RECEIVED
By Docket Room at
4:30pm, July 18, 2014

July 18, 2014

VIA ELECTRONIC DELIVERY

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

RE: Alaska LNG Project LLC, Docket No. 14 - 96 - LNG
Application for Long-Term Authorization to Export Liquefied Natural Gas

Dear Mr. Anderson:

Alaska LNG Project LLC is developing a project to export liquefied natural gas ("LNG") from Alaska. The LNG would be produced at a liquefaction facility to be constructed in the Nikiski area of the Kenai Peninsula in south central Alaska. The construction of the project (which includes: (i) liquefaction facility, storage and loading facilities, and other associated facilities; (ii) a large-diameter gas pipeline from the liquefaction facility to the gas treatment plant; (iii) gas treatment plant; and (iv) transmission lines between the gas treatment plant and producing fields) will be the subject of an application by Alaska LNG Project LLC to the Federal Energy Regulatory Commission ("FERC") for authorization under Section 3 of the Natural Gas Act. Alaska LNG Project LLC expects that it will commence the FERC Pre-Filing process in 2014.

In the enclosed application, Alaska LNG Project LLC seeks long-term multi-contract authorization under Section 3 of the Natural Gas Act to export 20 million metric tons per annum of LNG, in aggregate, for a term of 30 years beginning on the earlier of (i) the date of first export from the liquefaction facility or (ii) 12 years from the date the requested authorization is granted.

Alaska LNG Project LLC is seeking authority to export LNG from the liquefaction facility to (1) any country with which the United States currently has, or in the future may enter into, a free trade agreement requiring national treatment for trade in natural gas; and (2) any country with which the United States does not have a free trade agreement requiring national treatment for trade in natural gas with which trade is not prohibited by United States law or policy. Alaska LNG Project LLC seeks to export LNG on its own behalf and also as agent for third parties.

As demonstrated in the enclosed application, natural gas reserves and resources in Alaska are more than sufficient to support the in-state needs of Alaska's citizens as well as the requested export of 20 million metric tons of LNG per annum for a 30-year export term. As Alaska and its supply of natural gas are geographically isolated from the lower 48 states of the United States ("lower 48"), the enclosed application stands on its own merits without regard to the cumulative impacts of LNG exports from the lower 48. Additionally, given the unique nature of the proposed project and the geographically separate supply base, Alaska LNG Project LLC respectfully requests that the enclosed application not be subject to DOE/FE's existing Order of Precedence for Processing Non-FTA LNG Export Applications or any new procedures adopted as a result of DOE/FE's proposed procedural change for processing LNG export applications.[1]

Alaska LNG Project LLC respectfully requests that DOE/FE grant that portion of the enclosed application that seeks to export LNG to free trade agreement countries "without modification or delay" as required by the Natural Gas Act.

Alaska LNG Project LLC is currently comprised of the following members: ExxonMobil Alaska LNG LLC, BP Alaska LNG LLC and ConocoPhillips Alaska LNG Company. As set forth in the attached application, Alaska LNG Project LLC seeks authority to export the LNG on its own behalf and as agent for any or all of the following: (i) each of its members; (ii) the respective affiliates of its members; (iii) the State of Alaska or its nominee; and (iv) other third parties, under contracts to be executed in the future, as applicable.

Alaska LNG Project LLC is transmitting a check in the amount of $50.00 in payment of the applicable filing fee pursuant to 10 C.F.R. § 590.207. Please contact the undersigned at (202) 220-6915 if you have any questions regarding this filing.

Respectfully submitted,

James [illegible] Moriarty
Locke Lord LLP
701 8th Street, NW
Suite 700
Washington, DC 20001
(202) 220-6915
jmoriarty@lockelord.com

Counsel to Alaska LNG Project LLC

---

[1] 79 Fed. Reg. 32261 (Jun. 4, 2014).

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

	)	
Alaska LNG Project LLC	)	Docket No. 14 - 96- LNG
	)	

APPLICATION OF ALASKA LNG PROJECT LLC FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS

Lydia J. Johnson
Vice President
Daniel J. Brink
Counsel
ExxonMobil Alaska LNG LLC
lydia.j.johnson@exxonmobil.com
daniel.j.brink@exxonmobil.com

Darren Meznarich
President
Barbara Fullmer
Senior Counsel
ConocoPhillips Alaska LNG Company
darren.l.meznarich@conocophillips.com
barbara.f.fullmer@conocophillips.com

David E. Van Tuyl
President
Greg L. Youngmun
Senior Counsel
BP Alaska LNG LLC
david.vantuyl@bp.com
greg.youngmun@bp.com

James F. Moriarty
Jennifer Brough
Matthew T. Eggerding
Locke Lord LLP
701 8th Street, NW
Suite 700
Washington, DC 20001
(202) 220-6915
jmoriarty@lockelord.com
jbrough@lockelord.com
meggerding@lockelord.com

TABLE OF CONTENTS

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

	)	
Alaska LNG Project LLC	)	Docket No. 14 - ___ - LNG
	)	

APPLICATION OF ALASKA LNG PROJECT LLC FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS

Pursuant to Section 3 of the Natural Gas Act ("NGA"), 15 U.S.C. § 717b, and Part 590 of the regulations of the Department of Energy ("DOE"), 10 C.F.R. § 590, Alaska LNG Project LLC submits this application ("Application") to the DOE Office of Fossil Energy ("DOE/FE") for long-term authorization to export 20 million metric tons per annum ("MTPA") of liquefied natural gas ("LNG") (approximately 929 billion cubic feet ("Bcf") per annum of natural gas using a conversion factor of 46.467 Bcf[1] of natural gas per million metric tons of LNG) produced from Alaska sources for a 30-year period. The requested 30-year export term is fully supported herein by the accompanying studies and is appropriate and required due to the unique nature of the proposed Alaska LNG project ("Project"), including the size, scope, costs, required upstream development, and project development timeline that are more significant than any LNG project in the lower 48 states of the United States ("lower 48"). Consistent therewith, Alaska LNG Project LLC requests that the authorization commence on the earlier of (i) the date of first export from the liquefaction facility or (ii) 12 years from the date the requested authorization is granted.

Alaska LNG Project LLC seeks authorization to export 20 MTPA of LNG, in aggregate, from a liquefaction facility to be constructed in the Nikiski area of the Kenai Peninsula in south

[1] The conversion factor of 46.467 Bcf per million metric ton is appropriate due to the relatively high heating content (Btu/cubic foot gas) and associated physical characteristics of LNG that would be produced from Alaska sources. The conversion factors included in applications to export LNG from the lower 48 are therefore not applicable. *See, e.g.*, *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 (Mar. 24, 2014) (conversion factor of 48.7 Bcf per million metric ton used for lower 48 project).

central Alaska ("Liquefaction Facility") to (1) any country with which the United States currently has, or in the future may enter into, a free trade agreement ("FTA") requiring national treatment for trade in natural gas[2] and (2) any country with which the United States does not have a free trade agreement requiring national treatment for trade in natural gas with which trade is not prohibited by United States law or policy. In support of this Application, Alaska LNG Project LLC respectfully states the following:

I. EXECUTIVE SUMMARY

The export of natural gas from Alaska's North Slope is very positive for Alaska and for the United States.[3] Exporting Alaska natural gas will benefit local, regional, and national economies through resource development, an enhanced tax base, creation of thousands of jobs, and an increase in overall economic activity. As illustrated in the attached study by NERA Economic Consulting ("NERA"), an independent consultant, the export of Alaska natural gas will also have positive macroeconomic benefits for the United States.[4]

DOE/FE has already found that the export of LNG from Alaska is not inconsistent with the public interest.[5] In fact, the history of LNG exports from Alaska dates back nearly 50 years to 1967 when the original long-term authorization to export LNG from the Kenai LNG terminal

---

[2] The United States currently has FTAs requiring national treatment for trade in natural gas with Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore.

[3] *See* Sen. Lisa Murkowski, "The Narrowing Window: America's Opportunity to Join the Global Gas Trade" at 15, 17 (Aug. 6, 2013), *available at* http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=e1527027-558f-4fb0-92bd-f8b9d7515075 (urging the DOE to move forward on all LNG export applications in a timely manner and noting the unique opportunity for the export of natural gas from Alaska given the state's proximity to markets in Asia).

[4] NERA Economic Consulting, "Socio-Economic Impact Analysis of Alaska LNG Project" ("Socio-Economic Report"), June 19, 2014, attached hereto as Appendix F.

[5] *ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 at 18 (Apr. 14, 2014) ("DOE/FE is persuaded by [applicant's] evidence that the proposed exports will provide regional benefits to the local and state economy . . . on the basis of [the] Application and, because no party to this proceeding submitted evidence to rebut the statutory presumption that the requested authorization is consistent with the public interest, we grant the Application as filed."); *ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2860 at 19 (Oct. 5, 2010); *ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2500 at 65 (June 3, 2008).

to Japan was granted.[6] This year, DOE/FE affirmed its prior findings for FTA and non-FTA authorizations, noting that the proposed export of LNG from Alaska "will provide regional benefits to the local and state economy."[7]

To date, all LNG exported from Alaska has been produced from the Cook Inlet region in south central Alaska.[8] However, the vast resources of natural gas discovered on the Alaska North Slope ("North Slope") in 1968 have remained stranded.[9] Today, with the culmination of decades of effort, the major North Slope natural gas producers have aligned through an agreement with the State of Alaska setting out key principles upon which the parties intend to progress the evaluation and development of one integrated and interdependent Project.[10] The agreement outlines the "substantial benefits" that the Project would provide including job creation, infrastructure development and the opportunity for a competitively priced, reliable in-state gas supply.[11] On May 8, 2014, in furtherance of the agreement, Alaska Governor Sean Parnell signed Senate Bill 138 into law. The law enables participation in the Project by the State of Alaska.[12]

The Project would be the largest integrated gas/LNG project of its kind ever designed and constructed, with an estimated cost of $45 billion to $65 billion. With the granting of the authorization sought here, DOE/FE has the potential to unlock the vast natural gas resources on

---

[6] *Phillips Petroleum Co. and Marathon Oil Co.*, 37 FPC ¶ 777 (Apr. 19, 1967).
[7] *ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 at 18 (Apr. 14, 2014).
[8] United States Energy Information Administration, "Alaska Liquefied Natural Gas Exports to Japan," *available at* http://www.eia.gov/dnav/ng/hist/ngm_epg0_eng_sak-nja_mmcfa.htm.
[9] *Yukon Pacific Corporation*, ERA Docket No. 87-68-LNG, Order No. 350 at Section II (Nov. 16, 1989) (DOE/FE confirmed the efforts to monetize North Slope natural gas and concluded that despite legislative and policy changes designed to make the gas more competitive, "[a]s of yet, however, North Slope gas has been left undeveloped.").
[10] *See* Heads of Agreement By and Among the Administration of the State of Alaska, Alaska Gasline Development Corporation, TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc. for the Alaska LNG Project (Jan. 14, 2014) ("Heads of Agreement"), *available at* http://www.dor.alaska.gov/Portals/5/Docs/PressReleases/HOA.pdf.
[11] *Id.* at Article 3.
[12] *See* Press Release From The Office of Alaska Governor Sean Parnell, "The Alaska Project Begins" (May 8, 2014), *available at* http://gov.alaska.gov/parnell/press-room/full-press-release.html?pr=6832.

the North Slope. Absent granting of the requested export authorization needed to facilitate construction of the Project, the ability to meet Alaska in-state gas demand will continue to be very challenging.

Alaska LNG Project LLC herein requests long-term authorization to export 20 MTPA of LNG, in aggregate, produced from Alaska sources for a 30-year period commencing on the earlier of (i) the date of first export from the Liquefaction Facility or (ii) 12 years from the date the requested authorization is granted. Section 3(a) of the NGA creates a rebuttable presumption that proposed exports of natural gas are in the public interest. Indeed, DOE/FE *must* grant the authorization unless any opposition overcomes the rebuttable presumption by making an affirmative showing of inconsistency with the public interest.

The 30-year export term and 12-year start-up period requested herein are required to support a project of this size and the continued development of the world-class scale of resources on the North Slope. Alaska LNG Project LLC will be required to build each component of this greenfield Project from the ground up. Unlike proposed projects in the lower 48, there is no existing long-haul gas transportation infrastructure in Alaska. In addition, Alaska LNG Project LLC will be faced with unique and challenging Arctic construction conditions. As demonstrated here and in the attached studies, natural gas reserves and resources in Alaska are more than sufficient to support the in-state needs of Alaska's citizens as well as the requested 30-year export term.[13]

This Application demonstrates that the requested authorization is not inconsistent with the public interest and should be granted by DOE/FE.

---

[13] DeGolyer and MacNaughton ("D&M"), "Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012," April 2014 ("Supply Report"), attached hereto as Appendix E.

II. APPLICATION PROCESSING AND REVIEW

Given the unique nature of the proposed Project and the geographically separate supply base, Alaska LNG Project LLC respectfully requests that this Application not be subject to DOE/FE's existing Order of Precedence for Processing Non-FTA LNG Export Applications.

Further, Alaska LNG Project LLC respectfully requests that this Application not be subject to any new procedures adopted as a result of DOE/FE's proposed procedural change for processing non-FTA LNG export applications.[14] DOE/FE recently proposed "to suspend its practice of issuing conditional decisions on applications to export LNG *from the lower-48 states* to non-FTA countries prior to completion of [National Environmental Policy Act ("NEPA")] review."[15] As to Alaska, DOE/FE stated:

> The Department currently has no long-term applications before it to export LNG from Alaska. Lacking any such applications, the Department cannot say whether there may be unique features of Alaskan projects that would warrant exercise of the Department's discretionary authority to issue conditional decisions. Accordingly, this notice does not address the treatment of applications to export natural gas from Alaska.[16]

As demonstrated in this Application to export LNG from Alaska, there are many unique features of this Project that warrant exercise of DOE/FE's discretion to issue a conditional decision.

The proposed Project is unlike any lower 48 export project and should be processed differently. For example, the estimated cost alone ($45 billion to $65 billion) sets this Project apart from any other project in the lower 48. In addition to the capital investment required, all components of this greenfield Project must be built from the ground up. This is unlike lower 48 projects that can leverage the extensive existing gas grid. This integrated mega-project will also be constructed in an Arctic environment that poses additional challenges not experienced by any

[14] 79 Fed. Reg. 32261 (Jun. 4, 2014).
[15] *Id*. at 32263 (emphasis added).
[16] *Id*. at 32263 n.5.

lower 48 project. Due to the unique factors facing this Project, a conditional authorization will facilitate Alaska LNG Project LLC's ability to continue the ongoing substantial commercial and engineering activities and expenditures necessary to develop and construct the Project:

Decision Gate	**Concept Selection (Completed)**	**Pre-FEED**	**FEED (Front-End Engineering & Design)**	**EPC (Engineering, Procurement & Construction)**
Activities:		❑ Viable Technical Option(s) Identified ❑ Government Support ❑ Permits / Land Use Achievable ❑ Potential Commercial Viability	❑ Viable technical option ❑ Government Support ❑ Permits/Land Use Underway ❑ Potential Commercial Viability	❑ Secure Permits/ Land Use/ Financing/ Key Commercial Agreements ❑ Confirm Commercial Viability ❑ Execute EPC contracts
Peak Staffing:	~200	400 – 500	500 – 1,500	9,000 – 15,000
Cost ($):	Tens of Millions	Hundreds of Millions	Billions	Tens of Billions
Est. Engineering / Technical Duration*:		*2 - 3 Years*	*2 - 3 Years*	*5 - 6 Years*

NOTE: Duration of various phases may be extended by the time required for State of Alaska enabling legislation and negotiation of project-enabling contracts with State of Alaska which require ratification by the legislature; permitting and regulatory delays; any legal challenges; changes in commodity outlook; time to secure long-term LNG contracts; weather, labor, equipment, or construction delays; etc.

Processing this Application and issuing a conditional order is consistent with DOE/FE's stated rationale and will not affect any lower 48 applicant. This Project stands alone as there is no other application pending before DOE/FE to export North Slope natural gas.

DOE/FE has consistently treated applications to export LNG from Alaska differently from lower 48 applications.[17] DOE/FE should continue this practice and affirm that the proposed procedures for processing lower 48 export applications will not apply to the Project and that DOE/FE will exercise its discretion to issue a conditional authorization. Additionally, as Alaska and its supply of natural gas are geographically isolated from the lower 48, this Application stands on its own merits without regard to the cumulative impacts[18] of LNG exports from the lower 48 and should be processed as such.

III. <u>DESCRIPTION OF THE APPLICANT AND FACILITIES</u>

The exact legal name of the applicant is Alaska LNG Project LLC. Alaska LNG Project LLC is a Delaware Limited Liability Company. The current members of Alaska LNG Project LLC are ExxonMobil Alaska LNG LLC, ConocoPhillips Alaska LNG Company and BP Alaska LNG LLC, (collectively, the "Members"). Affiliates of the Members currently hold oil and gas leasehold interests in Alaska, including in the Prudhoe Bay and Point Thomson Units. Alaska LNG Project LLC may seek to amend the Application at a later date to add a State of Alaska designee.

Alaska LNG Project LLC plans to construct one integrated and interdependent Alaska LNG Project[19] that includes:

- a Liquefaction Facility to be built on a site in the Nikiski area of the Kenai Peninsula in south central Alaska. The Liquefaction Facility would consist of

[17] *See, e.g.*, *ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 at 5 (Apr. 14, 2014); *ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2500 at 45 (June 3, 2008).

[18] *See, e.g.*, *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 155-56 (Nov. 15, 2013) (DOE/FE stated that it would "continue to assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals.").

[19] A map of the Project is attached hereto as Appendix C. An affidavit demonstrating the land acquired for the Project to date is attached hereto as Appendix D.

three LNG trains having a total maximum capacity of 20 MTPA.[20] Storage and LNG delivery facilities would be constructed at the Liquefaction Facility for marine loading of LNG. To date, the Project team has secured over 200 acres of land (nearly half the total acreage) at the Liquefaction Facility site;

- an approximately 800-mile large-diameter gas pipeline from the Liquefaction Facility to the gas treatment plant. The pipeline would have multiple compressor stations along its route and at least five off-take points for delivery of gas to Alaska;[21]
- a gas treatment plant on the North Slope that would consist of three or more amine processing/treating train modules with compression, dehydration, and chilling. The gas treatment plant would be built in a modular fashion and sealifted to its location on the North Slope; and
- transmission lines between the gas treatment plant and producing fields on the North Slope.

Any construction of the requisite facilities would be subject to FERC approval. Alaska LNG Project LLC expects that it will commence the FERC Pre-Filing process in 2014.

---

[20] Alaska LNG Project LLC's requested authorization in the amount of 20 MTPA represents the planned maximum or peak liquefaction capacity of the Liquefaction Facility under optimal operating conditions. Alaska LNG Project LLC plans to seek authorization from the Federal Energy Regulatory Commission ("FERC") under Section 3 of the NGA to construct the Liquefaction Facility based on a 20 MTPA design parameter. DOE/FE has stated that it will issue authorizations consistent with the planned liquefaction capacity as outlined in the FERC application process. *See FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 162 (Nov. 15, 2013). Consistent therewith, FERC recently approved the amendment of an existing NGA section 3 authorization to account for the maximum or peak capacity of the LNG terminal at optimal operating conditions. *See Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.*, 146 FERC ¶ 61,117 at P 12 (2014) (FERC "believe[s] that it is appropriate for an ultimate authorization to reflect the maximum or peak capacity at optimal conditions as such level represents the actual potential production of LNG.").

[21] The 20 MTPA requested herein is the volume proposed to be exported. In-state volumes would be separate from and in addition to the 20 MTPA. As explained in Section VII, NERA concluded that there is more than sufficient natural gas supply and associated resource deliverability in Alaska to satisfy (i) Project requirements for a 30-year export term at 20 MTPA and (ii) in-state demand. *See infra* Section VII(B)(i)(1).

IV. COMMUNICATIONS

All communications and correspondence regarding this Application should be directed to the following persons:

Alaska LNG Project LLC c/o:

Lydia J. Johnson
Vice President
Daniel J. Brink
Counsel
ExxonMobil Alaska LNG LLC
lydia.j.johnson@exxonmobil.com
daniel.j.brink@exxonmobil.com

Darren Meznarich
President
Barbara Fullmer
Senior Counsel
ConocoPhillips Alaska LNG Company
darren.l.meznarich@conocophillips.com
barbara.f.fullmer@conocophillips.com

David E. Van Tuyl
President
Greg L. Youngmun
Senior Counsel
BP Alaska LNG LLC
david.vantuyl@bp.com
greg.youngmun@bp.com

James F. Moriarty
Jennifer Brough
Matthew T. Eggerding
Locke Lord LLP
701 8th Street, NW
Suite 700
Washington, DC 20001
(202) 220-6915
jmoriarty@lockelord.com
jbrough@lockelord.com
meggerding@lockelord.com

V. AUTHORIZATION REQUESTED

Alaska LNG Project LLC requests long-term authorization to export 20 MTPA of Alaska-produced LNG for a 30-year period commencing upon the earlier of (i) the date of first export from the Liquefaction Facility or (ii) the twelfth anniversary of the date authorization is granted by DOE/FE.

Alaska LNG Project LLC requests that such long-term authorization provide for export to (1) any country with which the United States currently has, or in the future may enter into, an

FTA requiring national treatment for trade in natural gas; and (2) any country with which the United States does not have an FTA requiring national treatment for trade in natural gas with which trade is not prohibited by United States law or policy.

The 30-year export term sought in this Application is appropriate and necessary for Alaska LNG Project LLC to (i) continue to incur the substantial cost of developing and constructing the Project, currently estimated at $45 billion to $65 billion and (ii) provide long-term access to market outlets needed to allow reasonable ability to recover investments in the continued development of the world-class scale of resources.

Affiliates of Members of Alaska LNG Project LLC hold gas development rights in Alaska, including in the Prudhoe Bay and Point Thomson Units on the North Slope. Alaska LNG Project LLC expects that the natural gas developed and produced by the respective affiliates of its Members will be delivered to the liquefaction facilities where LNG will be produced and made available for export. Alaska LNG Project LLC seeks authority to export the LNG on its own behalf and as agent for any or all of the following: (i) each of its Members; (ii) the respective affiliates of its Members; (iii) the State of Alaska or its nominee; and (iv) other third parties, under contracts to be executed in the future, as applicable. The agency rights requested here would encompass any exports of any State of Alaska (or its nominee) share of LNG from the Project facilities. Alaska LNG Project LLC contemplates that the title holder at the point of export[22] may likely be another party other than itself, such as the respective affiliates of its Members or other third parties pursuant to an LNG sales and purchase contract.

Alaska LNG Project LLC requests authorization to register each LNG title holder for whom Alaska LNG Project LLC seeks to export as agent, with such registration including a

[22] "LNG exports occur when the LNG is delivered to the flange of the LNG export vessel." *See Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 2913 at n.4 (Feb. 10, 2011); *Dow Chemical Company*, FE Order No. 2859 at 7 (Oct. 5, 2010).

written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included by DOE/FE in Alaska LNG Project LLC's export authorization, and to include those requirements in any subsequent purchase or sale agreement entered into by that title holder. In addition to the registration of any LNG title holder for whom Alaska LNG Project LLC seeks to export as agent, Alaska LNG Project LLC will file under seal with DOE/FE any relevant long-term commercial agreements once they have been executed. This approach will conform to DOE/FE's goal of providing that all authorized exports are permitted and lawful under United States laws and policies, including the rules, regulations, orders, policies and other determinations of the Office of Foreign Assets Control of the United States Department of the Treasury.[23]

DOE/FE has consistently granted the type of agency authority sought here by Alaska LNG Project LLC.[24] DOE/FE first addressed the concept of agency rights in *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC* ("FLEX").[25] DOE/FE found that "FLEX has requested an acceptable process by which FLEX can act as agent for others who want to export LNG" and that "FLEX's agency rights and registration procedures are an alternative to the non-binding policy adopted by DOE/FE in DOE Opinion and Order No. 2859 . . . which set forth a non-binding policy that the title for all LNG authorized to be exported shall be held by the authorization holder at the point of export."[26] DOE/FE also accepted FLEX's proposal to file the

[23] *See The Dow Chemical Company*, DOE/FE Order No. 2859 at 7-8 (Oct. 5, 2010).
[24] *See, e.g., Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 148 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391 at 137 (Feb. 11, 2014); *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 159 (Nov. 15, 2013); *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 146 (Sept. 11, 2013); *Lake Charles Exports, LLC*, DOE/FE Order No. 3324 at 130 (Aug. 7, 2013); *Freeport LNG Expansion, L.P., Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 116 (May 17, 2013); *Gulf Coast LNG Export, LLC*, DOE/FE Order No. 3163 (Oct. 16, 2012).
[25] DOE/FE Order No. 2913 (Feb. 10, 2011).
[26] *Id*. at 7 (*citing The Dow Chemical Company*, DOE/FE Order No. 2859 at 7-8 (Oct. 5, 2010)).

relevant long-term commercial agreements under seal once they have been executed.[27] DOE/FE stated that by "accepting FLEX's requested registration process and contract terms, DOE/FE will ensure that the title holder is aware of all requirements in the Order, including destination restrictions, that DOE will have a record of all authorized exports, and that DOE will have direct contact information and point of contact with the title holder."[28] DOE/FE concluded that "[t]his process is responsive to current LNG markets and provides an expedited process by which companies seeking to export LNG can do so."[29] DOE/FE should grant Alaska LNG Project LLC's proposed procedure as it is identical to the procedure that DOE/FE consistently has granted for FLEX and others.

VI. <u>EXPORT SOURCES</u>

As described above, Alaska LNG Project LLC plans to construct one integrated and interdependent Project that includes (i) a Liquefaction Facility, storage and loading facilities, and other associated facilities; (ii) a large-diameter gas pipeline from the Liquefaction Facility to the gas treatment plant; (iii) a gas treatment plant on the North Slope; and (iv) transmission lines between the gas treatment plant and producing fields.

Alaska LNG Project LLC seeks authorization to export natural gas from Alaska, in particular the North Slope Point Thomson Unit and Prudhoe Bay Unit production fields. Affiliates of Members of Alaska LNG Project LLC are leaseholders of natural gas resources in Alaska. Thus, as required by DOE/FE, the Project "has access to a source of natural gas supply that is within the power of [Alaska LNG Project LLC] or the [Project] to secure."[30]

---

[27] *Id.* at 8. The practice of filing contracts after DOE/FE has granted export authorization is well established. *See Yukon Pacific Corporation*, ERA Docket No. 87-68-LNG, Order No. 350 (Nov. 16, 1989); *Distrigas Corporation*, FE Docket No. 95-100-LNG, Order No. 1115 at 3 (Nov. 7, 1995).
[28] DOE/FE Order No. 2913 at 8.
[29] *Id.*
[30] *See* Dismissal of Alaska Gasline Port Authority's DOE/FE Application, Docket No. 12-75-LNG at 7 (Mar. 7, 2013). The Project's access to a source of natural gas, along with its progress in acquiring land for the Project

VII. PUBLIC INTEREST

Alaska LNG Project LLC's requested authorization as described herein is not inconsistent with the public interest and should be granted by DOE/FE under the individual statutory provisions that apply separately to exporting LNG to FTA and non-FTA countries.

A. FTA Countries

NGA section 3(c), as amended by Section 201 of the Energy Policy Act of 1992 (Pub. L. 102-486), provides that:

> [T]he exportation of natural gas to a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest, and applications for such importation or exportation shall be granted without modification or delay.[31]

Under this statutory presumption, that portion of this Application that seeks to export LNG to nations with which the United States currently has, or in the future may enter into, an FTA requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest. As required by the NGA, DOE/FE should grant such authorization without modification or delay. Indeed, DOE/FE promptly grants authorizations, as it should do here, for export to FTA nations as a matter of statutory requirement.[32]

B. Non-FTA Countries

NGA section 3(a) sets forth the general standard of review for export applications:

---

facilities and its plan to construct a pipeline to transport gas to the contemplated liquefaction facility, thus clearly distinguishes the instant application from the Application of the Alaska Gasline Port Authority that DOE/FE dismissed on March 7, 2013. *Id*.

[31] 15 U.S.C. § 717b(c) (2006).

[32] *See, e.g.*, *Magnolia LNG, LLC*, DOE/FE Order No. 3406 (Mar. 5, 2014); *Annova LNG, LLC*, DOE/FE Order No. 3394 (Feb. 20, 2014); *Delfin LNG LLC*, DOE/FE Order No. 3393 (Feb. 20, 2014); *ConocoPhillips Alaska Natural Gas Corporation*, DOE/FE Order No. 3392 (Feb. 19, 2014); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3384 (Jan. 22, 2014); *Barca LNG LLC*, DOE/FE Order No. 3365 (Nov. 26, 2013); *EOS LNG LLC*, DOE/FE Order No. 3364 (Nov. 26, 2013); *Advanced Energy Solutions, LLC*, DOE/FE Order No. 3360 (Nov. 14, 2013); *Argent Marine Management, Inc.*, DOE/FE Order No. 3356 (Nov. 6, 2013); *Venture Global LNG, LLC*, DOE/FE Order No. 3345 (Sept. 27,2013); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3307 (July 12, 2013); *Freeport-McMoRan Energy LLC*, DOE/FE Order No. 3290 (May 24, 2013); *Gasfin Development USA, LLC*, DOE/FE Order No. 3253 (Mar. 7, 2013); *Trunkline LNG Export, LLC*, DOE/FE Order No. 3252 (Mar. 7, 2013).

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] *shall issue* such order upon application, *unless*, after opportunity for hearing, [the Secretary] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.[33]

According to DOE/FE, "[a]pplying the foregoing statutory language, DOE has consistently ruled that Section 3(a) of the NGA creates a rebuttable presumption that proposed exports of natural gas are in the public interest."[34] Accordingly, DOE/FE "must grant such an application unless opponents of the application overcome that presumption by making an affirmative showing of inconsistency with the public interest."[35]

In evaluating the "public interest" DOE/FE "has identified a range of factors that it evaluates when reviewing an application for export authorization."[36] The factors include "economic impacts, international impacts, security of natural gas supply, and environmental impacts, among others."[37] DOE/FE also applies the principles set forth in its Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas, which are intended

[33] 15 U.S.C. § 717b(a) (2006) (emphasis added). This authority has been delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04D (Nov. 6, 2007).

[34] *Sabine Pass Liquefaction, LLC*, DOE/FE Docket 10-111-LNG, Opinion and Order Denying Request for Review Under Section 3(c) of the NGA (Oct. 21, 2010); *see also Panhandle Producers and Royalty Owners Assoc. v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987) ("A presumption favoring import authorization, then, is completely consistent with, if not mandated by, the statutory directive.").

[35] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 6 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391 at 6 (Feb. 11, 2014); *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 8 (Nov. 15, 2013); *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 7 (Sept. 11, 2013); *Lake Charles Exports, LLC*, DOE/FE Order No. 3324 at 6-7 (Aug. 7, 2013); *Freeport LNG Expansion, L.P., Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 6 (May 17, 2013).

[36] *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 6 (May 17, 2013).

[37] *Id.*

to promote free and open trade by minimizing federal government interference.[38] Under the Policy Guidelines:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas. . . . The federal government's primary responsibility in authorizing imports [or exports] should be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[39]

DOE/FE recently affirmed that "it continues to subscribe to the principle set forth in our 1984 Policy Guidelines that, under most circumstances, the market is the most efficient means of allocating natural gas supplies."[40] While the Policy Guidelines solely address imports, DOE/FE has found that the principles are applicable equally to exports.[41]

Consistent with DOE/FE's criteria, the following public interest analysis reviews: (i) the domestic need for the natural gas proposed to be exported (including Alaska natural gas supply and demand); (ii) the impact of the proposed export on natural gas market prices;[42] (iii) the Presidential Finding Concerning Alaska Natural Gas; (iv) the economic benefits of the proposed export; (v) the benefits to national security; and (vi) the environmental benefits. This Application fully addresses each of the criteria applied by DOE/FE in reviewing export applications and confirms that the proposed export is not inconsistent with the public interest and should be approved by DOE/FE.

---

[38] *Id.*; *see Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas*, 49 Fed. Reg. 6,684 (Feb. 22, 1984) ("Policy Guidelines").
[39] Policy Guidelines at 6,685.
[40] *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 112 (May 17, 2013).
[41] *See, e.g.*, *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 7 (Mar. 24, 2014) (*citing Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 1473 at 14 (Apr. 2, 1999)).
[42] All pricing information or forecasts contained in the attached Socio-Economic Report are those solely of the independent consultant (NERA). Neither Alaska LNG Project LLC nor its respective Members or their affiliates provided any pricing or other commercially-sensitive information to NERA in the preparation or review of the attached Socio-Economic Report.

(i) **Domestic Need for the Natural Gas Proposed to be Exported - Regional**

A focus of DOE/FE's public interest analysis is whether there is a projected domestic need in the United States for the gas to be exported.[43] Domestic need is measured by looking at supply and demand. DOE/FE has historically compared the total volume of natural gas reserves and recoverable resources available to be produced during the proposed export period to total gas demand during the export period to determine whether there is a domestic need for the gas to be exported.[44]

As DOE/FE has recognized, Alaska is geographically isolated from the lower 48 and its natural gas market is not connected to that in the lower 48. The natural gas reserves and resources in Alaska are not accessible by consumers in the lower 48 and are analyzed separately.[45] DOE/FE recently affirmed that "[w]here an applicant proposes to export LNG produced in Alaska, DOE/FE has determined that the traditional 'domestic need' criterion should be focused specifically on the *regional* need of the natural gas proposed to be exported from the local gas market in Alaska."[46] As DOE/FE has held, due to the "geographic isolation of Alaska and the Cook Inlet area from the rest of the United States," the question of general domestic need for the natural gas is not relevant and "regional need is the only relevant need consideration."[47] Narrowing its focus further, DOE/FE affirmed that "[e]ven within Alaska, DOE/FE evaluates regional need based on the particular region where the gas is produced[.]"[48]

---

[43] *See, e.g.*, *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 1473 at 13 (Apr. 2, 1999).
[44] *Id*. at 29, 40, 46.
[45] *See ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2500 at 45 (June 3, 2008).
[46] *ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 at 5 (Apr. 14, 2014) (emphasis in original).
[47] *Id*. at n.48; *see also ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2500 at 45 (June 3, 2008) ("[G]iven the relative geographic isolation of the natural gas market in the Cook Inlet region of Alaska, OFE in Order No. 1473 focused specifically on the regional need for the gas for which the export application in that case was sought.").
[48] *ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 at 5 (Apr. 14, 2014).

Therefore, the standard of review for an application to export LNG from Alaska is "whether the proposed export is inconsistent with the public interest standard and, in particular, whether there is a shortage of natural gas supplies in the local [regional] market such that local needs for natural gas cannot be met[.]"[49]

DOE/FE's recent review of applications to export LNG from the lower 48 has not considered any impact such exports could have on gas supply or demand in Alaska. DOE/FE's LNG Export Study specifically excluded discussion of the impact of natural gas exports from Alaska and did not include Alaska when estimating the effect of LNG exports on domestic US markets.[50] While any discussion of the cumulative impact of lower 48 exports has no bearing on the authorization requested herein, even so Alaska LNG Project LLC has demonstrated that the Project's LNG exports will have positive market and macroeconomic impacts on Alaska and the United States as a whole.[51]

As demonstrated below, and as supported by the attached studies, estimated recoverable natural gas reserves and resources in Alaska are abundant and more than sufficient to meet demand for both Alaska in-state consumption and Alaska LNG Project LLC's proposed export over the requested 30-year export term. Accordingly, the proposed export authorization will not have a detrimental impact on the regional domestic supply of natural gas and, therefore, is not inconsistent with the public interest.

[49] *Id.* at 6 (*citing ConocoPhillips Alaska Natural Gas Corp. and Marathon Oil Co.*, DOE/FE Order No. 2860 at 16 (Oct. 5, 2010)).

[50] United States Energy Information Administration, "Effect of Increased Natural Gas Exports on Domestic Energy Markets" at 3 (Jan. 2012) ("Additionally, EIA assumed that an Alaska pipeline, which would transport Alaskan produced natural gas into the lower-48 United States, would not be built during the forecast period in any of the cases in order to isolate the lower-48 United States supply response.").

[51] Socio-Economic Report at 4.

(1) Domestic natural gas supply – Alaska

Domestic natural gas supply is the first component of DOE/FE's analysis. When reviewing whether sufficient supplies exist in Alaska to meet in-state demand as well as Project requirements, it is important to note that the North Slope gas that is proposed to be exported may not reach consumers in the population centers of south central and south east Alaska if the Project is not constructed. Unlike in the lower 48, where gas that is not exported might be used to serve domestic needs via the existing interstate pipeline grid, there is no existing infrastructure in Alaska to move the gas over 800 miles from the North Slope. Absent construction of the Project, the ability to meet Alaska in-state gas demand will continue to be very challenging.

Alaska LNG Project LLC engaged DeGolyer and MacNaughton ("D&M") to evaluate whether there are the necessary natural gas reserves and resources in Alaska to support domestic natural gas demand in Alaska and the Project's feed gas requirements, and to evaluate the possible term of such export. A copy of D&M's report ("Supply Report") is attached hereto as Appendix E. The Supply Report focuses on the conservative expected supply scenario ("Expected Supply"), which fully supports a 30-year LNG export term as requested herein.[52] The Supply Report also examines an alternative high supply scenario ("High Supply"), which would support a 40+-year LNG export term.[53]

The Supply Report's Expected Supply scenario establishes a total gas supply estimate of 63.493 trillion cubic feet ("Tcf") of natural gas in Alaska. Comparing the Expected Supply estimates to NERA's Expected Demand estimates of 47.5 Tcf of natural gas (discussed in the following sub-section), the Expected Supply scenario analyses indicate there is more than

[52] The Supply Report also includes support for an even longer export period of 40+ years, which demonstrates that the export term requested in this Application is conservative. For the High Supply scenario, the Supply Report estimates natural gas reserves and resources of 109.393 Tcf. Supply Report at 2.

[53] Supply Report at 3, Appendix F. The High Supply scenario is included as an appendix to the Supply Report.

sufficient natural gas supply and associated resource deliverability in Alaska to satisfy (i) Project requirements for a 30-year export term at 20 MTPA and (ii) in-state demand.[54] Specifically, at the end of the 30-year export term, the Expected Supply/Expected Demand scenario analyses indicate almost 16 Tcf (approximately 25 percent of the total Expected Supply) of natural gas would remain to satisfy future Alaska in-state natural gas demand:

FIGURE 1
D&M - Remaining Gas Supply in Expected Supply/Expected Demand Scenario (30-Year LNG Export Term)[55]

Category	Amount (Tcf)	Reference
Total Estimated Reserves and Resources	63.493	Figure 5
Upstream Lease Operations Fuel (2013-2052)	(10.200)	Figure 6
Domestic Demand (2013-2022)	(0.997)	Figure 6
Domestic Demand (2023-2052)	(4.420)	Figure 6
LNG Feed Gas (includes fuel/shrink)	(31.880)	Figure 6
Remaining Gas Supply	**15.997**	

The Supply Report compiles information from accredited public domain sources of potential natural gas reserves and resources that are identified as being technically recoverable within Alaska using current technology and were prepared using a reasonable assessment method.[56] The Supply Report analyzes the Cook Inlet fields (which is the only area considered to have proved gas reserves[57]) at the individual field level since these fields are currently producing hydrocarbons. For the discovered and undiscovered resources estimates, the Supply Report analyzes estimates for the North Slope, Southern Alaska (which includes Cook Inlet), and

---

[54] *See id*. at 3.
[55] *Id*. at Figure 1. The "Reference" column refers to figures in the Supply Report.
[56] *Id*. at 2.
[57] While the Alaska Department of Natural Resources, Division of Oil & Gas indicates there are currently approximately 34.8 Tcf proven discovered "reserves" in the North Slope area of Alaska, under a strict interpretation of Petroleum Resources Management System and Society of Petroleum Engineers definitions, these discovered, known gas supplies must be technically characterized as resources rather than reserves due to factors such as the lack of existing access to viable markets where such gas can be sold and monetized. *See id.* at 6.

the Outer Continental Shelf. Specifically, the Supply Report analyzes reserves and only higher certainty resource estimates for onshore Alaska in the North Slope and Cook Inlet, and for offshore Alaska in the Beaufort Shelf and Cook Inlet in water depths 200 meters or less.[58]

As detailed in the Supply Report and in the figure below, D&M estimates, for the Expected Supply scenario (30-year export term), natural gas reserves of 1.143 Tcf and natural gas resources of 62.350 Tcf, for a total gas supply of 63.493 Tcf:

FIGURE 2
D&M - Reserves and Resources Estimates for the Expected Supply Scenario[59]

		Resources Most Likely			
Alaska Region and Assessment Segment	**Reserves (Tcf)**	**Probable (Tcf)**	**Possible (Tcf)**	**Total Reserves + Resources (Tcf)**	**Reference**
Alaska Onshore					
North Slope	0	30.200	15.000	45.200	Figure 15 (PGC)
Cook Inlet	1.143	0.650	1.400	3.193	Figure 4, Figure 15 (PGC)
Alaska Offshore, 0-200 Meters					
Beaufort Shelf	0	2.000	12.000	14.000	Figure 15 (PGC)
Cook Inlet Basin	0	0.400	0.700	1.100	Figure 15 (PGC)
Grand Total - Expected Supply Scenario	**1.143**	**33.250**	**29.100**	**63.493**	

These supply estimates utilize only higher probability (*i.e.*, more conservative) reserves and resources estimates.[60] The Supply Report did not consider estimates of unconventional gas resources in Alaska (*e.g.*, hydrates, shale gas, and coal bed methane resources) or the maximum or lower probability resources estimates due to their more speculative nature.[61]

The Supply Report also analyzes the volumes in excess of NERA's Expected Demand estimates (47.5 Tcf) that will be required in order to provide adequate resource deliverability

[58] *Id*. at 8.
[59] *Id*. at Figure 5. The "Reference" column refers to figures in the Supply Report.
[60] *Id*. at 2.
[61] *Id*. at 8.

throughout the 30-year export term. Assuming a conservative recovery of 75 percent of estimated supplies before total production begins to decline, the Expected Supply scenario estimate of 63.493 Tcf of natural gas results in a plateau duration of approximately 30 years.[62] Thus, the Expected Supply scenario (63.493 Tcf of natural gas) is more than sufficient to provide 30 years of LNG exports at 20 MTPA as well as fully meet the associated Alaska in-state natural gas demand both from the perspective of absolute volume of estimated supply and the likely deliverability associated with such supply.

(2) Domestic natural gas demand – Alaska

Domestic natural gas demand is the second component of DOE/FE's analysis. DOE/FE has stated that for applications to export natural gas from Alaska, it focuses on the regional need for the gas based on the particular region where the gas is produced (*i.e.,* the North Slope).[63] The export proposed herein clearly satisfies this test as the gas demand in the North Slope producing region is minimal due to a low population. While this test is satisfied, Alaska LNG Project LLC has provided further support for a finding that the proposed export is not inconsistent with the public interest by demonstrating that natural gas supply in Alaska far exceeds the demand in Alaska, even beyond the North Slope region.

Alaska LNG Project LLC engaged NERA to conduct an analysis of the natural gas market and macroeconomic impacts that the Project could potentially have on both Alaska and the United States as a whole. A copy of NERA's report ("Socio-Economic Report") is attached hereto as Appendix F. Similar to the Supply Report's examination of the Expected Supply and High Supply scenarios, the Socio-Economic Report focuses on an expected demand scenario ("Expected Demand") and the requested 30-year LNG export term. Information for an

[62] *Id*. at 18.
[63] *ConocoPhillips Alaska Natural Gas Corp.,* DOE/FE Order No. 3418 at 5 (Apr. 14, 2014).

alternative high demand scenario ("High Demand") and the associated 40+-year LNG export scenario is included in an appendix to the Socio-Economic Report.

NERA concludes that, in the Expected Demand scenario, approximately 47.5 Tcf of natural gas supply is necessary to meet both estimated Alaska in-state natural gas demand and Project feed gas requirements:

FIGURE 3
NERA - Alaska Natural Gas Demand in Expected Scenario (Bcf)[64]

		2013	2018	2023	2028	2033	2038	2043	2048	Cumulative Total (Tcf)
Alaska Demand	Upstream Lease Operations Fuel	255	255	255	255	255	255	255	255	10.2
	In-State Use	98	102	116	134	145	154	162	176	5.4
LNG Exports Demand[65]		-	-	878	1,099	1,099	1,099	1,099	1,099	31.9
Total Natural Gas Demand		353	357	1,249	1,488	1,499	1,508	1,516	1,530	47.5

Thus, the Socio-Economic Report concludes that the Expected Supply in the Supply Report is sufficient to meet and exceed the Expected Demand.[66]

To conduct its analysis, NERA developed an Alaska-specific version of its N_{ew}ERA model and its Global Natural Gas Model ("GNGM") to estimate the macroeconomic and market impacts of the Project. The N_{ew}ERA model estimates the impacts of projects on regional

[64] Socio-Economic Report at Figure 3. All results in tables and charts throughout the Socio-Economic Report, unless specified otherwise, are presented in model years which each represent a span of five years (*i.e.*, 2013 represents the years 2013, 2014, 2015, 2016, and 2017). Each model year result represents the average annual result for the time specified by that model year (*i.e.*, in Figure 3 the 2013 Alaska Demand represents the average annual demand in 2013 through 2017). In addition, cumulative totals may not equal the sum of all years due to differences in rounding.
[65] This includes LNG-related fuel use and shrinkages (after ramp-up, 1,099 Bcf/year equals approximately 929 Bcf/year for LNG export and 171 Bcf/year for fuel use and shrinkages).
[66] Socio-Economic Report at 6.

economies at a sectoral level. The GNGM estimates global production, pricing, and trade of natural gas and LNG, particularly price estimates for expected LNG exports.

Using certain model inputs and assumptions, NERA developed Baseline, Expected, and High scenarios to measure the economic impacts of the Project. The Baseline scenario assumes that the Project is not constructed. The Expected and High scenarios, each of which is measured against the Baseline, include the construction of the Project, associated LNG export volumes, and different Alaska in-state natural gas demand forecasts, as indicated below:

FIGURE 4
NERA - Scenarios Considered in the Analysis[67]

Scenario Name	**Alaskan Outlook**			**Lower-48**
	Alaska LNG Export and Pipeline Infrastructure	**Natural Gas Demand**	**Natural Gas Supply**	**LNG Exporting**
Baseline	No	Baseline	Baseline	Yes
Expected	20 MTPA over 30 years	Expected	Expected	Yes
High	20 MTPA over 40 years	High	High	Yes

NERA finds that in addition to the reductions in natural gas prices compared to the Baseline scenario (as discussed below), the benefits of the increased supplies of natural gas brought to market by the Project include eliminating reliance on imported natural gas, additional revenues from LNG exports, and increased availability of natural gas for expansion of natural gas intensive industries.[68] NERA finds that the decrease in natural gas prices[69] over time compared to the Baseline scenario will induce additional consumption of natural gas in Alaska's

[67] *Id*. at Figure 12.
[68] *Id*. at 3.
[69] *Id*. at 30.

economy, such that by model year 2048, total Alaska natural gas domestic consumption, as indicated below, is about 10% higher in the Expected scenario than the Baseline:[70]

FIGURE 5
NERA - Expected Scenario Alaska In-State Natural Gas Demand by Sector (Bcf/yr)[71]

Sector	2013	2018	2023	2028	2033	2038	2043	2048	Cumulative Total (Tcf)
Electricity	36	39	25	33	39	42	44	51	1.5
Commercial	23	23	27	30	32	34	37	41	1.2
Residential	22	24	34	36	38	41	43	46	1.4
Manufacturing	6	7	14	17	16	17	16	16	0.5
Government	5	4	4	5	5	5	6	6	0.2
Energy-Intensive	4	5	10	13	13	14	14	14	0.4
Trucking Transportation	0	0	0	0	0	1	1	1	< 0.1
Other Transportation	0	0	0	0	0	0	0	0	< 0.1
Upstream Lease and Operations Fuel	255	255	255	255	255	255	255	255	10.2
Sectoral Total	353	357	370	388	399	409	417	431	15.6
Total Change from Baseline	0	0	16	25	31	33	34	40	0.9

As demonstrated by the foregoing analysis and the Supply Report and Socio-Economic Report, the natural gas to be exported pursuant to this Application will not be needed to meet estimated demand in Alaska. Therefore, permitting the export of natural gas is not inconsistent with the public interest. Moreover, as explained above, granting the export authorization

[70] *Id*.
[71] *Id*. at Figure 18. The items and totals in this table exclude feed gas and fuel/shrinkage requirements.

requested herein will enable additional supplies, that may otherwise be stranded, to serve consumers in Alaska.

(ii) **<u>Impact on Natural Gas Market Prices</u>**[72]

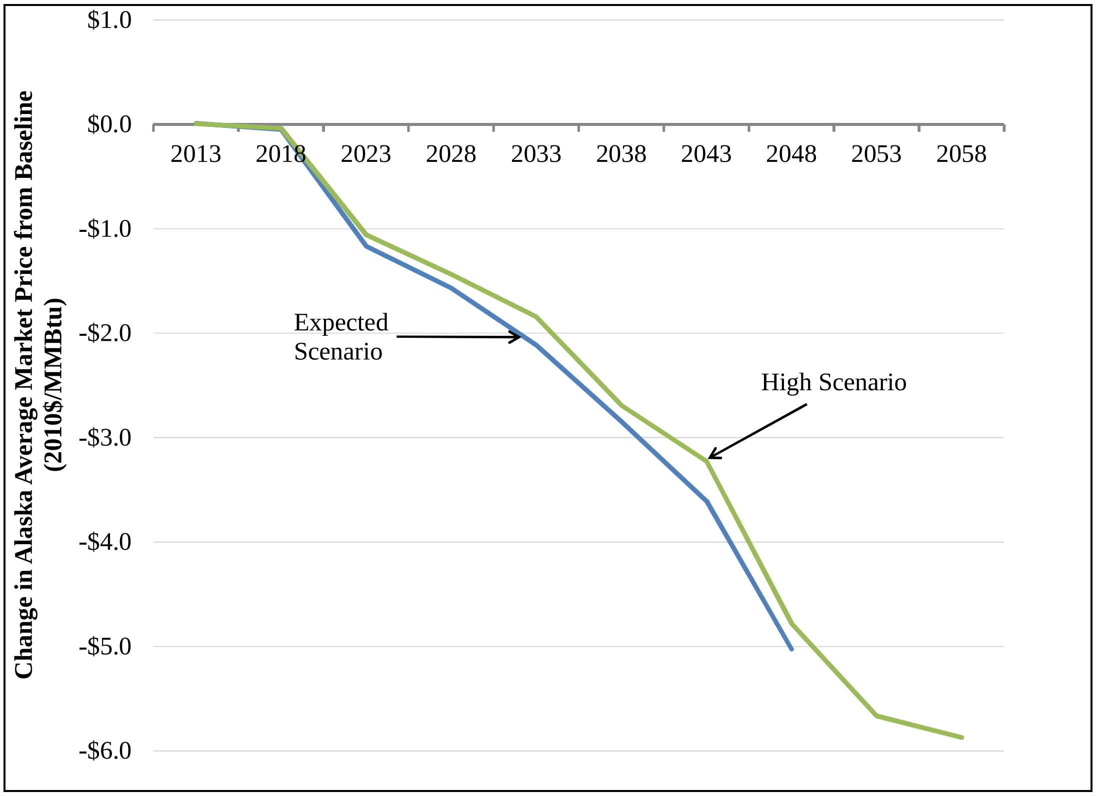
As the Policy Guidelines make clear,[73] it is not the policy of the federal government to manipulate domestic energy prices by approving or disapproving import and export applications. United States policy is that markets, and not the government, should allocate resources, determine supply and demand, and set prices.[74]

Nonetheless, the Socio-Economic Report finds that the Project would lead to lower natural gas prices in Alaska:

---

[72] All pricing information or forecasts contained in the attached Socio-Economic Report are those solely of the independent consultant (NERA). Neither Alaska LNG Project LLC nor its respective Members or their affiliates provided any pricing or other commercially sensitive information to NERA in the preparation or review of the Socio-Economic Report.
[73] Policy Guidelines at 6,685.
[74] *Id*.

