Moore, Larine

From: Jody McCaffree [mccaffrees@frontier.com]
Sent: Saturday, January 26, 2013 3:29 PM
To: LNGStudy
Cc: Moore, Larine
Subject: Re: 2012 LNG Export Study
Attachments: DOEStudy_1_CALNG_Jan_24_2013_Comments_Final.pdf; DOEStudy_2_CALNG_Index_for_Exhibits.pdf; DOEStudy_3_Exb_A_FERC_Existing_Oper_LNG_Terminals.pdf; DOEStudy_4_Exb_B_Existing_N_Amer_LNG_Terminals.pdf; DOEStudy_5_Exb_C_Approved_N_Amer_LNG_Terminals.pdf; DOEStudy_6_Exb_D_Proposed-Potential_LNG_Terminals.pdf; DOEStudy_7_Exb_E_DOE_summary_lng_applications.pdf; DOEStudy_8_Exb_F_CALNG_Aug_6_2012_Testimony.pdf; DOEStudy_9_Exb_G_CALNG_9-12-2012_ Response_to_JCEP_Answer.pdf; DOEStudy_10_Exb_H_GAO_Report_of_Shale_Fracking.pdf; DOEStudy_11_Exb_I_LOOK-BEFORE-YOU-LEAP_Report.pdf; DOEStudy_12_Exb_J_Gas_Bubble_Leaking_About_to_Burst.pdf; DOEStudy_13_Exb_K_LNG_Exports_May_Fall_Short.pdf

Dear Ms. Moore:

Attached are the files sent into the DOE from the Citizens Against LNG concerning comments on the NERA 2012 LNG Export Study. They are all PDF format and numbered in the order they should be uploaded. The number is directly after the words DOEStudy in the file name.

Thank you for your time working with us on this. Please let me know that these were received.

Sincerely,

Jody McCaffree
Individual / Executive Director
Citizens Against LNG Inc
PO Box 1113
North Bend, OR 97459

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In the Matter of:

NERA Economic Consulting Study	)	**FR Doc No: 2012-29894**
"*Macroeconomic Impacts of LNG*	)	
***Exports from the United States*"**	)	
December 3, 2012	)	
	)	

The following sent by Email to LNGStudy@hq.doe.gov

Jody McCaffree
Individual / Executive Director
Citizens Against LNG Inc
PO Box 1113
North Bend, OR 97459

January 24, 2013

U.S. Department of Energy (FE-34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
P.O. Box 44375
Washington, DC 20026–4375

Re: 2012 LNG Export Study

Dear Mr. John Anderson / Mr. Edward Meyers:

On December 11, 2012, the Office of Fossil Energy at the U.S. Department of Energy posted in the Federal Register a Notice of Availability of a 2012 LNG Export Study and a request for comments. The Federal Register Notice listed the following 15 proposed LNG Export terminals:

- Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC - [FE Docket No. 10–161–LNG]
- Lake Charles Exports, LLC - [FE Docket No. 11–59–LNG]
- Dominion Cove Point LNG, LP - [FE Docket No. 11–128–LNG]
- Carib Energy (USA) LLC - [FE Docket No. 11–141–LNG]
- Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC - [FE Docket No. 11–161–LNG]
- Cameron LNG, LLC Gulf - [FE Docket No. 11–162–LNG]
- Gulf Coast LNG Export, LLC - [FE Docket No. 12–05–LNG]
- Jordan Cove Energy Project, L.P - [FE Docket No. 12–32–LNG]
- LNG Development Company, LLC (d/b/a Oregon LNG) - [FE Docket No. 12–77–LNG]
- Cheniere Marketing, LLC - [FE Docket No. 12–97–LNG]
- Southern LNG Company, L.L.C - [FE Docket No. 12–100–LNG]
- Gulf LNG Liquefaction Company, LLC - [FE Docket No. 12–101–LNG]
- CE FLNG, LLC - [FE Docket No. 12–123–LNG]
- Excelerate Liquefaction Solutions I, LLC - [FE Docket No. 12–146–LNG]

• Golden Pass Products LLC - [FE Docket No. 12–156–LNG]

Currently (as of January 11, 2013) there are now 23 proposed LNG export terminals seeking approval before the U.S. Department of Energy, Office of Fossil Energy, to export LNG.[1] These 23 proposed terminals have a combined capacity request to export 31.41 Bcf/d of LNG to Free Trade Agreement Nations and 24.80 Bcf/d of LNG to Non-Free Trade Agreement Nations. The U.S. Department of Energy, Office of Fossil Energy, has already approved LNG exports totaling 29.21 Bcf/d of LNG exports requested, mostly to Free Trade Agreement Nations. The NERA LNG Export study considered a High/Rapid LNG scenario of LNG export at 12 Bcf/d phased in at a rate of 3 Bcf/d per year. (NERA Page 14). This is far below what the U.S. Department of Energy (DOE) has already approved. In addition to this, the NERA study stated on page 210 the following;

> "Since the EIA assumed that all of the demand for domestic production associated with LNG exports was located in the Gulf region, it was not possible in this study to examine regional impacts on either natural gas prices or economic activity. The Gulf Coast is not necessarily a representative choice given the range of locations now in different applications, so that any attempt to estimate regional impacts would be misleading without more regional specificity in the location of exports." [2] (*Emphasis added*)

This is just a few of numerous inconsistencies and shortcomings we have found reviewing the recently released NERA Economic Consulting study commissioned by the U.S. Department of Energy (DOE). We agree with Senator Wyden's January 10, 2013, letter to the Department expressing concerns with the Department of Energy's approval process for liquefied natural gas ("LNG") export applications. The Natural Gas Act ("NGA") requires the Department to determine whether approving an application to export LNG is in the "public interest," and the Department has indicated that this report will be central to the approval process for these applications. The shortcomings of the NERA study are numerous and render this study insufficient for the Department to use in any export determination.

The NERA study left out significant data in its analysis and would need to be updated to include this data along with new EIA projections, more realistic market assumptions, regional impacts of the proposed actual export terminals, and evaluations of the actual impacts on consumers and businesses of exporting LNG. Since the DOE has approved more LNG export volumes to Free Trade Agreement Nations than the NERA 2012 LNG Export Economic Study fully analyzed in its modeling, **we have to wonder if the LNG export volumes that have already been approved by the DOE are currently even feasible**?

Before the DOE proceeds with making any more decisions to allow exports of LNG, it is imperative that the U.S. Department of Energy, Office of Fossil Energy and the Federal Energy Regulatory Commission assess the entire economic and environmental impacts of ALL the proposed LNG export projects as a whole, not just in the Gulf Coast but in other regions of the United States as well. (*See Exhibits A, B, C, D & E*) The programmatic environmental assessment should include the cumulative environmental impacts of hydraulic fracking and the cumulative impacts of all proposed LNG export projects on water and air quality and water supply. An assessment of alternative ways to meet energy needs should also be considered along with an independent analysis of what the sustainable natural gas supplies truly are. **It would not be a good idea to allow LNG Export facilities to be built which may need to be**

[1] http://www.fe.doe.gov/programs/gasregulation/reports/summary_lng_applications.pdf
[2] NERA Economic Consulting Study "*Macroeconomic Impacts of LNG Exports from the United States,*" Dec 2012 http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

abandoned due to an overbuild of these facilities and/or the lack of an adequate fuel supply. A rigorous independent unbiased economic analysis that includes "all" potential probabilities and impacts (both negative and positive) of Exporting Domestic and Canadian natural gas is needed. This analysis should include both the cumulative and individual impacts of all the proposed LNG Export terminals in North America.

We have brought to the attention of the DOE in previous letters a host of issues and concerns having to do with public interest issues and concerns with the exportation of LNG, specifically with regards to the Jordan Cove Energy Project. (*See Exhibits F & G*) Many of our concerns have not yet been addressed by the DOE nor have they been addressed in this current NERA Study. The NERA Study fully admits that it is inadequate on pages 210 and 211 and supplies a list of factors that the Study did not include in its analysis. These are listed as:

A. How Will Overbuilding of Export Capacity Affect the Market
B. Engineering or Infrastructure Limits on How Fast U.S. Liquefaction Capacity Could Be Built
C. Where Production or Export Terminals Will Be Located
D. Regional Economic Impacts
E. Effects on Different Socioeconomic Groups
F. Implications of Foreign Direct Investment in Facilities or Gas Production

Additional concerns with the NERA 2012 LNG Export Study are addressed further below.

1) <u>The NERA Study based its predictions and assumptions on "EIA IEO 2011 Natural Gas Production and Consumption" which is now two years old and outdated</u>.

Many of the current proposed LNG Export terminals were actually proposed Import terminals in 2011. In addition to this, the NERA analysis also did not consider LNG Export terminals that are currently being built and/or proposed to come on-line in the international market as well. 31 percent of global LNG exports in 2011 were supplied from Qatar, which also accounted for two-thirds of export growth. But that outlook is set to change over the next decade. The NERA study stated on page 5:

> "The global LNG market was treated as a largely competitive market with one dominant supplier, Qatar, whose decisions about exports were assumed to be fixed no matter what the level of U.S. exports…"

According to the GIIGNL (International Group of Liquefied Natural Gas Importers), in 2011 there were 10 LNG export projects in the works in Australia, one to three in Canada, two in Indonesia, and others in Algeria, Angola, Libya, Nigeria, Papua New Guinea, and Qatar.[3] Major new gas finds off the coast of West Africa and in South America suggest other new exporters in the pipeline. Angola LNG will open the African nation's first liquefaction plant in the first quarter of this year, about a year later than planned, Petroleum Minister Jose Maria Botelho de Vasconcelos said last month.[4]

[3] GIIGNL (International Group of Liquefied Natural Gas Importers) The LNG Industry in 2011 - Report (pg http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GIIGNL_The_LNG_Industry_2011.pdf
[4] http://www.bloomberg.com/news/2013-01-22/billionaire-fredriksen-winning-as-lng-tanker-rates-drop-freight.html

Projects in Australia, Papua New Guinea and Indonesia were once considered potential sources of LNG for the Jordan Cove Energy LNG Project when it was proposing to Import LNG. Should the Jordan Cove LNG Export project actually be permitted and built, these projects would end up being in competition with Jordan Cove when and if it should ever come on-line.

The NERA study did not take into account all these additional exporting projects and proposals in its economic analysis. The study admits that it did not analyze, "*Implications of Foreign Direct Investment in Facilities or Gas Production*" and states on page 211:

> "In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources..."

The NERA Study on page 35 states:

> "It is outside the scope of this study to analyze alternative responses by other LNG suppliers in order to determine what would be in their best economic interest or how they might behave strategically to maximize their gains. This would require a different kind of model that addresses imperfect competition in global LNG markets and could explain the apparent ability of some large exporters to set prices for some importing countries at prices higher than the cost of production plus transportation." (*Emphasis added*)

2) The NERA study did not consider the development of natural gas extraction and distribution technology happening in other countries that are currently importing LNG.

According to an Oct 2012 article in InvestorPlace, China accounted for 22% of Asia-Pacific gas consumption last year and 4% of global demand. How it's meeting that demand could be a cause concern for U.S. natural gas suppliers — especially the firms looking to export some or all of their production. The article states:

> "It seems that China has begun to ramp its imports of piped natural gas from Eurasia…"

> "According to recent customs data, China for the first time is importing more natural gas overland via pipeline than it is by sea via LNG tanker. The country increased pipeline shipments from Turkmenistan by more than 55% to 9.85 million metric tons in the first eight months of the year. The ex-Soviet nation is home to one of the largest non-shale natural gas reserves on the planet, and it provides of almost all China's piped-in supplies…"

> "… Given China's growing thirst for cheaper piped natural gas, as many as 12 U.S. projects that have applied for an LNG export license — including Cheniere's (NYSE:LNG) Sabine Pass facility in Louisiana — could be thrown for a loop. At the same time, more $100 billion worth of LNG projects in Australia, such as Exxon Mobil's (NYSE:XOM) and BHP Billiton's () Scarborough gas field and Hess's (NYSE:HES) Equus project could be canceled if China continues to expand its usage of piped natural gas…." [5] (*Emphasis added*)

[5] "*Trouble in China for U.S. LNG Exports?- U.S. firms may find it's meeting demand from other sources*" By Aaron Levitt, InvestorPlace Contributor | Oct 16, 2012; http://investorplace.com/2012/10/trouble-in-china-for-u-s-lng-exports/

China is also looking to develop its own natural gas resources from shale beds just like the United States. Forbes reported the following in September:

> "…China is expected to put up 17 shale gas blocks for auction in the coming weeks in a bid to develop a robust shale gas industry. It is hoping to attract American energy firms to invest in the industry and form partnerships with domestic companies. It wants to see the success of the American shale gas industry replicated in China. China had no commercial shale gas production in 2011, but has set itself an ambitious target of producing 229.5 billion cubic feet of shale gas a year by 2015…" [6]

The issue of hydrofracking and the development of natural gas extraction being developed in other countries was also addressed to some degree in the following April 8, 2012, article that ran in the Eugene Register Guard concerning the proposed Jordan Cove LNG Export project:

> "….So, will it happen? The proposed Coos County import terminal has some tactical advantages over facilities on the Gulf Coast in its proximity to Asia, but it faces competition with a terminal in Kitimat, B.C., that won approval in October to export gas.
>
> "Western Canada has a big advantage over Coos Bay," Pursell said. "I'd be shocked if your facility got built."
>
> Braddock says he can get gas to Asia just as cheaply as Kitimat, but he's much farther behind. He also said there are far more abundant supplies of natural gas in other countries, but that they haven't developed the technology — yet — to tap into it.
>
> "<u>What we have is a head start in the technology, and they will get it, too, no question," Braddock said. "If no export facilities are built within the next seven or eight years, export facilities will probably never be built</u>."….[7] (*Emphasis added*)

In other words, in 7 to 8 years the proposed Jordan Cove LNG Export facility would most likely be obsolete. Why build it then? Why wasn't this issue addressed in the NERA economic study?

3) <u>The NERA study did not consider the impacts or costs of hydrafracking which could entail environmental, economic and health related problems and issues</u>.

These issues were brought to the DOE's attention in detail in our August 6, 2012, letter to the DOE. (*Attached as Exhibit F*) Issues surrounding LNG Exports including Hydrofracking are covered in detail in the two following attached reports:

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[6] *"Will ConocoPhillips Help China Tap Its Shale Gas Reserves?"* Forbes – 9/19/2012 http://www.forbes.com/sites/greatspeculations/2012/09/19/can-conocophillips-help-china-tap-its-shale-gas-reserves/

[7] *" IN THE PIPELINE? Proposed Coos Bay natural gas terminal remains up in the air";* By Winston Ross / The Register-Guard – April 8, 2012 ; http://www.registerguard.com/web/business/27868629-41/gas-braddock-natural-terminal-energy.html.csp

• Exhibit H: "*OIL AND GAS Information on Shale Resources, Development, and Environmental and Public Health Risks"*; By U.S. Government Accountability Office, September 2012
• Exhibit I: "*LOOK BEFORE THE LNG LEAP - Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start*"; By Craig Segall, Staff Attorney, Sierra Club Environmental Law Program.

While the gas industry looks to reap huge profits, local communities will be left to deal with the consequences such as poisoned drinking water, devastated coasts, and extreme air pollution. Both the liquefaction and fracking process will contribute to an increase in green house gasses emissions, thus contributing to climate-disrupting global warming pollution and more violent weather and storms. In addition, the massive super-cooling process needed to create the liquefied natural gas for export uses an incredible amount of energy. That is energy that could have been used here domestically. Why is it assumed by the DOE and the NERA study that we will have an infinite amount of fossil fuel energy in the future?

The following articles noted below have also been included as exhibits since they address many significant issues with regard to the viability of LNG Export and hydrofracking:

• Exhibit J: *"Gas Bubble Leaking, About to Burst"*by Richard Heinberg, originally published by Post Carbon Institute | Oct 22, 2012
• Exhibit K: The New York Times "*Exports of American Natural Gas May Fall Short of High Hopes*" January 4, 2013

4) The NERA study did not include the economic impacts of the influx of manufacturing that is coming back to the United States due in part to lower natural gas energy prices and production costs.

In December of 2012, The Atlantic reported in an article entitled, "*The Insourcing Boom,"*that after years of offshore production, General Electric (GE) was moving much of its far-flung appliance-manufacturing operations back home to Appliance Park, in Louisville, Kentucky, and GE was not alone in this move. The Atlantic article went on to state that part of the reason for this move was lower manufacturing costs brought on in part by lower natural gas energy costs:

> "…The natural-gas boom in the U.S. has dramatically lowered the cost for running something as energy-intensive as a factory here at home. (Natural gas now costs four times as much in Asia as it does in the U.S.)…" [8]

In February 2012, GE opened an all-new assembly line to make cutting-edge, low-energy water heaters. As The Atlantic article further explains, GE wasn't just able to hold the retail sticker to the "China price." It beat that price by nearly 20 percent. The China-made GeoSpring retailed for $1,599. The Louisville-made GeoSpring retails for $1,299.

In March 2012, GE started a second assembly line to make new high-tech French-door refrigerators. Another assembly line is under construction to make a new stainless-steel dishwasher starting in early

[8] "*The Insourcing Boom"* by Charles Fishman, December 2012, The Atlantic Magazine http://www.theatlantic.com/magazine/archive/2012/12/the-insourcing-boom/309166/

2013. "I don't do that because I run a charity," Jeff Immelt, CEO of GE, said at a public event in September. "I do that because I think we can do it here and make more money."

GE is not alone in moving the manufacture of many of its products back to the U.S. Forbes reported in December that Tim Cook, Job's successor as CEO of Apple, had announced that Apple will resume manufacturing one of their existing Mac lines in the U.S. next year.[9] Cook told BusinessWeek that Apple plans to spend $100 million on manufacturing in the U.S. in 2013. This transformation is mirrored in dozens of other places, with Whirlpool bringing mixer-making back from China to Ohio, Otis bringing elevator production back from Mexico to South Carolina, even Wham-O bringing Frisbee-molding back from China to California. As the Atlantic article explains in more detail, **lower energy and production costs in the U.S. are playing a key part in making this all happen.**

Thousands of manufacturing jobs are in the process of coming back to the U.S. but the NERA study did not consider or analyze this influx of new manufacturing jobs in its analysis.

Recently Huntsman Corporation announced that it has joined a coalition of U.S. manufacturers and others opposed to proposals from LNG exporters to permit the unlimited export of American natural gas. According to an LNG World News article:

> **"Peter Huntsman, President and CEO of Huntsman**, stated, *"We think it very short-sighted and bad public policy to allow our nation's natural gas advantage to be stripped and sent overseas to build a new manufacturing base that would otherwise be built here in the U.S."*
>
> He continued, *"Completely unfettered U.S. exports may enrich a few LNG exporters in the short term, but real, sustained and broad-based growth in the U.S. economy will come from a balanced approach that considers the needs of American manufacturers and consumers, and ensures that natural gas can be exported without undermining this emerging sunrise for American manufacturing and all the supporting industries and services. Our nation must not squander this opportunity."*[10]

Bloomberg's Businessweek reported in August that Dow Chemical Co. had e-mailed out a statement that laid out all the benefits that cheap natural gas has had for manufacturers, before concluding; *"[D]ecisions around the export of natural gas should include a rigorous analysis of potential impact on the domestic economy and job creation, and place a high priority on the manufacturing sector*." The Businessweek article also stated that **the large supply of cheap natural gas had helped revive U.S. manufacturing, which had added 500,000 jobs since February 2010**.[11]

The NERA study on the other hand, states on page 2 that, "LNG exports are not likely to affect the overall level of employment in the U.S…." This may be true for workers in the natural gas sector but would obviously not be true for workers in the manufacturing sector. Economic models as we know are only as good as their inputs and as we explained in our September 12, 2012, response letter in Jordan Cove's DOE FE Docket No. 12-32-LNG, (*See Exhibit G*) those inputs can sometimes be incorrect and/or wrong and may end up favoring a certain outcome that later proves to be incorrect.

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9 "*Why Apple and GE Are Bringing Back Manufacturing*" by Steve Denning, Forbes 12/7/2012 http://www.forbes.com/sites/stevedenning/2012/12/07/why-apple-and-ge-are-bringing-manufacturing-back/

10 "*U.S. Manufacturers Oppose LNG Exports*" Posted January 23, 2013 http://www.lngworldnews.com/u-s-manufacturers-oppose-lng-exports/

11 *"Strange Bedfellows Debate Exporting Natural Gas"* By Matthew Philips on August 22, 2012, Bloomberg Businessweek: http://www.businessweek.com/articles/2012-08-22/strange-bedfellows-debate-exporting-natural-gas

5) The NERA study did not consider the future economic costs to Americans from exporting our current known reserves of natural gas.

We have exported LNG from Alaska until now the supply in Cook Inlet is running out. In November the Alaska Journal of Commerce stated the following:

> "...There is increasing sensitivity to the Cook Inlet gas supply situation because existing fields are declining in production and local utility demand is expected to exceed annual production by the 2014-15 winter, requiring gas to be imported as LNG or compressed natural gas, utility officials told the state regulatory commission in a recent briefing.
>
> Several companies are exploring for oil and gas in Cook Inlet but no major discoveries have been made yet. Even if they are it is unlikely they can be put into production in time to meet the projected 2014-15 shortfall...." [12] (*Emphasis added*)

We should also learn a thing or two from China. China started out exporting their coal and then one day they had no more coal to export, nor any for their own energy needs. They then had to become an importer of coal in order to keep their economy going. **Is America so DUMB that we will do the same thing with natural gas?**

6) The NERA Study Did not consider that some of the companies proposing these American LNG Export projects, such as the Jordan Cove Energy Project, are foreign owned and controlled.

Capital Resources for the most part would not come back to the United States in these cases as the NERA study assumes. Our resources would end up being exploited in this scenario with no real benefit to the "Public Interest." The NERA study on page 78 assumes that "owners of businesses involved directly and indirectly in natural gas production and exports" would be American, which we have explained in earlier testimony to the DOE will clearly not be the case with the Jordan Cove Energy Project. The NERA study on page 211 states that that study did not address, "*Implications of Foreign Direct Investment in Facilities or Gas Production*":

> "In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources. Macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment ("FDI") that was additional to baseline capital flows into the U.S. FDI would largely affect the timing of macroeconomic effects, but quantifying these differences would require consideration of additional scenarios in which the business model was varied."

The NERA study also did not consider that some of the natural gas supply proposed to be exported from American Export terminals is proposed to be coming from Canadian sources.

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[12] *"Hilcorp consent degree will cap gas prices, limit LNG sales"* Tim Bradner, Alaska Journal of Commerce; Nov 15, 2012 http://www.alaskajournal.com/Alaska-Journal-of-Commerce/November-Issue-3-2012/Hilcorp-consent-degree-will-cap-gas-prices-limit-LNG-sales/

7) The NERA study assumes the market will be able to regulate itself as to whether LNG export of American gas will be feasible. The study did not consider the cost for projects that may be built based on wrong economic assumptions.

The philosophy and thinking that the free market will regulate itself and do the right thing has not proven to be correct in the past with regard to other large scale energy projects. As we have also seen more recently in the banking industry, the market needs regulation and guidance to ensure the protection of investors, the public and the environment.

A good example of how energy projects can go very wrong can be found in the Northwest in the 1970′s. The Washington Public Power Supply System (WPPSS, aka "whoops") began in the 70's the largest nuclear power plant construction project in U.S. history: reactors 1, 2, and 4 at Hanford, and reactors 3 and 5 at Satsop, west of Olympia. By 1983, cost overruns, delays, a slowing of electricity demand growth, concerns over nuclear power, and several other factors led to cancellation of two plants and a construction halt on two others. **The agency in the end defaulted on $2.25 billion in municipal bonds, which is still the largest municipal bond default in U.S. history**. The monumental court case which followed took nearly a decade to fully resolve. At Satsop, construction was well along on plants 3 and 5, with plant number 3 being about 85% complete, with the reactor in place, when the default occurred. Cooling towers, 480 feet tall, never saw a breath of steam, and demolition costs are estimated to be in the hundreds of millions. Ironically, the energy blackouts predicted by the industry to justify the building of the plants never occurred after the projects were stopped. The unfinished plants have been sitting there in limbo at Satsop ever since - too expensive to tear down, too unwieldy to be bought, too costly to maintain in mothballs forever. Proposals to turn them into everything from a nuclear weapons demolition plant to a theme park have come and gone.

These plants I am sure met energy modeling criteria at the time they were proposed to be built similar to what has been done by the NERA study, but they proved that even the best assumptions and predictions can end up being wrong in the end. In similarity to the WPPSS fiasco, the Jordan Cove LNG Export project is just one of a multitude of proposed LNG "plant" projects that are being proposed on the Pacific Coast. Another Pacific Coast LNG export "plant" project is being proposed in Warrenton, Oregon, along the Columbia River, and there are several more proposed projects near Kitimat, British Columbia, Canada. Canada's National Energy Board has already handed LNG-export licenses to at least two of the planned liquefaction projects there. In addition, another LNG export project is also being proposed in Alaska.

There are several West Coast LNG terminals that are already existing and/or being proposed to be built. These include the following:

West Coast "Existing" LNG Import/Export Terminals:
- Baja California, MX: 1.0 Bcfd, (Sempra – Energia Costa Azul)
- Kenai Alaska - ConocoPhillips LNG Export Plant - Currently in operation although the plants future remains unclear due to declining reserves. The plant has a license to export LNG until March 2013.

West Coast "Approved" LNG Import/Export Terminals
- Manzanillo, MX: 0.5 Bcfd (KMS GNL de Manzanillo) [Approved - Under Construction]
- Baja California, MX : 1.5 Bcfd (Sempra - Energia Costa Azul - Expansion) [Approved - Not Under Construction yet]

West Coast "Proposed" LNG Export Terminals

● Coos Bay, OR: 0.8 - 1.2 Bcfd (Jordan Cove Energy Project) - Fort Chicago LNG II U.S.L.P., a Delaware limited partnership (Canadian) owns seventy-five percent. Energy Projects Development L.L.C., a Colorado limited liability company, owns twenty-five percent.
● Astoria, OR: 1.25 - 1.5 Bcfd (Oregon LNG) - LNG Development Company, LLC, d/b/a Oregon LNG, Warrenton, Ore
● Alaska Gasline Port Authority: 2.0 - 2.4 Bcfd (Pipeline Capacity 3 – 3.5 Bcfd); LNG Export Terminal development partnership between the State of Alaska, ExxonMobil, ConocoPhillips, BP and TransCanada.

West Coast Canadian "Proposed" LNG Export Terminals

● Douglas Island, BC: 0.25 Bcfd (BC LNG Export Cooperative) - A privately held 13-member co-operative.
● Kitimat, BC: 0.7 Bcfd (Apache Canada Ltd.) - Backed by Apache Corp, Encana Corp and EOG Resources;
● Prince Rupert Island, BC: 1.0 Bcfd (Shell Canada) - Shell Canada Limited (Royal Dutch Shell plc) (40%),and its partners Korea Gas Corporation (KOGAS) (20%), Mitsubishi Corporation (20%), and PetroChina Company Limited (20%)

The gas slated to supply several of these proposed West Coast LNG Export projects appears to be coming from the same supply sources. We have concerns about the cumulative impacts of all these LNG Export proposals on gas supply and the domestic price of natural gas.[13] Environmental impacts are of concern also.[14] Property where pipelines and LNG facility development occurs would be limited in the future from use by other development should the LNG projects default after being built. Pipeline right of ways would negatively impact local industries such as Ranching, Timber, Farming, Fishing, Recreation and Tourism.

A Programmatic Economic and Environmental Impact Study based on sound science and true impacts should be completed first in order to determine which proposals, if any, applying for this same market share of natural gas would be the least environmentally impacting and in the best interest of Oregonians and Americans as a whole. The NERA study admits on page 210 that it did not address directly "*Regional Economic Impacts"* nor "*Where Production or Export Terminals would be located*." The study states on page 210 the following:

> "There are proposals for export facilities in the Mid-Atlantic, Pacific Northwest and Canada, all of which could change basis differentials and potentially the location of additional natural gas production, with corresponding implications for regional impacts. To analyze alternative locations

[13] "*Exports of LNG May Raise U.S. Prices as Much as 54%, Agency Says*"
- By Katarzyna Klimasinska – Jan 19, 2012 – Bloomberg:
http://www.bloomberg.com/news/2012-01-19/lng-exports-may-spur-higher-u-s-natural-gas-prices-report-says.html

[14] ***"Methane and the greenhouse-gas footprint of natural gas from shale formations"***
A letter – Robert W. Howarth, Renee Santoro and Anthony Ingraffea – Published April 12, 2011
http://journalistsresource.org/studies/environment/energy/natural-gas-hydrofracking-greenhouse/
"Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation"- Paulina Jaramillo; W. Michael Griffin; and H. Scott Matthews – Civil and Environmental Engineering Department, Tepper School of Business, and Department of Engineering and Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, Pennsylvania 15213-3890 – July 25, 2007
http://www.ce.cmu.edu/~gdrg/readings/2007/09/13/Jaramillo_ComparativeLCACoalNG.pdf

of export facilities it would be necessary to repeat both the EIA and the NERA analyses with additional scenarios incorporating demand for natural gas export in different regions." (*Emphasis added*)

It is imperative that the U.S. Department of Energy, Office of Fossil Energy follow their own NERA study's advice here. The shortcomings of the NERA study as we have stated previously and throughout this letter are numerous and render this study insufficient for the Department to use in any export determination.

A thorough independent programmatic analysis on LNG exports is still needed, however. Unfortunately, citizens in rural poor areas such as Coos Bay, Oregon, do not have the resources that the multinational corporations and the gas and oil industry have to conduct such a thorough independent analysis. We citizens depend on agencies such and the U.S. Department of Energy and the Federal Energy Regulatory Commission to do such an analysis for us and to make sure their decisions are in the public interest. It would not be fair to citizens who live in poor rural areas to have large scale LNG Export projects pushed off on them due to the fact they lack the resources to be able to do the independent and thorough analysis that is needed.

Sincerely,

/s/ Jody McCaffree

Jody McCaffree

Index for Exhibits
For Citizens Against LNG Comments to the DOE
January 24, 2013
Re: 2012 LNG Export Study

Exhibit A: *Existing Operational LNG Terminals in the United States.* www.ferc.gov

Exhibit B: *North American LNG Import /Export Terminals – Existing as of Dec 5, 2012 Operation*

Exhibit C: *North American LNG Import /Export Terminals – Approved as of Dec 5, 2012*

Exhibit D: *North American LNG Import /Export Terminals – Proposed/Potential as of Dec 5, 2012*

Exhibit E: *Applications Received by the DOE/FE to Export Domestically Produced LNG from the Lower-48 States, as* of January 11, 2013; http://www.fe.doe.gov/programs/gasregulation/reports/summary_lng_applications.pdf

Exhibit F: CALNG August 6, 2012, Motion to Intervene, Protest and Comments sent to the DOE regarding the Jordan Cove Energy Project, L.P., FE Docket No. 12-32-LNG

Exhibit G: CALNG September 12, 2012, Response to Answer of Jordan Cove Energy Project, L.P. to Protests of Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG

Exhibit H: "*OIL AND GAS Information on Shale Resources, Development, and Environmental and Public Health Risks*"; By U.S. Government Accountability Office, September 2012

Exhibit I: "*LOOK BEFORE THE LNG LEAP - Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start*"; By Craig Segall, Staff Attorney, Sierra Club Environmental Law Program.

Exhbit J: "*Gas Bubble Leaking, About to Burst*" by Richard Heinberg, originally published by Post Carbon Institute | Oct 22, 2012

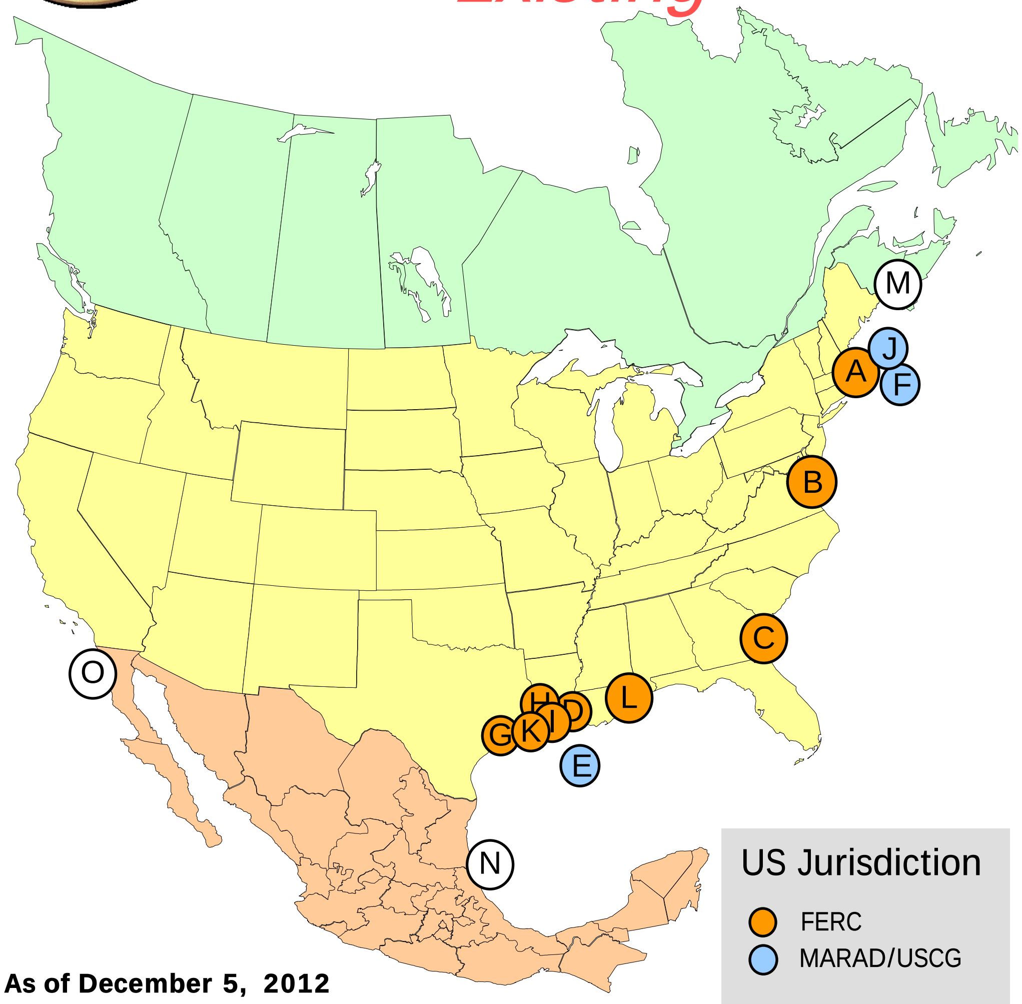
Exhibit K: The New York Times "*Exports of American Natural Gas May Fall Short of High Hopes*" January 4, 2013

Exhibit A

Existing Operational LNG Terminals in the United States
www.ferc.gov

North American LNG
Import/Export Termi

Existing



As of December 5, 2012

U.S.

