that between 34,000 and 42,000 jobs will be created as a result of the project. Balance of trade benefits are estimated to be $7.3 billion per year.

The *Freeport LNG Expansion, L.P.Project* application to the DOE for long-term export authorization was filed on January 12, 2012. This project would involve the export of the LNG equivalent of 1.4 billion cubic feet per day for a 25-year period.[11] The application estimates that that project would involve more than 3,000 jobs during the four year design and construction process and hundreds of additional jobs to support the construction of the facilities. During operation, the application estimates that in addition to the direct employees, between 17,000 and 21,000 new domestic jobs will be supported indirectly by the increase in natural gas drilling. Total economic benefits during operation are estimated to be $3.6 to $5.2 billion per year during operation, with total balance of payment impacts of $3.9 billion per year at an assumed average price of $7/Mbtu.

The *Jordan Cove LNG Terminal* is a proposed terminal that would allow for the export of LNG from the proposed location in Coos County, Oregon.[12] The project would involve the use of four trains located on a 360 acre site and would have a maximum production capacity of 6.0 million metric tons per year with an expected production of 5.4 million metric tons per year. The design would also include a 350 MW combined cycle power plant and would involve the construction of a 36 inch, 234 mile natural gas pipeline having the capability to deliver 1.1 billion cubic feet per day when operations begin at the end of 2017. The economic analysis that estimated project impacts found that during each year of operation:

- The annual O&M expenditures would be approximately $65 million each year.
- 146 workers would be directly employed or their salaries paid by the project; 647 jobs would be created through secondary impacts

[9] The DOE lists 14 dockets involving applications for LNG and Long-Term Natural Gas Applications (these applications are at various stages of review and approval. See http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_Long_Term_Applications.html, accessed August 23, 2012.)

[10] See *Application of Gulf Coast LNG Exports, LLC For Long-Term Authorization to Export Liquefied Natural Gas*, filed with the DOE Office of Fossil Energy on January 10, 2012.

[11] See *Application of Freeport LNG Expansion, P.P. and FLNG Liquefaction, LLC For Long-Term Authorization to Export Liquefied Natural Gas to Free Trade Agreement Countries*, filed with the DOE Office of Fossil Energy on January 12, 2012.

[12] See An Economic Impact Analysis of Jordan Cove LNG Terminal and Pacific Gas Connector Pipeline Operations by ECONorthwest, March 6, 2012.

- More than $10 million in property taxes would be created at the county level plus the project would contribute $30 million in payments in lieu of property taxes.
- $ 1.5 billion in GDP would be generated (note: these estimates are higher than the current study because the analysis of impacts for the Lavaca Bay LNG Project include only impacts from O&M expenditures plus upstream impacts whereas the Jordan Cove LNG analysis estimated the project value added, which was defined in the study as the market value of LNG for export less all spending on goods and services for producing the LNG including the market value of the natural gas consumed by the terminal).

The *Cameron LNG project*, to be located along the Gulf Coast in Louisiana, would export up to 12 million metric tons per year of LNG produced from domestic sources.[13] The project would have a capital cost of more than $4 billion and would export approximately $8.6 billion of LNG annually. The application to the US Department of Energy estimated that the economic benefits of the project would include:

- On-site job creation of more than 1,300 over a four-year construction period.
- An economy-wide creation of 63,000 job-years.
- A total economic impact of construction of $7.6 billion.
- An average of 53,000 jobs during the 20-year operations period.
- An increase in US output of $336 billion over the 20-year operation period (again, these operational estimates are much higher than in the current study that has conservatively restricted operational impacts in the IMPLAN analysis to the impact of O&M expenditures).
- An improvement of the US trade balance of $10.8 billion per year in 2011 dollars, consisting of $8.6 billion in LNG exports and $2.2 billion in natural gas liquids production.

In May, 2011, the US Department of Energy conditionally approved the export of LNG from the *Sabine Pass LNG Terminal* in Louisiana. The project will involve the export of up to 803 billion cubic feet per year of domestically produced natural gas as LNG for a period of 20 years. The project will involve the retrofit of an existing LNG import terminal in Louisiana so that it can accommodate exports, and the project was the first long-term authorization to export natural gas from the lower 48 states as LNG to all US trading partners. Project studies estimate that the project will create or sustain approximately 3,000 jobs during the development and construction phases and an estimated 150 to 250 full-time positions during the operational phase. In addition, it is estimated that 30,000 to 50,000 permanent jobs would be supported in the exploration and production sector associated with natural gas upstream development.

An economic impact study was performed in 2005 by the University of Maine to evaluate the impacts of the construction and operation of a $400 million *LNG import facility* to be located in Robbinston, Maine.[14] The project would include a pier, two LNG storage tanks, gasification

---

[13] See the Application of Cameron LNG, LLC For Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Countries, submitted to the US Department of Energy Office of Fossil Energy, December 21, 2011.
[14] See *Economic and Fiscal Impacts of a Proposed LNG Facility in Robbinston, Maine*, prepared by Todd Gabe, Jonathan Rubin, Charles Morris and Lisa Bragg, Department of Resource Economics and Policy Margaret Chase Smith Policy Center, University of Maine, REP Staff Paper #556, November 2005

processes able to process 180 billion cubic feet of natural gas, and a natural gas pipeline. The three year construction project and subsequent operations were projected to have the following impacts:

- Construction would support an estimated 1,053 jobs in the state each of the three construction years (300 of these would be direct).
- Construction activities would generate nearly $43 million in direct and secondary income each year.
- Operational impacts would support 253 jobs in Maine over the life of the terminal (78 would be direct jobs).
- The 253 workers would earn approximately $10.7 million of income each year.

This sample of studies for other LNG-related projects supports the findings in this study that there are significant economic benefits associated with the construction and operation of LNG facilities in the US. Benefits will occur in the areas of employment, income, tax generation, value added, and improvements in the US trade balance. The results of other studies support the view that the present analysis of the Lavaca Bay LNG Project is reasonable and conservative.

9 Conclusions

The proposed Lavaca Bay LNG Project will have an initial investment value of $2.1 billion in 2012 dollars for Phase 1. Of this total expenditure, approximately $1.36 billion will be spent directly in the US on activities varying from dredging to design of the FLSO vessel. While the largest impact of these expenditures will be realized in the Primary Impact Area and in the rest of Texas, the remainder of the US will also benefit as these initial impacts work their way through the economy.

The total impact of the project construction includes:

- The combined expenditures are projected to support or create 21,367 jobs or an average of 7,122 jobs per year during the three year construction period expenditures.
- The combined expenditures are estimated to create more than $1.37billion in labor income at an average of $64,163 per job across all impacted industries.
- The combined expenditures are estimated to contribute more than $2.06 billion in value added.
- The combined expenditures are estimated to account for nearly $3.31 billion in total economic output, which is the total value of production from all industries impacted by the investment expenditures.
- The combined construction expenditures are projected to generate $154 million in state and local taxes and more than $241 million in total federal tax revenues.

The operational phase will also generate economic benefits, and these impacts will be long-term in nature. This study focused only on the economic impacts of Phase 1 O&M expenditures (estimated to be $45 million per year) during the operational period but nevertheless found the impacts from these expenditures to be significant. The total expected impacts during each year of operation are projected to include the following:

- The combined O&M expenditures are projected to support or create 696 jobs.
- The combined O&M expenditures are estimated to create more than $49 million in labor income.
- The combined O&M expenditures are estimated to contribute nearly $66 million in value added.
- The combined O&M expenditures are estimated to account for more than $102 million in total economic output.
- The combined O&M expenditures are projected to generate more than $3.7 million in state and local taxes each year and nearly $6.0 million in total federal tax revenues.

Phase 1upstream benefits include the estimated support of 3,872 jobs per year, $286 million in labor income, $600 million in value added, $1.23 billion in total output, $82 million in state and local taxes, and $73 million in federal taxes. These impacts conservatively assume that Phase 1 production is 80 percent of the maximum output capability (i.e., 4 MTPA production out of 5 MTPA capacity).

While not directly measured in the IMPLAN modeling of the project, there will also be significant benefits to the US economy in the form of an improved balance of trade during operation. Even at a market natural gas price of $3/Mbtu and 80 percent utilization, the project will result in added exports in the range of $1.35 billion each year when including a tolling and project pipeline transport fee of approximately $3.5/Mbtu. This annual impact increases to approximately $1.78

billion at a natural gas price of $5/Mbtu and approximately $2.2 billion at a market price of $7/Mbtu.

There could be many additional and significant benefits arising from Phase 1 of the Lavaca Bay LNG Project that were not directly included in the impact analysis. These additional benefits may include:

- The benefits that will be associated with expenditures of project revenues for interest payments and return on equity, as well as the income taxes directly generated from project operations.
- The added benefits that could arise if excess power is sold to the grid.
- The added benefits that could arise from additional investment in shipping and export operations located in Lavaca Bay made possible with the project dredging. The widening of the Panama Canal further enhances the locational advantage of Lavaca Bay.
- The added benefit of the potential for a Phase 2, which would essentially double the production capability of the Lavaca Bay LNG Project.
- The benefits associated with shipping costs and wages that would arise if US vessels and staff are used to deliver LNG to its final destination.

Finally, in that this analysis evaluated impacts from Phase 1 of the Lavaca Bay LNG Project, the benefits from Phase 2 would further increase project benefits. Phase 2 expenditures would be on the order of two-thirds of the Phase 1 construction expenditures, and would essentially double the productive capability during the operational period.

APPENDIX F – DELOITTE MARKETPOINT ANAYLYSIS

Deloitte.

Deloitte MarketPoint.
Analysis of Economic Impact of LNG Exports from the United States

Contents

Executive summary

Deloitte MarketPoint LLC (“DMP”) has been engaged by Excelerate Energy L.P. ("Excelerate") to provide an independent and objective assessment of the potential economic impacts of LNG exports from the United States. We analyzed the impact of exports from Excelerate’s Lavaca Bay terminal, located along the Gulf coast of Texas, by itself and also in combination with varying levels of LNG exports from other locations.

A fundamental question regarding LNG exports is: Are there sufficient domestic natural gas supplies for both domestic consumption and LNG exports. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas resources to supply both domestic consumption and exports? A more difficult question is: How much will U.S. natural gas prices increase as a result of LNG exports? To understand the possible answers to these questions, one must consider the full gamut of natural gas supply and demand in the U.S. and the rest of the world and how they are dynamically connected.

In our view, simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. The real issue is not one of volume, but of price impact. In a free market economy, price is one of the best measures of scarcity, and if price is not significantly affected, then scarcity and shortage of supply typically do not occur. In this report, we demonstrate that the magnitude of domestic price increase that results from exports of natural gas in the form of LNG is projected to be quite small.

However, other projections, including those developed by the DOE’s Energy Information Administration (EIA), estimate substantially larger price impacts from LNG exports than derived from our analysis. We shall compare different projections and provide our assessment as to why the projections differ. A key determinant to the estimated price impact is the supply response to increased demand including LNG exports. To a large degree, North American gas producers’ ability to increase productive capacity in anticipation of LNG export volumes will determine the price impact. After all, there is widespread agreement of the vast size of the North American natural gas resource base among the various studies and yet estimated price impacts vary widely. If one assumes that producers will fail to keep pace with demand growth, including LNG exports, then the price impact of LNG exports, especially in early years of operations, will be far greater than if they anticipate demand and make supplies available as they are needed. Hence, a proper model of market supply-demand dynamics is required to more accurately project price impacts.