FIGURE 6
NERA - Alaska Average Natural Gas Market Price Compared to Baseline (2010$/MMBtu)[75]



As determined by NERA, by model year 2048, the Alaska market price of natural gas is $5.02/MMBtu lower in the Expected Demand scenario than in the Baseline (which assumes that the Project is not constructed), a 39% price difference.[76] The Project's impact on natural gas prices, as estimated by NERA, lends further support to the conclusion that permitting the export of the natural gas for a 30-year term as requested in this Application is not inconsistent with the public interest.

(iii) <u>Presidential Finding Concerning Alaska Natural Gas</u>

Section 12 of the Alaska Natural Gas Transportation Act ("ANGTA"), 15 U.S.C. § 719j, states that "before any Alaska natural gas in excess of 1,000 Mcf per day may be exported to any

---

[75] Socio-Economic Report at Figure 1.
[76] *Id*. at 2.

nation other than Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality nor increase the total price of energy available to the United States."[77] Pursuant to this statutory directive, President Reagan issued such a finding, concluding:

- "There exist adequate, secure, reasonably priced supplies of natural gas to meet the demand of American consumers for the foreseeable future."[78]
- "Exports of Alaska natural gas would not diminish the total quantity or quality of energy available to U.S. consumers because world energy resources would be increased and other more efficient supplies would thus be available."[79]
- "Finally, exports would not increase the price of energy available to consumers since increased availability of secure energy sources tends to stabilize or lower energy prices."[80]

The Presidential Finding concluded "that exports of Alaska natural gas in quantities in excess of 1,000 Mcf per day will not diminish the total quantity or quality nor increase the total price of energy available to the United States."[81]

The Presidential Finding is not limited in scope to a particular project or time period. In fact, the Presidential Finding "*remove[d] the Section 12 regulatory impediment to Alaskan natural gas exports* in a manner that allows *any private party* to develop this resource and sets up competition for this purpose."[82] According to the Presidential Finding, "removal of this impediment to private sector development of Alaska's vast natural gas resources . . . will benefit

[77] 15 U.S.C. § 719j (2006).
[78] Presidential Finding Concerning Alaska Natural Gas, 53 Fed. Reg. 999 (Jan. 15, 1988).
[79] *Id*.
[80] *Id*.
[81] *Id*.
[82] *Id*. (emphasis added).

our entire Nation."[83] As explained in the Presidential Finding, "[t]he operation of market forces is the best guarantee that Alaska natural gas will be developed efficiently and that there is an incentive to find additional reserves."[84] The Presidential Finding therefore remains valid and is applicable to this Project.

While the Presidential Finding was originally issued in the context of earlier efforts to develop the vast natural gas resources on the North Slope, its broad language applies equally to this latest Application to develop these same resources. The Presidential Finding was initially applied to the Yukon Pacific project, a project that bears remarkable similarities to this Project.

	Alaska LNG Project (as currently proposed)	**Yukon Pacific (as proposed in DOE LNG export application)[85]**
Project Type	Integrated greenfield project	Integrated greenfield project
Liquefaction Facility Capacity	20 MTPA	14 MTPA
Liquefaction Trains	3	4
Liquefaction Facility Location	South-central Alaska	Southern Alaska
Pipeline	~800-mile large-diameter pipeline from the North Slope	~800-mile large-diameter pipeline from the North Slope
Requested Export Term	30 years	25 years (granted in DOE Order No. 350)[86]
Proposed Target LNG Destination	Asia	Asia

[83] *Id*.
[84] *Id*.
[85] *See Yukon Pacific Corporation*, ERA Docket No. 87-68-LNG, Order No. 350 (Nov. 16, 1989).
[86] *Id*. at 44.

	Alaska LNG Project (as currently proposed)	**Yukon Pacific (as proposed in DOE LNG export application)[85]**
Known Discovered Alaska Upstream Gas Supply	Approximately 35 Tcf	Approximately 26 Tcf
Access to Gas Supplies	Affiliates of Members of Alaska LNG Project LLC currently hold oil and gas leasehold interests in Alaska, including in the Prudhoe Bay and Point Thomson Units	No direct access; would require third-party purchases

In addition to the similarities between the two projects, the facts of today's natural gas landscape only further support the continued validity of the Presidential Finding. Energy Information Administration estimates of U.S. natural gas reserves have nearly *doubled* in the years following the Presidential Finding.[87] Lower 48 gas resource estimates have increased over 300% since the Presidential Finding.[88] Additionally, as referenced above, NERA concluded that the Project would lead to lower natural gas prices in Alaska[89] and would have "unequivocally positive" economic impacts in Alaska and the United States as a whole.[90]

In *Yukon Pacific*, DOE/FE favorably cited and relied upon the Presidential Finding as removing the section 12 impediment to the very exports of North Slope natural gas proposed here.[91] DOE/FE stated that the Presidential Finding had "fulfilled [ANGTA's] statutory

[87] United States Energy Information Administration, "U.S. Natural Gas, Wet After Lease Separation - Proved Reserves," *available at* http://www.eia.gov/dnav/ng/hist/rngr21nus_1a.htm.
[88] Report of the Potential Gas Committee, "Potential Supply of Natural Gas in the United States," at 3, Table 2 (Dec. 31, 2012).
[89] Socio-Economic Report at 2.
[90] *Id*. at 4.
[91] *See Yukon Pacific Corporation*, ERA Docket No. 87-68-LNG, Order No. 350 at 7 (Nov. 16, 1989) ("On January 12, 1988, President Reagan removed the section 12 impediment to exports of North Slope natural gas[.]").

condition precedent."[92] DOE/FE determined that the Presidential Finding is a "generic finding by the President" that DOE/FE could apply to the facts of the case before it.[93]

In accordance with DOE/FE precedent, the Presidential Finding is valid and applicable to this Project. Therefore, the requirement of Section 12 of ANGTA has been satisfied.

(iv) <u>Economic Benefits</u>

The requested authorization will benefit local, regional, and national economies and is not inconsistent with the public interest. The proposed export of LNG would make available to both the global LNG market as well as Alaska in-state domestic markets natural gas that would otherwise be stranded, at long last capitalizing on Alaska's abundant natural gas resource base. As DOE/FE stated nearly twenty-five years ago, "North Slope natural gas is a major energy resource whose efficient development has been a goal of U.S. energy policy since its discovery in 1968."[94] As stated in the Presidential Finding, "[l]eaving this resource undeveloped benefits no one."[95] Now is the time for the United States to achieve this goal and realize the economic benefits of Alaska natural gas.

The development of new resources creates new jobs and new opportunities for American workers and is consistent with President Obama's National Export Initiative.[96] The President noted that "[a] critical component of stimulating economic growth in the United States is ensuring that U.S. businesses can actively participate in international markets by increasing their exports of goods[.] Improved export performance will, in turn, create good high-paying jobs."[97] The National Export Initiative has the goal of doubling exports by helping businesses overcome

---

[92] *Id*. at 27.
[93] *Id*.
[94] *Yukon Pacific Corporation*, ERA Docket No. 87-68-LNG, Order No. 350 at Section II (Nov. 16, 1989).
[95] Presidential Finding Concerning Alaska Natural Gas, 53 Fed. Reg. 999 (Jan. 15, 1988).
[96] Exec. Order No. 13534, 75 Fed. Reg. 12,433 (Mar. 11, 2010).
[97] *Id.*

hurdles to entering new export markets, assisting with financing, and pursuing a government-wide approach to export advocacy abroad.[98]

Granting the requested authorization would improve the United States balance of trade. In 2012, the national trade deficit was approximately $540 billion, with $291 billion (over half) resulting from a negative balance in the trade of petroleum products.[99] Alaska LNG Project LLC's proposed exports of 20 MTPA of LNG for a 30-year term will make a positive impact on the balance of trade. In approving other export applications, DOE/FE has acknowledged the positive impact that LNG exports can have on the balance of trade with destination countries.[100]

Moreover, consistent with the aims of the National Export Initiative and the DOE's policy of "promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements,"[101] the export of LNG from Alaska will help to improve economic trade and relations between the United States and the destination countries. As the Socio-Economic Report finds, the proposed exports would "allow the U.S. to produce LNG at a globally competitive price."[102] According to the Socio-Economic Report:

> LNG exports provide the U.S. with a means to obtain international goods and services with fewer resources. Therefore, the value of U.S. net exports increases because of the increase in revenues from LNG exports. The large surplus in the current account balance of Alaska as a result of the AKLNG project is a primary driver in the increase in net exports which results in an improvement in the U.S. balance of trade.[103]

---

[98] *Id.*

[99] Bureau of Economic Analysis, United States Department of Commerce, "U.S. International Trade in Goods and Services: Annual Revision for 2012," (June 4, 2013) at 11, *available at* http://www.census.gov/foreign-trade/Press-Release/2012pr/final_revisions/final.pdf. In 2012, the United States exported only $123 billion in petroleum products while importing over $413 billion.

[100] *See, e.g., ConocoPhillips Company*, DOE/FE Order No. 2731 at 10 (Nov. 30, 2009) ("The exportation of LNG will help to improve the United States' balance of payments with the destination countries named in the application[.] Accordingly, I find that mitigation of balance of payment issues may result from a grant of the application."); *Cheniere Marketing, Inc.*, DOE/FE Order No. 2651 at 14 (June 8, 2009) ("[M]itigation of balance of payments issues may result from a grant of the [export] application.").

[101] *Cheniere Marketing, Inc.*, DOE/FE Order No. 2651 at 11 (June 8, 2009).

[102] Socio-Economic Report at 46.

[103] *Id.*

The Socio-Economic Report concludes that the Project would have "unequivocally positive" economic impacts in Alaska and the United States as a whole.[104] The Socio-Economic Report finds that the Project would have strong positive economic impacts on all key indicators of Alaska's economy as compared to the Baseline.[105] In percentage terms, NERA concludes that economic "impacts on Alaska would be much larger than impacts on the U.S. as a whole, but economic impacts in both Alaska and the U.S. are positive for both scenarios relative to the Baseline."[106]

Exporting Alaska natural gas will provide a boost to local, regional, and national economies through resource development, an enhanced tax base, creation of thousands of jobs, and an increase in overall economic activity. The Heads of Agreement concerning the Project notes the substantial benefits that the Project would provide including, (i) the opportunity for competitively priced, reliable in-state gas supply; (ii) job creation in the exploration, development, production, and transportation of natural gas; and (iii) infrastructure to enhance exploration and production opportunities.[107] Construction of the Project would be the single largest investment in Alaska's history. It is anticipated to create up to 15,000 jobs during construction and approximately 1,000 jobs for operation of the Project.

As summarized in the following figure, the Project would boost Alaska's overall economic well-being (as represented by the improvement in consumer welfare, which measures household consumption and leisure), gross product (gross state product ("GSP") for Alaska, and gross domestic product ("GDP") for the United States), and personal income (as represented by consumption):

---

[104] *Id*. at 4.
[105] *Id*. at 6.
[106] *Id*. at 5.
[107] Heads of Agreement at Article 3.

FIGURE 7
NERA - Summary of Alaska Macroeconomic Impacts Compared to Baseline in Expected Scenario[108]

	2013	2018	2023	2028	2033	2038	2043	2048
Welfare (%)	0.1%	0.2%	0.5%	0.9%	1.0%	1.1%	0.9%	0.8%
GSP (%)	1.2%	2.7%	6.0%	7.7%	7.9%	8.4%	9.0%	9.2%
Consumption (%)	0.1%	0.3%	0.6%	0.9%	1.0%	1.1%	1.1%	1.1%

In addition, the Socio-Economic Report finds that "the increased economic activity in Alaska leads to overall benefits for the U.S. as a whole":[109]

FIGURE 8
NERA - Summary of U.S. Macroeconomic Impacts Compared to Baseline in Expected Scenario[110]

	2013	2018	2023	2028	2033	2038	2043	2048
Welfare (%)	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.02%	0.03%
GDP (%)	0.01%	0.03%	0.05%	0.06%	0.06%	0.06%	0.06%	0.05%
Consumption (%)	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%

The Project's positive macroeconomic impacts on Alaska and the United States as a whole lend further support to the conclusion that permitting the export of the natural gas as requested in this Application is not inconsistent with the public interest.

[108] Socio-Economic Report at Figure 5
[109] *Id.* at 5.
[110] *Id*. at Figure 7.

(v) **<u>Benefits to National Energy Security</u>**

The LNG exports associated with the requested authorization will not adversely affect, and in fact will support, United States energy security. DOE/FE recently found that exports can have a positive impact on national energy security:

> to the extent U.S. exports can counteract concentration within global LNG markets, thereby diversifying international supply options and improving energy security for many of this country's allies and trading partners, authorizing U.S. exports may advance the public interest for reasons that are distinct from and additional to the economic benefits identified in the [DOE/FE-sponsored] LNG Export Study.[111]

DOE/FE also analyzed the positive "international consequences" of approving LNG exports and concluded:

> An efficient, transparent international market for natural gas with diverse sources of supply provides both economic and strategic benefits to the United States and our allies. Indeed, increased production of domestic natural gas has significantly reduced the need for the United States to import LNG. In global trade, LNG shipments that would have been destined to U.S. markets have been redirected to Europe and Asia, improving energy security for many of our key trading partners. To the extent U.S. exports can diversify global LNG supplies, and increase the volumes of LNG available globally, it will improve energy security for many U.S. allies and trading partners.[112]

In addition, the Socio-Economic Report analyzes the impact that natural gas exports can have on enhancing energy security using the metrics of supply assurance, price stability, and foreign policy.[113] For example, the Socio-Economic Report concludes as follows:

- <u>Supply Assurance</u>:

> From the point of view of U.S. price stability and assured supplies, the production capacity that is supplying export markets is in effect

[111] *Freeport LNG Expansion, L.P., FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 153 (Nov. 15, 2013).
[112] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 142 (Mar. 24, 2014).
[113] Socio-Economic Report at 52.

> spare capacity that can be diverted to domestic uses. The larger and more liquid the global natural gas market is, the more effective this spare capacity will be. [114]

- Foreign Policy:

> Natural gas exports can have clear foreign policy benefits: reducing dependence of other countries on exports from countries that are not allies of the U.S. will reduce the influence of those countries on the policies of potentially friendly countries importing U.S. LNG. Removing restrictions on exports will also signal the U.S. commitment to WTO and GATT principles, to support free market regimes in other countries, and make it easier to press other countries to remove export restrictions that are damaging to U.S. industry.[115]

As outlined in the Socio-Economic Report, meeting these metrics clearly demonstrates the benefits that the proposed export of LNG will have on United States energy security.

(vi) Environmental Benefits

LNG exports significantly benefit the environment because natural gas is cleaner burning than other fossil fuels. According to the United States Environmental Protection Agency, compared to the average air emissions from coal-fired generation, natural gas-fired generation produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides at a power plant.[116] Accordingly, an increased supply of natural gas made possible through LNG export can help countries reduce their reliance on less environmentally friendly fuels. To the extent that the 20 MTPA of LNG is used in foreign countries as a substitute for coal and fuel oil, it will reduce emissions significantly over the 30-year export term.

With regard to environmental benefits in the United States, the Socio-Economic Report finds that due to fuel-switching from non-gas fuels to natural gas, particularly in the electric

---

[114] *Id*.
[115] *Id.*
[116] *See* http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

sector, emissions will decline in the long-run, although changes in total United States emissions are small at approximately -0.01%.[117]

VIII. <u>ENVIRONMENTAL IMPACT</u>

Pursuant to NEPA, 42 U.S.C. § 4231 *et seq.*, while DOE shall give appropriate consideration to the environmental effects of its proposed decisions regarding a proposed export to FTA countries, that consideration is provided "in light of DOE's statutory obligation to grant the application without delay or modification."[118] That portion of Alaska LNG Project LLC's Application that seeks authority to export LNG only to nations with which the United States currently has, or in the future may enter into, an FTA requiring national treatment for trade in natural gas, "falls within Section 3(c), as amended, and therefore, DOE/FE is charged with granting the application without delay or modification."[119]

Regarding the proposed export to non-FTA countries, Alaska LNG Project LLC requests that DOE/FE issue the export authorization to non-FTA countries conditioned on FERC's completion of the NEPA review and approval of Project construction.[120] DOE/FE has routinely issued orders with such a condition.[121] It has been standard practice for DOE/FE to "complete its

---

[117] Socio-Economic Report at 46-47, 51.

[118] *Sabine Pass Liquefaction LLC,* DOE/FE Order No. 2833 at 5 (Sept. 7, 2010).

[119] *Id.*

[120] As explained in Section II above, despite DOE/FE's recent proposal to change its procedures for processing non-FTA export applications, there are many unique features of this Project that warrant exercise of DOE/FE's discretion to issue a conditional decision.

[121] *See, e.g.*, *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 152 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391 at 140-41 (Feb. 11, 2014); *Freeport LNG Expansion, L.P., FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC,* DOE/FE Order No. 3357 at 163-64 (Nov. 15, 2013); *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 150-51 (Sept. 11, 2013); *Lake Charles Exports, LLC*, DOE/FE Order No. 3324 at 133-34 (Aug. 7, 2013); *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 120-21 (May 17, 2013); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 at 41 (May 20, 2011); *Yukon Pacific Corp.*, ERA Docket No. 87-68-LNG, Order No. 350 (Nov. 16, 1989) ("The DOE believes that energy projects can and must be undertaken consistent with environmentally acceptable practices. To ensure this result, the DOE is attaching a condition to the export approval that all aspects of the export project must be undertaken in accordance with the appropriate environmental review process and must comply with any and all preventative and mitigative measures imposed by Federal or State agencies.").

NEPA review as a cooperating agency in FERC's review of the [proposed export facilities]."[122] According to the established protocol, "DOE/FE's participation as a cooperating agency in the FERC proceeding is intended to avoid duplication of effort by agencies with overlapping environmental review responsibilities, to achieve early coordination among agencies, and to concentrate public participation in a single forum."[123] Here, DOE/FE should continue to follow its well-established practice of granting the requested non-FTA authorization conditioned on the completion of the environmental review process at FERC. As noted above, Alaska LNG Project LLC expects that it will commence the FERC Pre-Filing process in 2014.

IX. EXPORT TERM AND COMMENCEMENT OF EXPORT OPERATIONS

As explained herein and supported by the attached studies, Alaska is unique, as is the Project. The requested 30-year export term and 12-year period for the commencement of operations are appropriate and necessary in order to support the unprecedented investment required, Project scope and time requirements needed to bring North Slope gas to market. Current estimates are that the Project will cost between $45 billion and $65 billion to construct. The estimated cost of construction includes the cost of (i) a Liquefaction Facility, storage and loading facilities, and other associated facilities; (ii) a large-diameter gas pipeline from the Liquefaction Facility to the gas treatment plant; (iii) a gas treatment plant on the North Slope; and (iv) transmission lines between the gas treatment plant and producing fields. Alaska LNG Project LLC will be required to build each component of this greenfield Project from the ground up. Unlike proposed projects in the lower 48, there is no existing long-haul gas transportation infrastructure in Alaska.

[122] *See, e.g.*, *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 150 (Sept. 11, 2013).
[123] *Id.*

In addition, Alaska LNG Project LLC will be faced with unique Arctic construction conditions. The challenges of moving equipment and a workforce over long distances to the construction sites are magnified under the extreme Arctic conditions in Alaska. The Arctic weather conditions cause limitations in the construction timeline. For example, the gas treatment plant facilities will be constructed in a modular fashion and then sealifted to the North Slope for installation. Due to ice conditions in and around Prudhoe Bay, there is a very short time window in the late summer where a sealift operation is possible. If that window is missed due to any number of factors (*e.g.*, weather, labor, equipment, or construction delays), construction of the required facilities will be delayed at least one year until the next available sealift window. These ice-free periods are subject to fluctuations each year due to late thaw or early freeze, thereby increasing the unpredictability of the construction timeline.

Other construction on the North Slope, such as the construction of flow lines and initial gravel infrastructure, is limited to winter periods and necessitates the construction and use of ice roads for access. Such complex construction conditions lead to labor productivity on the North Slope that is approximately one-third of that experienced in the Gulf Coast region of the lower 48. These Arctic construction conditions, coupled with inherently longer upstream resource development periods, necessitate a longer export term and start-up period.

DOE/FE has previously issued authorizations for export from the lower 48 to non-FTA countries with 20-year terms.[124] DOE/FE's rationale for the 20-year terms was that the LNG Export Study commissioned by DOE/FE for the lower 48 "contains projections over a 20-year

[124] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 153 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391 at 142 (Feb. 11, 2014); *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 157 (Nov. 15, 2013); *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 145 (Sept. 11, 2013); *Lake Charles Exports, LLC*, DOE/FE Order No. 3324 at 135 (Aug. 7, 2013); *Freeport LNG Expansion, L.P., Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 122 (May 17, 2013); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-A at 29 (Aug. 7, 2012).

period beginning from the date of first export"[125] and, accordingly, "caution recommends limiting this conditional authorization to no longer than a 20-year term beginning from the date of first export."[126] DOE/FE stated that it was "mindful that LNG export facilities are capital intensive and that, to obtain financing for such projects, there must be a reasonable expectation that the authorization will continue for a term sufficient to support repayment."[127] DOE/FE concluded that the 20-year term "is likely sufficient to achieve this result."[128]

However, the 20-year projection window contained in the DOE/FE's LNG Export Study is not applicable to this unique Alaska Project. The Supply Report and the Socio-Economic Report attached hereto both contain projections over a 30-year period beginning from the assumed date of first export in 2023.[129] As explained in detail above, the requested 30-year term is fully supported by the natural gas reserves and resources estimates in the Supply Report and the demand estimates in the Socio-Economic Report.

Additionally, as explained, an Alaska project is significantly more capital intensive than a lower 48 project and so, by DOE/FE's own reasoning, an Alaska LNG project requires a longer export term. The significant capital investment also requires assurance of a longer-term outlet for the natural gas in order to recover the initial investments and investments following Project start-up. The requested 30-year export term will facilitate enhanced resource development. Furthermore, the 30-year term is consistent with typical industry design standards for the Liquefaction Facility life.

---

[125] *See, e.g.*, *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 157 (Nov. 15, 2013) (*citing* NERA Economic Consulting, "Macroeconomic Impacts of LNG Exports from the United States" (Dec. 2012) at 5).
[126] *Id.*
[127] *Id.* at 157-58.
[128] *Id.* at 158.
[129] The Supply Report and the Socio-Economic Report both contain, as an appendix thereto, projections over a 40-year export period.

With respect to the commencement of operations, DOE/FE has required that lower 48 export operations commence no later than seven years from the date the authorization is issued.[130] DOE/FE stated that "[t]he purpose of this condition is to ensure that other entities that may seek similar authorizations are not frustrated in their efforts to obtain those authorizations by authorization holders that are not engaged in actual export operations."[131] The "other entities that may seek similar authorizations" referenced by DOE/FE are the entities in the queue of lower 48 non-FTA export applicants (currently at 26 applicants) awaiting decision by DOE/FE. The authorization requested herein is not similar to any of the authorizations requested by applicants in the lower 48 queue. Accordingly, DOE/FE's identified purpose in limiting the commencement date to seven years does not apply here. Granting the authorization requested by Alaska LNG Project LLC and permitting a 12-year period for the commencement of export authorizations will not frustrate any other applicant in its efforts to obtain an export authorization.[132]

There is no other application pending before DOE/FE to export North Slope natural gas. In addition, as discussed above, the 12-year period is appropriate and necessary given the complex Arctic construction conditions inherent in any Alaska project and the massive size,

---

[130] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 at 153 (Mar. 24, 2014); *Cameron LNG, LLC*, DOE/FE Order No. 3391 at 142 (Feb. 11, 2014); *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 158 (Nov. 15, 2013); *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331 at 145 (Sept. 11, 2013); *Lake Charles Exports, LLC*, DOE/FE Order No. 3324 at 128 (Aug. 7, 2013); *Freeport LNG Expansion, L.P., Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282 at 122 (May 17, 2013); *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-A at 33 (Aug. 7, 2012).

[131] *See, e.g.*, *FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC and FLNG Liquefaction 3, LLC*, DOE/FE Order No. 3357 at 158 (Nov. 15, 2013).

[132] DOE/FE recently granted authorization to ConocoPhillips Alaska Natural Gas Corporation to export a total of 40 Bcf of natural gas from an existing facility over a two-year period. The two-year authorization commenced on the date of issuance of the order granting the requested authorization (April 14, 2014). The authorization requested in the instant Application will have no impact on the export authorization granted to ConocoPhillips Alaska Natural Gas Corporation as that two-year export authorization will have been completed well before Alaska LNG Project LLC's requested authorization would commence. *See ConocoPhillips Alaska Natural Gas Corp.*, DOE/FE Order No. 3418 (Apr. 14, 2014).

scope, and cost of the proposed Project. Due to its complexity, the Project will require a one to two year Pre-Front End Engineering Design ("FEED") phase in addition to the typical FEED phase. Additionally, the expansive scope of the Project will lengthen the NEPA review and permitting timelines. Unique to this Project, the parties must negotiate several complex project-enabling contracts with the State of Alaska, some of which will require ratification by the Alaska legislature. All of these factors combine to necessitate a longer start-up period than typically granted for lower 48 projects. It is therefore appropriate for DOE/FE to grant Alaska LNG Project LLC's requested 12-year period for the commencement of export operations.

X. APPENDICES

The following appendices are included with this Application:

Appendix A	Verifications
Appendix B	Opinion of Counsel
Appendix C	Project Map
Appendix D	Affidavit of Jeffrey D. McDonald
Appendix E	Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012
Appendix F	Socio-Economic Impact Analysis of Alaska LNG Project

XI. CONCLUSION

WHEREFORE, for the reasons set forth above, Alaska LNG Project LLC respectfully requests that DOE/FE issue an order granting Alaska LNG Project LLC long-term authorization to export 20 million metric tons per year of Alaska LNG (929 Bcf of natural gas) for a term of 30 years to (1) any country with which the United States currently has, or in the future enters into, an FTA requiring national treatment for trade in natural gas; and (2) any country with which the United States does not have an FTA requiring the national treatment for trade in natural gas with which trade is not prohibited by United States law or policy. As demonstrated herein, the authorization requested is not inconsistent with the public interest and, accordingly, should be granted pursuant to Section 3 of the Natural Gas Act.

Alaska LNG Project LLC respectfully requests that DOE/FE grant that portion of the Application that seeks to export LNG to FTA countries "without modification or delay" as required by the Natural Gas Act.[133]

Respectfully submitted,

James [illegible] Moriarty
Jennifer Brough
Matthew T. Eggerding
Locke Lord LLP
701 8th Street, NW
Suite 700
Washington, DC 20001
(202) 220-6915
jmoriarty@lockelord.com
jbrough@lockelord.com
meggerding@lockelord.com

Lydia J. Johnson
Vice President
Daniel J. Brink
Counsel
ExxonMobil Alaska LNG LLC
lydia.j.johnson@exxonmobil.com
daniel.j.brink@exxonmobil.com

Darren Meznarich
President
Barbara Fullmer
Senior Counsel
ConocoPhillips Alaska LNG Company
darren.l.meznarich@conocophillips.com
barbara.f.fullmer@conocophillips.com

David E. Van Tuyl
President
Greg L. Youngmun
Senior Counsel
BP Alaska LNG LLC
david.vantuyl@bp.com
greg.youngmun@bp.com

On behalf of Alaska LNG Project LLC

Dated: July 18, 2014

---

[133] 15 U.S.C. § 717b(c) (2006).

APPENDIX A

Verifications

VERIFICATION

Third Judicial District)
)
State of Alaska)

BEFORE ME, the undersigned authority, on this day personally appeared David E. Van Tuyl, who, having been by me first duly sworn, on oath says that he is the President of BP Alaska LNG LLC and is duly authorized to make this Verification on behalf of BP Alaska LNG LLC; that he has read the foregoing instrument and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

David E. Van Tuyl

SWORN TO AND SUBSCRIBED before me on: July 16, 2014

CATHERINE M. BARNETT
NOTARY PUBLIC
My Commission Expires July 4, 2018
STATE OF ALASKA

Notary Public

VERIFICATION

Third Judicial District)
)
State of Alaska)

BEFORE ME, the undersigned authority, on this day personally appeared Darren Meznarich, who, having been by me first duly sworn, on oath says that he is the President of ConocoPhillips Alaska LNG Company and is duly authorized to make this Verification on behalf of ConocoPhillips Alaska LNG Company; that he has read the foregoing instrument and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

SWORN TO AND SUBSCRIBED before me on:

Notary Public
MADISON WHYBARK-MARSHALL
State of Alaska
My Commission Expires April 08, 2018

Notary Public

SUBSCRIBED and SWORN to before me this 18 day of July, 2014

Notary Public in and for the State of Alaska, residing at 700 G St 1199 Anch AK 99501

VERIFICATION

Harris County)
)
State of Texas)

BEFORE ME, the undersigned authority, on this day personally appeared Lydia J. Johnson, who, having been by me first duly sworn, on oath says that she is the Vice President of ExxonMobil Alaska LNG LLC and is duly authorized to make this Verification on behalf of ExxonMobil Alaska LNG LLC; that she has read the foregoing instrument and that the facts therein stated are true and correct to the best of her knowledge, information and belief.

DONNA F. STEPHENSON
Notary Public, State of Texas
My Commission Expires
January 20, 2015

Lydia J. Johnson 16 JULY 2014

SWORN TO AND SUBSCRIBED before me on:

Notary Public

APPENDIX B

Opinion of Counsel

July 18, 2014

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

RE: Alaska LNG Project LLC
Application for Long-Term Authorization to Export Liquefied Natural Gas

Dear Mr. Anderson:

This opinion of counsel is submitted pursuant to Section 590.202(c) of the regulations of the United States Department of Energy, 10 C.F.R. § 590.202(c) (2014). The undersigned is counsel to Alaska LNG Project LLC. I have reviewed the corporate documents of Alaska LNG Project LLC and it is my opinion that the proposed export of natural gas as described in the application filed by Alaska LNG Project LLC to which this Opinion of Counsel is attached as Appendix B, is within the limited liability company powers of Alaska LNG Project LLC.

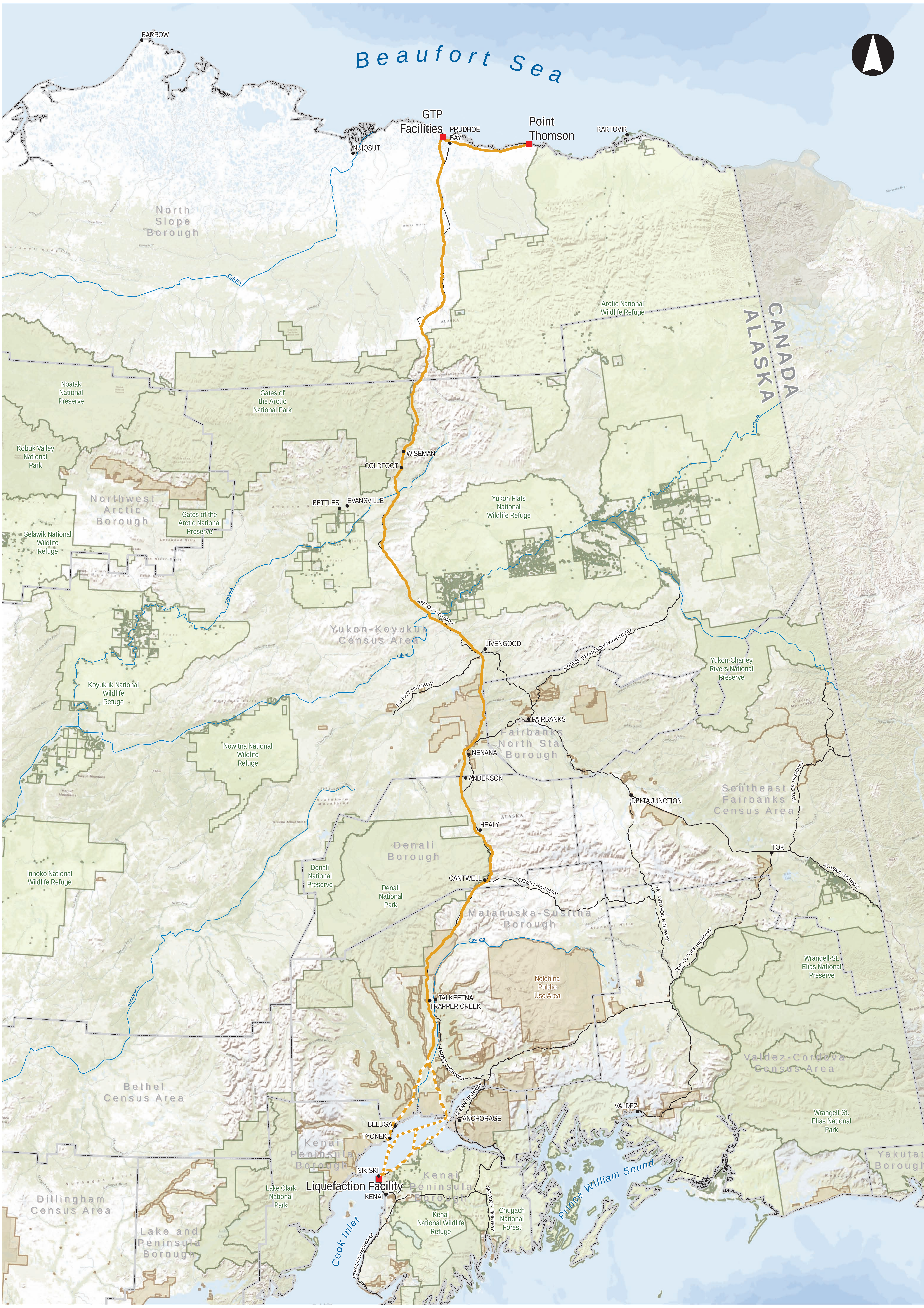
Respectfully submitted,

James F. Moriarty
Locke Lord LLP
701 8th Street, NW
Suite 700
Washington, DC 20001
(202) 220-6915
jmoriarty@lockelord.com

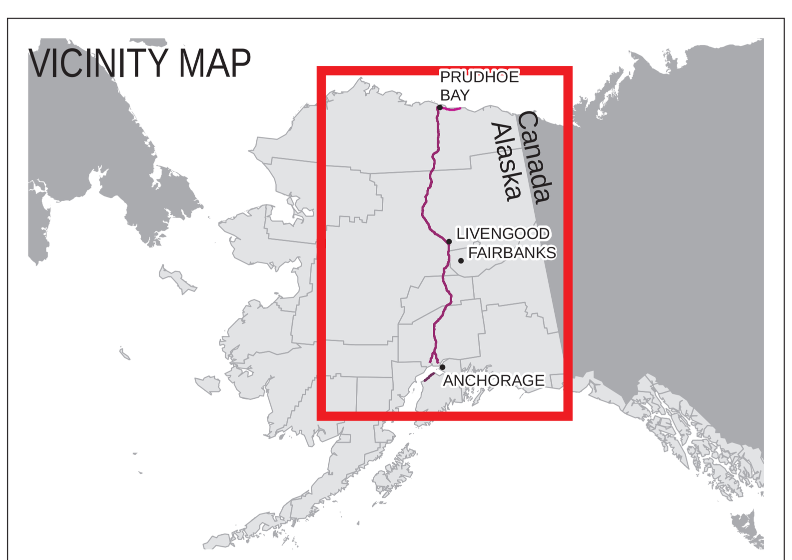
Counsel to Alaska LNG Project LLC

APPENDIX C

Project Map



VICINITY MAP



LEGEND

- Project Facility Location
- Alaska Place Names
- Current Preferred Route
- Optional Routes
- Borough/ Census Area Boundary
- Major Highways
- Major Rivers
- Federal Lands
- State Lands

0 40 80 160 Miles

DATA SOURCES

(1) Alaska LNG Project Data
(2) Alaska DOT
(3) Alaska DNR
(4) US Census

PREPARED BY:	EXP ENERGY SERVICES INC.
SCALE:	1:1,800,000
DATE: 2014-06-18	SHEET: 1 of 1

PROJECT OVERVIEW MAP

Alaska LNG

X:\Projects\ExxonMobil\SCLNG\Mapping\20140529_ProjectUpdateReportMapping\OverviewMap 22x34.mxd

APPENDIX D

Affidavit of Jeffrey D. McDonald

APPENDIX D
Affidavit of Jeffrey D. McDonald

State of Texas)
)
Harris County)

The undersigned, Jeffrey D. McDonald, upon being duly sworn, states as follows:

1. My name is Jeffrey D. McDonald, and I work as a Land/Right of Way Advisor for ExxonMobil Development Company and have 32 years' experience working as a land/right of way professional with a number of ExxonMobil affiliates. For the past 12 months, I have worked on land acquisition and rights of way matters for the Alaska LNG Project ("Project"), and have personal knowledge of the facts stated herein.

2. The Alaska LNG Project LLC ("LLC") is comprised of three member companies: ExxonMobil Alaska LNG LLC ("ExxonMobil"), BP Alaska LNG LLC, and ConocoPhillips Alaska LNG Company.

3. The LLC has already acquired 120.39 acres of fee title land rights in the Nikiski, Alaska area for the liquefaction facility. The Kenai Peninsula Borough Recorder's Office recording numbers for the deeds which evidence fee title to the land in the name of the LLC are provided in Attachment 1 to this Affidavit.

4. Approximately ten contract land brokers are continuing to work in the Nikiski, Alaska area to acquire additional land rights for the LLC, both for fee title land for the liquefaction facility site and shorter-term land access rights for studies within a corridor surrounding the lands anticipated to be acquired for the Project facilities. The LLC currently has 97 acres of additional land under contract for purchase. In addition to lands under contract for purchase, the Kenai Peninsula Borough is progressing a conveyance of 29.94 acres of borough-owned land to the LLC.

5. ExxonMobil (and/or its affiliates) has acquired land access rights for conducting environmental and geological/geophysical due diligence studies for over 800 miles along the Project's pipeline and transmission line routes. To date, land access rights have been acquired as follows: (1) approximately 460.58 miles of land owned by the State of Alaska through the State Pipeline Coordinator's Office; (2) approximately 234.18 miles of land owned by the United States government and managed by the Bureau of Land Management; (3) approximately 33.8 miles of land owned by local municipalities; and (4) approximately 31.6 miles of privately owned lands. The general land locations for these agreements are illustrated on the maps in Attachment 2 to this Affidavit.

6. ExxonMobil is in the process of acquiring additional land access rights for conducting further environmental and geological/geophysical due diligence studies at specific locations along the Project's pipeline and transmission line routes.

7. ExxonMobil is working with BP Exploration (Alaska) Inc., Operator of the Prudhoe Bay Unit ("PBU"), to obtain access rights for conducting environmental and geological/geophysical due diligence studies for the Project's gas treatment plant site located within the PBU on Alaska's North Slope.

8. Access to approximately 80 percent of the land anticipated to be necessary for construction of the Project is deemed to be sufficient for such due diligence studies at this time.

Jeffrey D. McDonald

SUBSCRIBED AND SWORN TO before me at Houston, Texas, by Jeffrey McDonald, this 16th day of July, 2014

Teresa A. Dimmer
Public Notary in and for Texas
My commission expires: 11-20-2015

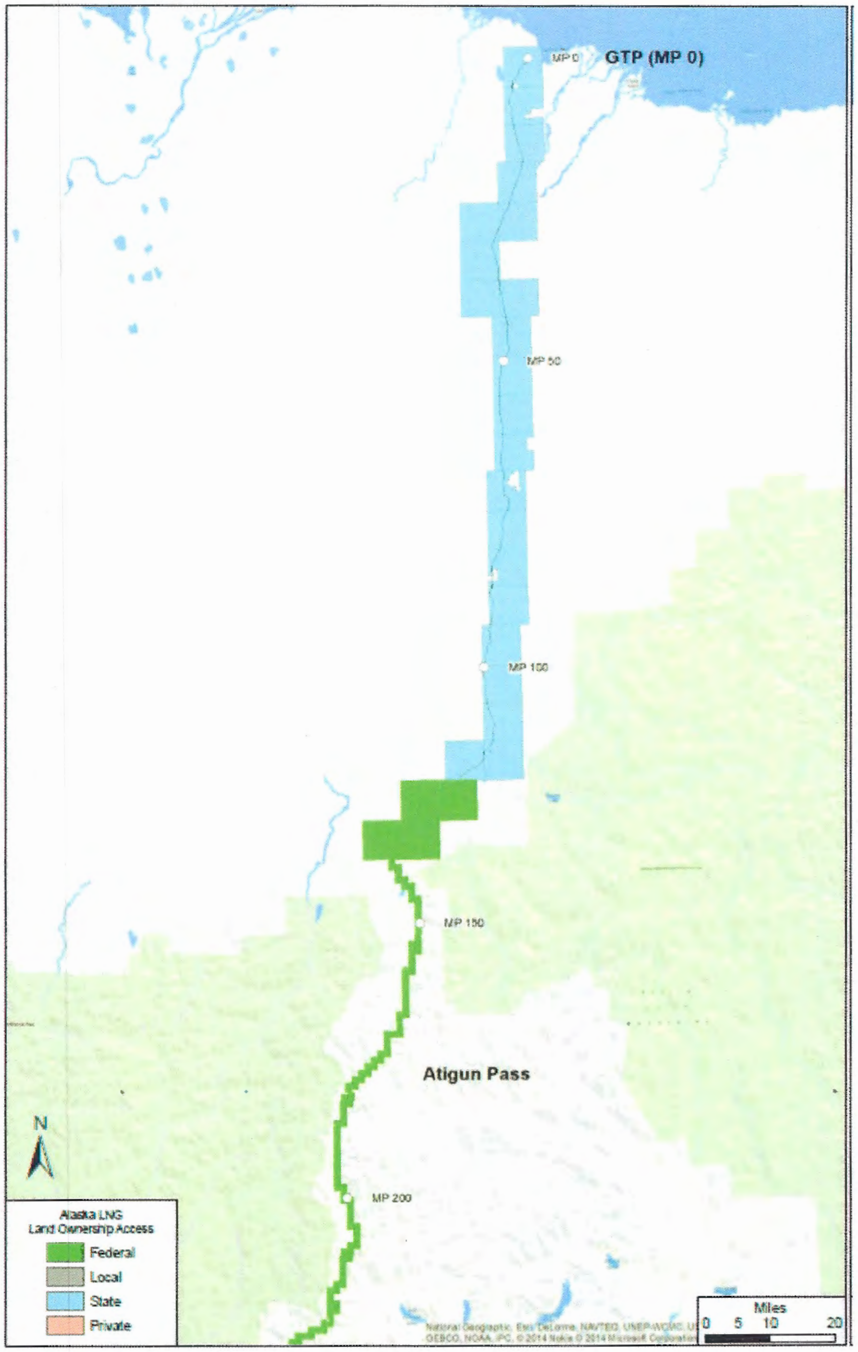
TERESA A. DIMMER
Notary Public, State of Texas
My Commission Expires
November 20, 2015

Attachment 1
Description of Acres Acquired
Liquefaction Facility Site
Nikiski, Alaska

PARCEL ID	GRANTOR	ACRES	TRANSFER DATE	RECORDING DOCUMENT NO.
01502012	Sagami Norman	1.04	06/12/14	2014004746
01502013	Smada Inc	0.63	04/18/14	2014002935
01503002	Teilborg Yova A & Lynn Yova A	0.28	06/20/14	2014005029
01503006	Wearly Michael & Shirley	0.28	05/09/14	2014003570
01503007	Skinner Audrey H	0.28	04/25/14	2014003189
01503013	Bundy Camilla	0.29	06/20/14	2014005036
01503014	Bundy Camilla	0.29	06/20/14	2014005036
01503022	Baker Evan	0.28	05/08/14	2014003535
01504008	Lowell N. & Eileen S. Harris	40.00	04/09/14	2014002635
01504026	Sanborn Catherine H	1.19	05/15/14	2014003758
01504027	Wilcox Properties Llc	1.23	05/29/14	2014004160
01504028	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504029	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504030	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504031	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504033	Munson Matti L	1.19	05/02/14	2014003383
01504034	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504035	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504036	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504037	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504038	Wilcox Properties Llc	1.19	05/29/14	2014004160
01504039	Wilcox Properties Llc	1.20	05/29/14	2014004160
01504048	Ihle Toshiko K Living Trust	2.04	04/18/14	2014002923
01504049	Ihle Toshiko K Living Trust	1.07	04/18/14	2014002923
01504066	Tuttle David	15.00	07/03/14	2014005405
01505009	Thornton Richard C	4.70	04/23/14	2014003014
01505031	Fox Tony R	7.17	06/18/14	2014004995
01506001	Penn Clifford Jr & Teri K	0.35	05/06/14	2014003448
01506002	Penn Clifford Jr & Teri K	0.31	05/06/14	2014003448
01506003	Penn Clifford Jr & Teri K	0.39	05/06/14	2014003448

PARCEL ID	GRANTOR	ACRES	TRANSFER DATE	RECORDING DOCUMENT NO.
01506005	Payment Glen	0.39	07/07/14	2014005445
01506006	Payment Glen	0.39	07/07/14	2014005445
01506015	Stewart Steven Lee & Ruth Mary	0.39	06/25/14	2014005131
01506016	Stewart Steven Lee & Ruth Mary	0.35	06/25/14	2014005131
01506017	Stewart Steven Lee & Ruth Mary	0.44	06/25/14	2014005131
01506018	Stewart Steven Lee & Ruth Mary	0.44	06/25/14	2014005131
01506022	Steinbeck Builders A Partnership	0.44	04/24/14	2014003037
01506023	Birch Ronald G etal	0.44	06/05/14	2014004477
01506027	Eyles William	0.41	05/12/14	2014003601
01506029	Purbaugh Donald	3.06	04/24/14	2014003038
01515020	Poole Rocky M & Crystal R	1.99	06/30/14	2014005303
01520001	Peterson Andrew Jr	9.10	05/23/14	2014004081
01520002	Gordon Dan	1.41	04/16/14	2014002814
01520003	Gordon Dan	1.40	04/16/14	2014002814
01520004	Gordon Dan	1.40	04/16/14	2014002814
01520005	Gordon Dan	1.41	04/16/14	2014002814
01520006	Gordon Dan	1.40	04/16/14	2014002814
01520007	Gordon Dan	1.39	04/16/14	2014002814
01520011	Harker Faith Marie	1.41	04/25/14	2014003190
01520012	Harker Faith Marie	1.40	04/25/14	2014003190
01520016	Sturgeon Russell	1.44	06/02/14	2014004278

Attachment 2
Locations of Rights of Way and Permits for Environmental and Geological/Geophysical Due Diligence Studies




Atigun Pass
MP 200
MP 250
MP 300
MP 350
MP 400
Livengood
N
Alaska LNG
Land Ownership Access
Federal
Local
State
Private
Miles
0 5 10 20


MP 400
Livengood
MP 450
MP 550
MP 600
N
Alaska LNG
Land Ownership Access
Federal
Local
State
Private
Miles
0 5 10 20

APPENDIX E

Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

This is a digital representation of a DeGolyer and MacNaughton report.

Each file contained herein is intended to be a manifestation of certain data in the subject report and as such is subject to the definitions, qualifications, explanations, conclusions, and other conditions thereof. The information and data contained in each file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

REPORT
on a study of
ALASKA GAS RESERVES and RESOURCES
for
CERTAIN GAS SUPPLY SCENARIOS
as of
DECEMBER 31, 2012
prepared for
LOCKE LORD LLP

APRIL 2014

TABLE of CONTENTS

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

REPORT
on a study of
ALASKA GAS RESERVES and RESOURCES
for
CERTAIN GAS SUPPLY SCENARIOS
as of
DECEMBER 31, 2012
prepared for
LOCKE LORD LLP

APRIL 2014

FOREWORD

Scope of Investigation

This report documents the results of an engineering review of data from public sources for gas fields in the state of Alaska. DeGolyer and MacNaughton was engaged to evaluate the quantity of Alaska's gas reserves and resources and the associated probability of gas deliverability in developing gas supply scenarios for the export of liquefied natural gas (LNG) from the proposed Alaska LNG (AKLNG) project. Additionally, the engagement included consideration of the potential impact an LNG export project could have on the domestic gas supply in Alaska.

Authority

This report was prepared at the request of Locke Lord LLP on behalf of BP, ConocoPhillips, and ExxonMobil (collectively, "Sponsors") for use in the assessment and evaluation of gas reserves and resources in Alaska for the proposed AKLNG project. This report has been prepared in accordance with standard geological and engineering methods generally accepted by the gas and petroleum industry. This report has been prepared solely for use by Locke Lord LLP and Sponsors. It is not intended for use by any other entity or for other purposes, and neither DeGolyer and MacNaughton nor Locke Lord LLP shall have any liability arising out of or related to any such use.

EXECUTIVE SUMMARY

DeGolyer and MacNaughton evaluated public data to investigate whether Alaska holds the necessary gas reserves and resources to support domestic gas and LNG export feed gas requirements associated with the export of 20 million metric tons per annum (MTPA) of LNG and the possible term of such export.[1,2] This study presents a compilation of information from accredited sources in the public domain of potential gas reserves and resources that are considered to be technically recoverable within the state of Alaska using current technology and were prepared using a reasonable assessment method. This report focuses on a conservative 30-year LNG export scenario, while information for a 40+-year LNG export scenario is included in Appendix E to this report.

According to the Potential Gas Committee Agency's (PGC) relatively conservative resources estimates, there is a total of 143.050 trillion cubic feet (Tcf)[3] of discovered and undiscovered potentially technically recoverable conventional gas resources in the applicable Alaska regions.[4] With regard to reserves, an estimated 1.495 Tcf of natural gas reserves is reported to be located in Cook Inlet, based on data from a study conducted by the State of Alaska Department of Natural Resources Division of Oil and Gas (ADNR) in 2009. This 1.495 Tcf has been adjusted to 1.143 Tcf herein based on production from 2009 until December 2012.

As detailed herein, the gas supplies are 63.493 Tcf for the Expected Supply scenario and 109.393 Tcf for the High Supply scenario, utilizing only higher probability (i.e., more conservative) reserves and resources estimates. The resources estimates in this report do not include gas quantities attributable to unconventional sources, such as hydrates, shale gas, and coal bed methane resources.