A. Everett, MA : 1.035 Bcfd (GDF SUEZ - DOMAC)
B. Cove Point, MD : 1.8 Bcfd (Dominion - Cove Point LNG)
C. Elba Island, GA : 1.6 Bcfd (El Paso - Southern LNG)
D. Lake Charles, LA : 2.1 Bcfd (Southern Union - Trunkline LNG)
E. Gulf of Mexico: 0.5 Bcfd, (Excelerate Energy - Gulf Gateway Energy Bridge)
F. Offshore Boston: 0.8 Bcfd, (Excelerate Energy – Northeast Gateway)
G. Freeport, TX: 1.5 Bcfd, (Cheniere/Freeport LNG Dev.) ★
H. Sabine, LA: 4.0 Bcfd (Cheniere/Sabine Pass LNG) ★
I. Hackberry, LA: 1.8 Bcfd (Sempra - Cameron LNG) ★
J. Offshore Boston, MA : 0.4 Bcfd (GDF SUEZ – Neptune LNG)
K. Sabine Pass, TX: 2.0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II)
L. Pascagoula, MS: 1.5 Bcfd (El Paso/Crest/Sonangol - Gulf LNG Energy LLC)

Canada

M. Saint John, NB: 1.0 Bcfd, (Repsol/Fort Reliance - Canaport LNG)

Mexico

N. Altamira, Tamulipas: 0.7 Bcfd, (Shell/Total/Mitsui – Altamira LNG)
O. Baja California, MX: 1.0 Bcfd, (Sempra – Energia Costa Azul)

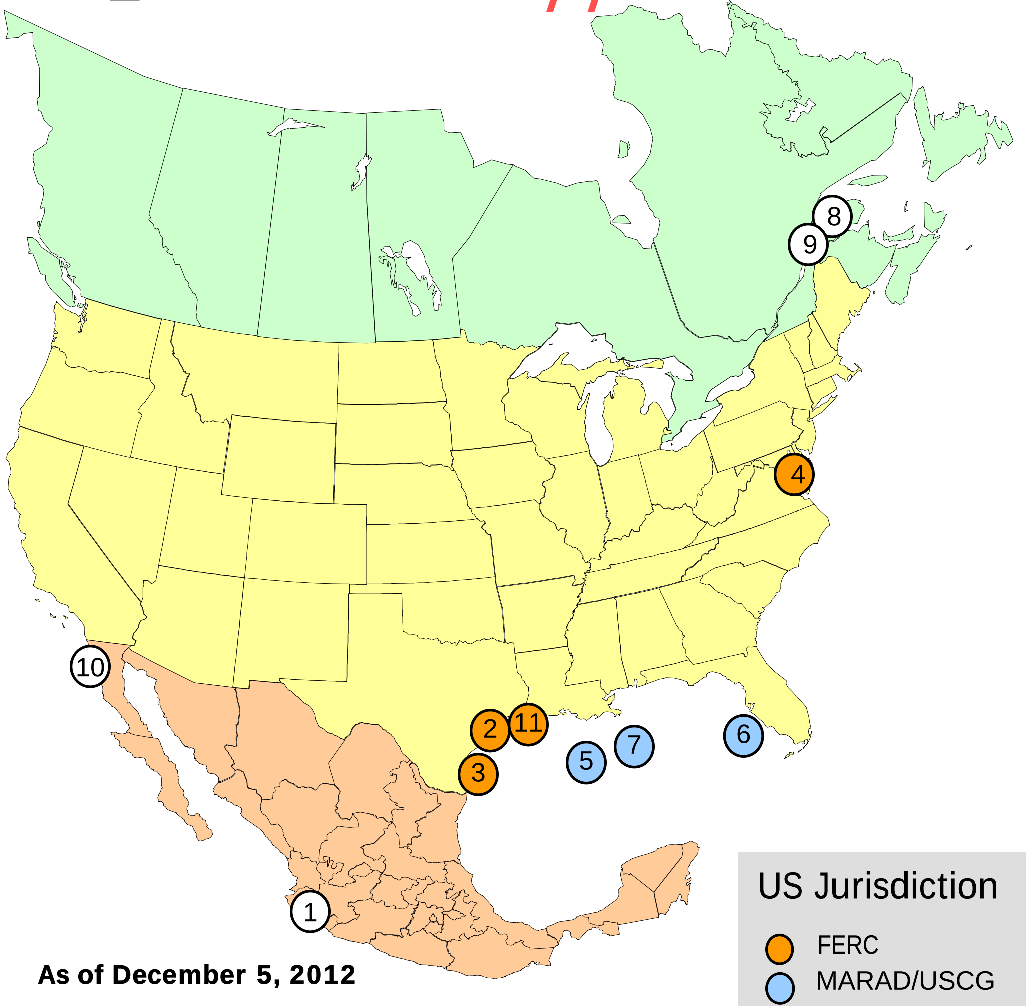
Note: There is an existing import terminal in Peñuelas, PR. It does not appear on this map since it can not serve or affect deliveries in the Lower 48 U.S. states.

★ *Authorized to re-export delivered LNG*
★★ *Pending/Potential to re-export delivered LNG*

Office of Energy Projects

North American LNG Import /Export Terminals

Approved



As of December 5, 2012

* *Expansion of an existing facility*

Import Terminal

<u>APPROVED - UNDER CONSTRUCTION</u>

<u>Mexico</u>

1. Manzanillo, MX: 0.5 Bcfd (KMS GNL de Manzanillo)

<u>APPROVED - NOT UNDER CONSTRUCTION</u>

<u>U.S. - FERC</u>

2. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev. - Expansion)*

3. Port Lavaca, TX: 1.0 Bcfd (Gulf Coast LNG Partners – Calhoun LNG)

4. Baltimore, MD: 1.5 Bcfd (AES Corporation – AES Sparrows Point)

<u>U.S. - MARAD/Coast Guard</u>

5. Gulf of Mexico: 1.0 Bcfd (Main Pass McMoRan Exp.)

6. Offshore Florida: 1.2 Bcfd (Hoëgh LNG - Port Dolphin Energy)

7. Gulf of Mexico: 1.4 Bcfd (TORP Technology-Bienville LNG)

<u>Canada</u>

8. Rivière-du- Loup, QC: 0.5 Bcfd (Cacouna Energy - TransCanada/PetroCanada)

9. Quebec City, QC : 0.5 Bcfd (Project Rabaska - Enbridge/Gaz Met/Gaz de France)

<u>Mexico</u>

10. Baja California, MX : 1.5 Bcfd (Sempra - Energia Costa Azul - Expansion)

Export Terminal

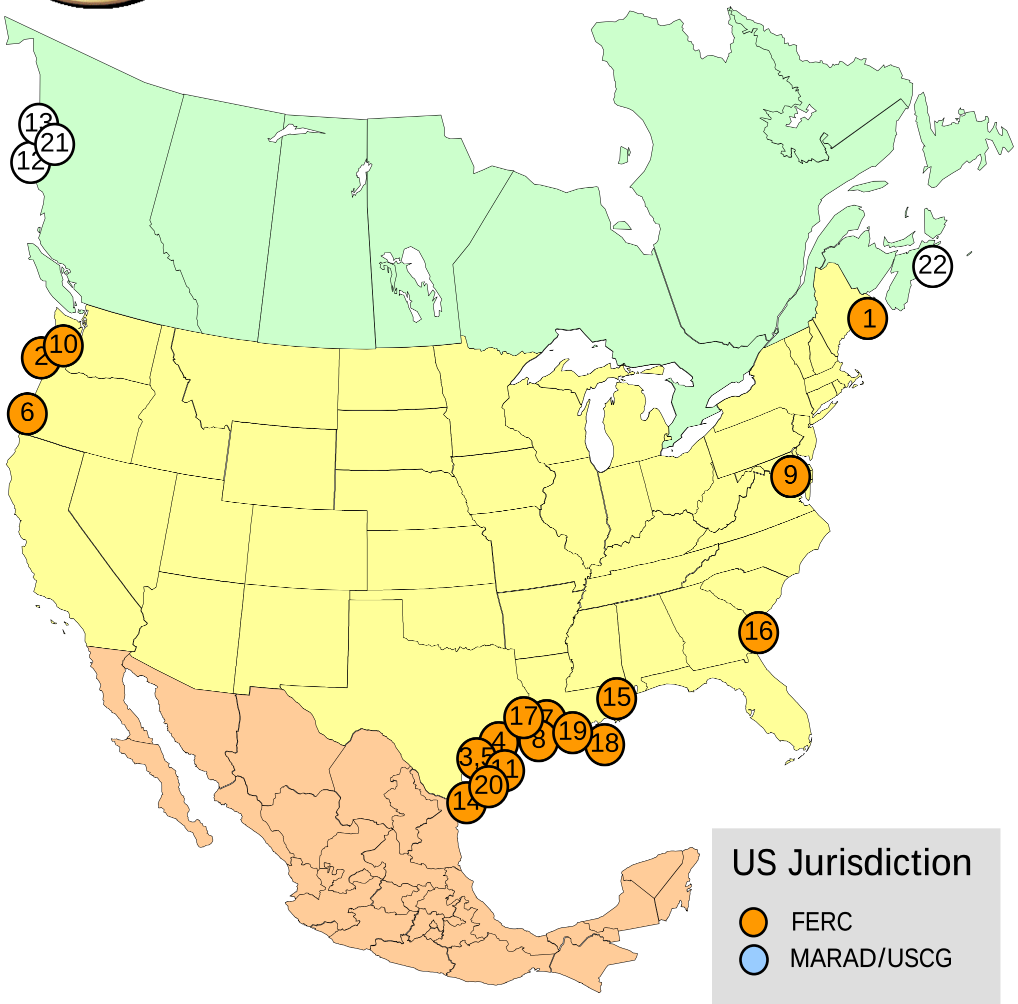
<u>APPROVED - UNDER CONSTRUCTION</u>

<u>U.S. - FERC</u>

11. Sabine, LA: 2.6 Bcfd (Cheniere/Sabine Pass LNG)

North American LNG Import/Export Terminals

Proposed/Potential



Import Terminal

PROPOSED TO FERC

1. Robbinston, ME: 0.5 Bcfd (Kestrel Energy - Downeast LNG)
2. Astoria, OR: 1.5 Bcfd (Oregon LNG)
3. Corpus Christi, TX: 0.4 Bcfd (Cheniere – Corpus Christi LNG)

Export Terminal

PROPOSED TO FERC

4. Freeport, TX: 1.8 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction)
5. Corpus Christi, TX: 2.1 Bcfd (Cheniere – Corpus Christi LNG)
6. Coos Bay, OR: 0.9 Bcfd (Jordan Cove Energy Project)
7. Lake Charles, LA: 2.4 Bcfd (Southern Union - Trunkline LNG)
8. Hackberry, LA: 1.7 Bcfd (Sempra – Cameron LNG)
9. Cove Point, MD: 0.75 Bcfd (Dominion – Cove Point LNG)
10. Astoria, OR: 1.30 Bcfd (Oregon LNG)
11. Lavaca Bay, TX: 1.38 Bcfd (Excelerate Liquefaction)

PROPOSED CANADIAN SITES IDENTIFIED BY PROJECT SPONSORS

12. Kitimat, BC: 0.7 Bcfd (Apache Canada Ltd.)
13. Douglas Island, BC: 0.25 Bcfd (BC LNG Export Cooperative)

POTENTIAL U.S. SITES IDENTIFIED BY PROJECT SPONSORS

14. Brownsville, TX: 2.8 Bcfd (Gulf Coast LNG Export)
15. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction)
16. Elba Island, GA: 0.5 Bcfd (Southern LNG Company)
17. Sabine Pass, TX: 2.6 Bcfd (ExxonMobil – Golden Pass)
18. Plaquemines Parish, LA: 1.07 Bcfd (CE FLNG)
19. Cameron Parish, LA: 0.16 Bcfd (Waller LNG Services)
20. Ingleside, TX: 1.09 Bcfd (Pangea LNG (North America))

POTENTIAL CANADIAN SITES IDENTIFIED BY PROJECT SPONSORS

21. Prince Rupert Island, BC: 1.0 Bcfd (Shell Canada)
22. Goldboro, NS: 0.67 Bcfd (Pieridae Energy Canada)

As of December 5, 2012

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of January 11, 2013)

All Changes Since January 4, 2013 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Sabine Pass Liquefaction, LLC	2.2 billion cubic feet per day (Bcf/d) [d]	Approved (10-85-LNG)	Approved (10-111-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	1.4 Bcf/d [d]	Approved (10-160-LNG)	Under DOE Review (10-161-LNG)
Lake Charles Exports, LLC	2.0 Bcf/d [e]	Approved (11-59-LNG)	Under DOE Review (11-59-LNG)
Carib Energy (USA) LLC	0.03 Bcf/d: FTA 0.01 Bcf/d: non-FTA [f]	Approved (11-71-LNG)	Under DOE Review (11-141-LNG)
Dominion Cove Point LNG, LP	1.0 Bcf/d [d]	Approved (11-115-LNG)	Under DOE Review (11-128-LNG)
Jordan Cove Energy Project, L.P.	1.2 Bcf/d: FTA 0.8 Bcf/d: non-FTA [g]	Approved (11-127-LNG)	Under DOE Review (12-32-LNG)
Cameron LNG, LLC	1.7 Bcf/d [d]	Approved (11-145-LNG)	Under DOE Review (11-162-LNG)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC [h]	1.4 Bcf/d [d]	Approved (12-06-LNG)	Under DOE Review (11-161-LNG)
Gulf Coast LNG Export, LLC [i]	2.8 Bcf/d[d]	Approved (12-05-LNG)	Under DOE Review (12-05-LNG)
Gulf LNG Liquefaction Company, LLC	1.5 Bcf/d[d]	Approved (12-47-LNG)	Under DOE Review (12-101-LNG)
LNG Development Company, LLC (d/b/a Oregon LNG)	1.25 Bcf/d[d]	Approved (12-48-LNG)	Under DOE Review (12-77-LNG)
SB Power Solutions Inc.	0.07 Bcf/d	Approved (12-50-LNG)	n/a
Southern LNG Company, L.L.C.	0.5 Bcf/d[d]	Approved (12-54-LNG)	Under DOE Review (12-100-LNG)
Excelerate Liquefaction Solutions I, LLC	1.38 Bcf/d[d]	Approved (12-61-LNG)	Under DOE Review (12-146-LNG)
Golden Pass Products LLC	2.6 Bcf/d[d]	Approved (12-88 -LNG)	Under DOE Review (12-156-LNG)
Cheniere Marketing, LLC	2.1 Bcf/d[d]	Approved (12-99-LNG)	Under DOE Review (12-97-LNG)
Main Pass Energy Hub, LLC	3.22 Bcf/d	Approved (12-114-LNG)	n/a
CE FLNG, LLC	1.07 Bcf/d[d]	Approved (12-123-LNG)	Under DOE Review (12-123-LNG)
Waller LNG Services, LLC	0.16 Bcf/d	Approved (12-152-LNG)	n/a
Pangea LNG (North America) Holdings, LLC	1.09 Bcf/d[d]	Pending Approval (12-174-LNG)	Under DOE Review (12-184-LNG)
Magnolia LNG, LLC	0.54 Bcf/d	Pending Approval (12-183-LNG)	n/a

Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of January 11, 2013)

All Changes Since January 4, 2013 Update Are In Red

Company	Quantity [a]	FTA Applications [b] (Docket Number)	Non-FTA Applications [c] (Docket Number)
Trunkline LNG Export, LLC	2.0 Bcf/d	Pending Approval (13-04-LNG)	n/a
Gasfin Development USA, LLC	0.2 Bcf/d	Pending Approval (13-06-LNG)	n/a
Total of all Applications Received		**31.41 Bcf/d**	**24.80 Bcf/d**

(a) Actual applications were in the equivalent annual quantities.

(b) FTA – Applications to export to free trade agreement (FTA) countries. The Natural Gas Act, as amended, has deemed FTA exports to be in the public interest and applications shall be authorized without modification or delay.

(c) Non-FTA applications require DOE to post a notice of application in the Federal Register for comments, protests and motions to intervene, and to evaluate the application to make a public interest consistency determination.

(d) Requested approval of this quantity in both the FTA and non-FTA export applications. Total facility is limited to this quantity (i.e., FTA and non-FTA volumes are not additive at a facility).

(e) Lake Charles Exports, LLC submitted one application seeking separate authorizations to export LNG to FTA countries and another authorization to export to Non-FTA countries. The proposed facility has a capacity of 2.0 Bcf/d, which is the volume requested in both the FTA and Non-FTA authorizations.

(f) Carib Energy (USA) LLC requested authority to export the equivalent of 11.53 Bcf per year of natural gas to FTA countries and 3.44 Bcf per year to non-FTA countries.

(g) Jordan Cove Energy Project, L.P. requested authority to export the equivalent of 1.2 Bcf/d of natural gas to FTA countries and 0.8 Bcf/d to non-FTA countries.

(h) DOE/FE received a new application (11-161-LNG) by FLEX to export an additional 1.4 Bcf/d of LNG from new trains to be located at the Freeport LNG Terminal, to non-FTA countries, and a separate application (12-06-LNG) to export this same 1.4 Bcf/d of LNG to FTA countries (received January 12, 2012). This 1.4 Bcf/d is in addition to the 1.4 Bcf/d FLEX requested in dockets (10-160-LNG and 10-161-LNG).

(i) An application was submitted by Gulf Coast on January 10, 2012, seeking one authorization to export LNG to any country not prohibited by U.S. law or policy. On September 11, 2012, Gulf Coast revised their application by seeking separate authorizations for LNG exports to FTA countries and Non-FTA countries.

UNITED STATES OF AMERICA
DEPARTMENTOF ENERGY

Jordan Cove Energy Project, L.P.	)	**FE Docket No. 12–32–LNG**
	)	
Application for Certificate	)	**Jordan Cove Energy Project, L.P.; Application for Long-Term Authorization to Export Liquefied Natural Gas Produced From Domestic and Canadian Natural Gas Resources to Non-Free Trade Agreement Countries for a 25-Year Period**

CITIZENS AGAINST LNG, Inc;
CITIZENS AGAINST LNG
NOTICE OF INTERVENTION, PROTEST AND COMMENTS

On June 6, 2012, the Office of Fossil Energy at the Department of Energy posted in the Federal Register a Notice of receipt of an application (Application), filed on March 23, 2012, by Jordan Cove Energy Project, L.P. (Jordan Cove), requesting long-term, multi-contract authorization to export as liquefied natural gas (LNG) both natural gas produced domestically in the United States and natural gas produced in Canada and imported into the United States, in an amount up to the equivalent of 292 billion cubic feet (Bcf) of natural gas per year, 0.8 Bcf per day (Bcf/d), over a 25-year period, commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted. The LNG would be exported from the proposed LNG terminal to be located on the North Spit of Coos Bay in Coos County, Oregon, to any country (1) with which the United States does not have a free trade agreement (FTA) requiring national treatment for trade in natural gas, (2) which has developed or in the future develops the capacity to import LNG via ocean-going carrier, and (3) with which trade is not prohibited by U.S. law or policy. Jordan Cove is requesting this authorization to export LNG both on its own behalf and as agent for other parties who hold title to the LNG at the point of export. The Application was filed under section 3 of the Natural Gas Act (NGA).

Citizens Against LNG is a grassroots organization of citizens that formed during the Federal Energy Regulatory Commission Prefiling phase of the Jordan Cove Energy Project, L.P. and the Pacific Connector Gas Pipeline, L.P., LNG Import project. We represent over 4,000 citizens in Southern Oregon who live, work, have businesses, recreate and socialize in areas that would be negatively impacted by the Jordan Cove LNG terminal, storage tanks, liquefaction facility and the Pacific Connector Gas Pipeline.

Citizens Against LNG, and the citizens who support our cause, declare that a liquefied natural gas (LNG) export terminal, storage tanks and liquefaction facility is not a well conceived or appropriate industry for the Southern Oregon Coast and that LNG represents an unacceptable risk to the people of the State of Oregon. For the safety, security, and well being of the citizens of our communities, the Citizens Against LNG ask the U. S. Department of Energy to immediately take action to stop the Jordan Cove LNG Export terminal, storage tanks and liquefaction facility proposed for the North Spit of Coos Bay and the 230 mile, 36 inch Pacific Connector natural gas pipeline to the California border. We ask the U. S. Department of

Energy to not approve the Jordan Cove Energy Project's application to Export LNG to non-free trade agreement nations as this would not be in the best interest of the public at large. Further details as to our reasons for this are spelled out in the attached comment letter and exhibits.

In order to protect the interest of citizens in Southern Oregon, Citizens Against LNG, Inc, also known as Citizens Against LNG, moves to intervene in this proceeding, pursuant to 10 C.F.R. § 590.303(b).

The Citizens Against LNG previously petitioned, intervened and was part of a coalition of groups that filed a Request for Rehearing to the Federal Energy Regulatory Commission (FERC) concerning their Environmental Impact Statement and their December 17, 2009, Order on the Jordan Cove LNG Terminal and Pacific Connector gas pipeline project. We also petitioned the FERC to protect Coos, Douglas, Jackson, and Klamath Counties and the State of Oregon by taking action to stop the Jordan Cove LNG Terminal and the Pacific Connector gas pipeline. Over 4,000 people have signed our petition opposing this project. A large portion of our petitions are on file in the FERC e-Library.[1] We ask the DOE to note the filed petitions linked below as a reference, along with these additional submitted petitions we have included in with this filing as supporting justification that our intervention in this proceeding should be granted.

In addition, Citizens Against LNG would like to go on record as being in full support of the Sierra club and the Landowners United motion to intervene, protest and comments that are also being filed in this proceeding.

Please send any correspondence to:

Jody McCaffree
Executive Director
Citizens Against LNG
PO Box 1113
North Bend, OR 97459
mccaffrees@frontier.com

Curt Clay
President
Citizens Against LNG
PO Box 1113
North Bend, OR 97459
curtclay@gmail.com

Sincerely,

Jody McCaffree

Jody McCaffree

[1] Petition Filing 1) http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20070326-0003
Petition Filing 2) http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20070906-0013
Petition Filing 3) http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20091112-5040 - Exhibit P

Citizens Against LNG Inc
PO Box 1113
North Bend, OR 97459

August 6, 2012

By Email and by Electronic Filing on the Federal
eRulemaking Portal under FE Docket No. 12–32–LNG:
fergas@hq.doe.gov
http://www.regulations.gov

Ms. Larine A. Moore
Docket Room Manager
FE-34
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG

Dear Ms. Moore:

Please accept for filing the following protest of Citizens Against LNG Inc regarding the application of Jordan Cove for Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations. For the following reasons, we believe the Department of Energy should reject Jordan Cove's application because it would be detrimental to the public interest.

1. Jordan Cove's proposed export facility would hurt consumers in the United States by increasing the prices for domestic natural gas

It is not in dispute that Jordan Cove's proposed LNG export facility would increase the price for domestic natural gas in the United States. The only question is how much domestic natural gas prices in the United States would increase and how badly this would impact consumers. According to the latest assessment of the U.S. Department of Energy, allowing LNG export facilities, including Jordan Cove's proposed LNG export facility, would raise domestic natural gas prices substantially, by as much as 54% under certain scenarios:

> "Increased exports of natural gas lead to increased wellhead prices in all cases and scenarios. The basic pattern is evident in considering how prices would change under the Reference case (Figure 3):
>
> • The pattern of price increases reflects both the ultimate level of exports and the rate at which increased exports are phased in. In the low/slow scenario (which phases in 6 Bcf/d

of exports over six years), wellhead price impacts peak at about 14% ($0.70/Mcf) in 2022. However, the wellhead price differential falls below 10 percent by about 2026.

• In contrast, rapid increases in export levels lead to large initial price increases that would moderate somewhat in a few years. In the high/rapid scenario (which phases in 12 Bcf/d of exports over four years), wellhead prices are about 36 percent higher ($1.58/Mcf) in 2018 than in the no-additional-exports scenario. But the differential falls below 20 percent by about 2026. …..

• Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices, especially during the decade between 2025 and 2035. The differential between wellhead prices in the high/slow scenario and the no-additional-exports scenario peaks in 2026 at about 28 percent ($1.53/Mcf), and prices remain higher than in the high/rapid scenario. ….

"In particular, with more pessimistic assumptions about the Nation's natural gas resource base (the Low Shale EUR case), wellhead prices in all export scenarios initially increase more in percentage terms over the baseline case (no additional exports) than occurs under Reference case conditions. <u>For example, in the Low Shale EUR case the rapid introduction of 12 Bcf/d of exports results in a 54 percent ($3.23/Mcf) increase in the wellhead price in 2018; whereas under Reference case conditions with the same export scenario the price increases in 2018 by only 36 percent ($1.58/Mcf)</u>. But the percentage price increase falls in later years under the Low Shale EUR case, even below the price response under Reference case conditions. Under Low Shale EUR conditions, the addition of exports ultimately results in wellhead prices exceeding the $9 per Mcf threshold, with this occurring as early as 2018 in the high/rapid scenario."[1] (Emphasis added).

In a recent Congressional Report prepared by the staff of Representative Edward J. Markey, the Department of Energy's findings were summarized as follows:

"The United States faces a critical decision about whether to export natural gas following the rapid expansion of domestic production in recent years. The Department of Energy has already approved one export application and is currently considering eight others. If these applications are approved and the companies export at full capacity, the United States could soon be exporting more than 20 percent of current consumption. <u>The Energy Information Administration has estimated that exporting even less natural gas than what is currently under consideration could raise domestic prices 24 to 54 percent, which would substantially increase energy bills for American consumers and could potentially have catastrophic impacts on U.S. manufacturing</u>."[2]

---

[1] U.S. Department of Energy (January 2012) "Effect of Increased Natural Gas Exports on Domestic Energy Markets." http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/exhibits_11-128-LNG/15._EIA_Effects_of_increased_NG_exports_.pdf

[2] Representative Edward J. Markey (March 2012) "Drill Here, Sell There, Pay More: The Painful Price of Exporting Natural Gas." http://democrats.naturalresources.house.gov/sites/democrats.naturalresources.house.gov/files/2012-03-01__RPT_NGReport.pdf

Therefore, proposed LNG export facilities, including Jordan Cove's proposed facility which could 'substantially increase energy bills for American consumers and could potentially have catastrophic impacts on U.S. manufacturing' are simply not in the public interest.

2. Jordan Cove's proposed LNG export facility would likely cause a net loss in U.S. employment by causing job losses in manufacturing

Jordan Cove argues that its proposed LNG export facility would be in the public interest by creating jobs in Coos County. According to Jordan Cove's application:

> "The jobs impact of construction of the Jordan Cove Project will be consequential. On average, the Project will employ 1,768 workers a year, and it will create 1,530 indirect and 1,838 induced jobs a year. ….
>
> "The employment impacts of the Jordan Cove Project in the typical operating year will include 99 direct jobs at the Jordan Cove terminal and the PCGP pipeline, 51 indirect jobs paid by Jordan Cove (Sheriff's deputies, firefighters, tugboat crews and emergency planners), 404 other indirect jobs and 182 induced jobs for a total of 736 total jobs in Coos County."[3]

What Jordan Cove did not consider is how these possible jobs gained in Coos County would be more than offset by jobs lost in U.S. manufacturing generally. According to the Industrial Energy Consumers of America:

> "In regards to using natural gas for export as LNG, IECA supports free trade. At the same time, affordable, abundant natural gas is critical to U.S. manufacturing growth, which in turn is critical to the U.S. economy. The manufacturing sector uses one-third of all of the natural gas and one-third of all electricity (of which one-third is produced from natural gas) which fuels the employment of 12 million high-paid workers. As with any resource that is critical to America's economic growth, <u>any decision to approve the export of natural gas should include a rigorous analysis of the potential impact on the domestic economy and job creation, and place a high priority on the manufacturing sector</u>. ….
>
> "<u>Affordable and abundant natural gas is vital to the recent renaissance in the nation's manufacturing sector. This renaissance has already contributed to up to a half million new American jobs.</u> In fact, for every manufacturing job created, three to five additional jobs across the broader economy are also created. Natural gas is used as a fuel for the entire manufacturing sector, to make nitrogen fertilizer, and it is also used as a raw material for the production of chemicals that are converted into an immense array of products that are used every day. Manufacturing natural gas consumption creates far more jobs per unit of gas consumed than any other application. The chemical industry

[3] Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG, at pages 21-22.

alone has estimated that over $35 billion dollars of U.S. investments will be made by abundant, affordable supplies of natural gas."[4]

The Industrial Energy Consumers of America has concluded:

> "Jobs created by natural gas export facilities are small, relative to the opportunities to increase manufacturing jobs. Higher resulting natural gas prices will negatively impact U.S. manufacturing employment and ultimately additional jobs across the broader economy as well."[5]

Therefore, Jordan Cove's proposed LNG export facility, which could cause job losses in U.S. manufacturing that outweigh job gains locally, is not in the public interest.

3. Coos Bay would suffer the aftermath of unemployment that follows temporary employment in large-scale construction works

Unemployment impacts after the construction phase of the Jordan Cove / Pacific Connector project will not be in the public interest. The high unemployment in rural areas such as Coos Bay would be devastating to the local economy and clearly would not be in the public interest.

In 2003/2004 Coos County built a natural gas pipeline from Coos Bay to the Williams Northwest Grants Pass lateral pipeline that that runs along the I-5 hwy. The Coos County pipeline was a $51M gamble sold to the public with the promise of 2,900 jobs for the county. Despite all the promises made by industry speculators, those jobs never materialized and that pipeline currently is only operating at 5 to 7 percent of its capacity.

Jordan Cove estimates that 1,110 different jobs would need to be filled to build their project but the average job would only last 14 months. (FEIS 4.8-11)[6] After that there would be massive unemployment in the area and more people would be out of work than what we have now. The few jobs the facility would estimate to have as permanent jobs in no way justifies the public need for the facility. The Pacific Connector gas pipeline is estimated to end up with only 5 permanent employees after the construction phase of the pipeline is over. [7]

The Portland State University Population Research Center estimated that in July 2007, the population of Coos County was 63,050 people; which represented about a 4 percent increase since 2000. The two closest cities to the proposed Jordan Cove LNG terminal are North Bend, with a population estimated at 9,830 people, and Coos Bay, with a population of about 16,210 in

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4 July 16, 2012 letter from the Industrial Energy Consumers of America to the Brookings Institute. Re: Hamilton Project: "A Strategy for U.S. Natural Gas Exports" by Michael Levi. http://www.ieca-us.com/wp-content/uploads/07.16.12_IECA-Response-to-Brookings.pdf

5 Ibid.

6 FERC Final Environmental Impact Statement (FEIS) for Jordan Cove LNG Import Facility; http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp Page 4.8-11

7 FERC Jordan Cove Import Terminal Final EIS -http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp Page 4.8-22

July 2007 (Proehl 2008). (FEIS 4.8-11) The 56 to 99 jobs promised by Jordan Cove would not make a significant impact to what is truly needed in the area and when you count the jobs that will be lost due to the facilities impacts, the project most likely will end up being a job loser.

There is already high unemployment in the area which has been a continual example of plundering by industry speculators who come to town with big promises of jobs and prosperity and leave us with boondoggles and rotting infrastructure and eyesores. It has been so bad here that several books have been written about our area, the most recent being Wim de Vriend's book, "The Job Messiahs", which came out just this last December and is now in its second edition. Other books include, "Plundertown, USA: Coos Bay Enters the Global Economy" and David Cay Johnston's New York best selling book, "Free Lunch: How the Wealthiest Americans Enrich Themselves at Government Expense (and Stick You With the Bill)," where Johnston devoted two full chapters to Coos County.

4. Jordan Cove's economic analysis rests on the mistaken assumption that U.S. water supplies will be adequate to sustain increased production of natural gas by hydraulic fracturing

Jordan Cove argues that domestic natural gas prices in the United States would not increase that much because the burgeoning use of hydraulic fracturing will continue to create a vast oversupply of domestic natural gas. However, hydraulic fracturing consumes large quantities of water and the continued burgeoning use of hydraulic fracturing rests on assumptions that water supplies will, in the future, be adequate to sustain the continued increased use of this technology.

However, this assumption is likely to be wrong. According to the Pacific Institute:

> "There is some evidence that the water requirements for hydraulic fracturing are already creating conflicts with other uses and could constrain future natural gas production in some areas. For example, in Texas, a major drought in 2011 prompted water agencies in the region to impose mandatory reductions in water use. Water agencies, some of which sold water to natural gas companies, indicated they might have to reconsider these sales if the drought persisted. Natural gas companies also tried to purchase water from local farmers, offering $9,500 to nearly $17,000 per million gallons of water (Carroll 2011). Likewise, at an auction of unallocated water in Colorado during the spring 2012, natural gas companies successfully bid for water that had previously been largely claimed by farmers, raising concerns among some about the impacts on agriculture in the region and on ecosystems dependent on return flows (Finley 2012).
>
> "Concerns over water availability are not limited to drier climates. Pennsylvania is generally considered a relatively water-rich state. However, in August 2011, 13 previously approved water withdrawal permits in Pennsylvania's Susquehanna River Basin were temporarily suspended due to low stream levels; 11 of these permits were for natural gas projects (Susquehanna River Basin Commission 2011). While parts of the state were abnormally dry, the basin was not experiencing a drought at the time, suggesting that natural gas operations are already creating conflict with other uses under normal conditions. In many basins, the application of fracking is still in its infancy and

continued development could dramatically increase future water requirements and further intensify conflicts with other uses."[8]

The United States is experiencing one of the worst droughts in 60 years, and this is affecting energy production in the United States. According to a recent editorial in the New York Times:

> "We're now in the midst of the nation's most widespread drought in 60 years, stretching across 29 states and threatening farmers, their crops and livestock. But there is another risk as water becomes more scarce. Power plants may be forced to shut down, and oil and gas production may be threatened.
>
> "Our energy system depends on water. About half of the nation's water withdrawals every day are just for cooling power plants. In addition, the oil and gas industries use tens of millions of gallons a day, injecting water into aging oil fields to improve production, and to free natural gas in shale formations through hydraulic fracturing."[9]

If Jordan Cove's application is approved and an LNG export facility is built in Coos Bay, then this facility would be contractually bound to continue LNG exports to Asia regardless of whether future drought conditions would constrain the use of hydraulic fracturing to produce natural gas domestically. This would drive up U.S. natural gas prices and would hurt consumers and businesses in the United States by indirectly causing water shortages and exacerbating water scarcity. This would not be in the public interest.