DMP applied its integrated North American and World Gas Model (WGM or Model) to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects

[1] This report was prepared for Excelerate Energy L.P. ("Client") and should not be disclosed to, used or relied upon by any other person or entity. Deloitte Marketpoint LLC shall not be responsible for any loss sustained by any such use or reliance. Please note that the analysis set forth in this report is based on the application of economic logic and specific

monthly prices and quantities over a 30 year time horizon based on demonstrated economic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM solves for prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along each stage of the supply chain. It rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. More information about WGM is included in the Appendix.

Vital to this analysis, the WGM represents fundamental natural gas producer decisions regarding when and how much reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the price impact. Indeed, producers will anticipate the export volumes and make production decisions accordingly. LNG exporters might back up their multi-billion dollar projects with long-term supply contracts, but even if they do not, producers will anticipate future prices and demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to over-estimate the price impact of a demand change. Typically, users have to override this assumption by manually adjusting supply to meet demand. If insufficient supply volumes are added to meet the incremental demand, prices could shoot up until enough supply volumes are added to eventually catch up with demand.

Instead of a static approach, the WGM uses sophisticated depletable resource modeling to represent producer decisions. The model uses a "rational expectations" approach, which assumes that today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

It is well documented that shale gas production has grown tremendously over the past several years. According to the EIA, shale gas production climbed to over 35% of the total U.S. production in January of 2012[2]. By comparison, shale gas production was only about 5% of the total U.S. production in 2006, when improvements in shale gas production technologies (e.g., hydraulic fracturing combined with horizontal drilling) were starting to significantly reduce production costs. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, WGM projects production based resource volumes and costs, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

assumptions and the results are not intended to be predictions of events or future outcomes.

Notwithstanding the foregoing, Client may submit this report to the U.S. Department of Energy and the Federal Energy Regulatory Commission in support of Client's liquefied natural gas "(LNG") export application.

[2] Computed from the EIA's Natural Gas Weekly Update for week ending June 27, 2012.

Based on our existing model and assumptions, which we will call the "Reference Case", we developed five cases with different LNG export volumes to assess the impact of LNG exports. The five LNG export scenarios and their assumed export volumes by location are shown in Figure 1. Other Gulf in the figure refers to all other Gulf of Mexico terminals in Texas and Louisiana besides Lavaca Bay.

All cases are identical except for the assumed volume of LNG exports. The 1.33 Bcfd case assumed only exports from Lavaca Bay so that we could isolate the impact of the terminal. In the other LNG export cases, we assumed the Lavaca Bay terminal plus volumes from other locations so that the total exports volume equaled 3, 6, 9, and 12 Bcfd. The export volumes were assumed to be constant for twenty years from 2018 through 2037.

We represented LNG exports in the model as demands at various model locations generally corresponding to the locations of proposed export terminals (e.g., Gulf Texas, Gulf Louisiana, and Cove Point) that have applied for a DOE export license. The cases are not intended as forecasts of which export terminals will be built, but rather to test the potential impact given alternative levels of LNG exports. Furthermore, the export volumes are assumed to be constant over the entire 20 year period. Since our existing model already represented these import LNG terminals, we only had to represent exports by adding demands near each of the terminals. Comparing results of the five LNG export cases to the Reference Case, we projected how much the various levels of LNG exports could increase domestic prices and affect production and flows.

Given the model's assumptions and economic logic, the WGM projects prices and volumes for over 200 market hubs and represents every state in the United States. We can examine the impact at each location and also compute a volume-weighted average U.S. "citygate" price by weighting price impact by state using the state's demand. Impact on the U.S. prices increase along with the volume of exports.

As shown in Figure 2, the WGM's projected

Figure 1: LNG export scenarios

	Export Case				
Terminal	**1.33 Bcfd**	**3 Bcfd**	**6 Bcfd**	**9 Bcfd**	**12 Bcfd**
Lavaca Bay	1.33	1.33	1.33	1.33	1.33
Other Gulf		1.67	4.67	6.67	9.67
Cove Point (MD)				1.0	1.0
Total	1.33	3.0	6.0	9.0	12.0

Figure 2: Potential Impact of LNG export on U.S. prices (Average 2018-37)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	0.4%	0.4%	0.3%
3 Bcfd	1.0%	1.7%	0.9%
6 Bcfd	2.2%	4.0%	1.9%
9 Bcfd	3.2%	5.5%	3.2%
12 Bcfd	4.3%	7.7%	4.1%

impact on average U.S. citygate prices for the assumed years of operation (2018 to 2037) ranged from well under 1% in the 1.33 Bcfd (Lavaca Bay only) case to 4.3% in the 12 Bcfd case. However, the impacts vary significantly by location. Figure 2 shows the percentage change relative to the Reference Case to the projected average U.S. citygate price and at the Henry Hub and New York prices under various LNG export volumes.

As Figure 2 shows, the price impact is highly dependent on location. The impact on the price at Henry Hub, the world's most widely used benchmark for natural gas prices, is significantly higher than the national average. The reason is that the Henry Hub, located in Louisiana, is in close proximity to the prospective export terminals, which are primarily located in the U.S. Gulf of Mexico region. Since there are several cases analyzed, we will primarily describe results of the 6 Bcfd export case since it is the middle case. The impacts are roughly proportional to the export volumes. In the 6 Bcfd export case, the impact on the Henry Hub price is an increase of 4.0% over the Reference Case. Generally, the price impact in markets diminishes with distance away from export terminals as other supply basins besides those used to feed LNG exports are used to supply those markets. Distant market areas, such as New York and Chicago, experience only about half the price impact as at the Henry Hub. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total estimated impact on the U.S. consumers.

The results show that if exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

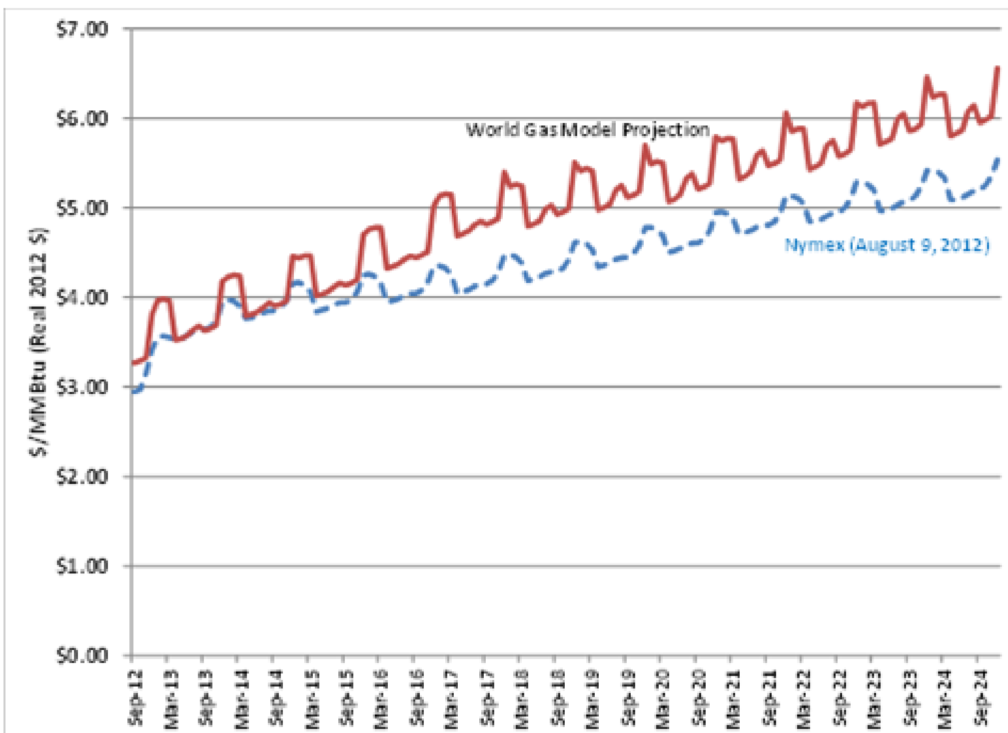
According to our projections, 12 Bcfd of LNG exports are projected to increase the average U.S. citygate gas price by 4.3% and Henry Hub price by 7.7% on average over a twenty year period (2018-37). This indicates that the projected level of exports is not likely to induce scarcity on domestic markets. The domestic resource base is expected to be large enough to absorb the incremental volumes required by LNG exports without a significant increase to future production costs. If the U.S. natural gas industry can make the supplies available by the time LNG export terminals are ready for operation, then the price impact will likely reflect the minimal change in production cost. As the industry has shown in the past several years, it is capable of responding to market signals and developing supplies as needed. Furthermore, the North American energy market is highly interconnected so any change in prices due to LNG exports from the U.S. will cause the entire market to re-equilibrate, including gas fuel burn for power generation and net imports from Canada and Mexico. Hence, the entire North American energy market would be expected to in effect work in tandem to mitigate the price impact of LNG exports from the U.S.

Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no LNG exports from the United States. U.S. gas demand growth rates for all sectors except for electricity were based on EIA's recently released Annual Energy Outlook (AEO) 2012 projection, which shows a significantly higher US gas demand than in the previous year's projection. Our gas demand for power generation is based on projections from DMP's electricity model, which is integrated with our WGM. (There is no intended advocacy or prediction of these events one way or the other. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall conclusion would be rather similar.)

In the WGM Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2012 dollars), benchmark U.S. Henry Hub spot prices are projected by the WGM to increase from currently depressed levels to $5.34 per MMBtu in 2020, before rising to $6.88 per MMBtu in

Figure 3: Projected Henry Hub prices from the WGM compared to Nymex futures prices



2030 in the Reference Case scenario.

The WGM Reference Case projection of Henry Hub prices is compared to the Nymex futures prices in Figure 3. (The Nymex prices, which are the dollars of the day, were deflated by 2.0%[3] per year to compare to our projections, which are in real 2012 dollars.) Our Henry Hub price projection is similar to the Nymex prices in the near-term but rises above it in the longer term. Bear in mind that our Reference Case by design assumes no LNG exports whereas there is possible there is some expectation of LNG exports from the U.S. built into the Nymex prices. Under similar assumptions, the difference between our price projection and Nymex likely would be even higher. Hence, our Reference Case would represent a fairly high price projection even without LNG exports.

