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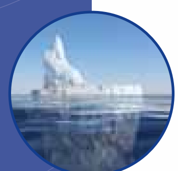

Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas

Charles Ebinger
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Preface

In May 2011, The Brookings Institution Energy Security Initiative (ESI) began a year-long study into the prospects for a significant increase in liquefied natural gas (LNG) exports from the United States.

To inform its research ESI assembled a Task Force of independent natural-gas experts, whose expertise and insights provided the foundation for this study. The conclusions of this report are those of the authors and do not necessarily reflect the views of the members of the task force.

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Executive Summary

Driven by technological breakthroughs in unconventional gas production, major increases in U.S. natural gas reserves and production have led to supply growth significantly outpacing forecasts in recent years. As a result, natural gas producers have sought new and additional sources of demand for the newfound volumes. One proposed end-use is the exportation of U.S. natural gas in the form of liquefied natural gas (LNG). While the United States already exports modest quantities of natural gas, mostly via pipeline, current proposals, some of which have already received full or partial approval from the federal government, would increase substantially the volume of LNG exports. There is a growing debate between policymakers, industry, and energy analysts as to the merits of exporting greater quantities of U.S. natural gas. Some domestic natural gas consumers contend that exporting U.S. gas would result in an increase in domestic natural gas prices and therefore in higher prices for businesses and households. Proponents of natural gas exports argue that they would provide valuable foreign exchange and would be a source of economic growth and job creation.

This report, the result of a year-long study, addresses the merits of increased LNG exports through an examination of the feasibility of exports and their likely implications. It concludes that, given current information on resources, increased LNG exports from the United States are technically feasible. While new policies may serve to change the logistics or economics of shale gas production, under current circumstances, the challenges to LNG exportation, including physical and human capacity and demands for natural gas from competing domestic sectors, are not insurmountable. It also finds that, in light of current global supply and demand projections, some amount of U.S. LNG exports is likely to be competitive in global markets. The study finds that U.S. LNG exports are likely to have a modest upward impact on domestic prices, and a limited impact on the competitiveness of U.S. industry and job creation. It finds that U.S. LNG is likely to make a positive, albeit relatively small, contribution to the U.S. gross domestic product (GDP), trade balance, and that the potential for U.S. LNG exports to make a positive impact on global greenhouse gas emissions is minimal. It further finds that there is potential for positive foreign policy impacts from U.S. entry in the global gas market, through both increased supply diversity for strategic gas-importing allies, and as a contributory factor in weakening the oil-linked contract pricing structure that works to the advantage of rent-seeking energy suppliers.

The study recommends that U.S. policy makers should refrain from introducing legislation or regulations that would either promote or limit additional exports of LNG from the United States. The nature of the LNG sector, both the costs associated with producing, processing, and shipping the gas, and the global market in which it will compete, will place upper bounds on the amount of LNG that will be economic to export. Incremental increases in the price of domestic gas (as a result of domestic demand or export) negatively impact the economics of each additional proposed export project, which even with government approval will still require private financing and interested buyers. Efforts to intervene in the market by policy makers are likely to result in subsidies to consumers at the expense of producers, and to lead to unintended consequences. They are also likely to weaken the position of the United States as a supporter of a global trading system characterized by the free flow of goods and capital.

Introduction

Less than a decade ago, the United States was facing a major shortfall in the supply of natural gas as declining conventional production and reserves were outpaced by rising demand. The situation was so acute that private companies, encouraged by federal-government policies, began constructing import terminals for LNG, which was regarded as the only way to meet growing demand.[1] Since 2005, the situation has dramatically reversed. Driven by advances in exploration and production technology and a precipitous rise in the price of natural gas to 2008, the U.S natural gas sector has undergone a revolution as vast amounts of previously uneconomic "unconventional" resources in shale formations across the Northeast, Midwest, and South have been developed.

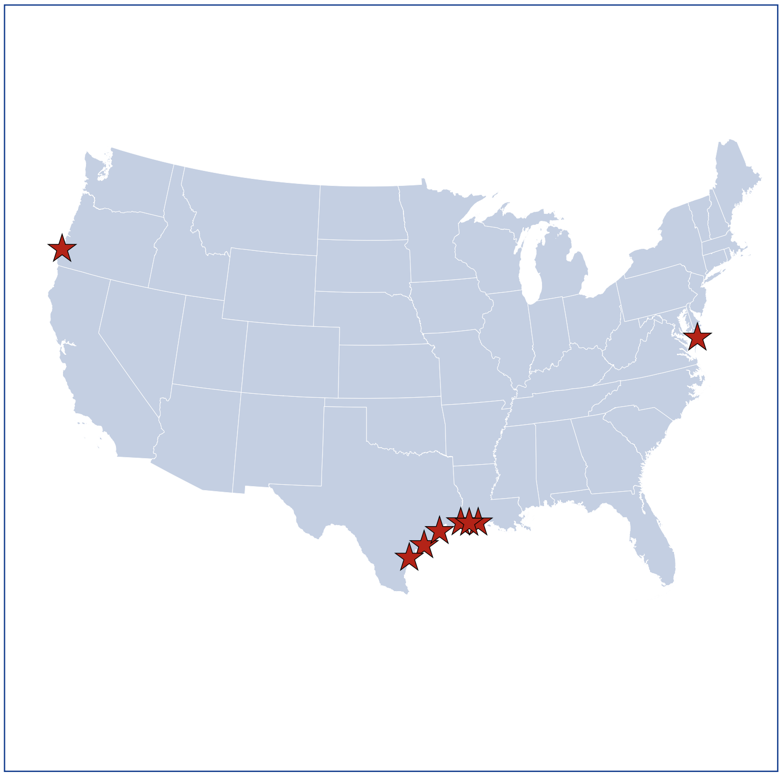
Early estimates of the size of the unconventional gas resource have varied. However, it is clear to producers and end users alike that the increased available volumes of shale gas mean that there is far more potential for natural gas in the U.S. energy mix than previously estimated. While the domestic focus has been on the potential for increased natural gas use in the power, industrial, petrochemical, and transportation sectors, there is also increased interest among policy makers and private investors in the prospect of the United States becoming a significant exporter of LNG (see **Figure 1** for a list of proposed and potential lower-48 LNG export terminals).

The United States already exports modest volumes of natural gas via pipeline to Mexico and Canada and, until November 2011, in the form of LNG from the Kenai Terminal in Alaska to Japan, although the latter facility has recently been temporarily idled.[2] Several projects currently under consideration would involve the development of liquefaction facilities to enable the export of LNG in increased quantities. These proposed projects, some of which have been given partial approval by the federal government over the past year, are currently evaluated by energy and environmental regulators on a case-by-case basis.

[1] The 2005 Energy Policy Act demonstrated Federal government support for a streamlined LNG import process through both codification of the 2002 "Hackberry Decision" by the Federal Energy Regulatory Commission (FERC), which absolved U.S. LNG import terminals from open-access requirements and allowed them to charge market based rates; and by granting FERC exclusive authority to approve siting, construction, expansion and operation of such import terminals.

[2] The Kenai liquefaction plant, inaugurated in 1969, exported to Japan modest amounts (30 bcf in 2010) of gas produced from the Cook Inlet. ConocoPhillips, the owner and operator of the facility, had initially planned on closing the plant in March 2011 due to an inability to renew supply contracts; however, following the earthquake and subsequent nuclear disaster in Japan, it decided to extend operations of the plant for six months to allow for additional shipments to Japan.

Figure 1: Proposed/Potential North American LNG Export Terminals (as of February 28, 2012)



Source: Federal Energy Regulatory Commission, Department of Energy

FTA and non-FTA Approved Projects (approval by Depaertment of Energy):

- Sabine Pass, Louisiana (Cheniere Energy): 2.2 bcf/day;proposed to FERC

FTA Approved Projects:

- Freeport, Texas (Freeport LNG): 1.8 bcf/day; proposed to FERC
- Lake Chalres, Louisiana (BG and Southern Union): 2.0 bcf/day
- Cove Point, Maryland (Dominion): 1.0 bcf/day
- Hackberry, Louisiana (Cameron LNG): 1.7 bcf/day
- Coos Bay, Oregon (Jordan Cove Energy): 1.2 bcf/day

Awaiting Approval

- Corpus Christi, Texas (Cheniere Energy): 1.8 bcf/day; proposed to FERC
- Brownsville Texas (Gulf Coast to LNG Export): 2.8 bcf/day

Note: two other companies are looking to export a total of 0.3 bcf/day of LNG from various locations.

Supporters of these projects maintain that they will provide a valuable source of economic growth, gains from trade, and job creation for the United States. Opponents contend that they will raise domestic natural gas prices to the detriment of U.S. consumers and negatively affect U.S. energy security.

The Brookings Institution's Energy Security Initiative has undertaken a year-long study to assess the feasibility and implications of an increase in U.S. LNG exports. To inform its research, ESI assembled a Task Force of independent natural gas experts, whose discussions and deliberations provide the basis of the project's conclusions. The conclusions of this report are the authors' alone and do not necessarily represent the views of the Task Force. This report represents the conclusion of the study, and is structured in two parts. Part I assesses the **feasibility** of LNG exports and the factors that are likely to have a bearing on the ability of the United States to export more gas. Part II looks at the **implications** of significantly increased LNG exports from the United States. Part III presents the study's findings and conclusions and offers recommendations to policy makers.

Part I: Feasibility

For the purpose of this study, the Brookings research team identified the various factors that affect the feasibility of increased U.S. LNG exports. These factors were divided into four main categories: domestic supply, domestic demand, international gas markets, and economic rationale. On the supply side, feasibility is defined as the physical capacity of the United States to have gas volumes available for export. Factors in this regard include: resource availability and production sustainability; regulatory and environmental considerations; and infrastructure issues, including pipeline availability, storage, and shipping capacity. On the demand side, feasibility of exports is defined by the extent to which potential exports compete with various domestic end uses for increased natural gas, including electricity generation, transportation, and industrial and petrochemical production. With regard to international markets, feasibility is the extent to which potential U.S. exports can compete with other LNG sources to meet demand, and includes an assessment of the potential markets that U.S.-origin LNG would serve. It also includes an assessment of the nature of contractual pricing agreements, particularly the linkage between natural gas prices and oil prices in target markets. Economic feasibility assesses factors other than feedstock costs that have a bearing on the extent to which LNG exports have a long-term positive return on investment, and includes the costs of liquefaction, transportation, and regasification, and the availability of financing.

Domestic Supply Factors

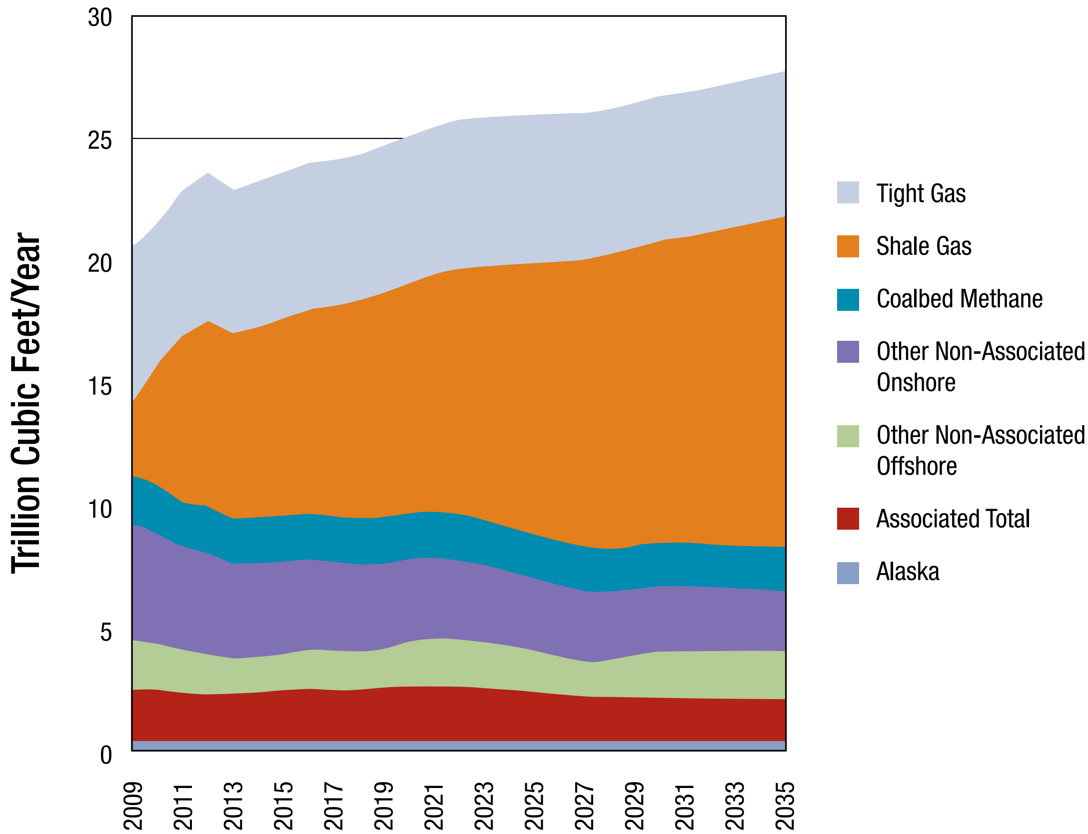
The domestic U.S. natural gas supply situation is determined primarily by three sets of factors: resource availability and production sustainability; policy, regulatory, and environmental considerations; and capacity and infrastructure constraints.

Resource Availability and Production Sustainability

For an increase in U.S. exports of LNG to be considered feasible, there has to be an adequate and sustainable domestic resource base to support it. Natural gas currently accounts for approximately 25 percent of the U.S. primary energy mix.[3] While it currently provides only a minority of U.S. gas supply, shale gas production is increasing at a rapid rate: from 2000 to 2006, shale gas production increased by an average annual rate of 17 percent; from 2006 to 2010, production increased by an annual average rate of 48 percent (see Figure 2).[4] According to the Energy Information Adminis-

[3] "AEO 2012 Early Release Overview," Energy Information Administration (EIA, 2012a).
[4] Annual Energy Outlook 2011 with Projections to 2035," Energy Information Administration, April 2011. pp. 37, 39. (EIA, April 2011a)

Figure 2: U.S. Natural Gas Production by Source, 2009-2035 (tcf/year)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011

tration (EIA), shale gas production in the United States reached 4.87 trillion cubic feet (tcf) in 2010, or 23 percent of U.S. dry gas production. By 2035, it is estimated that shale gas production will account for 46 percent of total domestic natural gas production.[5]

Given the centrality of shale gas to the future of the U.S. gas sector, much of the discussion over potential exports hinges on the prospects for its sustained availability and development. For exports to be feasible, gas from shale and other unconventional sources needs to both offset declines in conventional production and compete with new and incumbent domestic end uses. There have been a number of reports and studies that attempt to identify the total amount of technically recoverable shale gas resources—the volumes of gas retrievable using current technology irrespective of cost—available in the United States. These estimates vary from just under 700 trillion cubic feet (tcf) of shale gas to over 1,800 tcf (see **Table 1**). To put these numbers in context, the United States consumed just over 24 tcf of gas in 2010, suggesting that the estimates for the shale gas resource alone would be enough to satisfy between 25 and 80 years of U.S. domestic demand.[6] The estimates for recoverable shale gas

[5] Ibid.

[6] "U.S. Natural Gas Production, Consumption, and Net Imports," Energy Information Administration, (http://www.eia.gov/todayinenergy/detail.cfm?id=770)

resources also compare with an estimate for total U.S. gas resources (onshore and offshore, including Alaska) of 2,543 tcf.[7] Based on the range of estimates below, shale gas could therefore account for between 29 percent and 52 percent of the total technically recoverable natural gas resource in the United States.

Table 1. Comparison of shale gas estimates for the Lower 48 States, (Technically Recoverable Resources, excluding proven reserves; in tcf)

	Reserve Estimate (tcf)
ICF	1,842
Advanced Resources International	1,189
Energy Information Administration (EIA), 2011	827
Potential Gas Committee	687

Source: ICF International, Advanced Resources International, EIA, Potential Gas Committee.

Sustainability of Shale Gas Production

In addition to the size of the economically recoverable resources, two other major factors will have an impact on the sustainability of shale gas production: the productivity of shale gas wells; and the demand for the equipment used for shale gas production. The productivity of shale gas wells has been a subject of much recent debate, with some industry observers suggesting that undeveloped wells may prove to be less productive than those developed to date. However, a prominent view among independent experts is that sustainability of shale gas production is not a cause for serious concern, owing to the continued rapid improvement in technologies and production processes.

The sustained productivity of shale gas wells rests primarily on technological developments in two areas: the hydraulic fracturing ("fracking") process, in which water, sand, and other chemicals are forced at high pressure into rock formations to free trapped gas; and the length of horizontal wells ("laterals") drilled into the shale layer. Shale gas technologies and production processes have been developing rapidly in recent years, improving the economics of extraction. Companies now are drilling longer laterals and are increasing the number of frack stages—the number of different fracking sections in each lateral section—per well, leading to an increase in available reserves and well productivity.[8] An analysis of well-specific-data illustrates that both initial production rates and ultimate well recovery have been growing across all production regions (or "plays"), thereby driving down per unit costs of production.