5. If Jordan Cove is mistaken about Asian demand for imported LNG, then the proposed export facility would be mothballed, but after causing substantial impacts during its construction

Jordan Cove cites to Asian demand for imported LNG as the rationale for building its proposed export facility. In its application, Jordan Cove stated:

> "The Jordan Cove facility is the only LNG export terminal proposed for the U.S. West Coast. It is thus uniquely positioned among United States terminals, not only to source its natural gas from Canadian and U.S. Rockies supply basins and <u>to serve Asian demand</u> without the longer routes and Panama Canal transits necessary from the Gulf Coast, but also to provide specific advantages (in addition to the economic benefits already detailed) for gas markets in the United States, in the country's two non-contiguous states of Alaska and Hawaii and in Oregon along the route of the new PCGP pipeline.
>
> "Given North America's enormous shale gas resources and the <u>Asian demand for its production</u>, there is little doubt that Pacific Northwest LNG export facilities will be built."[10]

[8] Pacific Institute (June 2012) "Hydraulic Fracturing and Water Resources: Separating the Frack from the Fiction." http://pacinst.org/reports/fracking/full_report.pdf
[9] Webber, E. (July 23rd, 2012) "Will Drought Cause the Next Blackout?" The New York Times.
[10] Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG, at page 27.

Jordan Cove has already demonstrated its inability to predict demand for natural gas imports and exports. Jordan Cove based the proposed Jordan Cove LNG import terminal in Coos Bay on predictions that an import facility would be needed to meet growing U.S. demand for natural gas imports from overseas. These predictions turned out to be wrong.

Jordan Cove's assumption about sustained Asian demand for LNG imports is likely to be wrong as well; the same factors that created an oversupply of domestic natural gas would likely also create an oversupply of natural gas in Asia, curtailing demand for LNG imports from the U.S. and rendering a West Coast-based LNG export facility economically unviable. According to a recent report of the International Energy Agency:

> "The size of unconventional gas resources in China is at an early stage of assessment, but it is undoubtedly large. At end-2011, China's remaining recoverable resources of unconventional gas totalled almost 50 tcm, comprised of 36 tcm of shale gas, 9 tcm of coalbed methane and 3 tcm of tight gas.5 This is around thirteen times China's remaining recoverable conventional gas resources. China's shale gas resources lie in several large basins spread across the country, with plays in the Sichuan and Tarim Basins believed to have the greatest potential.
>
> "The Chinese government has outlined ambitious plans for boosting unconventional gas exploration and production. These call for coalbed methane production of more than 30 bcm and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015. In support of this effort, China plans to complete a nationwide assessment of shale gas resources and build nineteen exploration and development bases in the Sichuan Basin in the next four years. Efforts are also supported by the international partnerships that Chinese companies have formed in North America to develop shale gas acreage, which will provide valuable development experience. ….
>
> "China's huge unconventional gas potential and strong policy commitment suggest that these resources will provide an increasingly important share of gas in the longer term, though the pace of development through to 2020 – the key period of learning – remains uncertain. Because of China's highly centralised regulatory and policy-making framework and the high priority placed on industrial and economic development, unconventional gas projects may face fewer hurdles stemming from environmental concerns than those in Europe or the United States."[11]

Eastern Europe and Eurasia are also poised to vastly increase production of natural gas from unconventional gas resources. Unlike Jordan Cove, production of natural gas from these locations can supply Asia with natural gas by pipeline.[12]

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[11] International Energy Agency (2012) "Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas," at pages 115-120.
.http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf
[12] Ibid., at page 87.

The State of Oregon has found that Jordan Cove's proposed LNG import facility would have had adverse impacts on private landowners and the environment because of this facility's construction.[13] If Jordan Cove is mistaken (again) about future demand for LNG exports and imports, then the proposed facility would cause adverse impacts on private landowners and the environment by building a facility that would not be economically viable to operate. This would not be in the public interest. (See Exhibits A-G)

6. Liquefaction of natural gas for export/import is energy intensive and greatly diminishes the benefits of using natural gas

The liquefaction of natural gas requires a great amount of energy to compress methane into a liquid. This inherently wastes a substantial portion of the natural gas, which is burned in order to provide power to run compressors at liquefaction facilities. According to Jordan Cove's own study:

> "<u>Approximately 6.2 percent of the gas delivered to the JCEP terminal would be either consumed as fuel to operate the liquefaction process</u> or be removed from the feed gas stream (trace sulfur compounds, carbon dioxide, nitrogen and water) prior to or during the liquefaction step. Any hydrocarbons recovered that have a higher molecular weight than methane will fuel the power plant."[14] (Emphasis added).

Transoceanic transport and regasification of LNG are also energy intensive processes. According to a life-cycle assessment prepared by researchers with the Tepper School of Business, and Department of Engineering and Public Policy Carnegie Mellon University comparing coal and LNG:

> "The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (24, 25). The energy required to power this engine is 11.6MMBtu/MWh(26). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. <u>A loaded tanker with a rated power of 20MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day</u>. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (22). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.
>
> "For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (13, 27). In the future LNG could travel as far as far as 11,700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (27)). This range of distances is representative of distances from LNG countries to U.S.

[13] State of Oregon's Motion to Reopen the Record and Request to Set Aside Order. December 2, 2011.
[14] ECONorthwest Construction Impact Study, at page 4.

terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (22)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO2 equiv/MMBtu.

"Regasification emissions were reported by Tamura et al. to be 0.85 lb CO2 equiv/MMBtu (21). Ruether et al. report an emission factor of 3.75 lb of CO2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (28). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which maybe generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG."[15]

These researchers with Carnegie Mellon University concluded.

"In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas."[16]

The magnitude of the environmental benefits of natural gas fade away when natural gas is liquefied for export and importation. In general, natural gas supplies should be consumed on the continent they are produced, without liquefaction. For this additional reason, the proposed Jordan Cove export facility is contrary to the public interest.

7. Because Jordan Cove is owned and controlled by foreign investors, any profits from the project would only benefit non-U.S. investors.

The N-FTA Federal Register notice for Jordan Cove states the following:

"…Both Jordan Cove and its general partner are owned by the two limited partners in Jordan Cove. The first, Fort Chicago LNG II U.S.L.P., a Delaware limited partnership owns seventy-five percent. It is wholly owned and controlled, through a number of

[15] Jaramillo, P., et al (Sep 2007) "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation Environ Sci Technol. 41(17):6290-6. http://www.fossil.energy.gov/programs/gasregulation/authorizations/2011_applications/exhibits_11-128-LNG/32._Jaramillo_ComparativeLCACoalNG.pdf

[16] Ibid., at page 6294.

intermediate wholly owned and controlled companies, by Veresen, Inc., a Canadian corporation based in Calgary, Alberta, which, prior to its organization as a corporation, was Fort Chicago Energy Partners L.P., a Canadian limited partnership (**although the name of the parent changed, the name of the subsidiary owning Jordan Cove did not**)…'" (Emphasis added)

Fort Chicago Energy Partners L.P. is a Canadian limited partnership in which "only Canadians" are allowed to invest.

> "Fort Chicago is organized in accordance with the terms and conditions of a limited partnership agreement which provides that no Class A Units may be held by or transferred to, among other things, a person who is a "non- resident" of Canada, a person in which an interest would be a "tax shelter investment" or a partnership which is not a "Canadian partnership" for purposes of the Income Tax Act (Canada)."[17]

Profits projected to be made by Jordan Cove would then be funneled out of the country to only foreign investors. This would not be in the public interest. [18]

8. Obtaining natural gas from Hydro-Fracking techniques is not in the public interest

Jordan Cove Energy Project is currently proposing to export hydro-fracked gas from shale beds in Canada or the United States in the form of Liquefied Natural Gas (LNG). The LNG would be exported from their proposed LNG terminal to be located on the North Spit of Coos Bay in Coos County. Just because the industry has learned how to extract fossil fuel natural gas from shale bed formations does not mean this is a reliable, sustainable or environmentally friendly process. There are loads of factors that affect how much natural gas will actually be produced, and for how long.

The wave of fracking that is currently gong on across the country may soon find limitations due to the detrimental impacts of the fracking process itself. New research was recently published in the Proceedings of the National Academy of Sciences that concluded fluids from the Marcellus Shale are likely seeping into Pennsylvania's drinking water.[19] This means hydro-fracking contaminants will find their way into Pennsylvania's water supply also. This issue has create a storm of controversy and after months of research and discussion, Nationwide Insurance issued a memo stating they had determined that the exposures presented by hydraulic fracturing were too great to ignore and they would not be covering fracking damage.[20] Issues such as these

[17] CNW Group, "*Canadian Newswire Fort Chicago announces monthly cash distribution for September 2009"* September 21, 2009 http://www.newswire.ca/en/releases/archive/September2009/21/c7157.html

[18] Bloomberg - "*Exports of LNG May Raise U.S. Prices as Much as 54%, Agency Says*"
- By Katarzyna Klimasinska – Jan 19, 2012 http://www.bloomberg.com/news/2012-01-19/lng-exports-may-spur-higher-u-s-natural-gas-prices-report-says.html

[19] ProPublica – "*New Study: Fluids From Marcellus Shale Likely Seeping Into PA Drinking Water"*
by Abrahm Lustgarten; July 9, 2012;
http://www.propublica.org/article/new-study-fluids-from-marcellus-shale-likely-seeping-into-pa-drinking-water

[20] The Huffington Post – "*Nationwide Insurance: Fracking Damage Won't Be Covered*"
AP | By MARY ESCH; 07/12/2012;
http://www.huffingtonpost.com/2012/07/13/nationwide-insurance-fracking_n_1669775.html?utm_hp_ref=green

could spell a reduction or even a halting of fracking in some areas and as quickly as the shale bed fracking natural gas market has emerged; it could be gone, leaving fast amounts of land taken by the gas industry, possibly by eminent domain, and fossil fuel infrastructure to lay fallow.

9. Jordan Cove's proposed LNG export facility will negatively impact existing local and sustainable jobs and industries in the Coos Bay area

9.1 Tourism and Recreation

According to a 2011 study by Dean Runyan Associates for the Oregon Tourism Commission, during the period of 2007 to 2011, direct spending from tourism travel brought in more than a billion dollars into Coos County, Oregon alone.[21] Tourism travel dollars spent in the area have steadily increased every year going from 94.5 million in 1991 to 220.1 million in 2011. <u>There are 3,090 employment jobs in Coos County related to this industry, a direct result of not developing our beaches, dunes and coastline</u>.

Adjacent to the proposed Jordan Cove LNG export facility is a designated Dunes National Recreation Area that is used year round. In addition to this there is the Sunset Bay State Park and Campground which is also used year round along with multiple trails and beach areas in the area, some directly adjacent to the proposed Jordan Cove project. Other examples in the area include the Shore Acres State Park which has a Christmas light show every year that goes from Thanksgiving until New Years. The Park had an estimated 57,768 visitors for the 2011 light show. People came from 25 countries (other than the U.S.) and 42 states.[22] Winter months can see just as many recreational and tourist activates as summer months in our Coos Bay area.

The Final Environmental Impact Statement (FEIS) for Jordan Cove's Import Facility stated the following with regard to this issue: (Emphasis and photos are added)

FEIS Page 4.7-5: "*…The top five recreational activities along southern Oregon beaches include **walking (43 percent), relaxing in a stationary location (24 percent), walking dogs (10 percent), driving OHVs (8 percent), and beachcombing (3 percent)** (OPRD 2002).*"

FEIS Page 4.7-6: "*…Sunset Bay State Park includes a beach, picnic tables, hiking trails, 27 full recreational vehicle (RV) hookups, 66 tent spaces, and eight yurts. A public golf course is next to the park. **An OPRD study indicated that Sunset Bay State Park receives 800,000 visitors a year** (Hillmann 2006)*"

FEIS Page 4.7-6: "*…The Oregon Islands National Wildlife Refuge is administered by the FWS, and covers 1,850 rocks, reefs, islands, and two headlands, spanning a total of 320 miles along the Oregon coast. The **Oregon Islands National Wildlife Refuge provides sanctuary for seabirds and marine mammals**….*"

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[21] Oregon Travel Impacts *1991-2011p* –May 2011; Dean Runyan Associates; *Prepared for the* Oregon Tourism Commission, Salem, Oregon; Page 83 - http://www.deanrunyan.com/impactsOR.html

[22] Shore Acres State Park Holliday Light Show Stats: http://www.shoreacres.net/images/pdf/stats-hol-lts-2011-wp.pdf

Birds swim just off of tidal sand areas at low tide and several species leave footprints in the wet tidal sands where the LNG slip dock is proposed to be built.

According to the World Newspaper; Monday, November 02, 2009:

> "Coos Bay got a bit of a tourism boost over the last several days, as 200 or so birders came to the bay to see a rare brown booby that is hanging out near Charleston. People came to scope out the tropical bird from places including Eugene, Portland, Bend, McMinnville, Coos Bay and Washington. The rare tropical bird showed up last week and

is the fourth verified sighting of this species of bird in Oregon. The last local sighting was in October 2008, when a dead female washed ashore at Lighthouse Beach."[23]

<u>The Weyerhaeuser site where the Jordan Cove LNG Export facility is proposing to build is arguably one of the best birding destinations in Coos County and attracts a multitude of breeding, migrant and vagrant species year-round.</u>[24] There are species like Wilsons Phalarope and Ring necked Duck. This is a crucial stop-over location for shorebirds during migration where they can rest and refuel, building fat reserves to last them on the next leg of their migration flight.

Oregon has lost much of its shorebird habitat through urban development and filling in wetlands and this site is one of the last significant "refueling stations" left on the Oregon Coast. Shorebirds by the thousands feed in late summer and fall here…

FEIS Page 4.7-7: *Figure 4.7-2 list **34 Recreational Areas that are within** the **LNG Zones of Concern** along the waterway for the proposed LNG Marine Traffic.*

FEIS Page 4.7-16: "…*The Siuslaw National Forest administers the **Oregon Dunes National Recreation Area (NRA)**. It extends 40 miles along the Oregon Coast between Florence and Coos Bay. The Oregon Dunes NRA contains the largest expanse of coastal sand dunes in North America, as well as a coastal forest and over 30 lakes and ponds. **Recreational opportunities at the NRA include OHV use, hiking, camping, horseback riding, angling, canoeing, sailing, water-skiing, and swimming.** Thousands of OHV owners take advantage of the three main off-highway riding areas within the Oregon Dunes NRA. **The day use and overnight camping facilities are used by over 400,000 visitors a year**…*"

For an Oregon Department of Fish and Wildlife listing of county expenditure estimates for Fishing, Hunting, Wildlife Viewing, and Shellfishing in Coos County and Oregon, see footnote below[25]

Coos County Local Recreation Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$904,977	2.90%	N/A
Fishing	$2,551,433	3.30%	N/A
Wildlife Viewing	$1,637,158	4.90%	N/A
Shellfishing	$1,080,963	20.60%	N/A
Total	$6,174,531	4.20%	N/A

[23] "*Flocking to see a rare bird*"; The World Newspaper; Monday, November 02, 2009 http://theworldlink.com/news/local/flocking-to-see-a-rare-bird/article_4c58af85-d571-52c5-b820-3301baf6f9d3.html

[24] "*Site Guide: Weyerhaeuser Settling Pond Site on the North Spit of Coos Bay",* Tim Rodenkirk: Oregon Birds 32(2): Pg 68 - 72, Summer 2006

[25] "*Fishing, Hunting, Wildlife Viewing, and Shellfishing in Oregon - 2008 State and County Expenditure Estimates*"; Prepared for the Oregon Department of Fish and Wildlife - Travel Oregon; DeanRunyan Associates; May 2009 http://www.dfw.state.or.us/agency/docs/Report_5_6_09--Final%20%282%29.pdf

Coos County Travel-Generated Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$2,534,940	2.40%	1.40%
Fishing	$12,253,254	4.60%	6.70%
Wildlife Viewing	$14,110,950	3.10%	7.70%
Shellfishing	$4,552,379	14.70%	2.50%
Total	$33,451,523	3.90%	18.30%

The Jordan Cove Project will clearly negatively impact this industry and all the permanent and sustainable jobs it supports as well as many others. Incredulously, the ECONorthwest study did not take into account the economic impacts of Jordan Cove's proposed LNG export facility on local tourism and recreation.

9.2 Commercial and Recreational Fishing

The ECONorthwest study did not include negative impacts to our commercial and recreational fishing fleet. This could include negative impacts from transiting LNG tankers, the negative impacts from additional Bay dredging, or negative impacts to salmon bearing streams crossed by the pipeline. **This is despite the fact Coos Bay is the third most important harbor in the state of Oregon in terms of total personal income generated from commercial fishing** (exceeded only by Astoria and Newport). Commercial landing data compiled by ODFW indicate that a total of $20.1 million worth of fish and shellfish were landed at Charleston in 2006.[26]

Landowners and non-profit groups who have done restoration projects to help restore fish runs in Southern Oregon will have their projects and efforts destroyed by the pipeline construction. This would not be in the public interest. (See Exhibits A, B)

FEIS Page 4.7-4: "*…According to a 2005 study by the Oregon State Marine Board (OSMB)* ***recreational boaters in Coos Bay took a total of 30,996 boat trips the previous year. Nearly 90 percent of the boat usedays involved fishing*** *(including angling, crabbing, and clamming), 9 percent was for pleasure cruising, and the remainder was for sailing and water skiing. Forty percent of the boating activities in Coos Bay originated from the Charleston Marina, and 20 percent at the Empire ramp…*"

FEIS Page 4.7-4: "*…**Recreational clamming and crabbing occurs year-round and brings tourism based revenue to the region. Crabbing occurs in the main channel areas from the Southern Oregon Regional Airport to the mouth of the bay around slack tides. Clamming occurs year-round in the mud flats of Coos Bay,** but is subject to closure as necessary by the ODA Food Safety Division for reasons of public health (Oregon Department of Agriculture Food Safety Division 2008)….*"

[26] FERC Final EIS for Jordan Cove LNG Import Facility; http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp - Page 4.8-8

Photo to Left: People clamming at low tide in the Lower Coos Bay along Cape Arago Hwy.

Photo to Right: Evidence of Clams in the tidal areas where the LNG slip dock is proposed to be built.

The ECONorthwest study did not account for the total time it would take homeland security to clear the bay before an LNG tanker would transit through the bay, nor did the study account for an accurate number of potential ship transits through the bay. When Freeport LNG import terminal began operating in April of 2008, Petty Officer Second Class Richard Ahlers said it would probably take up to three hours for the boat and its security perimeter to pass through in the first arrivals. Each time a LNG ship crawls into the harbor there, water-borne authorities like the Coast Guard plan on shutting down all boat traffic in a 1,000-meter radius of the transiting LNG vessel. Surfside Beach Mayor Jim Bedward said the village boat ramp, once it opened, would be closed as the ships pass. The City Hall in Freeport would get a 92-hour warning of the oncoming ships but would keep knowledge of the high-security vessels' arrival to themselves — for obvious reasons. [27]/[28]

Likewise the Jordan Cove LNG facility consultants have shown that ship transits would have security zones that are very similar to Freeport except that in some cases security zones for Jordan Cove would encompass the entire width of the Coos Bay and would take from 90 minutes to two hours. <u>This would be an extreme hardship on the Commercial fishing fleet that also need high slack tides in order to transit the Coos Bay</u>.

In Coos County the Pacific Connector is slated to directly negatively impact native Olympia oysters in Haynes Inlet and also Clausen Oyster Company's highly productive silver point Pacific oyster beds. Coos Bay is the largest commercial producer of shellfish in the state of Oregon. Pacific oysters are commercially raised in the mudflats of South Slough and Haynes Inlet and the upper bay east of McCullough Bridge. Clamming also occurs at Haynes Inlet. (FEIS page 4.7-17) In recent testimony provided by the Clausen Oyster Company, Lilli Clausen stated the following:

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[27] "*Coast Guard preparing for port shutdowns*", The Facts, by Hunter Sauls, April 14, 2008 http://thefacts.com/story.lasso?ewcd=f482d0ca682cb716

[28] Platts LNG Daily April 11, 2008 [subscription required] reports that the Sabine Pass LNG terminal expects to receive its commissioning cargo aboard the LNG carrier Celestine River today. In preparation for the arrival of the ship, the U.S. Coast Guard will impose a security zone at the Sabine Pass in Louisiana for approximately three hours between noon and 7 p.m…

"When the engineer and some other people representing LNG were in our office a few weeks ago my husband, Max, and I tried to explain that the proposed line was too destructive to our oyster business…" (See Exhibit E)

9.3 Timber Production

The Jordan Cove proposal will force a significant change and a significant cost increase in accepted tree farm and forest practices on agricultural and forest lands. Including but not limited to:

● Permanent loss of timber in pipeline right of way.

● Increased loss in timber production due to increased wind in the pipeline right of way. Coos County Commissioner, Fred Messerle, who is also a local private timber operator stated recently in public testimony,

> "Cutting and maintaining an extended "hard edge" in an existing and/or new stand of timber will dramatically increase the wind loss over the 40 year rotation and thus increase cost and decrease yield."

● Increase risk of foot traffic and spread of disease and root rot. Pacific Connector's plan will significantly change the accepted practices involved in raising a 40-year crop and/or in a worst case, eliminates the value of the land all together for timber production.

● Increased risk of noxious weed growth which negatively impacts timber production.

● An open vector (right of way) with dry grass and brush creates a path for fire to "run on." This means an increase in fire hazard exposure and risk in currently high timber production areas.

● Project significantly changes and or increases the costs of accepted practices overall. According to Commissioner Messerle,

> "Timber harvesting (logging) has always had a very "thin margin" of profit. Logging is not a "get rich quick" proposition. Any change to accepted logging practices will increase costs, decrease margins and significantly change the cost of accepted forest practices." (See Exhibit F)

Yankee Creek Forestry also issued similar statements with regard to the negative impacts this proposed LNG project and pipeline will have on timber production. (See Exhibit G)

Construction of the Pacific Connector pipeline would affect about 3,035 acres of forest and woodland, 623 acres of agricultural lands, 488 acres of grasslands-shrubland, and 131 acres of non- riparian vegetation. (FEIS page 5-9). Approximately 151 miles, or 66 percent, of the proposed pipeline route would cross private property, which could be taken by eminent domain. The remaining 79 miles (34 percent) of pipeline route would cross public lands administered by the BLM (18 percent), USFS (12 percent), BOR (0.14 percent), (FEIS page 4.8-25)

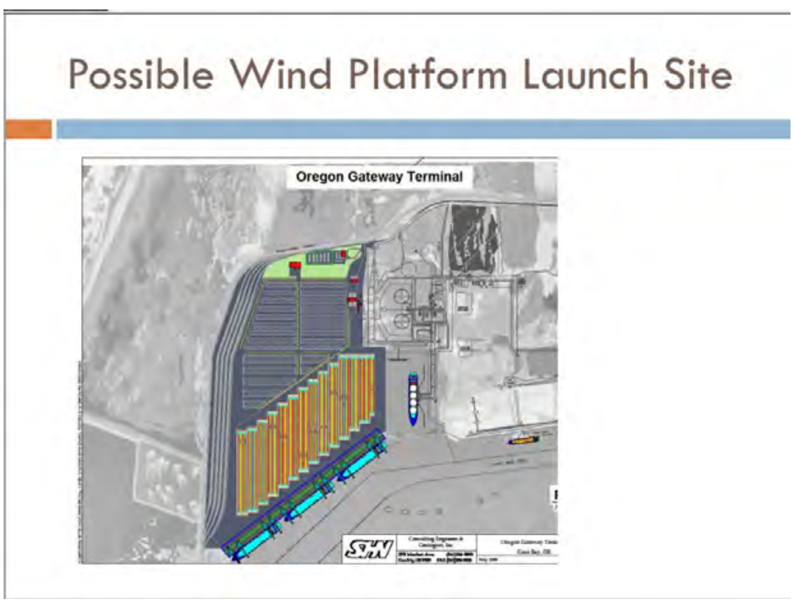
It is difficult enough for a small family owned operation to monitor and oversee its base operation. The Jordan Cove / Pacific Connector project will change family owned and operated practices and increase costs to timber production. Some businesses are likely to go out of business due to this increased cost.

In addition, Jordan Cove did not analyze timber jobs that will be impacted and lost from the flooding of the market with 144 miles of forestlands that will be clear-cut for pipeline construction. This will force timber prices to an all time low which will negatively impact the industry even more than it already has been. It could take years to recover.

9.4 Loss of other Proposed Port Developments

The negative impacts of the Jordan Cove Energy / Pacific Connector pipeline project to bay area businesses, including future potential businesses, industries and land owners was not considered in Jordan Cove's economic reports.

For example, on January 20, 2011 the Oregon International Port of Coos Bay presented the following diagram at their Port Commission meeting concerning a proposed Wind Project the Port is currently working on potentially developing.[29]



Unfortunately the proposed Jordan Cove Energy LNG Project Thermal Radiation Zones and Vapor Dispersion Zones would negatively impact the above proposed development as shown in the following diagrams below taken from the Final EIS of the Jordan Cove Import facility.[30]

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[29] January 20, 2011, Oregon International Port of Coos Bay Wind Development presentation: http://www.portofcoosbay.com/minutes/wind.pdf

[30] FERC Final EIS for Jordan Cove / Pacific Connector - Diagrams of Jordan Cove's Thermal Radiation Zones and Vapor Dispersion Zones - Pages 4.12-19 and 4.12-21 : http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp

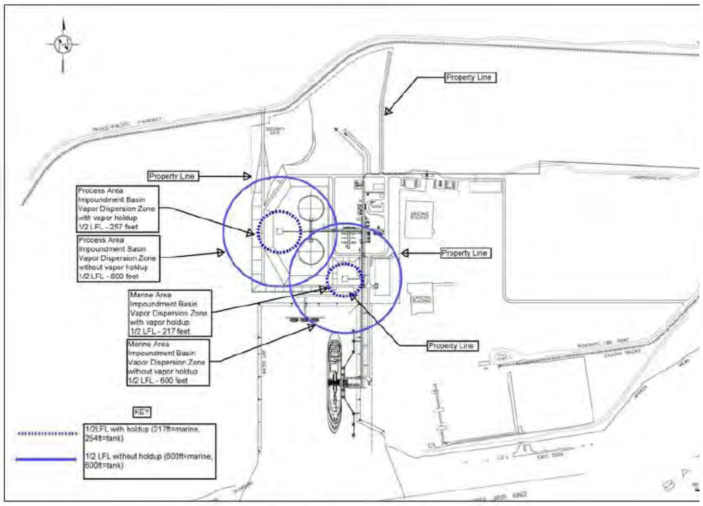

Figure 4.12-2. Vapor Dispersion Zones

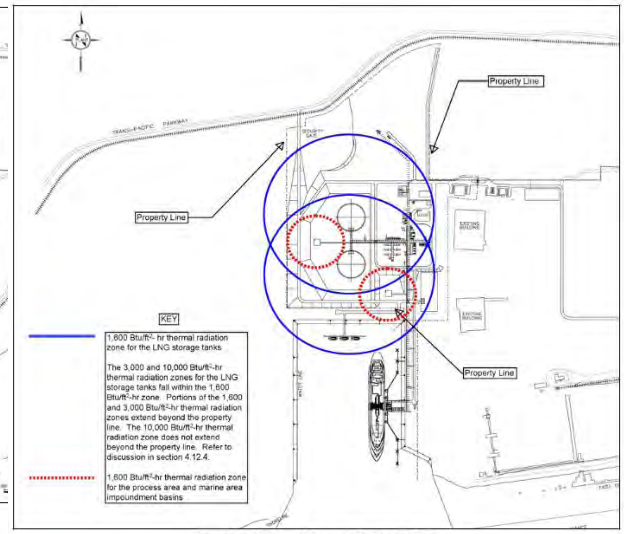

Figure 4.12-1. Thermal Radiation Zones

On October 8, 2010, FERC sent a letter to Jordan Cove requesting that Jordan Cove revise their Flammable Vapor-Gas Exclusion Zone requirements and modeling to be in compliance with PHMSA Recent Guidance contained in Title 49 CFR Part 193.2059.[31] It is highly likely that the Jordan Cove facility's hazard exclusion zones will end up being much larger than they currently are when they are calculated properly to be in compliance with PHMSA**.** This could have devastating impacts to other users of the harbor, adjacent landowners and industrial development including the Port's proposed Oregon Gateway cargo terminal, which would not be allowed to operate in these hazard zones. Jordan Cove has not to date filed with FERC their revised Flammable Vapor Gas Exclusion Zone requirements and modeling. Clearly Jordan Cove is aware of this problem and by now the Port should be.

In December 2011, a revised Land Option Agreement with the Jordan Cove Energy Project took back a large portion of Henderson Marsh to the west of the Jordan Cove facility to satisfy these thermal radiation and flammable vapor gas exclusion zone requirements. These thermal radiation and flammable vapor gas exclusion zones must be controlled by the Jordan Cove Energy Project at all times and must remain within the property boundaries of the facility. This will put any planned development to the west of the proposed Jordan Cove facility, including the above proposed wind turbine development, at risk.

The Oregon International Port of Coos Bay says its proposed Marine Terminal Slip is being designed for the Jordan Cove LNG docking facility and other potential marine uses on the west side berth. But the Marine Slip will not likely be usable for purposes other than those associated with and/or controlled by the Jordan Cove Energy Project. At a recent site tour held on March 27, 2012, that was sponsored by the Jordan Cove Energy Project, Bob Braddock from Jordan Cove stated that the current proposed Marine Terminal Slip was only designed to handle one vessel. Presumably this is due to Jordan Cove's thermal radiation and vapor dispersion exclusion

[31] October 8, 2010 letter requesting Jordan Cove Energy Project, L.P. provide the informing described in Enclosure 3 to assist the FERC in their review re the PHMSA Interpretations on the Part 193 Exclusion Zone Regulations under CP07-444. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20101008-3036

zones referenced above and also the Coast Guard safety and security hazard zones proposed for the LNG facility and berth that will preclude the use of the berth for other purposes.

The safety and security hazard zones the Coast Guard has proposed to impose will encompass the LNG vessel both while the vessel is moored and even when the LNG vessel is not moored. When the LNG vessel is at the docking facility there will be a 150 yard security zone around the vessel to include the entire terminal slip and when there is no LNG vessel moored, the security zone shall cover the entire terminal slip and extend 25-yards in the waterway. (CG-WSA page 2)[32] In addition, the Coast Guard has also set a moving safety/security zone for the LNG tanker ship that extends 500-yards around the vessel but ends at the shoreline. No vessel may enter the safety /security zone without first obtaining permission from the Coast Guard Captain of the Port who resides in the Portland, OR office.[32]

As a result of the above safety zones, the Port's proposed Marine slip can realistically serve only LNG terminal purposes.

In addition, the ECONorthwest study assumes there will be only 80 - 90 shipments per year and not the more realistic number of between 186 - 232 LNG vessel harbor disruptions that would include LNG vessels both coming and leaving the lower Coos Bay during high slack tides. (See Exhibit J)

Detailed issues concerning Pollution, Noise, Visual Impacts, Security, LNG Hazards, Natural Hazards and Emergency Response were filed with the Federal Energy Regulatory Commission for the Jordan Cove LNG Import / Pacific Connector Docket numbers CP07-444-000 and CP07-441-000. Most of these issues were never fully addressed and would apply whether you were importing or exporting LNG.[33]

FERC's Order[34] that was recently pulled had 128 Conditions of Approval, many highly unlikely that Jordan Cove would ever be able to meet. The impacts of these issues and the true negative effects of the Jordan Cove LNG proposal on jobs in tourism, recreation, real estate, fishing, clamming, crabbing, oyster harvesting, timber, etc, were not addressed or considered fully in any economic study.

10. The proposed project will not provide tax revenue to local government

The Jordan Cove LNG facility will not increase the tax base of Coos County. The facility will sit in an Enterprise Zone and will be exempt from paying taxes for 3 or more years. The facility

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[32] Coast Guard - LOR / WSR / WSA for Port of Coos Bay / Jordan Cove Energy Project: http://homeport.uscg.mil/mycg/portal/ep/contentView.do?contentTypeId=2&contentId=63626&programId=12590&pageTypeId=16440&BV

[33] January 15, 2010, letter to FERC with detailed information on LNG Hazard information and studies; http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20100115-5057

[34] December 17, 2009, FERC Order on the Jordan Cove / Pacific Connector LNG Import Project - Dockets CP07-441-000; CP07-444-000 et al: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20091217-3076

also will sit in an Urban Renewal District for the North Spit, which is administered by the Oregon International Port of Coos Bay. Money received is to go to Urban Renewal for the North Spit. The Oregon International Port of Coos Bay has already announced at Port meetings how they plan on spending this money. It will not go into the County general fund for roads, schools, sheriffs, and other necessary county expenditures.

11. Jordan Cove proposed LNG export facility would create substantial risks to public safety

Building an LNG import-export terminal on dredging spoils located on a sand spit (an unstable sand dune area) directly across the bay from an airport runway, in the flight path of the runway, in an extreme tsunami inundation zone, in an earthquake subduction zone, in an area known for high winds and ship disasters, less than a mile from a highly populated city not only violates multiple safety codes and regulations but is not in the public interest.

The Jordan Cove LNG facility is not following gas industry recommended guidelines for the safe siting of LNG Ports and jetties, putting thousands of people in the Coos Bay area at risk.

11.1 Tsunami and Earthquake Hazards

The Jordan Cove Energy Project has never complied with FERC's request to show that that their facility which will be located on dredging spoils on a sand spit in a natural hazard zone has met engineering designs in order to withstand a Cascadia subduction 9.0 earthquake event and/or a tsunami.[35] Since it is not a matter of "if" but a matter of "when" a Cascadia subduction event will occur off of our Pacific West Coast, placing a hazardous LNG facility in these natural hazard zones would not be in the public interest.[36] (See Exhibit H)

It is estimated to take 90 minutes to 2 hours for an LNG tanker to transit from K Buoy to the marine slip dock. It is also estimated that it will take around 15-20 minutes from the time of a Cascadia subduction earthquake event until a tsunami would come ashore in the Coos Bay. A new study from Oregon State University says that the South Coast has a 40 percent chance of experiencing a major earthquake and resulting tsunami sometime in the next 50 years. The study further suggests that that tsunami could have a greater impact on the South Coast — around Coos

[35] December 17, 2009, FERC Order - pages 79-84, Conditions 52-65,70,74: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20091217-3076

[36] The World, Coos Bay – **"***Not a matter of 'if' It's a matter of when. What will the South Coast look like after a major disaster?*" Stories by Jessica Musicar, Nia Towne, Andy Rossback and Nate Traylor. Illustrations by Jeff Trionfante, Benjamin Brayfield and Andy Rossback The World | Posted: Saturday, August 7, 2010 http://theworldlink.com/news/local/not-a-matter-of-if/article_d4b8e520-a1f3-11df-89f5-001cc4c03286.html

● *"Oregon geology: 'The next 'Big One' is imminent'":* Story Published: Oct 16, 2009; *Courtesy OSU News & Communications*; http://www.kval.com/news/tech/64534977.html: *"…The release of pressure between two overlapping tectonic plates along the subduction zone regularly generates massive 9.0 magnitude earthquakes – including five over the last 1,400 years," Corcoran said. "The last 'Big One' was 309 years ago. We are in a geologic time when we can expect another 'Big One,'… … "Prudence dictates that we overcome our human tendencies to ignore this inevitability," he added…".*

● Visit www.oregontsunami.org for more information on current tsunami maps and hazards in the vicinity of the Jordan Cove Energy LNG project.