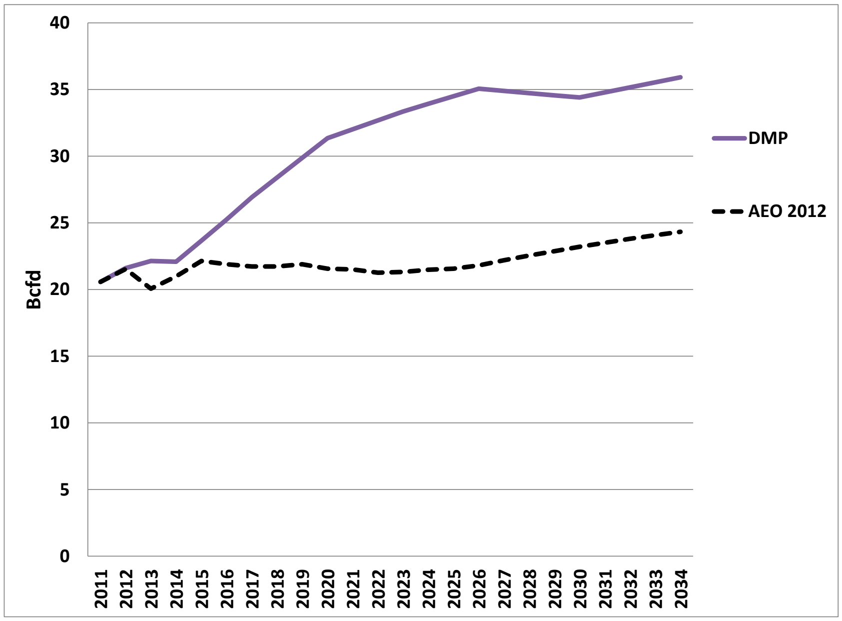
One possible reason why our price projection in the longer term is higher than market expectation, as reflected by the Nymex futures prices, is because of our projected rapid increase in gas demand for power generation. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 4, the DMP projected gas demand for U.S. power generation gas is far greater than the demand predicted by EIA's AEO 2012, which forecasts fairly flat demand for power generation. In the U.S., the power sector, which accounts for nearly all of the projected future growth, is projected to increase by about 50% (approximately 11 Bcfd) over the next decade. Our integrated electricity model projects that natural gas will become the fuel of choice for power generation due to a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; coal plant retirements; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO 2012 forecast, our Reference Case projection does not assume any new carbon legislation.

Our electricity model, fully integrated with our gas (WGM) and coal models, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO2, SOx, NOx, and mercury). The integrated structure of these models is shown in Figure 5. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a number of factors, including plant capacities, fuel prices, heat rates, variable costs, and environmental emissions costs. The model integration of North American natural gas with the rest of the world and the North American electricity market captures the global linkages and also the inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates.

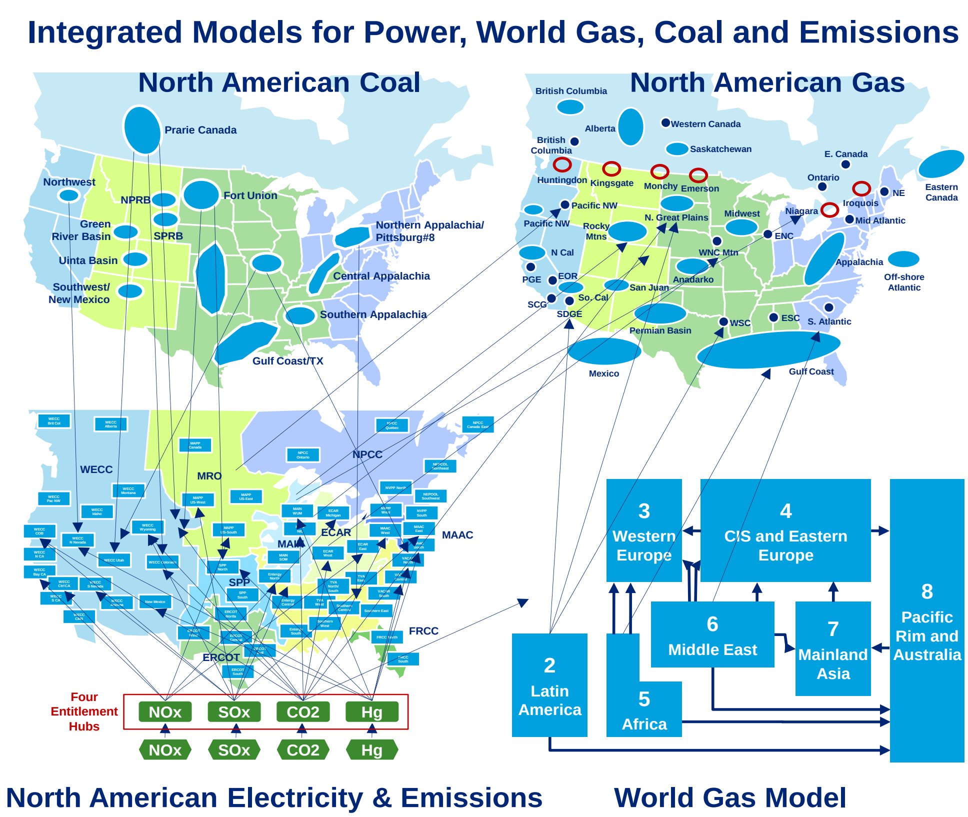
[3] Approximately the average consumer price index over the past 5 years according to the Bureau of Labor Statistics.

Figure 4: Comparison of projections of the U.S. gas demand for power generation



Furthermore, the electricity sector is projected to be far more responsive to natural gas price than any other sector. We model demand elasticity in the electricity sector directly rather than through elasticity estimates.

Figure 5: DMP North American Representation



Hence, the WGM projections include the impact of increased natural gas demand for electricity generation, which vies with LNG exports for domestic supplies. From the demand perspective, this is a conservative case in that the WGM would project a larger impact of LNG export than if we had assumed a lower US gas demand, which would likely make more supply available for LNG export and tend to lessen the price impact. Higher gas demand would tend to increase the projected prices impacts of LNG export. However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports. The absolute price of natural gas will be determined by a number of supply and demand factors in addition to the volume of LNG exports.

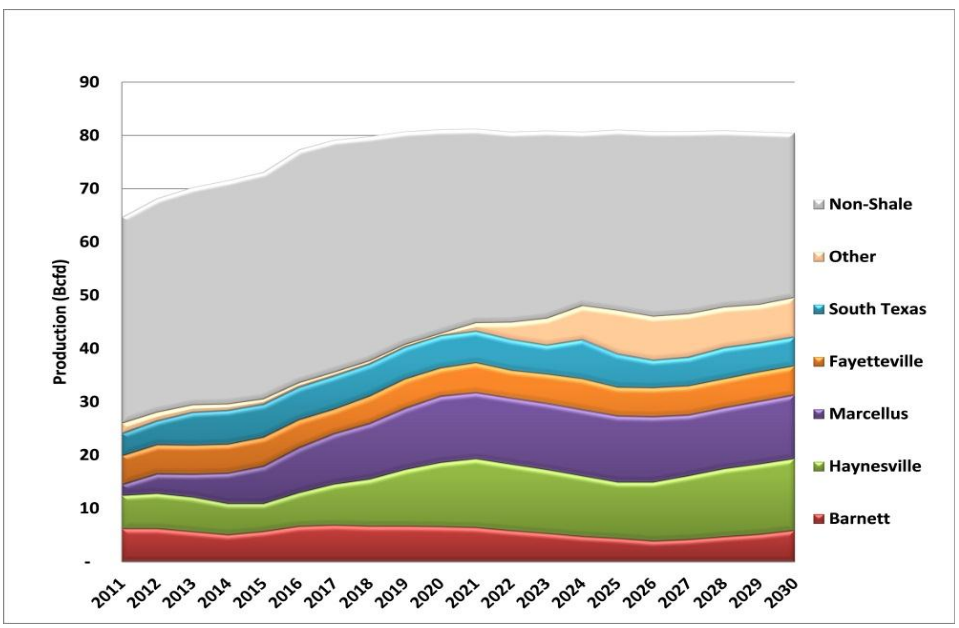
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas which we project to be an increasingly important component of domestic supply. As shown in Figure 6, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 66 Bcfd in 2011 to almost 79 Bcfd in 2018 before tapering off.

The growth in production from a large domestic resource base is a crucial point and consistent with fundamental economics. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. They believe, de facto, that natural gas supply is highly “elastic,” i.e., the supply curve is very flat.

A flattening supply curve is consistent with the resource pyramid diagram that the United States Geological Survey and others have postulated. At the top of the pyramid are high quality gas supplies which are low cost but also are fairly scarce. As you move down the pyramid, the costs increase but the supplies are more plentiful. This is another interpretation of our supply curve which has relatively small amounts of low cost supplies but as the cost increases, the supplies become more abundant.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in

Figure 6: U.S. gas production by type



production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S.

Rather than basing our production projections solely on the physical decline rates of producing fields, the WGM considers economic displacement as new, lower cost supplies force their way into the market. The North American natural gas system is highly integrated so Canadian supplies can easily access U.S. markets when economic.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, has already started to transform historical basis relationships (the difference in prices between two markets) and the trend is projected to continue during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, although to a lesser degree.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. Indeed, the flattening of Eastern bases is already becoming evident. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Gas production from Marcellus Shale will help shield the Mid-Atlantic region from supply and demand changes in the Gulf region. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The result could be displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Understanding the dynamic nature of the natural gas market is paramount to understanding the impact of LNG exports. If LNG is exported from any particular location, the entire North American natural gas system will potentially reorient production, affecting basis differentials and flows. Basis differentials are not fixed and invariant to LNG exports or any other supply and demand changes. On the contrary, LNG exports will likely alter basis differentials, which lead to redirection of gas flows to highest value markets from each source given available capacity.

Potential impact of LNG exports

Impact on natural gas prices

We analyzed five LNG export cases within this report: one case with Lavaca Bay only (1.33 Bcfd) and four other cases with varying levels of total U.S. LNG export volumes (3 Bcfd, 6 Bcfd, 9 Bcfd and 12 Bcfd exports). Each case was run with the DMP's Integrated North American Power and Gas Models in order to capture the dynamic interactions across commodities.

For ease of reporting, we will focus on the results with 6 Bcfd of LNG exports, our middle case, without any implication that it is more likely than any other case. Given the model's assumptions, the WGM projects 6 Bcfd of LNG exports will result in a weighted-average price impact of $0.15/MMBtu on the average U.S. citygate price from 2018 to 2037. The $0.15/MMBtu increase represents a 2.2% increase in the projected average U.S. citygate gas price of $6.96/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.26/MMBtu during this period. It is important to note the variation in price impact by location. The impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

For all five export cases considered, the projected natural gas price impacts at the Henry Hub, New York, and average US citygate from 2018 through 2037 are shown in Figure 7.

To put the impact in perspective, Figure 8 shows the price impact of the midpoint 6 Bcfd case compared to projected Reference Case U.S. average citygate prices over a twenty year period. The height of the bars represents the projected price with LNG exports.