NERA Economic Consulting (NERA) estimated in its companion study that the total gas demand (including in-state domestic gas demand, upstream operations fuel gas needs, and LNG exports of

---

[1] For purposes of this study and the associated evaluations, it is assumed that LNG production and export will begin in 2023. However, variance from this assumption will not have any appreciable effect on the analyses or conclusions of this study.

[2] These analyses and resulting gas supply scenarios are also incorporated into a separate but companion "Socio-Economic Impact Analysis of Alaska LNG Project" by NERA Economic Consulting.

[3] *See* Figure 15.

[4] PGC's total resources estimate is conservative compared to the corresponding 286 Tcf resources estimate obtained from the U.S. Geological Survey, Alaska Department of Natural Resources, and the U.S. Bureau of Ocean Energy Management. *See* Figure 16.

20 MTPA) requires a minimum of 47.496 Tcf of gas supply for an Expected Demand scenario (30-year LNG export term) and 67.583 Tcf of gas supply for a High Demand scenario (40+-year LNG export term). Consequently, these analyses indicate that sufficient gas supplies exist for the premised 30- and 40+-year LNG export scenarios. Figure 1 below demonstrates that, in the Expected Supply/Expected Demand scenario, almost 16 Tcf of gas supply remains following the proposed 30-year, 20 MTPA LNG export term. This remaining supply is volumetrically equivalent to 35 years of gas supply for in-state gas demand beyond the end of proposed exports:

Figure 1
Remaining Gas Supply in Expected Supply/Expected Demand Scenario
(30-Year LNG Export Term)

Category	Amount (Tcf)	Reference
Total Estimated Reserves and Resources	63.493	Figure 5
Upstream Lease Operations Fuel (2013-2052)	(10.200)	Figure 6
Domestic Demand (2013-2022)	(0.997)	Figure 6
Domestic Demand (2023-2052)	(4.420)	Figure 6
LNG Feed Gas (includes fuel/shrink)	(31.880)	Figure 6
Remaining Gas Supply	**15.997**	

Notes:
1. Petroleum quantities classified as Reserves or Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification.
2. Numbers may not add due to rounding.

SOURCES of INFORMATION

Information used in the preparation of this report was obtained from accredited sources in the public domain regarding potential gas reserves and resources that are considered to be technically recoverable within the state of Alaska using current technology. With public data being the only data considered for this study, it was essential to verify that the public data collected came from accredited sources and were estimated using a reasonable method for assessing gas reserves and resources. DeGolyer and MacNaughton relied on public data and did not prepare any separate independent estimates regarding either (1) the uncertainty of existing gas reserves in place or recoverable gas quantities or (2) economic considerations in estimating future field production performance.

Gas Reserves Estimates

ADNR's 2009 Annual Report served as the primary source of gas reserves estimates, in developing the gas supply scenarios utilized in this report. ADNR follows the U.S. Securities and Exchange Commission guidelines for proved reserves. The ADNR report was utilized for purposes of gas reserves estimates, which are currently limited to the Cook Inlet area of Alaska.

Gas Resources Estimates

PGC's December 31, 2012, publication titled "Potential Supply of Natural Gas in the United States" served as the primary source of gas resources estimates in developing the gas supply scenarios utilized in this report. PGC's assessment procedures for probable, possible, and speculative resources are shown in Appendix F to this report. PGC's assessments of potential resources included all undiscovered gas resources plus discovered resources that are not included in proved reserves. The PGC report was utilized for purposes of state-wide Alaska gas resources estimates. It should be noted that PGC's resources estimates are considered to be more conservative based on a comparison of resources estimates from other public sources, including U.S. Government sources such as the U.S. Geological Survey (USGS) and the U.S. Bureau of Ocean Energy Management (BOEM).

However, data from other public sources, such as the State of Alaska Division of Geological and Geophysical Surveys (DGGS), the U.S. Department of Energy (DOE), IHS Global Inc., (IHS), National Energy Technology Laboratory (NETL), the U.S. Department of Interior Minerals Management Service (MMS) (including the Alaska Outer Continental Shelf (OCS) Region), Wood Mackenzie, and the U.S. Department of Interior's Bureau of Land Management (BLM) were also examined and may occasionally be cited as secondary sources of information and referenced as noted herein.

In all cases, the most recent gas reserves and resources estimates available as of the date of this report were utilized in this report. These publications (and corresponding publication dates) are listed in the References section of this report.

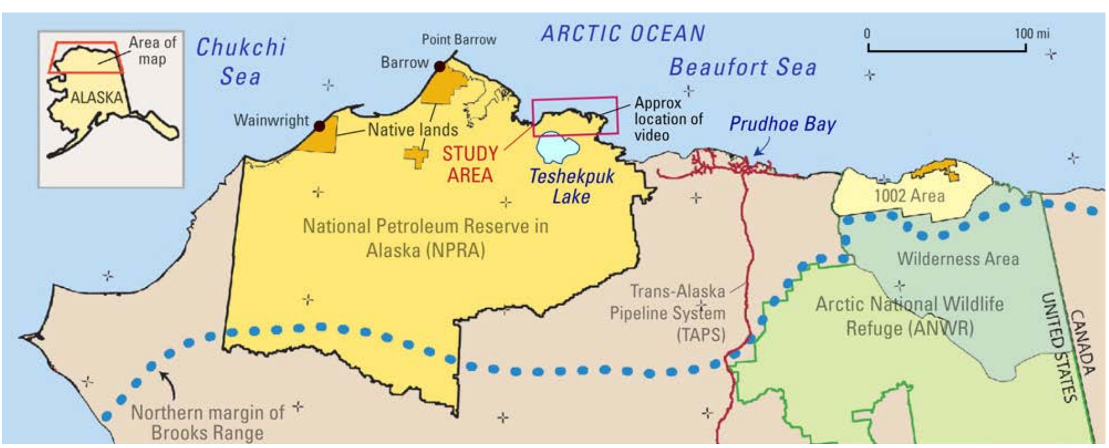
<u>RESERVES and RESOURCES AREAS</u>

DeGolyer and MacNaughton reviewed public data on estimates of gas reserves and resources for several province areas in Alaska. Cook Inlet fields contain estimated gas reserves, which, according to ADNR, were analyzed at the individual field level since these fields are currently producing hydrocarbons. However, for discovered and undiscovered resources plays, the gas estimates were analyzed according to PGC at the regional or producing province level. According to PGC, only four provinces out of 31 currently have natural gas production, while about 20 provinces are estimated to contain conventional hydrocarbon resources. Resources estimates incorporated into this report focus on these four provinces, which include North Slope, Cook Inlet onshore, Cook Inlet offshore, and the Beaufort Shelf province of the OCS. Within these areas, both PGC and other public data sources estimated a range of discovered and undiscovered technically recoverable conventional gas reserves and resources. The complete range of the gas reserves and resources estimates can be found in Appendices C and D to this report.

Arctic Alaska
<u>Petroleum Province Overview</u>

The Arctic Alaska Petroleum Province (including the North Slope and offshore Alaska) extends about 1,100 kilometers east to west beginning at the United States-Canadian border and ranging westward to the maritime boundary towards Russia. It extends northward from the Brooks Range for a distance between 100 to 600 kilometers to a boundary at the edge of the Continental Shelf, as shown in Figure 2 below.

Figure 2
Map of Arctic Alaska Petroleum Province



Cook Inlet Overview

Cook Inlet stretches 180 miles (290 kilometers) from the Gulf of Alaska to Anchorage in south-central Alaska, as shown in Figure 3 below. Cook Inlet almost surrounds Anchorage by branching into Knik Arm and Turnagain Arm at its northern end. Cook Inlet has been producing hydrocarbons since 1958.

Figure 3
Map of Cook Inlet

CONVENTIONAL RESERVES and RESOURCES

Estimates of unconventional gas resources (e.g., hydrates, shale gas, and coal bed methane resources) in Alaska were not considered in this report given their more speculative nature. Further, only the estimated most likely or mean gas quantities were considered. The more speculative estimated maximum or lower probability resources estimates were excluded from consideration.

Classifications

The estimated reserves were classified using definitions established by the Society of Petroleum Engineers (SPE) for the Petroleum Resources Management System (PRMS) (hereinafter, the "SPE PRMS definitions," which are listed in Appendix A). The gas resources were classified using definitions established by PGC (listed in Appendix B along with SPE PRMS Definition and Classification of Resources). Two sets of definitions are required as PGC specializes in resources estimates only and utilizes its own definitions.

Conventional Reserves

This report considered and analyzed only discovered and potentially undiscovered technically recoverable conventional gas reserves and resources estimates available from ADNR and PGC, respectively. Moreover, for offshore resources estimates, only those PGC resources estimates associated with the Beaufort shelf and Cook Inlet Basin at relatively shallow (200 meters or less) water depths were considered. Due to their more speculative nature, PGC resources estimates associated with the Chukchi Shelf, Norton Basin, Hope Basin, Navarin Basin, St. George Basin, Bristol Bay, Shumagin-Kodiak Shelf, Aleutian Shelf, Northern Gulf of Alaska Shelf, and Southeastern Alaska Shelf were not included.

Cook Inlet Producing Reserves

For this study, Cook Inlet is the only area considered to have proved gas reserves according to SPE PRMS definitions. The gas reserves are classified based on the relative uncertainty of each category as (1) proved, (2) proved-plus-probable, and (3) proved-plus-probable-plus-possible, as discussed in detail in Appendix A. The gas reserves in these fields have been estimated in accordance with the SPE PRMS definitions. The gas reserves estimated in Cook Inlet are included in all the gas supply scenarios.

ADNR conducted a gas reserves evaluation in December 2009 using decline-curve analysis (DCA) and material-balance (MB) estimates on the wells then producing in the Cook Inlet fields. The total estimated reserves for the 28 producing fields was 0.863 Tcf when evaluated using DCA[5], which was 0.280 Tcf less than the estimates using MB[6] (compare the volumes in column “Total Cook Inlet Fields,” rows “DCA” and “MB” in Figure 4, below).

DCA is believed to be more conservative than MB because gas production was restricted due to infrastructure issues, making estimation more difficult with this technique. Four fields out of the 28 fields assessed contain the majority of the total reserves estimated. These fields were further evaluated using mapping techniques by analyzing pay and potential pay sandstone thickness for numerous producing zones. This technique confirms that these reservoirs contain an additional amount of technically recoverable gas reserves not accounted for in DCA and MB because they have yet to be in communication with producing wellbores. The geological analysis by pay category adds another 0.353 Tcf of reserves for the four largest fields in addition to the reserves estimates shown for DCA and MB methods (see the volumes in column “Total Cook Inlet Fields,” row “High Confidence Pay” in Figure 4, below).

When the geological analysis of lower confidence potential to pay category is added, there is an additional 0.643 Tcf of gas reserves added to the previous 0.353 Tcf estimated for higher confidence pay category. These volumes are presented in column “Total Cook Inlet Fields,” rows “Low Confidence Pay (risked 50%)” and “High Confidence Pay,” respectively, in Figure 4, below. For the purpose of this report, the additional 0.643 Tcf of natural gas was excluded due to the risk of producing these reserves, leaving the estimated Cook Inlet gas reserves of 1.495 Tcf as of December 2009.

The gas reserves of 1.495 Tcf are the sum of (a) the material balance and geological pay category estimates of 1.213 Tcf for the four greatest potential fields plus (b) 0.282 Tcf from the remaining fields. According to IHS, 0.352 Tcf of natural gas was produced from onshore Cook Inlet from January 2010 to December 2012 and must be subtracted from the estimated 1.495 Tcf of gas

[5] DCA uses current production trends to analyze declining production rates and forecast future well performance. DCA cannot measure gas reserves that exist in hydraulically isolated reservoir volumes.

[6] MB uses the volumetric relationship between pressure, gas properties, and production to define original gas in place in order to forecast future well performance. MB estimates are related to gas in pressure communication with producing wells. MB cannot predict gas estimates in isolated parts of the reservoir.

reserves (see the volumes in column "Total Cook Inlet Fields," row "Reserves Produced (January 2010 to December 2012)" in Figure 4, below). The following Figure 4 shows a summary of ADNR's reserves estimates based on the different estimations methods for the Cook Inlet fields, as well as recent production as reported by IHS.

Figure 4
Reserves Estimates for Cook Inlet Fields

	Sum of 4 Greatest Potential Fields (Tcf)	**Sum of other 24 Remaining Fields (Tcf)**	**Total Cook Inlet Fields (Tcf)**
Reserves as of December 2009			
DCA	0.697	0.166	0.863
MB	0.860	0.282	1.142
Geological Analyses (not being drained by current wells)			
High Confidence Pay	0.353	Not Reviewed	0.353
Low Confidence Pay (risked 50%)	0.643	Not Reviewed	0.643
Subtotal (MB + High Confidence Pay)			1.495
Production			
Reserves Produced (January 2010 to December 2012)			0.352
Total Reserves (Subtotal less Production)			1.143

Excluding any reserves growth between year-end 2009 and December 2012, for the purposes of this report the estimated gas reserves quantity for Cook Inlet as of December 31, 2012 is 1.143 Tcf.[7]

[7] Illustration of calculation: 1.142 Tcf (from MB estimates) + 0.353 Tcf (from Geological Analyses, High Confidence Pay) – 0.352 Tcf (from Reserves Produced) = 1.143 Tcf.

Conventional Resources

Alaska North Slope Resources

Alaska North Slope onshore contains an estimated 45.200 Tcf of probable and possible resources that are feasible to produce now or in the foreseeable future, as estimated by PGC.[8] As noted by PGC, a significant portion of these North Slope resources are in fact discovered and well delineated. In fact, the ADNR in its 2009 Annual Report lists 34.827 Tcf of reserves associated with discovered North Slope gas fields.[9] The overwhelming majority of this quantity is attributed to the Prudhoe Bay Unit and Point Thompson Unit, though under SPE PRMS definitions, these gas quantities are classified as resources rather than reserves due to current lack of viable access to markets. However, once the required infrastructure is in place to produce and transport these resources, a large quantity of these gas resources would be potentially reclassified as reserves according to SPE PRMS definitions, contingent upon a viable market for the gas supply.

Cook Inlet Resources

According to PGC, there is an estimated 2.050 Tcf of probable and possible resources available for onshore Cook Inlet.

Offshore Resources

PGC considered the offshore depth from zero to 200 meters in the Cook Inlet Basin and Beaufort Shelf to have the least amount of risk associated with Alaska offshore gas resources. These two areas contain speculative resources, but also contain probable and possible resources, as estimated by PGC. PGC did not include any other offshore areas as containing probable or possible resources. This report excludes consideration of offshore provinces where PGC indicates the presence of only speculative resources due to their lower probability. The probable and possible resources of Cook Inlet Basin and the Beaufort Shelf together are an estimated 1.100 Tcf and 14.000 Tcf of gas, respectively. Both of these areas are currently being produced, which results in resource estimates of higher probability.

The following Figure 5 shows the 1.143 Tcf of reserves for Cook Inlet (as described in section "Cook Inlet Producing

[8] *See* Figure 15.
[9] *See* Figure 16.

Reserves," above) as well as the distribution of probable and possible resources estimated by PGC for onshore and offshore Alaska for the Expected Supply scenario and the associated 30-year LNG export term, which is described in more detail below. Only probable and possible resources were included in the 30-year Expected Supply scenario because they contain less risk than speculative resources. The reduction in risk is due to the probable resources being associated with known fields and the possible resources existing on the outskirts of known fields; speculative resources are located in formations or geologic provinces defined but not yet proven productive.

Figure 5
Reserves and Resources Estimates for the Expected Supply Scenario

Alaska Region and Assessment Segment	Reserves (Tcf)	Resources Most Likely: Probable (Tcf)	Resources Most Likely: Possible (Tcf)	Total Reserves + Resources (Tcf)	Reference
Alaska Onshore					
North Slope	0.000	30.200	15.000	45.200	Figure 15 (PGC)
Cook Inlet	1.143	0.650	1.400	3.193	Figure 4, Figure 15 (PGC)
Alaska Offshore, 0-200 Meters					
Beaufort Shelf	0.000	2.000	12.000	14.000	Figure 15 (PGC)
Cook Inlet Basin	0.000	0.400	0.700	1.100	Figure 15 (PGC)
Grand Total - Expected Supply Scenario	**1.143**	**33.250**	**29.100**	**63.493**	

Note: Petroleum quantities classified as Reserves or Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification.

A relatively small portion of speculative resources is included in the High Supply scenario and the associated 40+-year LNG export term. It is considered reasonable to include some portion of speculative resources in the 40+-year LNG export scenario given the effective 50-year time frame (i.e., 10-year pre-export term and 40-year export term) for resources development associated with this scenario. The resources for the 30- and 40+-year LNG export scenarios associated with the Expected Supply and the High Supply scenarios, respectively, were evaluated and developed using the same provinces or areas and have a higher probability of being developed sooner than other provinces or areas in Alaska. This report focuses on the more conservative 30-year LNG export scenario, while information for the 40+-year LNG export scenario is included in Appendix E to this report.

METHODOLOGY and ANALYSIS

The requirements for the AKLNG project include not only a certain supply of gas in order to meet LNG export delivery contracts (LNG Export Gas Supply Requirements) but also additional quantities of gas to satisfy upstream needs and the current and future domestic gas demands of the Alaskan public ("Domestic and Upstream Gas Supply Requirements").

LNG Export Gas Supply Requirements Per the U.S. Department of Energy handbook on LNG, 1 million metric tons of LNG is equivalent to 46.467 Bcf of gas. An LNG sales rate of 20 MTPA for a 30-year duration is therefore volumetrically equivalent to 0.929 Tcf of gas per year. The fuel and shrink associated with the corresponding feed gas treating, pipeline transportation/compression and liquefaction is estimated at 0.171 Tcf per year for a total gas supply requirement of 1.100 Tcf per year. As further detailed below, feed gas requirements (including fuel/shrink) for the Expected scenario 30-year LNG export term (i.e., 2023 through 2052) at 20 MTPA requires a minimum gas supply of 31.880 Tcf.[10] In other words, this 31.880 Tcf represents the volume of gas supply that would be required and consumed for LNG exports alone in this scenario. The requirements for the High Supply scenario 40+-year LNG export term are included in Appendix E to this report.

Domestic and Upstream
Gas Supply Requirement The purpose of the companion "Socio-Economic Impact Analysis of Alaska LNG Project" by NERA is to evaluate the impact that the proposed AKLNG project and the associated development of gas supplies could have on the domestic gas demand in Alaska. It is important to verify that there will be a sufficient amount of gas resources to meet the domestic gas requirements, including fuel for upstream lease operations, as well as feed gas for the export term of the AKLNG project. The associated NERA study determined domestic gas demand in Alaska, including all associated fuel and shrink for both the Expected Supply and High Supply scenarios. This report focuses on NERA's Expected Demand scenario. The demand estimates from NERA's High Demand scenario are included in Appendix E to this report.

---

[10] Ideally, 20 MTPA of LNG sales over 30 years would require (1.1 Tcf/yr)(30 years) = 33.0 Tcf. The actual calculated requirement is slightly lower at 31.880 Tcf as a result of a three-year ramp-up period required to reach the 20 MTPA of LNG export.

NERA estimated that Alaska in-state requirements total 3.547 Tcf of natural gas for the pre-export term and 12.070 Tcf of natural gas for the export term, or 15.617 Tcf total for the 2013 through 2052 period (corresponding to a 10-year pre-export term and a 30-year LNG export term). By adding the in-state Alaska gas demands to the feed gas requirements of the LNG export plant, NERA estimated the total gas supply required at 47.496 Tcf for the Expected Demand scenario, as seen in Figure 6, below:

Figure 6
Total Gas Demand – Expected Demand Scenario
(Supplied by NERA)

	Pre-Export (2013-2022) (Tcf)	Export-Term (2023-2052) (Tcf)	Cumulative (2013-2052) (Tcf)
In-State Demand			
Electricity Generation	0.376	1.168	1.544
Residential	0.230	1.193	1.423
Government	0.048	0.158	0.206
Energy-Intensive Sectors	0.046	0.392	0.438
Manufacturing	0.065	0.483	0.548
Commercial Sector	0.230	1.002	1.232
Truck Transportation	0.001	0.016	0.017
Other Transportation	0.001	0.000	0.009
Subtotal of Domestic Demands	**0.997**	**4.420**	**5.417**
Upstream Lease Operations Fuel	2.550	7.650	10.200
Subtotal of In-State Demand	**3.547**	**12.070**	**15.617**
30-Year LNG Export Plant Demand			
Fuel/Shrink	0.000	4.943	4.943
LNG Feed Gas Requirements	0.000	26.937	26.937
Subtotal of Demand Associated with LNG Exports	**0.000**	**31.880**	**31.880**
Total Gas Demand - Expected Demand Scenario	**3.547**	**43.950**	**47.496**

Note: Numbers may not add due to rounding.

The following Figure 7, which is based upon NERA's in-state demand estimates for the post-export period in the Expected Demand scenario,[11] illustrates an average annual in-state gas demand of 453.109 Bcf per year beyond the export period:

Figure 7
Average Annual In-State Demand in the Post-Export Period for Expected Demand Scenario
(Supplied by NERA)

In-State Demand	Post-Term (2053 and Beyond) (Bcf/year)
Electricity Generation	58.830
Residential	50.929
Government	7.722
Energy-Intensive Sectors	15.414
Manufacturing	16.572
Commercial Sector	46.201
Truck Transportation	1.549
Other Transportation	0.890
Upstream Lease Operations Fuel	255.000
Average Annual In-State Post-Term Demand	**453.109**

Note: Numbers may not add due to rounding.

The following Figure 8 shows that 15.997 Tcf of natural gas reserves and resources will remain following the 10-year pre-export term and the proposed 30-year LNG export term and that the remaining 15.997 Tcf of gas supply would be volumetrically[12] equivalent to 35 years of supply to meet the average annual in-state post-term demand:

[11] NERA modeled in-state gas demand through 2062, which, for a 30-year export term, would include in-state demand estimates for a 10-year (2053-2062) post-export term. For the purposes of the analysis in this report, such as calculation of theoretical years of gas resources remaining after the export period, it has been assumed that in-state annual gas demand for the post-export period (including beyond 2062) is equivalent to the average annual in-state gas demand modeled for the 2053-2062 period.
[12] Volumetric equivalent of remaining supply does not take into consideration deliverability.

Figure 8
Estimation of Years of Supply Remaining for Expected Supply/Expected Demand Scenario

Category	Amount (Tcf)	Reference
Expected Supply	63.493	Figure 5
Expected Demand	(47.496)	Figure 6
Remaining Volumetric Supply at End of 30-Year LNG Export Term	**15.997**	
Average Annual In-State Post-Term Demand	0.453	Figure 7
Years of Volumetric Supply Remaining[13]	**35**	

With the aforementioned assumptions regarding domestic and export requirements, it can be concluded that, under the Expected Supply/Expected Demand scenario, there are sufficient gas reserves and resources available in Alaska to satisfy the volumetric requirements of a 30-year LNG export term as well as Alaska's domestic needs.

Gas Supply Case
Deliverability Considerations

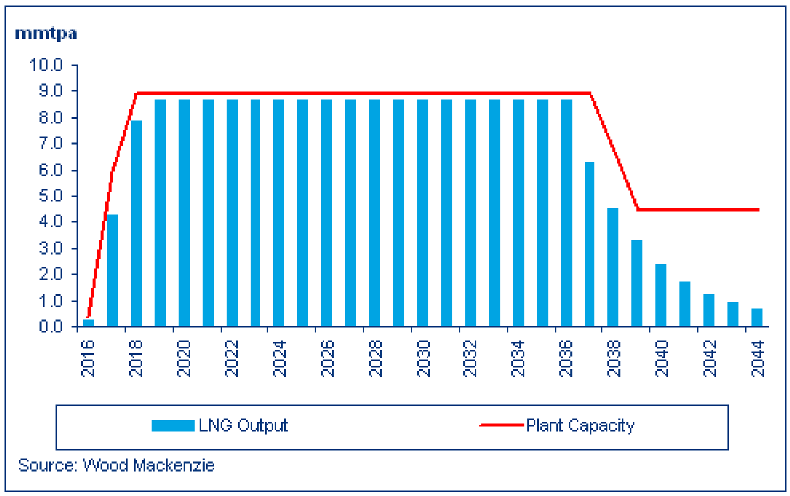
The Expected Demand requirement (47.496 Tcf) associated with the 30-year LNG export term demonstrated that the Expected Supply scenario was more than adequate from a volumetric perspective. Additional volumes over this 47.496 Tcf will be required, however, in order to ensure adequate gas supply deliverability throughout the term of this scenario. While rigorous analyses to ensure such deliverability would not be practical – particularly given the unknown and uncertain nature of undiscovered resources – it is possible to apply actual observed analogies as an empirical means to view the likely adequacy of the Expected Supply scenario (63.493 Tcf) with regard to deliverability.

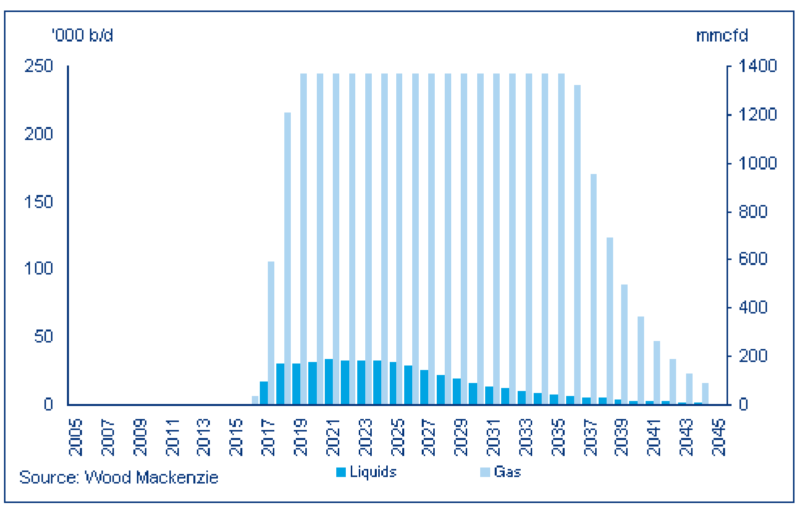
The financing and development of LNG projects have traditionally been underpinned by long-term LNG sales contracts. As a result, it is inherent that the upstream gas fields associated with such LNG projects

[13] Years of Volumetric Supply Remaining = (Remaining Supply) / (Average Annual In-State Post-Term Demand).

are developed in a manner whereby a relatively high percentage of available resources is produced at plateau rates corresponding to these contractual LNG sales rates before the fields' production declines. An example of this relationship between LNG sales contracts and associated upstream gas production rates is illustrated in Figures 9 and 10 below by Wood Mackenzie.

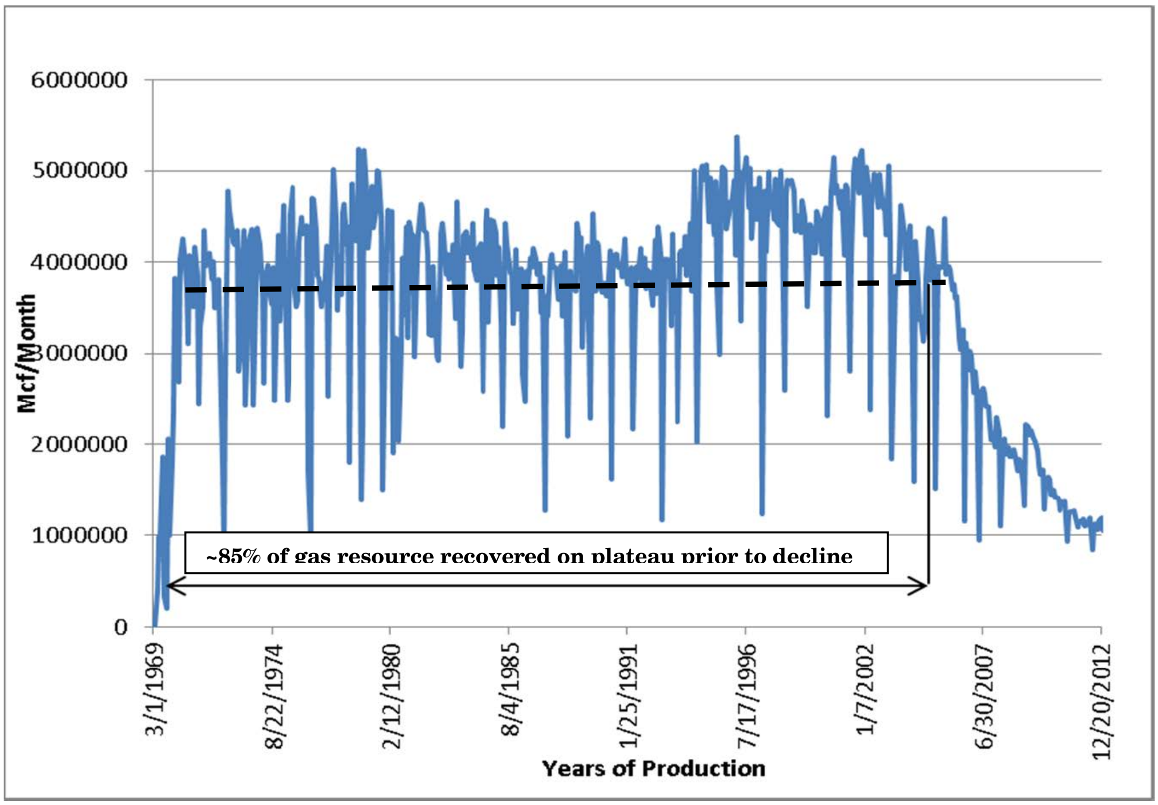
Figures 9 and 10
Example of Relationship between LNG Output and Upstream Production





Moreover, this characteristic has been validated in actual LNG projects that have now matured and where actual historical gas production history is available in the public domain. Specifically, this characteristic has been validated in the case of the North Cook Inlet field, which was effectively dedicated to the Alaska Kenai LNG export plant. Figure 11 below illustrates that the gas production rates for the North Cook Inlet Unit[14] did not decline from plateau rates until over 85 percent of the available gas supplies had been recovered. A detailed calculation is located in Appendix G.

Figure 11
Historical Gas Production for the North Cook Inlet Unit



Even assuming a significantly more conservative recovery of 75 percent of estimated supplies prior to the commencement of production declines for the AKLNG project, the Expected Supply estimate of 63.493 Tcf results in a plateau duration of approximately 30 years, while the High Supply estimate of 109.393 Tcf results in a plateau duration of approximately 49 years, as detailed in Figure 12 below.

[14] Total Gas Produced on Plateau through January 2006 is 1.7 Bcf and total estimated ultimate recovery is 2.0 Bcf. Calculated percentage total resources produced at Plateau is 1.7 Bcf/2.0 Bcf = 85 %.

Figure 12
Plateau Estimates Assuming Plateau Rates until 75% of Supply Recovered

	Expected 30-Year Scenario	High 40+-Year Scenario
Years on Plateau[15]	30	49
Remaining Resources after Plateau is Met (Tcf)[16]	15.873	27.348

Consequently, these analyses suggest that the Expected Supply scenario (63.493 Tcf) is sufficient to provide 30 years of 20 MTPA of LNG exports as well as the associated in-state gas demand both from the perspective of absolute volume of estimated supply and the likely deliverability associated with such supply. Likewise, these analyses also suggest the High Supply scenario (109.393 Tcf) is sufficient to provide over 45 years of 20 MTPA of LNG exports and associated in-state gas supply requirements both from the perspective of absolute volume of estimated supply and the likely deliverability associated with such supply.

[15] [(0.75)(63.493 Tcf) - (10 years)(0.355 Tcf/year of pre-term demand)]/(1.465 Tcf/year of demand during export term) = 30.1 years for the Expected 30-year scenario and [(0.75)(109.393 Tcf) - (10 years)(0.355 Tcf/year of pre-term demand)]/(1.601 Tcf/year of demand during export term) = 49.0 years for the High 40+-year scenario.
[16] (1-0.75)(63.493 Tcf) = 15.873 Tcf for the Expected 30-year scenario and (1-0.75)(109.393 Tcf) = 27.348 Tcf for the High 40+-year scenario.

RESULTS and CONCLUSIONS

After an analysis of PGC and ADNR gas reserves and resources estimates, DeGolyer and MacNaughton estimates in the Expected Supply scenario that at least 63.493 Tcf of discovered and undiscovered technically recoverable conventional gas reserves and resources are potentially available onshore and offshore (located in water depths 200 meters or less) Alaska. The Expected Supply scenario (63.493 Tcf) gas is sufficient, both from the standpoint of absolute supply quantity as well as associated deliverability, to supply, in the Expected Demand scenario, both in-state demand and LNG feed gas requirements associated with 20 MTPA of LNG export for a 30-year duration. The Expected Supply scenario (63.493 Tcf) does not include unconventional gas quantities or quantities classified as speculative resources for Alaska, which could potentially increase the gas supply. Moreover, the less conservative High Supply/High Demand scenario indicates potential sufficiency to provide for 20 MTPA of LNG exports and in-state demand needs in excess of 45 years.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
GREGORY KYLE GRAVES
70734
LICENSED
PROFESSIONAL ENGINEER

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

REFERENCES

"Alaska Department of Natural Resources of Division of Oil and Gas Annual Report 2009." *Alaska Department of Natural Resources of Division of Oil and Gas*. Alaska Department of Natural Resources, 2009. Web. 24 Apr. 2013. http://dog.dnr.alaska.gov/Publications/Documents/AnnualReports/Section1_2009.pdf.

"Alaska Department of Natural Resources of Division of Oil and Gas Annual Report 2011." *Alaska Department of Natural Resources of Division of Oil and Gas*. Alaska Department of Natural Resources, 2011. Web. 24 Apr. 2013. <http://dog.dnr.alaska.gov/Publications/Documents/AnnualReports/2011_Annual_Report.pdf>.

Attanasi, E. D., and K. J. Bird. "Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National, Digital Data Series 30." *1995 National Assessment of U.S. Oil and Gas Resources*. USGS Numbered Series, 1995. Web. <http://pubs.er.usgs.gov/publication/ofr9575J>.

Attanasi, E.D., and Freeman, P.A., 2009, "Economics of Undiscovered Oil and Gas in the North Slope of Alaska; Economic Update and Synthesis: U.S. Geological Survey Open-File Report 2009–1112", <http://pubs.usgs.gov/of/2009/1112>.

Attanasi, E.D., and Freeman, P.A., 2011, Economic analysis of the 2010 U.S. Geological Survey assessment of undiscovered oil and gas in the National Petroleum Reserve in Alaska: U.S. Geological Survey Open-File Report 2011–1103, 64 p., available only online at http://pubs.usgs.gov/of/2011/1103.

Bird, Kenneth J "Oil and Gas Resource Potential of the Arctic National Wildlife Refuge." *Oil and Gas Resource Potential of the Arctic National Wildlife Refuge*. U.S Geological Survey Open File Report 98-34, 10 Jan. 2013. Web. 27 Apr. 2013. <http://www.anwr.org/images/pdf/resources/1998anwr-report-large-size56p.pdf>.

Collett, T. S., W. F. Agena, M. W. Lee, M. V. Zyrianova, K. J. Bird, T. C. Charpentier, D. W. Houseknecht, T. R. Klett, R. M. Pollastro, and C. J. Schenk. "Assessment of Gas Hydrate Resources on the North Slope, Alaska, 2008." *Assessment of Gas Hydrate Resources on the North Slope, Alaska, 2008*. N.p., Oct. 2008. Web. 05 May 2013. <http://www.usgs.gov/science/cite-view.php?cite=2306>.

Bird, Kenneth J., David W. Houseknecht, Emil D. Attanasi, Thomas E. Moore, Phillip H. Nelson, Christopher J. Potter, Christopher J. Schenk, John H. Schuenemeyer, Mahendra K. Verma, Richard W. Saltus, Jeffery D. Phillips, Ronald R. Charpentier, Trop A. Cook, Timothy R. Klett, and Richard M. Pollastro. "Oil and Gas Assessment of Central North Slope, Alaska, 2005 | USGS Fact Sheet 2005-3043." *Oil and Gas Assessment of Central North Slope, Alaska, 2005 | USGS Fact Sheet 2005-3043*. USGS, 2005. Web. 23 Apr. 2013. <http://pubs.usgs.gov/fs/2005/3043/>.

Curtis, John B., and S. D. Schwochow. *Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee (December 31, 2012)*. Golden, CO: Potential Gas Agency, Colorado School of Mines, 2013. Print.

"Guidelines for Application of the Petroleum Resources Management System." *SPE*. Society of Petroleum Engineers, Nov. 2011. Web. 28 Apr. 2013. <http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf>.

Hartz, J. D., M. C. Kremer, D. L. Krouskop, L. J. Silliphant, J. A. Houle, P. C. Anderson, and D. L. Le Pain. "Preliminary Engineering and Geological Evaluation." *State of Alaska Department of Natural Resources Division of Oil and Gas and Division of Geological &*. Division of Oil and Gas, Dec. 2009. Web. 28 Apr. 2013. <http://dog.dnr.alaska.gov/ResourceEvaluation/Documents/Preliminary_Engineering_and_Geological_Evaluation_of_Remaining_Cook_Inlet_Gas_Reserves.pdf>.

Houseknecht, David W., and Kenneth J. Bird. "Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis." *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*. The U.S. Geological Survey, 04 Dec. 2008. Web. 27 Apr. 2013. <http://pubs.usgs.gov/fs/fs-0028-01/fs-0028-01.htm>.

Houseknecht, David W., and Kenneth J. Bird. "U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA) | FS 045-02." *U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA) | FS 045-02*. U.S. Geological Survey, 17 May 2005. Web. 10 May 2013. <http://pubs.usgs.gov/fs/2002/fs045-02/>.

Houseknecht, D. W., W. A. Rouse, C. P. Garrity, K. J. Whidden, J. A. Dumoulin, C. J. Schenk, R. R. Charpentier, T. A. Cook, S. B. Gaswirth, M. A. Kirschbaum, and R. M. Pollastro. "Fact Sheet 2012–3013: Assessment of Potential Oil and Gas Resources in Source Rocks of the Alaska North Slope, 2012." *Fact Sheet 2012–3013: Assessment of Potential Oil and Gas Resources in Source Rocks of the Alaska North Slope, 2012*. N.p., Feb. 2012. Web. 14 May 2013. <http://pubs.usgs.gov/fs/2012/3013/>.

Houseknecht, D.W., Bird, K.J., and Garrity, C.P., 2012, Assessment of Undiscovered Petroleum Resources of the Arctic Alaska Petroleum Province: U.S. Geological Survey Scientific Investigations Report 2012–5147, <http://pubs.usgs.gov/sir/2012/5147/pdf/sir2012-5147_arctic.pdf>.

Minerals Management Service. 2006: Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf. MMS Fact Sheet RED-2006-01b, 6 p.

Minerals Management Service. 2006: Planning Area Resources Addendum to Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf. MMS Fact Sheet RED-2006-02, 2 p.

Stanley, R.G., Pierce, B.S., and Houseknecht, D.W., 2011, U.S. Geological Survey 2011 Assessment of Undiscovered Oil and Gas Resources of the Cook Inlet region, south-central Alaska: U.S. Geological Survey Open-File Report 2011–1237, 37 p., available at<http://pubs.usgs.gov/of/2011/1237/>.

Stanley, R.G., Charpentier, R.R., Cook, T.A., Houseknecht, D.W., Klett, T.R., Lewis, K.A., Lillis, P.G., Nelson, P.H., Phillips, J.D., Pollastro, R.M., Potter, C.J., Rouse, W.A., Saltus, R.W., Schenk, C.J., Shah, A.K., and Valin Z.C., 2011, Assessment of undiscovered oil and gas resources of the Cook Inlet region, south-central Alaska, 2011: U.S. Geological Survey Fact Sheet 2011-3068, 2 p.

United States. Department of Energy. Office of Fossil Energy. *Liquified Natural Gas: Understanding the Basics*. Department of Energy, n.d. Web. 25 Apr. 2013. <http://energy.gov/sites/prod/files/2013/04/f0/LNG_primerupd.pdf>.

USGS World Assessment Team, 2000, U.S. Geological Survey World Petroleum Assessment 2000-Description and Results: U.S. Geological Survey Digital Data Series – DDS60 <http://pubs.usgs.gov/dds/dds-060/>.

Wall, Rance. "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011." *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer*

Continental Shelf, 2011. Bureau of Ocean Energy Management, 2011. Web. 24 Apr. 2013. <http://www.boem.gov/uploadedFiles/2011_National_Assessment_Factsheet.pdf>.

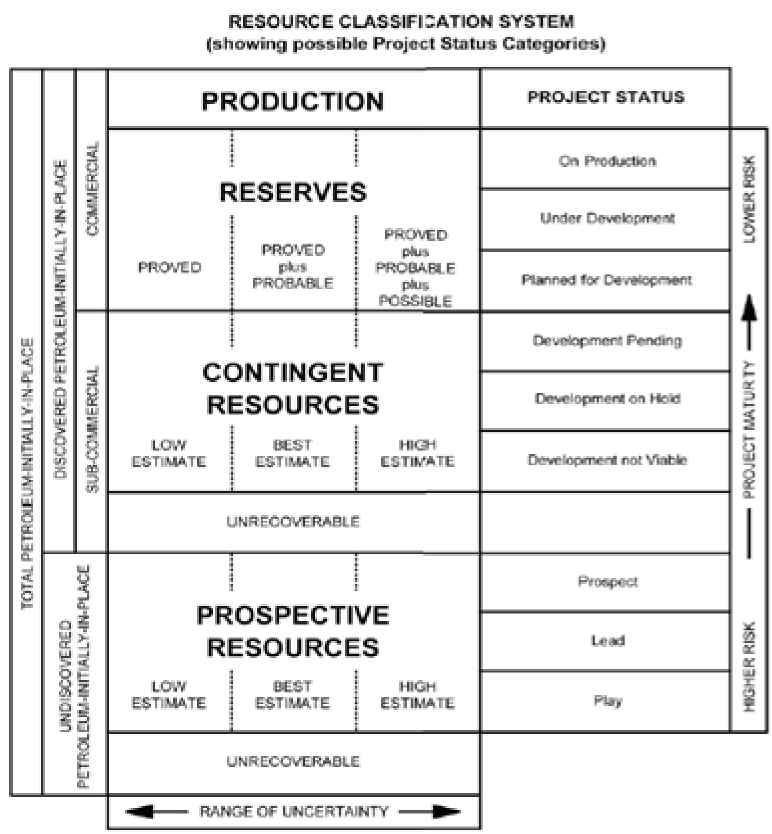
Mackenzie, Wood. "LNG Supply Analysis." *Wheatstone LNG* (2013): 1-19. Print.

Wilson, F.H., Hults, C.P., Schmoll, H.R., Haeussler, P.J., Schmidt, J.M., Yehle, L.A., and Labay, K.A, 2009, Preliminary geologic map of the Cook Inlet region, Alaska: U.S. Geological Survey Open-File Report 2009-1108, scale 1:250,000,< http://pubs.usgs.gov/of/2009/1108/>.

APPENDIX A – SPE PRMS DEFINITIONS of RESERVES

To categorize the estimated proved, probable, and possible reserves from the fields analyzed, the SPE PRMS definitions have been utilized. Figure 13 below illustrates the SPE PRMS classification system:

FIGURE 13
SPE PRMS Classification System



Definition of Reserves

The proved, probable, and possible reserves presented in this report have been prepared in accordance with the SPE PRMS definitions approved in March 2007 by the SPE, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. The PRMS contains the complete and official explanation of reserves definitions and guidelines utilized herein. The petroleum reserves are defined as follows:

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *Proved Reserves* – Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90-percent probability that the quantities actually recovered will equal or exceed the estimate.
>
> *Unproved Reserves* – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
>
> *Probable Reserves* – Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves – Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

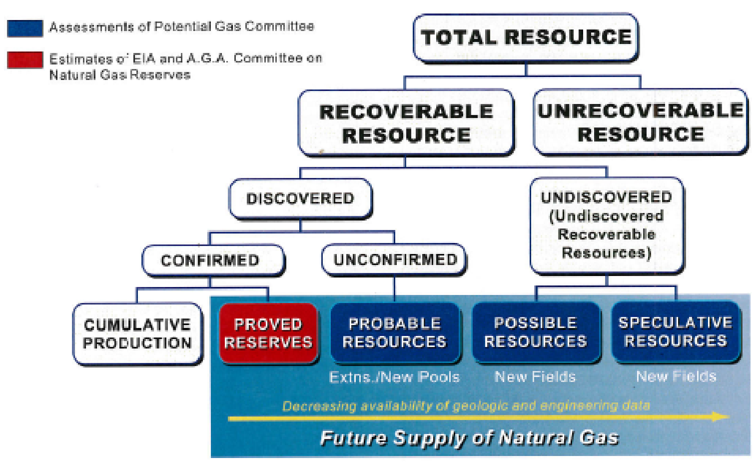
Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

APPENDIX B – DEFINITIONS of RESOURCES

PGC Definition of Resources

PGC's petroleum gas resources estimates, which are the primary source of resources estimates in this report, are classified according to the PGC's December 31, 2012, publication titled "Potential Supply of Natural Gas in the United States." These resources have been classified as probable, possible, or speculative resources. Because of the lack of commerciality or sufficient exploration drilling, the probable, possible, or speculative resources estimated herein cannot be classified as reserves. Both non-associated and associated gas are included in the categories. Associated gas resources would potentially include any gas cap or dissolved gas associated with oil resources. The PGC petroleum resources classification system is illustrated in Figure 14 below:

FIGURE 14
PGC Petroleum Resources Classification System



Probable Resources – Resources associated with known fields and are most assured of potential supplies. Relatively large amounts of geologic and engineering information are available to aid in the estimation of resources existing in this category. These resources bridge the boundary between discovered and undiscovered resources. The discovered portion includes the supply from future extension of existing pools in known productive reservoirs. Although the pools containing this gas have been discovered, their extent has not be completely delineated by development drilling. Therefore, the existence and quantity of gas in the undrilled part of the pool are as yet unconfirmed. The undiscovered part is expected to come from future new pool discoveries within existing fields either in reservoirs productive in the field or in shallower or deeper formations known to be productive elsewhere within the same geologic province or subprovince.

Possible Resources – Resources are a less assured supply because they are postulated to exist outside known fields, but they are associated with a productive formation in a productive province. Their occurrence is indicated by projection of plays or trends of a producing formation into a less well explored area of the same geologic province or subprovince. These resources are expected to arise from new field discoveries, postulated to occur within these trends or plays under both similar and difference geologic conditions – that is, the types of traps and/or structural settings may be either the same or different in some aspect.

Speculative Resources – are expected to be found in formations or geologic provinces that have not yet proven production. Geologic analogs are developed in order to ensure reasonable evaluation of these unknown quantities. The resources are anticipated from new pool or new field discoveries in formations not previously productive within a productive province or subprovince and from new field discoveries within a province not previously productive.

SPE PRMS Definition and Classification of Resources

USGS and BOEM/MMS petroleum resources estimates, which are occasionally cited as secondary sources of resources estimates in this report, are classified as contingent or prospective resources according to SPE PRMS resources definitions. Because of the lack of commerciality or sufficient exploratory drilling, the contingent or prospective resources estimated herein cannot be classified as reserves. The petroleum resources are classified as follows:

Definition of Contingent Resources

> *Contingent Resources* – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
>
> Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into three economic status groups:
>
>> *Marginal Contingent Resources* – Those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.
>>
>> *Sub-Marginal Contingent Resources* – Those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Undetermined Contingent Resources – Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is “undetermined.”

The estimation of resources quantities for an accumulation is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

1C (Low), 2C (Best), and 3C (High) Estimates – Estimates of petroleum resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

Definition of Prospective Resources

Prospective Resources – Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

The estimation of resources quantities for a prospect or an accumulation is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

Low, Median, Best, and High Estimates – Estimates of petroleum resources in this report are expressed using the terms low estimate, median estimate, best estimate, and high estimate to reflect the range of uncertainty.

A detailed explanation of the probabilistic terms used herein and identified with an asterisk (*) is included in the Glossary of

Probabilistic Terms in the appendix bound with this report. For probabilistic estimates of petroleum resources, the expected value* (EV), an outcome of the probabilistic analysis, is used for the best estimate. The low estimate reported herein is the P_{90}* quantity derived from probabilistic analysis. This means that there is at least a 90-percent probability that, assuming the prospect or accumulation is discovered and developed, the quantities actually recovered will equal or exceed the low estimate. The median estimate is the P_{50}* quantity derived from probabilistic analysis. This means that there is at least a 50-percent probability that, assuming the prospect or accumulation is discovered and developed, the quantities actually recovered will equal or exceed the median estimate. The high estimate is the P_{10}* quantity derived from probabilistic analysis. This means that there is at least a 10-percent probability that, assuming the prospect or accumulation is discovered and developed, the quantities actually recovered will equal or exceed the high estimate.

> *Uncertainties Related to Prospective Resources* – The volume of petroleum discovered by exploration drilling depends on the number of prospects that are successful as well as the volume that each success contains. Reliable forecasts of these volumes are, therefore, dependent on accurate predictions of the number of discoveries that are likely to be made if the entire portfolio of prospects is drilled. The accuracy of this forecast depends on the portfolio size and an accurate assessment of the probability of geologic success* (P_g).
>
> *Probability of Geologic Success* – P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate. P_g is estimated by quantifying the probability of each of the following individual geologic factors: trap, source, reservoir, and migration.* The product of these four probabilities or chance factors is computed as P_g.

In this report, estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation of the volumes for the total inventory of prospects.

Application of P_g to estimate the P_g-adjusted prospective resources volumes does not equate prospective resources with reserves or contingent resources. P_g-adjusted prospective resources volumes cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently made available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the study area, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_g.

Predictability versus Portfolio Size – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size relationship* (PPS). It is critical to be aware of PPS, because an unsuccessful drilling program which results in a series of wells that do not encounter measureable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

For a large prospect portfolio, the P_g-adjusted best estimate of the prospective resources volume should be a reasonable estimate of the recoverable petroleum quantities found if all prospects are drilled. When the number of prospects in the portfolio is small and the P_g is low, the recoverable petroleum actually found may be considerably smaller than the P_g-

adjusted best estimate would indicate. It follows that the probability that all of the prospects will be unsuccessful is smaller when a large inventory of prospects exists.