Bay — than other areas of the west coast.[37] According to the study's authors, the clock is ticking fast. There is no consideration for this LNG ship transit hazard in the FERC FEIS or the Coast Guard Letter of Recommendation (LOR) or Water Suitability Assessment (WSA) or Jordan Cove's 3/31/09 Emergency Response Memorandum of Understanding (MOU). There is no Emergency Response plan that encompasses this and/or other safety issues in regard to transiting LNG tanker ships, floating objects, adrift vessels, barges, etc. Effects of tectonic subsidence (prolonged changes in tidal elevation inherent in the earthquake source scenarios used for tsunami generation) were also not considered in the FERC FEIS.

11.2 LNG Safety and Security Hazard Guidelines and Impacts

Industry SIGTTO Guidelines,[38] Sandia National Laboratory Guidelines,[39] GAO Report Guidelines[40] and the most recent U.S. Department of Energy report to Congress, "Liquefied Natural Gas Safety Research"[41] are not being considered or followed. The FERC Final EIS did not address the project's notable departures from **industry standards or comments to them on those departures.**[38] It is not in the public interest to proceed with this proposed project until these issues are fully addressed.

If the Jordan Cove LNG project should proceed, LNG tanker ships will be transiting our Coos Bay harbor carrying around 39 million gallons of LNG. If only about 3 million gallons of LNG was to spill onto the water from an LNG tanker ship, flammable vapors from the spill could travel up to three miles[42]. If a pool fire was to develop, people up to a mile away would be at risk of 2nd degree burns in 30 seconds.[39/40/41]

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37 *Study: Coos Bay region in danger of megaquake*" By KATU.com Staff, Published: Aug 1, 2012 http://www.kpic.com/news/local/Study-Coos-Bay-region-in-danger-of-megaquake-164645456.html
● Oregon State University - "*13-Year Cascadia Study Complete – and Earthquake Risk Looms Large*" 8-1-12 - http://oregonstate.edu/ua/ncs/archives/2012/jul/13-year-cascadia-study-complete-%E2%80%93-and-earthquake-risk-looms-large

38 "*Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14*" - Published by Society of International Gas Tanker and Terminal Operators Ltd / 1997
http://www.dma.dk/themes/LNGinfrastructureproject/Documents/Risk%20analyses/sigtto-site%20selection%20and%20design%20lng%20ports%20jetties.pdf

39 SANDIA REPORT "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*"; Mike Hightower, Louis Gritzo, Anay Luketa-Hanlin, John Covan, Sheldon Tieszen, Gerry Wellman, Mike Irwin, Mike Kaneshige, Brian Melof, Charles Morrow, Don Ragland; SAND2004-6258; Unlimited Release; Printed December 2004; http://www.fossil.energy.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf

40 United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; "*Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf

41 U.S. Department of Energy report to Congress, "*Liquefied Natural Gas Safety Research*" ; May 2012 : http://www.fossil.energy.gov/programs/oilgas/storage/publications/DOE_LNG_Safety_Research_Report_To_Congre.pdf [NOTE: Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from a large LNG pool fire will decrease by at least 2 to 7 percent compared to results obtained from previous studies. In spite of this slight decrease, people up to a mile away are still at risk of receiving 2nd degree burns in 30 seconds should a LNG pool fire develop due to a medium to large scale LNG breach event.]

42 "*LNG and Public Safety Issues – Summarizing Current Knowledge about Potential Worst Case Consequences of LNG spills onto water*". Jerry Havens, Coast Guard Journal Proceedings, Fall 2005

11.3 Airport Issues and Hazards

The proposed Jordan Cove LNG facility and South Dune Power Plant and liquefaction facility are directly across the Bay in close proximity to the Southwest Oregon Regional Airport in North Bend. Airport airspace and hazard issues were not addressed properly in the FERC FEIS. LNG Tank Heights clearly violate Title 14 Code of Federal Regulations (CFR) Part 77, Objects Affecting Navigable Airspace. Many issues concerning this and other airport hazards were raised in comments to FERC (Docket # CP07-444-000 and CP07-441-000)[43] The airport will clearly be impacted negatively in order for LNG vessels to safely transit our Coos Bay harbor. This would greatly affect many businesses in the area including the Bandon Dunes World Renowned Golf Course. Currently, there are no plans to prevent this impact and protect citizens in this area and that is not in the public interest. Issues involving LNG tanker passage and air space issues were also not addressed in the Coast Guard's LOR, WSA or considered in Jordan Cove's economic analysis.

11.4 Inadequate Emergency Response Resources

Emergency Response is inadequate with most Emergency Responders located in the Hazard Zones of Concern of the facility and LNG tanker transit. See Hazard Zone maps on FEIS pages 4.7-3,-7,-15.[44] The Coast Guard WSA is not in line with the Gas Industry SIGTTO guidelines and recommendations nor the Sandia National Laboratories guidelines and recommendations. The Coast Guard did not account for many LNG potential hazards in the waterway, air and shoreline and they failed to consider or mention hazard issues listed in the Coos County Natural Hazards Mitigation Plan. They underestimated the number of annual vessel calls and included no plans for handling tsunamis and earthquakes in their reports.

"*Once ignited, as is very likely when the spill is initiated by a chemical explosion, the floating LNG pool will burn vigorously…Like the attack on the World Trade Center in New York City,* ***there exists no relevant industrial experience with fires of this scale from which to project measures for securing public safety****.*" – Statement by Professor James Fay, Massachusetts Institute of Technology

Sandia Laboratory's Dec 2004 Report; "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water",* states on page 83; "*... The distance from the fire to an object at which the radiant flux is 5 kW/m2 is 1.9 km"* (1.181 miles).

To clearly understand this one must understand that 5 kW/m2 is the heat flux level that can cause 2nd degree burns on exposed human skin in 30 seconds.

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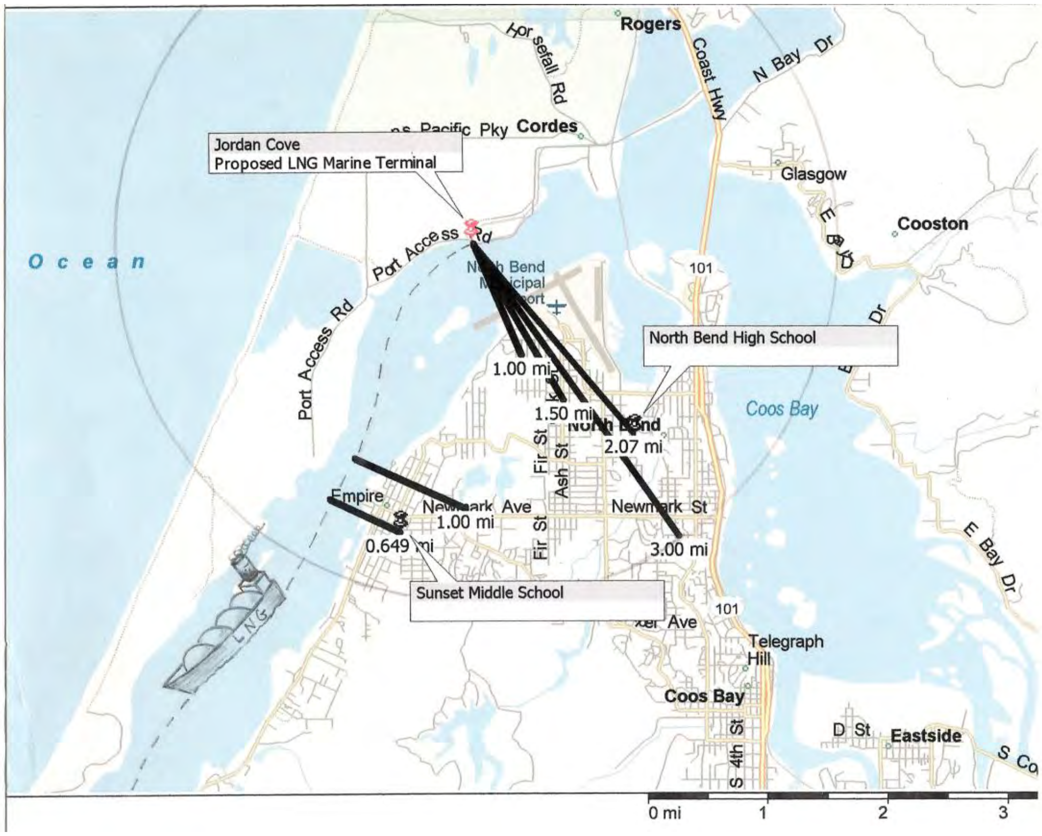
[43] March 31, 2009 comment letter to FERC addressing Safety and Security issues / Airport Hazards / Tsunami and Earthquake hazards:
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20090331-5160 - &
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20090401-5170

[44] FERC Final EIS for Jordan Cove / Pacific Connector http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp Pages 4.7-3,-7,-15



The FERC Jordan Cove Energy (Import) Project Final Environmental Impact Statement (FEIS) - Section 4-7, pages 4.7-3 and 4.7-15, has maps with diagrams of the structures that are within the LNG Ship Transit Route Hazard Zones of Concern.[45] (See Exhibit I) According to the FERC Final Environmental Impact Statement for Jordan Cove (FEIS page 4.8-2), 16,922 people live in these hazard zones along the waterway and yet there is little concern given for their safety. Trees and burnable scrub brush cover our area. Secondary fires will be paramount should an LNG accident occur. The FERC FEIS ignored comments on these dangers. The Coos Bay area has one hospital; it does not have a "Burn Unit." Neither the FEIS nor any public communication from Jordan Cove Energy Project, Inc. ("JCEP") has suggested how the medical response to even a minor LNG hazardous event could be handled in light of our area's obvious insufficiency of appropriate medical facilities and personnel.

Many of the guidelines for safety that are suggested in the gas industries "Society of International Gas Tanker & Terminal Operators" (SIGTTO)[46] Information Paper No. 14 have been completely ignored in this terminal siting, including the following:

1) **Approach Channels**. Harbor channels should be of uniform cross-sectional depth and have a minimum width, equal to five time the beam of the largest ship

[45] FERC Jordan Cove LNG Import FEIS pages 4.7-3 and 4.7-15: http://www.ferc.gov/industries/gas/enviro/eis/2009/05-01-09-eis.asp

[46] **Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14 -** Published by *Society of International Gas Tanker and Terminal Operators Ltd* / 1997

2) **Turning Circles**. Turning circles should have a minimum diameter of twice the overall length of the largest ship, where current effect is minimal. Where turning circles are located in areas of current, diameters should be increased by the anticipated drift.
3) **Tug Power**. Available tug power, expressed in terms of effective bollard pull, should be sufficient to overcome the maximum wind force generated on the largest ship using the terminal, under the maximum wind speed permitted for harbor maneuvers and with the LNG carrier's engines out of action.
4) **Site selection process** should remove as many risk as possible by placing LNG terminals in sheltered locations remote from other port users. Suggest port designers construct jetties handling hazardous cargoes in remote areas where ships do not pose a (collision) risk and where any gas escaped cannot affect local populations. Site selection should limit the risk of ship strikings, limiting interactive effects from passing ships and reducing the risk of dynamic wave forces within mooring lines.
5) **Building the LNG terminal on the outside of a river bend** is considered unsuitable due to fact that a passing ship may strike the berthed carrier if the maneuver is not properly executed.
6) **SIGTTO Examples given for reducing risk factors** beyond normal operations of ship/shore interface include LNG terminal patrols of the perimeter of the offshore safety zones with guard boats and to declare the air-space over an LNG terminal as being a restricted zone where no aircraft is allowed to fly without written permission.
7) **Restriction of the speed of large ships passing** close to berthed LNG carriers.

Also ignored were some of the safety guideline preventative measures in the Sandi National Laboratories Report – "Guidance on Risk Analysis and Safety Implications of Large Liquefied Natural Gas (LNG) Spill Over Water" – Dec 04:[47]

1) Appropriate off-shore LNG ship interdiction and inspections for explosives, hazardous materials, and proper operation of safety systems;
2) Appropriate monitoring and control of LNG ships when entering U.S. waters and **protection of harbor pilots and crews**;
3) **Enhanced safety zones around LNG vessels (safety halo) that can be enforced;**
4) **Appropriate control of airspace over LNG ships**; and
5) **Appropriate inspection and protection of terminal areas, tug operations prior to delivery and unloading operations.**

[47] Without an emergency response plan to review it is hard to know if some of these recommendations have been met. Page 4.8-9 of FEIS states, "The Coos County Airport District, which operates the airport, has stated that the airport would not have to stop operations while an LNG carrier was transiting in the waterway past the airport." "…and the Coos Bay Pilots Association foresees no delays for airplanes using the airport resulting from LNG marine traffic in the waterway." This clearly violates Sandia's safety guideline preventative measure recommendations.

Conclusion

It may be in the financial interest of some Canadian energy company to export domestic natural gas across the United States and across Oregon landowner's private property. But it is contrary to the public interest. Exporting Canadian and domestic natural gas from Jordan Cove will (1) put Coos Bay area residents at risk in the event of a Magnitude 9 earthquake and tsunami; (2) deprive many landowners of the full use of their private property; (3) negatively impact Oregon forests and waterways; (4) increase the costs for residential, commercial, and industrial natural gas users; and (5) negatively impact businesses and industries in Oregon and in other parts of the United States. The DOE should not grant such a permit for Jordan Cove to export LNG to non-free trade agreement nations when it is clearly not in "*the public interest*" both nationally and locally to do so.

Sincerely,

Jody McCaffree

Jody McCaffree
Executive Director,
Citizens Against LNG Inc

Citizens Against LNG
Index for Exhibits

Exhibit A - Coos Watershed Association, May 13, 2010, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01.

Exhibit B - Declaration of Russell R Lyon on Pacific Connector Gas Pipeline Case No. CV-10-6279-HO

Exhibit C - Williams / Metcalf, May 13, 2012, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01.

Exhibit D – McCauley, May 11, 2012, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01.

Exhibit E - Clausen Oyster, May 13, 2010, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01.

Exhibit F - Messerle and Sons, June 10, 2010, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01.

Exhibit G - Yankee Creek Forestry/Jake Robinson, June 7, 2010, comment letter on Pacific Connector Gas Pipeline Coos County CUP #HBCU-10-01

Exhibit H - Current 2012 Tsunami Evacuation Map of Jordan Cove Project area

Exhibit I - Jordan Cove LNG Tanker Hazard Zones from FERC Final EIS page 4.7-3

Exhibit J - Calculation of the approximate number of LNG Ship Transits needed to liquefy .8 and 1 billion cubic feet of gas per day and transport using 148,000 cubic meter ships.

Exhibit A

Coos Watershed Association

Coos Watershed Association
P.O. Box 5860
Charleston, OR 97420
(541) 888-5922
E-mail: cooswa@cooswatershed.org
Web: www.cooswatershed.org

RECEIVED
MAY 19 2010
COOS COUNTY
PLANNING DEPARTMENT

May 13, 2010

Ms. Patty Evernden, Planning Director
Coos County Planning Department
250 N. Baxter
Coquille, OR 97423

RE: Written Comments on Pacific Connector Pipeline #HBCU-10-01

Dear Ms. Evernden,

By a consensus vote without objection, the Board of Directors of the Coos Watershed Association at its regular meeting on May 10, 2010 authorized me to provide these written comments on the environmental effects of the Conditional Use Permit HBCU-10-01 to construct the Pacific Connector Liquefied Natural Gas (LNG) pipeline. The Association takes no position as to the merits of this project, but feels that certain aspects of the Hearings Board Conditional Use (HBCU) permit that affect watershed concerns need to be addressed. Based on the Proposed Route WC-1A from the FERC DEIS, which is the alignment being considered for the HBCU, we would like to provide information related to this route.

1. The alignment of Proposed Pacific Connector Pipeline (Route Alternative WC-1A) as identified in the Notice of Land Use Hearing does not follow a path of least environmental disturbance in the area covered by the Coos Bay Estuary Management Plan (CBEMP) of the Coos County Zoning and Land Development (CCZLDO). Alternative routes are available that would significantly reduce construction impacts and long term right-of-way maintenance impacts to streams and wetlands. Specifically, the Amended Blue Ridge Alternative Route includes a ridgeline alignment beginning at approximately MP 8 on the Proposed Route WC-1A in Section 20 (T.25S.;R.12W.) and joining with the Blue Ridge Route Variation in Section 33 (T.25S.;R.12W.). This route would avoid the impacts to lowland areas (particularly wetlands), while reducing the number of stream crossings. This "Amended Blue Ridge Alternative Route" largely follows the ridgeline between the Catching Slough and Daniels Creek watersheds, and is consistent with the design strategies identified in the Jordan Cover/Pacific Connector FERC DEIS to reduce environmental impacts.
2. This route crosses two significant streams (Kentuck Slough and Willanch Slough), both of which have high value for coho salmon. The area downstream from the proposed crossing at Willanch Slough is presently being considered for a Wetland Mitigation Bank, while the area upstream has had significant and successful riparian restoration projects. Information on the biological resources in these areas is available in our Coos Bay Lowlands Watershed Assessment (www.cooswatershed.org).

3. The route down Lilienthal Creek (T.25S.;R.12W., Sections 20 and 30) will cross the entirety of the Brunschmid Wetland Reserve Project (WRP) that has a perpetual easement held by the U.S.D.A. Farm Services Agency. This site has had significant restoration work during 2008 and was completed in the winter of 2009. Juvenile coho salmon (a Federally-listed Threatened species) were found during fish surveys in this wetland. We expect chronic sedimentation problems to occur in this wetland and Lilienthal Creek if the pipeline parallels the stream down this valley.

4. Across East Bay Drive—and hydrologically connected to the Brunschmid WRP—are high quality tidal fringe wetlands (low and high salt marsh) adjacent to the Cooston Channel that have also been identified as having potential for long-term protection and enhancement. These wetlands are in CBEMP zones 18RS, 18A-CA and 18B-CA. The area includes sites (U-12 and U-16(a)) identified as "high" priority for wetland mitigation as a Management Objective (§4.5.480), and this use would appear to be precluded by a 50' LNG pipeline right-of-way. Because juvenile coho salmon were found upstream in the Brunschmid WRP, they will also use this site.

5. Once it crosses the Coos River the proposed pipeline route will traverse lowlands adjacent to Catching Slough and its tributaries (approximately MP 8.25 to MP 18). These areas provide some of the most significant current lowland habitat for coho and Chinook salmon rearing, potential wetland restoration opportunities, and needed riparian restoration to reduce summer stream water temperatures. Of particular importance are Stock Slough (MP 10.1), the crossing in lower Catching Slough (MP 11), and Boone Creek (MP 15.75). All these streams and sloughs are used by coho salmon, and the adjacent riparian areas provide resources for these fish and other aquatic life. Additional information on these resources is found in the recently completed Catching Slough Assessment and Action Plan in the Publications section of our website (www.cooswatershed.org).

The Coos Watershed Association is interested in working with Coos County and Williams Pipeline consistent with our mission to "support environmental integrity and economic stability within the Coos watershed." In addition to our watershed assessments and restoration action plans, we have a deep knowledge of local conditions and landowner concerns in the project area in the Coos Bay Frontal watershed, as well as experience in designing and implementing water quality and habitat restoration and road upgrade projects. We would be happy to discuss such possibilities with the project proponents as plans progress.

Please don't hesitate to contact me if you have questions or need additional information.

Cordially,

Jon A. Souder

Jon A. Souder, Ph.D.
Executive Director

Pursuant to the CCZLDO Section 5.7.300.4.B(4), I certify that Dr. Jon A. Souder is authorized to provide these comments on behalf of the Coos Watershed Association.

John C Date: 5/13/10
JR Herbst, President

Exhibit B

Susan Jane M. Brown (OSB #054607)
Western Environmental Law Center
4107 N.E. Couch Street
Portland, Oregon 97232
Tel: 503-914-1323
Fax: 541-485-2475
brown@westernlaw.org

Attorney for Applicants-in-Intervention/Defendants

UNITED STATES DISTRICT COURT
DISTRICT OF OREGON
EUGENE DIVISION

PACIFIC CONNECTOR GAS PIPELINE, LP, a Delaware limited partnership; Plaintiff, vs. LOUISE SOLLIDAY, in her official capacity as Director of the Oregon Department of State Lands; and RICHARD WHITMAN, in his official capacity as Director of the Oregon Department of Land Conservation and Development; Defendants, and BOB BARKER, JOHN CLARKE, BILL GOW, RUSS LYON, and MARY MARGARET MUENCHRATH, individuals; and OREGON WOMEN'S LAND TRUST, a nonprofit corporation; Applicants-in-Intervention/Defendants.	Case No. CV-10-6279-HO **DECLARATION OF RUSSELL R. LYON**

I, RUSSELL R. LYON, do hereby declare and state:

1. My name is Russell R. Lyon. I make this declaration based on my own belief and knowledge.

2. My property, which I own with my wife Sandra G. Lyon, is located at 3880 Days Creek Road, Days Creek, Oregon, 97429.

3. The Pacific Connector pipeline would cross through our property.

4. We have a 306-acre ranch consisting of farm and forest land.

5. There are two large creeks on our ranch. Days Creek runs east to west near the southern edge for almost the full length of our property before turning south, and Fate Creek runs north to south near the western edge. Nestled between these two creeks at the southwest corner, our house and barns are spread out on about five acres.

6. The proposed 36-inch diameter pipeline transporting unscented natural gas at 1400psi, buried as little as 2 to 3 feet under the surface, will cross the southwest corner of our ranch within less than 500 feet of our house.

7. I understand that the minimum safe blast zone around this type of high pressure gas line is 900 feet.

8. The pipeline would first enter our property on the western side, cutting southeast through a pasture before crossing Fate Creek (at pipeline milepost 88.48) within 500 feet of our house. It would then exit our property through another pasture before crossing Days Creek south of our property, but still within 500 feet of our house, and as it turns to head southeast.

9. The proposed pipeline would rip open 75 foot wide swaths across any stream or river, and create a 100 foot wide scar everywhere along its route.

10. I would like to tell you about the Fate Creek Project.

11. Fate Creek is a small stream in Douglas County, Oregon. It is a poster child, so to speak, of what citizens can do to improve our water quality and salmon habitat. Back in 1990, my wife and I searched all over the West for a spot to settle down and raise our family in a healthy

environment. When we moved to Days Creek, Oregon, it fulfilled all our dreams of a rural environment off the beaten track, away from many of man's detrimental impacts on the environment. Never in our wildest dreams did we imagine that a huge natural gas pipeline would be proposed right through our property. (The first map from Pacific Connector Corporation showed it going right through our very house!)

12. My wife and I purchased a historic cattle ranch which, through our hard labor, we turned into an organic farm.

13. We have spent 18 years improving our environment, and in particular, Fate Creek. We sought out and worked with the local Soil and Water Conservation District, our local Watershed Council, Oregon Department of Fish and Wildlife, and the Bureau of Land Management (BLM) to carry out numerous improvement projects to this small rural stream to restore its historic salmon runs.

14. As a tributary to Days Creek, which in turn is a tributary to the South Umpqua River, Fate Creek is part of one of the Pacific Northwest's prime salmon recovery areas. Before we started our restoration efforts, Fate Creek had no salmon spawning in it. The creek was not fenced so that the cattle were degrading banks and fouling the waters.

15. Fate Creek now has nearly 2 miles of fence that keep the livestock out of the creek. Two bridges have been installed to allow cattle to be moved across without going through the creek. An off-stream stock-water system has been installed to provide livestock the water they need without entering the riparian zone.

16. There was a 14 foot dam for irrigation diversion, a second smaller 8 foot dam, and a culvert crossing Days Creek Road, that all prohibited fish passage. That culvert has now been replaced, and also one on the BLM lands upstream from us. The smaller dam has been totally

removed, and the larger dam has been retrofitted with a huge gate valve which is left open during the fall, winter, and spring providing unimpaired fish passage.

17. In addition, a large riparian restoration project was done where blackberries were removed and replaced with native trees and shrubs to provide further shading in addition to the existing large trees. This September 2010, log/boulder structures are being placed in both Fate and Days Creeks to restore the natural instream habitat that would have historically existed.

18. Fate Creek and its restoration efforts will be a show place of riparian restoration possibilities for public tours to show other ranchers and landowners how restoration efforts can be beneficial to both land-managers and wildlife. Coho, a listed fish species, are now spawning and rearing once again in Fate Creek after years of absence.

19. The proposed pipeline crossing right through this restoration project area would destroy all of this effort.

20. In order to build the pipeline, a large swath of riparian trees will be removed and not be allowed to be replanted.

21. The history of past pipeline projects shows that they have major problems with erosion and continually contribute to water turbidity. This will reverse all of the positive things we've been able to do on Fate Creek.

22. As landowners along the pipeline route, my wife and I have been very frustrated by the pipeline representatives and how they deal with landowners, so we have not given Pacific Connector access to our property.

23. Their environmental and social arrogance has been amazing.

24. The idea of using eminent domain, with minimal compensation for our loss of well-being and decreased property values, is, of course, of large concern.

25. But, also the very long-lasting environmental damage that will occur over the 280-mile pipeline route and its 379 water body crossings – as well as on our land – are of equal or greater concern.

26. I have watched and heard from the beginning the pipeline representatives give whatever answer they thought would work to relieve landowner concerns.

27. For example, a meeting was held July 2009 at the proposed crossing site of Fate Creek that involved Pacific Connector Pipeline Company's lead project engineer, environmental scientist, lead router, and two land agents; Oregon Department of Fish and Wildlife district biologist; executive director and project planner from Partnership for the Umpqua Rivers; an Oregon Department of Forestry engineer; and our family.

28. The Oregon Department of Fish and Wildlife had flagged the Fate Creek crossing in their response to the DEIS because of the numerous restoration work and projects in the creek.

29. From our meeting, it was immediately clear to us that Pacific Connector representatives didn't have a clear concept of the impact the crossings would have. The disruption of the ecosystem, the erosion of soils, added turbidity in the watershed, the loss of shade from the removal of mature trees, and the introduction of invasive species from contaminated equipment needed to be addressed. Their answer to nearly all the very real concerns was that, if there were a problem, mitigation somewhere else would make up for the local destruction and damage.

30. This lack of understanding and caring about the impact of the pipeline on landowners was offensive.

31. Why is all of this important? As stated above, salmon are now spawning again in Fate Creek, and the water quality has greatly improved because of the work and money put into

improving our streams by those of us who cared. The proposed natural gas pipeline would cross right through Fate Creek.

32. Fate Creek is not the only such stream in the Umpqua watershed where large salmon recovery projects have been carried out. The local watershed council, alone, has spent over ten million dollars to improve fish habitat in the Umpqua watershed. The proposed pipeline will cross dozens of streams as well as going under our major rivers. Precious riparian areas will be mowed down and denuded causing loss of stream cover and spawning habitat.

33. My wife and I were told that there will be minimal disruption, but the past record of a pipeline between Roseburg and Coos Bay has proven otherwise. Drilling can cause underground blowouts and produce desecration of our waters for years to come.

34. We have worked for years now to protect and increase shade cover for our streams. The pipeline would rip open 75 foot swaths across our streams and rivers, and create 100 foot scars across our hillsides and mountains, which consist of greatly varied soil types and stabilities.

35. Oregonians appreciate our natural landscape and are proud of our forests and rivers. The terminal and its pipeline would degrade our environment and put our lives at risk, all for no benefit to Oregonians. Oregonians would receive a very small fraction of this gas, if any.

36. Besides this environmental damage, the social and economical disruption along the pipeline could be extensive. Our own property and lives will definitely be impacted. The pipeline will cross through our irrigated pastures, trees will be cut down, and our driveway and fields will be used for staging areas.

37. Does anyone really believe that we would have any chance of selling our home, at anywhere near its current value, while a 36 inch un-scented high pressure gas pipeline is buried

within its blast range of our house? Pacific Connector only promises current per-acre value of land, which is much less than the property is actually worth.

38. What about loss of timber production? They also only promise current prices of timber sales. We, and other landowners like us, would not sell our timber at current low prices.

39. I guarantee this proposed pipeline will have, and already has had, extremely adverse impacts on us, and other landowners along its route.

40. The "landowner signature requirement" that Pacific Connector is challenging in its lawsuit against the State protects my interests in my property. It insures that my wife and I get to control what happens on our land, which we have worked so hard to restore and make into a wonderful place to live.

41. Eliminating the signature requirement would mean that Pacific Connector can run roughshod over property owners, without telling us what they intend to do with land that does not even belong to them.

42. To us, Pacific Connector is using this lawsuit to get around a "troublesome" problem, which is that Oregonians simply don't want this pipeline or terminal. The company should not be allowed to ignore the will of private property owners.

I declare under penalty of perjury that the foregoing is true and correct. Dated this 9th day of September, 2010.

/s/ Russ Lyon .
Russell R. Lyon
3880 Days Creek Road
Days Creek, OR. 97429

(Original signature on file with Applicants' Counsel of Record)

Exhibit C

TO: Coos County Planning Department

From: Virgil and Carol Williams / Mary Metcalf

Fairview Residents

Subject: Coos County Permit Application (FILE # HBCU-10-01)

RECEIVED
MAY 18 2010
COOS COUNTY
PLANNING DEPARTMENT

There are 5 main concerns we have with this Proposed Pipeline route.

1. We did NOT give pacific Connector pipeline permission to apply for a permit to come onto our private property.

2. The biggest concern is with our wells. The Aquifer in our area is very fragil and close to the surface. The productive wells here are hand dug and most are 25 to 35 ft. deep. Wells that have been drilled around 100 ft. to 200 ft. produce only brackish or Salty water, as was the one drilled on Metcalf property. It had to be filled in. The hand dug well they now have supplies 3 homes. The pipline route would have to go under this supply pipe, which is 4 ft. underground. That would be a substantial depth for their large pipe. and when they break through the Aquifer, what hapens to this well, along with 2 wells on the Williams property's, one of these also services a home on the other side of the road. Plus 3 other homes close by with shallow wells will

be in Jeperty. Thats 9 homes to survive without water. How will they compensate these homeowners? Mabe they could Contract out to have water delivered to a holding tank at each of them once a month.

(Well Quary Report from Water Master attached)

③ The pipeline route as planned, will cross the Williams property in the middle of a home site. When we purchased this property, the intention was to build a house on it. It was already septic tank aproved, with an existing well. (one of the above mentioned wells) We obtained an address, and made plans. Due to unexpected Health problems, building a house had to be put on hold, but not abandoned. If the pipeline pushes through with this route, there will no longer be a home site. and you know they will only compensate for the land as they see it, not for what a person plans to do with it.

④ after laying the pipline accross the Williams home site, Crossing Metcalfs well line, advancing accross more of Williams property, (Removing a small Barn in it's way) it will border along the side of a Natural pond (Registerd with The State) and cross the ponds drainage ditch that runs to the Coquille River. My concern here is that during Salmon Season, young smolt have been known to come up this drainage ditch from the Coquille River, into the pond. But besides the fish, without this drainage ditch, the field will floods in the Rainy Season.

Can it really be legal to distroy this drainage system?

(5.) Fire Hazard. The report says there will be no significant increase in Fire Hazard with this pipline. I believe only a fool would say NOTHING WILL EVER HAPPEN. I don't think they have a Crystle ball to look into. There is always an "IF" and that would be a big Catastrophe in this small Community of Fairview, with an all Volunteer Fire Department with limited resources. We have no fire hydrants. They draft water from the river and Creeks, so there is a limited supply of water on hand to fight a large fire.

DISASTERS DO HAPPEN

Just look at the Golf Coast Crises.

Does our small Coastal Community really need this Foreign fuel? I though the goal in the U.S. was to not be dependent on Foreign Fuel.

Sincerely,

Virgil + Carol Williams

Mary Metcalf

Virgil + CAROL Williams
58153 FairView Rd.
Coquille, OR 97423

541-396-4147

Well Log Query Results

Township: 27 S, Range: 12 W, Sections: 24

	T-R-S	Tax Lot	Street of Well	Owner	Company	Special Std	Well Type	First H2O	Comp Depth	Static	Yield	Completed Date	Received Date	Bonded Contractor	Start Card	Well ID #	New	Abandon	Deepen	Alt	Conversion	Demisp								
	27.00S-12.00W-24 NE-SE			CHORMICLE, EUGENE 36604 MUNYAN NEWARK CA 94560			W	23.00	160.00	22.0	2.0	05/03/1991	05/30/1991	BARRINGTON, RON	22750	684	√					√								
	27.00S-12.00W-24 SW-SW	1200	COQUILLE-FAIRVIEW CO RD	METCALF, JAMES HC 83 BOX 3365 COQUILLE OR 97423			W		200.00	0.0		11/19/1991	12/12/1991	SCHATTENKERK, DOUG	36522		√	√				√								
	27.00S-12.00W-24 -SE	1500	RC83 2973, COQUILLE	HOLMES, JIM	HOLMES, CARLENA PO BOX 1218 COOS BAY OR 97420		W	148.00	180.00	115.0	2.0	08/18/1992	09/04/1992	MEYER, GLEN L	45014		√					√								
	27.00S-12.00W-24 NE-SE	240		NEWMAN, MIKE	NEWMAN, LINDA HC 83 BOX 3426 COQUILLE OR 97423		W	42.00	205.00	36.0	3.0	10/22/1993	11/15/1993	BARRINGTON, RONALD L	50996		√					√								
	27.00S-12.00W-24 NE-NW	500		BAUCUM, DANNY HC 83 BOX 3430 COQUILLE OR 97423			W	12.00	105.00	85.0	1.0	10/26/1993	11/15/1993	BARRINGTON, RONALD L	53674		√					√								
	27.00S-12.00W-24 SW-NE	700		COOKE, GORDEN HC 83 BOX 3385 COQUILLE OR 97423			W	10.00	105.00	100.0	1.0	10/27/1993	11/15/1993	BARRINGTON, RONALD L	53678	63324	√					√								
	27.00S-12.00W-24 SW-NW			SINCLAIR, BOYD			W	0.00	80.00	18.0	4.0	05/30/1986	06/16/1986	BARRINGTON, RON			√					√								
	27.00S-12.00W-24 -			FULLER, ORVILLS A			W	10.00	0.00	0.0		10/02/1981	11/03/1981	BARRINGTON, DONALD				√												
	27.00S-12.00W-24 -			FOWLER, MADELINE J			W	0.00	0.00	0.0		05/12/1976	05/26/1976	BARRINGTON, DONALD			√	√												
	27.00S-12.00W-24 -			STEWART, J C			W	0.00	100.00	18.0	2.0	05/26/1969	06/23/1969	JONES, DELBERT S			√					√								

1

Exhibit D

MAY 11 2010

COOS COUNTY PLANNING DEPARTMENT

LADIES AND GENTLE MEN:

I'M WRITING TO LET YOU KNOW THAT WE ARE NOT IN FAVOR OF A PROPOSED GAS PIPELINE ACROSS OUR PROPERTY. OUR PROPERTY IS LOCATED BY TRS # 26S 12W 30 100 AND ACCOUNT #'S 4951.00/4951.90. ACCORDING TO A MAP GIVEN TO ME BY PACIFIC CONNECTOR, THE PIPELINE WOULD EXTEND FROM M.P. 13.7535 TO M.P. 14.2249, THAT'S A PERMANENT SCAR APPROXIMATELY 830 YD. LONG + 50 FT. WIDE ACROSS OUR PROPERTY, FURTHERMORE I WALKED THE PROPOSED ROUTE WITH A ROUTER FROM LNG. THE ROUTE WENT RIGHT OVER OUR ARTESIAN SPRING/WELL, WHICH WE HAVE WATER RIGHT TO (SEE OVER FOR CERTIFICATE COPY). IT'S AN IDYLLIC AREA THAT WE DON'T WANT AFFECTED ADVERSELY BY CONSTRUCTION. THE ROUTER SAID THEY COULD PROBABLY GO AROUND IT, WHICH IS IMPOSSIBLE TO THE WEST BECAUSE AN IRRIGATION PIPE EXTENDS FROM THE SPRING IN THAT DIRECTION. TO THE EAST THE LAND SLOPES STEEPLY UPHILL. THE WHOLE SITUATION PROPOSES A REAL MESS FOR OUR PROPERTY.