The small incremental price impact may not appear intuitive or expected to those familiar with market traded fluctuations in natural gas prices. For example, even a 1 Bcfd increase in demand due to sudden weather changes can cause near term traded gas prices to surge because in the short term, both supply and demand are highly inelastic (i.e., fixed quantities). However, in the long-term, producers can develop more reserves in anticipation of demand growth, e.g. due to LNG exports. Indeed, LNG export projects will likely be linked in the origination market to long-term supply contracts, as well as long-term contracts with LNG buyers. There will be ample notice and

Figure 7: Price impact by scenario for 2018-37 ($/MMBtu)

Export Case	Average US Citygate	Henry Hub	New York
1.33 Bcfd	$ 0.03	$ 0.03	$ 0.02
3 Bcfd	$ 0.07	$ 0.11	$ 0.06
6 Bcfd	$ 0.15	$ 0.26	$ 0.14
9 Bcfd	$ 0.22	$ 0.36	$ 0.23
12 Bcfd	$ 0.30	$ 0.50	$ 0.29

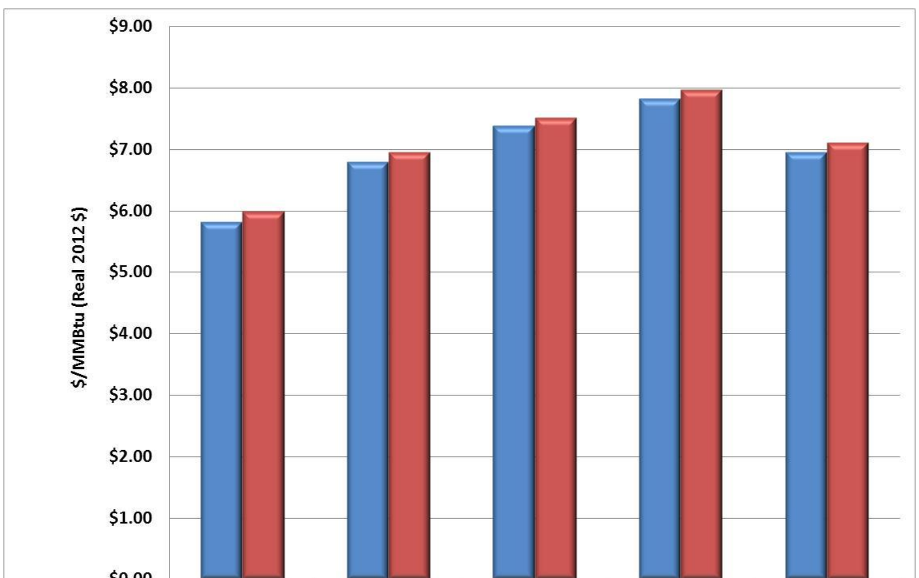
time in advance of the LNG exports for suppliers to be able to develop supplies so that they are available by the time export terminals come into operation. Therefore, under our long-term equilibrium modeling assumptions, long-term changes to demand may be anticipated and incorporated into supply decisions. The built-in market expectations allows for projected prices to come into equilibrium smoothly over time. Hence, our projected price impact primarily reflects the estimated change in the production cost of the marginal gas producing field with the assumed export volumes.

As previously stated, the model projected price impact varies by location as shown in Figure 9.

As previously described, the price impact diminishes with distance from export terminals. For all cases the impact is greatest at Henry Hub, situated near most export terminals. For the midpoint case of 6 Bcfd, the impact at the Houston Ship Channel is nearly as much as Henry Hub, at $0.26/MMBtu on average from 2018 to 2037. As distance from export terminals increases (i.e., distance to downstream markets such as Chicago, California and New York) the price impact is generally only about $0.12 to $0.14/MMBtu on average from 2018 to 2037.

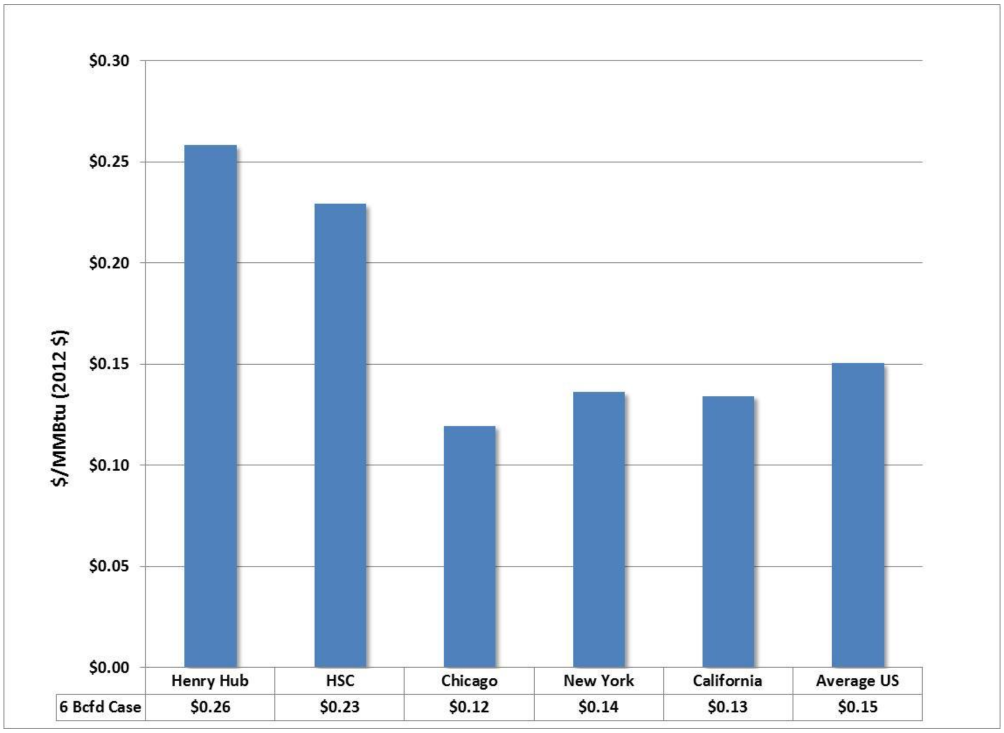
Similarly, Figures 8 and 9 corresponding to the other export cases (1.33, 3.0, 9.0 and 12.0 Bcfd) are shown in the Appendix.

Figure 8: Projected Impact of LNG exports on average U.S. Citygate gas prices (Real 2012 $)



	2018-2022	2023-2027	2028-2032	2033-2037	2018-2037
Reference Case	$5.83	$6.80	$7.38	$7.83	$6.96
6 Bcfd Case	$5.99	$6.96	$7.51	$7.97	$7.11

Figure 9: Price impact varies by location in 6 Bcfd export case (average 2018-37)



Impact on electricity prices

The projected impact on electricity prices is even smaller than the projected impact on gas prices. DMP's integrated power and gas model allows us to estimate incremental impact on electricity prices resulting from LNG export assumptions, as natural gas is also a fuel used for generating electricity. Since our integrated model represents the geographic linkages between the electricity and natural gas systems, we can compute the potential impact of LNG exports in local markets (local to LNG exports) where the impact would be the largest.

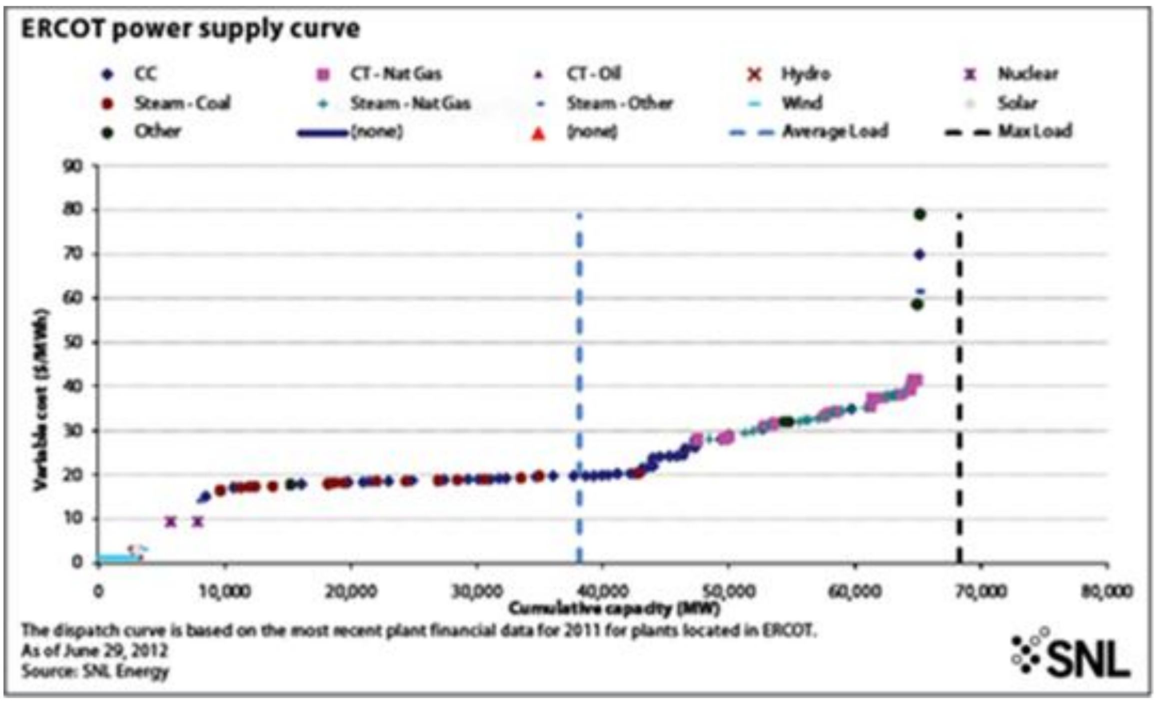
A similar comparison for electricity shows that the projected average (2018-2037) electricity prices increase by 0.8% in ERCOT (the Electric Reliability Council of Texas), under the 6 Bcfd export case. The impact on electricity prices is much less than the 4.0% Henry Hub gas price impact. For power markets in other regions, the electricity price impact is much lower, because the gas price impact is much lower.

A key reason why the price impact for electricity is less than that of gas is that electricity prices will only be directly affected by an increase in gas prices when gas-fired generation is the marginal source of power generation. That is, gas price only affects power price if it changes the marginal unit (i.e., the last unit in the generation stack needed to service the final amount of electricity load). When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive gas-fired generation to be the marginal source of generation. If gas-fired generation is already more expensive than the marginal source of generation, then an increase in gas price will not impact electricity price, since gas-fired generation is not being utilized because there is sufficient capacity from units with lower generation costs.

If gas-fired generation is the marginal source, then electricity price will increase with gas price, but only up to the point that some other source can displace it as marginal source. Every power region has numerous competing power generation plants burning different fuel types, which will mitigate the price impact of an increase in any one fuel type. Moreover, within DPM's integrated power and gas model, fuel switching among coal, nuclear, gas, hydro, wind and oil units is directly represented as part of the modeling.

Figure 10 shows the power supply curve for ERCOT. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a generating unit with a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized. Since the marginal source sets the price, a change in gas price under these conditions would not affect power prices.