> *Prospect Technical Evaluation Stage* – A prospect can often be subcategorized based on its current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.
>
> *Mature Prospects* – A mature prospect is a potential accumulation that is sufficiently well defined to be a viable drilling target. For a mature prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, determine reasonable ranges of geologic chance factors, engineering and petrophysical parameters, and estimate prospective resources.
>
> *Immature Prospects* – An immature prospect is less well defined and requires additional data and/or evaluation to be classified as a mature prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). An immature prospect may or may not be elevated to mature prospect status depending on the results of additional technical work.
>
> *Threshold Economic Field Size* – The threshold economic field size (TEFS) is the minimum amount of producible petroleum required to recover the total capital expenditure used to establish the prospect as having a present worth greater than zero. These investments include expenditures required to establish and prove profitable production and to conduct delineation or confirmation drilling. All geologic, geophysical, lease and/or contract-area acquisition costs and other anticipated field delineation costs are included in the estimation of TEFS as well. The present worth per resources volume methodology is a standard industry practice used to estimate resources value. This methodology is directly

formulated from the discounted cash flow analysis, which is fundamental to the present worth estimation. Accordingly, where this methodology is employed to estimate TEFS, no additional provision should be made for field development costs.

$$TEFS = \frac{\text{Geology} + \text{Geophysics} + \text{Drilling} + \text{Land} + \text{Transportation} + \text{Overhead}}{\text{Potential Present Worth per Barrel}}$$

Probability of Economic Success – The probability of economic success (P_E) is defined as the probability that a given discovery will be economically viable. It takes into account P_G, TEFS, capital costs, operating expenses, the proposed development plan, and other business and economic factors. P_E is calculated as follows:

$$P_E = P_G \times P_{TEFS}$$

Probability of Threshold Economic Field Size – The probability of threshold economic field size (P_{TEFS}) is defined as the probability of discovering an accumulation that is large enough to be economically viable. P_{TEFS} is estimated by using the prospective resources potential recoverable volumes distribution in conjunction with the TEFS. The probability associated with the TEFS can be determined graphically from the potential gross recoverable volumes distribution.

APPENDIX C – PGC RESOURCES ESTIMATES for ALASKA

Figure 15
PGC Resources Estimates for Alaska (Bcf)

Alaska Region and Assessment Segment	Probable Resources			Possible Resources			Speculative Resources			
	Min	Most Likely	Max	Min	Most Likely	Max	Min	Most Likely	Max	Total
Alaska Onshore, all drilling depths										
North Slope	2,6200	30,200	36,100	4000	15,000	43,000	6,000	23,000	72,000	68,200
S. Foothills and Brooks Range									1,000	0
Yukon Flats and Kandik Basins								200	500	200
Alaska Interior Basins								500	2,500	500
Northern Gulf of Alaska							100	700	3,550	700
Cook Inlet	400	650	1,600	700	1,400	2,800		2,400	4,800	4,450
Alaska Peninsula-Shelikof							200	300	300	200
Alaska Penisula-Bristol Bay							400	700	1,400	700
Aleutian Island									1,000	0
Total Onshore, all drilling depths		**30,850**			**16,400**			**27,700**		**74,950**
Alaska Offshore, all drilling depths										
Offshore, 0-200 meters										
Beaufort Shelf	1,000	2,000	11,000	3,000	12,000	41,000	3,500	19,500	62,500	33,500
Chukchi Shelf							3,500	19,500	62,500	19,500
Norton Basin								200	600	200
Hope Basin								550	2,000	550
Navarin Basin Shelf								1,000	4,500	1,000
St. George Basin Shelf							200	1,500	2,500	1,500
Briston Bay Shelf							1,850	3,750	6,000	3,750
Shumagin-Kodiak Shelf							200	1,700	5,200	1,700
Aleutian Shelf									1,000	0
Northern Gulf of Alaska Shelf							5,500	800	8,950	800
Southeastern Alaska Shelf							200	850	2,600	850
Cook Inlet Basin	200	400	800	350	700	1,400		1,000	2,400	2,100
Offshore, 200-1000 meters										0
Navarin Basin Slope									500	0
St. George Basin Slope									500	0
Southeastern Alaska Slope							450	2,650	6,500	2,650
Total- Offshore, 0-200 meters		2,400			12,700			50,350		65,450
Total- Offshore, 200-1000 meters								2,650		2,650
Area Grand Total (Most Likely Values)		**33,250**			**29,100**			**80,700**		**143,050**
Area Grand Total (Mean Values)										
Total Onshore, all drilling depths		31,720			22,300			40,420		94,440
Total Offshore, all drilling depths		5,140			19,500			74,790		99,430
Grand Total-Mean Values (non-additive)		**36,860**			**41,820**			**115,130**		**193,830**
PROVINCE										
Coalbed Gas Resources										
North Slope, Kobuk, Upper and Lower Koyukuk, Yukon Glats, Middle Tanana, Nenana Copper River, Susitna, Cook Inlet, Alaska Peninsula coal basins							15,000	57,000	76,000	57,000
Total Coalbed Gas								**57,000**		**57,000**

APPENDIX D – ADNR/ADOG RESERVES and PUBLIC RESOURCES ESTIMATES for ALASKA

Figure 16
ADNR/ADOG Reserves and USGS/BOEM Resources Estimates for Alaska
(Bcf)

Alaska Region and Assessment Segment	Reserves 1P	Reserves 2P	Reserves 3P	References:	Discovered Resources P95	Discovered Resources Mean	Discovered Resources P05	Undiscovered Resources P95	Undiscovered Resources Mean	Undiscovered Resources P05	Total Resources Mean	References:
Central North Slope												
Barrow						34					34	ADNR 2009 Annual Report Table 1
Colville River						400					400	ADNR 2009 Annual Report Table 1
Duck Island						843					843	ADNR 2009 Annual Report Table 1
Kuparuk River						600					600	ADNR 2009 Annual Report Table 1
Milne Point						0					0	ADNR 2009 Annual Report Table 1
Endicott						0					0	ADNR 2009 Annual Report Table 1
Northstar						450					450	ADNR 2009 Annual Report Table 1
Prudhoe Bay						24,500					24,500	ADNR 2009 Annual Report Table 1
Point Thomson						8,000					8,000	ADNR 2009 Annual Report Table 1
Total Central North Slope						**34,827**		**23,939**	**33,318**	**44,873**	**68,145**	USGS, Open-File Report 2005-3043; ADNR 2009 Annual Report Table 1
Nat'l Petrol Reserve Alaska								43,042	52,821	61,985	52,821	USGS, Open-File Report 2011-1103 pg 4
ANWR Coastal Plain								3,470	3,810	4,060	3,810	USGS, Open-File Report 2009-1112, pg 6
Western North Slope								6,130	10,360	12,400	10,360	USGS, Open-File Report 2009-1112, pg 6
Gas Hydrates											0	USGS, 2008 Assessment of Gas Hydrate
Non-associated Gas Shale Resources											0	
Brookian											0	USGS, 2012; Factsheet 2012-3013
Kingak											0	
Shublik											0	USGS, 2012; Factsheet 2012-3013
Total North Slope Onshore						**34,827**			**100,309**		**135,136**	
Southern Alaska (1)												
Cook Inlet (2)			354	ADNR, pg 6				3,138	13,726	28,414	13,726	USGS, 2011: Factsheet 2011-3068
Coalbed Methane											0	USGS, 2011: Factsheet 2011-3069
Beaver Creek	23	74		ADOG, pg 15							0	
Beluga River	377	473		ADOG, pg 15							0	
Birch Hill				ADOG, pg 15							0	
Cannery Loop	27	45		ADOG, pg 15							0	
Deep Creek	5	5		ADOG, pg 15							0	
Falls Creek				ADOG, pg 15							0	
Granite Point	7	9		ADOG, pg 15							0	
Ivan River	4	12		ADOG, pg 15							0	
Kaloa				ADOG, pg 15							0	
Kasilof		1		ADOG, pg 15							0	
Kenai River	90	114		ADOG, pg 15							0	
Lewis River	1	10		ADOG, pg 15							0	
Lone Creek				ADOG, pg 15							0	

Alaska Region and Assessment Segment	Reserves			References:	Discovered Resources			Undiscovered Resources			Total Resources	References:
	1P	2P	3P		P95	Mean	P05	P95	Mean	P05	Mean	
McArthur River (grayling gas sands)	113	133		ADOG, pg 15							0	
Middle Ground Shoal	2	3		ADOG, pg 15							0	
Moquawkie	0	0		ADOG, pg 15							0	
Nicolai Creek	1	1		ADOG, pg 15								
Ninilchik	62	62		ADOG, pg 15								
North Cook Inlet	145	192		ADOG, pg 15							0	
Pretty Creek				ADOG, pg 15							0	
Redoubt Shoal	0	0		ADOG, pg 15							0	
Sterling	1	1		ADOG, pg 15							0	
Swanson River	1	1		ADOG, pg 15							0	
Three Mile Creek	0	0		ADOG, pg 15							0	
Trading Bay	1	1		ADOG, pg 15							0	
West Foreland	1	4		ADOG, pg 15							0	
West Fork				ADOG, pg 15							0	
Wolf Lake				ADOG, pg 15							0	
Total*-Cook *Inlet	**861**	**1,141**	**1,495**								0	
Southern Cook Inlet OCS								30	1,200	3,480	1,200	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
North Aleutian OCS								400	8,620	23,280	8,620	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Gulf of Alaska OCS								0	4,040	13,870	4,040	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Other OCS Basins (3)								0	9,410	39,880	9,410	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Total Southern Alaska	**861**	**1,141**	**1,495**						**36,996**		**36,996**	
Arctic Alaska Outer Continental Shelf (OSC)												
Chukchi Shelf								10,320	76,770	209,53 0	76,770	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Beaufort Shelf								650	27,640	72,180	27,640	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Hope Basin								0	3,770	14,980	3,770	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Total *Arctic* OCS (offshore)									**108,180**		**108,180**	
Interior Alaska												
Yukon Flats Basin												BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Central AK-Multiple Basins								0	5,463	14,628	5,463	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Kandik Basin											0	BOEM, 2011 National Assessment Factsheet, MMS, 2007 Alaska OCS Assessment
Copper River Basin									116		116	
Total Interior Alaska											0	
Grand Total Reserves		**1,495**							**5,579**		**5,579**	
Area Grand Total- Mean Resources						**34,827**			**251,064**		**285,891**	

Notes:
(1) CBM not included except for in Cook Inlet estimates(~1,000 TCF OGIP).
(2) Cook Inlet 3P Total is the 3P number for the sum of 4 Major fields but the Sum of the other fields.
(3) Includes Navarian Basin, St. George Basin, Norton Basin, Shumagin, and Kodiak planning areas.
Most Likely is the Mean number for the Resources.
ADOG = 2009 Preliminary Eng. And Geo. Evaluation of Remaining Cook Inlet Gas Reserves.

APPENDIX E – HIGH SUPPLY/HIGH DEMAND SCENARIO (40+-YEAR EXPORT TERM)

Figure 17
Remaining Gas Supply in High Supply/High Demand Scenario (40+-Year LNG Export Term)

Category	Amount (Tcf)	Reference
Existing Reserves	1.143	Figure 18
Resources	108.250	Figure 18
Upstream Lease Operations Fuel (2013-2062)	(12.750)	Figure 19
Domestic Demand (2013-2022)	(0.996)	Figure 19
Domestic Demand (2023-2062)	(10.962)	Figure 19
LNG Feed Gas (includes fuel/shrink)	(42.875)	Figure 19
Remaining Gas Supply	**41.810**	

Note: Petroleum quantities classified as Reserves or Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification.

Figure 18
Reserves and Resources Estimates for the High Supply Scenario

Alaska Region and Assessment Segment	Reserves (Tcf)	Resources: Probable Most Likely (Tcf)	Resources: Possible Most Likely (Tcf)	Resources: Speculative Most Likely (Tcf)	Total Reserves + Resources (Tcf)	Reference
Alaska Onshore, all drilling depths						
North Slope	0.000	30.200	15.000	23.000	68.200	Figure 15 (PGC)
Cook Inlet	1.143	0.650	1.400	2.400	5.593	Figure 4, Figure 15 (PGC)
Alaska Offshore, all drilling depths						
Offshore, 0-200 meters						
Beaufort Shelf	0.000	2.000	12.000	19.500	33.500	Figure 15 (PGC)
Cook Inlet Basin	0.000	0.400	0.700	1.000	2.100	Figure 15 (PGC)
Grand Total Reserves + Resources - High Supply Scenario	**1.143**	**33.250**	**29.100**	**45.900**	**109.393**	

Note: Petroleum quantities classified as Reserves or Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification.

Figure 19
Total Gas Demand – High Demand Scenario
(Supplied by NERA)

	Pre-Export (2013 - 2022) (Tcf)	Export-Term (2023 - 2062) (Tcf)	Cumulative (2013-2062) (Tcf)
In-State Demand			
Electricity Generation	0.375	3.230	3.605
Residential	0.230	1.854	2.084
Government	0.048	0.201	0.250
Energy-Intensive Sectors	0.045	1.761	1.806
Manufacturing	0.065	1.767	1.832
Commercial Sector	0.231	1.702	1.932
Truck Transportation	0.001	0.288	0.289
Other Transportation	0.000	0.160	0.161
Subtotal of Domestic Demands	0.996	10.962	11.958
Upstream Lease Operations Fuel	2.550	10.200	12.750
Subtotal of In-State Demand	**3.546**	**21.162**	**24.708**
30-Year LNG Export Plant Demand			
Fuel/Shrink	0.000	6.647	6.647
LNG Feed Gas Requirements	0.000	36.228	36.228
Subtotal of Demand Associated with LNG Exports	**0.000**	**42.875**	**42.875**
Total Gas Demand - High Demand Scenario	**3.546**	**64.037**	**67.583**

Note: Numbers may not add due to rounding.

Figure 20
Average Annual In-State Demand in the Post-Export Period for High Demand Scenario
(Supplied by NERA)

	Post-Term Bcf/year (2063 and Beyond)[17]
In-State Demand	
Electricity Generation	115.655
Residential	60.063
Government	5.739
Energy-Intensive Sectors	72.434
Manufacturing	64.765
Commercial Sector	64.114
Truck Transportation	23.487
Other Transportation	14.176
Upstream Lease Operations Fuel	255.00
Average Annual In-State Post-Term Demand	**675.433**

Figure 21
Estimation of Years of Supply Remaining for High Supply/High Demand Scenario

Category	Amount (Tcf)	Reference
High Supply	109.393	Figure 18
High Demand	(67.583)	Figure 19
Remaining Supply at End of 40-Year LNG Export Term	41.810	
Average Annual In-State Post-Term Demand	0.675	Figure 20
Years of Supply Remaining	62	

[17] NERA modeled in-state gas demand through 2062, which, for a 40-year export term, would not include in-state demand estimates for a post-export (2063 and beyond) term. For the purposes of the analysis in this report, D&M assumed the same estimates as the in-state demand in the 2058-2062 period from the 40-year export term minus any gas associated with the LNG plant.

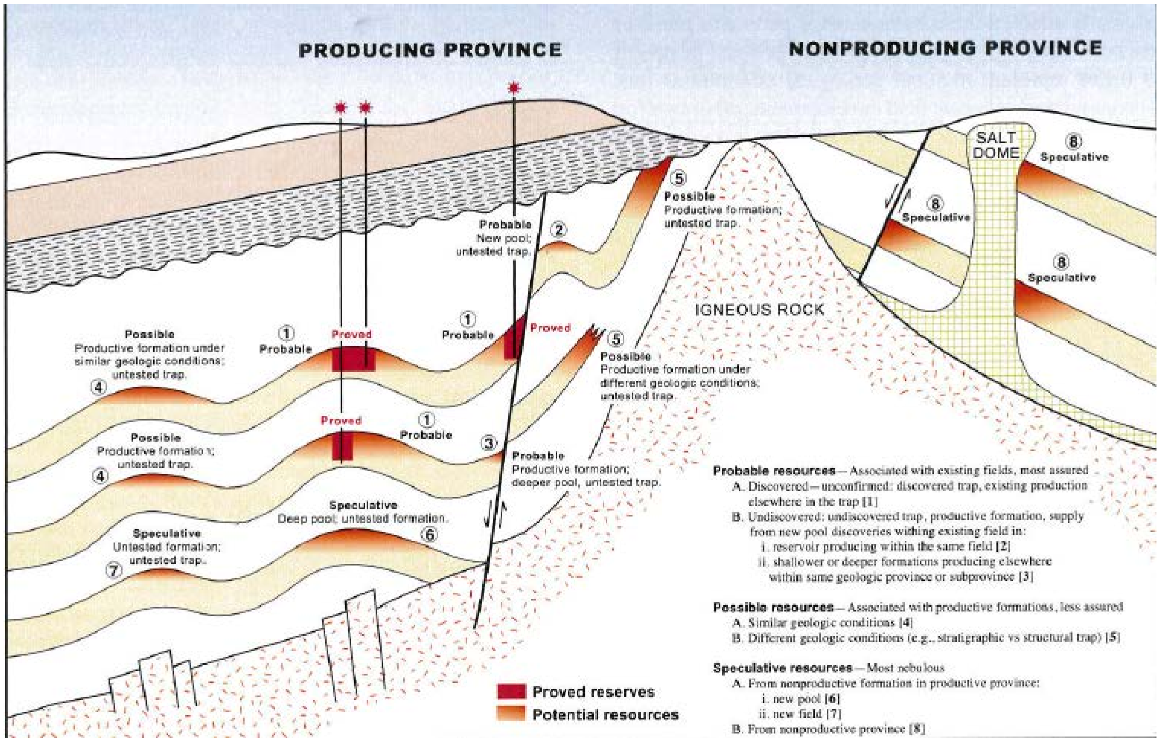
APPENDIX F – PGC RESOURCES ASSESSMENT PROCEDURES

PGC states, "Assessments do not include, and are distinct and separate from, the volumes of proved reserves contained within the nation's discovered fields" (PGC, pg 69). Estimates of proved reserves presented in this report have been prepared by ADNR. PGC's evaluation does not include gas reserves. PGC's main focus is the assessment of potential resources that can be recovered using today's technology. PGC classifies natural gas "as any gas (at conditions of standard pressure and temperature, 14.73 pounds per square inch absolute and 60 degrees Fahrenheit) of natural origin and consisting primarily of hydrocarbon molecules producible from a borehole" (PGC, pg 70). PGC also recognizes that most natural gas contains some portion of nonhydrocarbon gases. PGC assessment does not exclude these components from the hydrocarbon gas unless there is a substantial volume of nonhydrocarbon gases present. The following assessment procedure is a general breakdown of how resources are being estimated in Alaska by PGC. Each of the following steps are considered independently in preparing the assessment.

General Assessment Procedure

PGC's basic technique for assessing natural gas resources is to compare characteristics from known occurrences with characteristics present in prospective province areas. Each prospective province is compared to a known discovered area or province with similar geologic attributes, such as source rocks, sufficient maturation of organic material, and presence of reservoir rocks and traps. By understanding these attributes, gas supply estimates can be assessed based on productive capacity of a particular formation and average accumulation size. Figure 20 shows a "hypothetical cross section illustrating categories and types of occurrences of potential gas resources" according to PGC.

Figure 22
Illustration of PGC Categories



PGC's preparation assessment considered the following three situations separately.

> 1) "The existence of minimum number of traps, the most marginal of source-rock and reservoir conditions, the minimum reasonable yield factor and the possibility that many traps that might exist would not contain recoverable gas accumulations. In this case, an approximately 100 percent probability exists that at least this much gas resource is present. Such conditions lead to a *minimum* (100 percent probability) estimate of the resource."
>
> 2) "The most reasonable estimate of the existence of traps and accumulations and the most reasonable assessment of source-rock, yield factor and reservoir conditions. The probability is highest that these conditions prevail in the estimator's judgment and that the estimated quantity of gas resources

would be present. Such conditions lead to the *most likely* estimate of the resource."

3) "The quantity of gas that might exist and be recoverable under the most favorable conditions. The probability that such conditions prevail is near zero, and the probability is very low (essentially zero) that this much gas resource is present. This assumes a maximum number of potential traps with favorable source-rock and reservoir conditions, maximum reasonable yield factor and the condition that each trap is filled with a reasonable accumulation. These conditions lead to the maximum possible resources estimate."

As noted, this report and the associated analyses considered only the Most Likely category of resources estimates.

APPENDIX G – NORTH COOK INLET HISTORICAL GAS PRODUCTION

(Supplied by IHS Global, Inc., (IHS))

Report Date	Gas Production (Mcf)
3/1/1969	28,297
4/1/1969	20,884
5/1/1969	401,125
6/1/1969	990,204
7/1/1969	997,543
8/1/1969	1,868,406
9/1/1969	332,260
10/1/1969	195,514
11/1/1969	2,052,338
12/1/1969	994,753
1/1/1970	1,803,257
2/1/1970	2,327,699
3/1/1970	3,823,719
4/1/1970	2,963,351
5/1/1970	2,687,495
6/1/1970	4,038,627
7/1/1970	4,256,243
8/1/1970	4,110,156
9/1/1970	3,724,971
10/1/1970	3,106,297
11/1/1970	4,068,432
12/1/1970	4,037,222
1/1/1971	3,516,680
2/1/1971	4,164,035
3/1/1971	3,844,639
4/1/1971	2,436,696
5/1/1971	3,290,614
6/1/1971	3,512,586
7/1/1971	4,347,976
8/1/1971	3,950,361
9/1/1971	4,033,788
10/1/1971	4,103,879
11/1/1971	3,816,377
12/1/1971	4,006,668
1/1/1972	3,498,495
2/1/1972	3,725,582
3/1/1972	3,808,349
4/1/1972	3,055,376
5/1/1972	1,761,794
6/1/1972	885,977
7/1/1972	2,735,819
8/1/1972	4,780,894
9/1/1972	4,565,936
10/1/1972	4,355,767
11/1/1972	4,217,789
12/1/1972	4,187,989
1/1/1973	4,341,802
2/1/1973	2,799,724
3/1/1973	2,961,444
4/1/1973	4,075,070

	Bcf
Total Gas Produced on Plateau through 1/2006	**1,711.8**
Total Estimated Ultimate Recovery	**2,011.0**
Calculated % Total Resource Produced at Plateau	**85.1%**

(continued)

Report Date	Gas Production (Mcf)
5/1/1973	4,348,030
6/1/1973	2,423,565
7/1/1973	3,320,712
8/1/1973	4,237,444
9/1/1973	4,358,454
10/1/1973	2,429,734
11/1/1973	3,039,229
12/1/1973	4,373,968
1/1/1974	4,272,911
2/1/1974	4,192,305
3/1/1974	3,694,482
4/1/1974	2,678,909
5/1/1974	3,779,786
6/1/1974	3,972,920
7/1/1974	3,689,761
8/1/1974	3,532,530
9/1/1974	3,945,335
10/1/1974	2,471,093
11/1/1974	3,712,368
12/1/1974	4,295,873
1/1/1975	3,349,290
2/1/1975	4,194,850
3/1/1975	4,621,105
4/1/1975	3,824,131
5/1/1975	2,481,491
6/1/1975	2,697,998
7/1/1975	4,531,918
8/1/1975	4,823,716
9/1/1975	3,792,921
10/1/1975	3,511,527
11/1/1975	3,579,139
12/1/1975	4,213,587
1/1/1976	4,497,546
2/1/1976	4,307,934
3/1/1976	4,329,431
4/1/1976	4,400,834
5/1/1976	1,691,475
6/1/1976	961,364
7/1/1976	4,698,079
8/1/1976	4,686,386
9/1/1976	4,342,219
10/1/1976	3,846,660
11/1/1976	3,819,923
12/1/1976	3,509,404
1/1/1977	3,767,729
2/1/1977	3,597,835
3/1/1977	4,178,738
4/1/1977	2,531,487
5/1/1977	3,635,647
6/1/1977	4,374,579
7/1/1977	5,018,776

(continued)

Report Date	Gas Production (Mcf)
8/1/1977	4,481,126
9/1/1977	3,475,853
10/1/1977	3,955,205
11/1/1977	3,643,367
11/1/1977	3,643,367
12/1/1977	4,540,586
1/1/1978	4,638,217
2/1/1978	4,192,723
3/1/1978	4,391,621
4/1/1978	1,799,123
5/1/1978	4,854,592
6/1/1978	4,351,316
7/1/1978	4,225,163
8/1/1978	4,281,781
9/1/1978	5,232,927
10/1/1978	1,395,712
11/1/1978	2,174,990
12/1/1978	5,218,967
1/1/1979	4,756,811
2/1/1979	4,149,174
3/1/1979	4,302,908
4/1/1979	4,833,425
5/1/1979	4,370,467
6/1/1979	4,557,365
7/1/1979	4,998,864
8/1/1979	4,984,172
9/1/1979	4,503,062
10/1/1979	1,501,067
11/1/1979	2,395,271
12/1/1979	4,095,072
1/1/1980	4,573,172
2/1/1980	4,164,845
3/1/1980	4,558,782
4/1/1980	1,897,693
5/1/1980	3,168,884
6/1/1980	3,068,570
7/1/1980	2,037,788
8/1/1980	3,050,671
9/1/1980	4,045,373
10/1/1980	3,422,292
11/1/1980	4,385,305
12/1/1980	3,166,808
1/1/1981	4,439,884
2/1/1981	4,277,161
3/1/1981	4,292,187
4/1/1981	2,965,112
5/1/1981	4,010,276
6/1/1981	4,338,308
7/1/1981	4,630,977
8/1/1981	4,577,350
9/1/1981	4,346,134

(continued)

Report Date	Gas Production (Mcf)
10/1/1981	4,321,240
11/1/1981	4,083,704
12/1/1981	3,204,098
1/1/1982	3,196,622
2/1/1982	3,958,830
3/1/1982	3,526,529
4/1/1982	2,970,345
5/1/1982	2,919,878
6/1/1982	4,326,181
7/1/1982	4,432,586
8/1/1982	4,282,528
9/1/1982	3,863,235
10/1/1982	4,091,753
11/1/1982	3,815,719
12/1/1982	3,983,416
1/1/1983	4,195,521
2/1/1983	3,376,242
3/1/1983	4,667,656
4/1/1983	4,068,040
5/1/1983	2,855,255
6/1/1983	3,250,185
7/1/1983	4,292,434
8/1/1983	4,334,177
9/1/1983	4,103,275
10/1/1983	4,269,378
11/1/1983	4,032,821
12/1/1983	4,432,231
1/1/1984	3,915,058
2/1/1984	3,793,356
3/1/1984	4,141,410
4/1/1984	4,200,996
5/1/1984	3,350,251
6/1/1984	2,584,667
7/1/1984	4,441,458
8/1/1984	4,566,227
9/1/1984	3,334,294
10/1/1984	4,459,252
11/1/1984	3,735,232
12/1/1984	4,458,676
1/1/1985	4,324,368
2/1/1985	3,855,932
3/1/1985	4,168,974
4/1/1985	3,339,964
5/1/1985	2,195,780
6/1/1985	4,424,159
7/1/1985	4,212,402
8/1/1985	4,083,204
9/1/1985	3,871,359
10/1/1985	3,883,185
11/1/1985	3,325,734
12/1/1985	4,134,351

(*continued*)

Report Date	Gas Production (Mcf)
1/1/1986	3,482,336
2/1/1986	3,491,089
3/1/1986	3,933,501
4/1/1986	2,770,372
5/1/1986	2,469,472
6/1/1986	3,905,211
7/1/1986	3,742,113
8/1/1986	4,053,210
9/1/1986	3,938,710
10/1/1986	4,154,890
11/1/1986	4,038,861
12/1/1986	3,858,389
1/1/1987	3,982,682
2/1/1987	3,448,907
3/1/1987	3,839,442
4/1/1987	1,269,850
5/1/1987	3,623,310
6/1/1987	3,402,754
7/1/1987	4,015,834
8/1/1987	4,083,541
9/1/1987	3,943,200
10/1/1987	3,942,052
11/1/1987	3,742,856
12/1/1987	3,594,280
1/1/1988	3,966,366
2/1/1988	3,405,062
3/1/1988	4,117,407
4/1/1988	3,439,977
5/1/1988	2,079,407
6/1/1988	3,902,597
7/1/1988	3,737,081
8/1/1988	3,797,149
9/1/1988	3,674,065
10/1/1988	4,423,443
11/1/1988	4,171,321
12/1/1988	4,274,829
1/1/1989	3,062,210
2/1/1989	3,941,951
3/1/1989	4,033,219
4/1/1989	4,177,264
5/1/1989	2,286,527
6/1/1989	3,812,399
7/1/1989	4,528,314
8/1/1989	3,678,808
9/1/1989	4,216,183
10/1/1989	4,176,515
11/1/1989	3,708,458
12/1/1989	3,664,684
1/1/1990	3,776,263
2/1/1990	3,634,136
3/1/1990	3,634,045

(*continued*)

Report Date	Gas Production (Mcf)
4/1/1990	4,129,239
5/1/1990	1,610,307
6/1/1990	4,054,608
8/1/1990	4,084,100
9/1/1990	3,945,671
10/1/1990	3,967,172
11/1/1990	3,834,998
12/1/1990	4,261,381
1/1/1991	3,879,442
2/1/1991	3,762,421
3/1/1991	3,874,085
4/1/1991	3,936,003
5/1/1991	2,160,638
6/1/1991	3,625,146
7/1/1991	3,960,904
8/1/1991	3,826,361
9/1/1991	4,155,047
10/1/1991	3,758,491
11/1/1991	4,046,954
12/1/1991	3,709,725
1/1/1992	3,915,794
2/1/1992	3,875,910
3/1/1992	3,654,056
4/1/1992	3,521,963
5/1/1992	4,243,396
6/1/1992	3,658,259
7/1/1992	4,390,296
8/1/1992	4,072,261
9/1/1992	1,165,463
10/1/1992	4,038,885
11/1/1992	3,835,935
12/1/1992	4,038,503
1/1/1993	3,858,582
2/1/1993	3,301,118
3/1/1993	4,302,675
4/1/1993	3,501,277
5/1/1993	3,797,070
6/1/1993	2,244,535
7/1/1993	4,098,083
8/1/1993	4,127,592
9/1/1993	3,963,295
10/1/1993	4,276,021
11/1/1993	3,850,749
12/1/1993	4,208,034
1/1/1994	4,429,122
2/1/1994	3,685,504
3/1/1994	4,999,610
4/1/1994	3,653,633
5/1/1994	2,017,549
6/1/1994	4,514,532
7/1/1994	5,004,670
8/1/1994	5,059,584

(continued)

Report Date	Gas Production (Mcf)
9/1/1994	4,894,443
10/1/1994	5,063,669
11/1/1994	4,438,218
12/1/1994	4,928,806
1/1/1995	4,697,700
2/1/1995	4,298,497
3/1/1995	4,887,228
4/1/1995	3,735,307
5/1/1995	2,984,270
6/1/1995	4,759,391
7/1/1995	5,034,452
8/1/1995	5,000,197
9/1/1995	4,361,462
10/1/1995	4,529,618
11/1/1995	4,661,893
12/1/1995	4,590,674
1/1/1996	4,894,544
2/1/1996	4,077,892
3/1/1996	5,375,854
4/1/1996	4,524,138
5/1/1996	3,354,716
6/1/1996	4,949,627
7/1/1996	5,032,498
8/1/1996	5,148,871
9/1/1996	4,590,988
10/1/1996	5,023,377
11/1/1996	4,253,174
12/1/1996	4,749,986
1/1/1997	4,800,704
2/1/1997	4,469,089
3/1/1997	4,922,193
4/1/1997	4,441,852
5/1/1997	1,234,214
6/1/1997	4,785,762
7/1/1997	4,106,240
8/1/1997	4,994,788
9/1/1997	4,601,356
10/1/1997	4,741,674
11/1/1997	4,460,341
12/1/1997	4,907,360
1/1/1998	4,444,136
2/1/1998	4,396,153
3/1/1998	4,997,341
4/1/1998	4,551,127
5/1/1998	2,591,272
6/1/1998	4,724,021
7/1/1998	4,893,695
8/1/1998	4,857,675
9/1/1998	4,895,617
10/1/1998	4,773,447
11/1/1998	4,331,692

(continued)

Report Date	Gas Production (Mcf)
12/1/1998	4,507,684
1/1/1999	4,499,416
2/1/1999	4,317,733
3/1/1999	4,671,214
4/1/1999	4,492,093
5/1/1999	4,125,199
6/1/1999	3,513,581
7/1/1999	4,412,519
8/1/1999	4,375,828
9/1/1999	4,094,192
10/1/1999	4,095,070
11/1/1999	4,562,594
12/1/1999	4,469,724
1/1/2000	4,285,676
2/1/2000	4,086,383
3/1/2000	4,528,667
4/1/2000	4,591,292
5/1/2000	2,302,282
6/1/2000	4,289,871
7/1/2000	4,787,670
8/1/2000	5,140,597
9/1/2000	4,759,316
10/1/2000	4,843,664
11/1/2000	4,638,703
12/1/2000	4,587,291
1/1/2001	4,779,552
2/1/2001	4,077,465
3/1/2001	4,839,179
4/1/2001	4,801,013
5/1/2001	2,806,676
6/1/2001	4,023,408
7/1/2001	4,971,987
8/1/2001	5,127,934
9/1/2001	4,945,129
10/1/2001	4,756,984
11/1/2001	5,170,594
12/1/2001	5,230,610
1/1/2002	4,675,422
2/1/2002	4,295,040
3/1/2002	5,040,463
4/1/2002	4,769,116
5/1/2002	2,367,254
6/1/2002	4,635,466
7/1/2002	4,968,332
8/1/2002	4,896,776
9/1/2002	4,591,859
10/1/2002	4,959,942
11/1/2002	4,790,562
12/1/2002	4,584,010
1/1/2003	4,589,821
2/1/2003	4,296,868
3/1/2003	5,047,639

(continued)

Report Date	Gas Production (Mcf)
4/1/2003	4,242,897
5/1/2003	1,836,172
6/1/2003	3,152,253
7/1/2003	3,854,590
8/1/2003	3,753,137
9/1/2003	4,058,780
10/1/2003	4,623,109
11/1/2003	4,389,414
12/1/2003	4,255,331
1/1/2004	3,921,356
2/1/2004	4,295,071
3/1/2004	4,395,168
4/1/2004	3,803,452
5/1/2004	1,593,561
6/1/2004	4,229,843
7/1/2004	3,771,216
8/1/2004	3,360,782
9/1/2004	3,411,542
10/1/2004	3,136,000
11/1/2004	3,238,336
12/1/2004	3,831,361
1/1/2005	4,370,401
2/1/2005	3,796,343
3/1/2005	4,352,104
4/1/2005	4,000,564
5/1/2005	1,511,693
6/1/2005	3,952,855
7/1/2005	3,934,593
8/1/2005	3,952,428
9/1/2005	3,935,674
10/1/2005	4,473,174
11/1/2005	3,860,921
12/1/2005	3,955,677
1/1/2006	3,913,666
2/1/2006	3,688,256
3/1/2006	3,760,070
4/1/2006	3,606,762
5/1/2006	3,623,664
6/1/2006	3,161,706
7/1/2006	3,036,587
8/1/2006	3,265,463
9/1/2006	1,151,975
10/1/2006	3,111,534
11/1/2006	2,810,794
12/1/2006	3,024,938
1/1/2007	2,975,520
2/1/2007	2,573,689
3/1/2007	2,809,468
4/1/2007	2,633,019
5/1/2007	949,164
6/1/2007	2,572,894

(continued)

Report Date	Gas Production (Mcf)
7/1/2007	2,627,468
8/1/2007	2,550,633
9/1/2007	2,413,744
10/1/2007	2,414,873
11/1/2007	2,205,187
12/1/2007	2,045,448
1/1/2008	2,061,175
2/1/2008	1,969,981
3/1/2008	2,287,564
4/1/2008	2,142,317
5/1/2008	1,099,375
6/1/2008	2,038,155
7/1/2008	2,060,107
8/1/2008	1,885,560
9/1/2008	1,961,981
10/1/2008	1,867,102
11/1/2008	1,863,396
12/1/2008	1,942,109
1/1/2009	1,872,111
2/1/2009	1,700,443
3/1/2009	1,840,297
4/1/2009	1,793,113
5/1/2009	1,572,272
6/1/2009	1,329,486
7/1/2009	2,215,803
8/1/2009	2,189,281
9/1/2009	2,093,218
10/1/2009	2,144,454
11/1/2009	2,052,378
12/1/2009	2,027,575
1/1/2010	1,922,590
2/1/2010	1,758,331
3/1/2010	1,661,583
4/1/2010	1,718,554
5/1/2010	1,281,219
6/1/2010	1,593,735
7/1/2010	1,638,314
8/1/2010	1,617,536
9/1/2010	1,446,896
10/1/2010	1,495,763
11/1/2010	1,415,959
12/1/2010	1,414,119
1/1/2011	1,406,448
2/1/2011	1,276,776
3/1/2011	1,383,078
4/1/2011	1,338,259
5/1/2011	1,378,985
6/1/2011	931,640
7/1/2011	1,230,206
8/1/2011	1,266,440
9/1/2011	1,254,496

(continued)

Report Date	Gas Production (Mcf)
10/1/2011	1,269,871
11/1/2011	1,204,738
12/1/2011	1,087,660
1/1/2012	1,161,317
2/1/2012	1,150,283
3/1/2012	1,178,621
4/1/2012	1,108,856
5/1/2012	1,112,541
6/1/2012	1,152,820
7/1/2012	1,196,532
8/1/2012	847,706
9/1/2012	1,099,034
10/1/2012	1,124,869
11/1/2012	1,066,479
12/1/2012	1,174,070

APPENDIX F

Socio-Economic Impact Analysis of Alaska LNG Project

NERA
ECONOMIC CONSULTING

Socio-Economic Impact Analysis of Alaska LNG Project

Prepared for:

Locke Lord LLP

Final Report

June 19, 2014

NERA Project Team*

W. David Montgomery, NERA Economic Consulting (Project Leader)

Robert Baron, NERA Economic Consulting

Paul Bernstein, NERA Economic Consulting

David Harrison, NERA Economic Consulting

Sebastian Mankowski, NERA Economic Consulting

Meredith McPhail, NERA Economic Consulting

Sugandha D. Tuladhar, NERA Economic Consulting

Shirley Xiong, NERA Economic Consulting

Mei Yuan, NERA Economic Consulting

* The NERA project team acknowledges the valuable research support provided by the University of Alaska Institute for Social and Economic Research (ISER), whose participation was directed by Professor O. Scott Goldsmith. This report reflects the research, opinions, and conclusions of the NERA Project Team and does not necessarily reflect those of ISER, NERA Economic Consulting (NERA) or any of NERA's clients.

NERA Economic Consulting
1255 23rd Street NW
Washington, DC 20037
Tel: +1 202 466 3510
Fax: +1 202 466 3605
www.nera.com

Report Qualifications/Assumptions and Limitations

There are no third-party beneficiaries with respect to this report, and NERA Economic Consulting does not accept any liability to any third party.

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable, but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA Economic Consulting accepts no responsibility for actual results or future events.

The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

All decisions in connection with the implementation or use of advice or recommendations contained in this report are the sole responsibility of the client. This report does not represent investment advice nor does it provide an opinion regarding the fairness of any transaction to any and all parties.

Contents

List of Figures

Table of Acronyms

AEO: Annual Energy Outlook

AKLNG: Proposed Alaska Liquefied Natural Gas

C: Residential Sector

CES: Constant Elasticity of Substitution

CGE: Computable General Equilibrium

CO_2: Carbon Dioxide

Cook Inlet: Cook Inlet and Other Alaska Natural Gas

DOE: Department of Energy

DOE/FE: Department of Energy, Office of Fossil Energy

EIA: U.S. Energy Information Administration

EIS: Energy-Intensive Sectors

ELE: Electricity Sector

ELE Model: Electricity Sector Model

FTA: Free Trade Agreement

GATT: General Agreement on Tariffs and Trade

GDP: Gross Domestic Product

GNGM : NERA's Global Natural Gas Model

GSP: Gross State Product

IEO: International Energy Outlook

ISER: University of Alaska Institute for Social and Economic Research

LNG: Liquefied Natural Gas

Lower-48: U.S. Lower-48 States

Macro Model: U.S. General Equilibrium Model

MAN: Manufacturing Sector

MM: Million

MW: Megawatt

NERC: North American Electric Reliability Corporation

NERA: NERA Economic Consulting

NGA: Natural Gas Act

NS: North Slope Region of Alaska

SRV: Services Sector

Susitna: Susitna-Watana Hydroelectric Project

U.S.: United States (Lower-48, Alaska, and Hawaii)

EXECUTIVE SUMMARY

Introduction

NERA was retained by Locke Lord LLP to conduct an analysis of the market and macroeconomic impacts of a proposed Alaska Liquefied Natural Gas (AKLNG) project. The AKLNG project is proposed as a single integrated and interdependent project for the export and sale of liquefied natural gas (LNG) in foreign commerce. The proposed project would include the construction of a natural gas liquefaction and export terminal on the south central coast of Alaska, a natural gas pipeline from the liquefaction plant to the North Slope region of Alaska (NS) and a gas treatment plant and associated pipelines connecting to upstream fields. The study thoroughly analyzes the natural gas market and macroeconomic impacts that the AKLNG project could potentially have on both Alaska and the U.S. as a whole.

Methodology

For this analysis we use our state-of-the-art integrated energy and economic model, the N_{ew}ERA model, and NERA's Global Natural Gas Model (GNGM) to estimate the various macroeconomic and market impacts. The GNGM is used to assess impacts of Alaska LNG exports on global LNG demand and prices. Estimates of LNG export levels from the GNGM were then used as inputs into the N_{ew}ERA model to estimate macroeconomic impacts of the AKLNG project on the Alaska and U.S. economies. We developed various modeling assumptions through cooperation with ISER as well as various publicly available literatures.

Scenarios

To understand the possible range of impacts of the AKLNG project, we developed three scenarios. First a Baseline with no AKLNG project was needed against which to measure the economic impacts of the AKLNG project. Having defined the Baseline, we constructed two scenarios that include the development of the AKLNG project, associated LNG export volumes, and different in-state natural gas demand forecasts: an Expected scenario and a High scenario. To capture the range of potential impacts of the AKLNG project, the two scenarios differ significantly in that the High case assumes:

- 50% greater economic growth rate in Alaska;
- Increased supply of natural gas available to the market; and
- 40 year period of LNG exports for Alaska, as opposed to only a 30 year export period in the Expected scenario.

Most economic assumptions shared amongst the three cases were developed from public sources and with the assistance of consultations with ISER.

Gas Market Impacts

Proceeding with the AKLNG project and exporting LNG would lead to lower natural gas prices in Alaska and the U.S. as a whole. Figure 1 and Figure 2 show the amounts by which the AKLNG project could reduce natural gas prices in the U.S. as a whole and in Alaska as compared to the Baseline. The price reduction is seen to be greatest in Alaska where the 2048 average market price is $5.02/MMBtu lower than the Baseline in the Expected scenario and $4.78/MMBtu lower in the High scenario. The impact on the wellhead natural gas price in the U.S. as a whole is smaller in magnitude but still a reduction in price with the 2048 price being $0.17/MMBtu and $0.23/MMBtu lower than the Baseline in the Expected and High scenarios respectively.

Figure 1: Alaska Average Natural Gas Market Price Compared to Baseline (2010$/MMBtu)

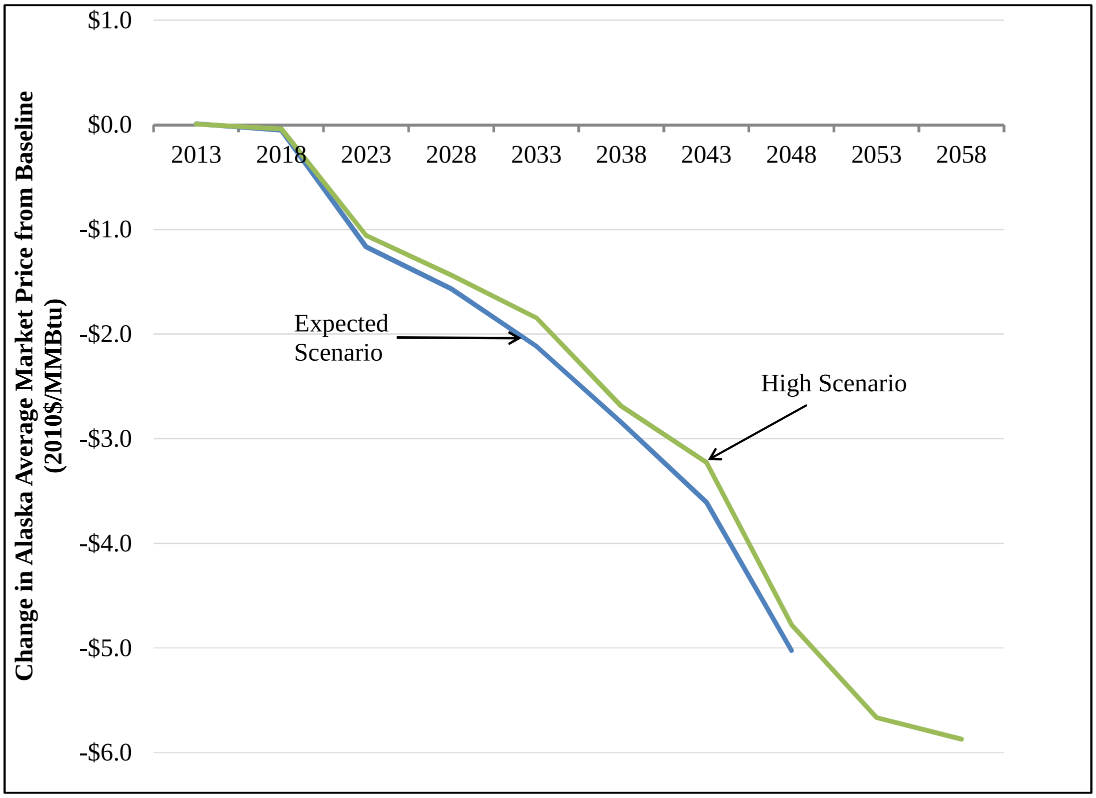
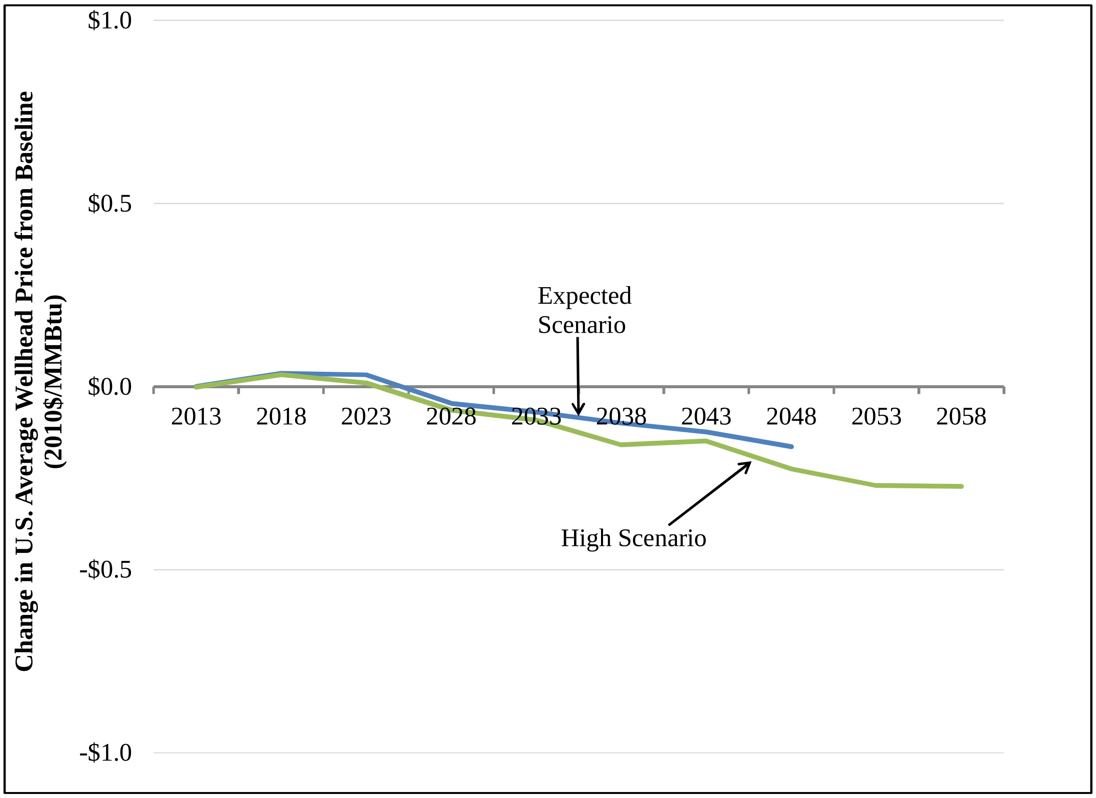


Figure 2: U.S. Average Wellhead Natural Gas Price Compared to Baseline (2010$/MMBtu)



In addition to the reductions in natural gas prices, the benefits of the increased supplies of natural gas brought to market by the AKLNG project include eliminating reliance on imported natural gas to make up for ultimate declines in Cook Inlet production, additional revenues from LNG exports, and increased availability of natural gas for expansion of natural gas intensive industries. Even with the increased levels of natural gas demand in Alaska driven by LNG exports, lower prices, and greater economic growth, we find that our assumed levels of natural gas reserves and resources are sufficient to meet and exceed additional consumption needs in both scenarios. Figure 3 and Figure 4 show the cumulative natural gas demand projections in both the Expected and High scenarios.

Figure 3: Alaska Natural Gas Demand in Expected Scenario (Bcf)[1]

		2013	2018	2023	2028	2033	2038	2043	2048	Cumulative Total (Tcf) [2]
Alaska Demand	Upstream Lease Operations Fuel	255	255	255	255	255	255	255	255	10.2
	In-State Use	98	102	116	134	145	154	162	176	5.4
LNG Exports Demand[3]		-	-	878	1,099	1,099	1,099	1,099	1,099	31.9
Total Natural Gas Demand		353	357	1,249	1,488	1,499	1,508	1,516	1,530	47.5

Figure 4: Alaska Natural Gas Demand in High Scenario (Bcf)

		2013	2018	2023	2028	2033	2038	2043	2048	2053	2058	Cumulative Total (Tcf)[4]
Alaska Demand	Upstream Lease Operations Fuel	255	255	255	255	255	255	255	255	255	255	12.8
	In-State Use	98	102	148	188	228	258	269	319	365	421	12.0
LNG Exports Demand[5]		-	-	878	1,099	1,099	1,099	1,099	1,099	1,099	1,099	42.9
Total Natural Gas Demand		353	357	1,281	1,542	1,582	1,612	1,623	1,673	1,719	1,775	67.6

Macroeconomic Impacts

Our analysis finds that if the AKLNG project were to be constructed, the economic impacts would be unequivocally positive. The project benefits the Alaska economy by boosting

[1] All results in tables and charts throughout this report, unless specified otherwise, are presented in model years which each represent a span of five years (*i.e.*, 2013 represents the years 2013, 2014, 2015, 2016, and 2017). Each model year result represents the average annual result for the time specified by that model year (*i.e.*, in Figure 3 the 2013 Alaska Demand represents the average annual demand in 2013 through 2017). See APPENDIX B. ADDITIONAL N_{ew}ERA MODEL DETAILS for further details on the N_{ew}ERA model.

[2] Cumulative totals may not equal the sum of all years due to differences in rounding.

[3] This includes LNG-related fuel use and shrinkages (after ramp-up, 1,099 Bcf/year equals approximately 929 Bcf/year for LNG export and 171 Bcf/year for fuel use and shrinkages).

[4] Cumulative totals may not equal the sum of all years due to differences in rounding.

[5] This includes LNG-related fuel use and shrinkages (after ramp-up, 1,099 Bcf/year equals approximately 929 Bcf/year for LNG export and 171 Bcf/year for fuel use and shrinkages).