WE RESPECTIVELY ASK YOU TO RECOMMEND DENYING PACIFIC CONNECTOR FURTHER PROGRESS IN THIS MATTER.

THANK YOU!

R.H. McCauley

(541) 267-2466

MCCAULEY, ROBERT H + LINDA S.
94621 COOS SUMNER LN.
COOS BAY, OR 97420

STATE OF OREGON

COUNTY OF COOS

CERTIFICATE OF WATER RIGHT

This Is to Certify, *That* GRAYDON R. THOM, JR.

of Route 3, Box 220, Coos Bay *, State of* Oregon *, has made proof to the satisfaction of the STATE ENGINEER of Oregon, of a right to the use of the waters of* a spring

a tributary of unnamed stream *for the purpose of* domestic use of one family

under Permit No. 30562 *of the State Engineer, and that said right to the use of said waters has been perfected in accordance with the laws of Oregon; that the priority of the right hereby confirmed dates from* June 15, 1965

that the amount of water to which such right is entitled and hereby confirmed, for the purposes aforesaid, is limited to an amount actually beneficially used for said purposes, and shall not exceed 0.01 cubic foot per second

or its equivalent in case of rotation, measured at the point of diversion from the stream. The point of diversion is located in the NE$\frac{1}{4}$ NW$\frac{1}{4}$, Section 30, T. 26 S., R. 12 W., W. M. Spring located 230 feet South and 1660 feet East from NW Corner, Section 30.

The amount of water used for irrigation, together with the amount secured under any other right existing for the same lands, shall be limited to - - - - - - - - *of one cubic foot per second per acre,*

and shall conform to such reasonable rotation system as may be ordered by the proper state officer.

A description of the place of use under the right hereby confirmed, and to which such right is appurtenant, is as follows:

Lot 1 (NW$\frac{1}{4}$ NW$\frac{1}{4}$)
Section 30
T. 26 S., R. 12 W., W. M.

The right to the use of the water for the purposes aforesaid is restricted to the lands or place of use herein described.

WITNESS the signature of the State Engineer, affixed

this date. June 17, 1969

CHRIS L. WHEELER
State Engineer

Recorded in State Record of Water Right Certificates, Volume 28 *, page* 36042

Exhibit E

SILVER POINT OYSTERS
PRODUCT OF CLAUSEN OYSTERS

CLAUSEN OYSTERS
66234 North Bay Road
North Bend, Oregon 97459
USA
(541) 756-3600
(541) 267-3704
Fax (541) 756-3200

I LOVE OYSTERS CLAUSEN OYSTERS COOS BAY, OREGON

Max & Lilli Clausen

May 13, 2010

Kimberly D Bose, Secretary
Federal Energy Regulatory Commission

We are very concerned about the route of the pipe line through Haynes Inlet and the bay on the West side of Highway 101! I realize that the diagonal path through Silverpoint I oyster bed was changed to run alongside the oyster bed.

However, according to the documentary we were shown some time ago, when a pipeline is constructed in the water, mud and sand are suspended in the water, especially on windy days, and would drift over our oyster beds which would kill our oysters.

Another problem is the fact when the line is build, the ground over the pipe and the right-of -way is altered to the point where it acts like quicksand. Our oyster crew could not cross there. They usually leave the boat at the edge of the oyster bed and walk to the predetermined site to fill the nets at low tide. The nets are later retrieved at high tide with the oyster barge hoist.

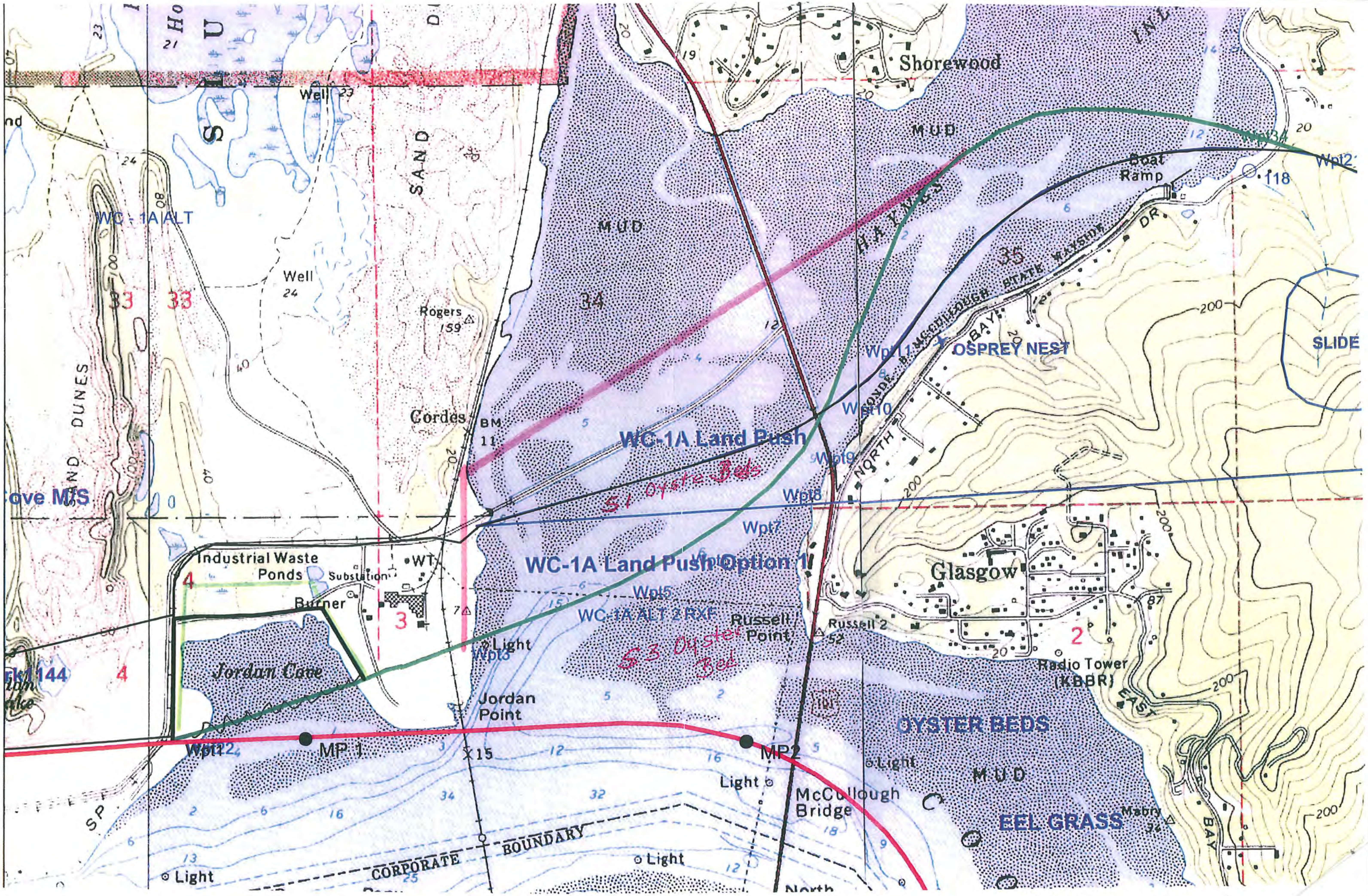
When the engineer and some other people representing LNG were in our office a few weeks ago my husband, Max, and I tried to explain that the proposed line was too destructive to our oyster business. Studying the maps it seems more logical and doable to swing away from our oyster plant from Haynes Inlet and continue straight West, North of Horsefall Beach Road, tunnel under Highway 101 through North Slough where nothing is planted due to poor water quality and ground conditions. There could even be a half mile saved in total distance to offset some of the additional cost.

Considering that the line is starting on the California border; crossing many roads and streets, this should be a possible solution without destroying our business. We do not like the idea of having a pipe line a few hundred feet from our oyster plant, but at least it would not impact our daily commute to and from the oyster beds. Most of the ground in the Northern part of Haynes Inlet is owned by the Division of State Lands while most of the ground in the North Slough is Coos County ground.

Please have your engineers take another look to alter the route to run North of Horsefall Beach Road, as sketched on the enclosed map. That change would eliminate any potential interference in our daily boating and harvesting activities, and hopefully also keep any harmful sediment away from our very productive oyster bed. In effect, you would not need our permission to survey this area, since your future installation would not take place on our land.

Thank you!

Lilli Clausen



Shorewood
MUD
Boat Ramp
Wpt21
118
HAYNES
WC-1A ALT
Well
Well 23
SAND
SAND DUNES
MUD
Rogers 159
33
33
34
35
CONDE B. McCULLOUGH STATE WAYSIDE DR
NORTH BAY
Wpt11
OSPREY NEST
SLIDE
Cordes
BM 11
Wpt10
WC-1A Land Push
Wpt9
51 Oyster Beds
Wpt8
Cove M/S
Wpt7
Industrial Waste Ponds
Substation
WT
Burner
WC-1A Land Push Option 1
Glasgow
Wpt5
WC-1A ALT 2 RXF
Russell Point
Russell 2
52
3
4
4
2
Light
Wpt3
53 Oyster Bed
Jordan Cove
Jordan Point
Radio Tower (KBBR)
EAST
OYSTER BEDS
Wpt12
MP 1
MP2
Light
Light
McCullough Bridge
MUD
EEL GRASS
Mabry
BAY
CORPORATE BOUNDARY
Light
Light

Exhibit F

MESSERLE
& SONS

94881 STOCK SLOUGH LANE
COOS BAY, OREGON 97420
(541) 267-2997
FAX (541) 269-1042

June 10, 2010

Coos County Planning Department
Attn: Patty Evernden
250 N. Baxter Street
Coquille, OR 97423

Re: HBCU 10-1

Dear Ms. Evernden:

Please forward the following discussion to Mr. Stamp for his consideration concerning the above referenced matter.

SIGNIFICANT CHANGES TO FORESTRY PRACTICES AND COSTS RELATIVE TO THE PROPOSED PIPELINE

The following is intended to provide the County with information requested relative to the proposed PCGP application. Specifically this information addresses the applicant's compliance with Section 4.8.400, 4.8.300 and 4.8.350.

Section 4.8.400 Review Criteria for Conditional Uses in Section 4.8.300 and Section 4.4.400

The use authorized by Section 4.8.300 and 4.8.350 may be allowed provided the following requirements are met.

A. The proposed use will not force a significant change in, or significantly increase the cost of, accepted farming or forest practices on agriculture or forest lands.

   Note: The proposed use will force a significant change and a significant cost increase in accepted forest practices.

   OVERVIEW
   As a 150 year old Coos County farming and forest family owned business, we operate over 1800 acres of intensity managed timberland. Our operation is

based on owning and holding the timberlands for the full term (rotation) from growth to harvest and re-plantation of the timber crop. Therefore, the applicants proposed use does significantly change and significantly increase the cost of our accepted practices in the following ways.

1. <u>The value of the timber</u>.
   The price of timber over the last 40 years has gone up 8% per year. Timber value has increased from an average of $30.00 per 1000 board feet to today's value of $600.00 per 1000 board feet (a multiplier of 20x).

   Based on the increase in worldwide demand and the decrease in supply of softwood (Douglas Fir) timber from Federal land we anticipate the rate of valuation increase to remain the same over the next 40 years.

   Therefore, we expect 40 year old Douglas Fir which has been intensively managed to increase in value to $12,000.00 per 1000 board feet.

   <u>Note</u>: This will result in a gross value of $240,000.00 per acre for 40 year old timber in 2050.

   IN OTHER WORDS
   We can produce now 20,000 board feet per acre at the end of a 40 year rotation.

2. The <u>wind loss</u> exposure (and expense) in today's accepted forest practice is limited by the number of and/or the distance of the "hard edge" in each "stand" of timber.

   IN OTHER WORDS
   Cutting and maintaining an extended "hard edge" in an existing and/or new stand of timber will dramatically increase the wind loss over the 40 year rotation and thus increase cost and decrease yield.

3. The current accepted practice on our managed forest lands includes severely <u>restricted access</u> to anyone. This restricted access is enforced to:

   a. Reduce the potential for the spread of soil born pathogens.

Specifically we are trying to stop:

- Port Orford Cedar root rot.
- Douglas Fir root rot.

Note: *These diseases produce a 100% mortality rate and once in the soil can never be gotten rid of.*

FURTHER
These diseases are typically spread by vehicle and foot traffic thus the increased access, and stated requirement by the applicant, to "walk and maintain the right of way" will significantly change the accepted practices involved in raising a 40 year crop and or, in a worst case, eliminates the value of the land all together for timber production.

Special Note: *Every timber company has "locked up" their land for these risks and or fire risks. The applicants proposed use completely changes the current practice of restricted access.*

4. Noxious weeds

   An open right of way (vector) through an existing or new stand of timber creates an area for infestation of noxious weeds, once established (even as small populations) are very difficult to get rid of.

   FURTHER
   Douglas Fir creates a "canopy" of shade that reduces the viability of noxious weeds. This open vector along the proposed right of way will require a significant increase in our costs and time to eliminate noxious weeds on our timber lands.

5. An open vector (Right of Way) with dry grass and or brush creates a path for fire to "run on".

   There is no question that this vector (right of way) will increase our fire hazard exposure and or risk in the event of a fire.

6. Accepted logging practices.

The applicant's proposed route is generally on ground that would allow mechanized equipment to perform the logging or thinning of the mature stand (i.e., feller buncher, cat, rubber tire skidder).

Our land was specifically acquired and has been developed for this type of ground based operation. The proposed pipeline would change the "established harvest layout" and thus increase the cost to harvest.

Specifically, we cannot "yard" and or drive our equipment (which would be dragging logs) across the right of way. Therefore, we have to go down or around or airlift to log.

IN OTHER WORDS
Each stand of timber has a specific way that we log it. Any breakup (by a right of way) significantly changes and or increases the costs of accepted practices.

Note: Today's logging costs for us run about $400.00 per 1000 board feet. We expect this cost to increase to at least $500.00 to $600.00 per 1000 board feet due to the proposed right of ways impact on accepted forest harvesting practices.

FURTHER
We expect the cost of logging to run parallel to the value of the timber "on the stump" over the next 40 years (8% increase per year on average).

FINALLY
Timber harvesting (logging) has always had a very "thin margin" of profit. Logging is not a "get rich quick" proposition. Any change to accepted logging practices will increase costs, decrease margins and significantly change the cost of accepted forest practices.

7. Valuation of existing stands of timber with the proposed pipeline versus valuation without the proposed pipeline.

IN GENERAL

The valuation of the land will be reduced and appreciation of the land will be in some way restricted.

IN OTHER WORDS

There is no way that a tract of land for timber production is more valuable with the pipeline going through it than a similar tract without a pipeline. In fact, two parcels of similar timber, one with the pipeline and one without, will see a higher value to the parcel without the pipeline.

Actual value reduction:

We do not know but it will be significant. It depends on a variety of things such as:

i. FERC restrictions and or any increase in the size of the vector if and when they choose to do so.
ii. Accidents, risks and or other requirements that result from incidents throughout the world.
iii. The value of timber land without a pipeline running through it.

8. The <u>real width of the right of way relative to timber</u>.

A 40 year stand of Douglas Fir timber will require a distance from the base of one tree on one side of the right of way to the base of the tree on the other side of 80' to maintain a 50' <u>visible</u> right of way.

IN OTHER WORDS

Two trees 80' apart will create an open strip that is 50' wide.

<u>Note</u>: *We are being "told" that we can plant trees 30' apart across the proposed right of way. From the air in 20 years you will not be able to see the ground across that 30'.*

Therefore, we expect to lose 80 feet by whatever length the pipeline is (in timber production) when all the dust settles.

9. <u>Trespass and or vandalism</u>.

In forestry practices trespass and fire is a big concern. The ATV path that the right of way will create is an irresistible temptation to the ATV or walking trespassers. And, no short fence or gate at the road is going to stop them. Therefore, the right of way, in its visibly open vector form, significantly increases fire hazard and fire suppression costs.

10. <u>The cost to cope with the applicants proposed construction and ongoing oversight</u>.

    In general, our oversight and monitoring of the proposed construction and ongoing operation of the pipeline through our farm and forest land significantly changes our practices and increases our costs.

    We will spend more time and more money than we do now.

    Currently we have no third party construction going on in any of our lands and we have no power or pipeline routes through any of our forestry lands either.

    It is difficult enough for a small family owned operation to monitor and oversee its base operation. This proposed addition will change our practices and increase our costs.

CONCLUSION
The county must find that the proposed use relative to Section 4.8.300, Section 4.8.350 and 4.8.400 <u>not</u> be allowed because the requirement for the use and its compatibility with forest operations and agriculture has not been met.

Specifically, the proposed use <u>will</u> significantly change and increase the cost of accepted tree farming and forestry practices on agricultural and forest lands.

EXCEPTION SHORTEST ROUTE (Mr. Stamp's letter indicates that the applicant is taking the shortest route).

The proposed route <u>is not</u> the shortest route. The Amended Blue Ridge Route is approximately 2 ½ miles shorter and it dramatically reduces the <u>miles</u> of private timber right of way required.

Therefore, the effect and cost on accepted forest practices can be reduced by a shorter route such as the Amended Blue Ridge Route.

Specifically, we are correcting the statement made by Mr. Stamp in second paragraph of Mr. Stamp's 6/6/10 Pg. 8 letter to Patty Everden.

The applicant by not proposing the shortest route has not met the intention of the provision. The Amended Blue Ridge Route causes less impact to many specific properties because:

a. It reduces the private landowners affected from 37 to 18.
b. Shortens the pipeline by 2.5 miles.
c. Changes the percentage of private to public land affected from:
   Current Route - 10.65% Federal Land
   Blue Ridge - 76.32% Federal Land

We appreciate the opportunity to provide further comment on this matter.

Fred Messerle & Sons, Inc.

Fred R. Messerle

Fred R. Messerle
Secretary-Treasurer

Exhibit G

7 June 2010

Coos County Planning Dept.
Attn: Hearings Officer, Mr. Andrew Stamp
250 N. Baxter Street
Coquille, OR 97423

RECEIVED
JUN 10 2010
COOS COUNTY
PLANNING DEPARTMENT

Re: *HBCU 10-01*

Mr Stamp;

I am writing you concerning the land use application submitted by Pacific Gas and Connector Pipeline for permission to construct a natural gas transmission pipe line across Coos Co. I may have stated some of my personal information during the verbal testimony portion of the hearing. Please forgive the repetition. I am a private consulting forester with 10 years experience and an operation base of the southwestern portion of Oregon. I have written forest management plans for over 2500 acres of private forest ground, and wrote the forest management plan for 5000 acres of forest at South Slough Reserve while employed for Oregon Dept of State Lands. I have also designed harvest lay out for commercial operations on both private and Federal forests. I have resided in Coos Co for the past 2 years at 94961 Stock Slough ln. This property would be crossed by the proposed pipeline route. I rent and am not the property owner.

The following comments are specific to **Coos Co Zoning Land Develop Ordinance (CCZLDO) 4.8.400** concerning forestry operations on lands zoned forestry. I believe that the proposed pipeline would significantly impact landowner's ability to practice timber stand maintenance and harvest on their lands. Most of these land owners rely heavily on periodic proceeds from timber harvest, for some it is a primary source of income. Logging is, in the best of times, a decent living. Under current conditions it is marginal at best. There are several issues which I will raise in regard to impacts. Any one of these impacts could be the difference between a profitable harvest and a break even project, combined they would make it very difficult to continue to economically harvest timber on land which is designated for that purpose.

- Increased costs associated with timber harvests; Most of the private timber ground along the pipeline route is under 35% slopes which makes it suitable for ground based harvesting. The applicants have proposed creating a limited number of 'hard crossings' across an otherwise 'no entry' easement. Having only a limited number of crossings will significantly increase logging costs because of changes to proposed harvest lay-out, increased length of skidding turns and haul routes, and reduced harvestable acreage within the stand. Ground based timber harvests require freedom of access, very little is done with long winch lines due to the inefficiency. Machinery is literally driven up to each and every tree. The cost increases would be different for different stands depending on amount if the stand the pipeline crossed, but it could easily range from 5-20%. Logging costs for a ground based operation would be $200-300 per thousand board feet(mbf). A 12% harvest cost increase at $200mbf for a 40 acre stand, with 20mbf per acre would work out to a loss of **$19,200**. This 40 acres is the typical annual harvest amount for local private forest owners, and $20,000 is probably close to the expected income. The timber ground in this area is expected to produce roughly 20mbf per acre at 40 years, which in the established rotational age.

- The creation of a ± 100' working easement and a 50' permanent easement would fragment some forest stands to the point which made harvest financially restrictive. The increased cost to access an isolated portion of a stand would mean that the planned harvest would be changed to either harvest the patch early or late depending on the age of the adjacent stand. Depending on the restriction of access this would affect patches >5 acres, a small but significant value at $20mbf per acre.
- Most of the private forest ground along the proposed route is intensively managed on a 40 year rotation. These trees have been planted on a ±11' spacing resulting in 360 trees per acre. Within Coos Co, wind is the dominant disturbance type, both periodic gusts and episodic storm events. Since these stands have grown up under dense conditions, the structural integrity of the stand it based on the uniformity of the stand and individual trees are supported and buffered by their neighbors. The proposed route would create a 'hard edge' through the middle of the forest stands. This hard edge would inevitably create blowdown within the adjacent stands, especially those over 20 years old. The amount of wind damage would be tough to calculate, it would be based upon aspect, slope, age of the stand and, in some cases, pure chance.
- Opening up a corridor within these private forests will inevitably promote trespass, both vehicular and foot traffic. Either will have a negative effect on forestry operations. The applicant has discussed mitigation efforts such as gates, obstacles, and fencing. None of these will have a 100% success rate. You yourself mentioned piano wire as an effective deterrent. The Oregon Dept of Forestry lists humans as the dominant cause of forest fires within the state. I looked at a 5 year trend (2002-2006), **70-80%** of all fires were human caused. (http://www.oregon.gov/ODF/FIRE/fire.shtml) These corridors will also provide a vector for the spread and establishment for noxious weeds, both during and after the consrtuction. Even if access is successfully limited to just the contract crews who will be preforming the maintance, the spread of soil borne pathogens will be increased as easliy as mud on a boot. Port Orford Cedar Root Rot, *Phytophthora lateralis*, and Douglas Fir Laminated Root Rot, *Phellinus weirii*, are both local soil borne pathogens, which, once introduced to a stand, can effectively kill all host stems as they radiate out from the infection source. *P. lateralis* in particular has devastated a once very valuable timber species in Coos and Curry county. Once established, these organisms cannot be removed from the stand without removing all host species stems for a period of at least ten years. If you throw in vandalism, un-authorized hunting, mushroom picking, bough collection and dumping, it is easy to see why all industrial private timber lands in the state are attempting to severely reduce access to their crop.
- The proposed pipeline would have a ±100' construction right of way, followed by a 50' permanent right of way. This would mean that the applicant proposes to replant the 20-25' on either side to return it to productive timber. Once established these two 25'wide swaths of trees would constitute un-harvestable ground. They would be of a significantly different age class then the surrounding timber and would have absolutely no access do to restriction on equipment operation within the permanent right of way. Also the trees, especially within the interior of the corridor, would be of poor quality due to the amount of limbs growing on the inside edge. Generally speaking, a landowner could expect 5-15% of the timber harvested to be of poor

quality due to it's limbiness, mills want straight trees with few knots. The proposed 'mini-stands' would not only have very limited access, they would also have at least 50% of the trees deducted due to limbs. Currently Doug Fir saw logs graded 1-3p (good) are $600/mbf, while limby poorer quality logs (2-3s) are $450/mbf, **a 25% decrease**.
http://www.oregon.gov/ODF/STATE_FORESTS/TIMBER_SALES/logP110.shtml

- The proposed pipeline would significantly reduce the landowner or local response team's ability to fight forest fires, especially if they occur as result of trespass along the cleared right of way. One of the most effective methods for stopping the spread of forest fire is to run a 'cat line' above the leading edge of the fire with a bulldozer. Most if not all of the long time loggers in Coos Co have had to do this at one time or another. If access is restricted to hard-crossings then you have the combination of a forest fire which you cannot get to on top of a 3' gas pipeline. The idea of a 'cleared right of way' is somewhat misleading. Having utilized powerline right of ways to access timber land to survey, I can say that they generally have high surface fuel loads. Mulching of the entire pipeline is not possibly, so hand slashing and spraying will be utilized frequently, creating lots of small diameter fuels with direct exposure to the sun making them even drier. This ribbon of dried fuels could easily hasten the spread of a wildfire across the property.
- Though not as common or as profitable as intensively managed timber harvesting, setting forest land aside for conservation easements, watershed benefits and the sale of sequestered carbon is becoming more and more prevalent. Certified forestry (Forest Stewardship Council) and government funding provides the landowner with some funding for these projects. None of these activities would be possible with a permanent easement across the property. This is even more restrictive for wetland mitigation projects within the lower grazing grounds. The applicant will be utilizing wetland mitigation banks to offset the loss of wetlands during the proposed terminal construction. The proposed pipeline would significantly reduce landowners rights to develop potential non-traditional funding sources.

Coos Co Zoning Land Develop Ordinance 4.8.400 states "*The proposed use will not force a significant change in, or significantly increase the cost of, accepted farming or forest practices on agriculture or forest lands.*" Most of the impacted forest lands within Coos Co are private, non-industrial timber lands. These landowners do not have the land-base to absorb the increased costs of timber operations which I described above, yet they often rely on the timber proceeds for some if not all of their income. These properties are some of the most productive timber lands in the nation, that is why they were zoned as such. Even with the high level of productivity, making money of off trees is marginal at best. The market fluctuations require a successful timber land owner to have enough options to ride out the lows and save from the high times. The proposed pipeline project could effectively end a livelihood for impacted properties by increasing the costs of doing business while increasing the associated risks.

Please feel free to contact me with any questions

Thanks

Jake Robinson
Yankee Creek Forestry
94961 Stock Slough Rd
Coos Bay, OR 97420
541 941 1822

Exhibit H

Exhibit H

Current 2012 Tsunami Evacuation Map of Jordan Cove Project area

Orange – Distant Tsunami evacuation zone

Yellow – Local Cascadia Earthquake and Tsunami evacuation zone

Full Tsunami Evacuation Map for Coos Bay Area available at: http://www.oregongeology.org/pubs/tsubrochures/CoosBayEvac.pdf (4.03 MB)

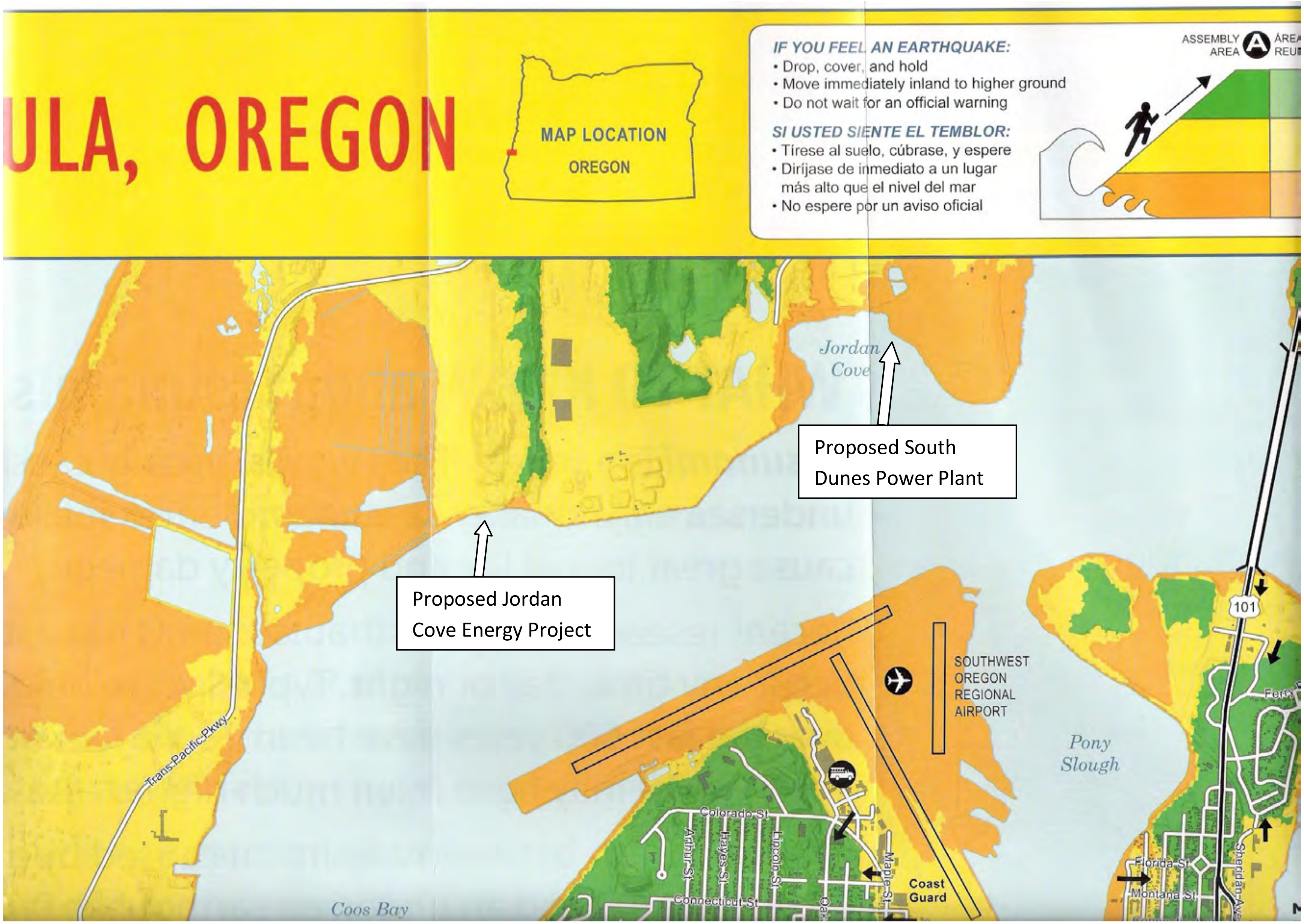


Exhibit I

Jordan Cove LNG Tanker Hazard Zones (FEIS Page 4.7-3)

No one is expected to survive in Zone 1 (yellow) - Structures will self ignite in this zone just from the heat. People in Zone 2 (green) will be at risk of receiving 2nd degree burns in 30 seconds on exposed skin. People in Zone 3 are still at risk of burns if they don't seek shelter but exposure time is longer than in Zone 2. Map does not include the hazard zones for the South Dunes Power Plant.