Figure 10: Power supply curve for ERCOT region

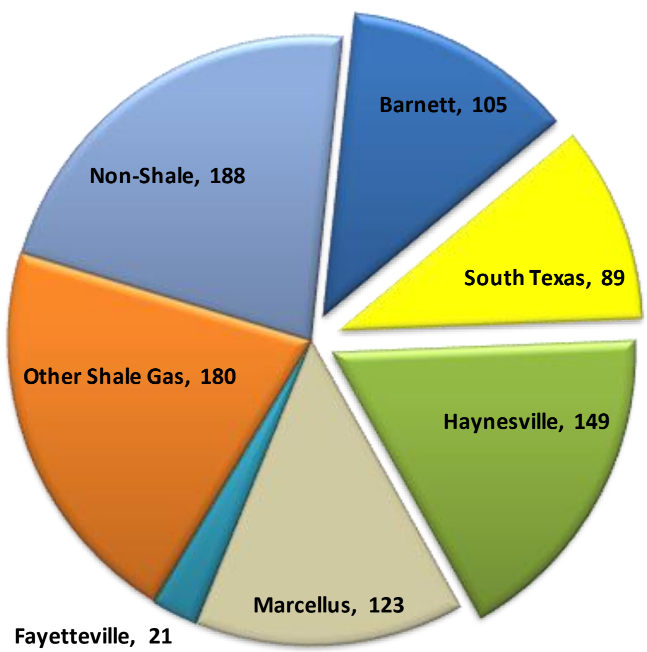


Incremental production impact in Texas from Lavaca Bay export

All of the gas used as feedstock for 1.33 Bcfd of LNG exports from Lavaca Bay is projected to come from Texas production. About one-third of the gas is incremental supplies from Texas production with the remaining two-thirds coming from Texas gas that would have otherwise been exported out of the state but instead is diverted to the terminal. The diverted volumes stimulate production in other supply basins outside Texas. Figure 11 shows the projected increase in production volume on average from 2018-2037.

The shale gas basins that are entirely or at least partially located in Texas are separated to highlight the impact on the State. One might expect South Texas, which includes Eagle Ford shales, to have a larger incremental impact. However, the region is rich in liquids and is projected to grow strongly even without boost from LNG exports. The incremental supplies indicate the marginal regions which would be stimulated with incremental demand.

Figure 11: Average incremental production with Lavaca Bay export, 2018-37 (MMcfd)

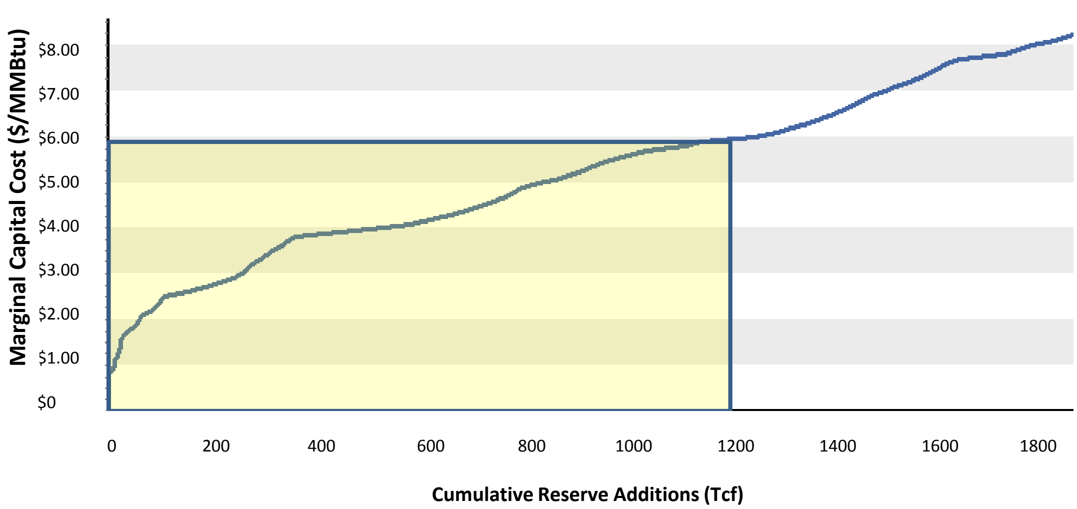


Large domestic supply buffers impact

Figure 12 shows the aggregate U.S. supply curve, including all types of gas formations. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The model includes over one hundred different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publically available documents and discussions with sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the DOE's Energy Information Administration.

The area of the supply curve that matters most for the next couple decades is the section below \$6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to get produced over the next couple decades. The Reference Case estimates about 1,200 Tcf available at wellhead prices below \$6/MMBtu in current dollars. To put the LNG export volumes into perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below \$6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to show the big picture. The magnitude of total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

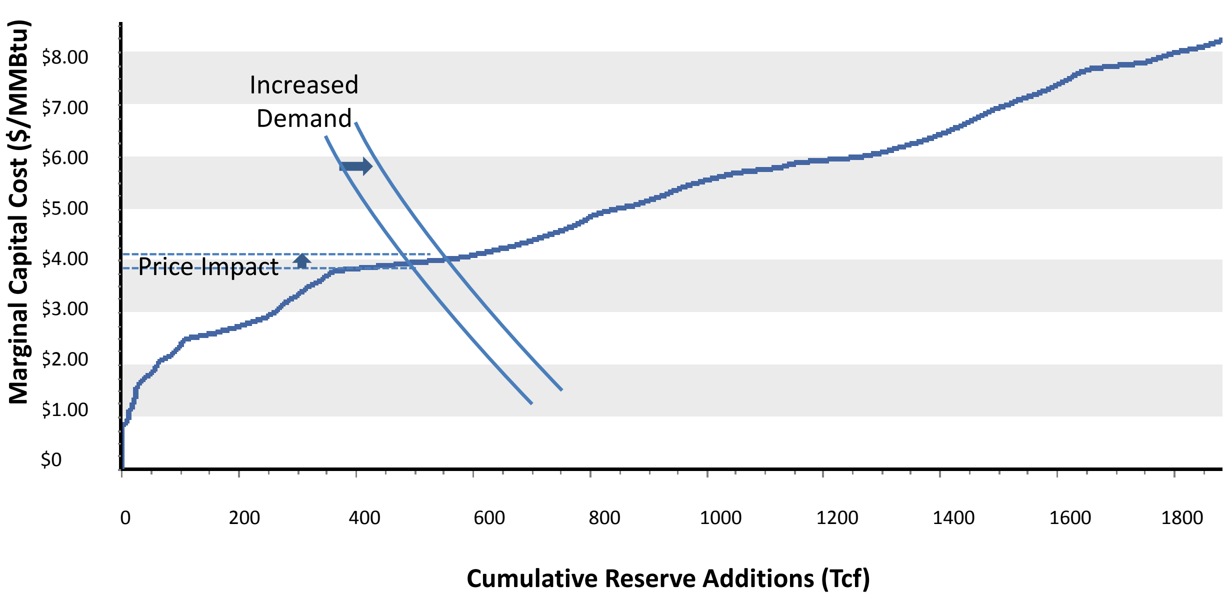
Figure 12: Aggregate U.S. natural gas supply curve (2012 \$)



With regards to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 13 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters. Hence, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG would not increase the price of domestic gas very much because it would not increase the production cost of domestic gas very much.

The projected sources of incremental volumes used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. Figure 14 shows the sources of incremental volumes in the 6 Bcfd LNG export case on average from 2018 to 2037, the assumed years of LNG exports. (The source fractions are similar for other LNG export cases so we only show the 6 Bcfd case.) The bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 18%. Higher U.S. prices induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The net exports to Mexico declines slightly as higher cost of U.S. supplies will likely prompt more Mexican production and would reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 19% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Figure 13: Impact of higher demand on price (illustrative)

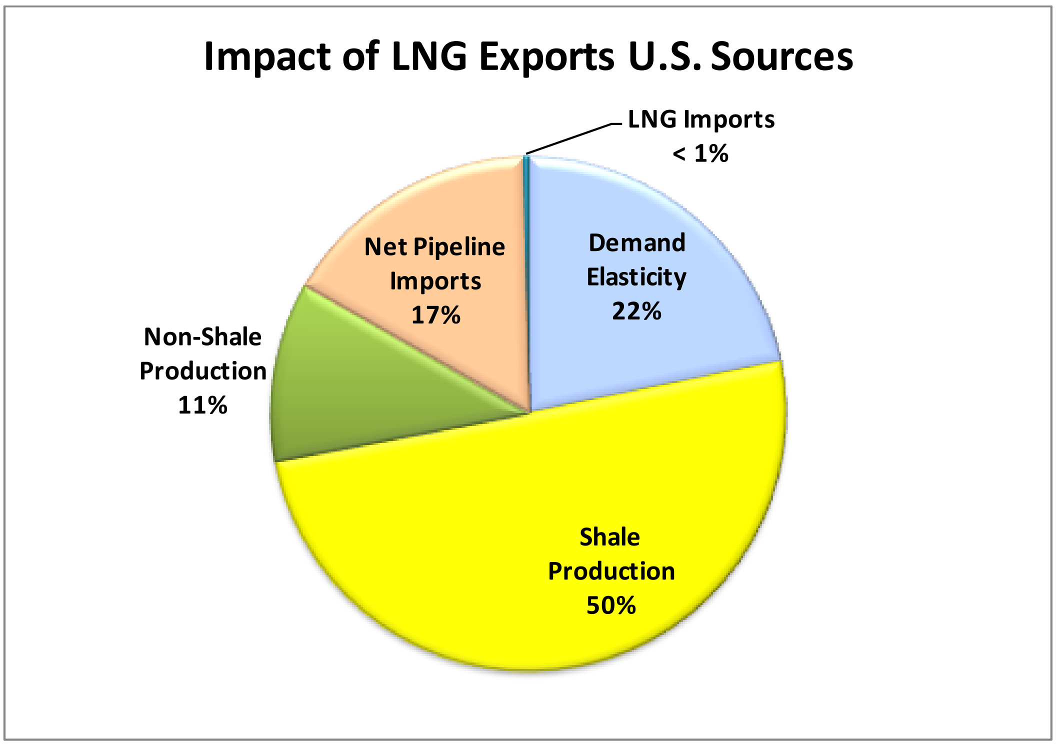


Finally, there is an insignificant increment, less than 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston will likely see higher prices than will Gulf terminals) and by time (e.g., LNG cargos will seek to arbitrage seasonal price).

These results underscore the fact that the North American natural gas market is highly integrated and the entire market works to mitigate price impacts of demand changes.

During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then it will be a simple calculation to see electricity price impact. At the projected Henry Hub gas price impact of \$0.26/MMBtu, a typical gas plant with a heat rate of 8,000 would cost an additional \$2.08/MWh (=\$0.26/MMBtu x 8000 Btu/MWh x 1 MMBtu/1000 Btu). We believe that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during mid-afternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 14: Projected sources of incremental volume in the 6 Bcfd Export Case (Average 2018-37)



Comparison of results to other studies

A number of studies, including others submitted to the DOE in association with LNG export applications, have estimated impacts of LNG exports from the U.S. The EIA also performed a study[4] at the request of the DOE. The various studies used different models and assumptions, but a comparison of their results might shed some light on the key factors and range of possible outcomes.

Figure 15 compares projections of estimated Henry Hub price impact from 2015 to 2035 with 6 Bcfd of LNG exports. The price impact ranges from 4% to 11%, with this study being on the low end and the ICF International being on the high end. The first observation is that, although the percentage differences are large on a relative basis, the range of estimated impacts is not so large. These studies consistently show that the price impact will not be that large relative to the change in demand. Bear in mind that 6 Bcfd is a fairly large incremental demand. In fact, it exceeds the combined gas demands in New York (3.3 Bcfd) and Pennsylvania (2.4 Bcfd) in 2011. These studies indicate that adding a sizeable incremental gas load on the U.S. energy system might result in a gas price increase of 11% or less.