A more immediate consideration with regard to production sustainability is the availability of drilling equipment and skilled labor. In addition to the demands for the latter from an increasing number of shale gas prospects, there is increasing competition from producers of shale oil and other "tight" oil resources, which use the same equipment to yield a product that is more valuable than gas at current market prices; and from producers who are more interested in plays rich in natural gas liquids, a valuable by-product of dry gas production. Formations such as the Eagle Ford Shale in Texas and the Utica Shale in Ohio and New York, which have higher condensate ratios—the ratio of liquids produced with gas production—have seen increasing interest from producers over the past two years. The displacement of rigs from "dry gas" prospects, such as the Haynesville Shale in Louisiana, to "wetter" prospects such as the Bakken field in North Dakota, is already occurring, as

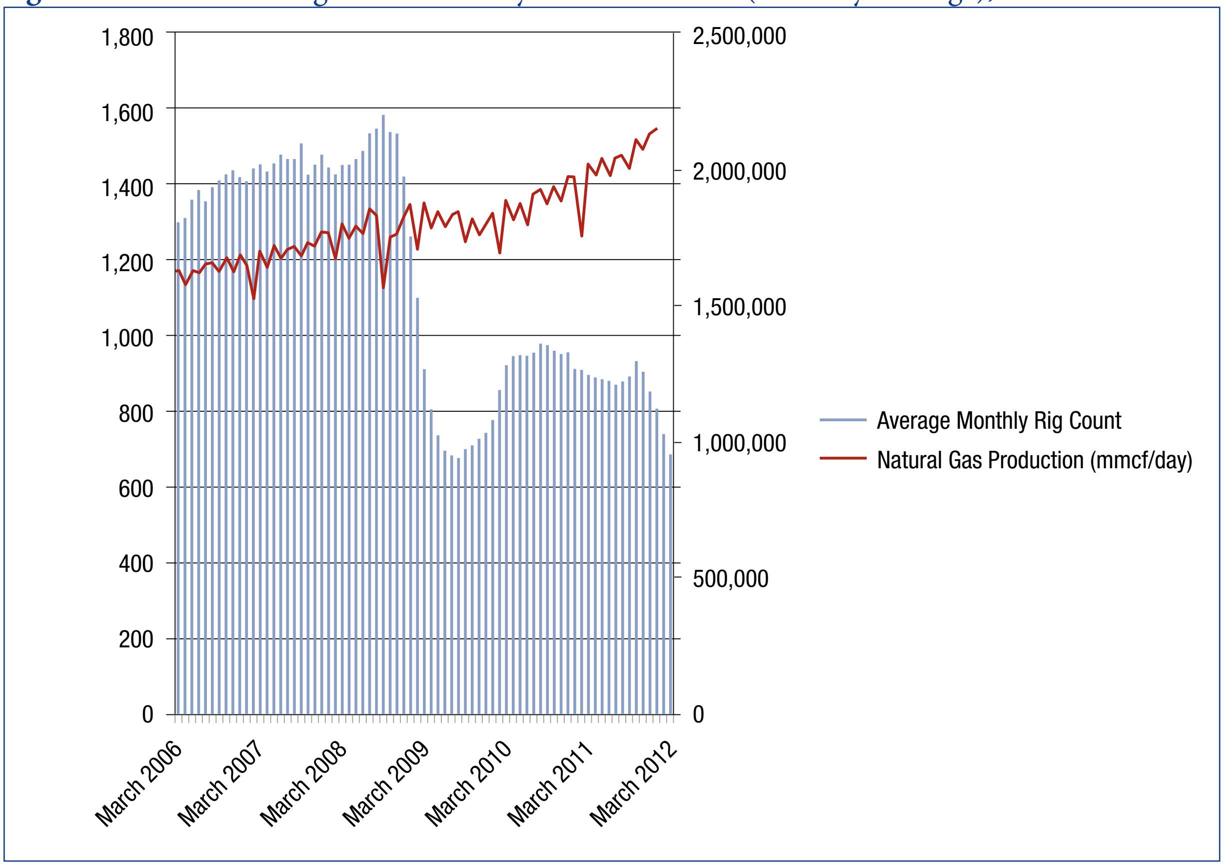
[7] "Assumptions to the Annual Energy Outlook 2011," Energy Information Administration, 2011.
[8] "U.S. Natural Gas Resources and Productive Capacity," Advanced Resources International, prepared for Cheniere Energy, April 26, 2010. "Exhibits to Application of Sabine Pass Liquefaction, LLC for Long-Term Authorization to Export Liquefied Natural Gas," U.S. Department of Energy. p. 275. Also see "Natural Gas Industry Fakes the Moon Landing," EPRINC Briefing Memorandum, Energy Policy Research Foundation, Inc., July 1, 2011. (EPRINC, July 2011)

evidenced by the declining gas rig count in the gas sector. Owing to technological improvements and the availability of associated dry gas at liquids-rich plays, dry production is keeping pace despite the declining rig count (see **Figure 3**).[9]

Environmental, Regulatory, and Stakeholder Considerations for Natural Gas Production

The case for U.S. LNG exports depends heavily on the continued development of unconventional gas. This development itself depends on the safe and sustainable continuation of the practice of fracking, a process that has been under intense public scrutiny since shale gas production increased. The conclusions of a 2011 report conducted by the Secretary of Energy's Advisory Board (SEAB) into the practices and oversight of shale gas development found that "absent action there will be little credible progress in reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource."[10] Concern around the negative environmental impact of shale gas development has led to the formation of local opposition groups, some of which call for outright bans on fracking. For its part, industry views the regulatory uncertainty around shale gas as among the greatest challenges to development.

Figure 3: Natural Gas Rig Count and Dry Gas Production (Monthly Average), 2006-2012



Source: Baker Hughers, EIA

[9] EPRINC, July 2011.
[10] "The SEAB Shale Gas Production Subcommittee Second Ninety-Day Report," Natural Gas Subcommittee of the Secretary of Energy Advisory Board, November 18, 2011. p.3. (SEAB, 2011)

Environmental Issues

There are three main environmental issues that need to be addressed if shale gas production is to continue at scale and provide the benefits many foresee: water, emissions, and other pollution such as noise and disruption caused by work-site activity.

The issue of water has been the most prominent to date, with the main focus being on the risk of contamination of surface water and water tables, the volume of water used in the process of fracking, and the disposal of waste water from the fracking process. The risk of groundwater contamination from fracking has been the subject of vigorous debate. Some environmental advocates charge that the technique can lead to seepage of gas and chemicals into water supplies, while energy companies maintain that correctly installed well casings combined with the depth of fracking operations—most of which are many thousand feet beneath the water table—make the process safe for drinking water supplies.

With regard to emissions, the major focus has been on unintentional leaks of natural gas, or "fugitive emissions," intentional venting of gas, and flaring. The latter issue is a particular concern in light of the developments at some shale oil plays, such as the Bakken and Niobrara. At both sites, the production of oil requires the production of large volumes of associated natural gas. Given the focus on the higher-value liquids production and the pace of development of these fields, the infrastructure for gathering and transporting this associated gas has not been adequately developed. The result is that large amounts of gas are being flared. In North Dakota, home of the Bakken shale oil field, roughly 30 percent of gas produced—over 3 billion cubic feet (bcf) per month—is currently flared; the percentage of flared gas from production at the Niobrara shale formation that straddles Colorado, Wyoming and Nebraska is considered by industry experts to be much higher.[11] There are concerns that the rapid development of NGL-rich shale plays, such as Eagle Ford and Utica, may similarly result in the flaring of associated dry gas, which is less valuable than natural gas liquids (NGLs).

A recent academic study suggested that, after considering "fugitive" methane emissions and venting, life-cycle emissions from natural gas production are higher than those from other fossil fuels, including coal. A number of studies by national laboratories, academics, and other analysts, however, have disputed this finding, concluding that the life-cycle emissions of shale gas used for power generation are still roughly 50 percent of those from coal.[12]

Other environmental issues that have been raised by opponents of fracking include the possibility of a link between fracking and seismic disruption, and issues of potential "fracture communication" through which fracking operations interact with existing natural geologic fractures, leading to a higher risk of groundwater contamination. There are also concerns that the disposal of wastewater through injection wells may cause seismic disruptions. The USGS has found that any seismic activity resulting from fracking is "almost always too small" to be a safety concern. The injection of wastewater from the fracking process into deep wells is the subject of further investigation.

[11] From the "Director's Cut" by the North Dakota Industrial Commission Department of Mineral Resources, July 21, 2011. (https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2011-07-21.pdf)

[12] For the former study see Robert Howarth et al, "Methane and the greenhouse gas footprint of natural gas from shale formations," Climatic Change Letters, 2011. For examples of responses to this study or national laboratory studies on the issue see: Nathan Hultman et al, "The greenhouse impact of unconventional gas for electricity generation," Environmental Research Letters, Vol. 6, no. 4 (October-December 2011); Mark Fulton et al, "Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal," Worldwatch Institute and Deutsche Bank Group Climate Change Advisors, August 25, 2011; and "Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production," National Energy Technology Laboratory, U.S. Department of Energy, October 24, 2011.

Regulatory Oversight for Natural Gas Production

A range of state and federal government agencies have jurisdiction over fracking and other aspects of natural gas development, and the extent to which, and the ways in which, these agencies implement regulations on shale gas production will have a major impact on the viability of exports.

Environmental Protection Agency

The Environmental Protection Agency (EPA) has a number of statutory authorities that apply to the regulation of shale gas production, including ensuring that harmful gases and pollutants are not released into the air (through the Clean Air Act) and that water supplies are kept free from waste water or methane leakages (through the Clean Water Act and Safe Drinking Water Act). The principal concerns for the EPA regarding shale gas production relate to water consumption, treatment, and storage.[13] Owing to the provisions of the 2005 Energy Policy Act, the EPA's regulation of underground injection of fluids relating to fracking under the Safe Drinking Water Act is limited to those operations that use diesel-based fracking fluids. However, the agency is addressing the issue of fracking through a variety of other statutory authorities.

As required by Congress, the EPA has begun a study on shale gas and fracking that focuses on five areas of water usage: water withdrawals, surface spills of fracking fluids, impacts of injection on drinking water, impacts of flowback and produced water, and wastewater treatment and disposal. The results of the study are due by the end of 2014, with an interim report scheduled for release in 2012. In October 2011, the EPA announced it would use the Clean Water Act to regulate the disposal of waste water produced by fracking. The agency is currently engaged in discussions with the various stakeholders and will announce a proposed rule by 2014.[14]

The EPA has also recently announced that it will use the Toxic Substances Control Act (TSCA) to "[initiate] a proposed rulemaking process … to obtain data on chemical substances and mixtures used in hydraulic fracturing."[15] Acknowledging that some states already engage in this practice, the EPA announced that it would complement, not duplicate, such efforts and that it would provide an "aggregate picture" of the chemical compounds used in fracking fluids.

In December 2011, the EPA released a draft analysis of data from an investigation into ground water quality in Pavillion, Wyoming. The draft report indicates that ground water in the aquifer under review contained "compounds likely associated with gas production practices including hydraulic fracturing," and that chemical samples were "generally below established health and safety standards."[16] The draft report has galvanized opponents of fracking. Responses to the report from gas industry representatives focus on the inconclusiveness of the findings and the possibility of the natural occurrence of some of the chemicals discovered in the samples. On March 8, 2012 the EPA, the State of Wyoming, and relevant Native American tribes in the region agreed that the peer review period would remain open until a report containing U.S. Geological Survey

[13] In November 2011, the EPA released its plan to study, at the request of Congress, the impacts of hydraulic fracturing on water resources. The report states that "many concerns about hydraulic fracturing center on potential risks to drinking water resources, although other issues have been raised." ("Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources," U.S. Environmental Protection Agency, November 2011. p. viii.)

[14] "Natural Gas Extraction—Hydraulic Fracturing," U.S. Environmental Protection Agency. (http://www.epa.gov/hydraulicfracture/).

[15] "Natural Gas Extraction—Hydraulic Fracturing," U.S. Environmental Protection Agency. (http://www.epa.gov/hydraulicfracture/).

[16] "EPA Releases Draft Findings of Pavillion, Wyoming Ground Water Investigation for Public Comment and Independent Scientific Review," Environmental Protection Agency, November 8, 2011.

(USGS) data becomes publicly available.[17] More recently, the EPA reported that it found no contamination levels that present health concerns at Dimock, Pennsylvania, the site of an existing lawsuit against a shale gas producer.

In addition to its focus on water, the EPA has several initiatives that focus on air quality and pollution. On April 17, 2012, it finalized rules for regulating air pollutants from fracking-related operations intended to significantly cut the amount of volatile organic compound (VOC) emissions from the completion of hydraulically fractured oil and gas wells. The regulations, which will come into effect in 2015, are expected by the EPA to reduce emissions from shale gas wells by as much as 95 percent.

Bureau of Land Management

The Bureau of Land Management (BLM) within the U.S. Department of Interior oversees the development of oil and gas resources on Federal land. While BLM does not need to approve "routine" fracking operations, such operations must be reported to the Bureau by the companies carrying them out within 30 days. "Non-routine" fracking operations require prior approval by the Bureau. However, as with the EPA's oversight of fracking, there is currently no definition for what constitutes a "routine" or a "non-routine" operation. Currently, BLM recommends and encourages the best land and water management practices for shale gas production. Secretary of the Interior Ken Salazar has also publicly stated that he is considering possible regulations for the disclosure of chemicals used in fracking on federal lands. Salazar announced in February 2012 that natural gas companies will be required to inspect wells after fracking on public lands to ensure safe drinking water supplies.[18]

Regional and State-Level Regulation

As large-scale shale gas production is a relatively new phenomenon, several aspects of the regulatory regime—including issues of federal-versus-state jurisdiction—have yet to be resolved. Currently, most states implement their own regulatory requirements for oil and gas production with the EPA having responsibility for ensuring that shale gas production meets national standards for air, dust, and water consumption and treatment. While many companies agree that a degree of regulation is necessary for certain practices, they are divided in their opinion on whether federal or state regulators should have jurisdiction over them: some think comprehensive federal oversight would stifle shale gas production, while others see the prospect of a single set of regulatory requirements as preferable to a patchwork of state-level rules.

Some notable state- and regional-level regulatory activity on shale gas production includes:

- The Texas Railroad Commission's June 2011 legislation that requires the development of regulations that mandate the disclosure of the composition of fluids used in hydraulic fracturing.[19]

- A commitment by Pennsylvania Governor Tom Corbett in October 2011 to implement a range of recommendations of that state's Marcellus Shale Advisory Commission, including provisions extending liability periods, increasing impact fees, and increasing the distance of shale-gas wells from private and public bodies of water.

[17] "Statement on Pavillion, Wyoming groundwater investigation," Environmental Protection Agency, March 8, 2012. (http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/17640d44f5be4cef852579bb006432de!opendocument)

[18] "Gas Well Inspections to be Required after Fracking, Salazar Says," *Bloomberg,* February 14, 2012. (http://www.bloomberg.com/news/2012-02-14/gas-well-inspections-to-be-required-after-fracking-salazar-says.html)

[19] Bill H.B. No. 3328, "An Act relating to the disclosure of the composition of hydraulic fracturing fluids used in hydraulic fracturing treatments," the 82nd Legislature, Government of the State of Texas. (http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=82R&Bill=HB3328).

- New York's temporary moratorium on fracking, which halted new fracking operations in the state. The Governor's office has put forward a draft environmental impact study for public comment, the results of which will inform a decision on whether to permit fracking to continue with specific exemptions.

- West Virginia's Joint Select Committee on Marcellus Shale's passage of a bill that increases drilling permit fees, with increased revenues allocated to the hiring of more well inspectors. The bill, which also lays out new terms for compensation to surface owners for damage to property, and minimum distances between wells from homes and drinking water, still needs to be voted on by the full state legislature.

- Colorado and Wyoming's mandatory requirement for "green completion" of natural gas wells, through which gas and vapors that would usually escape into the atmosphere during the completion phase of a well are captured and sold.

- The Delaware River Basin Commission's (DBRC, a federal interstate government agency comprised of the four basin states), consideration of new regulations on oil and gas production—and the attendant water consumption and disposal—within the basin. According to the DRBC, about 36 percent of the basin lies over the Marcellus Shale.[20]

- Pennsylvania's passage of a bill in February 2012 to allow counties to levy fees on natural gas wells, which is expected to generate about $211 million in revenues a year. Most of the money will go to communities affected by the drilling in Pennsylvania's portion of the Marcellus.[21]

The importance of state-level regulation of shale gas development was highlighted by the SEAB report, which recommended increased federal funding for the State Review of Oil and Natural Gas Environmental Regulations (STRONGER), and the Ground Water Protection Council, two existing organizations that help states to develop regulations and best practice.[22]

Other inter and intrastate authorities with influence over the regulatory environment for the development of shale gas include other river basin commissions; and municipal, town and village governments. The extent to which state law supersedes or conforms to local-level rulings on fracking and other aspects of shale gas production will have a significant bearing on the sustainability of shale-gas development operations.[23]

Environment, Regulations, and the Feasibility of LNG Exports

While several studies are ongoing into the effects of shale gas production on the environment, there has been no conclusive evidence found to date that links the practice of fracking to ground water contamination or increased seismic activity. As long as the current regulatory environment re-

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[20] "Natural Gas Drilling in the Delaware River Basin," Delaware River Basin Commission. (http://www.state.nj.us/drbc/naturalgas.htm)

[21] Romy Varghese, "Pennsylvania Set to Let Counties Put Fees on Natural-Gas Wells," *Bloomberg,* February 10, 2012. (http://www.businessweek.com/news/2012-02-10/pennsylvania-set-to-let-counties-put-fees-on-natural-gas-wells.html).

[22] SEAB, 2011, p.3.

[23] For an excellent analysis of the range of regulatory actors in the Marcellus Shale, see Andrew Blohme et al, "Impact of shale gas policy on domestic and international natural gas markets," Center for Integrative Environmental Research, University of Maryland, October 2011.

Table 2: Applications Received by the Department of Energy to Export LNG from the Lower-48 States (as of March 23, 2012)

Facility	Quantity	Location	FTA approved	Non-FTA approved
Sabine Pass	2.2 bcf/day	Louisiana	Yes	Yes
Freeport	1.4 bcf/day	Texas	Yes	Under Review
Lake Charles	2.0 bcf/day	Louisiana	Yes	Under Review
Carib Energy	FTA: 0.03 bcf/day Non-FTA: 0.01 bcf/day	various	Yes	Under Review
Dominion Cove Point	1.0 bcf/day	Maryland	Yes	Under Review
Jordan Cove Point	1.2 bcf/day	Oregon	Yes	Under Review
Cameron LNG	1.7 bcf/day	Louisiana	Yes	Under Review
Gulf Coast LNG Export	2.8 bcf/day	Texas	Under Review	Under Review
Cambridge Energy	0.27 bcf/day	various	Under Review	n/a

Source: U.S. Department of Energy

mains, shale gas development is likely to continue to produce the volumes that will make LNG exports feasible. However, a change in the regulatory landscape that imposes additional costs on producers could make marginal shale gas prospects uneconomic, reducing the size of the economically recoverable resource, thereby negatively affecting the feasibility of LNG exports. Conversely, well developed regulations, possibly based on sustainable best practice, could provide benefit to the public, the environment and industry. The recent announcement by the Obama Administration—in which it allocated $45 million to an interagency research and development program between the Department of Energy, Interior, and the EPA to identify ways to reduce the environmental impact of shale gas production—suggests that the Administration supports the sustainable development of shale gas resources.

Enforcement and Public Perception

Irrespective of the regulations in place or under consideration, an important aspect of the discussion around responsible and sustainable shale gas development is the effectiveness of enforcement and public perception on the safety of fracking. The interim findings of the SEAB report found that "while many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear."[24] The report emphasized the role for industry in the responsible development of shale gas and called for the formation of a "shale gas industry production organization" that would establish best practice for operations, share information with regulators, and act to build public trust. The latter consideration was of particular concern to the authors of the interim report, who noted that "some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion."[25] The extent to which industry can act as a responsible stakeholder and standard setter and the extent to which public confidence in fracking can be retained will have a large bearing on the feasibility of continued shale gas development and therefore the feasibility of U.S. LNG gas exports.

[24] SEAB, 2011.
[25] Ibid.

Regulatory Approvals for Export Facilities

Companies looking to construct or expand facilities for the export of LNG from the United States need to satisfy a number of federal regulatory requirements. These include the requirement for companies to seek export authorization from the Department of Energy's Office of Fossil Energy if the importing country is not subject to a free-trade agreement (FTA) with the United States (see **Table 2**).[26] Operators looking to modify existing LNG import terminals must obtain approval from the Federal Energy Regulatory Commission (FERC).[27] Other federal agencies that have a role in approving LNG export facilities include the U.S. Coast Guard, which, among other responsibilities, provides escort security in and out of port facilities; and the Pipeline and Hazardous Materials Safety Administration, which has jurisdiction over all pipelines. Under the National Environmental Policy Act, LNG export facilities may also be subject to environmental reviews in the form of an Environmental Impact Statement, an Environmental Assessment or under the terms of the Clean Air Act, or the Endangered Species Act..[28] (See **Box 1**).