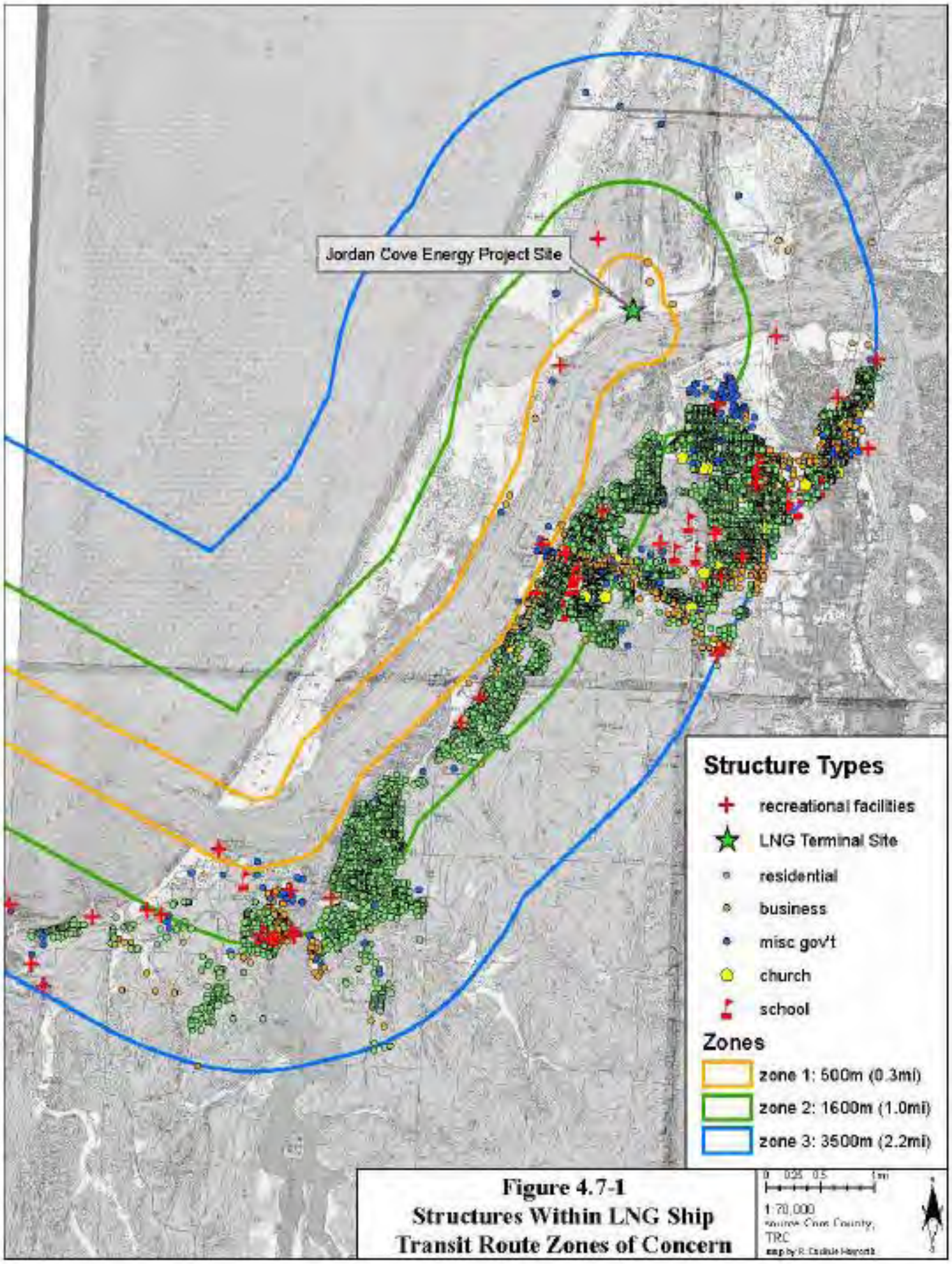


Figure 4.7-1
Structures Within LNG Ship Transit Route Zones of Concern

Exhibit J

EXHIBIT J

Calculating 148,000 cubic meter LNG ship at –
600 to 1 and 610 to 1 conversion from Natural Gas and how many shipments that would mean:

148,000 cubic meters LNG = 5,226,570.675 cubic feet LNG

5,226,570.675 X **600** = 3,135,942,405 cubic feet of natural gas

292,000,000,000 cubic feet of gas (yearly) :/: 3,135,942,405 cubic feet of gas per shipload = **93 shipments needed per year = 186 harbor disruptions at high slack tide.**

[**Note:** Jordan Cove non-FTA Application page one says JCEP will export 292 billion cubic feet (Bcf) per year (.8 Bcf/d); Page 13 states .9 Bcf/d beginning in 2017; ECONorthwest Construction Impact Study page 3 states; “ The PCGP would have a nameplate capacity of 1.1 billion cubic feet of natural gas per day (Bcfd). At a 90 percent capacity factor, throughput would average 0.99 Bcfd.” Page 5 states; “A single natural gas compressor station at Malin will allow the PCGP to transport 1.1 Bcfd to JCEP terminus in Coos County.”]

****

148,000 cubic meters LNG = 5,226,570.675 cubic feet LNG

5,226,570.675 X **600** = 3,135,942,405 cubic feet of natural gas

365,000,000,000 cubic feet of gas (yearly) :/: 3,135,942,405 cubic feet of gas per shipload = **116 shipments needed per year = 232 harbor disruptions at high slack tide**

****

148,000 cubic meters LNG = 5,226,570.675 cubic feet of LNG

5,226,570.675 X **610** = 3,188,208,111.75 cubic feet of natural gas

365,000,000,000 cubic feet of gas (yearly) :/: 3,188,208,111.75 cubic feet of gas per shipload = **114 shipments needed per year = 228 harbor disruptions at high slack tide**

****

116 shipments: /: 12 (months) = Ten shipments per month (roughly) A shipment every 2 – 3 days. Some of the LNG is left in the ship to keep the containers cold and there is also LNG lost to boil off (about 15 % per shipment by some estimates) that has not been figured into these estimates.

Who’s to say that the minute the DOE and FERC would approve this, Jordan Cove Energy Project would submit another application to increase their export capacity?

Another good question would be what is the pollution impact of having all these smaller ships? Right now most of the newer ships being built are much larger than 148,000 cubic meters - www.coltoncompany.com

Citizens Against LNG
Petition Exhibit

(Set 4 Beginning #501)

-----PROTECT COOS, DOUGLAS, JACKSON, & KLAMATH COUNTIES & THE STATE OF OREGON-----

STOP LNG TERMINAL & PACIFIC CONNECTOR GAS PIPELINE

PETITION TO PREVENT LNG EXPORT TERMINAL & STORAGE TANK FACILITY; PASSAGE OF LNG TRANSPORT VESSELS THROUGH THE COOS BAY HARBOR & CHANNEL; AND TO STOP THE 230 MILE, 36 INCH PACIFIC CONNECTOR GAS PIPELINE TO THE CALIFORNIA BORDER.

To State of Oregon Governor John Kitzhaber and to his appointed Port of Coos Bay Commissioners; to the Commissioners of Coos, Douglas, Jackson, & Klamath County Oregon; to those elected by the people of Oregon who represent the people of Oregon in any state or federal office; and to any person or persons elected by the people or appointed to represent the public trust and interest of the citizens of the State of Oregon.

We the undersigned declare that a liquefied natural gas (LNG) export terminal and storage tank facility is not a well conceived or appropriate industry for Oregon and that LNG represents an unacceptable risk to the people of the State of Oregon. For the safety, security, and well being of the citizens of our communities, the citizens and residents of the State of Oregon ask you to immediately take action to stop the LNG export terminal and storage tank facility proposed for the North Spit of Coos Bay and the 230 mile, 36 inch Pacific Connector natural gas pipeline to the California border.

NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Jody McCaffree	Jody McCaffree	Po Box 1113 North Bend, OR 97459	
2 Lydia Delgado	Lyd Delgado	555 Douglas Bandon OR 97411	
3 JC Williams	JC Williams	66642 E. Bay Rd NB 97459	
4 Chris Morrow	Christina Morrow	633 Shorepines HTS. Coos Bay. Or. 97420	
5 Dana Gaab	Dana Gaab	Box 991 North Bend, Or 97459	
6 Dawn Coburn	Dawn Coburn	25510 SW Canyon Creek Rd #Z101 Wilsonville, OR 97070	
7 MICHAEL HANCOCK	[illegible]	65472 E. BAY RD NORTH BEND, OR 97459	
8 LINDA E. MORRIS	Linda E. Morris	685 ELROD AVE CS BY OR 97420	
9 Camby Collier	Camby Collier	POB 181 90768 Travis, Coos Bay, OR 97420	
10 Rebecca Walker	Rebecca Walker	1055 E Central Ave. Sutherlin Or. 97479	[illegible]

Please return petition, completed or not, to: **Citizens Against LNG, P.O. Box 1113, North Bend, OR 97459**

-----PROTECT COOS, DOUGLAS, JACKSON, & KLAMATH COUNTIES & THE STATE OF OREGON-----

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Janet C. Stoffel	Janet C. Stoffel	62890 Olive Barber Rd. Coos Bay OR	[illegible]
2 Curt Clay	[illegible]	POB 822 CB 97420	
3 Claudia Turner	Claudia Turner	91498 Myrtle Ln Coquille, OR	rive (5
4 CHARLES W. TURNER	[illegible]	91498 MYRTLE LN. Coquille OR	(5
5 Joyce Fletcher	Joyce Fletcher	2064 Marion St. Apt D North Bend, Or 97459	
6 C Jones	Candy Jones	NB, OR	5
7 Tom Gregory	Tom Gregory	155 S Mill CB	
8 [illegible]	Andie Jonson	1381 Central Ave. Coos Bay 97420	54
9 Sarah Brunnier	Sarah Brunnier	935 S. 11th St., B Coos Bay, OR 97420	5
10 DAVID A OSIER	[illegible]	3490 BRUSSELLS ST. N.B. OR	5[illegible]

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Leslie Darryl Pirell	[signature]	63627 N Olive Rd Coos Bay Or.	5
2 Elizabeth H Coleman	Elizabeth T Coleman	P.O. Box 3354 CB OR 97420	5
3 Joseph Coleman	Joseph Coleman	P.O. Box 3354 C.B, OR 97420	
4 MARCUS SORLIE	Marcus Sorlie	PO BOX 363 Ethel, WA.	3
5 anthony Hajek	anthony Hajek	1530 Newmark Ave, Apt A Coos Bay	54
6 Jeanine Miller	Jeanine Miller	93346 N. Park Ln. Coos Bay	54
7 Ken Silup	Ken Silup	Pigeon Pt	5
8 Russell Tupac	Russ Tupac	90563 Cape Arago Hwy	54
9 Cherilyn Tupac	Cherilyn Tupac	90563 Cape Arago Hwy	54
10 Jeff Post	Jeffrey W. Post	91454 Span Ln, Cs.by OR	E-mai 541

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Carol Sanders	Carol Sanders	664 S. Empire	[illegible]
2 Judy Wagner	Judy Wagner	2465 Troy Ln. N.B.	
3 Karen Goette	Karen Goette	93649 Bay Park Ln C Bay	
4 Huie D. Knight Jr / Huie D Knight		99338 Lone Pine Ln. M.P.	5
5 Wm B Spellman	Wm B Spellman	694 S. Wasson C.B. OR	5
6 Mary-Margaret Stockert	Mary-Margaret Stockert	500 Edwards Ave, CB, OR	[illegible]
7 William Crombie	William Crombie	500 Edwards Ave., CB, OR	[illegible]
8 V. Sue Pearson	V. Sue Pearson	63715 Flanagan Rd. CB	[illegible]
9 Len Milbyer	Len Milbyer	1905 lindberg ave. CB OR	5 / 1
10 Kevin Bowman	Kevin Bowman	PO Box 5766 Charleston OR 97420	

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Don Sternberg	[signature]	OIMB	
2 Corena Perry	[signature]	Bandon OR 97411	
3 Lisa Fisher	[signature]	342 S. Marple St.	
4 Karen Wright	[signature]	342 S. Marple St.	
5 Mike Detwiler	[signature]	92723 Hyland Lane	
6 LINDA MINCHER	[signature]	395 BUSHNELL DR. WINSTON, OR 97496	
7 DEBORAH MARTIN	[signature]	825 A. St. MYRTLE POINT, OR 97458	
8 Marynett Davis	MARYNETT DAVIS	135 sp 8 Camas St.	
9 Sandy Thomson	S Thomson	879 S Marple	
10 Sondra Gomez	SONDRA GOMEZ	879 S. Marple	

Please return petition, completed or not, to: **Citizens Against LNG, P.O. Box 1113, North Bend, OR 97459**

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Anna-Marie Slate	Anna-Marie Slate	827 S. 5th St. Apt. #7 CB OR 97420	[illegible]
2 Sherri Ross	Sherri L. Ross	64218 Braley Rd CB OR 97420	
3 Tony Ross	Tony Ross	" " "	
4 Dave Holmes	[illegible]	91354 ~~Barkow~~ → Barklow Ln.	[illegible]
5 Charity Lewis	[illegible]	245 S. Shoreman apt C-1 CB	[illegible]
6 Woody Stokes Jr	Woody Stokes JR	250 S. Marple #10 Coos Bay	[illegible]
7 Austin R.	Austin Rairyhow	245 S. Shoreman apt 6	
8 Sarah Lusk	S. Lusk	OIMB	[illegible]
9 Thomas Van Hoef	Thomas Van Hoef		[illegible]
10 Jessica Butt	Jessica Butt	OIMB	[illegible]

Please return petition, completed or not, to: **Citizens Against LNG, P.O. Box 1113, North Bend, OR 97459**

-----PROTECT COOS, DOUGLAS, JACKSON, & KLAMATH COUNTIES & THE STATE OF OREGON-----

STOP LNG TERMINAL & PACIFIC CONNECTOR GAS PIPELINE

PETITION TO PREVENT LNG EXPORT TERMINAL & STORAGE TANK FACILITY; PASSAGE OF LNG TRANSPORT VESSELS THROUGH THE COOS BAY HARBOR & CHANNEL; AND TO STOP THE 230 MILE, 36 INCH PACIFIC CONNECTOR GAS PIPELINE TO THE CALIFORNIA BORDER.

To State of Oregon Governor John Kitzhaber and to his appointed Port of Coos Bay Commissioners; to the Commissioners of Coos, Douglas, Jackson, & Klamath County Oregon; to those elected by the people of Oregon who represent the people of Oregon in any state or federal office; and to any person or persons elected by the people or appointed to represent the public trust and interest of the citizens of the State of Oregon.

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	NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1	Clarence Adams	Clarence Adam	2039 Ireland Rd Winston	
2	EUGENE Scott	Eugene Scott	1909 Richardson Myrtle Ck.	
3	Richard Kremer	Richard Kremer	191 Weigle Rd. M. C	
4	Sandra Kremer	Sandra Kremer	PO Box 713 191 Weigle Rd., MyrtleCreek	
5	Diane E Phillips	Diane E. Phillips	PO Box 179 1746 Quines Ck Rd, Azalea	
6	Madalyn Dixon	Madalyn [illegible]	Box 753 Canyonville OR 97417	
7	Michael DIXON	Michael Dixon	Box 753 Canyonville OR 97417	
8	Jenny Council	[illegible]	886 Raven Lane, Roseburg 97471	
9	Bill Gow	Bill Gow	4993 Clarks Branch Rd. Roseburg, OR 97470	
10	M.A. HANSEN	MA Hansen	548 W Hickory St. & 32404 Bilger Creek Rd	

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Joan Dahlman	Joan Dahlman	344 Honey Run Ln Winston	
2 JAMES DAHLMAN	James E. Dahlman	344 HONEY RUN LN, WINSTON	
3 LOUIS DYKSTRA	Louis Dykstra	984 WAGONTIRE M.C.	
4 John Roberts	JOHN ROBERTS	2525 OLD FERRY RD. Shady Cove 97539	
5 Lynn H. Quam	Lynn H. Quam	3150 Olalla Rd, Winston	
6 FRANK C Adams	Frank C Adams	1731 Ireland Rd Winston OR 97496	
7 Raynor L Clack	Raynor L Clack	5589 N Myrtle Myrtle Creek. Ore. 97457	
8 CALVIN D. CLACK	Calvin D. Clack	660 Bilger rd Myrtle Creek Ore 97457	
9 Ruben Escalela	Ruben Escalera	203 BUCKBOARD LN MYRTLE CREEK 97457	
10 Laura Escalera	Laura Escalera	203 Buckboard LN. Myrtle Creek, OR. 97457	

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 Lesley Adams	[signature]	P.O. Box 533 Ashland OR 97520	
2 ANNE TAGGART TUNZI	[signature]	5622 N. Myrtle Rd. Myrtle Creek OR 97457	
3 JONATHAN HANSON	[signature]	62890 OLIVE BARBER RD. COOS BAY, OR 97420	
4 ~~MA Rohrer~~	~~[signature]~~	~~68765 Wildwood Road~~ ~~93558 Hollow Stu~~ ~~North Bend OR 97459~~	
5 MA Rohrer	[signature]	93558 Hollow Stump Lane North Bend OR 97459	
6 BILL ROHRER	[signature]	93558 HOLLOW STUMP LN. NORTH BEND OR. 97459	
7 RONNIE HERNE	[signature]	62650 FAIRVIEW ROAD COQUILLE OREGON 97423	
8 JAYE BELL	[signature]	62650 FAIRVIEW ROAD COQUILLE, OREGON 97423	
9 GENE LAROCHELLE	[signature]	1148 CALIFORNIA AVE COOS BAY, OR 97420	
10 WILLARD L. MCCAFFREE	[signature]	2650 CEDAR ST. NORTH BEND, OR 97459	

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 David Midcap	[signature]	148 S Wasson	54
2 Terri D Richter	[signature]	64710-A Washington Rd. CB	54
3 Richard F. Knoblin	[signature]	555 Delaware St. N.B. 97459	5
4 PETER S RYAN	[signature]	96078 Dean Mtn NB 97459	54
5 VERNE HERZ	[signature]	525 SO. MARPLE ST. COOS BAY OR 97420	5 PA
6 Mary Thegg	[signature]	1152 S.W. Blvd	5
7 BETSEY Fleming	[signature]	P.O. Box 3566, Coos Bay, OR 97420	
8 MATTHEW MURRAY	[signature]	277 S. Empire Blvd. Coos Bay OR 97420	5 TT
9 DEBRA WEST	[signature]	507 Clark St CB OR 97549	5
10			

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NAME (Print)	SIGNATURE	ADDRESS	PHONE / EMAIL
1 PAULA HOEHN	Paula Hoehn	63021 CROWN POINT Rd, COOS BAY, OR 97420	
2 William HOEHN	William Hoehn	63021 CROWN POINT Rd COOS BAY OR. 97420	
3			
4			
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8			
9			
10			

Please return petition, completed or not, to: **Citizens Against LNG, P.O. Box 1113, North Bend, OR 97459**

Jody McCaffree
Individual / Executive Director
Citizens Against LNG
PO Box 1113
North Bend, OR 97459

September 12, 2012

By Email
fergas@hq.doe.gov
larine.moore@hq.doe.gov

Ms. Larine A. Moore
Docket Room Manager
FE-34
U.S. Department of Energy
PO Box 44375
Washington, D.C. 20026-4375

Re: Answer of Jordan Cove Energy Project, L.P. to Protests of Application for Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations, FE Docket No. 12-32-LNG

Dear Ms. Moore:

Please accept for filing the following response of Citizens Against LNG to the recent "Answer" filed by the Jordan Cove Energy Project (JCEP) dated August 29, 2012. We received this document by postal mail only a few days ago and even though the document has yet to appear in the U.S. Department of Energy Office of Fossil Energy e-library web portal for FE Docket No. 12–32–LNG, we feel a response is warranted in this case.

The Jordan Cove "Answer" included yet another ECONorthwest report that was dated May 14, 2012, and titled, "*The Impact of the Jordan Cove Energy Project on Coos County Housing and Schools.*" As previously explained in our August 6, 2012, protest comments, the U.S. Department of Energy Office of Fossil Energy should take a closer look into the ECONorthwest reports being submitted by the Jordan Cove Energy Project. The following supporting evidence is being provided to you in addition to our previously submitted documentation to help give you a better understanding as to why a thorough independent economic analysis is in order by the U.S. Department of Energy.

In October 2006 the South Coast Development Council (SCDC) in Coos Bay, Oregon, who fully supported the proposed Jordan Cove liquefied natural gas (LNG) import project, engaged the Portland-based ECONorthwest to forecast the net economic benefits of the proposed Jordan Cove LNG project. The report, "*Forecast of the Net Economic Benefits of a Proposed LNG*

Terminal in Coos County, Oregon," [1] was used as a justification for the Jordan Cove LNG import facility and was relied on by the Federal Energy Regulatory Commission (FERC) in the preparation of the Environmental Impact Statement (EIS) that led to the FERC Order approving the project in 2009. The ECONorthwest report was flawed for several reasons in that it did not include negative economic impacts that would have occurred as a result of the proposed Jordan Cove LNG import facility, nor did the report confirm the specifics as to the high number of jobs they were predicting would result due to Jordan Cove's operations. We now know the 2006 predictions and projections by ECONorthwest were incorrect. On Feb. 29, 2012, Jordan Cove notified FERC that due to current market conditions they no longer intended to implement their Dec. 17, 2009, FERC Order authorizing them to construct and operate a LNG import terminal. FERC vacated the Order for the Jordan Cove import project on April 16, 2012. Obviously the Jordan Cove Energy Project would not have produced the economic benefits and jobs that the 2006 ECONorthwest report had predicted would occur from the importation of LNG.

The U.S. Department of Energy should consider taking a thorough investigative review of the ECONorthwest reports similar to what the United States Department of Agricultural (USDA) Rural Development did in 2008. In December of 2008, the USDA Rural Development questioned the reliability and accuracy of an ECONorthwest report that was being used to justify a $6 million dollar proposed expansion of the Salmon Harbor resort in Winchester Bay, Oregon. The USDA did their own investigation and found the ECONorthwest projections used to justify the proposed expansion were not feasible, nor were the ECONorthwest conclusions warranted. As a result of the investigation, the USDA pulled their funding for that proposed project. (See Exhibit A) Likewise, the U.S. Department of Energy Office of Fossil Energy should not rely solely on the economic projections being provided by the Jordan Cove Energy Project. Before our property rights, businesses, people and the environment are potentially put at risk there should be an in-depth, complete and accurate economic analysis that includes the impacts on the public both now and in the future from exporting LNG. As we stated earlier in our August 6, 2012, protest comments on page 7:

> "Jordan Cove has already demonstrated its inability to predict demand for natural gas imports and exports. Jordan Cove based the proposed Jordan Cove LNG import terminal in Coos Bay on predictions that an import facility would be needed to meet growing U.S. demand for natural gas imports from overseas. These predictions turned out to be wrong.
>
> "Jordan Cove's assumption about sustained Asian demand for LNG imports is likely to be wrong as well; the same factors that created an oversupply of domestic natural gas would likely also create an oversupply of natural gas in Asia, curtailing demand for LNG imports from the U.S. and rendering a West Coast-based LNG export facility economically unviable…."

An example of the kind of economic analysis that should be done by the U.S. Department of Energy can be found in the 2006 Passamaquoddy Whole Bay Study (Part 1) that was completed

[1] "*Forecast of the Net Economic Benefits of a Proposed LNG Terminal in Coos County, Oregon*" An Economic Impact Analysis Prepared for the South Coast Development Council – October 16, 2006 ; ECONorthwest

by Yellow Wood Associates, Inc.[2] Citizens of three nations, the United States, Canada and the Passamaquoddy Tribe, commissioned the Whole Bay Study to determine what the potential costs and benefits of one or more LNG terminals in Passamaquoddy Bay would mean from the perspective of Bay communities. The focus of the Part 1 Whole Bay Study was on direct employment impacts on local residents and businesses, economic impacts on the real estate market, and fiscal impacts related to community infrastructure, transportation, housing, public safety and property values.

Unlike the ECONorthwest reports being presented to the U.S. Department of Energy Office of Fossil Energy by the Jordan Cove Energy Project, the Passamaquoddy Whole Bay Study looked at both economic benefit and loss. Part 1 of the Whole Bay Study concluded that there was no net gain that was realized overall by these LNG facilities and that the economic stimulus provided to a region by one or more LNG import terminals would be limited. The study also concluded the following:

> "…LNG is not a local resource. The beneficiaries of LNG development, including both investors and consumers, will be overwhelmingly from away. LNG is not a renewable resource. LNG is not an inexpensive form of energy. Even if LNG were made available through pipeline extensions and connections to local communities, it would not shield these communities from price hikes dictated by multinational corporations and the global economy. Nor would it increase the capacity of local communities to meet their own energy needs affordably today and in the future…
>
> "...**Economic Diversification**
> A diversified economic base in which the elements are compatible and synergistic is widely viewed as contributing to the health, resiliency, and vitality of rural communities. Diversity means that no single employer dominates the market, no single landowner dominates the tax rolls, and no single buyer determines the fate of the community.
>
> " Several of the LNG terminals proposed for Passamaquoddy Bay communities are offering millions of dollars in "support" to host communities in an attempt to make their development proposals more palatable. Although millions of dollars sounds like (and is) a lot of money in the context of a small rural community, in the context of LNG, it is very little. Each proposed terminal on Passamaquoddy Bay has the capacity to handle more than $1 billion worth of natural gas each year at present prices. Local communities need to be aware of the trade-offs made in accepting such "support." Once a single corporate entity comprises the majority of the tax base, communities rapidly lose the capacity and ability to make independent decisions regarding local services and investments..."[3]"

---

[2] "*Report on Potential Economic and Fiscal Impacts of LNG Terminals on the Whole Passamaquoddy Bay*". Prepared by Yellow Wood Associates, Inc – June 20th 2006
http://www.savepassamaquoddybay.org/documents/community_impact_studies/whole_bay_study/whole_bay_study/WholeBayStudy-Part_1.pdf
"*Study: Impacts of LNG costly, benefit limited*", Edward French; THE QUODDY TIDES Newspaper; Vol. 38, No. 14; June 23, 2006; http://quoddytides.com/lng6-23-06.html

[3] "*Report on Potential Economic and Fiscal Impacts of LNG Terminals on the Whole Passamaquoddy Bay*". Prepared by Yellow Wood Associates, Inc – June 20th 2006 – Page 121

The Yellow Wood Associates determined that a more thorough study would be required to determine the extent to which any economic gains that do result from LNG may be offset by damage to existing sections and that may create new obstacles of future economic diversification and sustainability.

Citizens in rural poor areas such as Coos Bay, Oregon, do not have the resources that the multinational corporations and the gas and oil industry have to conduct such a thorough independent analysis. We citizens depend on agencies such and the United States Department of Agricultural (USDA) Rural Development and the U.S. Department of Energy to do such an analysis for us and to make sure their decisions are in the public interest.

It would "not" be in the public interest of our fishing, timber, clamming, crabbing, oyster growing, farming, tourism, recreation and industries that use natural gas for the U.S. Department of Energy to make a decision on Jordan Cove exporting LNG to non-free trade agreement nations based solely on economic projections and reports provided by the Jordan Cove Energy Project. The decision as to whether Jordan Cove should be allowed to export LNG to nations that do not have a free trade agreements with the United States should be based on a rigorous independent economic and environmental impact analysis that includes "all" potential impacts (both negative and positive) of exporting natural gas from both natural gas produced domestically in the United States and natural gas produced in Canada. The analysis should encompass all proposed and potential LNG export proposals in North America.

Sincerely,

/s/ Jody McCaffree

Jody McCaffree

cc:
DOE/FE
john.anderson@hq.doe.gov
marc.talbert@hq.doe.gov
DOE/GC
edward.myers@hq.doe.gov

By postal mail to all persons listed in the Service list for FE Docket No. 12-32-LNG

The World – Coos Bay
http://theworldlink.com/news/local/feds-say-no-to-resort-funding/article_9b6904dc-b754-5a19-a23c-409471752788.html

Feds say no to resort funding

Monday, December 28, 2009 By Alex Powers, Reedsport Staff Writer

REEDSPORT — Federal officials have pulled funding for the Salmon Harbor Marina's proposed Phase III expansion to its resort.

In a letter dated Dec. 14 to the Port of Umpqua, Clem Singer, Roseburg area director for USDA Rural Development, told commissioners "there remains some serious doubt" if the expansion could pay for itself.

The nearly $6 million expansion calls for 46 new campsites, a bathroom and an about $1.8 million, 9,576-square-foot community building in Winchester Bay. According to an economic impact study prepared in 2008 by Portland-based ECONorthwest, that center could draw guests to the park during winter, a time of year that historically sees low usage from RVs. The study said in its first year, the expanded RV resort is expected to make $426,855 and more each year after that.

"It's not feasible. That building is not going to pay for itself. It's just not," Singer said.

Singer said USDA was not satisfied with ECO Northwest's projections.

"The conclusions that they drew weren't warranted, in our opinion," he said.

He said USDA also examined the occupancy earlier this year at Lakeside's Osprey Point RV Resort, Woahink Lake RV Resort and Sea Perch RV Resort in Yachats.

"All three of those, we were told, have high wintertime occupancy," Singer said.

USDA found they have few guests during winter.

Harbor Master Jeff Vander Kley said Salmon Harbor cannot become a special district and tax for revenue. It may look to Douglas County for assistance.

"This effort to expand the RV resort was to reduce the need for the county … contributions to the operations," Vander Kley said. "It's a big conundrum."

County Commissioner Susan Morgan asked the marina earlier this month to re-evaluate ECONorthwest's analysis.

Marina project manager Linda Noel said the marina probably will plug updated cashflow information from the resort into the original report, while Vander Kley said the agency may consider downsizing or phasing the project.

CERTIFICATE OF SERVICE

I hereby certify that in accordance with 10 C.F.R. § 509.107 (c), I have this 12th day of September 2012 caused a copy of the foregoing to be served by mail to the following individuals listed in the Service list for FE Docket 12-32 LNG:

Elliott L. Trepper, President
Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay OR 97420

Joan M. Darby, Attorney for Jordan Cove Energy Project
Dickstein Shapiro LLP
1825 Eye Street NW
Washington DC 20006-5403

Clarence Adams
Landowners United
2039 Ireland Road
Winston, OR 97496

David Schryver, Executive Vice President
The American Public Gas Association
201 Massachusetts Avenue , Suite C-4
Washington DC 20002

William T. Miller, Attorney
Miller, Balis & O'Neil, P.C.
Twelfth Floor
1015 Fifteenth Street, N.W.
Washington DC 20005

Lesley Adams,Program Director
Rogue Riverkeeper
P.O. Box 102
Ashland, OR 97520

Joseph Vaile, Program Director
Klamath-Siskiyou Wildlands Center
P.O. Box 102
Ashland, OR 97520

Nathan Matthews, Attorney
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Kathleen Krust, Paralegal
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Sincerely,

/s/ Jody McCaffree

Jody McCaffree

United States Government Accountability Office

GAO

Report to Congressional Requesters

September 2012

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

GAO-12-732

September 2012

GAO Highlights

Highlights of GAO-12-732, a report to congressional requesters

OIL AND GAS

Information on Shale Resources, Development, and Environmental and Public Health Risks

Why GAO Did This Study

New applications of horizontal drilling techniques and hydraulic fracturing—in which water, sand, and chemical additives are injected under high pressure to create and maintain fractures in underground formations—allow oil and natural gas from shale formations (known as "shale oil" and "shale gas") to be developed. As exploration and development of shale oil and gas have increased—including in areas of the country without a history of oil and natural gas development—questions have been raised about the estimates of the size of these resources, as well as the processes used to extract them.

GAO was asked to determine what is known about the (1) size of shale oil and gas resources and the amount produced from 2007 through 2011 and (2) environmental and public health risks associated with the development of shale oil and gas. GAO reviewed estimates and data from federal and nongovernmental organizations on the size and production of shale oil and gas resources. GAO also interviewed federal and state regulatory officials, representatives from industry and environmental organizations, oil and gas operators, and researchers from academic institutions.

GAO is not making any recommendations in this report. We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review. The Department of the Interior and the Environmental Protection Agency provided technical comments, which we incorporated as appropriate. The Department of Energy did not provide comments.

View GAO-12-732. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

Estimates of the size of shale oil and gas resources in the United States by the Energy Information Administration (EIA), U.S. Geological Survey (USGS), and the Potential Gas Committee—three organizations that estimate the size of these resources—have increased over the last 5 years, which could mean an increase in the nation's energy portfolio. For example, in 2012, EIA estimated that the amount of technically recoverable shale gas in the United States was 482 trillion cubic feet—an increase of 280 percent from EIA's 2008 estimate. However, according to EIA and USGS officials, estimates of the size of shale oil and gas resources in the United States are highly dependent on the data, methodologies, model structures, and assumptions used to develop them. In addition, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. Estimates are based on data available at a given point in time and will change as additional information becomes available. In addition, domestic shale oil and gas production has experienced substantial growth; shale oil production increased more than fivefold from 2007 to 2011, and shale gas production increased more than fourfold from 2007 to 2011.

Oil and gas development, whether conventional or shale oil and gas, pose inherent environmental and public health risks, but the extent of these risks associated with shale oil and gas development is unknown, in part, because the studies GAO reviewed do not generally take into account the potential long-term, cumulative effects. For example, according to a number of studies and publications GAO reviewed, shale oil and gas development poses risks to air quality, generally as the result of (1) engine exhaust from increased truck traffic, (2) emissions from diesel-powered pumps used to power equipment, (3) gas that is flared (burned) or vented (released directly into the atmosphere) for operational reasons, and (4) unintentional emissions of pollutants from faulty equipment or impoundments—temporary storage areas. Similarly, a number of studies and publications GAO reviewed indicate that shale oil and gas development poses risks to water quality from contamination of surface water and groundwater as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gases and chemicals. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In addition, shale oil and gas development poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting fluids underground. However, the extent of these risks is unknown. For example, the studies and publications GAO reviewed on air quality conditions provide information for a specific site at a specific time but do not provide the information needed to determine the overall cumulative effects that shale oil and gas activities may have on air quality. Further, the extent and severity of environmental and public health risks identified in the studies and publications GAO reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations; climatic conditions; business practices; and regulatory and enforcement activities.

Contents

Abbreviations

BLM	Bureau of Land Management
Btu	British thermal unit
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
NORM	naturally occurring radioactive materials
Tcf	technically recoverable gas
USGS	U.S. Geological Survey

United States Government Accountability Office
Washington, DC 20548

September 5, 2012

Congressional Requesters

For decades, the United States has relied on imports of oil and natural gas to meet domestic needs. As recently as 2007, the expectation was that the nation would increasingly rely on imports of natural gas to meet its growing demand. However, recent improvements in technology have allowed companies that develop petroleum resources to extract oil and natural gas from shale formations,[1] known as "shale oil" and "shale gas," respectively, which were previously inaccessible because traditional techniques did not yield sufficient amounts for economically viable production. In particular, as we reported in January 2012, new applications of horizontal drilling techniques and hydraulic fracturing—a process that injects a combination of water, sand, and chemical additives under high pressure to create and maintain fractures in underground rock formations that allow oil and natural gas to flow—have prompted a boom in shale oil and gas production.[2] According to the Department of Energy (DOE), America's shale gas resource base is abundant, and development of this resource could have beneficial effects for the nation, such as job creation.[3] According to a report by the Baker Institute, domestic shale gas development could limit the need for expensive imports of these resources—helping to reduce the U.S. trade deficit.[4] In addition, replacing older coal burning power generation with new natural gas-fired generators could reduce greenhouse gas emissions and result in fewer air pollutants

[1]Shale oil differs from "oil shale." Shale is a sedimentary rock that is predominantly composed of consolidated clay-sized particles. Oil shale requires a different process to extract. Specifically, to extract the oil from oil shale, the rock needs to be heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. Oil shale is not currently economically viable to produce. For additional information on oil shale, see GAO, *Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development*, GAO-11-35 (Washington, D.C.: Oct. 29, 2010).

[2]GAO, *Energy-Water Nexus: Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production*, GAO-12-156 (Washington, D.C.: Jan. 9, 2012).

[3]EIA is a statistical agency within DOE that provides independent data, forecasts, and analyses.