Although we have limited data relating to specific assumptions and detailed output from the other studies, we can infer why the impacts differ so much. By most accounts, the resource base in the United States is plentiful, perhaps sufficient to last some 100 years at current production levels. All of the studies listed, including our own, had estimated natural gas resource volumes, including proved reserves and undiscovered gas of all types, of over 2,000 Tcf. Why then would the LNG export impacts vary as much as they do?

An important distinction between our analysis and the other studies is the representation of market dynamics, particularly for supply response to demand changes. That is, how do the studies represent how producers will respond to demand changes? The World Gas Model has a dynamic supply representation in which producers are assumed to anticipate demand and price changes. Producers do more than just respond to price that they see, but

Figure 15: Comparison of projected price impact from 2015-35 at the Henry Hub with 6 Bcfd of LNG exports

Study	Price without Exports ($/MMBtu)	Price with Exports ($/MMBtu)	Average Price Increase (%)
EIA	$ 5.28	$ 5.78	9%
Navigant (2010)	$ 4.75	$ 5.10	7%
Navigant (2012)	$ 5.67	$ 6.01	6%
ICF International	$ 5.81	$ 6.45	11%
Deloitte MarketPoint	$ 6.11	$ 6.37	4%

Source: Brookings Institute for all estimates besides Deloitte MarketPoint's

[4] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Howard Gruenspecht, EIA, January 2012.

rather anticipate events. Accordingly, prices will rise to induce producers to develop supplies in time to meet future demand.

Other models, primarily based on linear programming (LP)[5] or similar approaches, use static representation of supply in that supply does not anticipate price or demand growth. These static supply models require the user to input estimates of productive capacities in each future time period. The Brookings Institution completed a study assessing the impact of LNG exports and analyzing different economic approaches.[6] . As the Brookings study states:

"… static supply model, which, unlike dynamic supply models, does not fully take account of the effect that higher prices have on spurring additional production."

Since the supply volumes available in each time period is an input into LP models, the user must input how supply will respond to demand. In the case of LNG exports, the user must input how much supplies will increase and how quickly given the export volumes. Hence, the price impact is largely determined by how the user changes these inputs.

The purpose of this discussion is not to assert which approach is best, but rather to understand the differences so that the projections can be understood in their proper context. Assuming little or no price anticipation will tend to elevate the projected price impact while assuming price anticipation will tend to mitigate the projected price impact. Depending on the issue being analyzed, one approach may be more appropriate than the other. In the case of LNG export terminals, our belief is that the assumption of dynamic supply demand balance is appropriate. Given the long lead time, expected to be at least five years, required to permit, site, and construct an LNG export terminal, producers will have both ample time and plenty of notice to prepare for the export volumes. It would be a different matter if exports were to begin with little advanced notice.

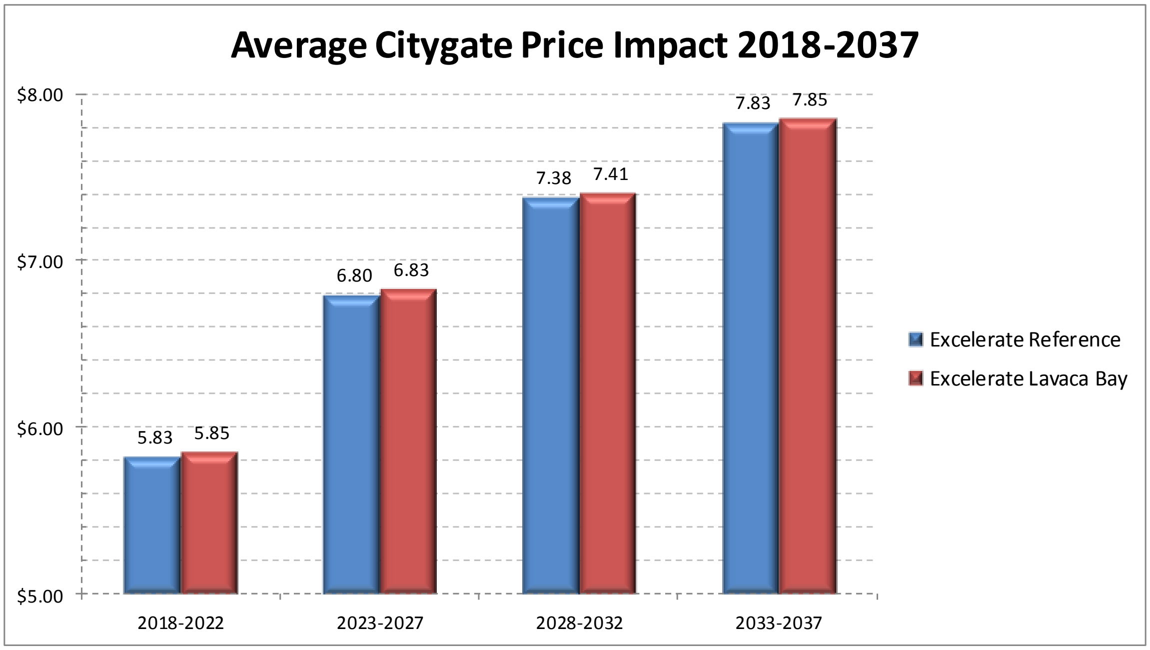
The importance of timing is evident in EIA's projections. The projected price impact is highly dependent on how quickly export volumes are assumed to ramp up. Furthermore, in all cases, the impacts are the greatest in the early years of exports. The impacts dissipate over time as supplies are assumed to eventually catch up with the demand growth.

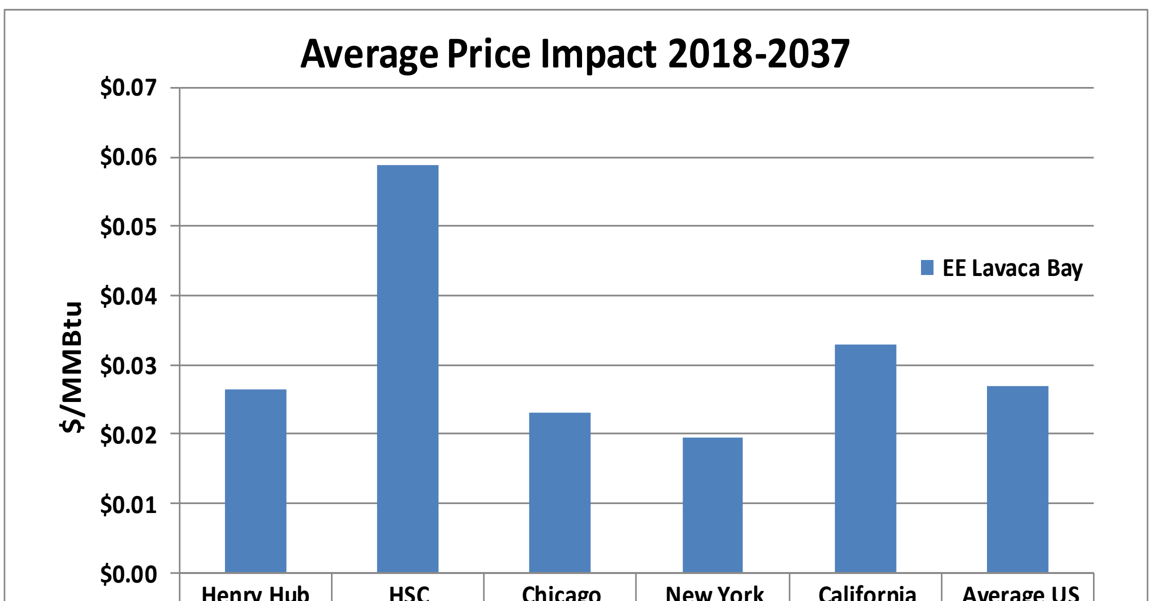
Natural gas producers are highly sophisticated companies with analytical teams monitoring and forecasting market conditions. Producers, well aware of the potential LNG export projects, are looking forward to the opportunity to supply these projects.

[5] Linear programming ("LP") is a mathematical technique for solving a global objective function subject to a series of linear constraints

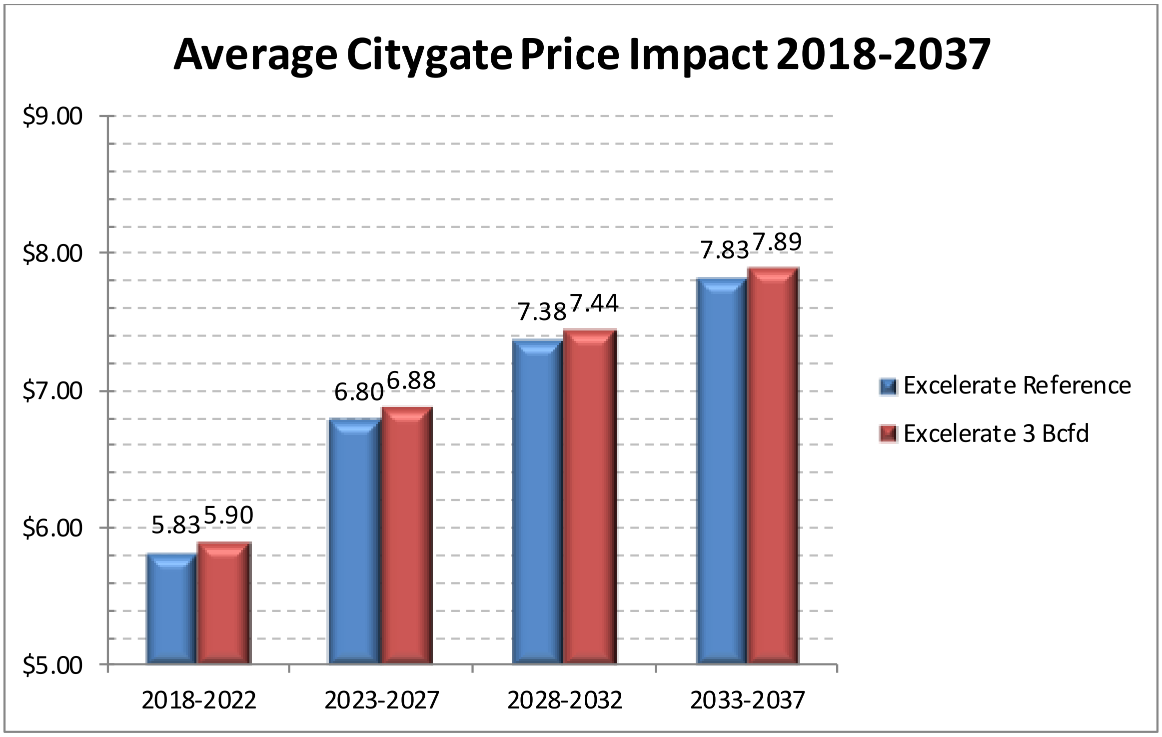
[6] "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution (2012).