Alaskan's personal income as represented by consumption, their overall economic well-being as reflected in the increase in welfare, and by increasing state tax income which is recycled back into the local economy and increases gross state product (GSP). The increased economic activity in Alaska leads to overall benefits for the U.S. as a whole. In percentage terms, impacts on Alaska would be much larger than impacts on the U.S. as a whole, but economic impacts in both Alaska and the U.S. are positive for both scenarios relative to the Baseline. All key indicators examined for Alaska and the U.S., including consumer welfare, U.S. gross domestic product (GDP), Alaska GSP, and consumption, improved with the construction of the AKLNG project. Tax income accounts for approximately one-third of GSP increases and is recycled back into the Alaskan economy. Figure 5, Figure 6, Figure 7, and Figure 8 show some key macroeconomic indicators for Alaska and the U.S. for both the Expected and High scenarios.

Figure 5: Summary of Alaska Macroeconomic Impacts Compared to Baseline in Expected Scenario

	2013	2018	2023	2028	2033	2038	2043	2048
Welfare (%)	0.1%	0.2%	0.5%	0.9%	1.0%	1.1%	0.9%	0.8%
GSP (%)	1.2%	2.7%	6.0%	7.7%	7.9%	8.4%	9.0%	9.2%
Consumption (%)	0.1%	0.3%	0.6%	0.9%	1.0%	1.1%	1.1%	1.1%

Figure 6: Summary of Alaska Macroeconomic Impacts Compared to Baseline in High Scenario

	2013	2018	2023	2028	2033	2038	2043	2048	2053	2058
Welfare (%)	0.2%	0.1%	0.4%	0.8%	0.9%	0.9%	0.8%	0.5%	0.1%	0.1%
GSP (%)	0.5%	2.7%	6.3%	8.0%	8.3%	8.7%	9.0%	9.4%	9.6%	8.9%
Consumption (%)	0.2%	0.2%	0.4%	0.7%	0.9%	1.0%	1.0%	1.0%	0.9%	0.9%

Figure 7: Summary of U.S. Macroeconomic Impacts Compared to Baseline in Expected Scenario

	2013	2018	2023	2028	2033	2038	2043	2048
Welfare (%)	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.02%	0.03%
GDP (%)	0.01%	0.03%	0.05%	0.06%	0.06%	0.06%	0.06%	0.05%
Consumption (%)	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%

Figure 8: Summary of U.S. Macroeconomic Impacts Compared to Baseline in High Scenario

	2013	2018	2023	2028	2033	2038	2043	2048	2053	2058
Welfare (%)	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%
GDP (%)	0.01%	0.04%	0.05%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
Consumption (%)	0.03%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%

Environmental Impacts

As with impacts on the natural gas market and other macroeconomic metrics, we see improvement in environmental outcomes going along with the increased availability of lower cost natural gas supplies as a result of the AKLNG project completion. Domestically, we see reductions in emissions, particularly from the electric sector, due to lower priced natural gas inducing coal-to-gas fuel switching.

Conclusion

Our analysis finds that the construction of the AKLNG project and commencing LNG exports would have strong positive economic impacts on the state of Alaska and also have positive economic impacts on the U.S. as a whole. Increased natural gas supplies in Alaska result in reduced natural gas prices throughout the U.S., not just in Alaska, which lowers costs for energy-intensive industries and households. LNG exports bring in additional revenues to the state government, businesses, and residents. Coal-to-gas switching in the electric sector and other industrial sectors results in reduced emissions of pollutants. Greater domestic supply reduces reliance on the imports of energy supplies. The Alaska natural gas reserves and resources estimated by the engineering consultants are sufficient to meet and exceed the AKLNG project-related and in-state demands. These benefits of increased supply and revenues accrue primarily to the Alaskan economy but also to the U.S. as a whole.

I. INTRODUCTION

This report evaluates the potential economic effects of the AKLNG project in Alaska as well as in United States as a whole. The analyses include the effects of two different scenarios regarding the length of time the AKLNG project would operate: a 30 year scenario, which represents an expected level of natural gas supply and demand; and a 40 year scenario, which represents a high level of natural gas supply and demand.

A. Background on Natural Gas in Alaska

NS oil field operations and the Southern Railbelt are the main consumers of natural gas in Alaska. The Southern Railbelt consists of the regions of Mat-Su Valley, Anchorage, and the Kenai Peninsula. Natural gas needed for the oil field operations is taken directly from the natural gas that is produced when crude oil is extracted from the NS oil fields. The Southern Railbelt relies on natural gas produced in the Cook Inlet. Therefore, Alaska has been self-sufficient and as recently as 2012, Alaska exported its excess natural gas to Japan in the form of LNG.

Historically, the Cook Inlet has been able to produce enough natural gas to keep pace with Southern Railbelt demand. However, according to the Alaska Department of Natural Resources, there is the potential for shortages as early as 2018 assuming full development of known and higher probability reserves.[6] There is believed to be sufficient probable reserves and resources (when taking into account the broader categories of reserves and resources) in the Cook Inlet so that if drilling and exploration were to increase markedly, Southern Railbelt demand could be met for the most part with Cook Inlet produced natural gas through 2030. But thereafter, recoverable reserves are forecasted to decline rapidly forcing Alaska to rely almost solely on imports to satisfy its natural gas needs unless the AKLNG project is undertaken and natural gas is transported from the NS to the Southern Railbelt region.

B. Background on LNG Process

Section 3 of the Natural Gas Act (NGA) (15 U.S.C. Section 717b) requires authorization from the Department of Energy's Office of Fossil Energy (DOE/FE) in order to export natural gas from the United States. Applications to export to countries with which the United States has a Free Trade Agreement (FTA) "shall be granted without modification or delay." NGA Section 3 provides that exports to non-FTA countries also are to be authorized by Department of Energy (DOE) "unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest."

As part of its process in determining whether LNG exports to non-FTA countries are consistent or inconsistent with the public interest, DOE commissioned two studies: (1) a domestic price

[6] "Cook Inlet Natural Gas Production Cost Study," State of Alaska Department of Natural Resources, June, 2011. Available at: http://dog.dnr.alaska.gov/ResourceEvaluation/Documents/Cook_Inlet_Natural_Gas_Production_Cost_Study.pdf.

impact study by the U.S. Energy Information Administration (EIA) and released in January 2012; and (2) an economic impact study by NERA that was released in December 2012. The NERA studies concluded that for all levels of LNG exports considered there would be a net benefit to the U.S. economy.

In addition to these two studies, DOE has provided indications of how to assess "public interest" in various publications, including a set of Policy Guidelines issued in 1984, Order No. 1471, and Delegation Order No. 0204-111. These were primarily related to imports, but DOE has indicated that they also apply to exports.[7] In its approval of Cheniere Energy's non-FTA permit in May 2011, DOE listed various criteria for determining whether LNG exports to non-FTA countries are or are not in the public interest: "domestic need, adequacy of supply, the environment, geopolitics, and energy security".[8] In total, DOE has given approval to seven non-FTA applications for approximately 9.27 Bcf/day of LNG exports to date between Cheniere Energy; Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC; Lake Charles Exports LLC; Dominion Cove Point LNG, L.P.; Cameron LNG, LLC; and Jordan Cove Energy Project, L.P.[9] These approvals provide additional indications of relevant criteria for public interest analysis: impact on natural gas prices, benefits to local, regional, and national economy, benefits of international trade, and environmental benefits.

It is important to note that the AKLNG facility is located in Alaska, while the other potential LNG facilities that have been considered are located in the U.S. Lower-48 states (Lower-48). Indeed, the DOE-sponsored studies did not specify the location of projects because they were designed as national studies[10] and did not differentiate projects or impacts by their geographical location. In this analysis we take the project location into account insofar as the economic impacts the project may have in its geographic area of operation as well as the potential impacts, or lack thereof, it may have on the rest of the U.S.

C. Objectives of Report

The overall objective of this report is to provide a macroeconomic analysis of the potential impacts of LNG exports from Alaska at national and regional levels. We consider the potential effects of the AKLNG project on energy markets as well as on economic, environmental, and energy security impacts. We use a state-of-the-art integrated energy and economic model, the N_{ew}ERA model, and NERA's GNGM to estimate these various effects. The versions of N_{ew}ERA

[7] "U.S. Natural Gas Exports: New Opportunities, Uncertain Outcomes," Congressional Research Service, April 8, 2013. Available at: http://www.fas.org/sgp/crs/misc/R42074.pdf.

[8] "U.S. Natural Gas Exports: New Opportunities, Uncertain Outcomes," Congressional Research Service, April 8, 2013. Available at: http://www.fas.org/sgp/crs/misc/R42074.pdf.

[9] "Summary of LNG Export Applications," U.S. Department of Energy, March 24, 2014. Available at: http://energy.gov/sites/prod/files/2014/03/f13/Summary%20of%20LNG%20Export%20Applications.pdf.

[10] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," U.S. Energy Information Administration, January, 2012. Available at: http://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf.

and GNGM that we use are updated and customized versions of the model used in the study commissioned by DOE noted above.

In this analysis, the effects of the AKLNG project are measured relative to a status quo Baseline scenario with no AKLNG project or LNG exports related to the project. The Baseline includes an integrated economic forecast that has been calibrated to the reference case from the Annual Energy Outlook (AEO) 2013 of the EIA and then modified to account for Alaska-specific information provided by local experts on the Alaska energy system and economy.

The assessments in this study cover four general categories of impacts:

1. Alaska energy market and macroeconomic impacts;
2. U.S. energy market and macroeconomic impacts;
3. Environmental impacts; and
4. Regional and national security impacts.

There are substantial uncertainties involved in developing these estimates of the effects of the AKLNG project, including uncertainties related to the estimated supplies and prices of global LNG trade and estimated Alaskan natural gas supply and demand. Alaska demand for natural gas is important because although the facility would be primarily designed to export LNG, the pipeline would allow for additional natural gas to be provided to local Alaska industries and residents.

D. Outline of this Report

The remainder of the report is organized as follows. Section II summarizes the N_{ew}ERA modeling tools. Section III provides information on the modeling approach and the various scenarios we consider: the Baseline and the scenarios involving expected Alaska LNG supply and expected Alaska natural gas demand. Section IV presents the results of our analyses followed by a summary of the macroeconomic impacts at the U.S. level in Section V. The appendices provide results from an additional LNG export scenario and details on the N_{ew}ERA model.

II. MODEL DESCRIPTIONS

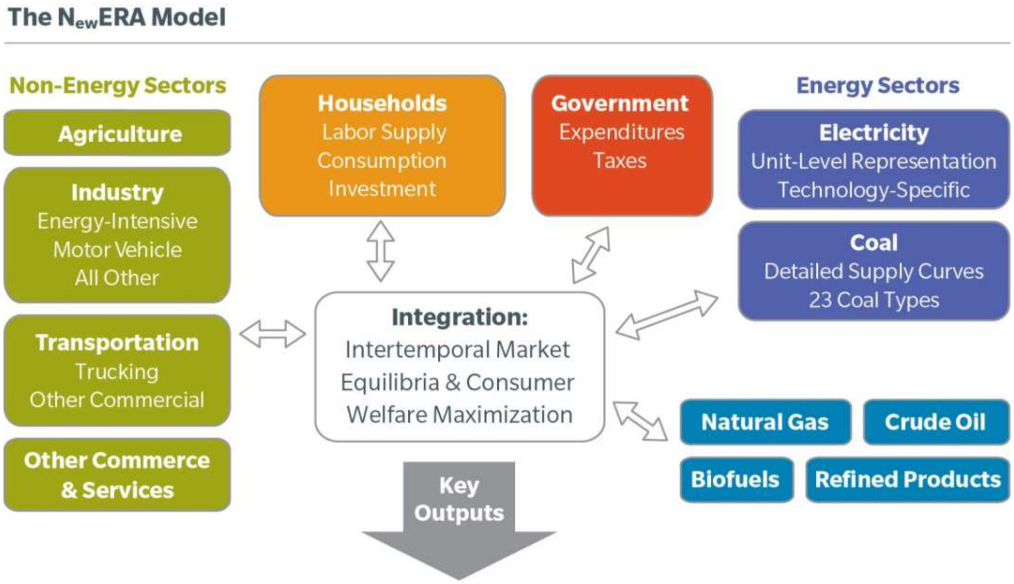
The N_{ew}ERA model is a top-down, general equilibrium model of Alaska, Hawaii, and other regions of the Lower-48 combined with a detailed bottom-up model of the North American electricity sector (ELE). The model includes all sectors of the economy and a representative household in each region. Producers and consumers in the model interact in the marketplace such that supply and demand in each market equilibrate. The responses of producers and consumers to a policy change enable the computation of energy and economic impacts.

The N_{ew}ERA model is routinely used to project impacts of various policies (including command and control regulations, market based policies, and trade policies, such as LNG export policies) and major projects on regional economies at a sectoral level. Different types of policies and projects could impact a given sector in a variety of ways. When evaluating policies that have impacts on the entire economy, such as LNG exports, which lead to changes in export revenues and changes in the natural gas market, one needs to use a model that captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The N_{ew}ERA modeling framework takes into account interactions between all parts of the economy and policy consequences as transmitted throughout the economy as sectors respond to policies. The model's flexibility allows it to incorporate many different types of policies, such as those affecting the natural gas market, capital investment projects, environmental, financial, labor, and tax matters. Figure 9 depicts the integration of the N_{ew}ERA modeling framework.

The GNGM is used to develop estimates of global production, pricing, and trade of natural gas, in particular LNG. When conducting analysis of the economic impacts of LNG export scenarios, the GNGM provides a method of establishing price estimates for the volumes of expected LNG exports which are a key input into the broader macroeconomic impacts modeled by the N_{ew}ERA model.

The following sections provide summaries of the major components of the N_{ew}ERA model and the GNGM. More detailed examinations of the two models are contained in the Appendices.

Figure 9: The N_{ew}ERA Modeling Framework



Macroeconomic (National/Regional)	**Primary Energy** (National/Regional)	**Electricity** (National/Regional/Generating Unit)
Welfare	Demand	Prices
GDP, consumption, investment	Prices	Builds, retrofits, retirements
Output by sector	Production	Load and Dispatch

A. U.S. General Equilibrium Model

The U.S. General Equilibrium Model (Macro model) of the N_{ew}ERA integrated model is a forward-looking dynamic computable general equilibrium (CGE) model of the United States, represented by 7 regions. The model simulates all economic interactions between the Alaskan economy and the rest of the U.S. economy, including those among industries, households, government, and rest of the world. Industries and households maximize profits and utility assuming perfect foresight. The model represents the circular flow of goods, services, and payments in the economy (every economic transaction has a buyer and a seller whereby goods/services go from a seller to a buyer and payment goes from the buyer to the seller).

The macroeconomic model incorporates all production sectors, including liquefaction plants for LNG exports, and final demand of the economy. The AKLNG project is represented as a separate production function in the modeling scenarios that is absent in the Baseline. In the scenarios, LNG is produced if the market price is higher than the marginal production cost. The model includes a representative household, which characterizes the behavior of an average consumer, and 12 industrial sectors, which represent the production sectors of the economy. In the model, the government collects initial labor and capital tax revenues and returns it back to the consumers on a lump-sum basis.

Households receive income from providing labor and capital to businesses, receive transfers from government, pay taxes to the government, and put savings into financial markets, while also consuming goods and services. Industries produce goods and services, pay taxes to and receive subsidies from the government, and use labor and capital. Industries are both consumers and producers of capital for investment in the rest of the economy. Within the circular flow, equilibrium is found whereby demand for goods and services is equal to their supply, and investments are optimized for the long term. Thus, supply equals demand in all markets. The model finds equilibrium by assuming perfect foresight and ensuring goods and services markets balance, production meets the zero profit condition, consumers maintain income balance conditions, there is no change in monetary policy, and there is full employment within the U.S. economy. Additional details of the macroeconomic model are provided in Appendix B.

The $\mathrm{N_{ew}ERA}$ model is based on a unique set of databases that NERA constructed by combining economic data from the IMPLAN 2008 database and energy data from EIA's AEO 2013. The IMPLAN 2008 database provides Social Accounting Matrices for all states for the year 2008. These matrices contain inter-industry goods and services transaction data; we merge the economic data with energy supply, demand, and prices for 2008 from EIA. In addition, we include tax rates in the dataset from NBER's TAXSIM model. By merging economic data from IMPLAN, energy data from EIA, and tax rates from NBER, we build a balanced energy-economy dataset.

GDP, energy supply, energy demand, and energy price forecasts come from EIA's AEO 2013. The forecasts for the Alaskan economy have been further refined based on inputs and expertise provided by ISER. Labor productivity, labor growth, and population forecasts from the Census Bureau are used to forecast labor endowments along the baseline and ultimately employment by industry.

B. Electricity Sector Model

The bottom-up Electricity Sector Model (ELE model) simulates the electricity markets in Alaska, the rest of the U.S., and parts of Canada. The model includes more than 17,000 electric generating units, and capacity planning and dispatch decisions are represented simultaneously. The model dispatches electricity to load duration curves. A long-term solution typically includes 10 or more model years out through 2050 (each year is not evaluated but rather represented by a model year). The model determines investments to undertake and units to dispatch by solving a dynamic, non-linear program with an objective function that minimizes the present value of total incremental system costs, while complying with all constraints, such as demand, peak demand, emissions and transmission limits, and other environmental and electric specific policy mandates.

Having a bottom-up ELE representation for the Alaska economy provides an advantage to evaluate trade-offs between different technologies especially in an environment with high supply of natural gas. In addition, the integrated nature of the $\mathrm{N_{ew}ERA}$ model enables it to provide impacts on the electricity price consistent with a realistic electric system representation while being able to compute macroeconomic impacts.

We solve the bottom-up and the top-down models iteratively using a decomposition method. The top-down macroeconomic model solves for equilibrium prices, while the bottom-up model solves for equilibrium quantities. The solution process is iterated until prices and quantities converge.

C. GNGM

The GNGM is a partial-equilibrium model designed to estimate the amount of natural gas production, consumption, and trade by major world natural gas consuming and/or producing regions. The model maximizes the sum of consumers' and producers' surplus less transportation costs, subject to mass balancing constraints and regasification, liquefaction, and pipeline capacity constraints.

The model divides the world into 14 regions. These regions are largely adapted from the EIA International Energy Outlook (IEO) regional definitions, with some modifications to address the LNG-intensive regions. The model's international natural gas consumption and production projections for these regions are based upon the EIA's AEO 2013 and IEO 2011 Reference cases.

The supply of natural gas in each region is represented by a constant elasticity of substitution (CES) supply curve. The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function.

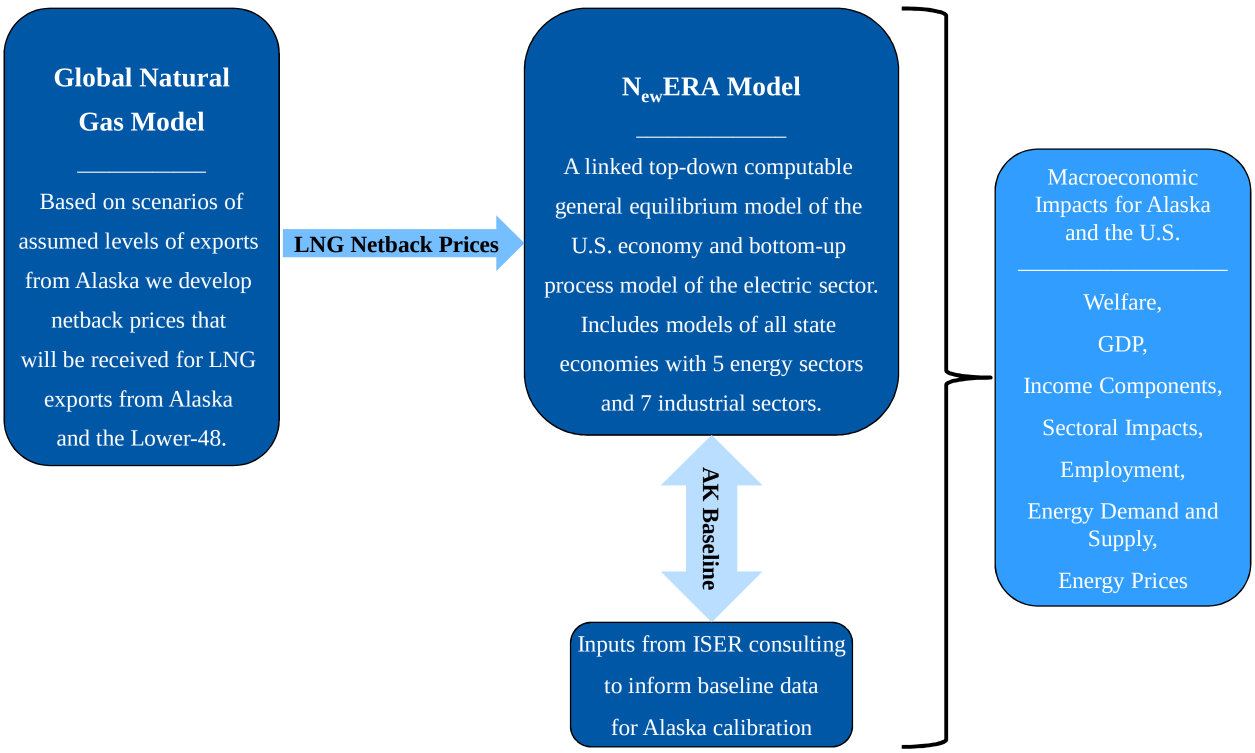
III. MODELING APPROACH

This section provides information on the modeling approach used in this study including the overall framework and specific assumptions made to develop the scenarios that are modeled.

A. Modeling Framework

The NERA modeling approach for this project involves using the N_{ew}ERA model with inputs from the GNGM and ISER in order to develop an analysis that is consistent and covers the key market interactions for this analysis. Figure 10 depicts the interaction of the various inputs and N_{ew}ERA modeling tools utilized to generate the key output measures for the analysis.

Figure 10: Interdependency of Modeling Tools and Inputs



1. Modifications to N_{ew}ERA Model for Analysis of Alaska

Several modifications were made to NERA's standard N_{ew}ERA model to represent Alaska in a more precise and granular perspective. We made changes to both the Macro and ELE models. For the Macro model, we first developed a database which treated Alaska as a separate region as opposed to its usual inclusion with other states as part of the Pacific-Northwest region. In order to properly analyze the impacts of the AKLNG project on Alaska, we made this separation so that we could better measure the impacts of the project and associated LNG exports on Alaska and the rest of the U.S.

After separating out Alaska, we enhanced the standard representation of a Macro model region as follows:

- Created two sources of natural gas production for Alaska – NS and Cook Inlet production; and
- Added a new natural gas production sector for Alaska to represent the activity of bringing NS natural gas to market either as LNG or conventional gas.

To correctly account for the impacts of NS natural gas on Alaska, it is critical to represent the different uses and the demand for this natural gas supply. NS natural gas can be used to meet domestic demand both in the Northern and Southern Railbelt regions as well as international demand in the form of LNG. Currently most of the Southern Railbelt natural gas demand is met by natural gas produced from Cook Inlet. There is believed to be sufficient probable reserves and resources (when taking into account the broader categories of reserves and resources) in the Cook Inlet so that if drilling and exploration were to increase markedly, Southern Railbelt demand could be met for the most part with Cook Inlet produced natural gas through 2030. But thereafter, recoverable reserves are forecasted to decline rapidly. In the Baseline without any new NS natural gas production, a greater share of the Southern Railbelt natural gas demand will be met by imports. If the AKLNG project comes online, then it will play a greater role in meeting Southern Railbelt demand instead. To capture this trade-off between NS and Cook Inlet natural gas plays, we include two natural gas resources and production sectors.

We account for the cost of shipping natural gas from NS to the LNG facility by incorporating a pipeline construction activity that demands capital, labor, and operating expenses. We also incorporate the liquefaction plant cost into the model in a similar manner. Given that the Alaskan labor supply is insufficient to realistically support the construction of the LNG project facilities, we allow out of state workers to be used in the construction of the LNG facility and the pipeline.

Workers are allowed to migrate from other U.S. regions to Alaska to work on the AKLNG project if the project's demand for labor causes Alaskan wage rates to increase to a level which would incentivize migrant workers to move, with an associated migration cost, from their current location to work in Alaska. The infrastructure activities are formulated such that the demand for migrant workers and outside capital is based on the size of the project.

Before the recent boom in shale-based natural gas resource development, the U.S. had been a net importer of natural gas through pipelines. Over the last couple of years the U.S. situation has changed, and EIA forecasts place the U.S. as becoming a net exporter of natural gas along pipelines. To represent this changing situation, we modified our model to allow for Lower-48 pipeline exports to be consistent with AEO 2013 projections. The levels of these exports are show in Figure 11.

In addition to changing the macro model and its database, we modified the ELE model and its accompanying database to more closely capture the nuances of Alaska's ELE. We calibrated Alaska's electric sector generation profile to the EIA State Electricity profile.[11] First, the model was calibrated to match the current electricity production profile in terms of total demand and generation by type. As part of the Baseline forecast, we assumed the construction of the 600 megawatt (MW) Susitna-Watana Hydroelectric Project (Susitna) in keeping with Alaska's stated goal of supplying more generation from renewable sources. This unit also appears in the Expected scenario but is removed from the High scenario. Susitna was excluded in the High scenario as part of developing a bottom-up natural gas demand forecast commensurate with the high natural gas demand intended for this scenario.

Figure 11: Lower-48 Net Natural Gas Pipeline Export Projections in the Baseline (Tcf)[12]

Nations Importing Lower-48 Pipeline Exports	2013	2018	2023	2028	2033	2038
Mexico and Canada	-1.56	-0.73	0.37	0.60	0.83	1.63

B. Scenarios for Analysis

This section summarizes the scenarios we analyze in this study. Figure 12 provides an overview of the Baseline, Expected, and High Scenarios we model.

The Baseline assumes that the AKLNG project is not developed. Thus, the Baseline includes no pipeline construction in Alaska and no Alaska LNG exports.[13] It includes Baseline levels of LNG exports from the Lower-48. Susitna comes online in 2023, displacing the need for new natural gas-fired generation and hence reducing natural gas demand.

Economic conditions in Alaska over the Expected and High scenarios differ in terms of the time period of LNG exports from Alaska as well as the levels of natural gas supply and natural gas demand in Alaska. For the Expected scenario, the pipeline and LNG facilities are built in Alaska, and the available reserves and resources are 63 Tcf. The AKLNG project will export 20

[11] "Alaska Electricity Profile 2010," U.S. Energy Information Administration, January, 2012. Available at: http://www.eia.gov/electricity/state/alaska/pdf/alaska.pdf.

[12] U.S. Energy Information Agency, "Annual Energy Outlook 2013," May, 2013. Since AEO 2013 projections only extend to 2040, we held the net export levels in our Baseline modeling constant at the 2038 model year level through the end of the modeling horizon.

[13] Although building the pipeline would likely lead to significant reductions in gas prices as compared to the Baseline for all of Alaska in both the Expected and High scenarios, without allowance for LNG exports the pipeline is much less likely to be constructed.

MTPA of natural gas for 30 years from 2023[14] through 2052 but NS natural gas supply will continue to be available to the domestic Alaska economy beyond 2052 when the export period ends. Demand for natural gas in Alaska develops in line with the Baseline economic forecast and is derived relative to the increased natural gas supplies. Susitna is assumed to come online in 2023.

For the High scenario, the AKLNG project is constructed as scheduled in the Expected scenario and NS available resources are increased to 109 Tcf. Additionally, the time period for exports is extended to 40 years through 2062. The Alaskan economy is assumed to grow 50% faster than in the Expected scenario. This assumed higher growth rate is based on ISER's high growth scenario for Alaska.[15] Furthermore, this scenario assumes mining projects are more prevalent and there is greater natural gas consumption throughout the economy. On the electric side, Susitna is assumed never to come online, so that natural gas demand from the electric sector is higher than in the Expected scenario.

For both the Expected and the High scenarios, the assumed available levels of natural gas reserves and resources act as a constraint that limits the equilibrium supply within the model. Natural gas production cannot exceed the available reserves and resources specified over the period of the modeling horizon, although given the production levels we see in our scenario analyses, the constraint is not binding in either scenario. A detailed breakdown of Alaska natural gas demand in each scenario is presented in the relevant results sections.

A more detailed description of the Baseline, Expected, and High scenarios is provided in the following sections.

---

[14] For purposes of this study and the associated economic impact analyses, it is assumed that LNG production and export will begin in 2023. However, variance from this assumption will not have any appreciable effect on the analyses or conclusions of this study. Also, for both the Expected and High scenarios, there is a period of ramp-up activity for the project starting in 2023.

[15] Goldsmith, Scott, "Economic and Demographic Projections for Alaska and Greater Anchorage 2010–2035," in association with Northern Economics, December 2009.

Figure 12: Scenarios Considered in the Analysis

Scenario Name	Alaskan Outlook			Lower-48
	Alaska LNG Export and Pipeline Infrastructure	**Natural Gas Demand**	**Natural Gas Supply**	**LNG Exporting**
Baseline	No	Baseline	Baseline	Yes
Expected	20 MTPA over 30 years	Expected	Expected	Yes
High	20 MTPA over 40 years	High	High	Yes

C. Assumptions Regarding Baseline Projections of the Alaska Economy

We developed Baseline conditions for the Alaskan economy based upon N_{ew}ERA (largely based on AEO 2013) and ISER's economic projections regarding likely future economic and demographic conditions.[16]

ISER's Base case labor growth rate averages one percent per year through 2035. Assuming the labor growth rate is about half of the overall economic growth rate, implying labor productivity growth of 1% per year, we assume that the Alaskan economy grows at about 2% per year through 2035 and then declines a bit after this to reflect projections about shifts in demographics toward lower population growth and aging of the population.

The ELE Baseline demand is derived from AEO 2013 data and adjusted to be consistent with ISER's Base case forecast for the greater Anchorage area. This includes total demand load over time as well as peak load for each year. Specific ELE generating unit characteristics and fuel costs were calibrated to target current operating conditions in the ELE, and we particularly ensured that the generation mix by fuel source was in line with the current market. Additionally, although it is not yet under construction and is not in our default ELE generating unit database for N_{ew}ERA, we assume, consistent with the recent Federal planning approvals,[17] that Susitna will be constructed. Therefore, we include this new source of hydroelectric power in our generation build projections for the Baseline as well as the Expected scenario (but not the High scenario).

[16] Goldsmith, Scott, "Economic and Demographic Projections for Alaska and Greater Anchorage 2010–2035," in association with Northern Economics, December 2009.

[17] http://www.susitna-watanahydro.org/newsroom/news-releases/.

D. Assumptions Regarding Alaska Natural Gas Prices

The Cook Inlet natural gas market is structured differently than the Lower-48 natural gas market. It is not connected by a pipeline network to the Lower-48 and natural gas transactions take place between few buyers and sellers without a spot market. This unique structure means that natural gas prices are established through the bilateral negotiation of term gas sales and purchase agreements between a buyer and seller rather than the liquid market trading mechanisms of the Lower-48. The Regulatory Commission of Alaska (RCA) also ensures that the prices that are negotiated between buyers and sellers are reasonable. Natural gas prices in Alaska, in general, are pegged to a basket of Lower-48 price indices including natural gas, crude oil, and heating oil.[18] High oil prices in recent years have led to higher natural gas prices in Alaska relative to Lower-48 natural gas prices.[19] Additionally, the production from Cook Inlet is expected to decline in the future, as discussed in the following section.

In light of the projected scarcity of Cook Inlet production and the unique makeup of the natural gas market in Alaska, we assume Cook Inlet wellhead price to be 50 cents higher than the Lower-48 wellhead price in 2013 and indexed to the Lower-48 wellhead price in the Baseline in the absence of NS natural gas supplies.[20] It should be noted that the Cook Inlet price assumptions we use are not the price delivered to the end user and therefore do not take into account distribution costs. They essentially represent an assumed marginal cost of production of the Cook Inlet natural gas resource based on the literature and are most likely conservative estimates. If one were to assume higher Cook Inlet prices than we do in our analysis then the benefits accrued from the AKLNG project and the access to lower cost NS natural gas supplies would be even greater in magnitude than what our analysis indicates.

Figure 13 illustrates an overview of the natural gas flows in Alaska as handled in our analysis. NS natural gas is first treated prior to supplying the market through the dedicated pipeline. Part of the NS natural gas and Cook Inlet natural gas is comingled before it is supplied to end-users through the existing distribution network. A large volume of NS natural gas production is diverted to the liquefaction plant to produce LNG that is shipped to the international market. The cost of extracting NS natural gas and Cook Inlet natural gas is different in our analysis. In addition, we assumed distribution costs, natural gas treatment costs, pipeline tariffs, liquefaction costs, and storage/loading costs based on secondary sources. Based upon the analysis of Attanasi and Freeman, we estimated the cost of natural gas treatment at $1.50/MMBtu and the cost to

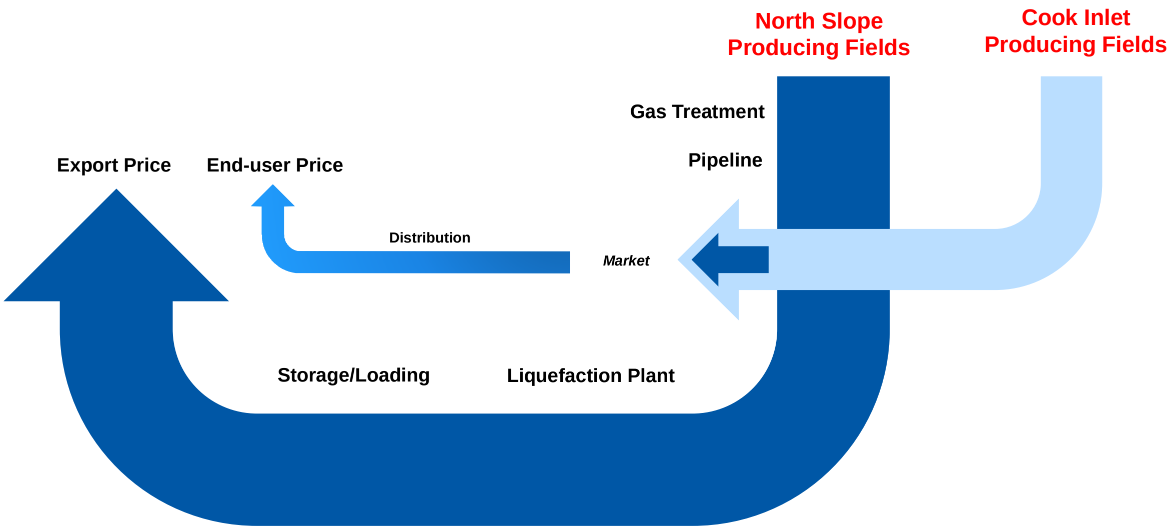
[18] Fay, Ginny and Saylor, Ben, "Alaska Fuel Price Projections 2010-2030," Institute of Social and Economic Research, University of Alaska Anchorage, July 30, 2010.

[19] According to EIA, Alaskan Citygate price was higher by 50 cents, 90 cents, and $1.40 in 2010, 2011, and 2012, respectively.

[20] To calibrate Cook Inlet prices to be close to the Lower-48, RCA approved a contract that is pegged to Lower-48 spot price index, Fay et al (2010).

transport the natural gas by pipeline to be approximately $2.60/MMBtu.[21] Our natural gas price modeling is based on competitive market pricing in South Central Alaska with supplies coming from both NS and Cook Inlet. The delivered price of natural gas to industrial users and utilities includes additional distribution costs in addition to the market price. The LNG export price is high enough to cover storage/loading, liquefaction, and pipeline costs in addition to the NS pipeline inlet price.

Figure 13: Overview of Alaskan Natural Gas Flows



We assumed that the first 30 Tcf of natural gas is supplied from the existing NS fields and has a relatively low cost of production. It is expected that in the early years the natural gas will be produced from existing NS fields as associated dissolved natural gas. Over time, as the existing fields deplete, it will be necessary to develop new fields on the NS to continue to supply the liquefaction plant. We assume that the price of natural gas into the liquefaction plant will increase with time reflecting the costs to find, develop, and produce from these new fields. The cost of the new natural gas will be greater than that of the existing gas to reflect the higher marginal cost of production.

The cost of extracting natural gas from existing fields is assumed to be about $0.30/MMBtu. The cost of natural gas increases to about $1.80/MMBtu as additional natural gas production from new fields comes online. Combining the intermediate costs yields an initial market price for natural gas of about $4.50/MMBtu at the LNG plant inlet in the first export period in 2023.[22]

[21] Attanasi, Emil D. and Freeman, Philip A., "Commercial Possibilities for Stranded Conventional Gas from Alaska's North Slope," Natural Resources Research, DOI: 10.1007/s11053-013-9213-9, International Association for Mathematical Geosciences, July 10, 2013, Table 4.

[22] The values cited do not sum because of rounding.

E. Assumptions Regarding Alaska Natural Gas Supply

NERA developed three different cases for natural gas supply in Alaska. We relied upon information from multiple sources including engineering consultants contracted by Locke Lord LLP,[23] ISER, and publicly available sources. Based upon these sources, we decided to divide the Alaska domestic natural gas reserves and resources into 1) NS resources and, 2) Cook Inlet and other Alaska natural gas (Cook Inlet) reserves and resources. Assumptions about the size of these resources are the two main variables in determining our Alaska natural gas supply curves. For Cook Inlet, we relied upon the engineering consultant's reserves and resources estimate of 2.4 Tcf. We calibrated the supply curve so that production in the Baseline is targeted to be approximately 90 Bcf per year until 2028 and declining thereafter.[24] For the NS resources, we also relied upon the engineering consultant's estimates for the range of potential resources. In total, 63 Tcf represents the lower estimate and 109 Tcf the upper estimate of the total Alaskan natural gas reserves and resources (*i.e.*, Cook Inlet plus NS). These estimates include 30 Tcf of recoverable natural gas from the NS fields that are currently producing.

These inputs were used in the construction of our three supply cases:

1. **Baseline –** This supply case assumes that the AKLNG project is not built, so NS natural gas resources are available only for oil field operations on the NS and not for either consumption in Alaska or export as LNG. The natural gas supply forecast for the rest of the U.S. is primarily based on AEO 2013. Natural gas necessary to meet Alaska domestic natural gas demand beyond the approximate 90 Bcf per year provided by Cook Inlet is met by foreign imports.[25]
2. **Expected –** In this supply case, the Alaskan natural gas pipeline and LNG facilities are built. We assume that 63 Tcf of the NS and Cook Inlet natural gas reserves and resources are producible. NS natural gas resources continue to be available to the domestic Alaska economy beyond 2052 when the 30-year export period ends.
3. **High –** This supply case is identical to the Expected case, with the exception that there is an additional 46 Tcf of NS natural gas resources available for a total of 109 Tcf of producible natural gas reserves and resources. As a result, the time period for exports in this analysis is extended to 40 years ending in 2062.

---

[23] DeGolyer and MacNaughton, "Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012."

[24] "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves," State of Alaska Department of Natural Resources, December, 2009. Available at: http://dog.dnr.alaska.gov/ResourceEvaluation/Documents/Preliminary_Engineering_and_Geological_Evaluation_of_Remaining_Cook_Inlet_Gas_Reserves.pdf.

[25] "Cook Inlet Natural Gas Production Cost Study," State of Alaska Department of Natural Resources, June, 2011. Available at: http://dog.dnr.alaska.gov/ResourceEvaluation/Documents/Cook_Inlet_Natural_Gas_Production_Cost_Study.pdf.

The price of natural gas into the liquefaction plant is estimated to be about $4.50/MMBtu starting in the year 2023. It is expected that in the early years after startup the natural gas will be proven natural gas produced from existing NS fields as associated dissolved natural gas. Over time, as the existing fields deplete, it will be necessary to develop new fields on the NS to continue to supply the liquefaction plant. We assume that the price of natural gas into the liquefaction plant will increase with time reflecting the costs to find, develop, and produce from these new fields.

F. Assumptions Regarding Alaska Natural Gas Demand

NERA developed three different sets of assumptions for expectations of natural gas demand in Alaska that are used in the scenarios:

1. **Baseline –** In this case, natural gas demand develops in line with the baseline forecast primarily based on AEO 2013.
2. **Expected –** In this case, demand for natural gas in Alaska develops in line with the baseline economic forecast and is derived relative to the increased natural gas supplies in the Expected Supply case.
3. **High –** The Alaskan economy is assumed to grow 50% faster than in the Expected scenario. Furthermore, this scenario assumes mining projects are more prevalent and there is greater natural gas consumption throughout the economy. On the electric side, Susitna is assumed to never come online.

We consulted several sources to develop our baseline projection for natural gas consumption with and without the AKLNG project.[26]

The bottom-up construction of natural gas demand divides natural gas use into five key categories, each of which is discussed in turn:

1. End-use demand in the Southern Railbelt;
2. End-use demand in the Northern Railbelt;
3. End-use demand for mining or industrial projects;
4. Demand for natural gas in the oil fields; and

[26] Fay, Ginny, Meléndez, Alejandra Villalobos, and West, Corinna, "Alaska Energy Statistics: 1960-2011 Preliminary Report," November, 2012.

Goldsmith, Scott in association with Northern Economics, "Economic and Demographic Projections for Alaska and Greater Anchorage 2010–2035," prepared for HDR Alaska, Inc., December, 2009.

"Appendix B: In-State Needs Study - In-State Gas Demand Study Volume I: Report," Northern Economics in association with Institute of Social and Economic Research of Anchorage and Science Applications Incorporated Corporation, January, 2010.

Stokes, Peter, "Cook Inlet Gas Study - 2012 Update," Petrotechnical Resources of Alaska, October, 2012.

5. Demand for natural gas associated with the export of LNG (this includes the export volumes themselves and all losses associated with taking the natural gas out of the ground and delivering it as LNG to the tanker).

1. Railbelt Demand

Demand in the Southern Railbelt comprises three primary categories: space heating (commercial and residential), electricity, and other (includes military, trucking, and industrial). In 2013, space heating, electricity, and other are assumed to consume 90, 105, and 48 MMcf/d of natural gas, respectively. Natural Gas demand for space heating is forecasted to grow at 1.1% for the Expected scenario and 1.6% for the High scenario.

For electric sector natural gas demand, we made use of our bottom-up electricity model, calibrated to the North American Electric Reliability Corporation (NERC) forecast for ELE demand. A key assumption centers on Susitna. In the Baseline and Expected scenarios, this unit comes online in 2023, which initially reduces natural gas demand from the electric sector. For the High scenario, this unit never comes online.

Initially, natural gas demand in the Baseline from other sectors drops with the decline in industrial activity in the Southern Railbelt: LNG exports cease and chemical plants close. But over time, with the growth of the economy demand from other sectors is expected to increase.

Demand in the Northern Railbelt is initially close to zero. But by the 2020 time frame, the Northern Railbelt is assumed to have access to NS natural gas for space heating and electricity generation. Given the smaller population, the demand is about a quarter of that of the Southern Railbelt.

2. Mining and Other Industrial Demand

In the Expected case, we assume a mine similar in size to the proposed Pebble Mine, consuming natural gas estimated at 40 MMcf/d, to be fully operational by 2025. This demand is in addition to the demand from the Flint Hills refinery and the Livengood mine, which are estimated to total about 20 MMcf/d by the 2025 time period.[27] In the High case, the level of mining and other activities is assumed to peak at 220 MMcf/d. In this scenario, we assume that about three to four large mining projects are undertaken and either a chemicals plant is built or the old chemicals plant is brought back online.

[27] At the time of the analysis herein, NERA assumed that the Flint Hills refinery would continue refining operations. Flint Hills subsequently announced that the refinery will shut down in 2014 and become an oil shipping and storage terminal. http://www.alaskadispatch.com/article/20140204/blow-fairbanks-flint-hills-says-it-will-close-down-north-pole-refinery. If the Flint Hills refinery shuts down, accounting for this change would have no material effect on the results and conclusions of this report.

3. Project Demand

Demand associated with the oil field operations on the NS is assumed to remain the same in all scenarios for all years.[28] Natural gas use in these fields is estimated to be 255 Bcf/yr.[29]

Demand associated with natural gas export from LNG includes:

- Export of LNG is 20 MTPA (929 Bcf/yr after ramp-up).[30]
- Losses from transporting and liquefying the natural gas amount to 171 Bcf/yr (after ramp-up).[31]

Figure 14 summarizes Alaska's natural gas demand for the three different cases.

Figure 14: Alaska Natural Gas Demand Assumptions by Scenario (Tcf/yr)

Scenario	2013	2018	2023	2028	2033	2038	2043	2048	2053	2058
Baseline	0.35	0.36	0.36	0.36	0.37	0.38	0.38	0.39	0.40	0.41
Expected	0.35	0.36	1.25	1.49	1.50	1.51	1.52	1.53		
High	0.35	0.36	1.28	1.54	1.58	1.61	1.62	1.67	1.72	1.78

G. Assumptions Regarding International LNG Market Conditions

This section summarizes the information developed by the GNGM that were used as inputs into the N_{ew}ERA model. We used GNGM to develop three sets of input assumptions for the N_{ew}ERA model:

---

[28] Upstream lease operations fuel is assumed to remain flat to allow for an expected decrease in Prudhoe Bay Unit compression fuel that will serve to offset the potential increased fuel in other existing operations or new fields.

[29] Upstream lease operations fuel estimate is average fuel use for years 2007 through 2011 based on EIA data. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SAK_a.htm.

[30] Using the conversion factor of 1 million metric tons of LNG is equivalent to 46.467 Bcf of natural gas. U.S. Department of Energy, "Liquefied Natural Gas: Understanding the Basic Facts," at p. 9. Available at: http://energy.gov/sites/prod/files/2013/04/f0/LNG_primerupd.pdf. This conversion is appropriate for the AKLNG project because the relatively high heating content (Btu/cubic foot gas) and associated physical characteristics of LNG that would be produced by the AKLNG project are expected to approximate those reflected in this particular conversion table.

[31] LNG-related fuel/shrinkage is assumed to be 15.5% of the upstream hydrocarbon stream or "upstream feed" of 1100 Bcf/yr excluding upstream lease operations fuel usage.

1. Baseline U.S. LNG Exports (Alaska exports are assumed to be zero, so all exports are from the Lower-48);
2. Expected scenario U.S. LNG exports (includes Lower-48 and Alaska LNG exports) and Expected scenario Alaska LNG exports; and
3. LNG prices FOB at the terminal outlet in Alaska.

The details of the GNGM results used as inputs into N_{ew}ERA are provided in Figure 15 below.

Figure 15: Details of GNGM Results Used for AKLNG Project Analysis in N_{ew}ERA

	2013	2018	2023	2028	2033	2038	2043	2048
U.S. LNG Exports – Baseline (Tcf)	-	0.43	0.30	1.04	1.13	1.14	1.14	1.14
U.S. LNG Exports – Expected (Tcf)	-	0.43	0.83	1.68	1.70	1.72	1.72	1.72
AK LNG Exports – Expected (Tcf)[32]	-	-	0.74	0.93	0.93	0.93	0.93	0.93
AK LNG Export Prices[33] (2010$/Mcf)	-	-	$12.76	$14.19	$15.70	$17.43	$17.43	$17.43

H. Assumptions Regarding AKLNG Export Project

1. Project Assumptions

As stated in publicly available documents, the preliminary capital estimate for the AKLNG project is $45-65 billion incurred over a period of about 10 years. In order to infer the timing of the various capital expenditures within the 10 year construction timeline, NERA utilized the AKLNG work plan presented to Alaska legislators in February 2013[34] and elements of a more detailed investment profile for the Wheatstone LNG project in Australia as estimated in a proprietary data source supplied by Locke Lord.[35] Distinct from the Wheatstone LNG project, the AKLNG plant requires the construction of an 800+ mile long, 42-inch diameter pipeline thus, making the initial phases of the AKLNG project substantially more expensive than Wheatstone.

---

[33] These prices represent the LNG price at the dock.

[34] "Alaska South Central LNG Project Overview for Alaska Legislators," February 19, 2013. Available at: http://www.gasline.alaska.gov/newsroom/Presentations/SCLNG%20-%20HRES%20Lunch%20&%20Learn%202.19.13.pdf.

[35] "Asset Analyses - Australia- Australia Onshore - Wheatstone LNG," Wood Mackenzie, April, 2013.

The investment profile was computed based on investment profile of the Wheatstone LNG project. Figure 16 indicates the shape of the investment profile of the average annual capital expenditure inputs for the project in the N_{ew}ERA model. We assumed the total cost of the AKLNG project to be $65 billion.

Figure 16: LNG Investment Profile (2010$ billion)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Cost	$3.25	$3.25	$4.71	$4.71	$7.96	$7.96	$7.96	$7.96	$12.68	$3.25	$1.30
Percentage of Total Cost	5%	5%	7%	7%	12%	12%	12%	12%	20%	5%	2%

Using the above investment share, the following average annual capital expenditures were assumed as inputs for the capital investment aspect of the pipeline in the N_{ew}ERA model:

- 2013 model year input (average of 2013 through 2015 costs), $3.74 billion;
- 2018 model year input (average of 2016 through 2020 costs), $7.31 billion; and
- 2023 model year input (average of 2021 through 2023 costs), $5.74 billion.

The pipeline is assumed to have an initial capacity of 3.2 Bcf/d that the model allows to be expanded to meet demand at a cost equal to the average cost of the initial pipeline.[36]

The main taxes and royalty calculations were derived from Alaska and Federal government sources and include:

- Production tax rate on the gross value at the point of production in the field minus production costs of non-royalty natural gas;
- Property tax rate (based on assessed value of property, plant and equipment instead of the value of production, and currently represents 2% of gross wellhead value);
- Royalties;
- Federal Corporate Income Tax (35%) applied to the economic profit; and
- State Corporate Income Tax (9.4%) applied to the economic profit.

The 35% production tax rate applies to both oil and natural gas produced in the state under Alaska Statute 43.55.011(e) as amended by chapter 10 of the 2013 Session Laws of Alaska.

[36] "Alaska South Central LNG Project Overview for Alaska Legislators," February 19, 2013. Available at: http://www.gasline.alaska.gov/newsroom/Presentations/SCLNG%20-%20HRES%20Lunch%20&%20Learn%202.19.13.pdf.

According to the Alaska Department of Natural Resources Division of Oil and Gas the particular royalty rate applicable in a given situation varies from case to case and is based on the associated lease agreement. However, they also state that the most frequently seen rate is 12.5% so that is the level we chose to assume for our inputs.[37] This is not intended to imply any insight into any potential royalty rate agreements that may be negotiated in the future but is simply a representative assumption based on the Alaska Department of Natural Resources Division of Oil and Gas own statements and data.

[37] Typical royalty rate, as stated by the Alaska Department of Natural Resources Division of Oil & Gas. Available at: http://dog.dnr.alaska.gov/Royalty/Accounting.htm.

IV. STUDY RESULTS

This section provides the results of our analysis. We organize the results into the following sections:

- Alaska Energy Market Impacts;
- Alaska Macroeconomic Impacts;
- U.S. Energy Market and Macroeconomic Impacts; and
- U.S. Emissions Impacts.