[4]The Baker Institute is a public policy think tank located on the Rice University campus.

for the same amount of electric power generated.[5] Early drilling activity in shale formations was centered primarily on natural gas, but with the falling price of natural gas companies switched their focus to oil and natural gas liquids, which are a more valuable product.[6]

As exploration and development of shale oil and gas have increased in recent years—including in areas of the country without a history of oil and natural gas activities—questions have been raised about the estimates of the size of domestic shale oil and gas resources, as well as the processes used to extract them.[7] For example, some organizations have questioned the accuracy of the estimates of the shale gas supply. In particular, some news organizations have reported concerns that such estimates may be inflated. In addition, concerns about environmental and public health effects of the increased use of horizontal drilling and hydraulic fracturing, particularly on air quality and water resources, have garnered extensive public attention. According to the International Energy Agency, some questions also exist about whether switching from coal to natural gas will lead to a reduction in greenhouse gas emissions—based, in part, on uncertainty about additional emissions from the development of shale gas. These concerns and other considerations have led some communities and certain states to impose restrictions or moratoriums on drilling operations to allow time to study and better understand the potential risks associated with these practices.

In this context, you asked us to provide information on shale oil and gas. This report describes what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.[8]

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[5]EIA reported that using natural gas over coal would lower emissions in the United States, but some researchers have reported that greater reliance on natural gas would fail to significantly slow climate change.

[6]The natural gas liquids include propane, butane, and ethane, and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants.

[7]For the purposes of this report, resources represent all oil or natural gas contained within a formation and can be divided into resources and reserves.

[8]For the purposes of this report, we refer to risk as a threat or vulnerability that has potential to cause harm.

To determine what is known about the size of shale oil and gas resources and the amount of shale oil and gas produced, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the EIA, the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academics and industry representatives. We interviewed key officials from these agencies and the committee about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators—companies that develop petroleum resources to extract oil and natural gas.[9] To determine what is known about the amount of shale oil and gas produced from 2007 through 2011, we obtained data from EIA—which is responsible for estimating and reporting this and other energy information. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection efforts. We also met with officials from states, representatives from private industry, and researchers from academic institutions who are familiar with these data and EIA's methodology. We discussed the sources and reliability of the data with these officials and found the data sufficiently reliable for the purposes of this report. For all estimates we report, we reviewed the methodologies used to derive them and also found them sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas,[10] we reviewed studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. We identified these studies by conducting

[9]Proved reserves refer to the amount of oil and gas that have been discovered and defined.

[10]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale, but for the purposes of this report we focused on development of shale formations. Specifically, coalbed methane and tight sandstone formations may rely on these practices and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on shale formations.

a literature search, and by asking for recommendations during interviews with federal, state, and tribal officials; representatives from industry, trade organizations, environmental, and other nongovernmental groups; and researchers from academic institutions. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified currently known potential risks for shale oil and gas development. However, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas wells may be constructed. Second, the extent to which operators use effective best management practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few studies that are based on comparing predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse conditions to shale oil and gas development. In addition, changes to the federal, state, and local regulatory environments and the effectiveness of implementing and enforcing regulations will affect operators' future activities and, therefore, the level of risk associated with future development of oil and gas resources. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices which, in turn, may vary across oil and gas companies, making it difficult to distinguish between risks associated with the process to develop shale oil and gas from risks that are specific to particular business practices. To obtain additional perspectives on issues related to environmental and public health risks, we interviewed federal officials from DOE's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management (BLM) and Bureau of Indian Affairs, and the Environmental Protection Agency (EPA); state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas;[11] tribal officials from the Osage Nation; shale oil and gas operators;

[11]We selected these states because they are involved with shale oil and gas development.

representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. Appendix I provides additional information on our scope and methodology.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

This section includes (1) an overview of oil and natural gas, (2) the shale oil and gas development process, (3) the regulatory framework, (4) the location of shale oil and gas in the United States, and (5) information on estimating the size of these resources.

Overview

Oil and natural gas are found in a variety of geologic formations. Conventional oil and natural gas are found in deep, porous rock or reservoirs and can flow under natural pressure to the surface after drilling. In contrast to the free-flowing resources found in conventional formations, the low permeability of some formations, including shale, means that oil and gas trapped in the formation cannot move easily within the rock. On one extreme—oil shale, for example—the hydrocarbon trapped in the shale will not reach a liquid form without first being heated to very high temperatures—ranging from about 650 to 1,000 degrees Fahrenheit—in a process known as retorting. In contrast, to extract shale oil and gas from the rock, fluids and proppants (usually sand or ceramic beads used to hold fractures open in the formation) are injected under high pressure to create and maintain fractures to increase permeability, thus allowing oil or gas to be extracted. Other formations, such as coalbed methane formations and tight sandstone formations,[12] may also require stimulation to allow oil or gas to be extracted.[13]

Most of the energy used in the United States comes from fossil fuels such as oil and natural gas. Oil supplies more than 35 percent of all the energy the country consumes, and almost the entire U.S. transportation fleet—cars, trucks, trains, and airplanes—depends on fuels made from oil. Natural gas is an important energy source to heat buildings, power the industrial sector, and generate electricity. Natural gas provides more than 20 percent of the energy used in the United States,[14] supplying nearly half of all the energy used for cooking, heating, and powering other home appliances, and generating almost one-quarter of U.S. electricity supplies.

The Shale Oil and Gas Development Process

The process to develop shale oil and gas is similar to the process for conventional onshore oil and gas, but shale formations may rely on the use of horizontal drilling and hydraulic fracturing—which may or may not be used on conventional wells. Horizontal drilling and hydraulic fracturing are not new technologies, as seen in figure 1, but advancements, refinements, and new uses of these technologies have greatly expanded oil and gas operators' abilities to use these processes to economically develop shale oil and gas resources. For example, the use of multistage hydraulic fracturing within a horizontal well has only been widely used in the last decade.[15]

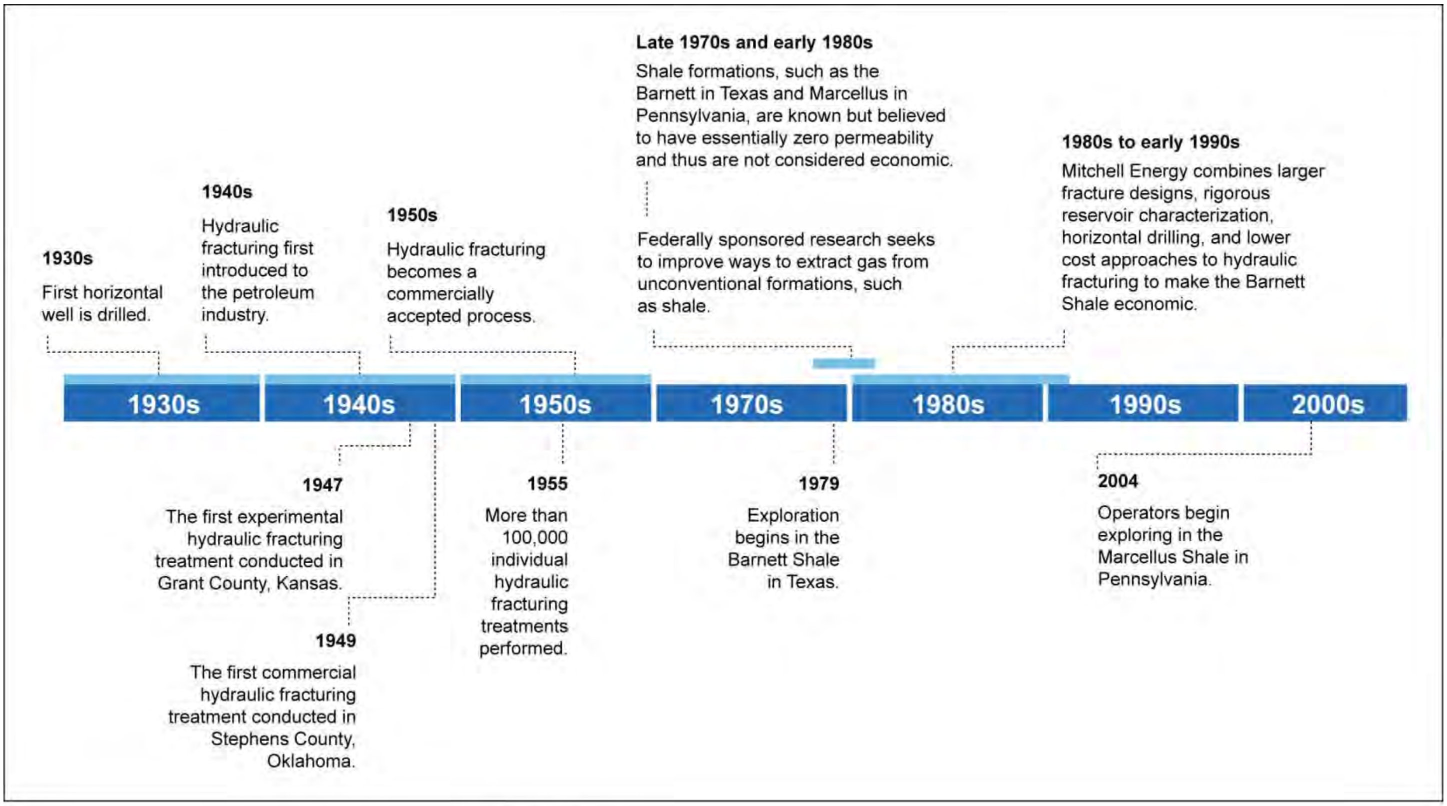
[12]Conventional sandstone has well-connected pores, but tight sandstone has irregularly distributed and poorly connected pores. Due to this low connectivity or permeability, gas trapped within tight sandstone is not easily produced.

[13]For coalbed methane formations, the reduction in pressure needed to extract gas is achieved through dewatering. As water is pumped out of the coal seams, reservoir pressure decreases, allowing the natural gas to release (desorb) from the surface of the coal and flow through natural fracture networks into the well.

[14]Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, a special report prepared at the request of the Department of Energy (Washington, D.C.: April 2009).

[15]Hydraulic fracturing is often conducted in stages. Each stage focuses on a limited linear section and may be repeated numerous times.

Figure 1: History of Horizontal Drilling and Hydraulic Fracturing



Source: GAO.

First, operators locate suitable shale oil and gas targets using seismic methods of exploration,[16] negotiate contracts or leases that allow mineral development, identify a specific location for drilling, and obtain necessary permits; then, they undertake a number of activities to develop shale oil and gas. The specific activities and steps taken to extract shale oil and gas vary based on the characteristics of the formation, but the development phase generally involves the following stages: (1) well pad

[16]The seismic method of exploration introduces energy into the subsurface through explosions in shallow “shot holes” by striking the ground forcefully (with a truck-mounted thumper), or by vibration methods. A portion of the energy returns to the surface after being reflected from the subsurface strata. This energy is detected by surface instruments, called geophones, and the information carried by the energy is processed by computers to interpret subsurface conditions.

preparation and construction, (2) drilling and well construction, and (3) hydraulic fracturing.[17]

Well Pad Preparation and Construction

The first stage in the development process is to prepare and construct the well pad site. Typically, operators must clear and level surface vegetation to make room for numerous vehicles and heavy equipment—such as the drilling rig—and to build infrastructure—such as roads—needed to access the site.[18] Then operators must transport the equipment that mixes the additives, water, and sand needed for hydraulic fracturing to the site—tanks, water pumps, and blender pumps, as well as water and sand storage tanks, monitoring equipment, and additive storage containers . Based on the geological characteristics of the formation and climatic conditions, operators may (1) excavate a pit or impoundment to store freshwater, drilling fluids, or drill cuttings—rock cuttings generated during drilling; (2) use tanks to store materials; or (3) build temporary transfer pipes to transport materials to and from an off-site location.

Drilling and Well Construction

The next stage in the development process is drilling and well construction. Operators drill a hole (referred to as the wellbore) into the earth through a combination of vertical and horizontal drilling techniques. At several points in the drilling process, the drill string and bit are removed from the wellbore so that casing and cement may be inserted. Casing is a metal pipe that is inserted inside the wellbore to prevent high-pressure fluids outside the formation from entering the well and to prevent drilling mud inside the well from fracturing fragile sections of the wellbore. As drilling progresses with depth, casings that are of a smaller diameter than the hole created by the drill bit are inserted into the wellbore and bonded in place with cement, sealing the wellbore from the surrounding formation.

Drilling mud (a lubricant also known as drilling fluid) is pumped through the wellbore at different densities to balance the pressure inside the wellbore and bring rock particles and other matter cut from the formation back to the rig. A blowout preventer is installed over the well as a safety measure to prevent any uncontrolled release of oil or gas and help

[17]The specific order of activities and steps may vary.

[18]According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, the average size of a well pad is 3.5 acres.

maintain control over pressures in the well. Drill cuttings, which are made up of ground rock coated with a layer of drilling mud or fluid, are brought to the surface. Mud pits provide a reservoir for mixing and holding the drilling mud. At the completion of drilling, the drilling mud may be recycled for use at another drilling operation.

Instruments guide drilling operators to the "kickoff point"—the point that drilling starts to turn at a slight angle and continues turning until it nears the shale formation and extends horizontally. Production casing and cement are then inserted to extend the length of the borehole to maintain wellbore integrity and prevent any communication between the formation fluids and the wellbore. After the casing is set and cemented, the drilling operator may run a cement evaluation log by lowering an electric probe into the well to measure the quality and placement of the cement. The purpose of the cement evaluation log is to confirm that the cement has the proper strength to function as designed—preventing well fluids from migrating outside the casing and infiltrating overlying formations. After vertical drilling is complete, horizontal drilling is conducted by slowly angling the drill bit until it is drilling horizontally. Horizontal stretches of the well typically range from 2,000 to 6,000 feet long but can be as long as 12,000 feet long, in some cases.

Throughout the drilling process, operators may vent or flare some natural gas, often intermittently, in response to maintenance needs or equipment failures. This natural gas is either released directly into the atmosphere (vented) or burned (flared). In October 2010, we reported on venting and flaring of natural gas on public lands.[19] We reported that vented and flared gas on public lands represents potential lost royalties for the federal government and contributes to greenhouse gas emissions. Specifically, venting releases methane and volatile organic compounds, and flaring emits carbon dioxide, both greenhouse gases that contribute to global climate change. Methane is a particular concern since it is a more potent greenhouse gas than carbon dioxide.

Hydraulic Fracturing

The next stage in the development process is stimulation of the shale formation using hydraulic fracturing. Before operators or service companies perform a hydraulic fracture treatment of a well, a series of

[19] GAO, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 (Washington, D.C.: Oct. 29, 2010).

tests may be conducted to ensure that the well, wellhead equipment, and fracturing equipment can safely withstand the high pressures associated with the fracturing process. Minimum requirements for equipment pressure testing can be determined by state regulatory agencies for operations on state or private lands. In addition, fracturing is conducted below the surface of the earth, sometimes several thousand feet below, and can only be indirectly observed. Therefore, operators may collect subsurface data—such as information on rock stresses[20] and natural fault structures—needed to develop models that predict fracture height, length, and orientation prior to drilling a well. The purpose of modeling is to design a fracturing treatment that optimizes the location and size of induced fractures and maximizes oil or gas production.

To prepare a well to be hydraulically fractured, a perforating tool may be inserted into the casing and used to create holes in the casing and cement. Through these holes, fracturing fluid—that is injected under high pressures—can flow into the shale (fig. 2 shows a used perforating tool).

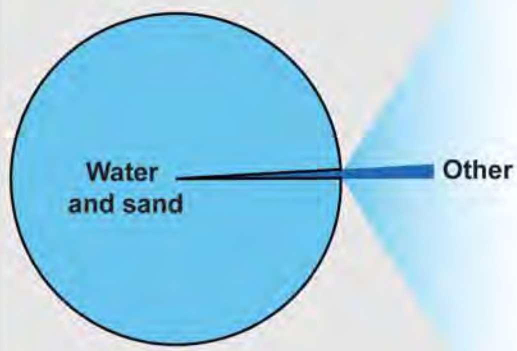
[20]Stresses in the formation generally define a maximum and minimum stress direction that influence the direction a fracture will grow.

Figure 2: Perforating Tool

Source: GAO.

Fracturing fluids are tailored to site specific conditions, such as shale thickness, stress, compressibility, and rigidity. As such, the chemical additives used in a fracture treatment vary. Operators may use computer models that consider local conditions to design site-specific hydraulic fluids. The water, chemicals, and proppant used in fracturing fluid are typically stored on-site in separate tanks and blended just before they are injected into the well. Figure 3 provides greater detail about some chemicals commonly used in fracturing.

Figure 3: Examples of Common Ingredients Found in Fracturing Fluid



Additive type	Use	Main compound
Acid	Removes near well damage	Hydrochloric acid
Biocide	Controls bacterial growth	Glutaraldehyde
Breaker	Delays breakdown of the geling agent	Ammonium persulfate
Corrosion inhibitor	Prevent corrosion of pipe	N,n-dimethyl formamide
Crosslinker	Maintains fluid viscosity as temperature increases	Borate salts
Friction reducers	Decreases pumping friction	Polyacrylamide
Gelling agents	Improves proppant placement	Guar gum
KCl	Creates a brine carrier fluid	Potassium chloride
Oxygen scavenger	Prevents corrosion of well tubulars	Ammonium bisulfite
pH adjusting agent	Adjusts the pH of fluid to maintain the effectiveness of other components	Sodium carbonate
Scale inhibitor	Prevents scale deposits in the pipe	Ethylene glycol
Surfactant	Winterizing agent	Isopropanol

Sources: Department of Energy and Groundwater Protection Council.

The operator pumps the fracturing fluid into the wellbore at pressures high enough to force the fluid through the perforations into the surrounding formation—which can be shale, coalbeds, or tight sandstone—expanding existing fractures and creating new ones in the process. After the fractures are created, the operator reduces the pressure. The proppant stays in the formation to hold open the fractures and allow the release of oil and gas. Some of the fracturing fluid that was injected into the well will return to the surface (commonly referred to as flowback) along with water that occurs naturally in the oil- or gas-bearing formation—collectively referred to as produced water. The produced water is brought to the surface and collected by the operator, where it can be stored on-site in impoundments, injected into underground wells, transported to a wastewater treatment plant, or reused by the operator in other ways.[21] Given the length of horizontal wells, hydraulic fracturing is often conducted in stages, where each stage focuses on a limited linear section and may be repeated numerous times.

Once a well is producing oil or natural gas, equipment and temporary infrastructure associated with drilling and hydraulic fracturing operations is no longer needed and may be removed, leaving only the parts of the infrastructure required to collect and process the oil or gas and ongoing produced water. Operators may begin to reclaim the part of the site that will not be used by restoring the area to predevelopment conditions. Throughout the producing life of an oil or gas well, the operator may find it necessary to periodically restimulate the flow of oil or gas by repeating the hydraulic fracturing process. The frequency of such activity depends on the characteristics of the geologic formation and the economics of the individual well. If the hydraulic fracturing process is repeated, the site and surrounding area will be further affected by the required infrastructure, truck transport, and other activity associated with this process.

Regulatory Framework

Shale oil and gas development, like conventional onshore oil and gas production, is governed by a framework of federal, state, and local laws and regulations. Most shale development in the near future is expected to occur on nonfederal lands and, therefore, states will typically take the lead in regulatory activities. However, in some cases, federal agencies oversee shale oil and gas development. For example, BLM oversees shale oil and gas development on federal lands. In large part, the federal laws, regulations, and permit requirements that apply to conventional onshore oil and gas exploration and production activities also apply to shale oil and gas development.

- *Federal*. A number of federal agencies administer laws and regulations that apply to various phases of shale oil and gas development. For example, BLM manages federal lands and approximately 700 million acres of federal subsurface minerals, also known as the federal mineral estate. EPA administers and enforces key federal laws, such as the Safe Drinking Water Act, to protect

[21] Underground injection is the predominant practice for disposing of produced water. In addition to underground injection, a limited amount of produced water is managed by discharging it to surface water, storing it in surface impoundments, and reusing it for irrigation or hydraulic fracturing.

human health and the environment. Other federal land management agencies, such as the U.S. Department of Agriculture's Forest Service and the Department of the Interior's Fish and Wildlife Service, also manage federal lands, including shale oil and gas development on those lands.

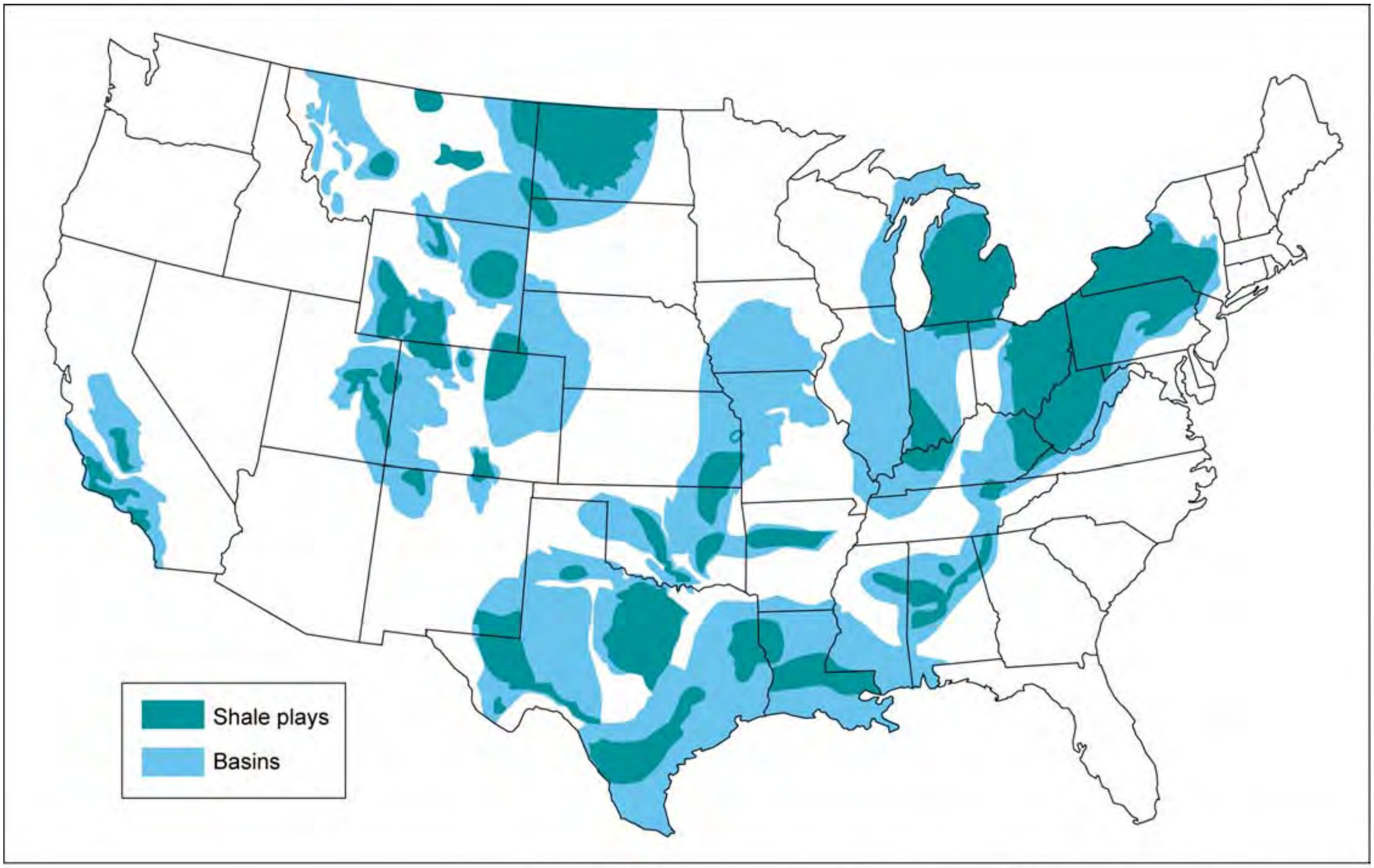
- *State.* State agencies implement and enforce many of the federal environmental regulations and may also have their own set of state laws covering shale oil and gas development.
- *Other.* Additional requirements regarding shale oil and gas operations may be imposed by various levels of government for specific locations. Entities such as cities, counties, tribes, and regional water authorities may set additional requirements that affect the location and operation of wells.

GAO is conducting a separate and more detailed review of the federal and state laws and regulations that apply to unconventional oil and gas development, including shale oil and gas.

Location of Shale Oil and Gas in the United States

Shale oil and gas are found in shale plays—a set of discovered or undiscovered oil and natural gas accumulations or prospects that exhibit similar geological characteristics—on private, state-owned, and federal lands across the United States. Shale plays are located within basins, which are large-scale geological depressions, often hundreds of miles across, that also may contain other oil and gas resources. Figure 4 shows the location of shale plays and basins in the contiguous 48 states.

Figure 4: Shale Plays and Basins in the Contiguous 48 States



Sources: Energy Information Administration (shale location data); (map) copyright © Corel Corp., all rights reserved.

A shale play can be developed for oil, natural gas, or both. In addition, a shale gas play may contain "dry" or "wet" natural gas. Dry natural gas is a mixture of hydrocarbon compounds that exists as a gas both underground in the reservoir and during production under standard temperature and pressure conditions. Wet natural gas contains natural gas liquids, or the portion of the hydrocarbon resource that exists as a gas when in natural underground reservoir conditions but that is liquid at surface conditions. The natural gas liquids are typically propane, butane, and ethane and are separated from the produced gas at the surface in lease separators, field facilities, or gas processing plants. Operators may then sell the natural gas liquids, which may give wet shale gas plays an economic advantage over dry gas plays. Another advantage of liquid petroleum and natural gas liquids is that they can be transported more easily than natural gas. This is because, to bring natural gas to markets and consumers, companies must build an extensive network of gas pipelines. In areas where gas pipelines are not extensive, natural gas produced along with liquids is often vented or flared.

Estimating the Size of Shale Oil and Gas Resources

Estimating the size of shale oil and gas resources serves a variety of needs for consumers, policymakers, land and resource managers, investors, regulators, industry planners, and others. For example, federal and state governments may use resource estimates to estimate future revenues and establish energy, fiscal, and national security policies. The petroleum industry and the financial community use resource estimates to establish corporate strategies and make investment decisions.

A clear understanding of some common terms used to generally describe the size and scope of oil and gas resources is needed to determine the relevance of a given estimate. For an illustration of how such terms describe the size and scope of shale oil and gas, see figure 5.

The most inclusive term is in-place resource. The in-place resource represents all oil or natural gas contained in a formation without regard to technical or economic recoverability. In-place resource estimates are sometimes very large numbers, but often only a small proportion of the total amount of oil or natural gas in a formation may ever be recovered. Oil and gas resources that are in-place, but not technically recoverable at this time may, in the future, become technically recoverable.

Technically recoverable resources are a subset of in-place resources that include oil or gas, including shale oil and gas that is producible given available technology. Technically recoverable resources include those that are economically producible and those that are not. Estimates of technically recoverable resources are dynamic, changing to reflect the potential of extraction technology and knowledge about the geology and composition of geologic formations. According to the National Petroleum Council,[22] technically recoverable resource estimates usually increase

[22]The National Petroleum Council is a federally chartered and privately funded advisory committee that advises, informs, and makes recommendations to the Secretary of Energy on oil and natural gas matters.

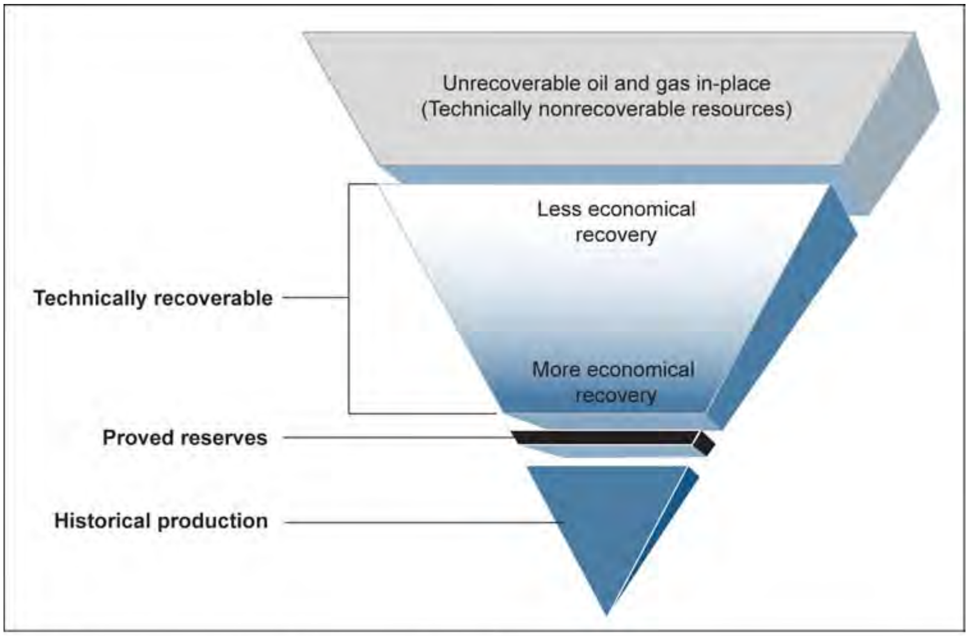
over time because of the availability of more and better data, or knowledge of how to develop a new play type (such as shale formations).

Proved reserve estimates are more precise than technically recoverable resources and represent the amount of oil and gas that have been discovered and defined, typically by drilling wells or other exploratory measures, and which can be economically recovered within a relatively short time frame. Proved reserves may be thought of as the “inventory” that operators hold and define the quantity of oil and gas that operators estimate can be recovered under current economic conditions, operating methods, and government regulations. Estimates of proved reserves increase as oil and gas companies make new discoveries and report them to the government; oil and gas companies can increase their reserves as they develop already-discovered fields and improve production technology. Reserves decline as oil and gas reserves are produced and sold. In addition, reserves can change as prices and technologies change. For example, technology improvements that enable operators to extract more oil or gas from existing fields can increase proved reserves. Likewise, higher prices for oil and gas may increase the amount of proved reserves because more resources become financially viable to extract.[23] Conversely, lower prices may diminish the amount of resources likely to be produced, reducing proved reserves.

Historical production refers to the total amount of oil and gas that has been produced up to the present. Because these volumes of oil and gas have been measured historically, this is the most precise information available as it represents actual production amounts.

[23]For example, secondary recovery operations can be costly (such as using a well to inject water into an oil reservoir and push any remaining oil to operating wells), but the costs may be justified if prices are high enough.

Figure 5: Common Terminology to Describe the Size and Scope of Shale Oil and Gas



Sources: GAO; based on illustration by the Congressional Research Service.

Note: This illustration is not necessarily to scale because all volumes, except historical production, are subject to significant uncertainty.

Certain federal agencies have statutory responsibility for collecting and publishing authoritative statistical information on various types of energy sources in the United States. EIA collects, analyzes, and disseminates independent and impartial energy information, including data on shale oil and gas resources. Under the Energy Policy and Conservation Act of 2000, as amended, USGS estimates onshore undiscovered technically recoverable oil and gas resources in the United States.[24] USGS has conducted a number of national estimates of undiscovered technically recoverable oil and natural gas resources over several decades. USGS geologists and other experts estimate undiscovered oil and gas—that is, oil and gas that has not been proven to be present by oil and gas companies—based on geological survey data and other information about

[24]Pub. L. No. 106-469 § 604 (2000), 114 Stat. 2029, 2041-42, codified, as amended, at 42 U.S.C. § 6217.

the location and size of different geological formations across the United States. In addition to EIA and USGS, experts from industry, academia, federal advisory committees, private consulting firms, and professional societies also estimate the size of the resource.

Domestic Shale Oil and Gas Estimates and Production

Estimates of the size of shale oil and gas resources in the United States have increased over time as has the amount of such resources produced from 2007 through 2011. Specifically, over the last 5 years, estimates of (1) technically recoverable shale oil and gas and (2) proved reserves of shale oil and gas have increased, as technology has advanced and more shale has been drilled. In addition, domestic shale oil and gas production has experienced substantial growth in recent years.

Estimates of Technically Recoverable Shale Oil and Gas Resources

EIA, USGS, and the Potential Gas Committee have increased their estimates of the amount of technically recoverable shale oil and gas over the last 5 years, which could mean an increase in the nation's energy portfolio; however, less is known about the amount of technically recoverable shale oil than shale gas, in part because large-scale production of shale oil has been under way for only the past few years. The estimates are from different organizations and vary somewhat because they were developed at different times and using different data, methods, and assumptions, but estimates from all of these organizations have increased over time, indicating that the nation's shale oil and gas resources may be substantial. For example, according to estimates and reports we reviewed, assuming current consumption levels without consideration of a specific market price for future gas supplies, the amount of domestic technically recoverable shale gas could provide enough natural gas to supply the nation for the next 14 to 100 years. The increases in estimates can largely be attributed to improved geological information about the resources, greater understanding of production levels, and technological advancements.

Estimates of Technically Recoverable Shale Oil Resources

In the last 2 years, EIA and USGS provided estimates of technically recoverable shale oil.[25] Each of these estimates increased in recent years as follows:

- In 2012, EIA estimated that the United States possesses 33 billion barrels of technically recoverable shale oil,[26] mostly located in four shale formations—the Bakken in Montana and North Dakota; Eagle Ford in Texas; Niobrara in Colorado, Kansas, Nebraska, and Wyoming; and the Monterey in California.

- In 2011, USGS estimated that the United States possesses just over 7 billion barrels of technically recoverable oil in shale and tight sandstone formations. The estimate represents a more than threefold increase from the agency's estimate in 2006. However, there are several shale plays that USGS has not evaluated for shale oil because interest in these plays is relatively new. According to USGS officials, these shale plays have shown potential for production in recent years and may contain additional shale oil resources. Table 1 shows USGS' 2006 and 2011 estimates and EIA's 2011 and 2012 estimates.

Table 1: USGS and EIA Estimates of Total Remaining Technically Recoverable U.S. Oil Resources

Barrels of oil in billions

	USGS		EIA	
	2006	**2011**	**2011**	**2012**
Estimated technically recoverable shale oil and tight sandstone resources	2	7	32	33
Estimated technically recoverable oil resources other than shale[a]	142	133	187	201

Source: GAO analysis of EIA and USGS data.

[25]As noted previously, for the purposes of this report, we use the term "shale oil" to refer to oil from shale and other tight formations, which is recoverable by hydraulic fracturing and horizontal drilling techniques and is described by others as "tight oil." Shale oil and tight oil are extracted in the same way, but differ from "oil shale." Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

[26]Comparatively, the United States currently consumes about 7 billion barrels of oil per year, about half of which are imported from foreign sources.

[a]Includes estimates for conventional offshore oil and gas, as well as natural gas liquids. In addition, the USGS estimates for 2006 and 2011 include a 2006 estimate of technically recoverable offshore conventional oil resources totaling 86 billion barrels of oil and natural gas liquids from the former Minerals Management Service, which has since been reorganized into the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement.