Capacity and Infrastructure Constraints

The feasibility of U.S. LNG exports depends upon the ability of the country's natural gas infrastructure to support the production, transportation, storage, and shipment of natural gas.

Pipeline and Storage Capacity

The development of shale gas plays is likely to have a profound effect on the regional dynamics of the U.S. natural gas market. Increased production from the Marcellus Shale is likely to displace some supplies from the Gulf Coast and other regions that currently serve the large Northeast market.[29] Moreover, if significantly increased LNG exports from the Gulf Coast go ahead, there may be a need to reverse the pipelines to allow gas to flow toward the Gulf Coast.

To maximize the economic potential of the U.S. shale gas endowment, whether for exports or for domestic use, there will be a requirement for significant expansion in the nation's continental natural gas pipeline network, particularly in the vicinity of the Marcellus Shale. In 2010, Marcellus producers predicted that fewer than half of the 1,100 wells drilled had pipeline access.[30] ICF International, a consultancy, estimates that 3,300 additional miles of pipeline will be built in the Northeast between 2009 and 2035.[31] There is currently 6 bcf/day of FERC-approved proposed pipeline capacity that will deliver gas from the Marcellus to demand centers. More than 2 bcf/day of this capacity is scheduled to be completed by the summer of 2012.[32] Another concern is whether a gas pipeline infrastructure network will be developed quickly enough in liquid-rich plays, such as the Eagle Ford, Niobrara, and Utica Shales, to fully capture the natural gas being produced. As out-

[26] This distinction was given greater weight by the November 2011 FTA between the United States and Korea, the world's second largest importer of LNG.

[27] Michael Ratner, Paul W. Parfomak, Linda Luther, "U.S. Natural Gas Exports: New Opportunities, Uncertain Outcomes," Congressional Research Service, November 2011. (Ratner, November 2011).

[28] See Ratner, November 2011 for a thorough examination of the federal regulations and approvals needed by LNG exporters.

[29] Tom Choi and Peter Robinson, "Navigating a fractured future: Insights into the future of the North American natural gas market" Deloitte Center for Energy Solutions, September 2011. (Deloitte, 2011).

[30] "The Beast in the East: Energy Market Fundamentals Report," Bentek Energy, March 19, 2010.

[31] Kevin Petak, David Fritsch, and E. Harry Vidas, "North American Midstream Infrastructure Through 2035—A Secure Energy Future," presentation and report prepared by ICF for the INGAA Foundation, June 28, 2011. (http://www.ingaa.org/File.aspx?id=14900).

Box 1: Approval Process for Natural Gas Exports

Under the Natural Gas Act (NGA) Section 3 (15 USC §717b), exporting natural gas from the United States requires authorizations from the Department of Energy's Office of Fossil Energy and from FERC. Below are some of the permits that must be approved before a facility can export natural gas:

File application with the DOE's Office of Fossil Energy for export authorization

1. Issuance of an export authorization is dependent upon the export being deemed consistent with the public interest. DoE can choose to issue permits up to a certain cumulative total volume, and then deny subsequent applications if it were found to be in the public's interest.

   a) A project is deemed consistent with the public interest if a free trade agreement exists between the U.S. and the LNG-recipient nation.

   b) If the U.S. does not have free trade agreements with the countries to which LNG is to be exported, the Office of Fossil Energy must issue the permit unless it finds it is not in the public interest after publishing a notice of the application in the Federal Register to seek public comments, protests, and notices of intervention.

File application with FERC for authorization to site, construct or operate LNG export facilities

1. Any proposals to site, construct or operate facilities for the use of exporting natural gas—or to amend an existing FERC authorization—must obtain approval from FERC. Certain activities may also require regulatory oversight from the U.S. Coast Guard or the Department of Transportation. Approved applications are issued a Certificate of Public Convenience and Necessity.

Environmental Review and Assessment

1. Both authorizations require an evaluation of the project's anticipated impact on the public and on the environment, in accordance with the National Environmental Policy Act (NEPA).
2. An Environmental Impact Statement is needed for every proposed major federal action that is expected to significantly affect the quality of the environment. Once the impacts are declared, the statement must be approved before a final Record of Decision can be issued.
3. Projects with less-than-significant impacts still require documentation. If the environmental impacts are uncertain, then an Environmental Assessment must be prepared in order to determine if an Environmental Impact Statement is necessary. If the Environmental Assessment finds that the project under consideration has no significant environmental impact, then a Finding of No Significant Impact report is provided.
4. Projects that are perceived to have no significant impacts at all on the environment can be processed as Categorical Exclusions. This means that those projects do not require the preparation of either an Environmental Impact Statement or an Environmental Assessment.

Other Considerations

1. During preparations for the documentation required under NEPA, the Department of Energy and FERC must also identify any other compliance requirements applicable to the authorization.

   a) For example, other regulations that are to be considered include the Clean Water Act, the Clean Air Act, the Endangered Species Act, and the National Historic Preservation Act. This may require the involvement or approval of other agencies at the federal, state or local level.

   b) Besides environmental requirements, LNG export projects may require compliance with safety or security-related requirements from various other agencies, including the Department of Transportation's Office of Pipeline Safety (which is situated within the Pipeline and Hazardous Materials Safety Administration), the National Fire Protection Association, and the Federal Emergency Management Agency.

Source: Adapted from Ratner, November 2011 lined above, vast quantities of natural gas are currently being flared at some shale sites in the U.S. mid-continent. One way to reduce such flaring is being considered by Wyoming's Office of State Lands and Investments, which has proposed a policy through which royalties payments would be required from operators of wells on state lands that continue to be flared for more than 15 days after completion. Absent strong state action on flaring, it is possible that the federal government will seek to regulate flaring at oil and natural gas wells. In addition to constraints on pipeline capacity, there are also concerns about the adequacy of natural gas storage infrastructure, particularly in the Northeast, although the investments in pipeline capacity should prompt similar investments in increased storage capacity.[33]

Drilling and Production Infrastructure

Even if there is sufficient transportation infrastructure to handle increased volumes and new regional bases for natural gas production, there may be limits on the amount of available equipment and qualified petroleum engineers to develop the gas. To date such a shortage of drilling rig availability in the U.S. natural gas sector has not materialized, as **Figure 3** illustrates. The increased productivity of new drilling rigs has served to ensure that supply has kept pace with demand. For example, in the Haynesville Shale play in Louisiana, the rig count fell from 181 rigs in July 2010 to 110 rigs in October 2011, yet production increased from 4.65 bcf/day to 7.58 bcf/day over the same period.[34] A similar trend is occurring in the Barnett Shale in Texas, where production rates have remained flat despite a declining rig count.[35] While the supply of drilling rigs remains adequate, the market for other equipment and services used for fracking—particularly high-pressure pumping equipment—is tight and likely to remain so for the near term.[36] Tight markets for drilling and completion equipment can result in increases in fracking costs.

Human Capacity

Human capital in the unconventional oil and gas development sectors is also in short supply. According to the National Petroleum Council (NPC), there has been a 75 percent decrease in petrochemical-related course enrollment since 1982 in the United States.[37] Moreover, within the next ten years, about 50 percent of the workforce in this industry will be eligible for retirement. The high demand for petroleum engineers, reflected in the high salaries of recent graduates in the field, is set to continue, with the NPC warning of a "considerable human resource challenge" in the oil and gas industry.[38]

Faculty at leading universities with petroleum-engineering departments point to a lack of research and development (R&D) funding, which they say is negatively affecting their capacity to adequately train people for jobs in the hydrocarbons sector. While some of the shortfall in public R&D funding has been made up by private-sector support,

[32] "Winter 2011-12 Energy Market Assessment," Federal Energy Regulatory Commission, Item No: A-3, October 20, 2011.
[33] MIT, 2011. p. 145.
[34] "Production Rises in Barnett, Haynesville Shales Even as Rig Counts Fall," *Platts,* October 11, 2011. (http://www.bentekenergy.com/InTheNews.aspx#Article5402)
[35] From an interview with Kenneth Medlock, Fellow, Energy Studies, James A. Baker III Institute for Public Policy, and member of the Brookings Energy Security Initiative Natural Gas Task Force, November 15-16, 2011.
[36] "Commodity Prices, Service Costs and Hedging: A guide to profit planning and protection in 2012", Maquarie Equities Research, November 11, 2011.
[37] Prudent Development - Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," National Petroleum Council, September 15, 2011. p. 1.
[38] Ibid.

academics note the frequent mismatch between the specific needs of individual companies and the long-term needs of the sector. Even if sufficient funding for R&D and training is now provided, there may also be a time lag before there is an adequate supply of petroleum engineers in the market.

Shipping Capacity

The successful export of LNG will depend upon the necessary shipping infrastructure and capacity being in place. Cheniere Energy is looking to export up to 2.2 bcf/day of gas from its Sabine Pass LNG terminal in Louisiana.[39] Depending on the size of the LNG vessel, this would require between three and five supertankers per week. In order to accommodate this volume of large ships, some domestic U.S. ports will require additional dredging. Other shipping-related concerns include security of vessels and the adequacy of Coast Guard capacity to provide that security (exporters must meet Coast Guard Waterway Suitability, Security, and Emergency standards prior to approval); and the capacity of sea lanes, particularly to Asia. Increasing shipments to Asia will depend on the capacity of the Panama Canal, which is currently too small to accommodate most LNG tankers. However, after the planned expansion of the canal is completed—expected to be in 2014—roughly 80 percent of the world's LNG tankers will be able to pass through the isthmus, resulting in a dramatic decline in shipping costs to Asia.[40]

Most potential capacity obstacles to LNG exports are likely to be short-term consequences of infrastructure investment failing to keep pace with rapid increases in shale gas production. Over time, it is likely that such bottlenecks will be resolved as markets respond and allocate investment to infrastructure and capacity development as needed.

Domestic Demand Factors

In the United States, potential natural gas exports will compete with two primary markets for the consumption of natural gas: the power-generation sector and the industrial sector, including petrochemical production. The prospects for increased natural gas demand in the transportation, commercial and residential sectors as a result of increased shale gas production are less strong.

Power Generation

Demand for natural gas in the electricity sector has been stimulated by the increased supply—and therefore lower prices, and by environmental concerns over coal-fired generation. The EIA estimates that natural gas power plants will account for 60 percent of new electric capacity additions between 2010 and 2035.[41]

New and revised EPA regulations will play an important role in determining the amount of coal-fired generation that remains online in the United States, and, therefore, the number of natural gas power plants to be built. The EPA's Cross-State Air Pollution Rule (CSAPR), which is aimed at controlling sulfur dioxide (SO_2) and nitrous oxide (NOx) emissions from power plants in 27 U.S. states that contribute to fine-particulate pollution and ozone in adjacent states, was scheduled to be implemented on January 1, 2012. However on December 30, 2011 it was delayed by a federal court appeal and has since undergone two minor adjustments. At the time of writing, the regulation had not yet been reintroduced for approval.

[39] Cheniere Energy's export permit from the Department of Energy allows for initial production of 1bcf/day with the possibility of expansion to 2.2 bcf/day.
[40] "Medium-Term Oil and Gas Markets 2010," International Energy Agency, 2010. p. 264.
[41] EIA, April 2011a. p. 74

A second EPA regulation, regarding Mercury and Air Toxics Standards (MATS), is scheduled to go into effect on January 1, 2015. The MATS will apply to hazardous air pollutants (HAPs)—including mercury, hydrogen chloride, and other particulate matter— from all power plants. These standards, which were finalized on December 16, 2011, are projected to result in a 90 percent reduction in mercury emissions. The same day the EPA issued its final Maximum Achievable Control Technology (MACT) rule. The rule, to be promulgated under the Clean Air Act, requires coal-fired power plants to achieve pollution controls for mercury, acid gasses and other pollutants equal to the best 12 percent of operating plants. Other regulations proposed by the EPA include:

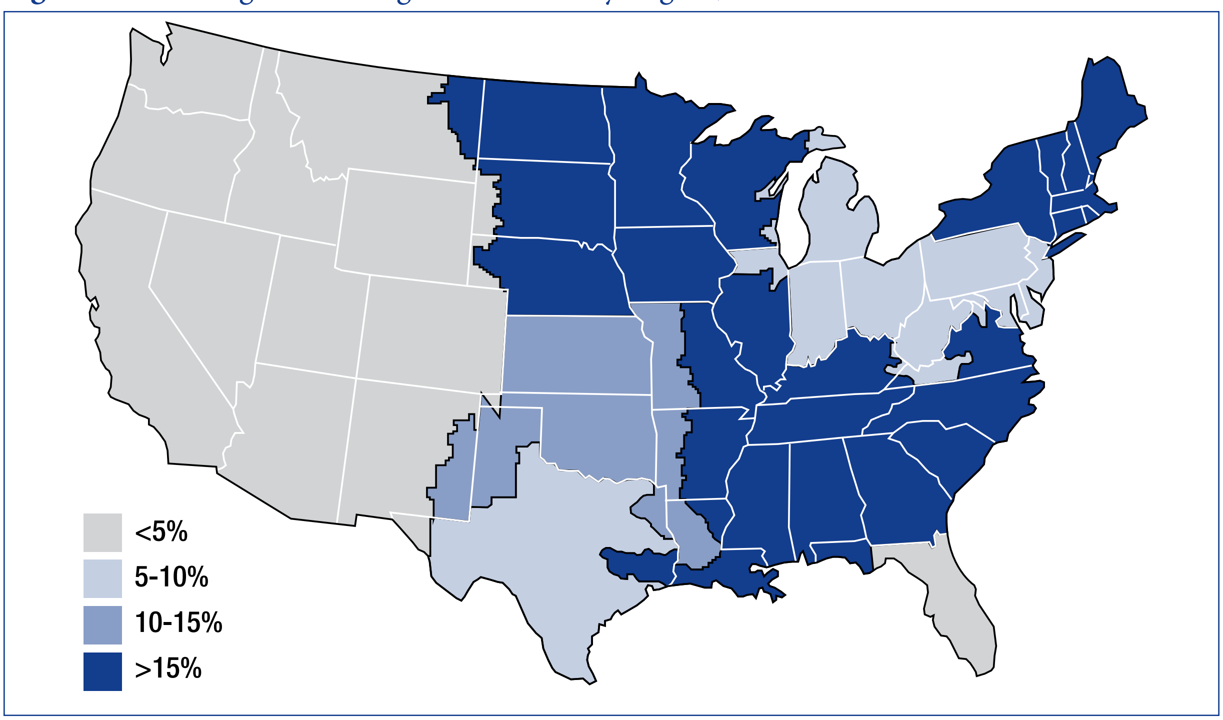
- Section 316b of the Clean Water Act: requiring cooling water intake structures to reflect Best Technology Available (BTA) to minimize environmental impacts;

- Coal Combustion Residuals (CCRs): changing the regulation of coal ash and waste by-products disposal;

- Greenhouse Gas (GHG) standards: proposing rules for GHG emissions standards for new and existing electric generation facilities. The GHG standards were released on March 27, 2012 and seek to set national limits on the amount of carbon dioxide that all new power plants can emit. The rules are expected to limit the construction of new coal-powered plants while making natural gas plants increasingly attractive.

ICF, a consultancy that has modeled gas penetration in the electricity sector and has made projections based on EPA's proposed regulations and the age of the existing coal power plant fleet, estimates that roughly 40 gigawatts (GW)—equivalent to

Figure 4: Percentage of Existing Coal Retired by Region, 2020



Source: ICF International

around 12 percent of the current coal-fired installed capacity—will be retired by 2020.[42]

Coal power plant retirements will vary by region: plants in the Southeast and Midwest (where many coal plants are located) will account for the bulk of reduction, as they are also located close to regions where natural gas is produced in larger volumes and the distribution networks are better developed (see **Figure 4**).

Various models have projections for what the displacement of coal-fired generation would mean for natural gas demand, which will be the primary replacement fuel. The estimates for the increase in natural gas demand in the power sector range from 1.1 tcf/year to 3.5 tcf/year. ICF projects that the increase in gas demand—either through the construction of new natural gas power plants or the use of existing idle natural gas combined cycle (NGCC) plants—could equal between 1.6 and 2 tcf/year.[43] Deloitte, a consultancy that also runs models on gas consumption, projects that gas demand for power generation can increase by as much as 10 bcf/day, or roughly 3.5 tcf/year.[44] Deutsche Bank estimates that 3 bcf/day of gas could replace about 80 of the least efficient, smaller, and older coal-fired power plants.[45]

While additional federal environmental policies inimical to coal-fired power plants are likely to be met with staunch opposition, most projections assume that such stringent environmental regulations will eventually be implemented. The result is likely to be additional retirements of older, less efficient coal-fired power plants, many of which will be replaced by more efficient natural-gas power plants.

Industrial Sector

The other major potential beneficiary of more abundant U.S. natural gas is the industrial sector. The sector currently consumes roughly 32 percent of total natural gas demand, 85 percent of which is consumed in manufacturing.[46] According to the EIA, demand for natural gas in the industrial sector is projected to grow by 27 percent between 2009 and 2035.[47]

The industrial sector is highly price-sensitive with respect to energy inputs. Because natural gas is a primary feedstock for many industrial consumers such as manufacturers or petrochemical producers, the industrial sector was heavily affected by the volatility in the natural gas market in the late 1990s and 2000s. According to Dow Chemical, one of the country's leading industrial companies, annual natural gas price rises of 167 percent from 1997 through 2008 resulted in an annual reduction of industrial demand of 22 percent.[48]

The shale gas boom has many industrial producers and chemical companies anticipating an increase in U.S. industrial and manufacturing competitiveness and petrochemicals production. A December 2011 report by PricewaterhouseCoopers, conducted in association with the National Association of Manufacturers, notes an increase in U.S. manufacturing activity due to shale gas development and suggests one million additional

[42] "Domestic Gas Usage in the Power Sector," presentation by John Blaney of ICF to the Brookings Natural Gas Task Force, August 3, 2011. A previous ICF assessment projected 51 GW of retirements, but the newly proposed regulations have shown more flexibility than earlier proposals, and more coal plants are expected to remain online.
[43] Ibid.
[44] Deloitte, 2011. p.5.
[45] "Unconventional Gas," presentation by Adam Sieminski of Deutsche Bank to the Cross Border Forum on Energy Issues, May 13, 2010.
[46] Ibid., p. 101.
[47] EIA, April 2011a. p. 68.
[48] U.S. Senate Committee on Energy and Natural Resources; "The Future of Natural Gas," testimony of George Biltz, Vice President, Energy and Climate Change, Dow Chemical; July 19, 2011.

manufacturing jobs could be created in EIA's high-shale gas recovery scenario (in which 50 percent more shale gas is recovered relative to the reference case) compared with its low shale recovery scenario (in which 50 percent less is recovered).[49] A particular area of interest is the resurgence in ethylene production and the manufacturing of ethylene-based goods in the United States. Ethylene, which is a principal component in a variety of goods ranging from anti-freeze to trash-bags, is produced from ethane, a byproduct of natural gas. Cheap domestic natural gas has provided chemical producers a global competitive advantage in ethane—and therefore ethylene—production, particularly compared with producers in Europe where ethylene is derived principally from naphtha, an oil-based product. Because crude oil prices have not dropped in parallel with gas prices in the United States, U.S. industrial producers are thus globally competitive again. As a result, a number of industrial producers are looking to reinvest in plants in the United States.[50] Bayer MaterialScience is opening an ethane cracker in West Virginia (the first cracker in the Marcellus) and Dow Chemical and Shell Chemical have announced plans to expand and open, respectively, crackers on the Gulf Coast. According to analysis by the American Chemistry Council (ACC), an industry trade association, a 25 percent increase in the supply of ethane in the United States could result in 17,000 direct new jobs in the chemical industry, 395,000 indirect jobs, and around $44 billion in additional federal, state, and local tax revenue over 10 years.[51] To achieve such returns ACC presumes an infusion of over $16 billion of private capital, and includes an assessment of induced impacts—"employment and output supported by the spending of those employed directly or indirectly by the sector." While the ACC does not make explicit assumptions about the shape of the U.S. natural gas supply curve or the future price of natural gas, it also assumes sustained low gas prices, and resultantly high oil-to-gas price ratio. While some analysts may take legitimate issue with the assumptions behind the projected job-creation figures, it is clear that the U.S. petrochemical and manufacturing sector will be a prominent competitor and potential beneficiary of abundant domestic natural gas. In Part II, the study will analyze the impact of U.S. LNG exports on the potential for a "renaissance" in the industrial sector.