A. Alaska Energy Market Impacts

This section discusses the impacts on the Alaska energy markets as a result of implementing the AKLNG project scenarios against a Baseline without any LNG exports from Alaska.[38]

1. Natural Gas Market Impacts

In the Baseline, no pipeline exists connecting the NS with the Southern Railbelt. Thus the only Alaskan natural gas supplies that can satisfy Southern Railbelt natural gas demand originate from Cook Inlet. There is believed to be sufficient probable reserves and resources (when taking into account the broader categories of reserves and resources) in the Cook Inlet so that if drilling and exploration were to increase markedly, Southern Railbelt demand could be met for the most part with Cook Inlet produced natural gas through 2030. But thereafter, recoverable reserves are forecasted to decline rapidly. Or put differently, the cost of extracting natural gas from the Cook Inlet becomes increasingly more expensive over time. Thus Southern Railbelt demand must be met with greater amounts of imported LNG, which is significantly more expensive than natural gas delivered from the NS.

In the Expected scenario, a pipeline is built so that NS natural gas supplies can be transported to the Southern Railbelt region. The difference between NS wellhead prices, inclusive of natural gas treating costs, and delivered market prices for in-state consumer use is the tariff that recovers the investment in the pipeline that connects the NS producing area with the Southern Railbelt and the liquefaction plant. The Cook Inlet price is set by supply and demand and competition between Cook Inlet and NS natural gas supplies. Cost of production at the NS will increase with cumulative production, as currently unmarketable natural gas production from Prudhoe Bay and

[38] This assumes no exports from the Conoco-Phillips Kenai plant, which was off-line at the time of our analysis. ConocoPhillips Alaska Natural Gas Corporation filed an application with DOE/FE on December 11, 2013, to export a total of 40 Bcf of natural gas from its Kenai plant over a two-year period. If this facility begins exporting gas again, accounting for this change would have no material effect on the results and conclusions of this report. If granted by DOE/FE, ConocoPhillips Alaska Natural Gas Corporation's two-year export authorization will have been completed well before the AKLNG project would commence operation.

other existing fields must be augmented by new exploration and production in new areas of the NS.[39]

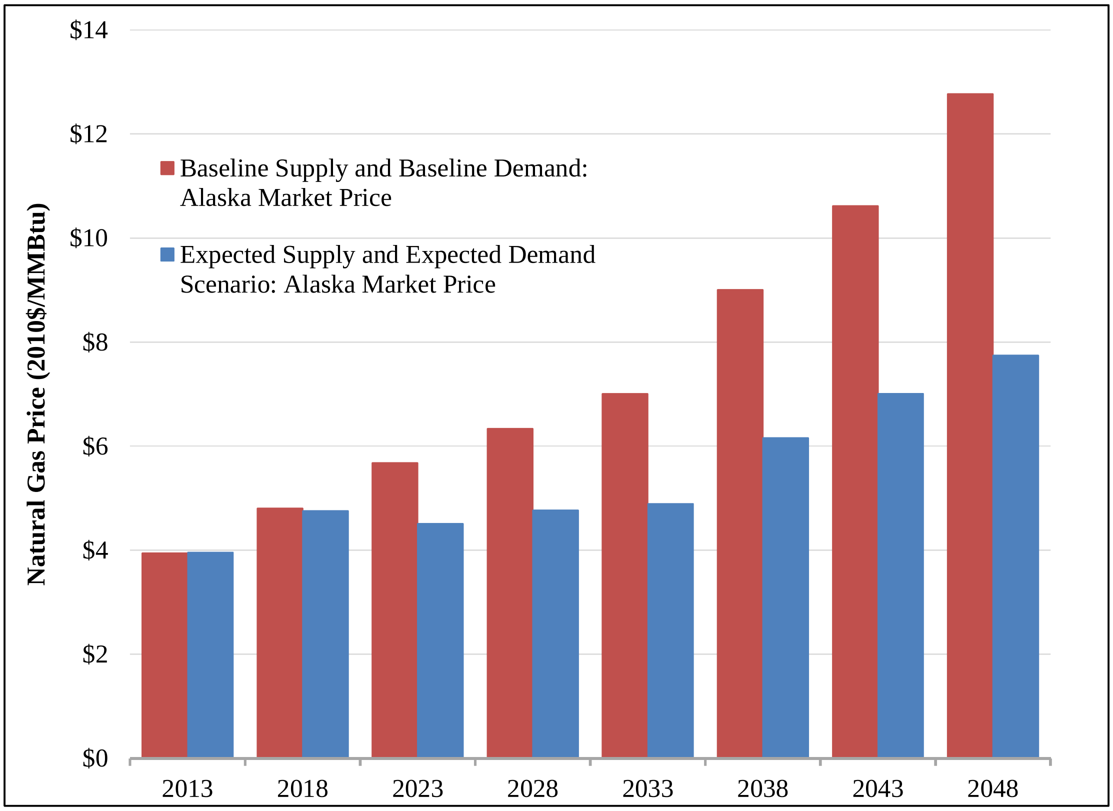
The cost of this NS natural gas is well below that of Cook Inlet and imported natural gas because NS natural gas supplies are far more abundant than Cook Inlet and do not require the transportation cost included in the price of imports to Alaska. The Alaskan market price is the price of natural gas to consumers; whereas the NS wellhead price is the price NS natural gas producers charge at the point of inlet to the pipeline. The natural gas market price in Alaska is composed of a weighted average of the Cook Inlet wellhead price and the NS wellhead price (which includes gas treating costs) plus pipeline costs. Therefore, the natural gas market price in Alaska decreases in the Expected scenario relative to the Baseline once increased supply from NS resources becomes available.

The natural gas price path and its response in the scenarios will depend on the availability and accessibility of natural gas resources in NS and also potential structural shifts in Alaska's economy that might be triggered by greater natural gas availability. The primary driver of the reduced natural gas market price in Alaska is the low cost supply coming from the NS. The NS wellhead price (which includes gas treating costs) plus the cost of pipeline transportation ranges from $4.47/MMBtu to $7.17/MMBtu during the period between 2023 and 2048. Figure 17 shows the natural gas market price to consumers in Alaska for the Baseline and Expected scenarios.

Under the Expected scenario, the Alaska market price of natural gas for in-state consumer use increases significantly less over time than in the Baseline when no NS natural gas is available. By 2048, the Alaska market price of natural gas is $5.02/MMBtu less in the Expected scenario with exports compared to the Baseline, a 39% price difference. The Expected scenario's lower price relative to the Baseline occurs even though over one Tcf per year of the natural gas extracted from the NS goes toward LNG exports (including LNG-related fuel use and shrinkages).

[39] NS natural gas and Cook Inlet natural gas are assumed to be differentiated products and comingled as an Armington aggregate at the market place.

Figure 17: Expected Supply and Expected Demand Scenario Alaska Natural Gas Market Prices (2010$/MMBtu)



Note: NERA adopted the net-forward pricing to establish a baseline market price path for modeling economic impact and benefits. The market price that NERA estimated is subject to uncertainties influenced by many factors and claims no knowledge of the ultimate negotiated market price. The model estimates overall net benefits regardless of how benefits and costs are distributed across various end-users and consumers.

The drop in natural gas prices over time induces additional consumption of natural gas in Alaska's economy, ignoring natural gas usage associated with the production and delivery of natural gas and LNG from the NS. By 2048, total Alaskan natural gas consumption is about 10% higher in the Expected scenario than the Baseline. The greatest expansion in natural gas use occurs in the residential sector (C) and natural gas intensive industries. Figure 19 shows that the total natural gas produced over the modeling horizon never exceeds the NS and Cook Inlet resource constraints assumed in this analysis (as specified in Section III.E above).

This expansion in natural gas demand is met primarily through the increased production levels of NS natural gas as can be seen in Figure 19. Cook Inlet natural gas production also continues to contribute to total Southern Railbelt supplies although to a much lesser degree and at lower levels over time given the diminishing economically accessible resources there.

Figure 18: Expected Scenario Alaska In-State Natural Gas Demand by Sector (Bcf/yr)[40]

Sector	2013	2018	2023	2028	2033	2038	2043	2048	Cumulative Total (Tcf)[41]
Electricity	36	39	25	33	39	42	44	51	1.5
Commercial	23	23	27	30	32	34	37	41	1.2
Residential	22	24	34	36	38	41	43	46	1.4
Manufacturing	6	7	14	17	16	17	16	16	0.5
Government	5	4	4	5	5	5	6	6	0.2
Energy-Intensive	4	5	10	13	13	14	14	14	0.4
Trucking Transportation	0	0	0	0	0	1	1	1	< 0.1
Other Transportation	0	0	0	0	0	0	0	0	< 0.1
Upstream Lease and Operations Fuel[42]	255	255	255	255	255	255	255	255	10.2
Sectoral Total	353	357	370	388	399	409	417	431	15.6
Total Change from Baseline	0	0	16	25	31	33	34	40	0.9

Figure 19: Expected Scenario Alaska Natural Gas Production by Source (Tcf/yr)

Source	2013	2018	2023	2028	2033	2038	2043	2048	Cumulative Total (Tcf)[43]
NS	0.26	0.26	1.18	1.42	1.45	1.47	1.51	1.52	45.3
Cook Inlet	0.09	0.10	0.07	0.07	0.05	0.04	0.01	0.01	2.2
Total	0.35	0.36	1.25	1.49	1.50	1.51	1.52	1.53	47.5

[40] The items and totals in this table exclude feed gas and fuel/shrinkage requirements.

[41] Cumulative totals may not equal the sum of all years due to differences in rounding.

[42] Upstream lease operations fuel estimate is average fuel use for years 2007 through 2011 based on EIA data. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SAK_a.htm.

[43] Cumulative totals may not equal the sum of all years due to differences in rounding.

2. Electricity Market Impacts

Increased supply of natural gas leads to lower natural gas prices and then cheaper delivered electricity prices. This would be a boon for the local economy and could encourage economic growth and improve welfare. Additionally, a greater amount of fuel-switching would occur in Alaska, primarily towards cheaper power generated from natural gas. In the Expected scenario, the abundant supplies of low cost natural gas resources results in a higher degree of availability and use of natural gas-fired generation, as seen in Figure 20. This switch to lower cost fuel results in lower delivered electricity prices to all sectors, as seen in Figure 21.

Figure 20: Expected Scenario Share of Alaska Electricity Generation from Natural Gas (%)

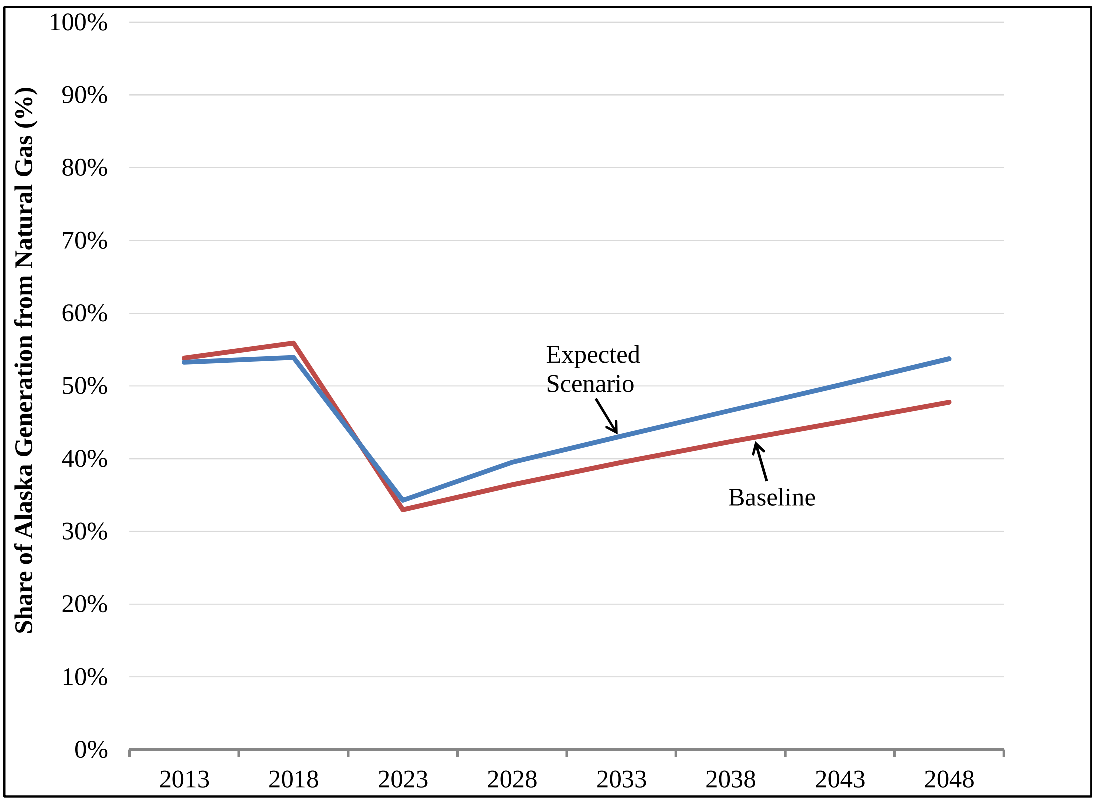
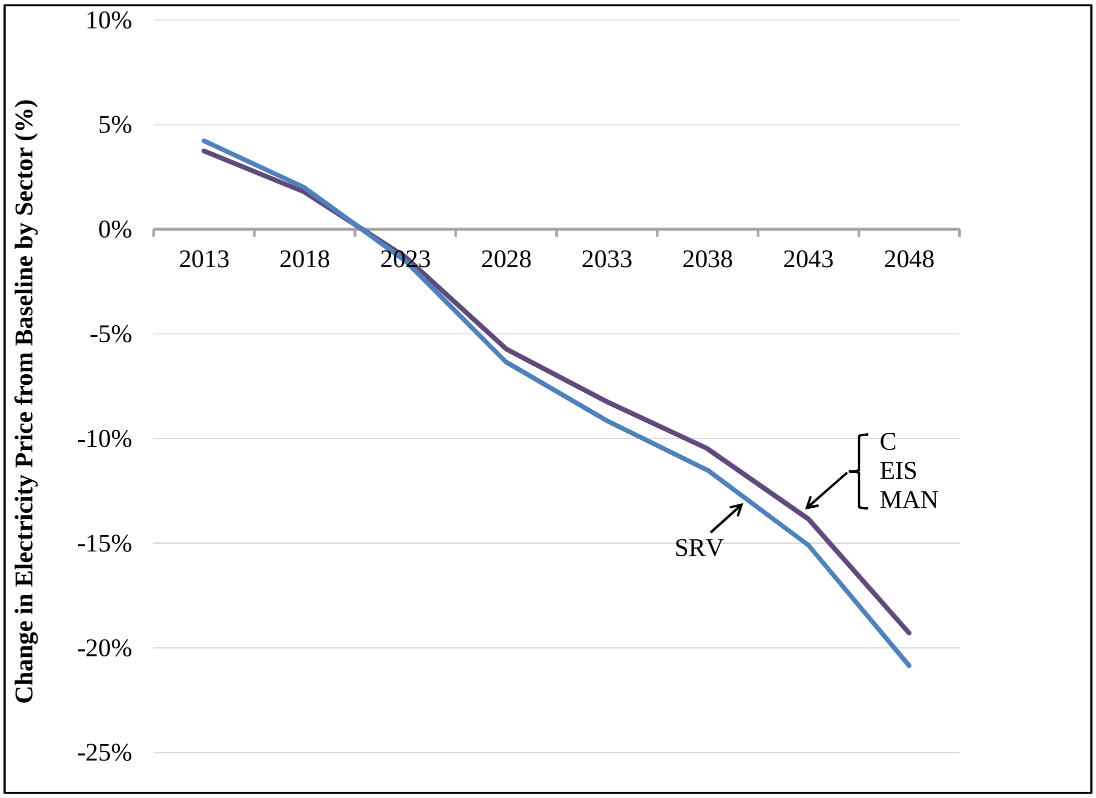


Figure 21: Expected Scenario Change in Alaska Delivered Electricity Price Compared to Baseline, by Sector[44] (%)



B. Alaska Macroeconomic Impacts

This section discusses the overall macroeconomic impacts on Alaska for the Expected scenario as a result of incorporating the implementation of the AKLNG project and comparing the results against the Baseline scenario, which assumes no LNG exports from Alaska. We report economic measures such as welfare, aggregate consumption, disposable income, GSP, and loss of wage income to illustrate the impact of the scenarios.

1. Welfare

Economic welfare is a concept used by economists that relates to the overall utility that individuals experience from the economy. In N_{ew}ERA, welfare is measured by the sum of the values of household consumption and leisure. Technically, welfare is measured as a Hicksian equivalent variation for the representative agent in the model. The equivalent variation measures

[44] The sectors referred to in this chart are C, Energy-Intensive Sectors (EIS), Manufacturing Sector (MAN), and Services Sector (SRV).

the monetary impact that is equivalent to the change in consumers' utility from the price changes and provides an accurate measure of the impacts of a policy on consumers.[45]

Expansion of natural gas exports changes the price of goods and services purchased by Alaska consumers. In addition, it also alters the income level of the consumers through increased wealth transfers in the form of tolling charges on LNG exports. These economic effects change the well-being of consumers as measured by equivalent variation in income.

A positive change in welfare means that the policy improves welfare from the perspective of the consumer. The results of the Expected scenario indicate that LNG exports are welfare-improving for Alaska consumers. Consumers[46] receive additional income from two sources. First, the LNG exports provide additional export revenues, and second, consumers who are owners of the liquefaction plants, receive take-or-pay tolling charges[47] for the amount of LNG exports. The increase in discounted present value of welfare from the Baseline to the Expected scenario over the export period is approximately $1.4 billion.

2. Gross Regional Product

GDP, or GSP, is another economic metric that is often used to evaluate the effectiveness of a policy; it measures the level of total economic activity in the economy of interest, country, or state, respectively. Figure 22 depicts the changes in Alaska GSP over time. In the short run, the GSP impacts are positive as the economy benefits from capital investment in the infrastructure to bring NS natural gas to the market, increased taxes and royalties, and increase in labor income associated with increased labor demand.[48] In the long run the LNG exports have a strong positive impact on GSP through increased export revenues and additional wealth transfer in the form of tolling charges. Capital income represents the distributed share of ownership of the resource from the household level. Tax income accounts for approximately one-third of GSP increases in Alaska and is recycled back into the Alaska economy.

---

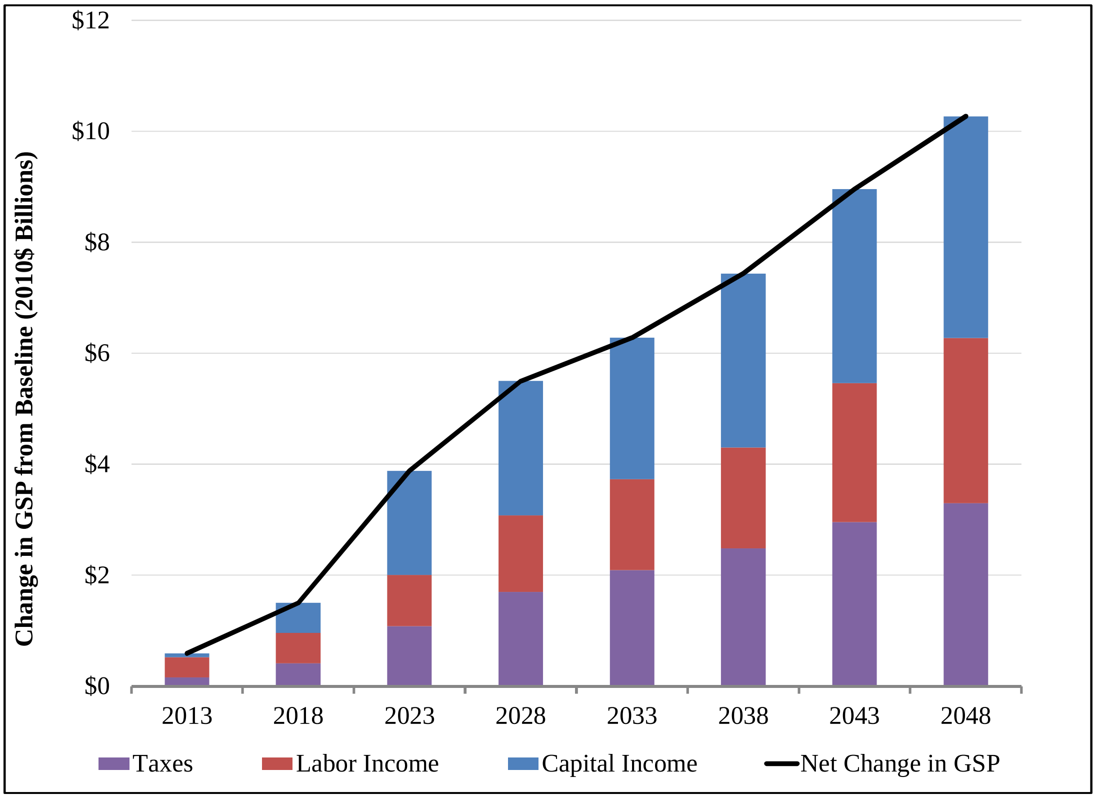
[45] Varian, Hal, "Intermediate Microeconomics: A Modern Approach", 7th Edition, W.W. Norton & Company, December, 2005, pp. 255-256. "Another way to measure the impact of a price change in monetary terms is to ask how much money would have to be taken away from the consumer *before* the price change to leave him as well off as he would be *after* the price change. This is called the **equivalent variation** in income since it is the income change that is equivalent to the price change in terms of the change in utility." (emphasis in original)

[46] Consumers own all production processes and industries by virtue of owning stock in them.

[47] Note that NERA, for convenience, is assuming a tolling structure for illustration purposes. While alternative structures might change the mechanism the ultimate economic impacts would not be significantly different.

[48] Direct resource income from developing natural gas resources has been decomposed into capital income, labor income, and taxes.

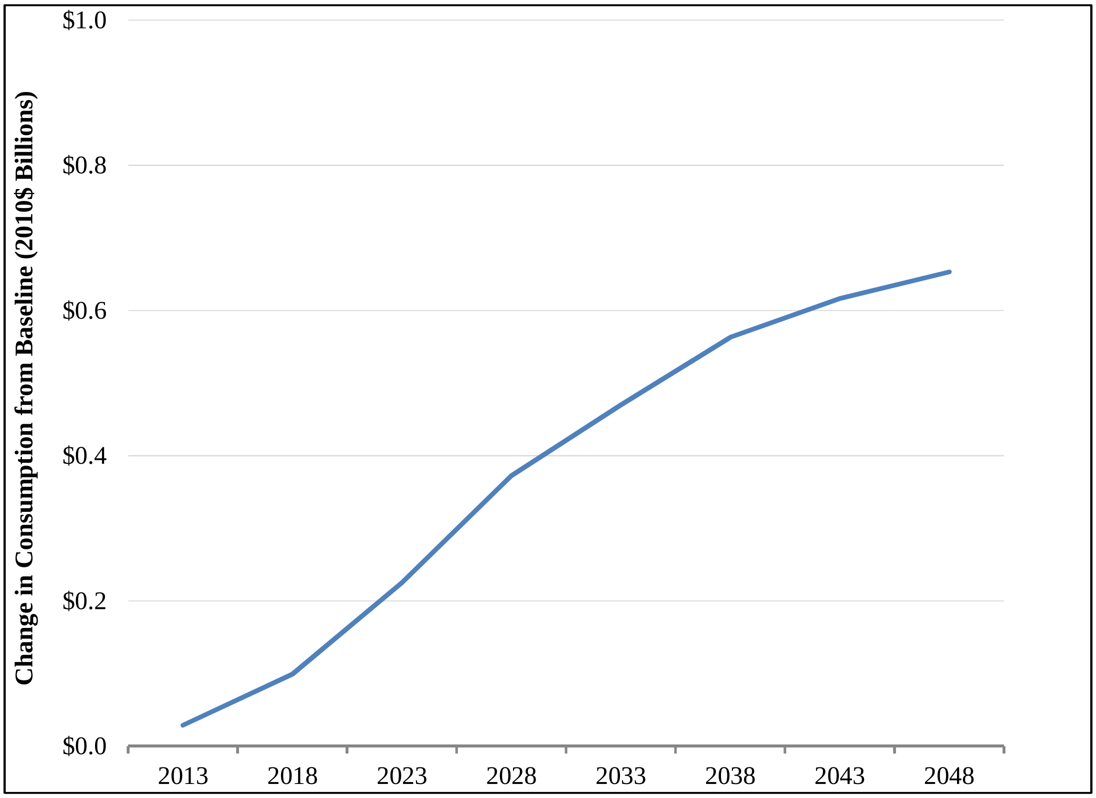
Figure 22: Expected Scenario Change in Alaska GSP Compared to Baseline (2010$ Billions)



3. Aggregate Consumption

Aggregate consumption measures the total spending on goods and services in the economy. Higher aggregate spending or consumption resulting from a policy suggests higher economic activity and more purchasing power for the consumers. Figure 23 shows the Expected scenario results where consumption increases over time due to increased benefits from the LNG export revenue and increased economic activity within Alaska.

Figure 23: Expected Scenario Change in Alaska Consumption Compared to Baseline (2010$ Billions)



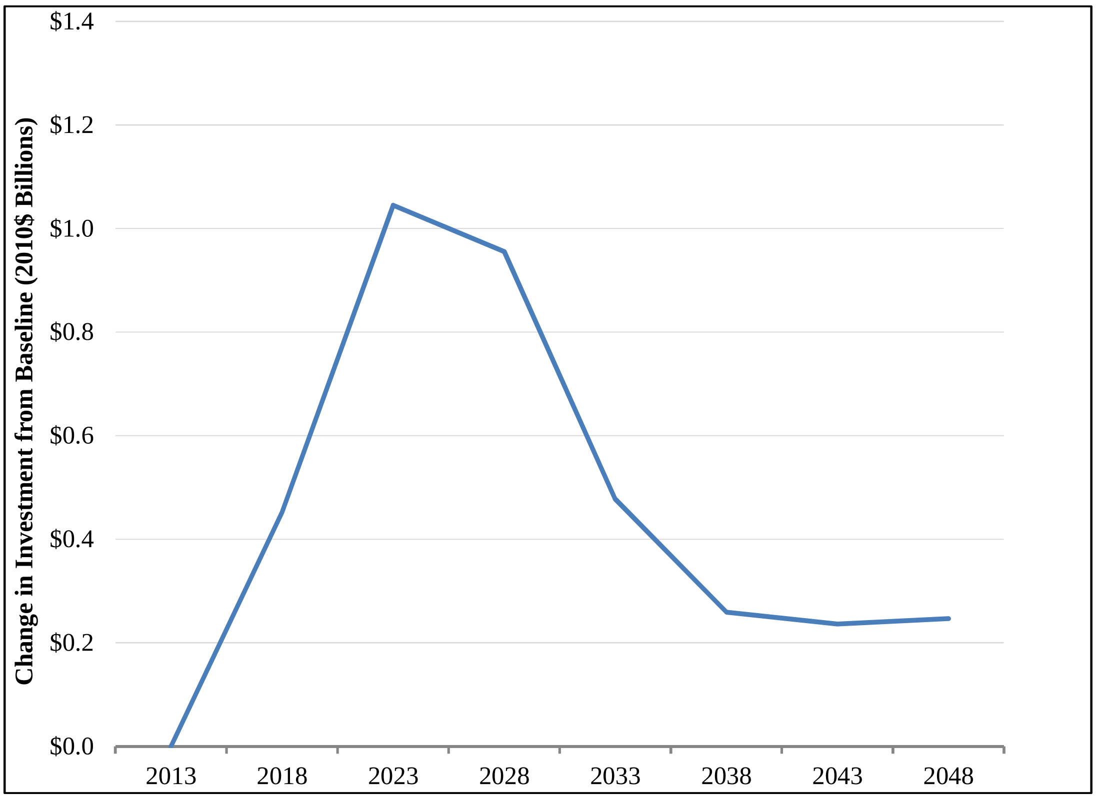
4. Aggregate Investment

Investment in the economy occurs to replace old capital and increase the stock of capital in place (net investment). In this study, additional investment takes place to finance the AKLNG project through the construction of export facilities and the pipeline that will transport natural gas resources from the NS to the export facilities. Investment in new natural gas production capacity is also required over time as NS production moves from the established Prudhoe Bay area into Point Thompson and other new areas. Net investment in Alaska is measured as the increase in the total stock of productive capital in Alaska, which in the scenario includes the value of the gas treating plant, the pipeline, the liquefaction plant, and structures, machinery, and equipment put in place in other industries and in NS natural gas fields.

Figure 24 shows that net investment in Alaska is higher in the Expected scenario than in the Baseline in all years, due to construction of the AKLNG project as well as expansion of other industrial sectors due to the greater availability and lower price of natural gas in the scenario. Financing for this total investment mostly comes from a national pool of investment capital, with a proportional share of investment from Alaska. Though most of the equipment to be installed in the pipeline and liquefaction facility and used for construction and for NS exploration and production will be manufactured in the Lower-48 or in other countries, when installed in Alaska it becomes part of the capital stock located in the state and is counted as investment in the State. The timing of the changes in investment from the Baseline seen in Figure 24 reflect the timing of the AKLNG project itself with the largest increases seen during years of construction in 2018, 2023, and 2028.

Alaska is able to attract more investment from the rest of the U.S. in the Expected scenario relative to the Baseline because of its lower natural gas prices as well as the opportunity presented by the AKLNG project, and this inflow of investment leads to Alaska having greater economic growth in the scenario than in the Baseline. This greater economic growth and the greater amount of outside investment allow Alaskans to increase their consumption and hence be better off than in the Baseline.

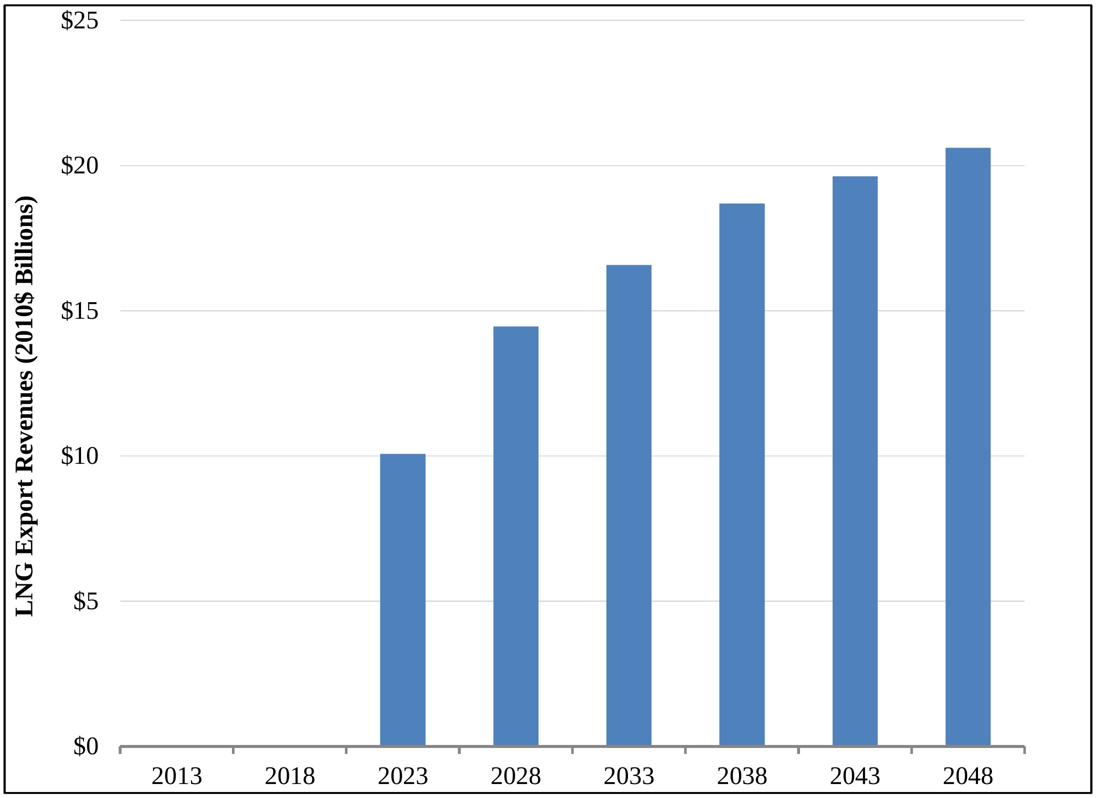
Figure 24: Expected Scenario Change in Capital in Place in Alaska Compared to Baseline (2010$ Billions)



5. Natural Gas Export Revenues

As a result of higher levels of natural gas exports, LNG export revenues offer an additional source of income to the economy. The average annual increase in revenues from LNG exports ranges from about $10 billion to almost $21 billion (2010$) for Alaska as seen in Figure 25.

Figure 25: Expected Scenario Average Annual Alaska LNG Export Revenues (2010$ Billions)



6. Trade Impacts

The development of the infrastructure to export LNG (*i.e.*, the export facility and connecting pipelines) and the exporting of LNG contribute to the increasing LNG export revenues shown above, but trade in other goods and services depends on how prices and costs in Alaska change relative to its competitors. The development of NS natural gas resources lowers the cost of natural gas in Alaska which lowers the cost of Alaskan goods dependent on natural gas consumption. However, with the construction of the LNG facility and associated pipelines, wage rates and capital costs increase in Alaska thus raising costs of production.

Overall, we see an increase in net foreign exports from Alaska as a result of LNG exports from baseline levels. This results in a large increase in the foreign current account balance. However, on the domestic side, to support higher domestic consumption, as a result of higher income levels, Alaska imports more from the Lower-48. On the whole, the increase in export revenues from LNG exports dominates any decrease in revenues from imports of other goods and services from the rest of the U.S. and results in significant improvement in the terms of trade position for Alaska. In net, the improvement in the current account balance for Alaska is between $10 and $20 billion.

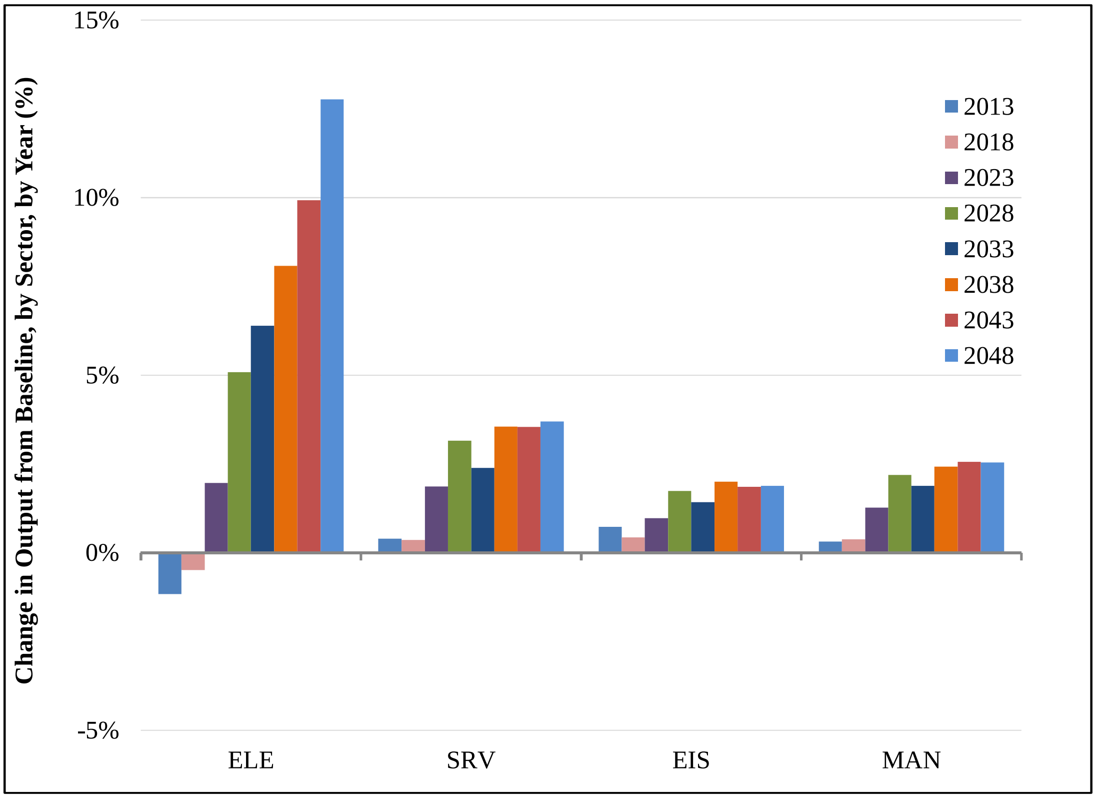
If we only look at net exports of goods and services excluding LNG, Alaska's net foreign exports are still higher. This suggests that Alaska prefers to import from the Lower-48 and export to the international market to take advantage of the lower natural gas prices.

7. Sectoral Output Changes for Some Key Economic Sectors

The effect of changes in natural gas prices on a particular sector depend on the sector's natural gas intensity and how easily the natural gas use can be substituted with other factors of production and intermediate goods and services. Economic sectors such as the ELE, EIS, and MAN are dependent on natural gas as a fuel and are therefore particularly impacted by changes in natural gas price. Another potentially significant benefit of the lower natural gas prices in Alaska is the possibility of attracting new development such as chemicals or mining to the state or restarting mothballed chemicals facilities. Additionally, natural gas producers and sellers will benefit from natural gas export prices and increased output. These varying impacts will shift income patterns between economic sectors. The overall effect on the economy depends on the degree to which the economy adjusts by fuel switching, introducing new technologies, and the stimulus of new investment.

Figure 26 illustrates how the range of impacts on sectoral output varies considerably by sector. The ELE and SRV sectoral output changes are the largest in the Expected scenario. The ELE, being the most dependent on natural gas and the one able to most easily switch from other fuel inputs to natural gas, sees the largest changes in gas usage – up by almost 13% in 2048. The SRV sector sees output gains starting early on due to the increased economic demand from the start of the pipeline project construction and increases as much as 4% by 2048 due to lower natural gas prices as compared to the Baseline. EIS and MAN see similar patterns of sectoral growth in the expected scenario as SRV although to a slightly smaller degree with maximum output increases of 2% and 3%, respectively. Availability of NS natural gas and sustained lower natural gas prices allow the industrial base to expand and maintain a higher growth path into the future in Alaska.

Figure 26: Expected Scenario Changes in Output for Key Alaska Economic Sectors Compared to Baseline (%)



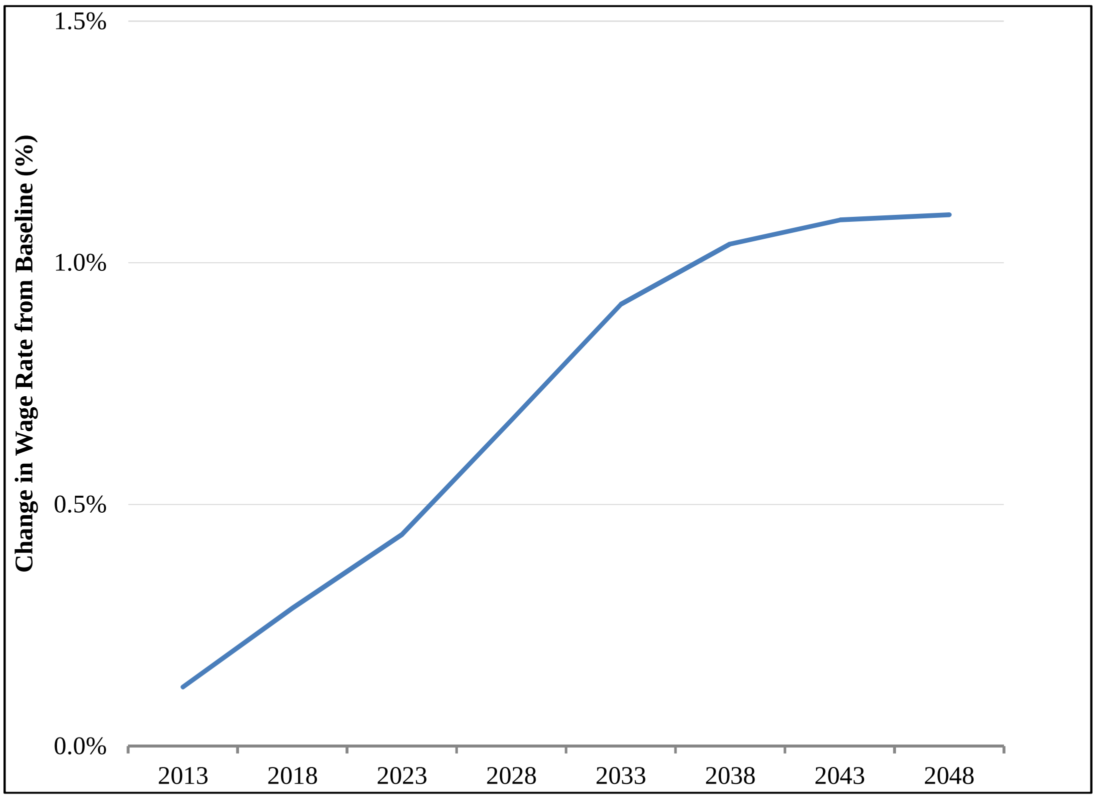
8. Wage Rates

Sectoral output, discussed in the previous section, translates directly into changes in factors of production for a given sector. In general, if the output of a sector increases so do the inputs associated with the production of this sector's goods and services. An increase in natural gas output leads to more wage income in the natural gas sector as domestic production increases. In the short run, industries are able to adjust to changes in demand for output by increasing employment if the sector expands or by reducing employment if the sector contracts.

As shown in the previous section, the production of lower cost natural gas lowers delivered natural gas prices and causes production costs for Alaskan industries, hence making Alaska businesses more competitive. The net result is increased output across key sectors. Because the Alaskan economy is supported by a small labor market, wage rates in Alaska could potentially increase significantly if it were to meet the increased demand for labor to support pipeline construction, oil and natural gas production, and increased industrial output with only Alaskan residents.[49] Instead, the demand for labor which results in wage rate increases attracts workers from other states to move to Alaska, either temporarily or permanently. The supply of out-of-state labor in meeting the increased labor demand in Alaska for the Expected scenario helps moderate the increase in wage rates, particularly in the early years when the pipeline and LNG facility are constructed. Toward the end of the export horizon, the increase in wage rates flattens due to smaller increase in labor demand, relative to the Baseline, as a result of the labor market anticipating the end of the LNG export period and the commensurate boon to economic activity.

Figure 27 shows the change in total Alaska wage rate for the Expected scenario as compared to the Baseline. Overall wage income increases in all sectors commensurate with the increase in wage rates.

Figure 27: Expected Scenario Change in Alaska Wage Rate Compared to Baseline (%)



C. U.S. Energy Market Impacts

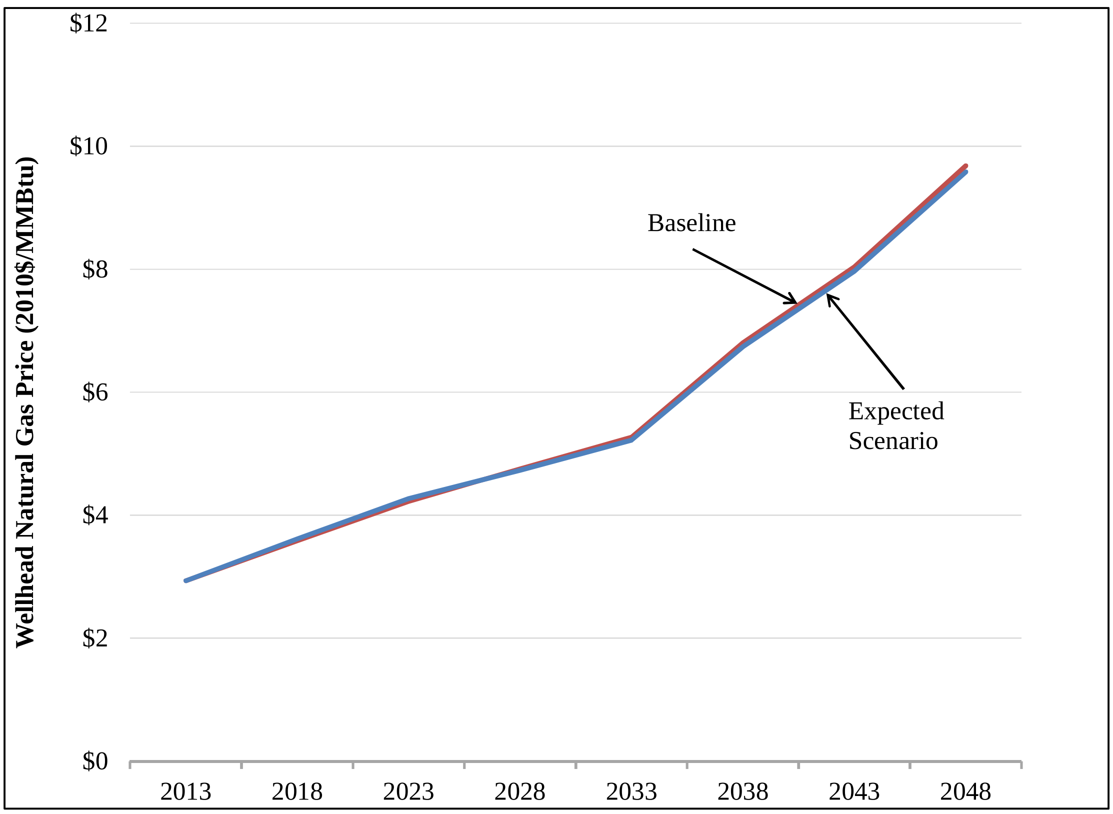
This section discusses the impacts on the U.S. energy markets as a result of implementing the AKLNG project scenarios against a Baseline without any LNG exports from Alaska. Because

[49] Our initial analysis suggested that the indigenous labor supply is insufficient to support the anticipated demand for labor in the Expected and the High scenario.

Alaska represents a small share of the U.S. economy, changes in Alaska's economy generally have only a small effect on the rest of the U.S. The only exception is in the energy markets, where Alaska's production of energy accounts for a modest share of U.S. output. [50]

As a result of Alaska developing the NS and exporting 0.93 Tcf of natural gas per year after 2025, total U.S. exports of LNG are approximately 0.6 Tcf higher than in the Baseline. The reduction in Lower-48 natural gas exports as compared to the Baseline leads to additional supplies for domestic consumption and hence a reduction in the average U.S. wellhead natural gas price, even though Lower-48 exports do increase over the model horizon. One way to view this impact on Lower-48 LNG exports is to consider them being delayed in time rather than permanently displaced (*i.e.*, the curve of export volumes is shifted to the right or forward into time). Under the Expected scenario, the average U.S. wellhead price in 2048 is $9.58/MMBtu compared to $9.68/MMBtu in the Baseline, a 1% decline. The AKLNG project thereby lowers average wellhead prices for the U.S. as a whole. The AKLNG project results in increased levels of U.S. LNG exports as a whole and lower U.S. natural gas prices.

Figure 28: Expected Scenario U.S. Projected Wellhead Natural Gas Price (2010$/MMBtu)



---

[50] According to the U.S. Bureau of Economic Analysis, Alaskan GSP was about 0.30% of the U.S. GDP in 2012. According to the EIA, Alaska's share of total U.S. energy production was about 2.1% in 2011.

D. U.S. Macroeconomic Impacts

This section discusses macroeconomic impacts for the U.S. as a whole as a result of implementing the AKLNG project in the Expected scenario against a Baseline without any LNG exports from Alaska. We used economic measures such as welfare, aggregate consumption, and GDP to estimate the impact of the scenarios.

1. Welfare

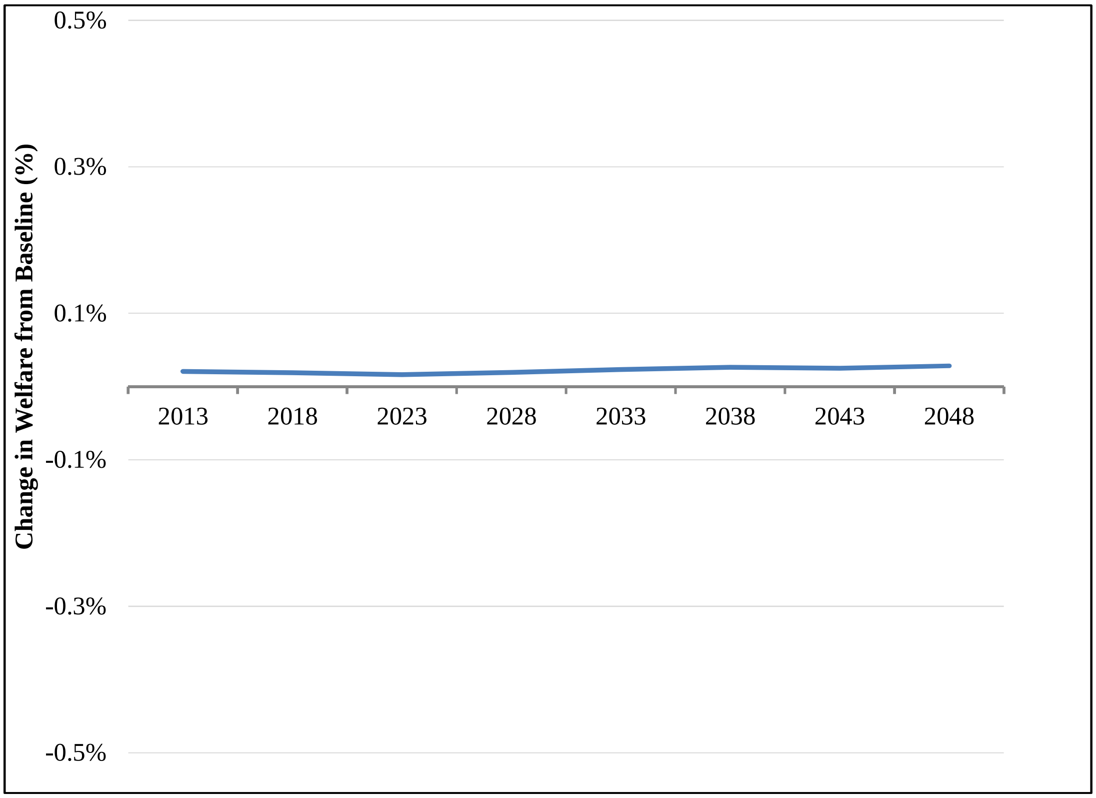
Expansion of natural gas exports changes the price of goods and services purchased by U.S. consumers. In addition, it also alters the income level of the consumers through increased wealth transfers in the form of tolling charges on LNG exports. These economic effects change the well-being of consumers as measured by equivalent variation in income. The equivalent variation measures the monetary impact that is equivalent to the change in consumers' utility from the price changes and provides an accurate measure of the impacts of a policy on consumers.

We report the change in welfare relative to the Baseline in Figure 29. A positive change in welfare means that the policy improves welfare from the perspective of the consumer. The Expected scenario is welfare-improving for U.S. consumers. Under the Expected scenario, consumers receive additional income from two sources. First, the LNG exports provide additional export revenues, and second, consumers who are owners of the liquefaction plants, receive take-or-pay tolling charges for the amount of LNG exports.[51] Although the Expected scenario does have a positive welfare impact on the U.S. as a whole, it should be noted that the magnitude of the impact is very small.