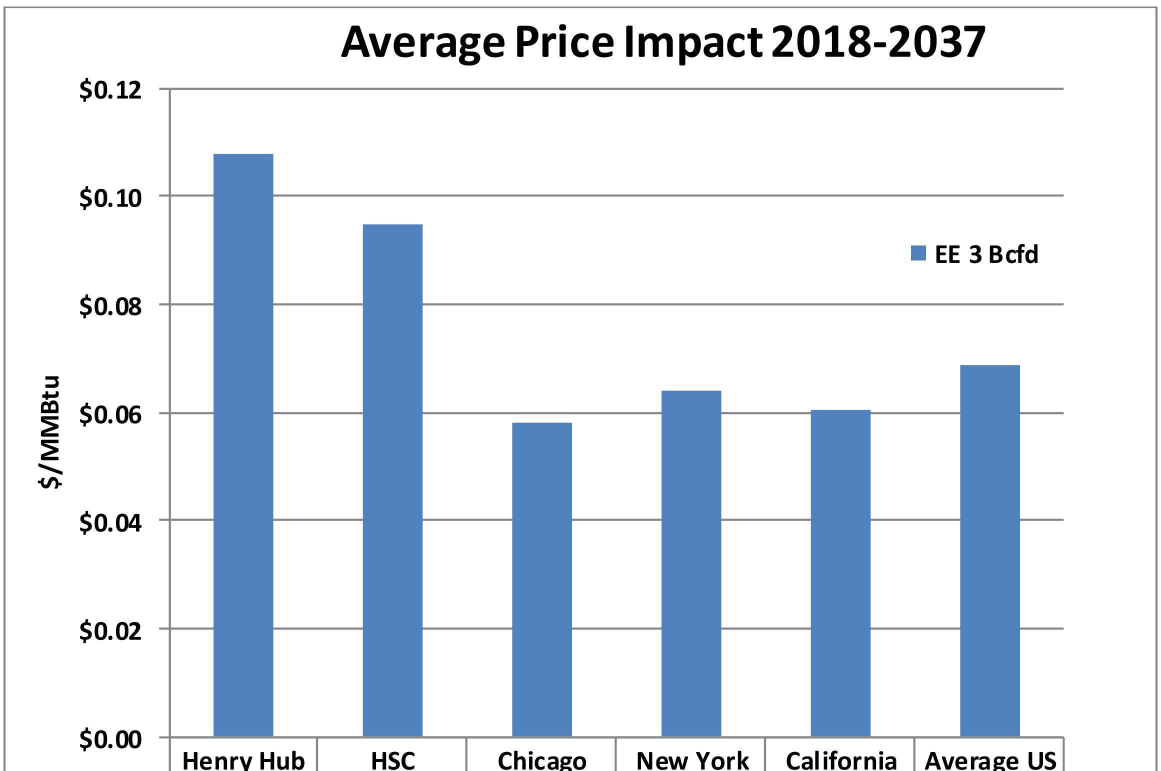
Appendix A: Price Impact Charts for other Export Cases



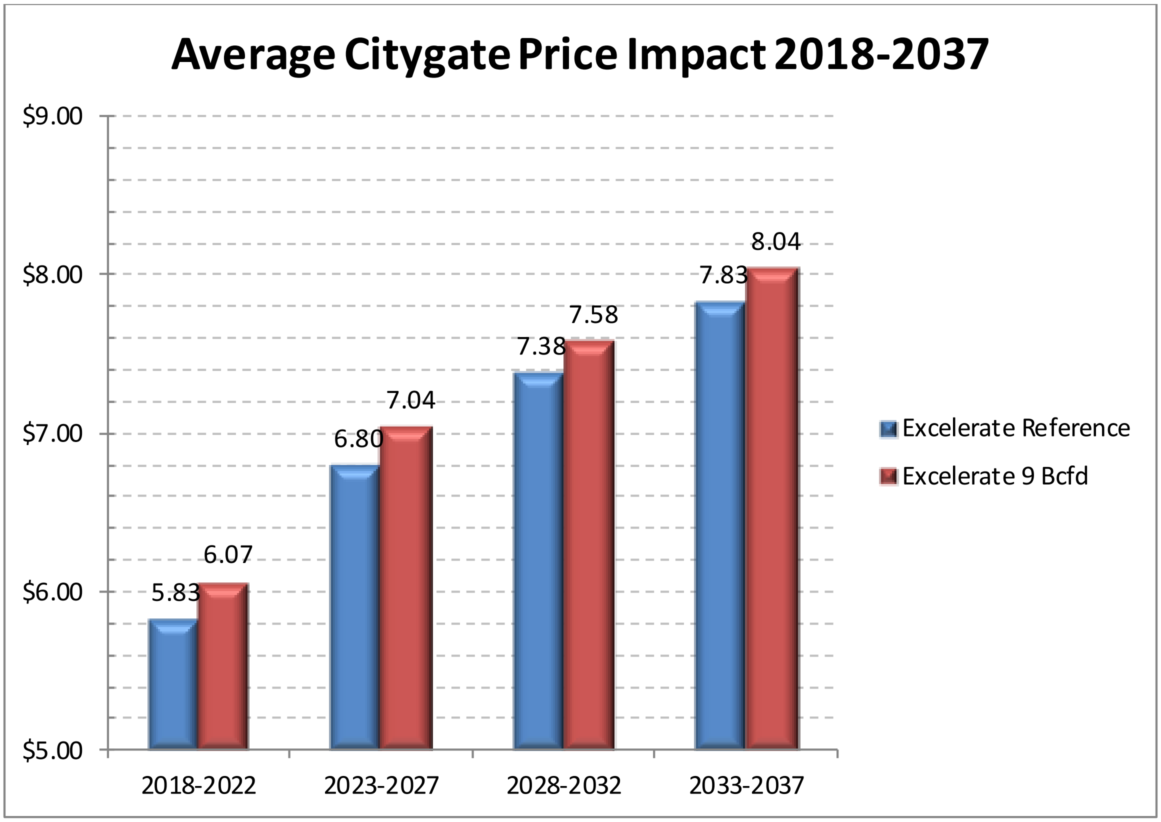


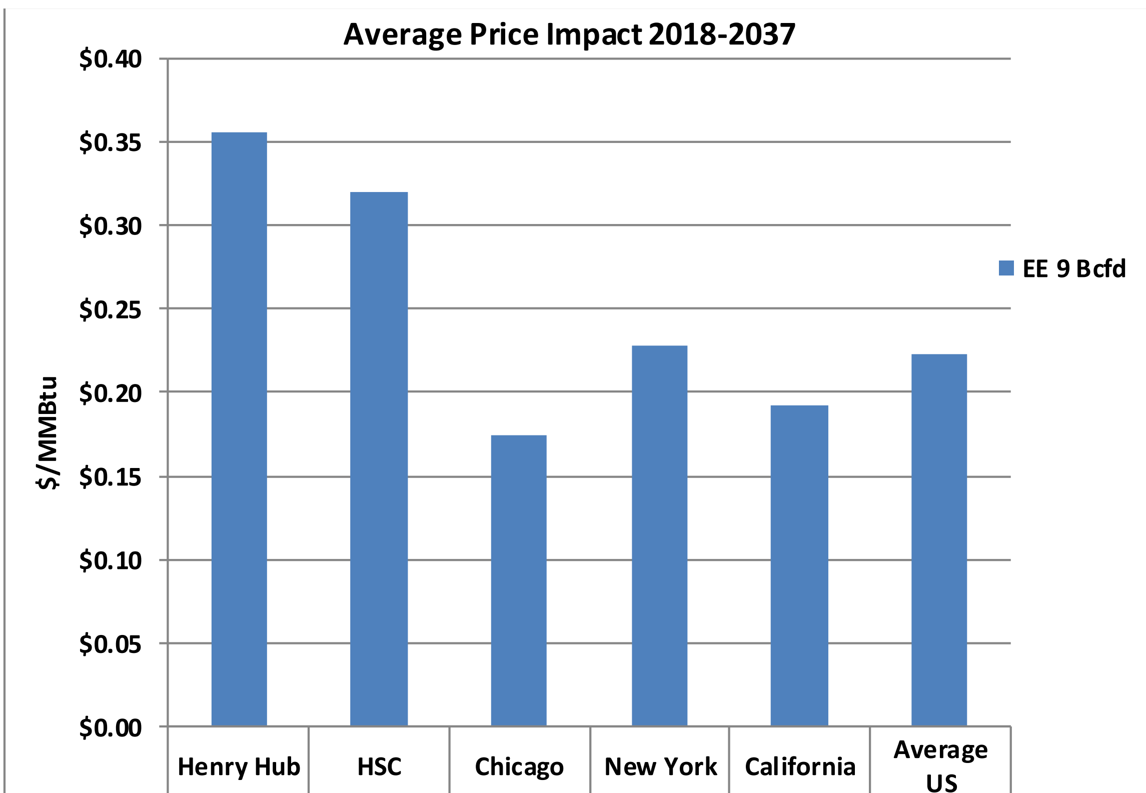
	Henry Hub	HSC	Chicago	New York	California	Average US
EE Lavaca Bay	0.03	0.06	0.02	0.02	0.03	0.03