Transportation Sector

Natural gas has also attracted a substantial amount of attention as a fuel for the transportation sector. Following his State of the Union address in January 2012, President Obama has been promoting the use of natural gas in both passenger and heavy-duty vehicles (HDV).[52] The New Alternative Transportation to Give Americans Solutions (NATGAS) Act which proposed legislation that would provide tax incentives to encourage the use of natural gas in the commercial trucking sector, has focused attention particularly on LNG use in the HDV fleet. (The legislation was defeated as an amendment to the Transportation Bill on March 14, 2012.)

Federal incentives have already been enacted for the purchase and operation of compressed natural gas (CNG) vehicles. The 2005 Energy Policy Act authorized credits for up to 80 percent of the incremental cost of purchasing CNG vehicles (the credits expired at the end of 2010); federal

[49] "Shale Gas: A Renaissance in U.S. Manufacturing," PricewaterhouseCoopers, December 2011.
[50] "Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing," American Chemistry Council, March 2011. p. 19. (American Chemistry Council, March 2011)
[51] Ibid.
[52] Charles Ebinger, "What Does the State of the Union Mean for Energy Policy," *Brookings Up-Front Blog,* January 27, 2012. (http://www.brookings.edu/opinions/2012/0127_sotu_energy_policy_ebinger.aspx)

tax credits for 30 percent of the cost of natural gas home refueling equipment, up to $1000, are in place until the end of 2011. However, despite the variety of existing and proposed policy incentives, a large-scale shift away from oil toward natural gas in the vehicle fleet is unlikely in the near term.

While LNG-powered HDVs can demonstrate competitive cost effectiveness and relatively short payback periods under certain circumstances, in most instances they require large fuel differentials between diesel and LNG, and high numbers of vehicle miles per year to realize savings that buyers would find acceptable.[53] A range of operational and cost issues—including limited range, a lack of existing refueling infrastructure, and an incremental cost premium for LNG trucks of around $70,000—are therefore likely to prevent a widespread conversion to natural gas absent the introduction of significant subsidies or mandates.[54] Moreover, many trucking companies depend on the truck resale market for revenues, particularly in Asia. Without a large LNG distribution infrastructure in Asia, LNG trucks will be unlikely to gain significant market penetration, further limiting U.S. interest in LNG trucks.

The logistical challenge of converting a large proportion of the passenger vehicle fleet to natural gas is even higher. Obstacles include those of range (the energy density of natural gas is lower than that of gasoline, requiring more frequent refueling in NGVs than in gasoline-powered cars) and longer refueling times for NGVs than their gasoline equivalents.

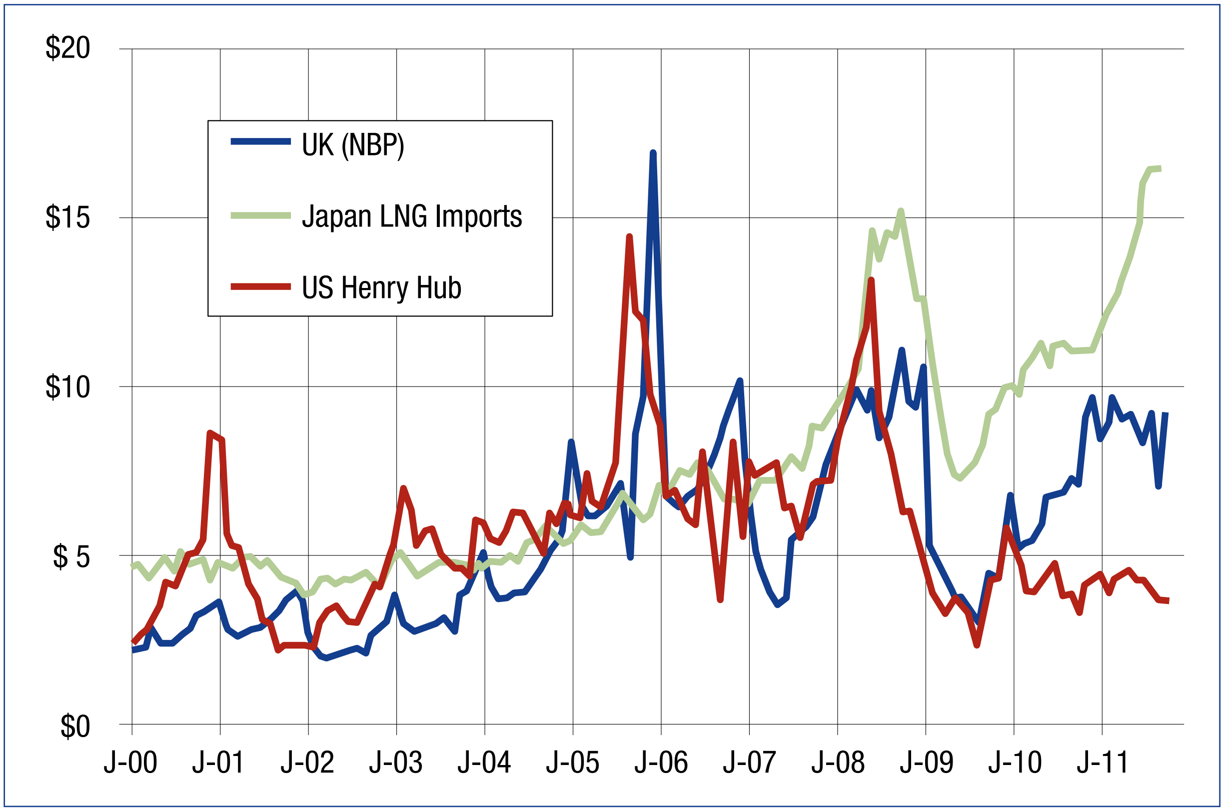
The prospects for vehicular fuels derived from gas-to-liquids (GTL)—a process that converts natural gas into high quality middle distillates that can serve as a supplement or substitute for diesel—in the transportation sector are also uncertain. There are significant upfront costs associated with GTL production, with a 20,000 barrel production plant costing the equivalent of $115,000 per barrel per day capacity.[55] Liquid fuels produced by GTL would compete directly with crude oil-derived fuels. A sharp fall in crude-oil prices would therefore make GTL instantly uneconomic. While the prospect of cheap and abundant shale gas has renewed interest in GTL production in the United States—with SASOL of South Africa announcing plans for a feasibility study of a $10 billion plant in Louisiana—the long lead time and substantial capital investment required, together with the risk of competing with a volatile oil market, present significant challenges to GTL-products in the vehicle fleet. Despite its technical feasibility and high public profile, natural gas usage in the U.S. commercial and passenger fleets—either as LNG, CNG, or derived from GTL production—is therefore likely to see limited growth in the foreseeable future in the absence of major policy incentives.

Commercial and Residential Sector Demand

The prospects for increased natural gas use in the commercial and residential sectors as a result of the availability of abundant shale gas reserves are also modest. EIA estimates show that widely varying assumptions for shale gas production levels in 2035 (5.5 tcf/year in the "Low Shale EUR" scenario versus 17.1/ tcf/year in the "High Shale EUR" scenario) result in relatively small changes in commercial and residential gas consumption (0.5 and 0.3 tcf, respectively).[56]

[53] Alan Krupnick, "Will Natural Gas Vehicles Be in Our Future?," Resources for the Future, May 2011. p.13
[54] MIT, 2011. pp. 123-124.
[55] Data from ClearView Energy Partners.

Figure 5: Benchmark Natural Gas Prices in the U.S., U.K. and Japan ($/MMBtu)



Source: ICF International

Global Gas Market

U.S. natural gas exports will not only compete with the domestic sources of demand listed above; they will also compete with other sources of gas—both LNG and pipeline gas—in the global market. The fundamental rationale for exporting natural gas is that the U.S. price is lower than the price in target markets, where natural gas is often purchased on more expensive long-term contracts that are indexed to the price of oil, leading to an opportunity for arbitrage. (See **Figure 5** for the difference between the three major global natural gas price benchmarks.)

A well-supplied global gas market will give U.S. exporters fewer opportunities for exports; similarly, a "tight" gas market, one where supplies are limited, will provide an economic opportunity for U.S. exporters. On the demand-side, gas exports will have to compete with other fuel substitutes such as coal, oil, and nuclear energy for electricity generation, and oil for transportation. Demand for gas imports may also be affected by the spread of unconventional gas development to additional countries.

The international gas market can be divided into two major regions in addition to North America: the Pacific Basin and the Atlantic Basin. Both of these markets are supplied by LNG shipments

[56] EIA, April 2011a.

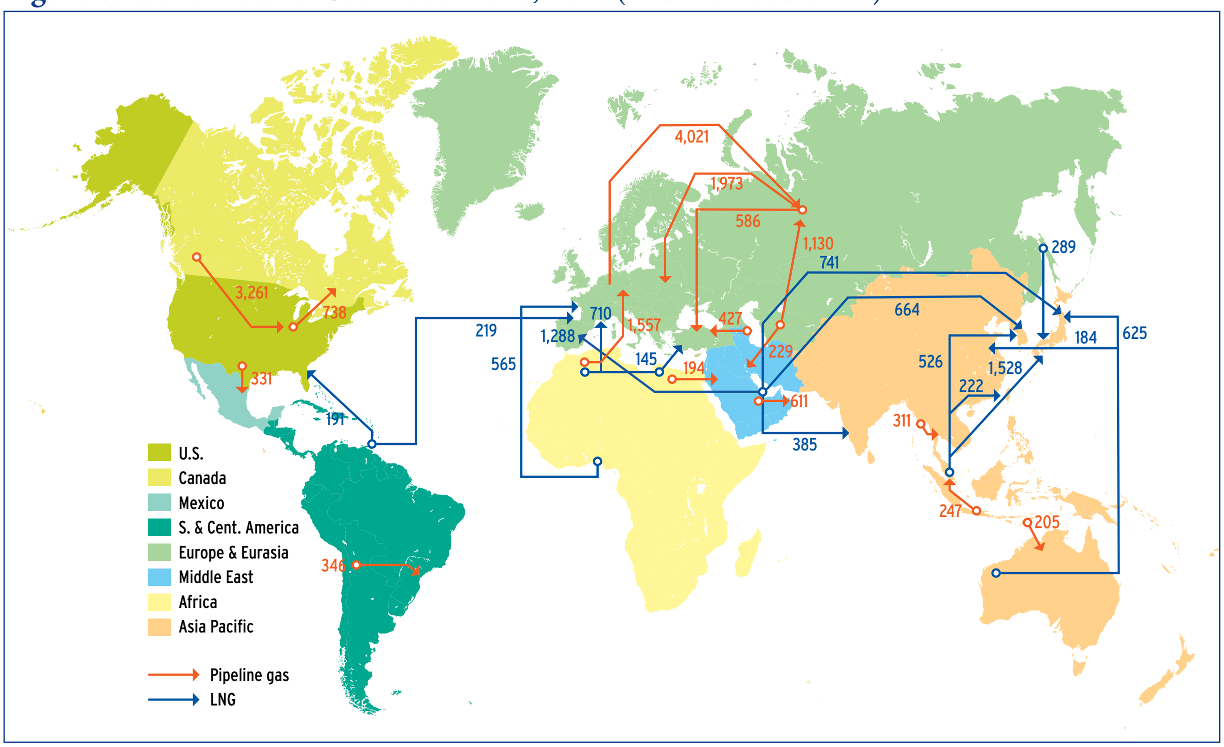
(much of which come from Qatar, Indonesia, Malaysia, Nigeria, and Australia) as well as by pipeline gas. Each importer and exporter has different supply and demand characteristics that will have a bearing on whether the United States will be able to compete against other sources of supply.

Pacific Basin

The Pacific Basin has historically been the cornerstone of the global LNG market. During the early and mid-1990s, Indonesia and Malaysia accounted for roughly half the LNG export market, and Japan and South Korea accounted for approximately 70 percent of the import market.[57] Today, Indonesia and Malaysia's supply dominance has been eroded by the emergence of new LNG exporters including Qatar (which has the largest liquefaction capacity in the world), Nigeria, and Australia. As a result, although both Indonesia and Malaysia were still, respectively, the second and third largest exporters of LNG in 2010, their share of the global natural gas market has dwindled to roughly 20 percent, and may decline further as domestic gas consumption increases. Nevertheless, Pacific Basin exports, which almost exclusively serve Pacific markets, are still projected to increase in quantity as a result of major liquefaction capacity additions in Australia, which is expected to have as much as 12 bcf/day of export capacity by 2020.[58]

While about 45 percent of the Pacific Basin's total gas demand is met by LNG imports from within the region, an additional 40 percent of its demand is met by LNG imports from outside the region,

Figure 6: World Natural Gas Trade Flows, 2010 (in billion cubic feet)



Source: BP Statistical Review of World Energy 2011

[57] "World LNG Report 2010," *International Gas Union (IGU)*, September 2011. pp. 6-9 (International Gas Union, September 2011).
[58] From an interview with Luke Smith, Energy Analyst, Commonwealth Bank of Australia. March 19, 2012.

primarily from the Middle East and Russia.[59] Qatar alone accounted for 11 percent of Japanese LNG imports in 2010. Qatari production predominantly serves both the European (mostly the U.K.) gas market and the Pacific Basin gas market. Current uncontracted supply available on the spot market is likely to be sent to Asia to take advantage of the Pacific Basin's higher prices. However, other than meeting the existing spare capacity for LNG production, the Middle East will have little excess supply capacity. This is in part because Qatar is trying to preserve its price structure with the East Asian market and partly because there is a moratorium on further development of Qatar's North Field, which together with Iran's South Pars Field, is the largest gas field in the world. Another reason for the limited excess supply from the Middle East is that Oman, which is the second largest Middle Eastern LNG exporter to Asia, is experiencing declining LNG exports as more gas is being consumed domestically. Iran, which has the world's second largest gas reserves, has proposed several LNG projects, but has been unable to implement them because of sanctions.

Gas demand in Asia remains strong, led by Japan, South Korea, and Taiwan, which accounted for more than half of all global LNG imports in 2010.[60] Japan, the world's largest importer of LNG, has seen a particular increase in projected natural gas demand as a result of the accident at the Fukushima nuclear power plant following the earthquake in March 2011. The nuclear accident, which has caused a short-term shutdown of most of Japan's nuclear reactors, has also prompted a review of Japan's nuclear energy policy. The review comes largely at the demand of the public, which is wary of Japan's reliance on atomic power.[61] In the event of a move away from nuclear power, a significant amount of Japan's electricity production will likely be met by additional LNG shipments. It is estimated that in 2012, Japan will require an additional 974 bcf of LNG to make up for the electricity shortfall resulting from the Fukushima accident and the reduction in nuclear power generation.[62]

While Japan has traditionally been the focal point for natural gas consumption in Asia, the economic rise of China and India has begun to have an increasing impact on forecasts for the Asian gas market. Although energy and electricity supply in both countries has been dominated by coal, both countries have expressed interest in expanding the role of natural gas. The International Energy Agency predicts that gas demand in China and India may grow as fast as 7.7 percent and 6.5 percent, respectively, per year to 2035.[63] Over the past five years, both countries have become significant importers of natural gas, mostly—exclusively, in the case of India—in the form of LNG. Both China and India have made significant investments in LNG regasification infrastructure with six LNG import terminals currently under construction in China and two in India (with an existing terminal also undergoing expansion), and more expected in the near future. In addition to the LNG imports, China imports gas from Turkmenistan via a pipeline that traverses Uzbekistan and Kazakhstan, is in the process of developing a pipeline interconnection with

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[59] "BP Statistical Review of World Energy 2011," BP, June 2011. (BP, June 2011)

[60] Ibid. It is important to note that the United States in November 2011 entered into a free-trade agreement (FTA) with South Korea as all but one of the projects that have been approved for the export of natural gas are only allowed to export LNG to countries with whom the United States has a FTA. Other than South Korea, the only countries which have regasification capacity and an FTA with the United States are Canada, Chile, the Dominican Republic, and Mexico.

[61] A recent poll in Japan demonstrated that the majority of the Japanese public is in favor of phasing out the country's existing nuclear reactors. "Japan poll finds 74% support nuclear phase-out," *Nuclear Power Daily,* June 14, 2011. (http://www.nuclearpowerdaily.com/reports/Japan_poll_finds_74_support_nuclear_phase-out_999.html)

[62] "Energy Challenges in Japan after 3.11,"presentation by Ken Koyama, Chief Economist, Institute of Energy Economics—Japan, to a private meeting at Harvard University, October 21, 2011, in Boston, Massachusetts.

[63] "World Energy Outlook 2011 Special Report: Are We Entering a Golden Age of Gas" International Energy Agency, 2011. p. 23. (IEA, 2011)

Myanmar, and has long been engaged in discussions with Russia over a potential pipeline interconnection. India, which does not currently share a pipeline with any other country, is looking to develop various international pipeline projects, from Turkmenistan, Myanmar, Oman, and Iran.

How the demand for gas in these countries continues to grow will depend on a number of factors, including the pace of economic growth, the policies for substitute fuels—primarily coal, nuclear power, and oil—and the speed and scale at which unconventional gas can be developed. With electricity demand increasing at rapid rates in countries across South and East Asia, there is also a very real possibility that LNG consumption will not be sufficient and that substantial coal demand will persist. However, while coal and oil will continue to make up a large part of the energy mix, natural gas demand is projected to increase steadily, prompting the need for more investment in imports and in supporting domestic production, particularly of unconventional gas. The EIA's recent global estimate for shale gas reserves suggests that India and China have roughly 63 tcf and 1,275 tcf of shale gas reserves, respectively.[64] The coal-bed methane (CBM) gas reserves of each country are estimated to be equally vast: one assessment of China's CBM reserves is 1,306 tcf and estimates of India's CBM reserves range from 71 to 162 tcf.[65] For both countries, these estimates for unconventional gas have stimulated national interest in unconventional gas production. However, development of these resources is likely to be a mid-to-long term proposition. The regulatory and policy environment in both countries will need to be amended to accommodate shale gas and CBM production and to address issues related to hydraulic fracturing, such as water consumption, treatment, and disposal. The extent to which natural gas prices are deregulated will also have a bearing on how quickly domestic unconventional gas will be produced as production companies will require economic incentives to begin and sustain production. Unconventional gas production will also require technical capacity and physical infrastructure, both of which are currently in short supply in both China and India. The former concern is partially being addressed through Chinese and Indian investments in North American shale plays. The latter concern will require significant attention, particularly as the pipeline networks in both China and India are inadequately developed and as the investment climate for foreign operators remains uncertain.[66]

Export Feasibility to the Pacific Basin

Owing to growing gas demand, limited domestic supply, and a more rigid and expensive pricing structure, Asia represents a near-to-medium term opportunity for natural gas exports from the United States. The expansion of the Panama Canal by 2014 will allow for LNG tankers to traverse the isthmus, thereby improving the economics of U.S. Gulf Coast LNG shipments to East and South Asian markets. This would make U.S. exports competitive with future Middle Eastern and Australian LNG exports to the region.