---

[51] The financial arrangement assumption for the Lower-48 LNG exports is based on the NERA 2012 study. We assume that the LNG tolling fee was based on a return of capital to the developer and financing of investment is assumed to originate from U.S. sources. The LNG export price received includes a tolling fee plus a 15% markup over Henry Hub price.

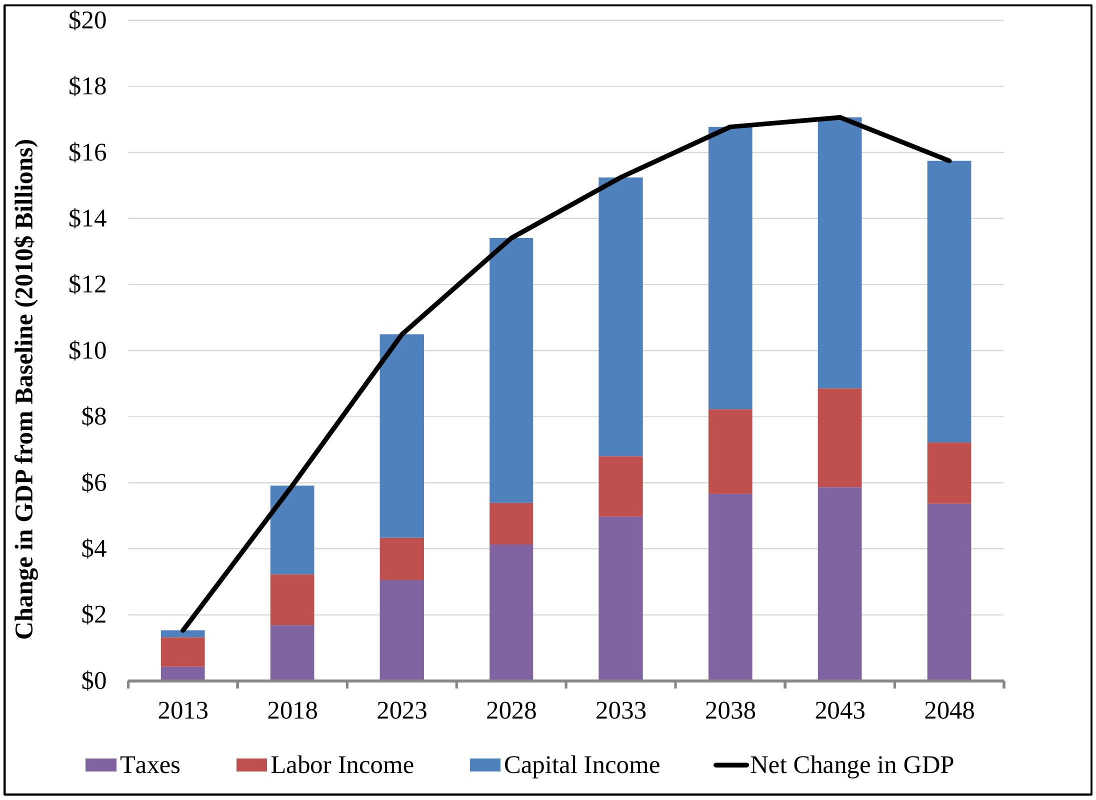
Figure 29: Expected Scenario Change in U.S. Welfare Compared to Baseline (%)



2. GDP

GDP is another economic metric that is often used to evaluate the effectiveness of a policy; it measures the level of total economic activity. In the short and medium run, the GDP impacts are positive as the U.S. economy benefits from capital investment in the LNG-related infrastructure, export revenues, taxes, and additional wealth transfer in the form of tolling charges. In the long run, GDP impacts remain positive but become slightly smaller due to a feedback employment effect from Alaska to the rest of the Lower-48. The reduction in labor demand in Alaska towards the end of the exporting period (primarily reducing demand on out-of-state workers) mitigates the decrease in labor supply in the Lower-48 and creates a downward pressure on the Lower-48 wage rates. This small reduction in Lower-48 wage rates therefore reduces the labor income and taxes on labor income components of U.S. GDP at the end of the export horizon. As a whole it should be noted that while the GDP impact of the AKLNG project in the U.S. is positive it is very small in magnitude relative to the size of the whole U.S. economy, less than 0.05% on average.

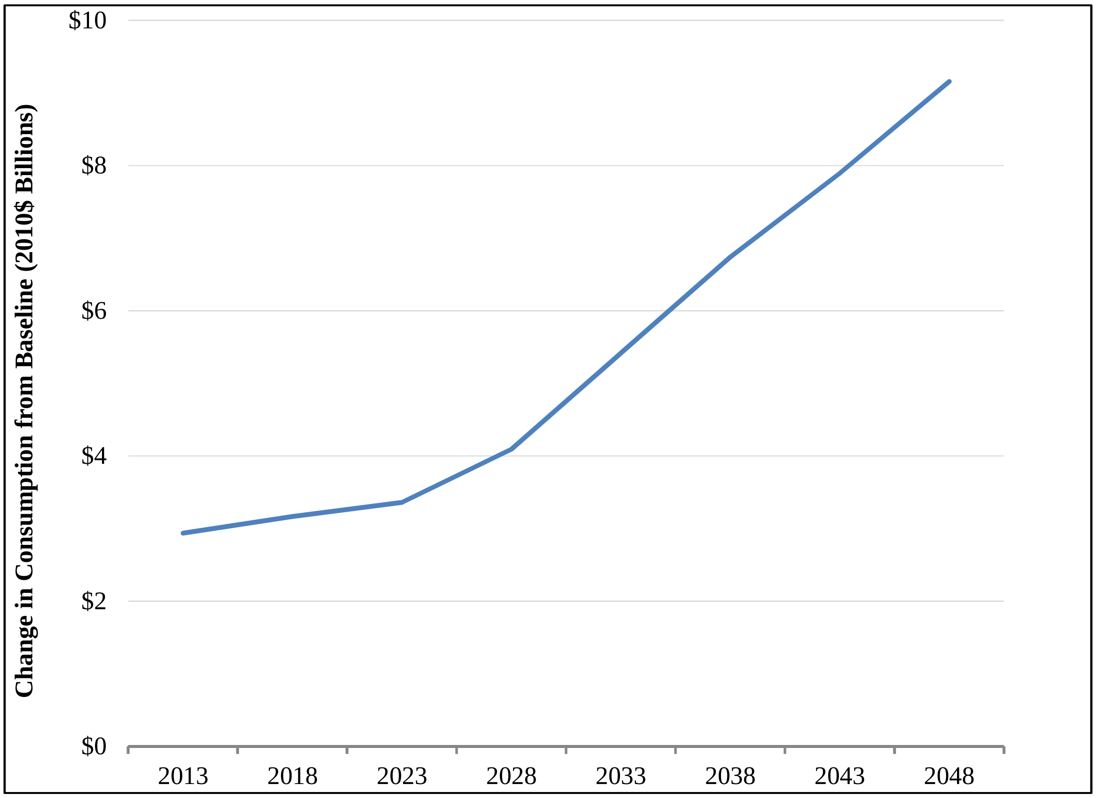
Figure 30: Expected Scenario Change in U.S. GDP Compared to Baseline (2010$ Billions)



3. Aggregate Consumption

Aggregate consumption measures the total spending on goods and services in the economy. Figure 31 shows that aggregate consumption in the U.S. increases steadily throughout the Expected scenario. Consumption rises more quickly after the AKLNG project is completed because more saving is require to support lower levels of capital investment demand. Additionally, increases in income from export revenues can go toward supporting higher levels of consumption.

Figure 31: Expected Scenario Change in U.S. Consumption Compared to Baseline (2010$ Billions)



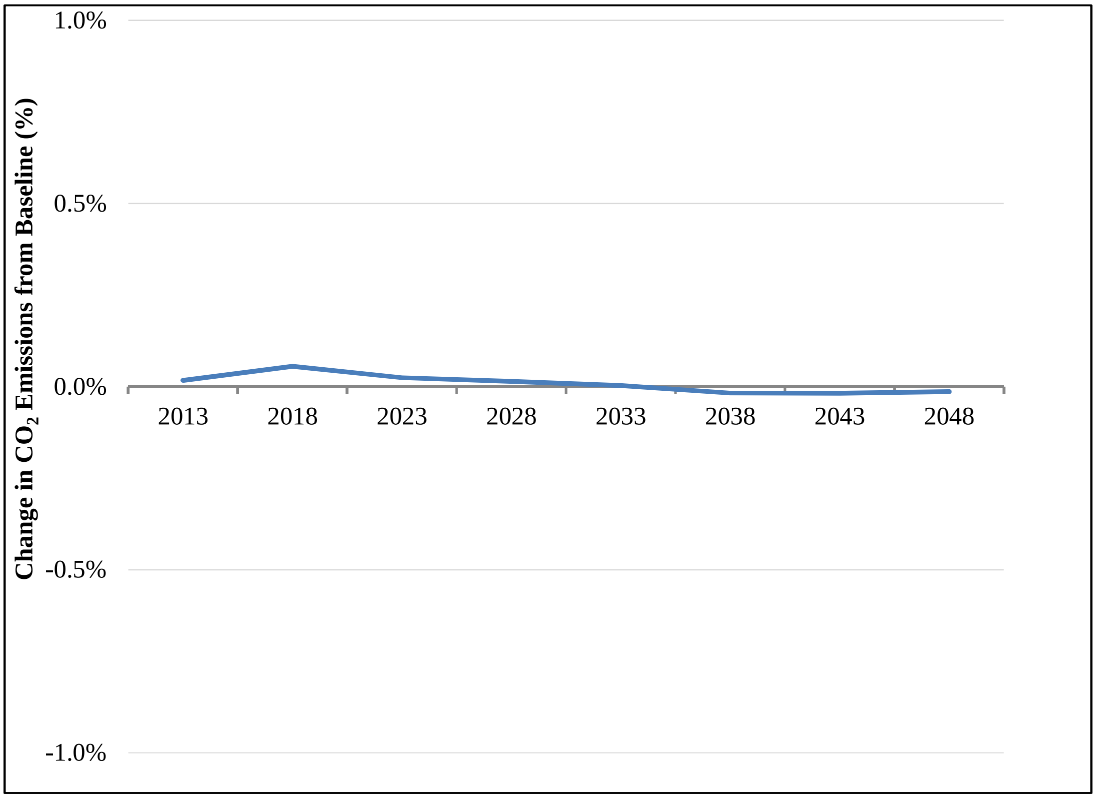
4. Balance of Trade

The AKLNG project would provide access to low cost NS natural gas supplies and allow the U.S. to produce LNG at a globally competitive price. In other words, LNG exports provide the U.S. with a means to obtain international goods and services with fewer resources. Therefore, the value of U.S. net exports increases because of the increase in revenues from LNG exports. The large surplus in the current account balance of Alaska as a result of the AKLNG project is a primary driver in the increase in net exports which results in an improvement in the U.S. balance of trade.

E. U.S. Emissions Impacts

The overall change in U.S. carbon dioxide (CO_2) emissions in the Expected scenario relative to the Baseline is minimal but slightly lower in the long run. The increase in economic activity as a result of greater availability of lower cost natural gas supplies is offset, in aggregate, by the lower carbon intensity of natural gas as a fuel compared to its alternatives. The fuel substitution effect occurs at a domestic level in terms of a coal-to-gas fuel switching in the electric sector due to the lower natural gas prices in the U.S. This fuel switching results in reductions in electric sector emissions of NO_X, SO_X, Hg, and CO_2. Given the large portion of total U.S. emissions of these types accounted for by the electric sector, the fuel switching effect drives reductions in these emissions from the U.S. as a whole.

Figure 32: Expected Scenario Change in U.S. CO_2 Emissions Compared to Baseline (%)



V. SUMMARY OF U.S. ECONOMIC IMPACTS

This section provides a summary of implications for macroeconomic impacts, environmental impacts, and national security impacts of producing natural gas and exporting much of it in the form of LNG from Alaska.

A. DOE Guidelines and Prior LNG Export Applications Approvals

The need to consider "public interest" when authorizing exportation of natural gas is stated in the NGA:

…no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest…[52]

In practice, DOE considers the previous excerpt to imply the creation of a "rebuttable presumption" favoring the exportation of natural gas.[53] It furthermore allows the public to participate in the process as "interveners" that can cite evidence, if any, that the application is inconsistent with the public interest.

In order to preclude any assertion that proposed exports are inconsistent with the public interest, permit applicants typically include supporting arguments and evidence along the following DOE suggested criteria:[54]

1. Domestic demand for the natural gas to be exported;
2. Adequacy of domestic natural gas supply;
3. U.S. energy security;
4. Impact on the U.S. economy, including impact on domestic natural gas prices;
5. International considerations; and
6. Environmental considerations.

As part of the analysis of domestic need for exportation and adequacy of domestic supply, applicants typically evaluate changes to natural gas prices and compare the total volume of natural gas available for production (both reserves and recoverable resources) during the

[52] 15 U.S.C. § 717b.

[53] Panhandle Producers and Royalty Owners Association v. ERA, 822 F. 2d 1105, 1111 (D.C. Cir. 1987).

[54] "DOE's Program Regulating Liquefied Natural Gas Export Applications," Office of Fossil Energy. Available at: http://energy.gov/fe/articles/doe-s-program-regulating-liquefied-natural-gas-export-applications.

specified exportation period to the analogous natural gas demand. It is not uncommon for these analyses to incorporate more than one natural gas demand/supply scenario in order to reflect possible outcomes from other potential paths the market may take.

To address the U.S. energy security criteria, applicants sometimes blend in arguments for adequate supply and international environmental considerations. They frequently support the assertion made in MIT's 2010 "The Future of Natural Gas" claiming that LNG exports "encourage the development of an efficient and integrated global gas market with transparency and diversity of supply."[55] Additionally, applicants will note that increasing global access to natural gas, a fuel that burns cleaner than coal or oil, will aid in slowing global climate change. Lastly, arguments for improvement in balance of trade and trade relations with destination countries, promoting the intent of the National Export Initiative, and consistency with U.S. obligations under the General Agreement on Tariffs and Trade (GATT) are made to complete the analysis of U.S. international concerns.[56]

B. U.S. Economic Impacts

In this section we briefly summarize the results of our analysis for the U.S. As discussed in the preceding sections, the impacts of the AKLNG project on the U.S. economy are positive in all metrics and the magnitude of the impacts is relatively small. Figure 33 shows the percentage change in the Expected scenario relative to the Baseline of several key metrics we have previously analyzed.

[55] MIT Energy Initiative, *The Future of Natural Gas*, p. 14 (2010), available at: http://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

[56] Hufbauer, Gary Clyde, "LNG Exports: An Opportunity for America," January 24, 2013. Available at: http://www.piie.com/blogs/realtime/?p=3315.

Figure 33: Summary of U.S. Natural Gas and Macroeconomic Impacts in Expected Scenario Compared to Baseline

	2013	2018	2023	2028	2033	2038	2043	2048
Wellhead Natural Gas Price (%)	-	0.5%	0.4%	-0.6%	-0.8%	-0.9%	-1.0%	-1.2%
Welfare (%)	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.02%	0.03%
GDP (%)	0.01%	0.03%	0.05%	0.06%	0.06%	0.06%	0.06%	0.05%
Consumption (%)	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%
CO_2 Emissions (%)	0.02%	0.06%	0.02%	0.01%	0.00%	-0.02%	-0.02%	-0.01%

1. U.S. Natural Gas Market Impacts

Development of the AKLNG project would affect U.S. natural gas markets in the following ways. First, supplies of domestic natural gas would increase because of the increased resource development in NS. The increase in supply would naturally lead to a decline in domestic natural gas prices since there would be more natural gas resources available for consumption. The lower prices would result in a slight rebound effect where U.S. natural gas demand in the Expected scenario exceeds that of the Baseline scenario and that increase in demand would have an upward pressure on natural gas prices, but not enough to offset the decrease in natural gas prices due to increased supply. The net result is higher natural gas demand and consumption but lower natural gas prices in the U.S. in the Expected scenario.

2. U.S. Macroeconomic Impacts

As for broader macroeconomic impacts, the change in the U.S. across all key macroeconomic metrics – GDP, consumption, and welfare – from the Baseline levels is positive.

The AKLNG project would provide access to low cost NS natural gas supplies and allow the U.S. to produce LNG at a globally competitive price. In other words, LNG exports provide the U.S. with a means to obtain international goods and services with fewer resources. Therefore, the value of U.S. net exports increases because of the increase in revenues from LNG exports. The large surplus in the current account balance of Alaska as a result of the AKLNG project is a primary driver in the increase in net exports which results in an improvement in the U.S. balance of trade.

C. Environmental Impacts

The development of the AKLNG project leads to different impacts which have competing effects on emissions. Increased natural gas supplies result in lower natural gas prices which lead to:

- Higher economic growth driving higher demand for natural gas and an increase in emissions; and
- Fuel switching from non-gas fuels to natural gas, particularly in the electric sector, which decreases emissions of CO_2, SO_x, NOx, and Hg in the long term.

On balance for the U.S., emissions decline in the long-run, but changes in total U.S. emissions are small at approximately -0.01%.

D. Energy Security

Energy security has a number of dimensions: assurance of supply, low and stable energy prices, and freedom of action in foreign policy are classic issues addressed in the case of crude oil and refined products. Although the debate has often been framed in terms of energy independence, until recently policies and planning for oil security assumed that the U.S. would continue to be an importer and affected negatively by supply shocks and price increases for imported oil. Since crude oil is traded in a global and liquid market, physical supply security has not been a real issue. Private inventories of crude oil and refined products have covered any delays in cargo arrivals, and the Strategic Petroleum Reserve stands ready to address longer delays.

Thus oil security came to be focused on reducing the likelihood and magnitude of the oil supply disruptions that could trigger price shocks, and to increasing the resilience of the U.S. economy to those shocks. The most direct measure of the potential magnitude of supply shocks is the share of the world's oil being produced in vulnerable or unstable regions, originally in the Persian Gulf but now increasingly in certain Latin America countries. Thus questions about how reduction in U.S. oil imports, whether through increased production or reduced demand, would enhance supply security came down to modeling how that reduction translated into a smaller share of world supply coming from vulnerable or unstable regions.

What was a concern about how dependence on oil imports limited freedom of action in foreign policy has been amplified by concern that oil revenues are propping up regimes that deny their people basic human rights and economic development or being funneled by state or private recipients into support of terrorist groups.

Since the U.S. was never a major importer of natural gas except from Canada, the issue of energy security has not been as well developed about natural gas markets. Starting with the basic criteria of supply assurance, low and stable prices, and foreign policy benefits, it is possible to develop some metrics of how natural gas exports can affect energy security.

- **Supply Assurance**: Exporting natural gas requires several investments that are irreversible in the short run: deliverability of natural gas from wellhead to terminal to support exports, and capacity to liquefy and export. From the point of view of U.S. price stability and assured supplies, the production capacity that is supplying export markets is in effect spare capacity that can be diverted to domestic uses. The larger and more liquid the global natural gas market is, the more effective this spare capacity will be. It is not necessary that DOE be prepared to revoke export licenses to ensure this, because as long as exporters are purchasing natural gas in the spot market or under contracts indexed to the U.S. market, U.S. consumers will be able to bid natural gas away from exporters if a domestic shortage were to occur.

- **Price Stability**: Although mostly outside the scope of this study, a number of experts on global commodity markets have concluded that being connected to a global LNG market will serve to reduce natural gas price volatility. Historically, U.S. natural gas prices have been much more volatile than world oil prices, so that even if a global LNG market became linked in some way to oil prices, having U.S. natural gas prices linked to the global LNG market would reduce volatility.[57] Moreover, to the extent that shocks to the global market and shocks to the U.S. market are not correlated, U.S. volatility would be reduced by the greater size of the market. Finally, export capacity is likely to be fully utilized. Under these conditions, shocks to the world natural gas market and even global LNG price spikes will not be transmitted to the U.S. market, though they would benefit those holding firm export capacity contracts. The reason is that exports will be limited by liquefaction capacity, and once that limit is reached there can be no further increase in exports and therefore no additional demand for U.S. natural gas. As a result the U.S. price will be unaffected by increases in global prices as long as terminals are at capacity.[58]

- **Foreign Policy**: Natural gas exports can have clear foreign policy benefits: reducing dependence of other countries on exports from countries that are not allies of the U.S. will reduce the influence of those countries on the policies of potentially friendly countries importing U.S. LNG. Removing restrictions on exports will also signal the U.S. commitment to WTO and GATT principles, to support free market regimes in other countries, and make it easier to press other countries to remove export restrictions that are damaging to U.S. industry.[59]

[57] Medlock, Kenneth B., "LNG, Globalization, and Price Volatility: Understanding the Paradigm Shift," prepared for the American Clean Skies Foundation. Available at: http://www.cleanskies.org/wp-content/uploads/2011/08/LNGMarketGlobalizationImpact.pdf.

[58] The only case in which an unexpected increase in global prices could affect U.S. prices is if global prices had fallen so low relative to expectations that there was excess capacity at some terminal. Even in this case, U.S. prices would not move directly with world prices but only up to a level consistent with U.S. terminals being used at capacity. Once terminals are at capacity, the U.S. is disconnected from any further increase in global prices.

[59] Hufbauer, Gary Clyde, "LNG Exports: An Opportunity for America," January 24, 2013. Available at: http://www.piie.com/blogs/realtime/?p=3315.

APPENDIX A. HIGH LNG EXPORT SCENARIO

In this appendix we discuss some results from the High scenario with a 40 year export horizon, natural gas supply resource of 109 Tcf, and higher demand induced primarily by a faster growing economy in Alaska. The economic impacts are generally consistent with the results from the Expected scenario with two exceptions:

1. The impact of not constructing Susitna; and
2. The impact of an extended LNG export horizon in Alaska.

Due to the generally consistent nature of the results in the High scenario, we focus our discussion in the following sections on differences in impacts relative to the Expected scenario impacts presented in the main body of the report.

A. Alaska Energy Market Impacts

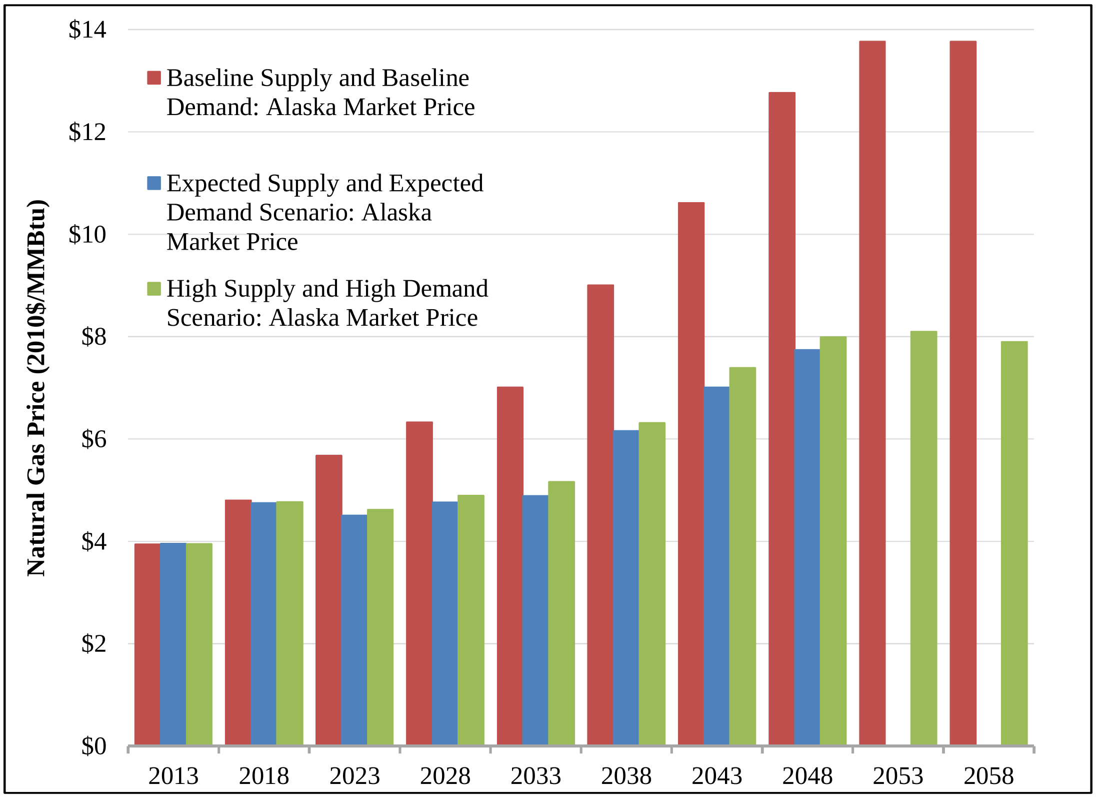
This section discusses the High scenario impacts on the Alaska energy markets as a result of implementing the AKLNG project compared to a Baseline without any LNG exports from Alaska, as well as the Expected scenario.

1. Natural Gas Market Impacts

Impacts on natural gas prices in Alaska under the High scenario are similar to those in the Expected scenario. This similarity occurs despite the increased demand primarily caused by the increased natural gas resource assumption but also because of the relatively low resource cost of NS natural gas supplies for the Alaska market. The NS wellhead price plus the cost of pipeline transportation in the High scenario ranges from being $0.05/MMBtu lower to $0.14/MMBtu greater than in the Expected scenario. The price comparisons can be seen in Figure 34. It is interesting to note that by the end of the export horizon in 2058 the Alaska market price of natural gas essentially converges with the NS wellhead price plus pipeline transportation charges. This shows the impact of resource depletion in Cook Inlet and that NS natural gas becomes a larger share of supplies to Alaska markets.

The decreases in natural gas prices relative to the Baseline seen in the High scenario, along with the increased demand assumptions, result in an even greater increase in natural gas consumption. The greatest expansion in natural gas use occurs in the ELE due to the need to replace the generation of Susitna that is not constructed in the High scenario. Figure 36 shows that the total natural gas produced over the modeling horizon never exceeds the NS and Cook Inlet resource constraints assumed in this analysis (as specified in Section III.E above).

Figure 34: High Supply and High Demand Scenario Alaska Natural Gas Market Prices (2010$/MMBtu)



Note: NERA adopted the net-forward pricing to establish a baseline market price path for modeling economic impact and benefits. The market price that NERA estimated is subject to uncertainties influenced by many factors and claims no knowledge of the ultimate negotiated market price. The model estimates overall net benefits regardless of how benefits and costs are distributed across various end-users and consumers.

Figure 35: High Scenario Average Alaska Natural Gas Demand by Sector (Bcf/yr)[60]

Sector	2013	2018	2023	2028	2033	2038	2043	2048	2053	2058	Cumulative Total (Tcf)[61]
Electricity	36	39	52	59	65	73	80	96	105	116	3.6
Commercial	23	23	28	31	34	38	41	49	56	64	1.9
Residential	22	24	35	38	40	44	47	52	56	60	2.1
Manufacturing	7	6	17	30	42	47	44	51	58	65	1.8
Government	5	4	4	5	5	5	5	5	6	6	0.3
Energy-Intensive	5	5	13	25	40	46	44	52	61	72	1.8
Trucking Transportation	0	0	0	0	1	3	5	9	15	23	0.3
Other Transportation	0	0	0	0	0	2	2	5	8	14	0.2
Upstream Lease and Operations Fuel[62]	255	255	255	255	255	255	255	255	255	255	12.8
Sectoral Total	353	357	403	443	482	513	524	573	619	675	24.7
Total Change from Baseline	0	0	48	80	114	137	141	183	221	267	12.6

Figure 36: High Scenario Average Alaska Natural Gas Production by Source (Tcf/yr)

Source	2013	2018	2023	2028	2033	2038	2043	2048	2053	2058	Cumulative Total (Tcf)[63]
NS	0.26	0.26	1.20	1.46	1.52	1.56	1.61	1.66	1.71	1.76	65.1
Cook Inlet	0.09	0.10	0.08	0.08	0.06	0.05	0.01	0.01	0.01	0.01	2.5
Total	0.35	0.36	1.28	1.54	1.58	1.61	1.62	1.67	1.72	1.77	67.6

[60] The items and totals in this table exclude feed gas and fuel/shrinkage requirements.

[61] Cumulative totals may not equal the sum of all years due to differences in rounding.

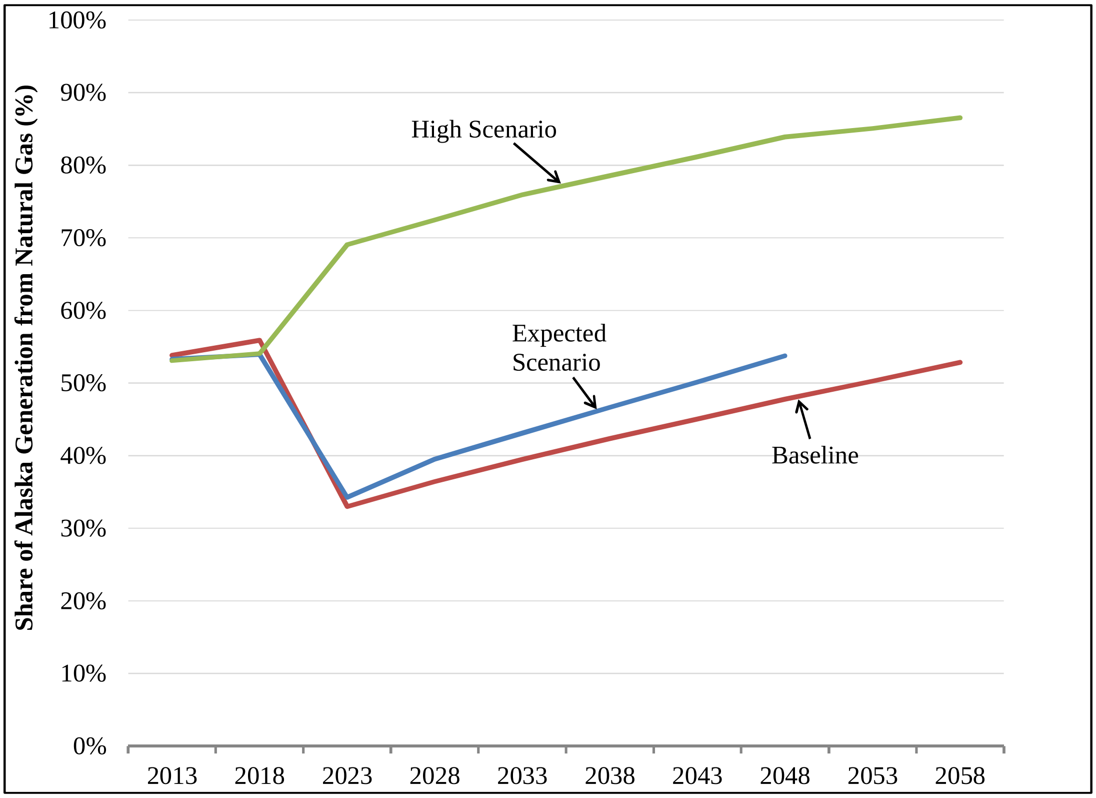
[62] Upstream lease operations fuel estimate is average fuel use for years 2007 through 2011 based on EIA data. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SAK_a.htm.

[63] Cumulative totals may not equal the sum of all years due to differences in rounding.

2. Electricity Market Impacts

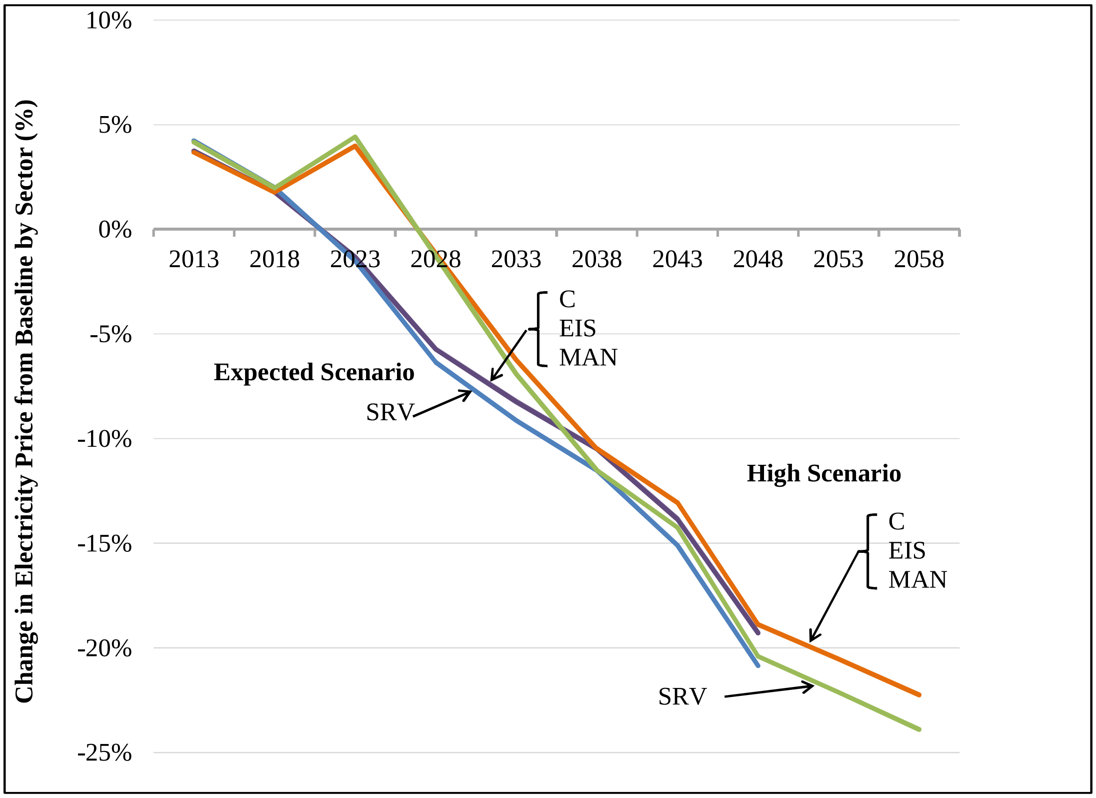
Without the construction of Susitna, there is a relatively large, but not unexpected, jump in the reliance on natural gas-fired generation in the ELE in the High scenario (Figure 37). This is due to the need to make up for the lack of generation provided by Susitna in both the Baseline and Expected Scenario.

Figure 37: High Scenario Share of Alaska Electricity Generation from Natural Gas (%)



An increase in delivered electricity prices relative to the Baseline is also seen in this scenario, particularly in 2023. Again, this is due to the lack of the generation provided by Susitna in the Baseline and Expected scenarios requiring more construction of natural gas-fired electricity generation which has a higher marginal cost of generation than hydroelectric generation. Even given the early year increases in delivered electricity prices, overall prices drop significantly over time and are in line with the reductions in electricity prices seen in the Expected scenario by 2038.

Figure 38: High Scenario Change in Alaska Delivered Electricity Price Compared to Baseline, by Sector (%)



B. Alaska Macroeconomic Impacts

This section discusses the overall macroeconomic impacts for the High scenario as a result of incorporating the implementation of the AKLNG project and comparing the results against the Baseline scenario, which assumes no LNG exports from Alaska, as well as the Expected scenario.

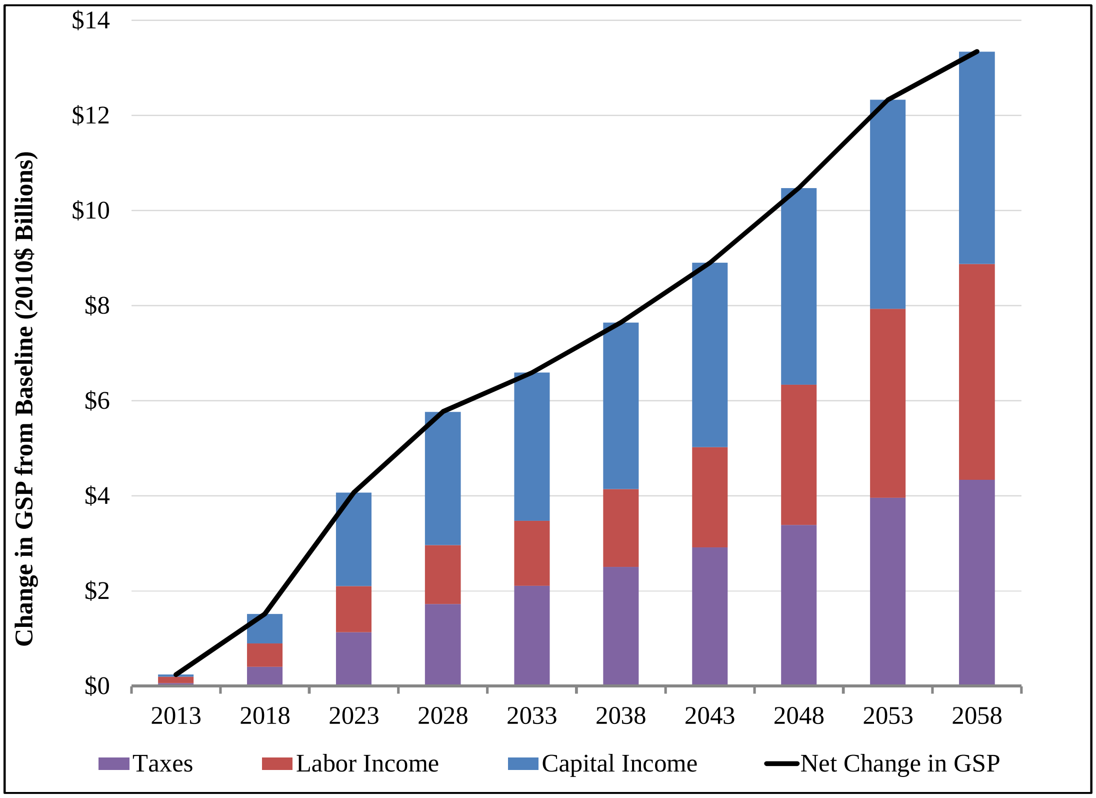
1. Welfare

The positive impacts in consumer welfare relative to the Baseline seen in the Expected scenario extend to the High scenario in approximately equivalent magnitudes over equivalent periods of the export horizon. The greatest difference lies in the extended modeling horizon for the High scenario which includes an extended period of LNG exports.

2. Gross Regional Product

Like welfare, the positive GSP impacts seen in the High scenario, relative to the Baseline, are similar to those in the Expected scenario over comparable period of time but are even greater further out in the horizon due to the extended period of LNG exports (Figure 39). The steadily increasing GSP impacts are driven by the increasing costs of natural gas and therefore the increasing LNG export revenues over time.

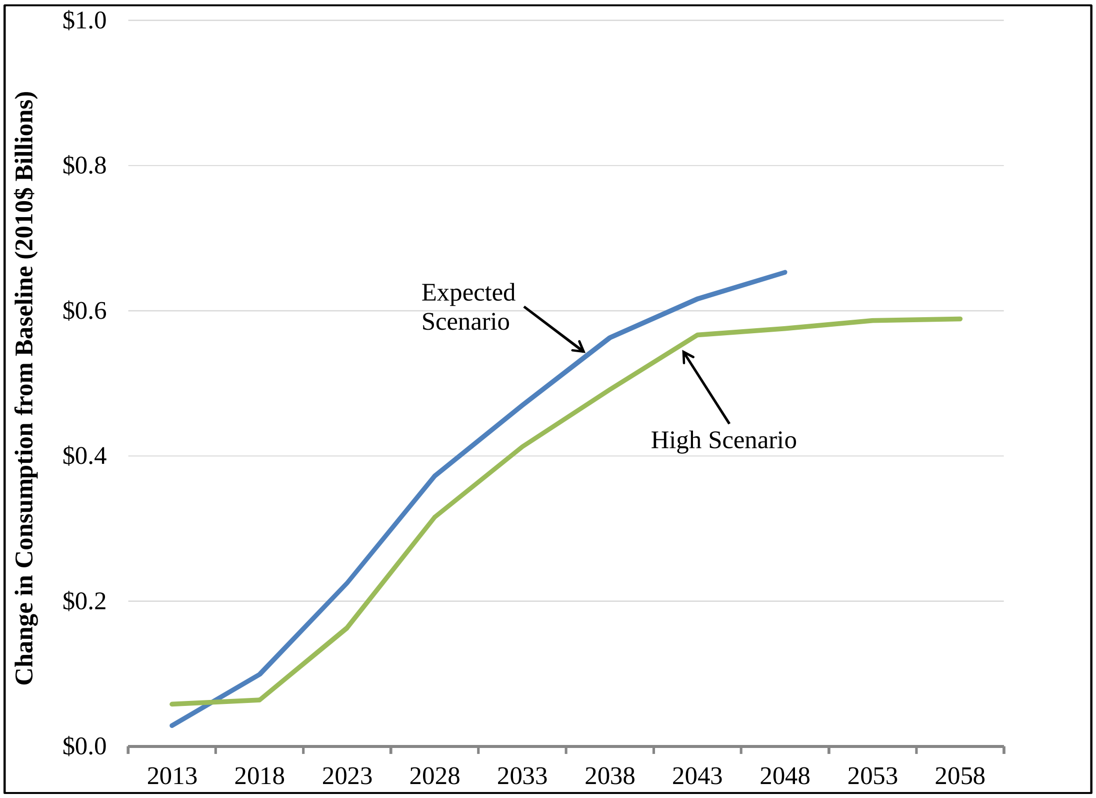
Figure 39: High Scenario Change in Alaska GSP Compared to Baseline (2010$ Billions)



3. Aggregate Consumption

The path of increased consumption in the High scenario closely follows that of Expected scenario with the amount of the increase leveling off towards the end of the extended LNG export horizon. The primary driver in the flattening of consumption increases in the High scenario is the greater increases in the Alaska natural gas prices over the 2048 through 2058 period. The higher prices raises the cost of goods in Alaska, leading to a lower rate of consumption growth while still allowing GSP to continue increasing due to the ever increasing LNG export revenues.

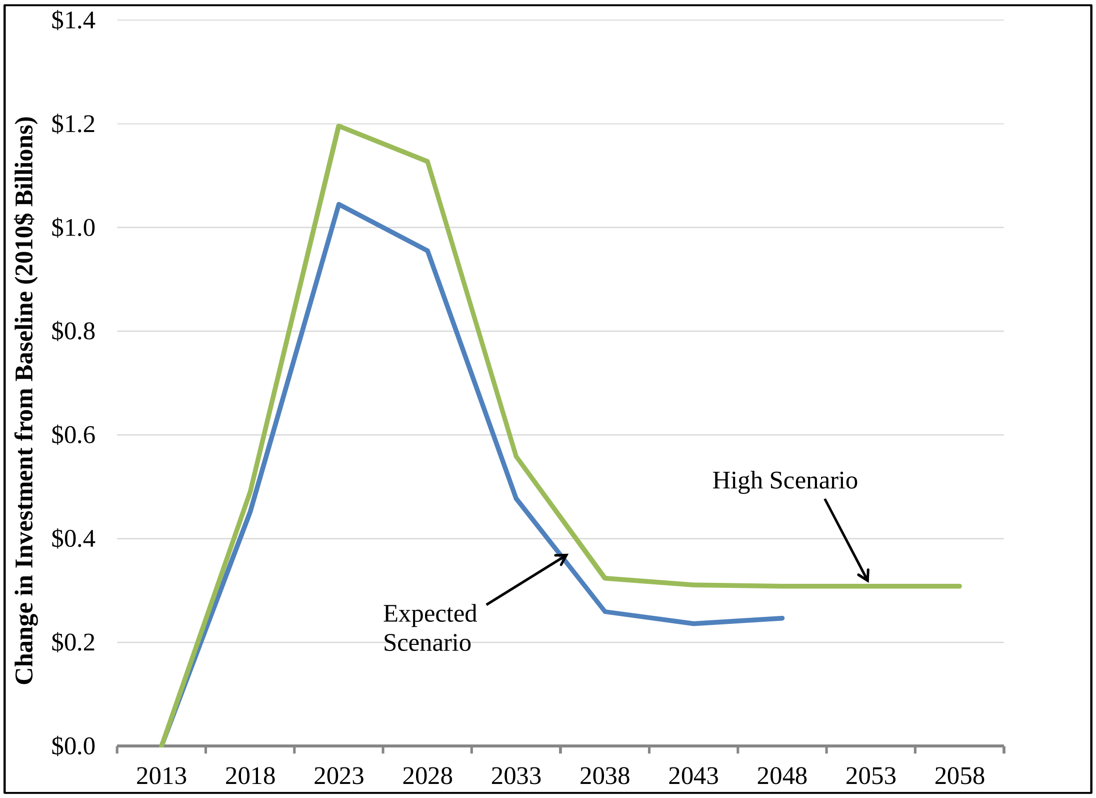
Figure 40: High Scenario Change in Alaska Consumption Compared to Baseline (2010$ Billions)



4. Aggregate Investment

As with welfare and GSP, the change in aggregate investment follows a similar path in the Expected and High scenarios over the time horizon of the Expected scenario. Alaska continues to attract more investment from the rest of the U.S. in the High scenario relative to the Baseline because of its lower natural gas prices as well as the opportunity presented by the AKLNG project. Additionally, the higher economic growth rate in the High scenario contributes to even higher aggregate investment than in the Expected scenario and this inflow of investment leads to Alaska having greater economic growth than in either the Baseline or Expected scenario.

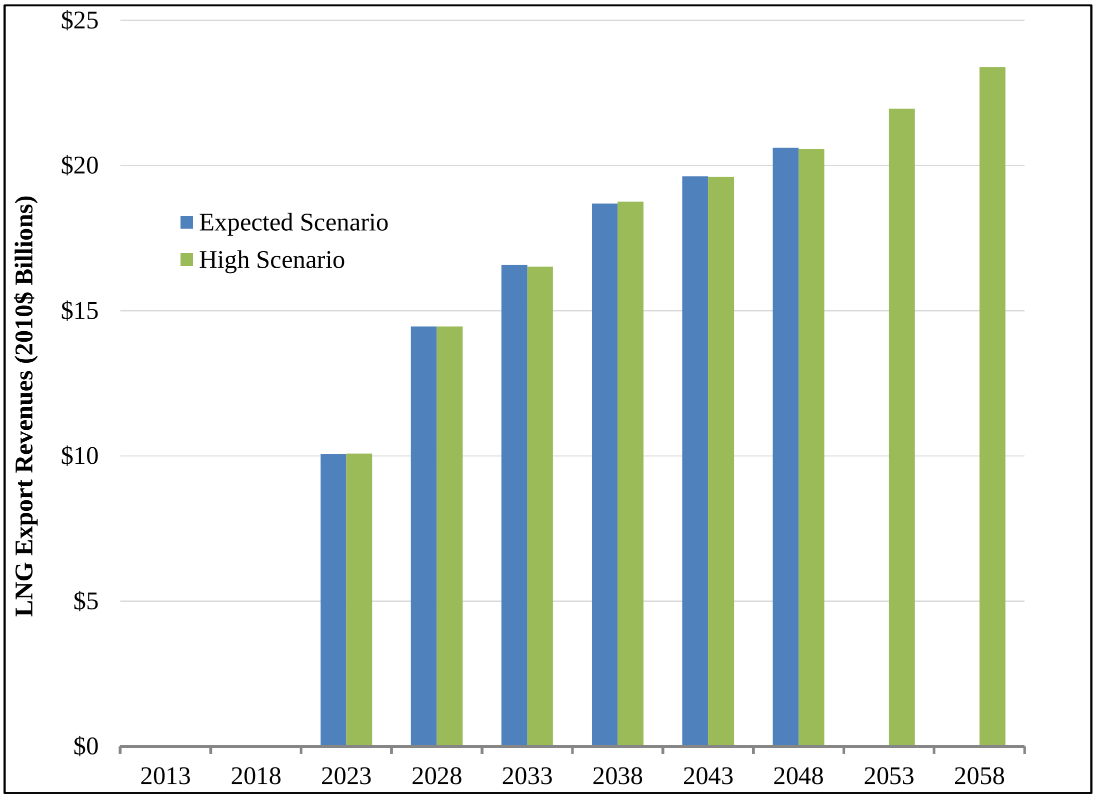
Figure 41: High Scenario Change in Capital in Place in Alaska Compared to Baseline (2010$ Billions)



5. Natural Gas Export Revenues

By design, the Expected and High scenarios export the same amount of natural gas over the horizon of the Expected scenario, but the High scenario assumes natural gas exports continue for another ten years, hence the export revenues from the High scenario continue. The revenues continue to increase over time because world natural gas prices increase faster than Alaska's wellhead price.

Figure 42: High Scenario Average Annual Alaska LNG Export Revenues (2010$ Billions)



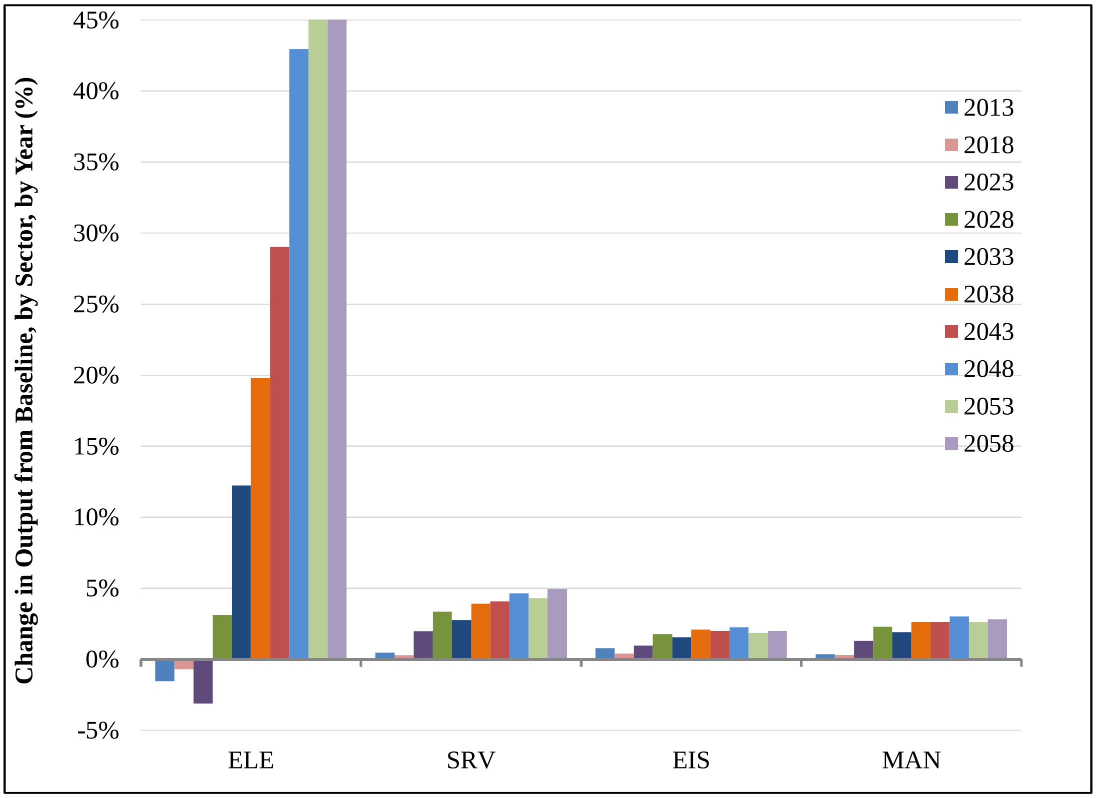
6. Trade Impacts

Trade impacts are essentially that same in the High scenario as in the Expected scenario. Overall, we see an increase in net foreign exports from Alaska as a result of LNG exports from baseline levels. This results in a large increase in the foreign current account balance.