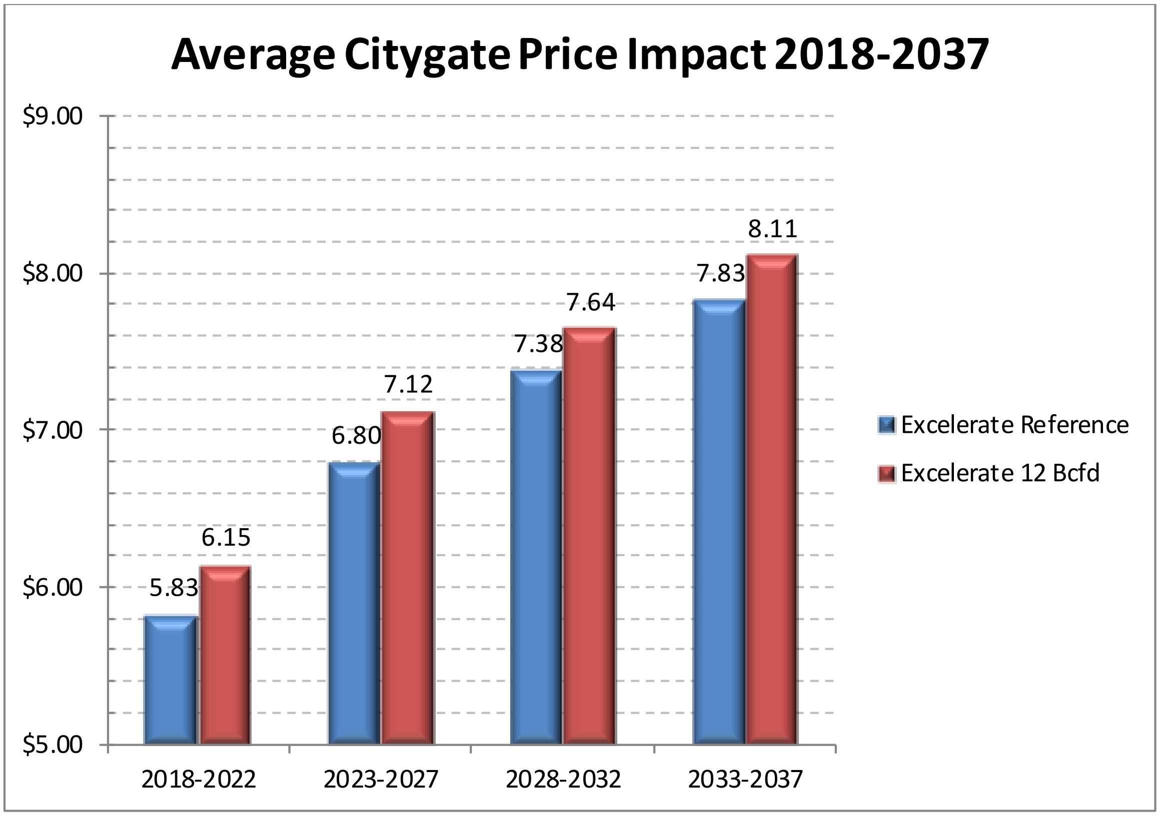


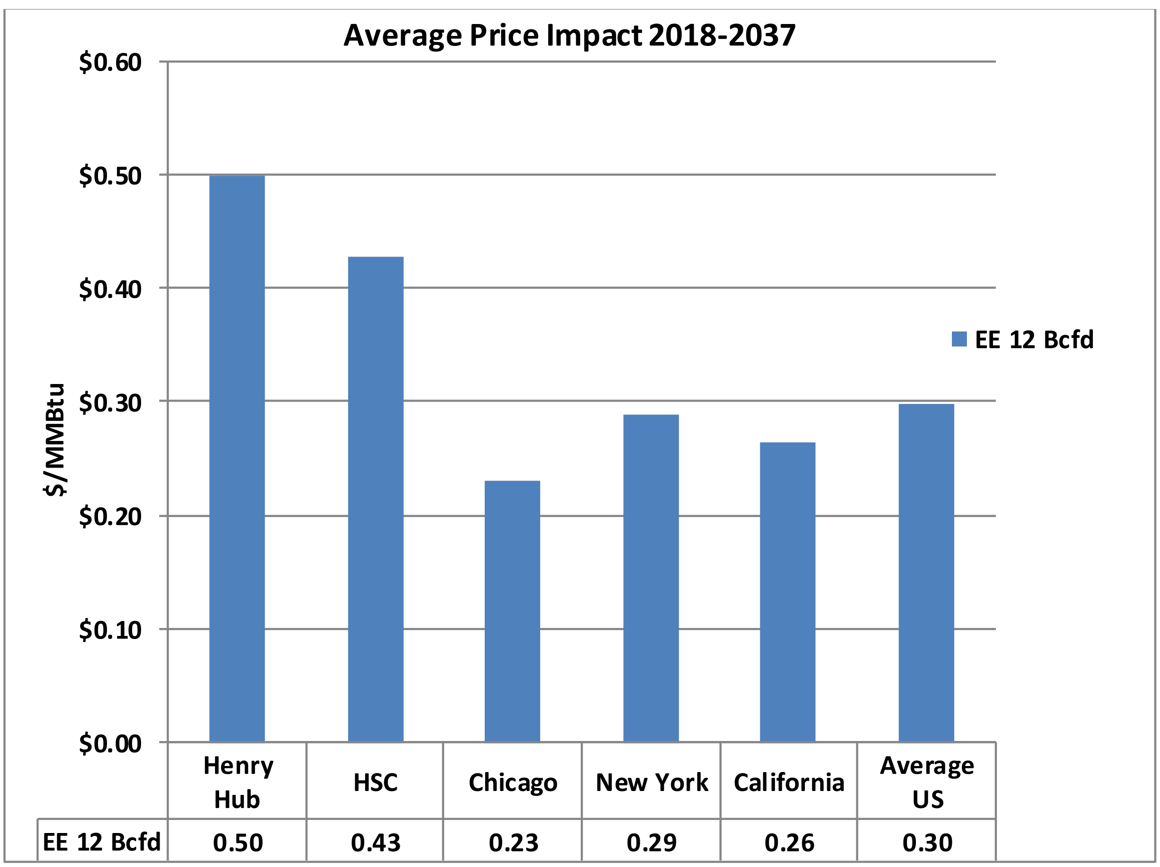
	Henry Hub	HSC	Chicago	New York	California	Average US
EE 3 Bcfd	0.11	0.09	0.06	0.06	0.06	0.07





	Henry Hub	HSC	Chicago	New York	California	Average US
EE 9 Bcfd	0.36	0.32	0.17	0.23	0.19	0.22


Average Citygate Price Impact 2018-2037
$9.00
$8.00
$7.00
$6.00
$5.00
5.83
6.15
6.80
7.12
7.38
7.64
7.83
8.11
2018-2022
2023-2027
2028-2032
2033-2037
Excelerate Reference
Excelerate 12 Bcfd


Average Price Impact 2018-2037
$/MMBtu
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
EE 12 Bcfd
Henry Hub
HSC
Chicago
New York
California
Average US
EE 12 Bcfd
0.50
0.43
0.23
0.29
0.26
0.30

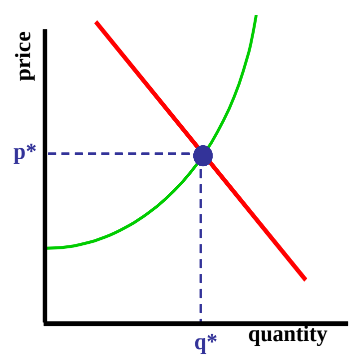
Appendix B: DMP's World Gas Model and data

To help understand the complexities and dynamics of global natural gas markets, DMP uses its World Gas Model ("WGM") developed in our proprietary MarketBuilder software. The WGM, based on sound economic theories and detailed representations of global gas demand, supply basins, and infrastructure, projects market clearing prices and quantities over a long time horizon on a monthly basis. The projections are based on market fundamentals rather than historical trends or statistical extrapolations.

WGM represents fundamental producer decisions regarding the timing and quantity of reserves to develop given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the market value of gas supply in remote parts of the world. The WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

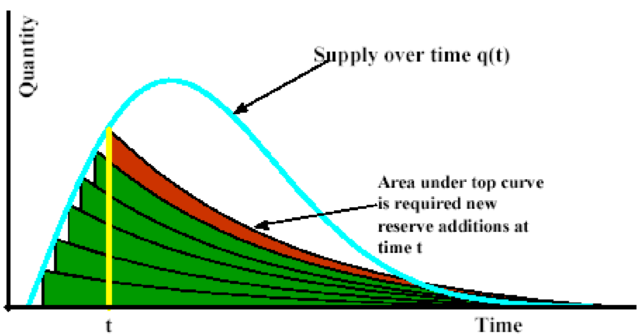
WGM simulates how regional interactions among supply, transportation, and demand interact to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit through 2046. The WGM divides the world into major geographic regions that are connected by marine freight. Within each major region are very detailed representations of many market elements: production, liquefaction, transportation, market hubs, regasification and demand by country or sub area. All known significant existing and prospective trade routes, LNG liquefaction plants, LNG regasification plants and LNG terminals are represented. Competition with oil and coal is modeled in each region. The capability to model the related markets for emission credits and how these may impact LNG markets is included. The model includes detailed representation of LNG liquefaction, shipping, and regasification; pipelines; supply basins; and demand by sector. Each regional diagram describes how market elements interact internally and with other regions.

Agent based economic methodology. MarketBuilder rigorously adheres to accepted microeconomic theory to solve for supply and demand using an "agent based" approach. To understand the benefits of the agent based approach, suppose you have a market comprised of 1000 agents, i.e., producers, pipelines, refineries, ships, distributors, and consumers. If your model of that market is to be correct, how many optimization problems must there be in your model of that 1000 agent market? The answer is clear—there must be 1000 distinct, independent optimization problems. Every individual agent must be represented as simultaneously solving and pursuing his or her own maximization problem, vying for market share and trying to maximize his or her own individual profits. Market prices



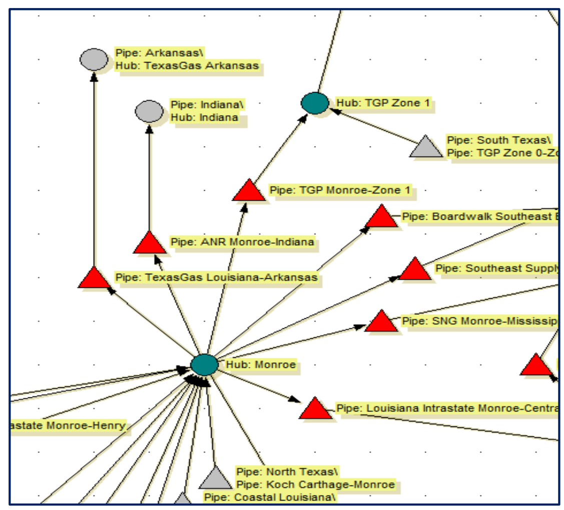
arise from the competition among these 1000 disparate, profit-seeking agents. This is the essence of microeconomic theory and competitive markets — people vying in markets for profits — and MarketBuilder rigorously approaches the problem from this perspective. In contrast, LP models postulate a single optimization problem no matter how many agents there are in the market; they only allow one, overall, global optimization problem. With LP, all 1000 agents are assumed to be manipulated by a "central authority" who forces them to act in lockstep to minimize the worldwide cost of production, shipment, and consumption of oil, i.e., to minimize the total cost of gas added up over the entire world.

Supply methodology and data. Working with data from agencies such as the United States Geological Survey (USGS), Energy Information Administration (EIA), and International Energy Agency (IEA), we have compiled a full and credible database of global supplies. In



particular, we relied on USGS' world oil and gas supply data including proved reserves, conventional undiscovered resources, growth of reserves in existing fields, continuous and unconventional deposits, deep water potential, and exotic sources. Derived from detailed probabilistic analysis of the world oil and gas resource base (575 plays in the US alone), the USGS data lies at the heart of DMP' reference case resource database. Only the USGS does a worldwide, "bottom up" resource assessment. Customers can easily substitute their own proprietary view where they believe they have better information. MarketBuilder allows the use of sophisticated depletable resource modeling to represent production of primary oil and gas (an extended Hotelling model). The DMP Hotelling depletable resource model uses a "rational expectations" approach, which assumes that today's drilling affects tomorrow's price and tomorrow's price affects today's drilling. Thus MarketBuilder combines a resource model that approaches resource development the same way real producers do given the available data.

Transportation data. DMP maintains a global pipeline and transportation database. DMP and our clients regularly revise and update the transportation data including capacity, tariffs, embedded cost, discounting behavior, dates of entry of prospective new pipelines, and costs of those new pipelines.



Non-linear demand methodology. MarketBuilder allows the use of multi-variate nonlinear representations of demand by sector, without limit on the number of demand sectors. DMP is skilled at performing regression analyses on historical data to evaluate the effect of price, weather, GNP, etc. on demand. Using our methodology, DMP systematically models the impact of price change on demand (demand price feedback) to provide realistic results.