However, challenges and uncertainties remain on both the demand and supply side. The development of indigenous unconventional gas in China or India may occur at a faster rate than

[64] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States," U.S. Energy Information Administration, April 2011. p. 4. (EIA, April 2011b)

[65] Estimate for China is from: Haijin Qiu, Strategic Research Center of Oil and Gas Resources, Ministry of Land Resources, "Coalbed Methane Exploration in China," adapted from an oral presentation at the AAPG Annual Convention in San Antonio, Texas, April 20-23, 2008. Estimates for India are from: M.P. Singh and Rakesh Saxena, "Status of Coal Bed Methane Investigations in India," *Glimpses of Geoscience Research in India*, p. 233.

[66] According to a report from Bernstein Research, a consultancy, July 7, 2011.

currently forecast, dampening demand for LNG imports to the region. A change in sentiment in Japan may see nuclear power restarted at a greater rate than currently anticipated; alternately, a greater-than-expected penetration of coal in the Japanese electricity sector would suppress gas demand. A change in the cost of Australian LNG production or a reversal of the Qatari moratorium on gas development could disrupt the current supply projections, as could the discovery of new conventional or unconventional resources. For instance, on December 29, 2010, Noble Energy, a U.S. oil and gas exploration company, discovered between 14 and 20 tcf of gas in Israel's offshore Leviathan gas field. Since then, other nations on the Eastern Mediterranean are exploring for potentially similarly large gas fields. A number of large natural gas discoveries in Mozambique have also prompted early interest in building significant liquefaction capacity in the Southeastern African nation. The high quality (low sulfur and carbon-dioxide content) and liquid-rich nature of Mozambican gas may make this resource a significant competitor in global LNG markets in the medium term.

Finally, the expansion of LNG export capacity from Alaska and the development of LNG export capacity in Western Canada may provide a source of strong competition for U.S. Gulf-coast origin LNG. Although Alaska's Kenai LNG export facility, which has been exporting small quantities of LNG to Northeast Asia for over 40 years, has been idled temporarily, some companies have demonstrated interest in large-scale exports of LNG from Alaska to East Asia. On March 30, 2012, ExxonMobil, along with its project partners BP and ConocoPhillips, settled a dispute with the Government of Alaska to develop its gas resources at Prudhoe Bay. The gas from this field is expected to travel from Alaska's North Slope to Valdez on Alaska's southern coast, where it will be liquefied and exported.[67] According to FERC, there are currently three Canadian export facilities under consideration in British Columbia: a proposed 1.4 bcf/day terminal at Kitimat (initial production would start at 0.7 bcf/day), which received a 20-year export license in October 2011; a proposed 0.25 bcf/day facility at Douglas Island; and a potential 1 bcf/day facility at Prince Rupert Island. Given the lower transportation costs (as a result of the shorter distance), Alaskan and West Canadian exports may prove to be a source of strong competition at the margin for U.S. LNG in the Pacific Basin.

Atlantic Basin

The Atlantic Basin comprises predominantly the gas markets in Europe, particularly the European Union. Other than Spain and the United Kingdom, which import 76 percent and 35 percent of their natural gas in the form of LNG, respectively, most European countries are dependent on pipeline imports from Russia, Norway, and Algeria. Algeria, Qatar, and Nigeria are the principal LNG exporters to the continent.[68]

European natural gas imports are dominated by the sale of Russian gas to European consumers at high, oil-indexed prices. Despite declines in Russia's two largest natural gas fields (Urengoy and Yamburg), its natural gas production is projected to increase by roughly one-third between 2010 and 2035.[69] According to the International Energy Agency, exports from Russia will increase by roughly 67 percent over the same period, with much of the growth coming from increased

[67] Yereth Rosen, "Alaska, Exxon deal opens way for LNG exports," *Reuters,* March 30, 2012. (http://www.reuters.com/article/2012/03/30/us-alaska-pipeline-idUSBRE82T12I20120330)
[68] BP, June 2011.
[69] IEA, November 2011. p. 306.

pipeline and LNG exports to Asia.[70] Norway is also a major supplier of natural gas to Europe and its production is projected to increase over the next two decades before reaching a plateau.[71] However, this will not compensate for the precipitous decline in domestic production in the U.K. and the Netherlands, two historically substantial producers of natural gas.[72]

As a result, for the near future it appears that the reliance on natural gas from Russia will continue—a trend underlined by the commissioning of the Nord Stream pipeline, the first pipeline that directly connects Russia with the EU. Russia accounts for about 31 percent of Europe's natural gas imports.[73] While it is clear that the gas relationship between Russia and European consumers will continue, the pricing relationship between the two parties will determine how much gas will be imported, and whether or not there will be an opportunity for U.S. LNG exports. Historically, most Russian gas exports to Europe are underpinned by long-term contracts with gas sold at oil-indexed prices. However, with new LNG cargoes previously destined for the U.S. now available on the global market, there has been an increase in spot-market trading of gas—with consumers in some cases finding it more economic to pay penalties for non-receipt of contract gas and to buy alternate supplies via LNG. The result has been increased pressure on the price of Russian gas exports and increased market power on the part of consumers to renegotiate oil-indexed contracts with Gazprom, the Russian state-owned gas company. Gazprom has agreed to renegotiate some contracts with its customers, primarily in Germany; however it has a number of arbitration cases under review and appears reluctant to renegotiate the terms for a large number of its contracts. Moreover, given Germany's recent decision to accelerate the phase out of its existing fleet of nuclear reactors, there is a strong likelihood that much of the resultant electricity shortage will be made up through increased natural gas consumption, thereby supporting demand and gas prices (for more on the foreign policy implications of potential U.S. LNG exports into Europe, see Part II).

In addition to Russian imports, Europe is likely to increase its LNG imports. Despite having excess regasification capacity—terminals ran at a 42 percent load factor in 2009—new regasification facilities are planned in a number of European countries.[74] In contrast to the developments in adding LNG import capacity, some of the international pipeline connections under consideration are experiencing development difficulties. Many of the various proposed pipelines from the Middle East, Central Asia and Russia, (Nabucco and South Stream, for instance) are considered to have either difficult economics or face technical and logistical obstacles and are not expected to be completed in the near term. However, some analysts find that other pipeline interconnections, such as the Trans-Adriatic Pipeline (TAP) are more likely in the mid-term. The TAP pipeline would transport gas from Azerbaijan's Shah Deniz gas field to continental Europe through Turkey, where the existing Southern Corridor Pipeline (SCP) ends.

As is the case in Asia, unconventional gas development in Europe may play a large role in the

[70] Ibid., p. 312.
[71] Ibid., p. 165.
[72] It is important to note that although U.K. production is declining, the exports from the U.K. to continental Europe through the Interconnector pipeline between the U.K. and Belgium continue to increase. ("Revolution in European Gas?" presentation by Pierre Noël, University of Cambridge to the Electricity Policy Research Group Energy Policy Dinner on February 24, 2011 in Cambridge, U.K.
[73] BP, June 2011.
[74] Anouk Honoré, *European Natural Gas Demand, Supply, and Pricing: Cycles, Seasons, and the Impact of LNG Price Arbitrage,* Oxford Institute for Energy Studies, (Oxford, UK: Oxford University Press, 2010). p. 167.

future of the Atlantic Basin gas market. Given Eastern Europe's dependence on Russia for natural gas supply, shale gas resources hold the prospect economic and geopolitical benefit. According to the EIA, Ukraine and Poland—with an estimated 42 and 187 tcf of shale gas resources, respectively—have been particularly interested in developing their shale gas assets. However, similar to unconventional gas development in Asia, regulatory and infrastructure obstacles will make large-scale shale gas production in the near-term difficult. Moreover, in some parts of Europe there is an active public opposition to shale gas production which may threaten the development of domestic resources in some countries and regions.[75] France has banned hydraulic fracturing and some environmental and public opposition groups are looking for sweeping, continental legislation against shale gas production.

Export Feasibility to the Atlantic Basin

The prospects for U.S.-origin exports to the Atlantic Basin rest on a range of factors. It primarily depends on the availability of pipeline gas from Russia, Algeria, and Norway and the availability of LNG from Algeria, Nigeria, and Qatar. It also depends on the demand for gas in the electricity sector. Germany's decision to accelerate the phase-out of its nuclear reactors was copied by Switzerland, which decided to phase out its nuclear reactors, and Italy, which decided against building new reactors. In the case of Italy, much of this demand will therefore be met by natural gas. A similar decision in France, a country that currently generates more than three-quarters of its electricity from nuclear power but which is in the midst of a presidential election where nuclear energy policy is one of the primary issues, would result in a significant demand disruption for the Atlantic Basin. The development of gas transportation infrastructure—both within the continent and with outside suppliers in Russia, the Middle East, and North Africa—will also have an impact on the prospect for LNG imports from the United States. With a greater diversity of gas supply leading to lower spot prices in Europe, the opportunity for LNG arbitrage of U.S. gas into the region is lower than in the Pacific Basin. The potential for Atlantic Basin shale gas development will also have a significant bearing on the long-term prospect for LNG imports to the European continent.

Central and Latin American Gas Markets

In addition to the Pacific and Atlantic basins, there are several smaller LNG export options for U.S. sourced-natural gas in the Caribbean, Mexico, and Chile. Many of the Caribbean nations currently burn refined oil products for power generation, a practice that is becoming increasingly expensive as oil prices rise. To diversify its energy mix, Jamaica is considering the construction of a floating LNG terminal; other Caribbean nations may follow. In addition to these smaller markets, both Mexico and Chile are potential markets for U.S. natural gas. While an increase in exports to Mexico would likely come via pipeline from Texas, Chile represents a potential opportunity for LNG imports from the United States. Chile, which has a free-trade agreement with the United States, currently imports more than 90 percent of its natural gas in the form of LNG (83 percent of which came from Equatorial Guinea, Egypt, and Trinidad and Tobago in 2010).[76] One factor that would impact Chile's natural gas imports will be the development of shale gas in Argentina. The EIA estimates that Argentina's shale gas reserves

[75] At the European Autumn Gas Conference in Paris on November 15-16, many speakers stated that the public opposition to hydraulic fracturing threatens to hinder shale gas production in Europe. ("Shale gas development to be slow in coming, speakers warn," *Platts Oil & Gas Journal,* November 28, 2011.)

[76] BP, June 2011.

are 774 tcf—the third largest shale gas reserves in the world.[77] If Argentina develops this resource in a timely manner, one logical export destination would be Chile, thereby reducing Chile's potential LNG import needs.

Economics and Financing

The fundamental economic calculation for natural gas exports is the price differential between domestic gas and that in overseas markets. In addition to the cost of the feedstock, there are several additional fixed costs that must be taken into consideration when assessing the economic feasibility of LNG exports, including those of liquefaction, transportation, and regasification. The construction of dedicated liquefaction facilities cost between $2 billion and $8 billion each, depending on capacity.[78] In order to secure financing for such facilities companies looking to export gas must have in place long-term contracts for the sale of LNG. Transportation costs depend on the size of vessel used to move the LNG, the cost of shipping fuel, and the distance the cargoes have to travel. Regasification can be the responsibility of either the supplier or the receiver according to the specific terms of a contract. While individual costs can vary as a function of size, local conditions, and fuel costs, MIT provides a profile of a typical cost structure for an LNG supply chain: for each MMBtu of gas, it estimates liquefaction costs at $2.15, shipping costs at around $1.25 (depending on fuel costs and transportation distance), and regasification costs at $0.70.[79] It is also important to consider that companies interested in exporting LNG will need to ensure that the price spread will need to remain for at least 10 to 12 years, to budget for pre-planning and facility construction. Based on current costs of liquefaction, transportation and regasification, the minimum difference between international LNG prices and the U.S. price of natural gas needs to remain at roughly $3.40 to ensure that U.S. LNG is competitive.

Many of the issues listed in the previous sections can have a bearing on the price of domestic gas. However, exports themselves are also likely to have an effect on the price of natural gas as they represent an additional source of demand. The actual price implication of LNG exports, as well as other economic and non-economic implications of LNG exports, is discussed in Part II.

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[77] EIA, April 2011b.
[78] Ratner, November 2011.
[79] MIT, 2011. p. 25.

Part II: Implications of U.S. LNG Exports

Part I of this report focused on the factors that will affect the ability of the United States to export increased volumes of LNG. The following section addresses the implications of such exports.

From the perspective of the U.S. federal government, the issue of implications is viewed in terms of "public interest." Under existing legislation, exports of natural gas to countries with a free trade agreement (FTA) with the United States are, by law, deemed to be in the public interest and authorization is required to be given without modification or delay. Projects looking for authorization to export LNG to countries without an FTA, which account for roughly 96 percent of current global LNG demand, are required to be approved by the Secretary of Energy unless, after public hearing, the Department of Energy finds that such exports are *not* in the public interest.[80] Although the legal definition of "public interest" is not explicitly given in existing legislation, according to public statements by officials from the Department of Energy, "public interest" includes:

- Adequate domestic natural gas supply;
- Domestic demand for natural gas proposed for export;
- Economic impacts of exports (on GDP, consumers, and industry);
- U.S. energy security;
- Job creation;
- U.S. balance of trade;
- International considerations;
- Environmental considerations;
- Consistency with DoE's policy of promoting market competition through free negotiation of trade[81]

The first two of these criteria were addressed in Part I. The remainder focus on the various domestic and international implications of U.S. LNG exports.

Domestic Implications

The domestic implications of U.S. LNG exports include their impact on natural gas prices, natural gas price volatility, jobs and competitiveness, and on overall energy security.

Price of Domestic Natural Gas

The domestic price impact of natural gas exports will be a significant factor in determining

[80] LNG statistics from BP, June 2011; the 96 percent figure does not include South Korea which has signed but not ratified and implemented a FTA agreement with the United States. For the full text of the legislation pertaining to natural gas exports see Natural Gas Act (NGA) Section 3 (15 USC §717b), (http://uscode.house.gov/uscode-cgi/fastweb.exe?getdoc+uscview+t13t16+1440+12++%28%29%20%20)

[81] Redacted from a statement by Christopher Smith, Deputy Assistant Secretary for Oil and Natural Gas, Office of Fossil Energy, U.S. Department of Energy before the Senate Committee on Energy and Natural Resources on November 8, 2011.

whether or not the United States should export LNG. While it is generally acknowledged that a domestic price increase will result from large-scale LNG exports, the size of the price increase is the subject of debate, with a number of studies suggesting a range of possible outcomes. The important considerations when analyzing the results and conclusions of the various existing studies are the assumptions and models that are used when making price forecasts. Below are the results and methodologies of five major pricing studies done by the EIA and three consultancies: Deloitte, ICF International, and Navigant Consulting, which published two studies.

2012 Energy Information Administration Study

In January 2012, the EIA published a study entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets."[82] The study, conducted at the request of the Office of Fossil Energy of the Department of Energy, analyzed four different export scenarios across four different resource base or economic assumptions to project price responses to LNG exports. In addition to a "baseline" scenario, where no LNG is exported, the EIA model considered four different export scenarios:

- A low export/slow growth scenario, where 6 bcf/day of LNG is exported, phased in at a rate of 1 bcf/day per year;
- A low export/rapid growth scenario, where 6 bcf/day of LNG is exported, phased in at a rate of 3 bcf/day per year;
- A high export/slow growth scenario, where 12 bcf/day of LNG is exported, phased in at a rate of 1 bcf/day per year;
- A high export/rapid growth scenario, where 12 bcf/day of LNG is exported, phased in at a rate of 3 bcf/day per year.

Given the uncertainty over the actual size of the shale gas resource base and the future growth of the U.S. economy, each of these scenarios (both "baseline" and export) were applied to four alternate background cases:

- A reference case, based on the EIA's 2011 Annual Energy Outlook;
- A low-shale estimated ultimate recovery (EUR) case, in which shale gas production from new, undrilled wells is 50 percent below the reference case scenario;
- A high-shale EUR case, in which shale gas production from new, undrilled wells is 50 percent higher than the reference case;
- A high economic growth case, in which U.S. GDP grows at 3.2 percent as opposed to the 2.7 percent assumed in the reference case.

Given the range of assumptions, the range of results was unsurprisingly wide. The results range from a 9.6 percent increase (from \$3.56 to \$3.90/mcf) in domestic natural gas prices in 2025 due to exports (in the case of high shale gas recovery, low export volumes and a slow rate of export growth) to a 32.5 percent increase (in the case of low shale gas recovery, high export volumes and a high rate of export growth). The percentage premium for domestic natural gas prices in 2025 for each scenario relative to the baseline scenario price estimate is detailed in **Table 3**.

In addition to the price premium for exporting natural gas that exists in each case, the EIA study projected a short-term spike in natural gas prices as a result of LNG exports. As **Figure 7** below illustrates, in 2015, the first year that LNG exports occur, domestic natural gas prices rise rapidly until total export capacity is reached. In the "low-rapid" scenario prices peak in 2016, after the 6 bcf/day of export capacity is built over 2 years;

[82] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Energy Information Administration, January 2012. (EIA, 2012a).

Table 3: Percentage Increase in Domestic Natural Gas Price Relative to Baseline Scenario, 2025

Scenario → / Case ↓	Baseline Scenario Projected Natural Gas Price in 2025 ($/mcf)	Low Export-Slow Growth	Low Export-Rapid Growth	High Export-Slow Growth	High Export-Rapid Growth
Reference Case	$4.70	10.0%	12.8%	14.3%	25.7%
High Shale EUR	$3.56	9.6%	12.9%	13.2%	24.2%
Low Shale EUR	$6.52	13.7%	17.0%	20.2%	32.5%
High Macroeconomic Growth	$4.99	11.0%	13.4%	15.6%	28.1%

Source: "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Energy Information Administration, January 2012.