7. Sectoral Output Changes for Some Key Economic Sectors

The biggest differences sectoral output changes in the High scenario compared to the Expected scenario occur in the ELE. The SRV, MAN, and EIS all show very similar, but slightly higher, changes in output relative to the Baseline when compared with the changes in the Expected scenario. The greater increase in ELE output in the High scenario is primarily a result of the higher economic growth rate assumption which drives significantly greater electricity demand in the state, particularly starting in 2033. By 2048, the last model year comparable amongst all three model runs, electricity generation in the High scenario is 13.1 TWh compared to 10.2 TWh in the Expected scenario and 9 TWH in the Baseline. This represents a demand for electricity in the High scenario which is 28% and 45% greater than in the Expected scenario and the Baseline respectively.

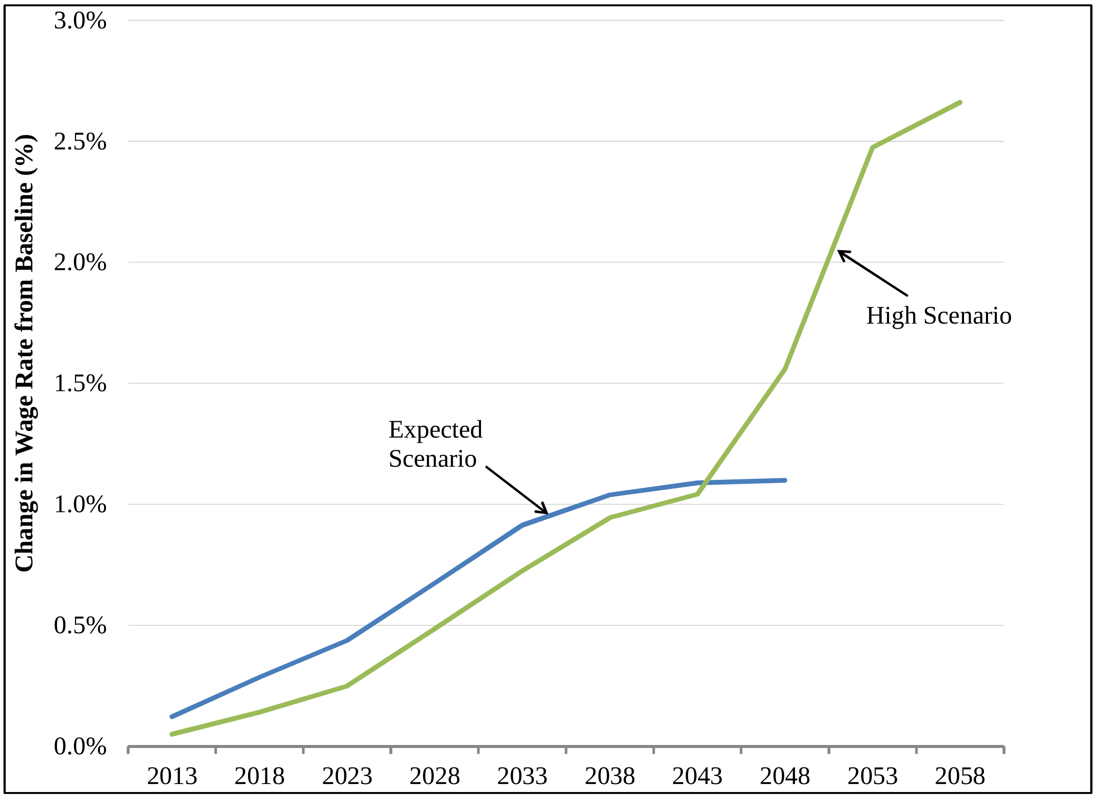
Figure 43: High Scenario Changes in Output for Key Alaska Economic Sectors Compared to Baseline (%)



8. Wage Rates

The increase in wage rates in the High scenario generally follows the increases seen in the Expected scenario with two differences. First, from the period through 2043, the level of the wage rate increase is slightly lower than in the Expected scenario due to slightly higher electricity and natural gas prices in the High scenario creating a small downward pressure on labor demand and therefore wage rates. Second, from 2048 through the end of the longer LNG export horizon in 2058, the greater rate of economic growth in Alaska assumed in the High scenario and the increased cost of out-of-state labor at this point in the modeling horizon combine to drive wage rate and labor demand increases to higher levels than seen in the Expected scenario.

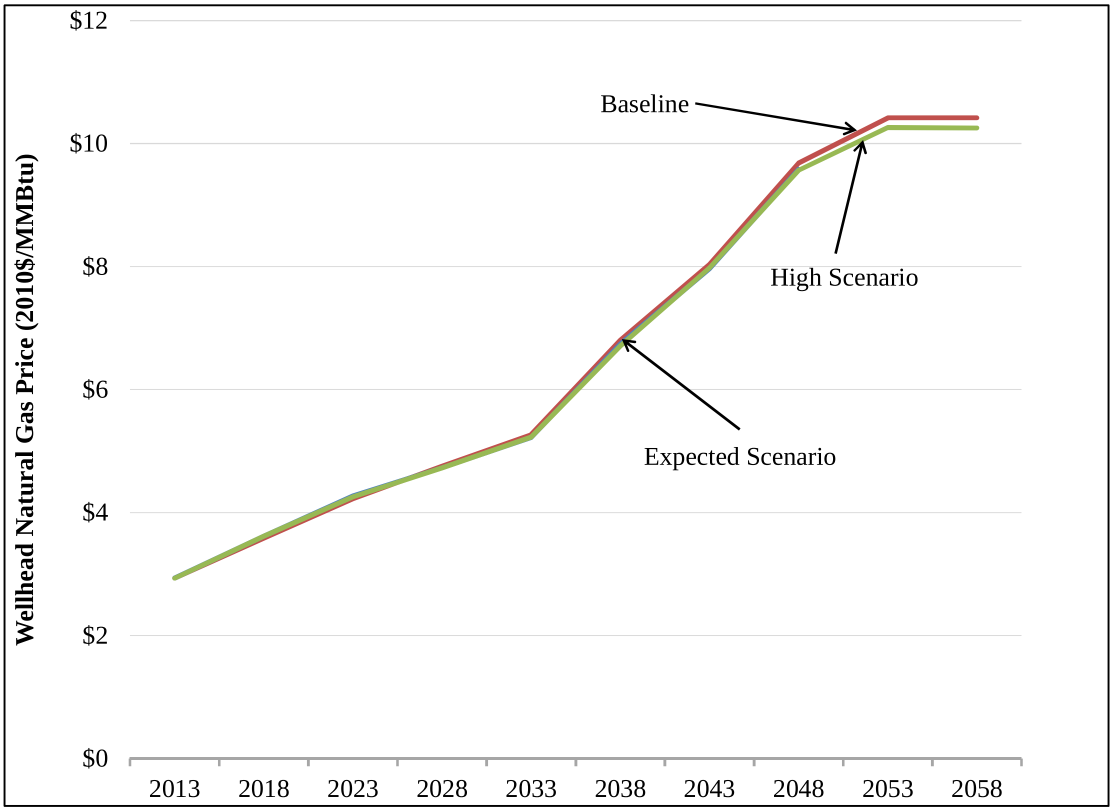
Figure 44: High Scenario Change in Alaska Wage Rate Compared to Baseline (%)



C. U.S. Energy Market Impacts

Alaskan exports of natural gas have a minimal impact on natural gas prices in the rest of the U.S. This relationship is true under both the Expected and High scenarios. The percentage change in natural gas prices from the Baseline to the High scenario is nearly constant over time.

Figure 45: High Scenario U.S. Projected Wellhead Natural Gas Price (2010$/MMBtu)



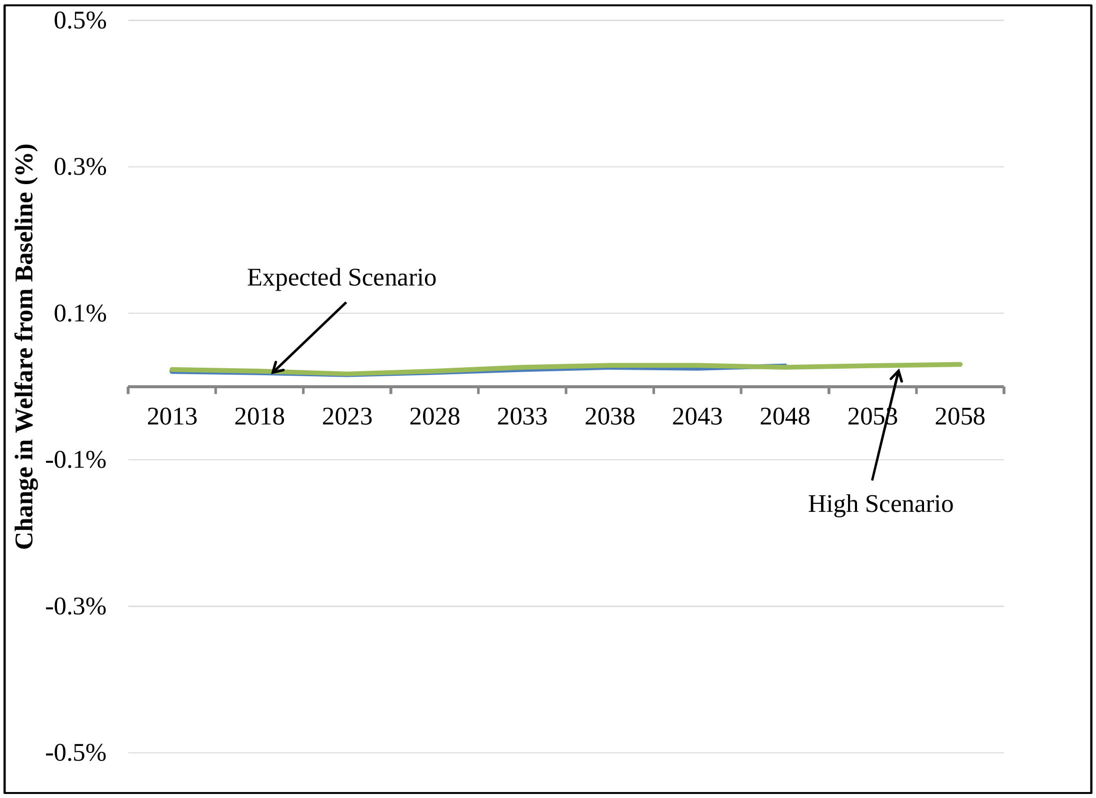
D. U.S. Macroeconomic Impacts

As with the natural gas prices, the impacts of the AKLNG project on the rest of the country's welfare, GDP, *etc.*, is quite small, and the changes in the High scenario closely track those of the Expected scenario throughout the scenario's horizon. After the time in which the Expected scenario is no longer analyzed, the High scenario sees to exhibit fairly similar macroeconomic impacts. Across all of the following metrics, the difference in impacts of the AKLNG project on the U.S. under both the Expected and High scenarios is positive and, on average over the modeling horizon, smaller than 0.05%.

1. Welfare

The change in welfare in the U.S. in the High scenario is virtually identical to the change in welfare in the Expected scenario. This change is positive but also very small, never exceeding 0.1% in a given modeling year.

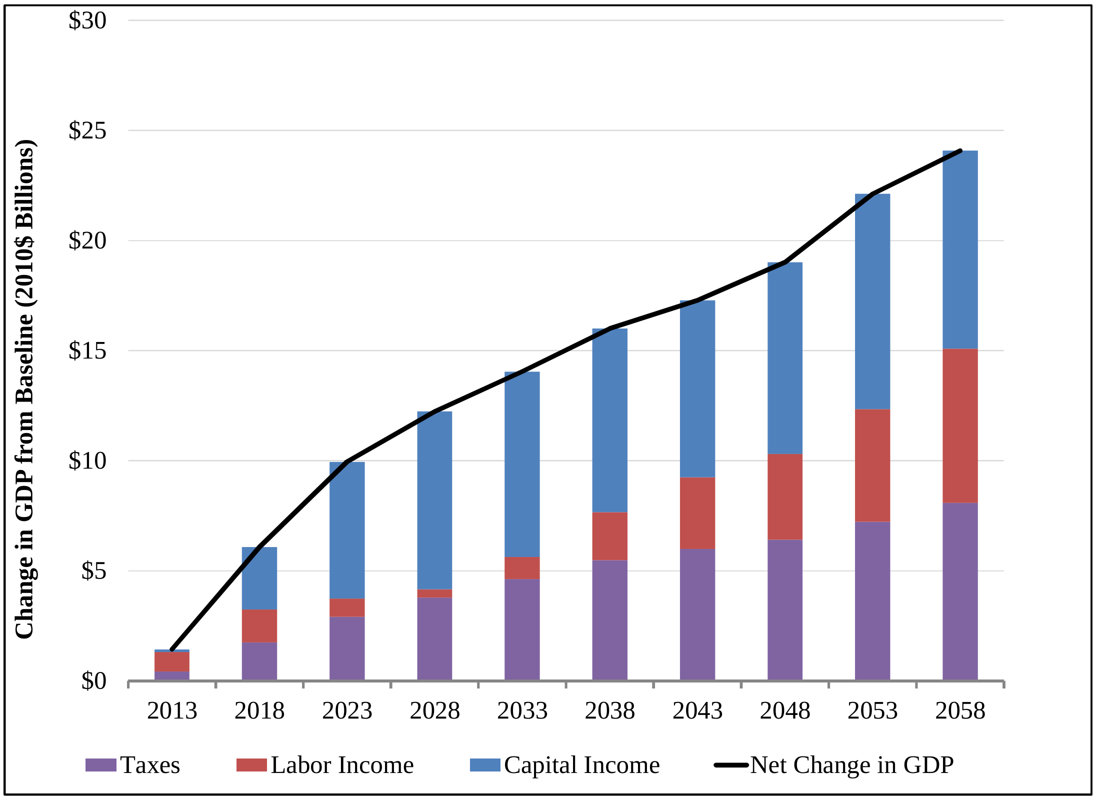
Figure 46: High Scenario Change in U.S. Welfare Compared to Baseline (%)



2. GDP

Increases in U.S. GDP generally follow the same pattern in the High scenario as in the Expected scenario with the exception of 2048 onward. Where in the Expected scenario we saw a tapering of GDP growth in 2048, we do not see the same impact in the High scenario due to the differences in wage rates in 2048 and onward. Due to the High scenario's higher economic growth rate assumption in Alaska as well as the longer period of LNG exports, we do not see the same reduction in Alaskan labor demand which fed back into the Lower-48 and created a downward force on overall U.S. wage rates. Instead the higher levels of sustained labor demand and increased wage rates drive continued growth in labor income and overall U.S. GDP over the High scenario modeling horizon. It should be noted that, much like in the Expected scenario, while the GDP impact in the U.S. is positive, it is still very small and smaller than 0.05% on average over the modeling horizon.

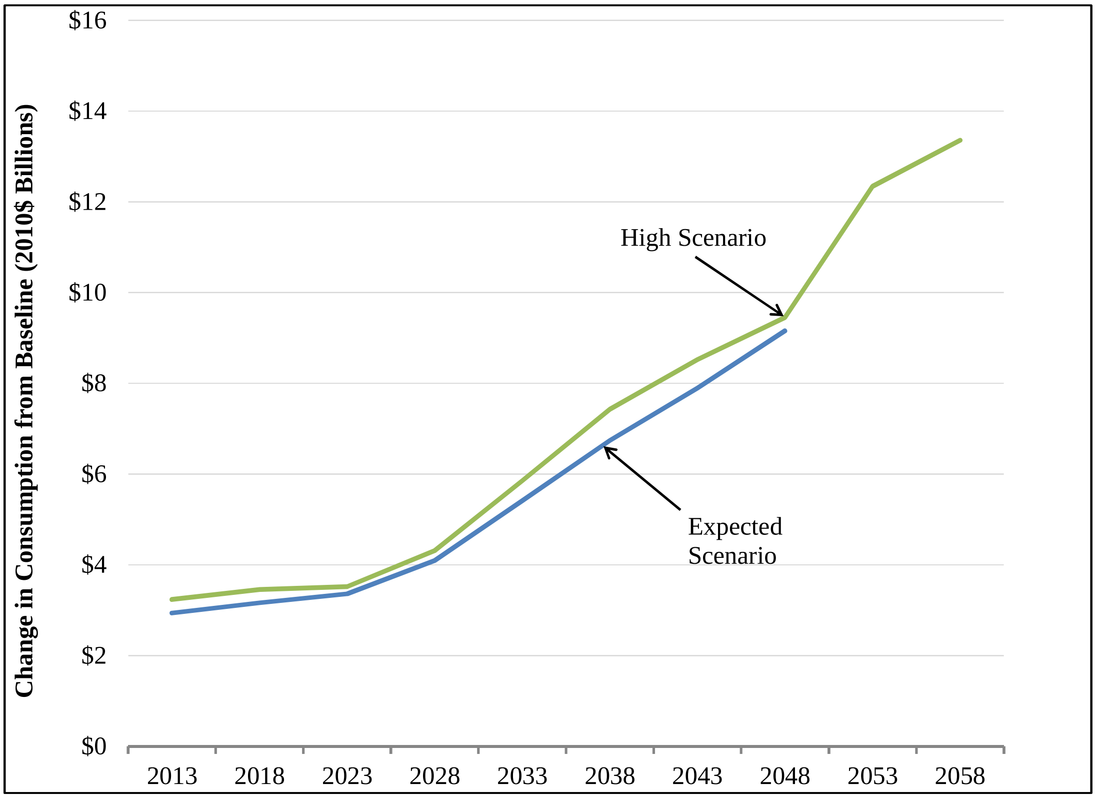
Figure 47: High Scenario Change in U.S. GDP Compared to Baseline (2010$ Billions)



3. Aggregate Consumption

The pattern of consumption increases in the High scenario follows almost exactly along the lines of the increases in the Expected scenario. Overall economic impacts are slightly more positive across the U.S., and the LNG export horizon is longer than in the Expected scenario, but otherwise the pattern is very similar.

Figure 48: High Scenario Change in U.S. Consumption Compared to Baseline (2010$ Billions)



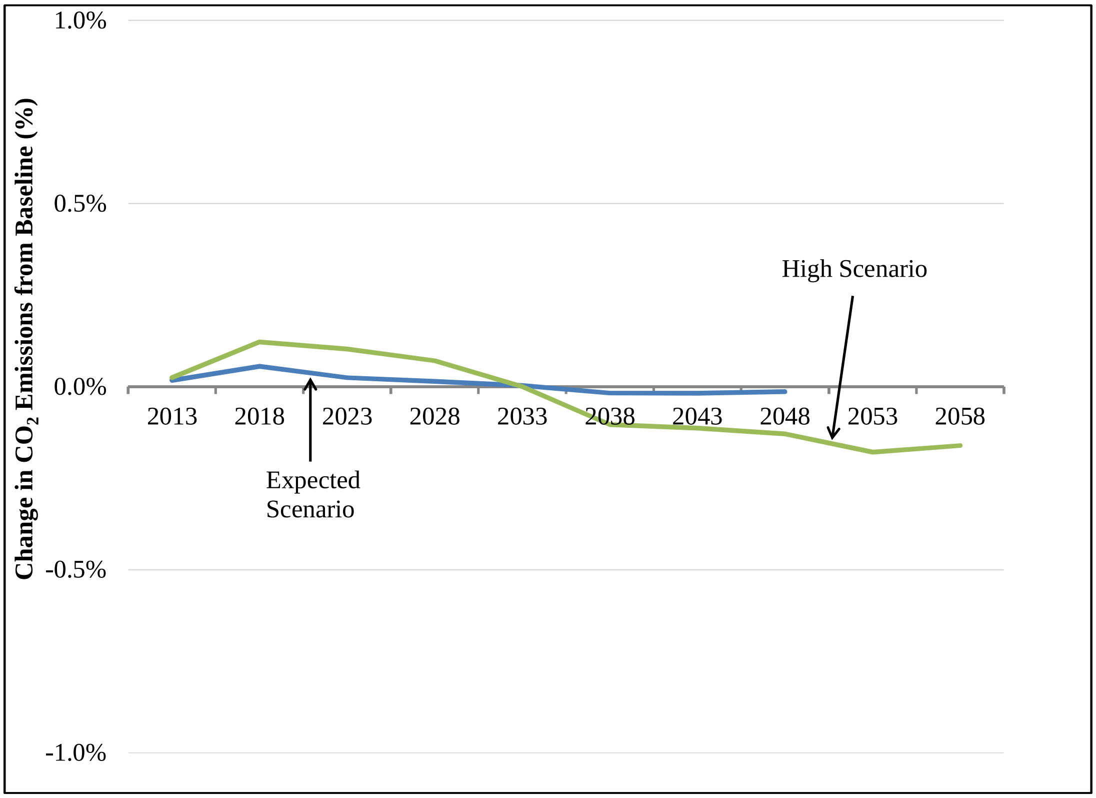
4. Balance of Trade

The impacts on balance of trade in the High scenario are also almost exactly the same as in the Expected scenario. The large surplus in the current account balance of Alaska as a result of the AKLNG project is a primary driver in the increase in net exports which results in an improvement in the U.S. balance of trade.

E. U.S. Emissions Impacts

The change in CO_2 emissions for the U.S. in the High scenario relative to the Baseline is similar to what we see in the Expected case with less than a 0.2% move in either direction in any given model year. Higher near term emissions due to investment-driven GDP growth are balanced by lower emissions in the long run due to extended natural gas supplies.

Figure 49: High Scenario Change in U.S. CO_2 Emissions Compared to Baseline (%)



APPENDIX B. ADDITIONAL N_{EW}ERA MODEL DETAILS

1. Overview of Macroeconomic Model

The N_{ew}ERA macroeconomic model is a forward-looking dynamic CGE model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. The benchmark year economic interactions are based on the IMPLAN 2008 database, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to the most recent AEO produced by the EIA. Because the model is calibrated to an internally-consistent energy forecast, the use of the model is particularly well suited to analyze economic and energy policies and environmental regulations.

The N_{ew}ERA model incorporates EIA energy quantities and energy prices into the IMPLAN Social Accounting Matrices. This approach, which has been developed by the NERA team, results in a balanced energy-economy dataset that has internally-consistent energy benchmark data as well as IMPLAN-consistent economic values.

The macroeconomic model incorporates all production sectors and final demanders of the economy and is linked through terms of trade. The effects of policies are transmitted throughout the economy as all sectors and agents in the economy respond until the economy reaches equilibrium. The ability of the model to track these effects and substitution possibilities across sectors and regions makes it a unique tool for analyzing policies such as those involving energy and environmental regulations. These general equilibrium substitution effects, however, are not fully captured in a partial equilibrium framework or within an input-output modeling framework. The smooth production and consumption functions employed in this general equilibrium model enable gradual substitution of inputs in response to relative price changes thus avoiding all-or-nothing solutions.

Business investment decisions are informed by future policies and outlook. The forward-looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment levels while anticipating future policies with perfect foresight. The alternative approach on savings and investment decisions is to assume agents in the model are myopic, and thus have no expectations for the future. Though both approaches are equally unrealistic to a certain extent, the latter approach can lead the model to produce inconsistent or incorrect impacts from an announced future policy.

A CGE modeling tool such as the N_{ew}ERA macroeconomic model can analyze scenarios or policies that call for large shocks outside of historical observation. Econometric models are unsuitable for policies that impose large impacts because these models' production and consumption functions remain invariant under the policy. In addition, econometric models assume that the future path depends on the past experience and therefore fail to capture how the economy might respond under a different and new environment. For example, an econometric model cannot represent changes in fuel efficiency in response to increases in energy prices. However, the N_{ew}ERA macroeconomic model can consistently capture future policy changes that envisage having large effects.

The N_{ew}ERA macroeconomic model is also a unique tool that can iterate over sequential policies to generate consistent equilibrium solutions starting from an internally consistent equilibrium baseline forecast (such as the AEO reference case). This ability of the model is particularly helpful to decompose macroeconomic effects of individual policies. For example, if one desires to perform economic analysis of a policy that includes multiple regulations, the N_{ew}ERA modeling framework can be used as a tool to layer in one regulation at a time to determine the incremental effects of each policy.

2. Model Scope

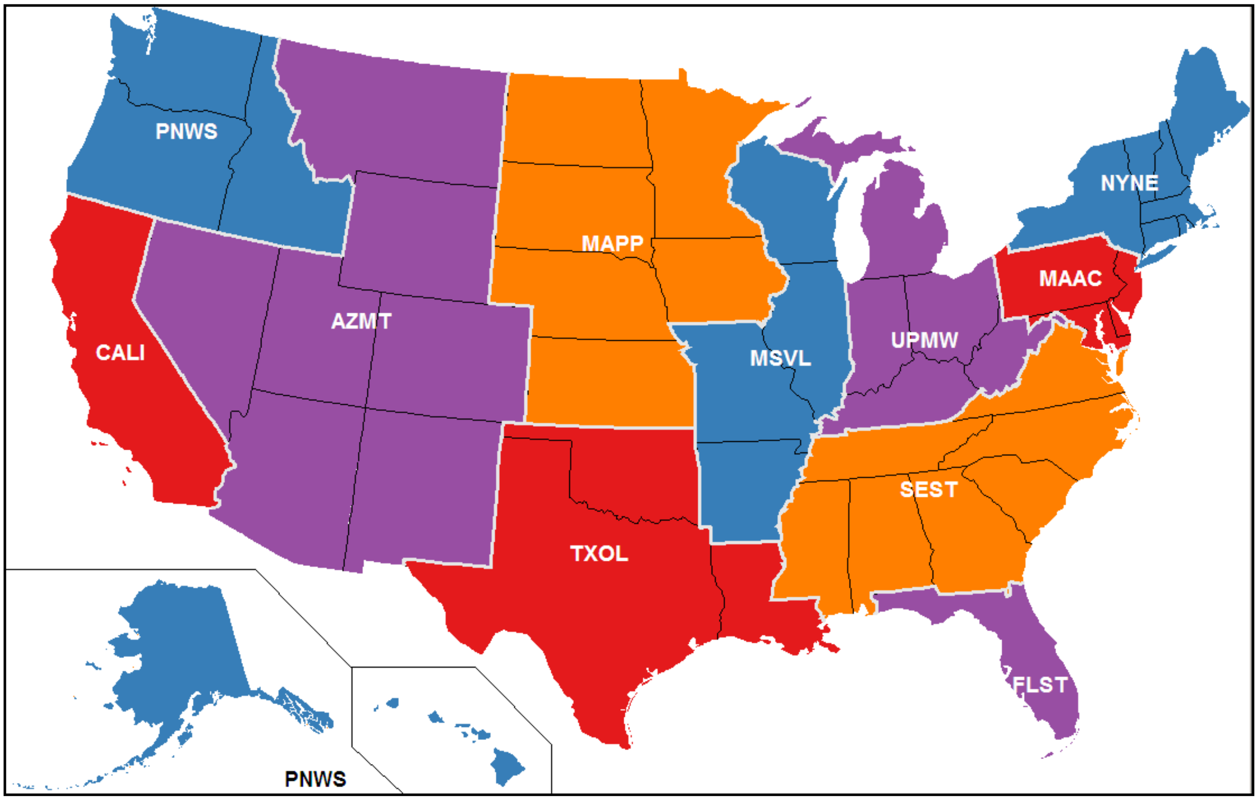
a. Regional Aggregation

The standard N_{ew}ERA macroeconomic model includes 11 regions: NYNE (New York and New England), MAAC (Mid-Atlantic Coast), UPMW (Upper Midwest), SEST (Southeast), FLST (Florida), MSVL (Mississippi Valley), MAPP (Mid-America), TXOL (Texas, Oklahoma and Louisiana), AZMT (Arizona and Mountain states), CALI (California) and (PNWS) Pacific Northwest.[64] The aggregate model regions are built up from the 50 U.S. states' and the District of Columbia's economic data. The model is flexible enough to create other regional specifications, depending upon the need of the project. The 11 N_{ew}ERA macroeconomic model regions and the states within each N_{ew}ERA region are shown in Figure 50.

For this study, the state of Alaska is broken out into its own region in order to model state-specific impacts and the relationship of Alaska with the Lower-48. The Alaska region is disaggregated from the PNWS region where it resides in the standard N_{ew}ERA database. For the sake of avoiding unnecessary modeling complications, we aggregated the regions of the Lower-48 and Hawaii into six regions, for a total of seven regions modeled in N_{ew}ERA.

[64] Hawaii and Alaska are also included in the PNWS region by default.

Figure 50: Standard N_{ew}ERA Macroeconomic Model Regions



b. Sectoral Aggregation

The N_{ew}ERA model includes 12 sectors: five energy sectors (ELE, coal, natural gas, crude oil, and refined petroleum products) and seven non-energy sectors (SRV, MAN, and EIS, and agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors. The model has the flexibility to represent sectors at different levels of aggregation.

c. Natural Gas and Oil Markets

There are great uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA modeling system is designed explicitly to address the key factors affecting future natural gas supply and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on international markets, the N_{ew}ERA modeling system includes two supply curves for U.S. natural gas:

- Conventional natural gas – represents current natural gas production by model region.
- Shale gas represents the potential supply that could come from shale by model region.

By including each type of natural gas, it is possible to incorporate expert judgments and sensitivity analyses about the extent of shale gas reserves, the cost of shale gas production and how it will change as drilling moves to new areas, the impacts of environmental regulations and access restrictions on supply and cost. By combining different possibilities, the model can represent a diverse range of scenarios that leads to different possible natural gas price trajectories.

The natural gas module also accounts for foreign imports and U.S. exports of natural gas, by using a supply (demand) curve for U.S. imports (exports) that represents how the global LNG market price would react to changes in U.S. imports or exports. This makes it possible to provide a consistent analysis of the connection between U.S. import levels, export policy, and the domestic price of natural gas.

Natural gas supply conditions will change over time and the model accounts for depletion of each of the two sources of natural gas by adjusting the available level of the natural gas resource over time. This capability makes it possible to investigate the kinds of assumptions about future shale gas resources and costs that are required to maintain stable prices or lead to rising prices.

The $\mathrm{N_{ew}ERA}$ model represents the domestic and international crude oil and refined petroleum markets. The international markets are represented by flat supply curves with exogenously specified prices. Because crude oil is treated as a homogeneous good, the international price for crude oil sets the U.S. price for crude oil. In the Baseline, we first calibrate the $\mathrm{N_{ew}ERA}$ model to match the desired forecast for crude oil prices (*e.g.*, the price in EIA's latest AEO forecast). For the scenario, we adjust the price of crude oil in response to the change in U.S. demand for crude oil. For example, if we assume a Baseline that omits the recent agreement on CAFE standards between the President and auto manufactures, then a scenario, which analyzed the impacts of this policy, would need to account for the effects of this policy on international crude oil markets and hence on domestic oil prices. Almost certainly the new CAFE standards will lead to lower levels of oil consumption and hence lower levels of demand for crude oil. To capture the effect of lower U.S. demand for international crude oil on international crude oil prices (and hence on U.S. domestic crude oil prices), the $\mathrm{N_{ew}ERA}$ model uses an international oil supply curve based on the EIA's alternate forecasts under different oil prices. For example, if the EIA's scenarios imply a 10% drop in U.S. demand for crude oil would lead to a 1% drop in international crude oil prices, then we would use this elasticity in conjunction with the drop in U.S. crude oil demand to set the international price of crude oil for the CAFE scenario run. This updating, however, is part of the iterative process as the macroeconomic and electric sector models iterate to a global equilibrium solution.

d. Model Features – How LNG export is modeled

There are many uncertainties in the outlook of natural gas supply. To address this, the model has parameters and structural features to calibrate different natural gas supply outlooks. The natural gas supply curve in the Baseline is consistent with the AEO natural gas price and supply quantity by region over time. The shape of the natural supply curve in the model is determined by the natural gas resource supply elasticity and the natural gas resource availability. The model is able to calibrate to either an optimistic or a pessimistic natural gas supply curve by adjusting the supply elasticity and resource. For a given supply elasticity, the availability of the resource in the model determines the natural gas price. A constrained resource supply will result in a higher equilibrium price. Hence, the model is able to target to a desired exogenous natural gas price path.

Consumption of electricity as a transportation fuel could also affect the natural gas market. The $\mathrm{N_{ew}}$ERA model is able to simulate impacts on the supply and disposition of transportation fuels (petroleum-based, biofuels, and electricity) along with responses to consumer driving behavior. Personal driving, or personal transportation services, is represented in the model by vehicle miles traveled, which takes vehicle capital, transportation fuels and other driving expenditures as inputs. The model chooses among changes in consumption of transportation fuels, changes in vehicle fuel efficiency and changes in the overall level of travel in response to changes in the transportation fuel prices.

Along with alternative transportation fuels, the model also includes different vehicle choices that consumers can employ in response to changes in the fuel prices. The model includes different types of Electrified Vehicles: Plug-in-Hybrid Electric Vehicles and Battery Electric Vehicles.

e. Model Outputs

As with other CGE models, the $\mathrm{N_{ew}}$ERA macroeconomic model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include GDP (or GSP), consumption, investment, cost of living or burden on consumers, and changes in "job equivalents" based on labor wage income.

3. Electric Sector Model in $\mathrm{N_{ew}}$ERA Modeling System

The electric sector model that is part of the $\mathrm{N_{ew}}$ERA modeling system is a bottom-up model of the electric and coal sectors. The model is a fully-dynamic model that includes perfect foresight. Thus, all decisions within the model are based on minimizing present value costs over the entire time horizon of the model. The model minimizes present value costs while meeting all specified constraints, most significant of which are demand, peak demand, emissions limits, transmission limits, RPS regulations, fuel availability and new build limits. The model set-up is intended to mimic (as much as is possible within a model) the approach that electric sector investors use to make decisions. In determining the least cost method of satisfying all these constraints, the model endogenously decides:

- What investments to undertake (*e.g.*, addition of retrofits, build new capacity, repower unit, add fuel switching capacity, or retire units);

- How to operate each modeled unit (*e.g.*, when and how much to operate units, which fuels to burn) and what is the optimal generation mix; and
- How demand will respond. The model thus assesses the trade-offs between the amount of demand-side management (DSM) to undertake and the level of electricity usage.

Each unit in the model has certain actions that it can undertake. For example, all units can retire (first year of retirement may be specified to prevent retirements in the near term that likely cannot be accommodated). Any known actions such as planned retirements or planned retrofits (for existing units) or new units under construction can be specified as forced actions. Coal units have more potential actions than other types of units. These include retrofits to reduce emissions of SO_2, NO_X, Hg, and CO_2 (we are also currently exploring representing HCl emissions and technologies that can reduce HCl). Coal units can also switch the type of coal that they burn.

Most of the coal units' actions would be in response to environmental limits that can be added to the model. These include emission caps (for SO_2, NO_X, Hg, and CO_2) that can be applied at the national, regional, state or unit level. We can also specify allowance prices for emissions, emission rates (especially for toxics such as Hg and HCl) or heat rate levels that must be met.

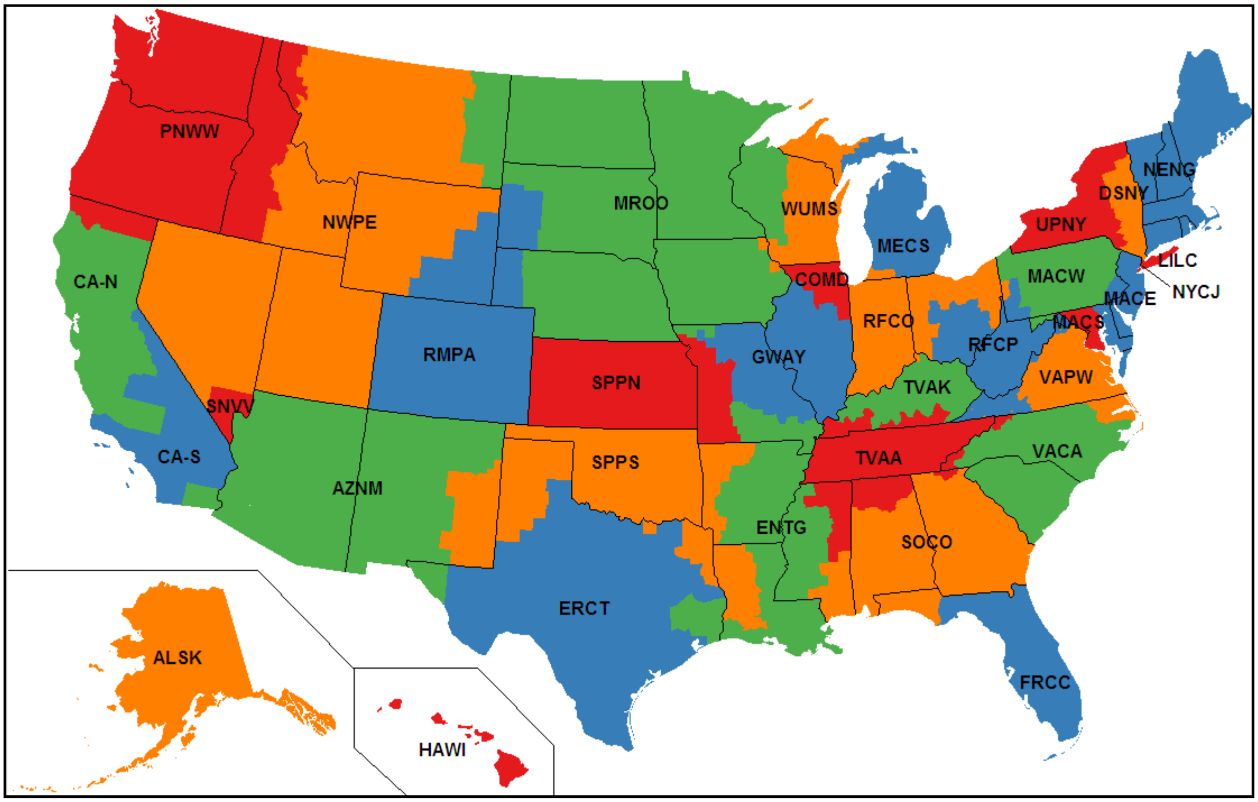
Existing policies that are part of the model include: Title IV for SO_2, the final cross state air pollution rule (CSAPR) for SO_2 and NO_X (annual and seasonal), Regional Greenhouse Gas Initiative for CO_2 in the Northeast, AB32 for CO_2 in California and all existing state renewable portfolio standards.

Just as with investment decisions, the operation of each unit in a given year depends on the policies in place (*e.g.*, unit-level standards), electricity demand, and operating costs, especially energy prices. The model accounts for all these conditions in deciding when and how much to operate each unit. The model also considers system-wide operational issues such as environmental regulations, limits on the share of generation from intermittent resources, transmission limits, and operational reserve margin requirements in addition to annual reserve margin constraints.

To meet increasing electricity demand and reserve margin requirements over time, the electric sector must build new generation. Future environmental regulations and forecasted energy prices influence which technologies to build. For example, if a national RPS policy is to come online, then some share of new generation capacity will need to come from renewable power. If on the other hand, there is a policy to address emissions, then it might elicit a response to retrofit existing fossil-fired units with pollution control technology or enhance existing coal-fired units to burn different types of coals, biomass, or natural gas. Policies calling for improved heat rates may lead to capital expenditure on repowering existing units. All of these policies will also likely affect retirement decisions. The N_{ew}ERA electric sector model captures endogenously all these different types of decisions.

The model currently contains 32 U.S. regions (and six Canadian regions), although we are currently looking into adding Alaska and Hawaii as new regions and splitting some existing regions. Figure 51 shows the U.S. regions.

Figure 51: N$_{ew}$ERA Electric Sector Model – U.S. Regions



The electric sector model is fully flexible in the model horizon and the years for which it solves. To remain consistent with the macroeconomic model and to analyze long-term effects, the model is usually set up to solve out to 2050 in five-year time steps.

a. Generator Representation

Each of the more than 17,000 electric generating units in the United States is represented in the model. Coal units are subject to more decisions in the model than any other type of generator. These include choosing among different coal types, investing in different pollution control equipment and/or being forced to retire. As such, larger coal units (greater than 200 MW) are individually represented in the model and smaller units are aggregated based on region, size, and existing controls. The smaller coal units can also be individually broken out within a region, but this will increase the problem size and possibly slow down the run time. All other types of units are included in different regional aggregates based on their operating characteristics. Again, there is considerable flexibility to break out additional units if that becomes more important to do so.

The model includes the following existing generating technologies:

- coal (including IGCC)
- natural gas combined cycle
- natural gas combustion turbine
- gas/oil steam
- oil combustion turbine
- nuclear
- wind (on-shore)
- hydroelectric (run-of-river and dispatchable)
- pumped storage hydroelectric
- biomass
- geothermal
- landfill gas
- municipal solid waste
- solar photovoltaic
- solar thermal

New technologies in addition to the existing ones include advanced coal with carbon capture and storage (CCS) and off-shore wind. Cumulative and annual addition rates can be specified to reflect real world constraints.

b. Electricity Demand

Electricity demand within the model is represented via load duration curves. These curves are created based on sorting the hourly demand for a region within a season and then aggregating together hours into a load block. The model currently has four seasons and a total of 25 load blocks (ten in the summer and five each in winter, spring, and fall). Four seasons are used to better capture the difference between hydroelectric generation in the spring and fall. Peak demand is also included and is used with reserve margins to determine capacity prices within the model.

Because the electric sector model is a non-linear program and it is integrated with the macroeconomic model, electricity demand can respond to changes in model inputs. This response differs from that of a standard linear program that must maintain demand at a fixed level. Furthermore, the electric sector model's demand constraint allows demand to be satisfied either through electricity production or demand-side management programs. Therefore, in the face of a policy such as a nationwide cap on GHG emissions, the model can choose among meeting demand as forecasted, meeting a lower level of demand (which results in lower values of consumer wellbeing), or implementing DSM programs. The model represents DSM programs through upward sloping supply curves for displaced electricity demand. These curves can be calibrated to the client's views on the cost and availability of various DSM programs. The resources required for the DSM programs are passed to the macroeconomic model just like other resource requirements for the electric sector.

c. Coal Representation

The steam coal sector is represented within the electric sector model of the N_{ew}ERA modeling system. Similar to the flexibility of the electric sector model to aggregate individual units however we choose, we enjoy great flexibility in selecting the number of coal types that we want to include in the model and how they can be mapped to individual coal generators. We also have the ability to model different scenarios for coal exports and/or non-electric coal demand, each of which would have an impact on the price of coal for the electric sector.

The model currently includes 22 steam coals:[65]

- 3 Central Appalachian coals – differentiated by SO_2 content;
- 5 Northern Appalachian coals – differentiated by SO_2 content;
- 1 Southern Appalachian coal;
- 3 Illinois Basin coals – differentiated by SO_2 content;
- 1 Arizona/New Mexico bituminous coal;
- 1 Montana bituminous coal;
- 2 Rockies coals – 1 in Colorado and 1 in Utah;
- 3 Powder River Basin (PRB) coals – 2 in Wyoming and 1 in Montana;
- 2 Lignite coals – one in the Gulf and one in the Dakotas; and
- 1 Import coal – not represented with a supply curve, but instead represented with a price premium relative to a specified coal (Central Appalachian coal).

Existing coal units each have an initial coal specified and, if they have burned any PRB coal, a maximum percentage of PRB coal that the unit can burn. Units can switch to burn more PRB coal than they currently burn, but would incur a capital cost and heat rate and capacity penalties in order to make the switch. Further, units can switch to burning other coals if the coal can be delivered to the unit. In the near term, the model can limit this switching to reflect the coal market realities that would likely limit a good deal of switching in the first few years of an analysis.

Coal use in the non-electric sectors and for exports is an exogenous input to the model, although it can be changed in each scenario. Non-electric coal use is a small share of total coal and likely to not grow. The much greater uncertainty is thermal coal exports, particularly if domestic coal demand is flat or declining. While export demand is currently driven by factors that are not part of the N_{ew}ERA modeling system, we can still develop coal export scenarios. For example, if we

---

[65] Metallurgical coals are represented in the macroeconomic model using a top-down approach. We have had some preliminary discussions about improving the representation of metallurgical coals, but do not anticipate that such a change would happen in the next several months.

have a low natural gas price scenario with strict environmental regulations that lead to significant coal retirements and hence declining domestic coal consumption, we might want to include higher exports of thermal coal than in a scenario without any new environmental limits and with relatively high natural gas prices.

The model utilizes coal supply curves, which paired with inputs for non-electric demand, export demand and endogenously-determined electric sector demand produces coal prices for each coal available in the model. The supply curves include prices at each step of the curve, along with annual production levels and total reserves at the price step. Demand in prior years depletes the total reserves going forward, which generally would lead to higher prices if total reserves at a price step are fully depleted.

There is a complete coal transportation matrix within the model that maps each generating unit to the coals that can be delivered to it, and assigns a transportation cost for each of the deliverable coals. This matrix accounts for costs associated with the different modes of transportation that may be used to deliver the coal, along with the distance that the coal must travel. We have also had some initial discussions about including blending facilities that may be used by generators as coal blending becomes more prevalent, but may be difficult for some units that lack the space needed for multiple coal piles. If this is important, then this is a feature that we would add.

4. Integrated $\mathrm{N_{ew}}$ERA Model

a. General Approach

The $\mathrm{N_{ew}}$ERA modeling framework fully integrates the macroeconomic model and the electric sector model so that the final solution is a consistent equilibrium for both models, and thus for the entire U.S. economy.

To analyze any policy scenario, the system first solves for a consistent baseline solution, and then it iterates between the two models to find the equilibrium solution for the scenario. For the baseline, the electric sector model is solved first under the desired forecasts for electricity demand and energy prices. The equilibrium solution provides the baseline electricity prices, demand, and supply by region as well as the consumption of inputs – capital, labor, energy, and materials – by the electric sector. These solution values are passed to the macroeconomic model.

After the electric sector model solves, the macroeconomic model solves the baseline while constraining the electric sector to replicate the solution from the electric sector model and imposing the same energy price forecasts as those used to solve the electric sector baseline. In addition to the energy price forecasts, the macroeconomic model's non-electric energy sectors are calibrated to the desired exogenous forecast (*e.g.*, EIA's latest AEO forecast) for energy consumption, energy production, and macroeconomic growth. The macroeconomic model solves for equilibrium prices and quantities in all markets subject to meeting the exogenous forecasts.

After solving the baseline, the integrated N_{ew}ERA modeling system solves for the scenario. First the electric sector model reads in the scenario definition (*e.g.*, RPS levels, emission constraints, MACT standards). The electric sector model then solves for the equilibrium level of electricity demand, electricity supply, and inputs used by the electric sector (*i.e.*, capital, labor, energy, emission permits). The electric sector model then passes these equilibrium solution quantities to the macroeconomic model. The modeling system then imposes on the macroeconomic model the appropriate elements of the same policy as imposed on the electric sector. Next, the macroeconomic model solves for the equilibrium prices and quantities in all markets, taking the quantities pertaining to the electric sector as exogenous inputs. The macroeconomic model then passes to the electric sector model the following (solved for equilibrium prices):

- Electricity prices by region;
- Prices of non-coal fuels used by the electric sector (*e.g.*, natural gas, oil, and biofuels); and
- Prices of any permits that are tradable between the non-electric and electric sectors (*e.g.*, carbon permits under a nationwide GHG cap-and-trade program).

The electric sector model then solves for the new electric sector equilibrium taking the prices from the macroeconomic model as exogenous inputs. The framework iterates between the two models – prices being sent from the macroeconomic model to the electric sector model and quantities being sent from the electric sector model to the macroeconomic model – until the prices and quantities in the two models differ by less than a fraction of a percent.

b. Policy Analysis Capabilities

The N_{ew}ERA modeling system has the capability to evaluate a range of current and proposed policies. Because the NERA team developed the N_{ew}ERA model, we are intimately familiar with how the model responds to various constraints and therefore are able to logically and effectively represent policies designed by regulators within our model. That is for any policy, we know exactly how to implement the real world policies so that the modeled policy affects the economy in a similar manner to how the policy would actually affect the economy.

As an example of policy capabilities, the N_{ew}ERA model can represent the following policies and types of policies:

- Emission taxes or prices;
- Emission cap-and-trade programs (*e.g.*, Title IV or CSAPR);
- Renewable portfolio standards (state, regional or national);
- Efficiency standards in electric and non-electric sectors (*e.g.*, MACT, heat rate standards, CAFE);
- Mandated construction of new builds or retrofits (or requirements to retrofit or retire);

- Financial incentives (*e.g.*, for renewables or for electric vehicles); and
- Low carbon fuel standards.

c. Advantages of an Integrated Modeling System

When modeling policies that will have significant impacts on the entire economy, one needs to use a model that captures the effects of the policy as it ripples through all sectors of the economy and the feedback effects of these impacts on production and consumption decisions. Of further desire is to use a model that also provides detail on the areas of the economy that are most affected by the policies of interest.

Because of computational limitations and differences in the goals, developing one single model to perform both tasks is infeasible. Therefore, the best solution is to construct an integrated modeling system. To this end we have brought together our top-down, macroeconomic model and our bottom-up electric sector model. A macroeconomic, general equilibrium model can account for the ripple and feedback effects of economy-wide policies, but because of computational issues, these models are unable to represent many specific sector interactions in great detail. Therefore, these models are referred to as top-down models. Models that address the impacts to one sector, or bottom-up models, are well suited to capture the details of the policy impacts on this particular sector, but these models cannot fully capture the feedback of the impacts on the particular sector on the rest of the economy and the impacts of the rest of the economy on the particular sector.

By combining our electric sector and macroeconomic models, we eliminated the shortcomings of each and created our fully integrated N_{ew}ERA model. The integrated framework combines a technologically rich bottom-up model with a top-down macroeconomic model of the rest of the economy to provide a consistent equilibrium.

The main benefit of this integrated framework is that the electric sector can be modeled in great detail as a bottom-up model. Electric technologies within the bottom-up model can be well represented according to engineering specifications. Such a consistent analysis would not be possible in a partial equilibrium framework as it would miss the feedback effects from rest of the economy, hence a partial equilibrium model would provide distorted results.

The integrated modeling approach provides consistent price responses since all sectors of the economy are modeled. For example, evaluating natural gas price response, which is consumed in both the electric and non-electric sectors, by just considering the changes in the electric sector (under a partial equilibrium analysis) will lose the changes that happen to the non-electric sectors thus providing an inaccurate response. Likewise employing only a top-down model of the economy would fail to correctly capture the coal-gas trade-off in the electricity sector.

NERA
ECONOMIC CONSULTING

NERA Economic Consulting
1255 23rd Street NW
Washington, DC 20037
Tel: +1 202 466 3510
Fax: +1 202 466 3605
www.nera.com