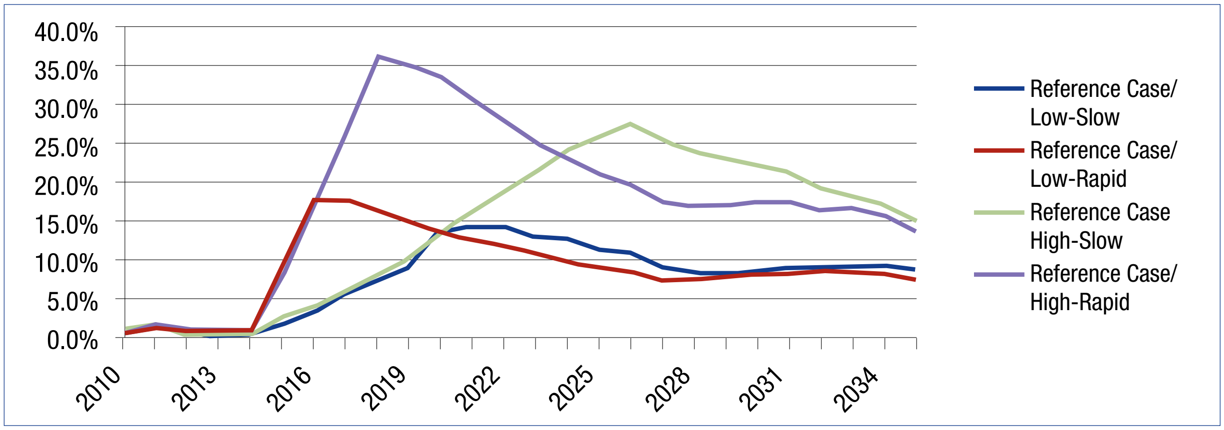
in the "high-slow" scenario, natural gas prices peak in 2026, after the 12 bcf/day of export capacity is built over 12 years. The immediate jump in price becomes more pronounced in the scenarios where LNG export capacity increases quickly. In the "low-rapid" scenario, the price of natural gas peaks at nearly 18 percent above the baseline case; in the "high-rapid" scenario, natural gas prices peak at 36 percent above the baseline case. This price impact is exacerbated in the Low Shale EUR and High Macroeconomic Growth cases, as LNG exports further tighten domestic natural gas markets. In the most extreme example, the high-rapid scenario for exports in a Low Shale EUR case, the price for natural gas peaks at more than 50 percent than the baseline case.[83]

There are two factors that should be considered when interpreting the results of this price impact study. The first is the assumption regarding the rate at which LNG could be exported. The results of EIA's analysis represent an extreme scenario for LNG exports. In the existing LNG market, it is particularly unlikely that either the "low-rapid" or the "high-rapid" scenarios would materialize. The former assumption stipulates that the United States would export 6 bcf/day of LNG by 2016. Given that, at the time of writing, only one facility has been approved to export 2.2 bcf/day to non-FTA countries starting in 2015, it is unlikely that another three plants would be approved and built in such a short time frame.[84] The latter scenario, that the United States would be exporting 12 bcf/day of LNG by 2018, suggests that in the next several years, the United States would grow from exporting negligible volumes of LNG to having roughly one-third of the global LNG export capacity. Not only would this supply growth outpace growth in global LNG demand, but this capacity addition would also have to compete with roughly

[83] Ibid.

[84] Of the major LNG export applications awaiting approval for non-FTA exports, it would require the next three plants—Freeport LNG, Lake Charles, and Dominion Cove Point—to be approved for the United States export capacity to cross the 6 bcf/day threshold.

Figure 7: Percentage Increase in Domestic Natural Gas Price Relative to Baseline Scenario, Reference Case 2010-2035



Source: "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Energy Information Administration, January 2012.

11 bcf/day of Australian-origin LNG that is expected to hit the market around the same time.[85]

The second issue is the model's assumptions for incremental investment in natural gas production as a result of increased export capacity. The spike in price depicted in **Figure 7** occurs because investment from gas producers lags additional demand. In the model, producers respond to, rather than anticipate, additional demand. For this reason, prices peak once the export capacity is filled, before steadily decreasing. In reality, the expectation of future demand would likely induce gas producers to invest in additional production before incremental demand occurs. As a result, the increase in prices would likely begin earlier and peak at a lower level than suggested by the model.

Deloitte Study

An earlier study released in November 2011 from the Deloitte Center for Energy Solutions highlighted the producer-response in its model. In addition to finding that LNG exports would produce a smaller increase in gas prices than the EIA report suggests, the Deloitte study points out that "producers can develop more reserves in anticipation of demand growth, such as LNG exports. There will be ample notice and time in advance of the exports to make supplies available."[86] Using a dynamic model, in which production increased in anticipation of new demand, the Deloitte study found that 6 bcf/day of exports of LNG would result in, on average, a 1.7 percent increase (from $7.09 to $7.21/MMBtu) in the price of natural gas between 2016 and 2035.

Further, the Deloitte study noted that there would be regional variations to the increase in natural gas prices resulting from LNG exports. As most of the proposed liquefaction terminals are expected to be on the Gulf Coast, the price of Henry Hub gas, which is the key benchmark for natural gas from the Gulf Coast, will increase by $0.22/MMBtu by 2035 as a result of U.S. LNG exports. This is more than double the price increase projected in regions further away from the LNG export terminals. In New York and Illinois, natural gas prices are projected to increase by less than $0.10/MMBtu. This is particularly important

[85] Australia has approximately 10 bcf/day of LNG export projects that have already reached final investment decision. Most of this capacity is already contracted out with the remainder expected to be sold on the spot market. More than 90 percent of this capacity is expected to come online between 2014 and 2017. (Authors' interview with analysts at the Commonwealth Bank of Australia, March 19, 2012.)

[86] Deloitte, 2011.

in the Northeast, which historically experiences some of the highest natural gas prices in the country, but will benefit from the development and consumption of natural gas from the nearby Marcellus shale play.

Other Studies

Three other studies of note have analyzed the price impacts of U.S. LNG exports. In August 2010, Navigant Consulting found that 2 bcf/day of LNG exports would cause a price increase of between 7 and 7.9 percent from 2015 to 2035 relative to a scenario with no gas exports. ICF International found in August 2011 that 6 bcf/day of exports would result in an 11 percent ($0.64/MMBtu) increase in natural gas prices over the same period.[87] More recently, Navigant released another study that analyzed the impact of two separate export scenarios. The first scenario modeled the impact of 3.6 bcf/day of LNG exports from three terminals in North America: Sabine Pass in Louisiana, Kitimat in British Columbia, and Coos Bay in Oregon. The second scenario modeled the impact of 6.6 bcf/day of LNG exports from the three aforementioned export projects and 2 bcf/day of added exports from the Gulf Coast and 1 bcf/day from Maryland.[88] This Navigant study found that 6.6 bcf/day of LNG exports would result in a 6 percent ($0.35/MMBtu) increase in natural gas prices from 2015 to 2035.

As with the EIA and Deloitte studies, the results of both Navigant and ICF's studies must be analyzed in the context of their respective methodologies and assumptions. Navigant's first study uses a more static supply model, which, unlike dynamic supply models, does not fully take account of the effect that higher prices have on spurring additional production. As a result, it takes a conservative estimate of supply growth potential. The report acknowledges that the price outcomes modeled in its analysis "establish the upper range of impacts that exports [...] might have on natural gas prices."[89] This study also did not factor in the reemergence of the industrial sector as a major consumer of natural gas following the shale gas "revolution." The study assumes that natural gas consumption by the industrial sector will decline by 0.3% per year to 2035. By contrast, the EIA model assumes that industrial sector demand will increase by roughly 1% per year over the same period.[90] The ICF study factors in various levels of production response from an increase in price. Under its 6 bcf/day export scenario, the price impact ranges from a $0.52/MMBtu increase in a more responsive drilling activity scenario to a $0.75/MMBtu increase in a less responsive drilling activity scenario.

Which Study is Right?

Given that these studies forecast natural gas prices two decades into the future, it is difficult to determine which study is most accurate. (**Table 4** shows a comparison of the price impact forecasts of the various models.) However, policymakers would benefit from having a better understanding of the results that are generated from each report. This includes choosing the most relevant results from each report. For instance, following the release of the EIA study, many commentators were quick to highlight that natural gas prices could increase by more than 50 percent as a result of LNG

[87] "Resource and Economic Issues Related to LNG Exports," *ICF International,* August 17, 2011; and "Markey Analysis for Sabine Pass LNG Export Project," *Navigant Consulting,* August 23, 2010. p. 5. (http://www.navigant.com/~/media/Site/Insights/Energy/Cheniere_LNG_Export_Report_Energy.ashx). It is important to note that both Navigant and ICF explored other scenarios and cases; however, for the purpose of this report, we analyzed the pricing impacts of the scenarios and cases that we thought were the most likely. For instance, the Navigant study analyzes price impacts for exports of 1 bcf/day and 2 bcf/day. Given that the Sabine Pass LNG export terminal is already contracted out for 2 bcf/day, this study focuses on that export scenario.

[88] "Jordan Cove LNG Export Project Market Analysis Study," *Navigant Consulting,* January 2012.

[89] Navigant Consulting, August 2010. p. 5.

[90] "Annual Energy Outlook 2011," Energy Information Administration, U.S. Department of Energy.

exports. However, this ignored the assumptions behind this number: it was based on the price of natural gas in one year under the most extreme assumptions of exports and domestic resource base. A more comprehensive analysis should include an assessment of the average price impact from 2015 to 2035. When distinguishing between the various studies, policymakers should identify which assumptions most resemble the existing natural gas market and its likely direction, and which models are most reflective of the complex nature of domestic and global natural gas trade. Assuming realistic volumes of natural gas exports as well as a reasonable supply response by natural gas producers are important considerations. It is important to note that the supply curves in the various studies reflect different interpretations of the economics of marginal production.

The Power Sector and Industrial Sector

Part I indicated that the power-generation and industrial sectors would account for most of the demand for newly available natural gas resources. As shown above, LNG exports are likely to increase domestic prices of natural gas, suggesting negative consequences for these two competing sectors. In their analyses, both Deloitte and EIA found that the majority—63 percent, according to both studies—of the exported natural gas will come from new production as opposed to displaced consumption from other sectors. By contrast, between 17 and 38 percent of supply of natural gas for export would be met by reduced demand, as higher prices pushes some domestic consumers to use less gas.

In the power generation and industrial sectors, the price impacts of LNG exports are likely to have modest impacts. In the power sector, natural gas has historically been used as a back up to coal and nuclear base-load generation. For such gas used at the margin, the increase in electricity prices as a result of LNG exports would be limited by its competitiveness relative to other fuels: as soon as it becomes more expensive than the alternative for back up generation, power producers will substitute away from gas.[91] According to ICF International, a $0.64/MMBtu increase in the price

Table 4: Study-by-study comparison of the Average Price Impact from 2015-2035 of 6 bcf/day of LNG exports (unless otherwise noted)

Study	Average Price without Exports ($/MMBtu)	Average Price with Exports ($/MMBtu)	Average Price Increase (%)
EIA*	$5.28	$5.78	9%
Deloitte	$7.09	$7.21	2%
Navigant (2010)** (2 bcf/day of exports)	$4.75	$5.10	7%
Navigant (2012)***	$5.67	$6.01	6%
ICF International***	$5.81	$6.45	11%

* Price impact figure for EIA study reflects the reference case, low-slow export scenario.
** The Navigant study did not analyze exports of 6 bcf/day.
*** Navigant (2010 and 2012) and ICF International studies are based on Henry Hub price.
Source: EIA, Deloitte, Navigant, ICF Internationa l.

[91] Information according to ICF International and Deloitte.

of natural gas would result in an electricity price increase of between $1.66 and $4.97/megawatt-hour (MWh), depending on how often gas is used as the marginal fuel for electricity. Deloitte estimates that the price increase of electricity would not be more than $1.65/MWh.[92] EIA estimates that electricity price impacts will be marginal as well (between $1.40/MWh and $2.90/MWh) except in the "high-rapid" export scenario.[93] The EIA Annual Energy Outlook 2011 estimates that, without exporting LNG, the average price of electricity (across all fuels) in 2035 will be $92/MWh.[94]

In the longer term, natural gas is itself likely to be used for more base-load generation. The rapid increase in shale gas production, coupled with the retirements of as much as 50 gigawatts (GW) of coal-fired electricity due to plant age or inability to adhere to possibly forthcoming EPA regulations is likely to increase the demand for natural gas in the power sector. According to some analysts, the near-term demand caused by the retirements of the oldest and least efficient coal-fired power plants could result in an additional natural gas demand of 2 bcf/day.[95] Given the lack of environmentally and economically viable alternatives, a moderate increase in gas prices is unlikely to result in a large move away from natural gas, although increased costs will be transferred to customers. Natural gas consumption in the power sector has been considered economic at prices much higher than those resulting from LNG exports in even the highest price-impact projections. Even prior to the shale gas "revolution," when natural gas prices were high, natural gas demand was increasing in the power sector. The EIA Annual Energy Outlook 2005—published in a year when average well head prices were over $7/MMBTU—projected that natural gas demand in the electricity sector would increase by 70 percent between 2003 and 2015.[96]

Unlike the power sector, which continued to build natural-gas fired generation during a period of increasing gas prices, the industrial sector was negatively affected by growing natural gas import dependence, high gas prices, and gas price volatility. Between 2000 and 2005, the price of natural gas increased by 99 percent and LNG imports more than doubled.[97] By 2005, the ratio of the price of oil to the price of natural gas was approximately 6:1, just below the 7:1 oil-to-gas price ratio at which U.S. petrochemical and plastics producers are globally competitive.[98] That same year Alan Greenspan, then-Chairman of the Federal Reserve, noted that because of natural gas price increases "the North American gas-using industry [was] in a weakened competitive position."[99]

Since then the price of natural gas has collapsed. In 2011, the oil-to-natural gas price ratio was more than 24:1. In 2012 it has been even higher. The decline in natural gas prices has galvanized the industrial sector. A joint study by PwC and the National Association for Manufacturers, an industry trade group, found that the development of shale gas could save manufacturers as much as $11.6 billion per year in feedstock costs through 2025.[100] New investments in petrochemical and plastics

[92] Deloitte, 2011.
[93] "Effect of Increased Natural Gas Exports on Domestic Energy Markets," Energy Information Administration, January 2012.
[94] EIA, April 2011a.
[95] According to a private ClearView Energy Partners Working Paper.
[96] "Annual Energy Outlook 2005," Energy Information Administration, U.S. Department of Energy. p. 159.
[97] According to EIA statistics.
[98] According to EIA statistics, in 2005 the price of Brent Crude oil was $54.57 per barrel and the price of natural gas at Henry Hub was $8.67 per MMBtu, giving an oil-to-gas price ratio (on a non-energy equivalent basis)n of approximately 6.3:1. The 7:1 threshold is according to the American Chemistry Council report, "Shale Gas and new Petrochemicals Investment," March 2011. (ACC, March 2011). One barrel of crude oil has nearly 6 MMBtu.
[99] Remarks by Alan Greenspan, Chairman of the Federal Reserve, before the National Petrochemical and Refiners Association Conference in San Antonio, Texas, April 5, 2005. (http://www.federalreserve.gov/boarddocs/speeches/2005/20050405/default.htm)
[100] "Shale Gas: A renaissance in U.S. manufacturing?" PwC with contribution from the National Association of Manufacturers, December 2011.

producing facilities are occurring throughout the East and Southeast, largely predicated on the availability of inexpensive natural gas.

Opponents of LNG exports contend that such investments would be deterred in the future as a result of increases in the price of natural gas. However, the evidence suggests that the competitive advantage of U.S. industrial producers relative to its competitors in Western Europe and Asia is not likely to be affected significantly by the projected increase in natural gas prices resulting from LNG exports. As European and many Asian petrochemical producers use oil-based products such as naphtha and fuel oil as feedstock, U.S. companies are more likely to enjoy a significant cost advantage over their overseas competitors. Even a one-third decline in the estimated price of crude oil in 2035 would result in an oil-to-gas ratio of 14:1.[101]

There is also the potential for increased exports to help industrial consumers. Ethane, a liquid byproduct of natural gas production at several U.S. gas plays, is the primary feedstock of ethylene, a petrochemical product used to create a wide variety of products. According to a study by the American Chemistry Council, an industry trade body, a 25 percent increase in ethane production would yield a $32.8 billion increase in U.S. chemical production. By providing another market for cheap dry gas, LNG exports will encourage additional production of natural gas liquids (NGL) that are produced in association with dry gas. According to the EIA, ethane production increased by nearly 30 percent between 2009 and 2011 as natural gas production from shale started to grow substantially. Ethane production is now at an all-time high, with more than one million barrels per day of ethane being produced.[102] Increased gas production for exports results in increased production of such natural gas liquids, in which case exports can be seen as providing a benefit to the petrochemical industry.

Natural gas price volatility

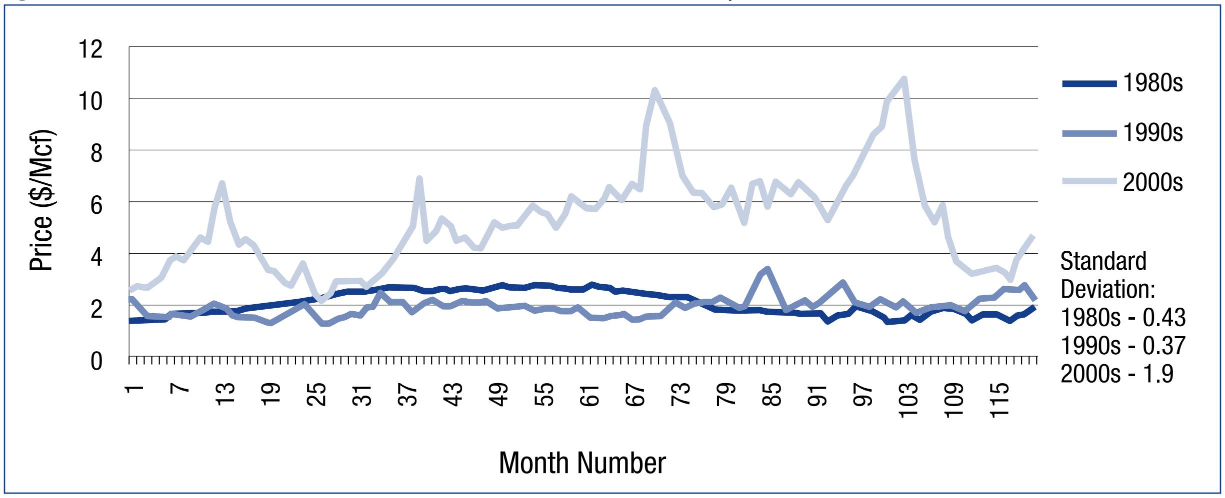
A major concern among domestic end users of natural gas is the possibility of an increase in natural gas price volatility resulting from an increase in U.S. LNG exports. As **Figure 8** demonstrates, the price volatility experienced during the 2000s was the highest the domestic gas market has experienced in the past three decades.

The volatility of the natural gas market in the 2000s was largely caused by a tight supply-demand balance. Natural gas demand increased substantially as the U.S. economy grew and natural gas was viewed as environmentally preferable to coal for power generation. This increase in demand coincided with a reduction in domestic supply and an increased reliance on imports. The recent surge in U.S. natural gas production has resulted in less market volatility since 2010. According to EIA, the standard deviation of the price of natural gas (a general statistical indicator of volatility) between 2010 and 2011 was one-third what it was during the 2000s.[103] Potential exports of U.S. LNG concerns some domestic consumers for two principal reasons: greater volatility in domestic natural gas prices; and exposure of domestic natural gas prices to higher international prices resulting in a convergence between low U.S. prices and high international prices.

There is an insufficient amount of data and quantitative research on the relationship between do-

[101] The International Energy Agency forecasts the price of oil in 2035 to be $140. The ratio of an oil price one-third that amount to EIA's forecasted gas price in 2035 (with 6 bcf/day of exports) is roughly 14:1 ($98/barrel:$6.98/MMBtu). Oil price from the International Energy Agency's World Energy Outlook 2011.
[102] Data from EIA "Natural Gas Plant Field Production" statistics.
[103] According to calculations of EIA natural gas price data, the standard deviation of domestic natural gas prices in 2010 and 2011 has been 0.54.

Figure 8: Natural Gas Prices in 1980s, 1990s, and 2000s, by month ($/Mcf)



Source: EIA

mestic natural gas price volatility and LNG exports. However, certain characteristics of the LNG market are likely to limit volatility. LNG is bound by technical constraints: it must be liquefied and then transported on dedicated tankers before arriving at terminals where a regasification facility must be installed. Liquefaction facilities have capacity limits to how much gas they can turn into LNG. If they are operating at or close-to full capacity, such facilities will have a relatively constant demand for natural gas, therefore an international price or supply shock would have little impact on domestic gas prices. Moreover, unlike oil trading, in which an exporter—theoretically—sells each marginal barrel of production to the highest bidder in the global market, the capacity limit on LNG production and export means that LNG exporters have an infrastructure-limited demand for natural gas leaving the rest of the natural gas for domestic consumption. As most LNG infrastructure facilities are built on a project finance basis and underpinned by long-term contracts, this demand can be anticipated by the market years in advance, reducing the likelihood of volatility.

The macroeconomy and jobs

The macroeconomic and job implications of LNG exports depend on two principal factors: the gains from trade from exploiting pricing differentials and inefficiencies of the global market; and the employment implications of those gains, higher domestic natural gas prices, and greater domestic natural gas production. The Department of Energy has commissioned a study on both the macroeconomic and employment implications of U.S. LNG exports, which will be released later this year. This study will provide a qualitative assessment of the implications of LNG exports to the U.S. economy and employment.

LNG exports are likely to be a net benefit to the U.S. economy, although probably not a significant contributor in terms of total U.S. GDP. Exports of U.S. natural gas will take advantage of the benefits of the existing producer's surplus resulting from the pricing differentials between the natural gas markets in the United States, Europe, and Asia. Contractual terms will determine how this surplus is shared between U.S. sellers and foreign buyers.[104] The benefit of this trade will likely outweigh the cost to domestic consumers of the increase in the price of natural gas as most of the natural gas demanded by exports will come from new natural gas production as opposed to displacing existing production from domestic consumers. On the other hand, LNG exports from the United States are likely to put marginal upward pressure on the relative value of the U.S. dollar. In March 2012, Citigroup released a report on North American hydrocarbon production that included a model of the macroeconomic impact of U.S. oil and gas exports. The Citi analysis found that oil and gas exports would cause a nearly two percent decline in the current account deficit by 2020, but that the exchange rate implications would be modest. By 2020, the U.S. dollar would appreciate by between 1.6 and 5.4 percent.[105]

The implications of LNG exports on job creation are similarly difficult to quantify. Other than temporary construction jobs created by the need to build liquefaction capacity, pipelines, and other ancillary infrastructure, the operation of the liquefaction facility will likely provide little permanent employment benefit. As outlined in the section on price impacts above, as much of the gas for export will come from new production, rather than the displacement of consumption in other sectors, the negative economic, and therefore job-related, effects on those sectors is likely to be limited. Beyond the labor required for additional gas production to satisfy LNG exports, the net impact of LNG exports is likely to be minimal. Further upstream, the job potential may be greater. By increasing domestic natural gas production, employment from additional oil and gas producers will increase, as will the demand for manufacturers of equipment for oil and gas production, gathering, and transportation.

Domestic energy security

Aside from the price impact of potential U.S. LNG exports, a major concern among opponents is that such exports would diminish U.S. "energy security"; that exports would deny the United States of a strategically important resource. The extent to which such concerns are valid depends on several factors, including the size of the domestic resource base, and the liquidity and functionality of global trade. As Part I of this report notes, geological evidence suggests that the volumes of LNG export under consideration would not materially affect the availability of natural gas for the domestic market. Twenty years of LNG exports at the rate of 6 bcf/day, phased in over the course of 6 years, would increase demand by approximately 38 tcf. As presented in Part I, four existing estimates of total technically recoverable shale gas resources range from 687 tcf to 1,842 tcf; therefore, exporting 6 bcf/day of LNG over the course of twenty years would consume between 2 and 5.5 percent of total shale gas resources. While the estimates for shale gas reserves are uncertain, in a scenario where reserves are perceived to be lower than expected, domestic natural gas prices would increase and exports would almost immediately become uneconomic. In the long-term, it is possible that U.S. prices and international prices will converge to the point at which they settle at similar levels. In that case, the United States would have more than adequate import capacity (through bi-directional import/export facilities) to import gas when economic.

[104] The amount of the producer's surplus depends on the structure of the LNG contract. Some contracts are free-on-board (FOB), whereby the buyer takes owner of the LNG once it is loaded onto a ship. The buyer is then responsible for delivery to the LNG facility, assuming both the price risk and the potential rents. Other contracts are delivered ex-ship (DES), where the buyer only takes ownership of the LNG once the cargo arrives at the receiving port. The seller is therefore responsible for the transportation and delivery, and assumes both the price risk and the potential rent.

[105] "Edward Morse et al, "Energy 2020: North America, the New Middle East?" Citigroup, March 20, 2012.

A further gas-related consideration with regard to energy security is the effects of increased production of associated natural gas with the increasing volumes of U.S. unconventional oil. As the primary energy-security concern for the United States related to oil, the application of fracking and horizontal drilling in oil production is reducing U.S. oil import dependence, while simultaneously producing substantial volumes of natural gas, which, given the relative economics of oil and gas, is effectively delivered at zero (or, in the case of producers who have to invest in equipment to manage flaring and venting, negative) cost. To the extent that associated gas from unconventional oil production is used for LNG export, it can be seen as a consequence of—rather than a threat to—increased U.S. energy security.

International Implications

The international implications of LNG exports from the United States can be divided into pricing, geopolitics, and environment.

International Pricing

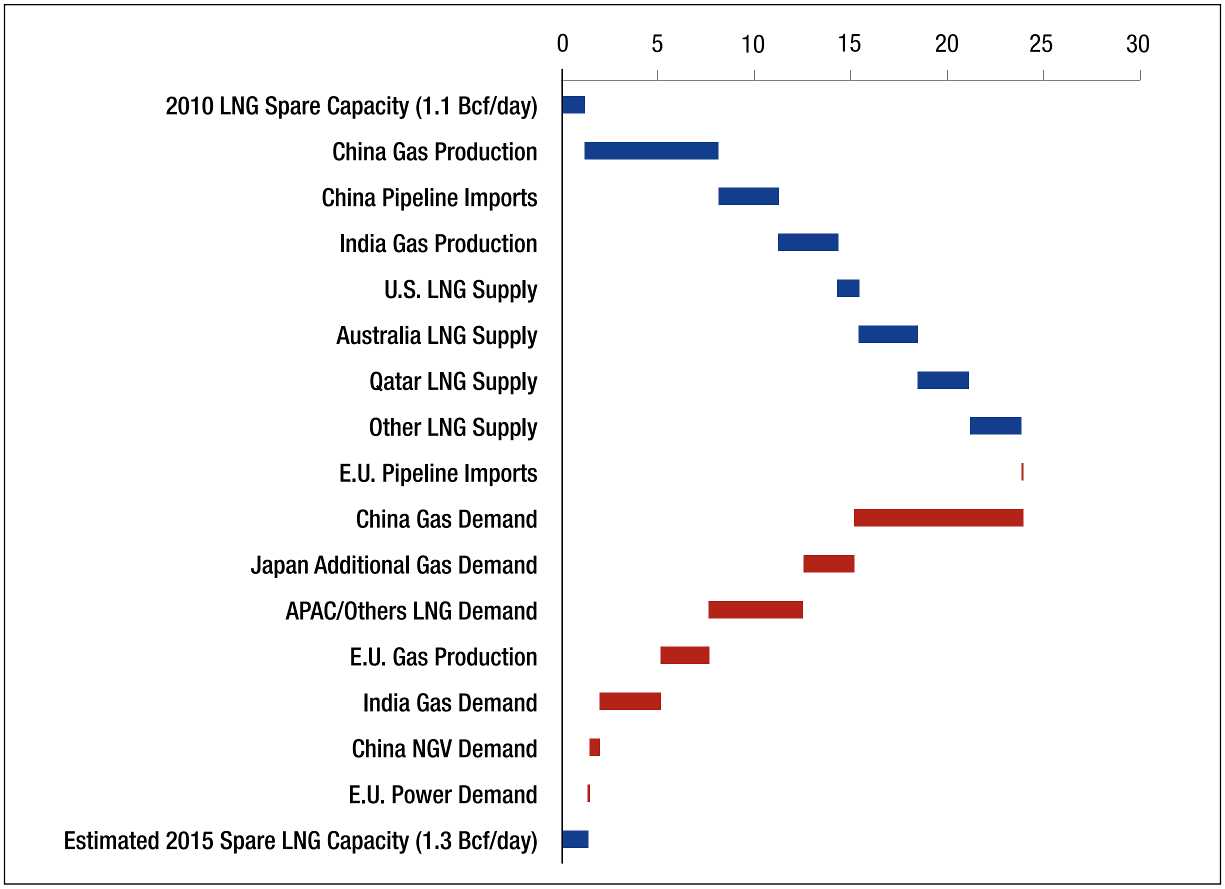
As discussed in Part I, the global LNG market is informally separated into three markets: North America, the Atlantic Basin (mostly Europe), and the Pacific Basin (including Japan, South Korea, Taiwan, China, and India). These markets are separated because of important technical differences that impact the pricing structure for LNG in each market. The North American natural gas market is competitive and prices are traded in a transparent and open market. The Atlantic Basin is dominated by European LNG consumers such as the United Kingdom, Spain, France, and Italy, and is a hybrid of a competitive U.K. market that was liberalized in the mid-1990s and a Continental European market that is dominated by oil-linked, take-or-pay contracts. In recent years, the U.K. hub, the National Balancing Point (NBP), has traded at a premium to the U.S. hub, the Henry Hub. The Pacific Basin is a more rigid market that depends heavily on oil-indexed contracts that are more expensive than those used in the Atlantic Basin. While they have no central trading hub, the Pacific Basin consumers such as Japan and South Korea (which is implementing its recently-signed free-trade agreement with the United States) currently import LNG based on a pricing formula known informally as the Japan Crude Cocktail, the average price of custom-cleared oil imports into Tokyo. Many Pacific Basin contracts have a built-in price floor and price ceiling depending on the price of oil.[106]

Without exporting any natural gas, the U.S. shale gas "revolution" has already had a positive impact on the liquidity of global LNG markets. Many LNG cargoes that were previously destined for gas-thirsty U.S. markets were diverted and served spot demand in both the Atlantic and Pacific Basins. The increased availability of LNG cargoes has helped create a looser LNG market for other consumers (see **Figure 9**). This in turn has helped apply downward pressure to the terms of oil-linked contracts resulting in the renegotiation of some contracts, particularly in Europe. Increased availability of LNG cargoes also accelerated a recent trend of increasing reliance of consumers on spot LNG markets. In 2010 short-term and spot contracts represented 19 percent of the total LNG market, up from only a fraction one decade earlier.[107] In this case, increasing demand for spot cargoes indicates that consumers are taking advantage of spot prices that are lower than oil-indexed rates.

[106] It is important to note that all oil-indexed contracts are not the same. While they are all indexed to oil prices, the formulae that determine the delivery price of LNG varies substantially from contract to contract.

[107] Howard Rogers, "The Impact of a Globalizing Market on Future European Gas Supply and Pricing: the Importance of Asian Demand and North American Supply," *Oxford Institute for Energy Studies,* January 2012. p. 9. (OIES, 2012)

Figure 9: Estimated LNG Spare Capacity from 2010-2015 (bcf/day)



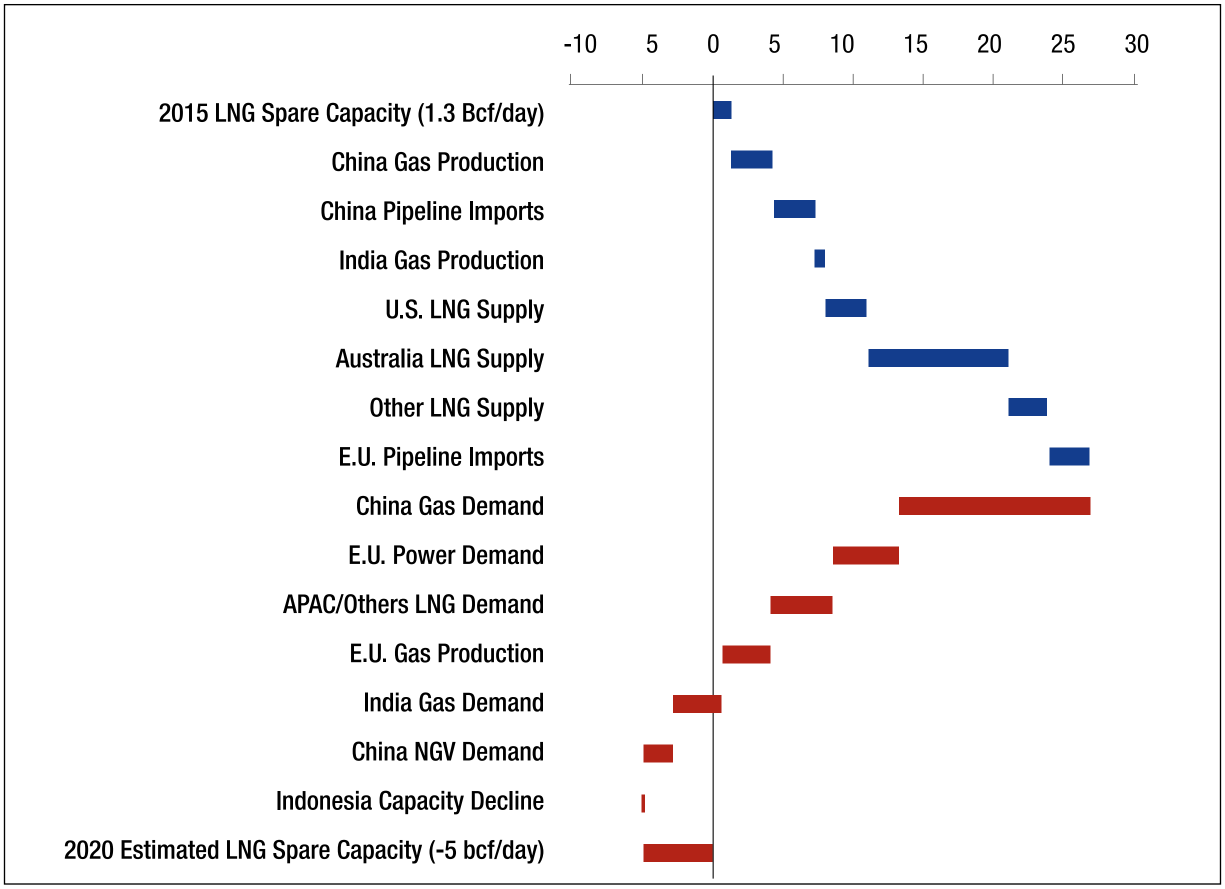
Source: Brookings analysis of Morgan Stanley research and data; IEA, EIA, ClearView Energy Partners

LNG exports will help to sustain market liquidity in what looks to be an increasingly tight LNG market beyond 2015 (see **Figure 10**). Should LNG exports from the United States continue to be permitted, they will add to roughly 10 bcf/day of LNG that is expected to emerge from Australia between 2015 and 2020. Nevertheless, given the projected growth in demand for natural gas in China and India and assuming that some of Japan's nuclear capacity remains offline, demand for natural gas will outpace the incremental supply. This makes U.S. LNG even more valuable on the international market.

Although it will be important to global LNG markets, it is unlikely that the emergence of the United States as an exporter of LNG will change the existing pricing structure overnight. Not only is the market still largely dependent on long-term contracts, the overwhelming majority of new liquefaction capacity emerging in the next decade (largely from Australia) has already been contracted for at oil-indexed rates.[108] The incremental LNG volumes supplied by the United States at floating Henry Hub rates will be small in comparison. But while U.S. LNG will not have a transformational impact, by establishing an alternate lower price for LNG derived through a different market mechanism, U.S. exports may be central in catalyzing future changes in LNG contract structure. As previously mentioned, this impact is already be-

[108] From an interview with Luke Smith, Energy Analyst, Commonwealth Bank of Australia. March 19, 2012.

Figure 10: Estimated LNG Spare Capacity from 2015-2020 (bcf/day)



Source: Brookings analysis of Morgan Stanley research and data; IEA, EIA, ClearView Energy Partners

ing felt in Europe. A number of German utilities have either renegotiated contracts or are seeking arbitration with natural gas suppliers in Norway and Russia. The Atlantic Basin will be a more immediate beneficiary of U.S. LNG exports than the Pacific Basin as many European contracts allow for periodic revisions to the oil-price linkage.[109] In the Pacific Basin this contractual arrangement is not as common and most consumers are tied to their respective oil-linkage formulae for the duration of the contract.[110] Despite the increasing demand following the Fukushima nuclear accident, however, Japanese LNG consumers are actively pursuing new arrangements for LNG contracts.[111]

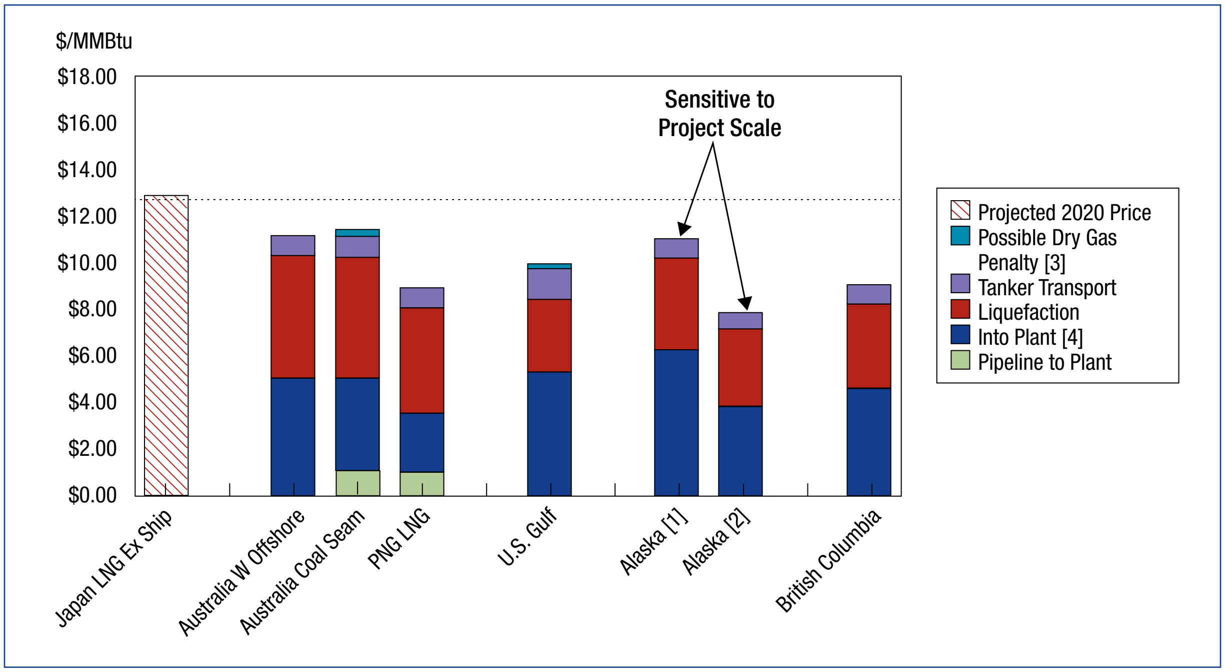
There are other limits to the extent of the impact that U.S. LNG will have on global markets. It is unlikely that many of the LNG export facilities under consideration will reach final investment decision. Instead, it is more probable that U.S. natural gas prices will have rebounded sufficiently to the point that exports are not commercially viable beyond a certain threshold. (**Figure 11** illustrates the estimated costs of delivering LNG to Japan in

[109] See Morten Frisch, "Current European Gas Pricing Problems: Solutions Based on Price Review and Price Re-opener Provisions," *University of Dundee Center for Energy Petroleum and Mineral Law and Policy,* for a thorough review of European natural gas contract structure.

[110] OIES, 2012. p. 5.

[111] "Fukushima's Impact on Global Gas," presentation by Leslie Palti-Guzman, Analyst for Global Energy and Natural Resources, Eurasia Group, at the Center for Strategic and International Studies in Washington, DC. March 2012.

Figure 11: Estimated Costs of Delivering LNG to Japan in 2020



Note: Gulf exports to Asia assume tankers travel through an expanded Panama Canal
[1]: Assumes 1 bcf/day from Valdez, Alaska
[2]: Assumes 3.1 bcf/day from Valdez, Alaska
[3]: Dry gas penalty is assumed at 2 percent
[4]: For Alaska and British Columbia, "Into Plant" refers to the opportunity cost relative to projections of Henry Hub price
Source: From a client presentation by James Jensen, Jensen Associates

2020.) This threshold, expected by many experts to be roughly 6 bcf/day by 2025, is modest in comparison to the roughly 11 bcf/day of Australian LNG export projects that have reached final investment decision and are expected to be online by 2020.

Also, the impact of U.S. LNG exports could be limited by a number of external factors that will have a larger bearing on the future of global LNG prices. For instance, a decision by the Japanese government to phase-out nuclear power would significantly tighten global LNG markets and probably displace any benefit provided by U.S. LNG exports. Conversely, successful and rapid development of China's shale gas reserves would limit the demand of one of the world's fastest-growing natural gas consumers. However, to the extent that U.S. LNG exports can help bring about a more globalized pricing structure, they will have economic and geopolitical consequences.

Geopolitics

A large increase in U.S. LNG exports would have the potential to increase U.S. foreign policy interests in both the Atlantic and Pacific basins. Unlike oil, natural gas has traditionally been an infrastructure-constrained business, giving geographical proximity and political relations between producers and consumers a high level of importance. Issues of "pipeline politics" have been most directly visible in Europe, which relies on Russia for around a third of its gas. Previous disputes between Moscow and Ukraine over pricing have led to major gas shortages in several E.U. countries in the winters (when demand is highest) of both 2006 and 2009. Further disagreements between Moscow and Kiev over the terms of the existing bilateral gas deal have the potential to escalate again, with negative consequences for E.U. consumers.

The risk of high reliance on Russian gas has been a principal driver of European energy policy in recent decades. Among central and eastern European states, particularly those formerly aligned with the Soviet Union such as Poland, Hungary, and the Czech Republic, the issue of reliance on imports of Russian gas is a primary energy security concern and has inspired energy policies aimed at diversification of fuel sources for power generation. From the U.S. perspective such Russian influence in the affairs of these democratic nations is an impediment to efforts at political and economic reform. The market power of Gazprom, Russia's state-owned gas monopoly, is evident in these countries. Although they are closer to Russia than other consumers of Russian gas in Western Europe, many countries in Eastern and Central Europe pay higher contract prices for their imports, as they are more reliant on Russian gas as a proportion of their energy mixes.

In the larger economies of Western Europe, which consume most of Russia's exports, there are efforts to diversify their supply of natural gas. The E.U. has formally acknowledged the need to put in place mechanisms to increase supply diversity. These include market liberalization approaches such as rules mandating third-party access to pipeline infrastructure (from which Gazprom is demanding exemption), and commitments to complete a single market for electricity and gas by 2014, and to ensure that no member country is isolated from electricity and gas grids by 2015.[112]

Despite these formal efforts, there are several factors retarding the E.U.'s push for a unified effort to reduce dependence on Russian gas. National interest has been given a higher priority than collective, coordinated E.U. energy policy: the gas cutoffs in 2006 and 2009 probably contributed to the acceptance of the Nord Stream project, which carries gas from Russia into Germany. Germany's decision to phase out its fleet of nuclear reactors by 2022 will result in far higher reliance on natural gas for the E.U.'s biggest economy. The environmental imperative to reduce carbon emissions—codified in the E.U.'s goal of essentially decarbonizing its power sector by the middle of century—mean that natural gas is being viewed by many as the short-to medium fuel of choice in power generation. Finally, the prospects for European countries to replicate the unconventional gas "revolution" that has resulted in a glut of natural gas in the United States look uncertain. Several countries, including France and the U.K., have encountered stiff public opposition to the techniques used in unconventional gas production, while those countries, such as Poland and Hungary, that have moved ahead with unconventional-gas exploration have generally seen disappointing early results. Collectively, these factors suggest that the prospects for reduced European reliance on Russian gas appear dim.

The one factor that has been working to the advantage of advocates of greater European gas diversity has been the increased liquidity of the global LNG market, discussed above. Russia's dominant position in the European gas market is being eroded by the increased availability of LNG. Qatar's massive expansion in LNG production in 2008, coupled with the rise in unconventional gas production in the United States as well as a drop in global energy demand due to the global recession, produced a global LNG glut that saw many cargoes intended for the U.S. market diverted into Europe. As mentioned previously, with an abundant source of alternative supply, some European consumers, mainly Gazprom's closest partners, were able to renegotiate their oil-linked, take-or-pay contracts with Gazprom. As **Figure 10** illustrates, however, in the wake of the Fukushima

[112] Note from the General Secretariat of the European Council to the Delegations on the Conclusions of the European Council, March 8, 2011. (http://register.consilium.europa.eu/pdf/en/11/st00/st00002-re01.en11.pdf); Paul Whitehead, "EU leaders commit to complete single energy market by 2014," *Platts,* December 9, 2011. (http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/8686978)

natural disaster and nuclear accident in Japan and a return to growth in most industrialized economies, the LNG market is projected to tighten considerably in the short-term, potentially returning market power to Russia.

However, there is a second, structural change to the global gas market that may have more lasting effects to Russia's market power in the European gas market. LNG is one of the fastest growing segments of the energy sector. The growth of the LNG market, both through long-term contract and spot-market sales, is likely to put increasing pressure on incumbent pipeline gas suppliers. A significant addition of U.S. LNG exports will accelerate this trend. In addition to adding to the size of the market, U.S. LNG contracts are likely to be determined on a "floating" basis, with sales terms tied to the price of a U.S. benchmark such as Henry Hub, eroding the power of providers of long-term oil linked contract suppliers such as Russia. While U.S. LNG will not be a direct tool of U.S. foreign policy—the destination of U.S. LNG will be determined according to the terms of individual contracts, the spot-price-determined demand, and the LNG traders that purchase such contracts—the addition of a large, market-based producer will indirectly serve to increase gas supply diversity in Europe, thereby providing European consumers with increased flexibility and market power.

Increased LNG exports will provide similar assistance to strategic U.S. allies in the Pacific Basin. By adding supply volumes to the global LNG market, the U.S. will help Japan, Korea, India, and other import-dependent countries in South and East Asia to meet their energy needs. The desire on the part of Pacific Basin countries for the U.S. to become a gas supplier to the region has been underlined by the efforts of the Japanese government, which has attempted to secure a free-trade agreement waiver from the United States to allow exports. As with oil price-linked Russian gas contracts in Europe, U.S. LNG exports linked to a floating Henry Hub benchmark, have the potential to weaken the market power of incumbent LNG providers to Asia, increasing the negotiating power of consumers and decreasing the price. As U.S. foreign policy undergoes a "pivot to Asia," the ability of the U.S. to provide a degree of increased energy security and pricing relief to LNG importers in the region will be an important economic and strategic asset.

Beyond the basin-specific considerations of U.S. LNG exports, they would provide a source of predictable natural gas supply that is relatively free from unexpected production or shipping disruption. With Qatar representing roughly one-third of the global LNG market, a blockade or military intervention in the Strait of Hormuz or a direct attack on Qatar's liquefaction facilities by Iran would inflict chaos on world energy markets. While the United States government will be unable to physically divert LNG cargoes to specific markets or strategic allies that are most affected (gas allocation will be made by the market players), additional volumes of LNG on the world market will benefit all consumers.

International Environmental Implications

Proposed LNG exports from the United States have encountered domestic opposition on environmental grounds. As outlined in Part I, natural gas production causes greenhouse gas emissions in the upstream production process through leakages, venting, and flaring. The greenhouse gas footprint of shale gas production has been the subject of vigorous debate, with some studies suggesting that methane from the production process leads to shale gas having a higher global warming impact than that of other hydrocarbons including coal. While the methodology underlying such studies has been widely criticized, there is no doubt that leakage and venting of natural gas is a serious negative environmental consequence of natural gas production and transportation: EPA has estimated that worldwide leakages and venting volumes were 3,353.5 bcf in 2010.[113]

By contrast, some advocates of U.S. exports of LNG maintain that they have the potential to bring global environmental benefits if they are used to displace more carbon-intensive fuels. According to the IEA, natural gas in general has the potential to reduce carbon dioxide emissions by 740 million tonnes in 2035, nearly half of which could be achieved by the displacement of coal in China's power-generation portfolio. Natural gas—in the form of LNG—also has the potential to displace more carbon-intensive fuels in other major energy users, including across the EU and in Japan, which is being forced to burn more coal and oil-based fuels to make up for the nuclear generation capacity lost in the wake of the Fukushima disaster. In addition to its relatively lower carbon-dioxide footprint, natural gas produces lower emissions of pollutants such as sulfur dioxide nitrogen oxide and other particulates than coal and oil.

Natural gas—both in the form of LNG and compressed natural gas—is also being viewed as a potential replacement for oil in the vehicle transportation fleet, with large carbon dioxide abatement potential.[114] However, as discussed in Part I, even the United States with its low gas prices is unlikely to see any significant move toward natural gas vehicles in the absence of government policies; the prospects for such vehicles entering the European or Asian markets, where gas is several times as expensive, are remote. On the other hand, additional volumes of natural gas in the global power generation fleet may also have longer-term detrimental consequences for carbon emissions. According to the IEA, by backing out nuclear and renewable energy generation, natural gas could add 320Mt of carbon dioxide by 2035.[115]

Whether U.S. LNG exports contribute to reduced carbon dioxide emissions through the displacement of coal fired power generation or to the crowding out of renewable and nuclear energy in the global energy mix is something of a moot point. According to the IEA, global power generation is projected to exceed 27,000 terawatt hours per year by 2020.[116] Even assuming U.S. exports of 6 bcf/day (on the upper end of the range of expectations), zero losses due to transportation, regasification, and transmission, and a high natural gas power plant efficiency level of 60 percent, such volumes would account for just over one percent of total global power generation.[117] Therefore, although the domestic environmental impacts associated with shale gas extraction may, pending the outcome of further study, prove to be a cause for concern with respect to greenhouse gas emissions, the potential for U.S. LNG exports to make a meaningful impact on global emissions through changes to the global power generation mix is negligible.

[113] "Global Anthropogenic Non-CO2 Greenhouse Gas Emissions: 1990-2020," Environmental Protection Agency, 2006.
[114] "Making the Green Journey Work: Optimised Pathways to Reach 2050 Abatement Targets with Lower Costs and Improved Feasibility," European Gas Advocacy Forum, February 2011, p. 32.
[115] IEA, 2011. p. 37.
[116] "World Energy Outlook 2011," International Energy Agency, 2011. p.178.
[117] Assuming heat content of natural gas of 1,000 Btu/cubic feet.

Part III: Conclusions and Recommendations

This paper has attempted to answer two questions: Are U.S. LNG exports feasible? If so, what are the implications of U.S. LNG exports?

For exports to be feasible, several demand and supply-related conditions need to be met. On the supply side, adequate resources must be available and their production must be sustainable over the long-term. The regulatory and policy environment will need to accommodate natural gas production to ensure that the resources are developed. The capacity and infrastructure required to enable exports must also be in place. This includes the adequacy of the pipeline and storage network, the availability of shipping capacity, and the availability of equipment for production and qualified engineers.

On the demand side, LNG exports will compete with two main other domestic end uses for natural gas: the power-generation sector, and the industrial and petrochemical sector. According to most projections, the U.S. electricity sector will see an increased demand for natural gas as it seeks to comply with policies and regulations aimed at reducing carbon-dioxide emissions and pollutants from the power-generation fleet. Cheaper natural gas in the industrial sector has the potential to lower the cost of petrochemical production and to improve the competitiveness of a range of refining and manufacturing operations. Advocates of natural gas usage in the transportation fleet – particularly in heavy-duty vehicles (HDVs) – see it as a way to decrease the country's dependence on oil, although absent major policy support, this sector is unlikely to represent a significant source of gas demand.

For increased U.S. LNG exports to be feasible, they will also need to be competitive with supplies from other sources. The major demand centers that would import U.S. LNG would be Pacific Basin consumers (Japan, South Korea, and Taiwan, and increasingly China and India), and Atlantic Basin consumers, mostly in Europe. The supply and demand balance in the Atlantic and Pacific Basins and, therefore the feasibility for natural gas exports from the United States, depend heavily on the uncertain outlook for international unconventional natural gas production. Recent assessments in countries such as China, India, Ukraine, and Poland indicate that each country has significant domestic shale gas reserves. If these reserves are developed effectively—which is likely to be difficult in the short-term due to a lack of infrastructure, physical capacity, and human capacity—many of these countries would dramatically decrease their import dependence, with negative implications for existing and newcomer LNG exporters.

Detailed analysis of the foregoing factors suggests that the exportation of liquefied natural gas from the United States is logistically feasible. Based on current knowledge, the domestic U.S. natural gas resource base is large enough to accommodate the potential increased demand for natural gas from the electricity sector, the industrial sector, the residential and commercial sectors, the transportation sector, *and* exporters of LNG. Other obstacles to production, including infrastructure, investment, environmental concerns, and human capacity, are likely to be surmountable. Moreover, the current and projected supply and demand fundamentals of the international LNG market are conducive to competitive U.S.-sourced LNG.

While LNG exports may be practically feasible, they will be subject to approval by policy makers if they are to happen. In making a determination on the advisability of exports, the federal government will focus on the likely implications of LNG exports: i.e. whether LNG exports are in the "public interest." The extent of the domestic implications is largely dependent upon the price impact of exports on domestic natural gas prices. While it is clear that domestic natural gas prices will increase if natural gas is exported, most existing analyses indicate that the implications of this price increase are likely to be modest. Natural gas producers will likely anticipate future demand from LNG exports and will increase production accordingly, limiting price spikes. The impact on the domestic industrial sector is likely to be marginal: to the extent that LNG exports raise domestic gas prices above the level at which they would have been in the absence of such exports, they will negatively affect the competitiveness of U.S. industry relative to international competitors. However, the competitiveness of natural-gas intensive U.S. companies relative to their counterparts is likely to remain strong, given the large differential between projected U.S. gas prices and oil prices, which are the basis for industrial feedstock by competitor countries. Further, LNG exports are likely to stimulate domestic gas production, potentially resulting in greater production of natural gas liquids such as ethane, a valuable feedstock for industrial consumers. LNG exports are also unlikely to result in an increase in price volatility. The volume of LNG exports is capped by the capacity limitations of liquefaction terminals. If liquefaction terminals are running at close to full capacity, an increase in international demand will do little to affect domestic demand for —and therefore domestic prices of —natural gas.

The potential benefits of U.S. LNG exports relate to trade, macroeconomics, and geopolitics. Exports of natural gas would bring foreign exchange revenues to the United States and have a positive effect on U.S. balance of payments, although in the context of overall U.S. trade, the impact of LNG revenues are likely to be small. The construction, operation, and maintenance of LNG export facilities and related infrastructure will also likely lead to some, limited, job creation. Exports may also serve as a stimulus to continue and even increase production of natural gas, which may result in an additional supply of employment. With some domestic production—mainly dry gas with little liquid content—being suspended due to gas prices being too low for continued economic extraction, exports may serve as an important source of incremental demand to support necessary volumes to stabilize gas prices. To the extent that gas for export is produced at zero or negative cost in association with unconventional oil, such gas can be seen as a consequence, rather than a detriment to increased U.S. energy security.

Additional volumes of U.S. LNG will be beneficial to the global gas market. While U.S. export volumes are unlikely to transform the existing fragmented structure of existing LNG trade, it will help to erode the basis of oil-linked contracts that have characterized it for decades, and to move the market toward global price convergence. In the short-term, the emergence of the United States as an exporter comes at a time of tightening global supply, meaning U.S. exports will provide much needed liquidity to natural gas consumers around the world, potentially improving the energy costs for consumers in LNG-dependent countries like Japan and India. While the economic benefits of this are clear, the progression towards a more global LNG market has substantial geopolitical implications as well. Although the U.S. government cannot directly influence the destination of each LNG cargo exported from the United States, U.S. foreign policy interests are served through a better-supplied global LNG market and through assistance to import-dependent strategic allies in Europe who will gain strategic leverage from the increased competition to Russian gas.

Beyond a simple cost-benefit analysis, there is a larger, more fundamental consideration that the U.S. government must consider when evaluating the merits of U.S. LNG exports. Policymakers should recognize that the non-exportation of U.S. LNG comes at the opportunity cost of forgoing the benefits of the free market. As a principal advocate and beneficiary of a global trading system characterized by the free flow of goods and capital, the United States has a long-term economic and political incentive to refrain from intervention in the market wherever possible. The economics of U.S. LNG exports—both the costs associated with producing, processing, and transporting LNG, and the competitive nature of the global market—are likely to impose market-determined boundaries on their viability. Irrespective of the status of permits, incremental additions to actual export capacity will be dependent on long-term financing and interest from contracting parties. Increases in domestic natural gas prices as a result of marginal increases in demand negatively impact the economics of additional export projects, thereby protecting domestic consumers from unlimited exports and price rises.

A proscription or limitation on LNG exports would constitute a de facto subsidy to domestic consumers at the expense of domestic producers. History suggests that government intervention in the allocation of rents can lead to inefficient outcomes and unintended consequences. To avoid these outcomes, the U.S. government should neither act to prohibit nor to promote LNG exports. In refraining from intervention in the gas market, the government will ensure that U.S. gas is allocated to its most efficient end uses, many of which will bring ancillary political and economic benefits to the United States and its partners and allies around the world.

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