Overall, estimates of the size of technically recoverable shale oil resources in the United States are imperfect and highly dependent on the data, methodologies, model structures, and assumptions used. As these estimates are based on data available at a given point in time, they may change as additional information becomes available. Also these estimates depend on historical production data as a key component for modeling future supply. Because large-scale production of oil in shale formations is a relatively recent activity, their long-term productivity is largely unknown. For example, EIA estimated that the Monterey Shale in California may possess about 15.4 billion barrels of technically recoverable oil. However, without a longer history of production, the estimate has greater uncertainty than estimates based on more historical production data. At this time, USGS has not yet evaluated the Monterey Shale play.

Estimates of Technically Recoverable Shale Gas Resources

The amount of technically recoverable shale gas resources in the United States has been estimated by a number of organizations, including EIA, USGS, and the Potential Gas Committee (see fig. 6). Their estimates were as follows:

- In 2012, EIA estimated the amount of technically recoverable shale gas in the United States at 482 trillion cubic feet.[27] This represents an increase of 280 percent from EIA's 2008 estimate.

- In 2011, USGS reported that the total of its estimates for the shale formations the agency evaluated in all previous years[28] shows the

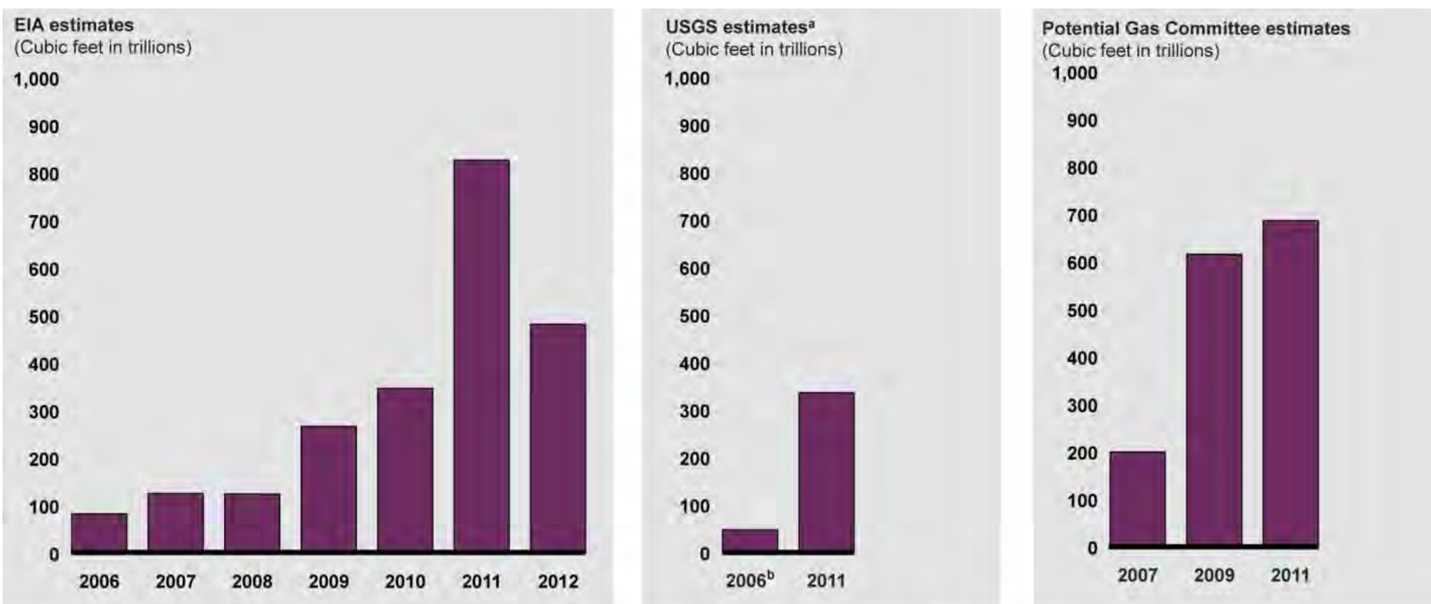
[27]EIA estimates are based on natural gas production data from 2 years prior to the reporting year; for example, EIA's 2012 estimate is based on 2010 data; the date cited here reflects the fact that EIA reported this latest estimate in 2012.

[28]USGS estimates are based on updated data in a few—but not all—individual geological areas, combined with data from other areas from all previous years. Each year USGS estimates new information for a few individual geological areas. For example, the 2011 USGS estimate includes updated 2011 data for the Appalachian Basin, the Anadarko Basin, and the Gulf Coast, combined with estimates for all other areas developed before 2011. See appendix III for additional information on USGS estimates. The date cited here reflects the fact that USGS reported this latest estimate in 2011.

amount of technically recoverable shale gas in the United States at about 336 trillion cubic feet. This represents an increase of about 600 percent from the agency's 2006 estimate.

- In 2011, the Potential Gas Committee estimated the amount of technically recoverable shale gas in the United States at about 687 trillion cubic feet.[29] This represents an increase of 240 percent from the committee's 2007 estimate.

Figure 6: Estimates of Technically Recoverable Shale Gas from EIA, USGS, and the Potential Gas Committee (2006 through 2012)



Sources: GAO analysis of EIA, Potential Gas Commitee, and USGS estimates.

Notes: Natural gas is generally priced and sold in thousand cubic feet (abbreviated Mcf, using the Roman numeral for 1,000). Units of a trillion cubic feet (Tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. One Tcf is enough natural gas to heat 15 million homes for 1 year or fuel 12 million natural gas-fired vehicles for 1 year. In 2012, EIA reduced its estimate of technically recoverable shale gas in the Marcellus Shale by about 67 percent. According to EIA officials, the decision to revise the estimate was based primarily on the availability of new production data, which was highlighted by the release of the USGS

[29]Potential Gas Committee estimates are based on natural gas production data from the previous year; for example, committee's 2011 estimate is based on 2010 data. The date cited here reflects the fact that the Potential Gas Committee reported this latest estimate in 2011.

estimate. In 2011, EIA used data from a contractor to estimate that the Marcellus Shale possessed about 410 trillion cubic feet of technically recoverable gas. After EIA released its estimates in 2011, USGS released its first estimate of technically recoverable gas in the Marcellus in almost 10 years. USGS estimated that there were 84 trillion cubic feet of natural gas in the Marcellus—which was 40 times more than its previous estimate reported in 2002 but significantly less than EIA's estimate. In 2012, EIA announced that it was revising its estimate of the technically recoverable gas in the Marcellus Shale from 410 to 141 trillion cubic feet. EIA reported additional details about its methodology and data in June 2012. See U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2012, With Projections to 2035 (DOE/EIA-0383 [2012], Washington, D.C., June 25, 2012).

[a]The 2006 USGS estimate of about 54 trillion cubic feet represents those assessments that had been done up to the end of 2006. As such, the estimate is partially dependent on how the agency scheduled basin studies and assessments from 2000 through 2006, rather than purely on changes in USGS views of resource potential since 2006.

[b]The Potential Gas Committee did not report separate estimates of shale gas until 2007 and has updated this estimate every 2 years since then.

In addition to the estimates from the three organizations we reviewed, operators and energy forecasting consultants prepare their own estimates of technically recoverable shale gas to plan operations or for future investment. In September 2011, the National Petroleum Council aggregated data on shale gas resources from over 130 industry, government, and academic groups and estimated that approximately 1,000 trillion cubic feet of shale gas is available for production domestically. In addition, private firms that supply information to the oil and gas industry conduct assessments of the total amount of technically recoverable natural gas. For example, ICF International, a consulting firm that provides information to public- and private-sector clients, estimated in March 2012 that the United States possesses about 1,960 trillion cubic feet of technically recoverable shale gas.

Based on estimates from EIA, USGS, and the Potential Gas Committee, five shale plays—the Barnett, Haynesville, Fayetteville, Marcellus, and Woodford—are estimated to possess about two-thirds of the total estimated technically recoverable gas in the United States (see table 2).

Table 2: Estimated Technically Recoverable Shale Gas Resources, by Play

Shale play	Location	Technically recoverable gas, in trillion cubic feet (Tcf)
Barnett	North Texas	43-53
Fayetteville	Arkansas	13-110
Haynesville	Louisiana and East Texas	66-110
Marcellus	Northeast United States	84-227[a]
Woodford	Oklahoma	11-27

Sources: GAO analysis of EIA, USGS, and Potential Gas Committee data.

Note: The estimated technically recoverable gas shown here represents the range of estimates for these plays determined by EIA, USGS, and the Potential Gas Committee.

[a]This estimate of the Marcellus also includes estimated shale gas from other nearby lands in the Appalachian area; but, according to an official for the estimating organization, the Marcellus Shale is the predominant source of gas in the basin.

As with estimates for technically recoverable shale oil, estimates of the size of technically recoverable shale gas resources in the United States are also highly dependent on the data, methodologies, model structures, and assumptions used and may change as additional information becomes available. These estimates also depend on historical production data as a key component for modeling future supply. Because most shale gas wells generally were not in place until the last few years, their long-term productivity is untested. According to a February 2012 report released by the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, production in emerging shale plays has been concentrated in areas with the highest known gas production rates, and many shale plays are so large that most of the play has not been extensively tested.[30] As a result, production rates achieved to date may not be representative of future production rates across the formation. EIA reports that experience to date shows production rates from neighboring shale gas wells can vary by as much as a factor of 3 and that production rates for different wells in the same formation can vary by as much as a factor of 10. Most gas companies estimate that production in a given well will drop sharply after the first few years and

[30]The Sustainable Investments Institute (Si2) is a nonprofit membership organization founded in 2010 to conduct research and publish reports on organized efforts to influence corporate behavior. The Investor Responsibility Research Center Institute is a nonprofit organization established in 2006 that provides information to investors.

then level off, continuing to produce gas for decades, according to the Sustainable Investments Institute and the Investor Responsibility Research Center Institute.

Estimates of Proved Reserves of Shale Oil and Gas

Estimates of proved reserves of shale oil and gas increased from 2007 to 2009. Operators determine the size of proved reserves based on information collected from drilling, geological and geophysical tests, and historical production trends. These are also the resources operators believe they will develop in the short term—generally within the next 5 years—and assume technological and economic conditions will remain unchanged.

Estimates of proved reserves of shale oil. EIA does not report proved reserves of shale oil separately from other oil reserves; however, EIA and others have noted an increase in the proved reserves of oil in the nation, and federal officials attribute the increase, in part, to oil from shale and tight sandstone formations. For example, EIA reported in 2009 that the Bakken Shale in North Dakota and Montana drove increases in oil reserves, noting that North Dakota proved reserves increased over 80 percent from 2008 through 2009.

Estimates of proved reserves of shale gas. According to data EIA collects from about 1,200 operators, proved reserves of shale gas have grown from 23 trillion cubic feet in 2007 to 61 trillion cubic feet in 2009, or an increase of 160 percent.[31] More than 75 percent of the proved shale gas reserves are located in three shale plays—the Barnett, Fayetteville, and the Haynesville.

Shale Oil and Gas Production

From 2007 through 2011, annual production of shale oil and gas has experienced significant growth. Specifically, shale oil production increased more than fivefold, from 39 to about 217 million barrels over this 5-year period, and shale gas production increased approximately fourfold, from 1.6 to about 7.2 trillion cubic feet, over the same period. To

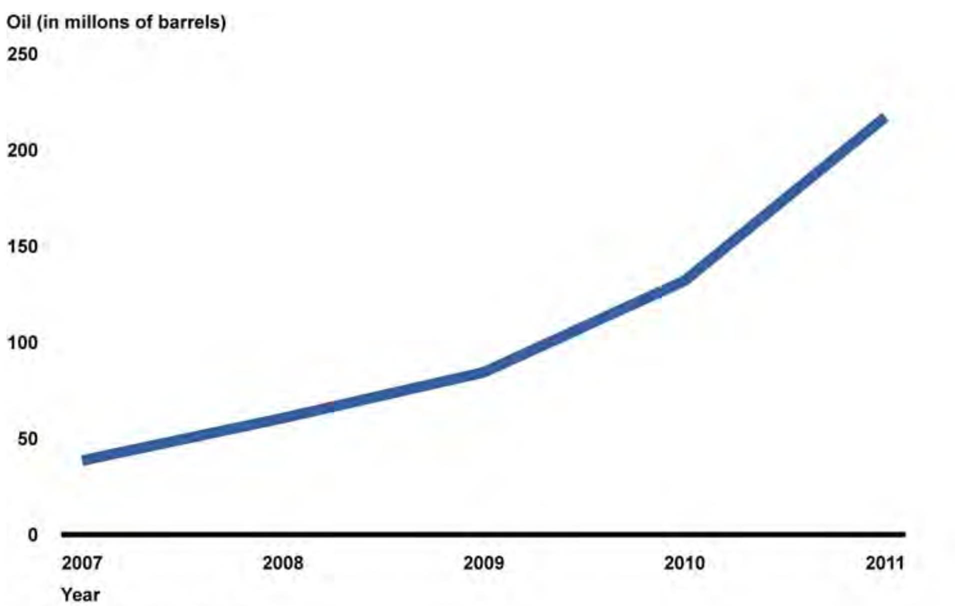
[31]Reserves are key information for assessing the net worth of an operator. Oil and gas companies traded on the U.S. stock exchange are required to report their reserves to the Securities and Exchange Commission. According to an EIA official, EIA reports a more complete measure of oil and gas reserves because it receives reports of proved reserves from both private and publically held companies.

put this shale production into context, the annual domestic consumption of oil in 2011 was about 6,875 million barrels of oil, and the annual consumption of natural gas was about 24 trillion cubic feet. The increased shale oil and gas production was driven primarily by technological advances in horizontal drilling and hydraulic fracturing that made more shale oil and gas development economically viable.

Shale Oil Production

Annual shale oil production in the United States increased more than fivefold, from about 39 million barrels in 2007 to about 217 million barrels in 2011, according to data from EIA (see fig. 7).[32] This is because new technologies allowed more oil to be produced economically, and because of recent increases in the price for liquid petroleum that have led to increased investment in shale oil development.

Figure 7: Estimated Production of Shale Oil from 2007 through 2011 (in millions of barrels of oil)



Source: GAO analysis of EIA data.

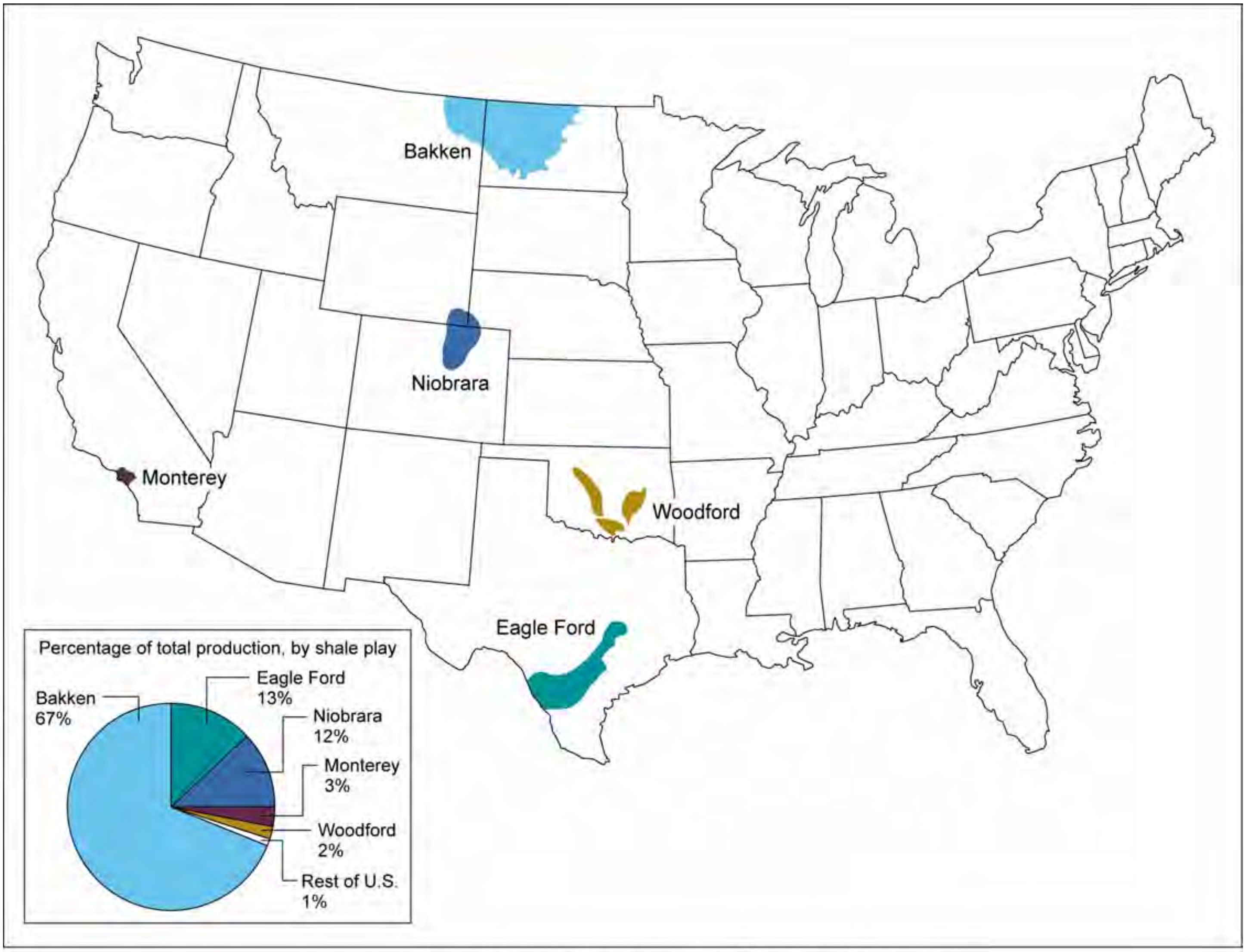
[32]As noted previously, for the purposes of this report, we use the term “shale oil” to refer to oil from shale and other tight formations, which is recovered by hydraulic fracturing and horizontal drilling and is described by others as “tight oil.” Shale oil and tight oil are extracted in the same way, but differ from “oil shale.” Oil shale is a sedimentary rock containing solid organic material that converts into a type of crude oil only when heated.

In total, during this period, about 533 million barrels of shale oil was produced. More than 65 percent of the oil was produced in the Bakken Shale (368 million barrels; see fig. 8).[33] The remainder was produced in the Niobrara (62 million barrels), Eagle Ford (68 million barrels), Monterey (18 million barrels), and the Woodford (9 million barrels). To put this in context, shale oil production from these plays in 2011 constituted about 8 percent of U.S. domestic oil consumption, according to EIA data.[34]

[33]EIA provided us with estimated shale oil production data from a contractor, HPDI LLC., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale oil production. EIA has not routinely reported shale oil production data separately from oil production.

[34]In addition to production from these shale oil plays, EIA officials told us that oil was produced from “tight oil” plays such as the Austin Chalk. The technology for producing tight oil is the same as for shale oil, and EIA uses the term “tight oil” to encompass both shale oil and tight oil that are developed with the same type of technology. In addition, EIA officials added that the shale oil data presented here is approximate because the data comes from a sample of similar plays. Overtime, this production data will become more precise as more data becomes available to EIA.

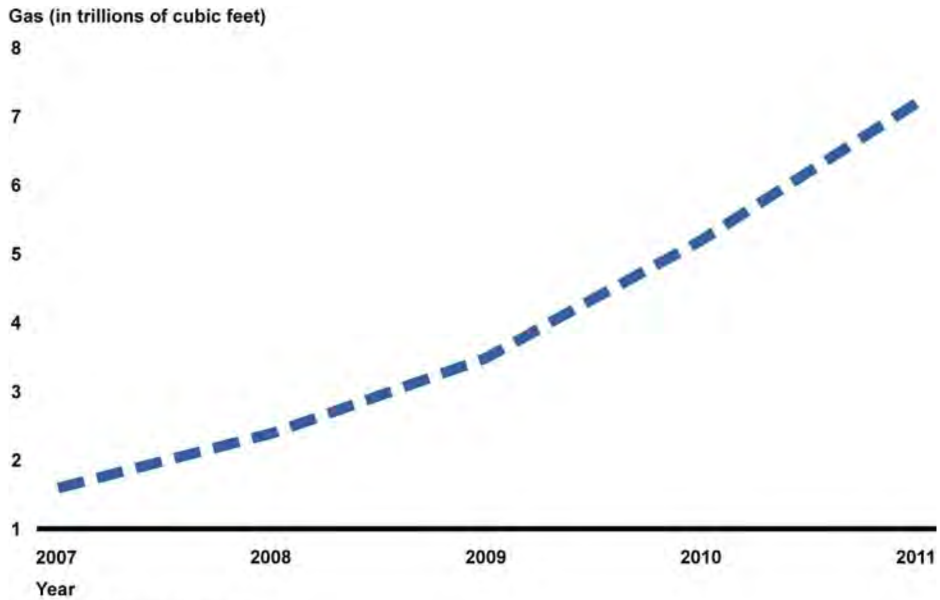
Figure 8: Shale Oil Production, by Shale Play (from 2007 through 2011)



Shale Gas Production

Shale gas production in the United States increased more than fourfold, from about 1.6 trillion cubic feet in 2007 to about 7.2 trillion cubic feet in 2011, according to estimated data from EIA (see fig. 9).[35]

Figure 9: Estimated Production of Shale Gas from 2007 through 2011 (in trillions of cubic feet)



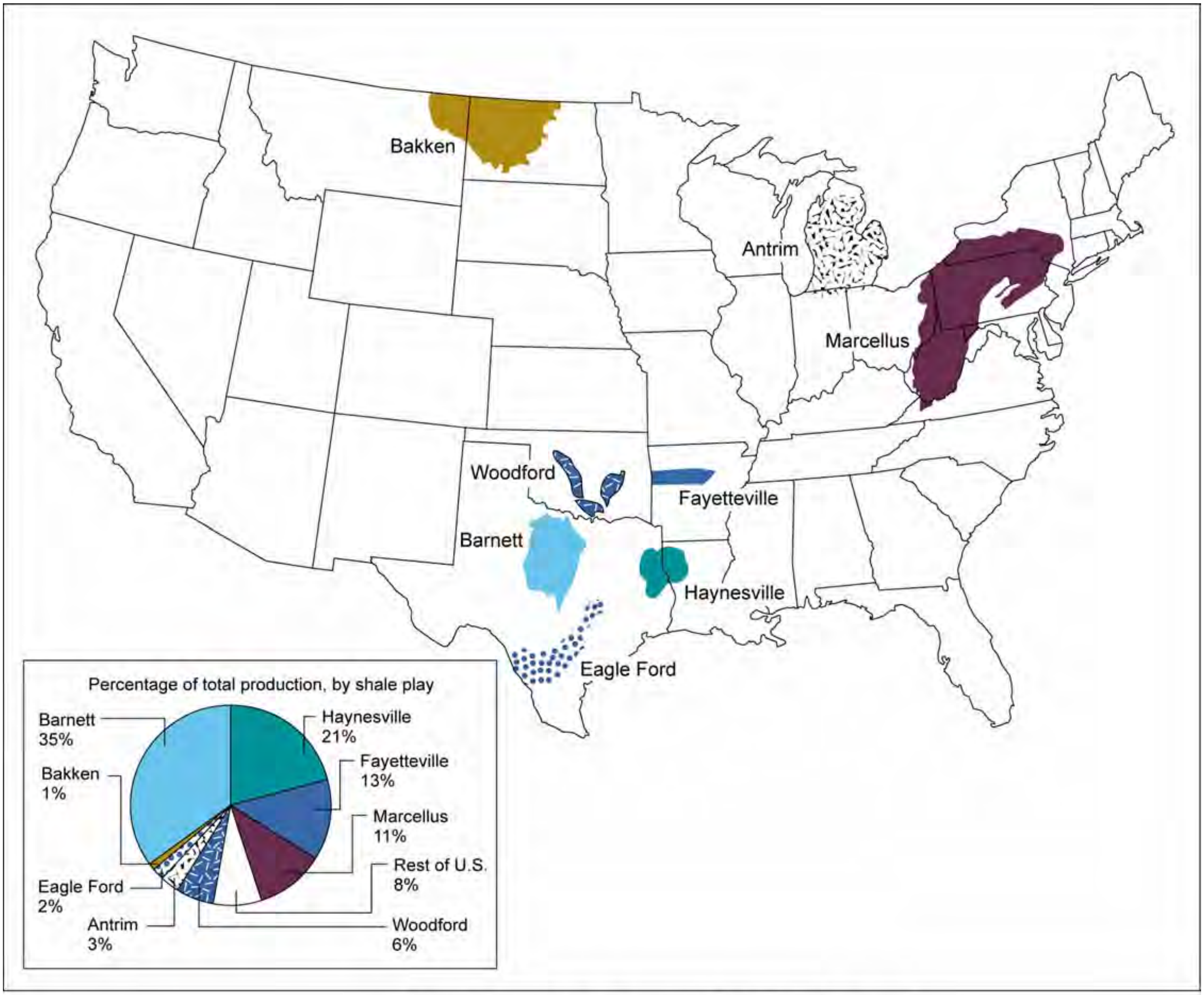
Source: GAO analysis of EIA data.

In total, during this period, about 20 trillion cubic feet of shale gas was produced—representing about 300 days of U.S. consumption, based on 2011 consumption rates. More than 75 percent of the gas was produced in four shale plays—the Barnett, Marcellus, Fayetteville, and Haynesville (see fig.10). From 2007 through 2011, shale gas' contribution to the nation's total natural gas supply grew from about 6 percent in 2007 to approximately 25 percent in 2011 and is projected, under certain assumptions, to increase to 49 percent by 2035, according to an EIA report. Overall production of shale gas increased from calendar years 2007 through 2011, but production of natural gas on federal and tribal

[35]EIA provided us with estimated shale gas production data from a contractor, Lippman Consulting, Inc., for 2007 through 2011. EIA uses these data for the purposes of estimating recent shale gas production. EIA has separately reported shale gas production data using reports from states for the years 2008 and 2009.

lands—including shale gas and natural gas from all other sources—decreased by about 17 percent, according to an EIA report. EIA attributes this decrease to several factors, including the location of shale formations—which, according to an EIA official, appear to be predominately on nonfederal lands.

Figure 10: Shale Gas Production, by Shale Play (from 2007 through 2011)



Sources: GAO analysis of EIA data; (map) copyright © Corel Corp., all rights reserved.

The growth in production of shale gas has increased the overall supply of natural gas in the U.S. energy market. Since 2007, increased shale gas production has contributed to lower prices for consumers, according to EIA and others.[36] These lower prices create incentives for wider use of natural gas in other industries. For example, several reports by government, industry, and others have observed that if natural gas prices remain low, natural gas is more likely to be used to power cars and trucks in the future. In addition, electric utilities may build additional natural gas-fired generating plants as older coal plants are retired. At the same time, some groups have expressed concern that greater reliance on natural gas may reduce interest in developing renewable energy.

Development of Wet Gas

EIA reported that operators have recently moved away from the development of shale plays that are primarily dry gas in favor of developing plays with higher concentrations of natural gas liquids. At current natural gas prices, natural gas liquids are a much more valuable product than dry gas. This is because the end products and byproducts of natural gas liquids contain more energy per unit of volume and have uses beyond heating and power generation and may be converted into products that can be more easily transported and traded in the global market. Shale plays with significant natural gas liquids include the Eagle Ford and Marcellus.

The greater availability of domestic shale gas has also decreased the need for natural gas imports. For example, EIA has noted that volumes of natural gas imported into the United States have fallen in recent years—in 2007, the nation imported 16 percent of the natural gas consumed and in 2010, the nation imported 11 percent—as domestic shale gas production has increased. This trend is also illustrated by an increase in applications for exporting liquefied natural gas to other countries. In its 2012 annual energy outlook, EIA predicted that, under certain scenarios, the United States will become a net exporter of natural gas by about 2022.[37]

Shale Oil and Gas Development Pose Environmental and Public Health Risks, but the Extent is Unknown and Depends on Many Factors

Developing oil and gas resources—whether conventional or from shale formations—poses inherent environmental and public health risks, but the extent of risks associated with shale oil and gas development is unknown, in part, because the studies we reviewed do not generally take into account potential long-term, cumulative effects. In addition, the severity of adverse effects depend on various location- and process-specific factors, including the location of future shale oil and gas development and the rate at which it occurs, geology, climate, business practices, and regulatory and enforcement activities.

[36]According to a 2012 report from the Bipartisan Policy Center, natural gas prices declined roughly 37 percent from February 2008 to January 2010.

[37]Department of Energy, Energy Information Administration, *Annual Energy Outlook 2012, With Projections to 2035*, DOE/EIA-0383 (Washington, D.C.: June 25, 2012).

Shale Oil and Gas Development Pose Risks to Air, Water, Land and Wildlife

Oil and gas development, which includes development from shale formations, poses inherent risks to air quality, water quantity, water quality, and land and wildlife.

Air Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to air quality. These risks are generally the result of engine exhaust from increased truck traffic, emissions from diesel-powered pumps used to power equipment, intentional flaring or venting of gas for operational reasons, and unintentional emissions of pollutants from faulty equipment or impoundments.

Construction of the well pad, access road, and other drilling facilities requires substantial truck traffic, which degrades air quality. According to a 2008 National Park Service report, an average well, with multistage fracturing, can require 320 to 1,365 truck loads to transport the water, chemicals, sand, and other equipment—including heavy machinery like bulldozers and graders—needed for drilling and fracturing. The increased traffic creates a risk to air quality as engine exhaust that contains air pollutants such as nitrogen oxides and particulate matter that affect public health and the environment are released into the atmosphere.[38] Air quality may also be degraded as fleets of trucks traveling on newly graded or unpaved roads increase the amount of dust released into the air—which can contribute to the formation of regional haze.[39] In addition to the dust, silica sand (see fig. 11)—commonly used as proppant in the hydraulic fracturing process—may pose a risk to human health, if not properly handled. According to a federal researcher from the Department of Health and Human Services, uncontained sand particles and dust pose threats to workers at hydraulic fracturing well sites. The official stated that particles from the sand, if not properly contained by dust control mechanisms, can lodge in the lungs and potentially cause silicosis.[40]

[38]Nitrogen oxides are regulated pollutants commonly known as NOx that, among other things, contribute to the formation of ozone and have been linked to respiratory illness, decreased lung function, and premature death. Particulate matter is a ubiquitous form of air pollution commonly referred to as soot. GAO, *Diesel Pollution: Fragmented Federal Programs That Reduce Mobile Source Emissions Could Be Improved*, GAO-12-261 (Washington, D.C.: Feb. 7, 2012).

[39]T. Colborn, C. Kwiatkowski, K. Schultz, and M. Bachran, “Natural Gas Operations From a Public Health Perspective,” *International Journal of Human & Ecological Risk Assessment* 17, no. 5 (2011).

[40]Silicosis is an incurable lung disease caused by inhaling fine dusts of silica sand.

The researcher expects to publish the results of research on public health risks from proppant later in 2012.

Figure 11: Silica Sand Proppant

Source: GAO.

Use of diesel engines to supply power to drilling sites also degrades air quality. Shale oil and gas drilling rigs require substantial power to drill and case wellbores to the depths of shale formations. This power is typically provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale—generating additional exhaust. In addition, other equipment used during operations—including pneumatic valves and dehydrators—contribute to air emissions. For example, natural gas powers switches that turn valves on and off in the production system. Each time a valve turns on or off, it “bleeds” a small amount of gas into the air. Some of these pneumatic valves vent gas continuously. A dehydrator circulates the chemical glycol to absorb moisture in the gas but also absorbs small volumes of gas. The absorbed gas vents to the atmosphere when the water vapor is released from the glycol.[41]

Releases of natural gas during the development process also degrade air quality. As part of the process to develop shale oil and gas resources, operators flare or vent natural gas for a number of operational reasons, including lowering the pressure to ensure safety or when operators purge water or hydrocarbon liquids that collect in wellbores to maintain proper well function. Flaring emits carbon dioxide, and venting releases methane and volatile organic compounds. Venting and flaring are often a necessary part of the development process but contribute to greenhouse gas emissions.[42] According to EPA analysis, natural gas well completions involving hydraulic fracturing vent approximately 230 times more natural gas and volatile organic compounds than natural gas well completions that do not involve hydraulic fracturing.[43] As we reported in July 2004, in addition to the operational reasons for flaring and venting, in areas where the primary purpose of drilling is to produce oil, operators flare or vent associated natural gas because no local market exists for the gas and transporting to a market may not be economically feasible.[44] For example, according to EIA, in 2011, approximately 30 percent of North Dakota's natural gas production from the Bakken Shale was flared by operators due to insufficient natural gas gathering pipelines, processing plants, and transporting pipelines. The percentage of flared gas in North Dakota is considerably higher than the national average; EIA reported that, in 2009,

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[41]GAO-11-34.

[42]Methane and other chemical compounds found in the earth's atmosphere create a greenhouse effect. Under normal conditions, when sunlight strikes the earth's surface, some of it is reflected back toward space as infrared radiation or heat. Greenhouse gases such as carbon dioxide and methane impede this reflection by trapping heat in the atmosphere. While these gases occur naturally on earth and are emitted into the atmosphere, the expanded industrialization of the world over the last 150 years has increased the amount of emissions from human activity (known as anthropogenic emissions) beyond the level that the earth's natural processes can handle.

[43]EPA, Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas industry (Research Triangle Park, NC: April 2012).

[44]GAO, *Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions*, GAO-04-809 (Washington, D.C.: July 14, 2004).

less than 1 percent of natural gas produced in the United States was vented or flared.

Storing fracturing fluid and produced water in impoundments may also pose a risk to air quality as evaporation of the fluids have the potential to release contaminants into the atmosphere. According to the New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals the potential for emissions of hazardous air pollutants, in particular methanol, from the fluids stored in impoundments.

As with conventional oil and gas development, emissions can also occur as faulty equipment or accidents, such as leaks or blowouts, release concentrations of methane and other gases into the atmosphere. For example, corrosion in pipelines or improperly tightened valves or seals can be sources of emissions. In addition, according to EPA officials, storage vessels for crude oil, condensate, or produced water are significant sources of methane, volatile organic compounds and hazardous air pollutant emissions.

A number of studies we reviewed evaluated air quality at shale gas development sites. However, these studies are generally anecdotal, short-term, and focused on a particular site or geographic location. For example, in 2010, the Pennsylvania Department of Environmental Protection conducted short-term sampling of ambient air concentrations in north central Pennsylvania. The sampling detected concentrations of natural gas constituents including methane, ethane, propane, and butane in the air near Marcellus Shale drilling operations, but according to this state agency, the concentration levels were not considered significant enough to cause adverse health effects.[45]

The studies and publications we reviewed provide information on air quality conditions at a specific site at a specific time but do not provide the information needed to determine the overall cumulative effect that

[45]Methane emissions represent a waste of resources and a fractional contribution to greenhouse gas levels.

shale oil and gas activities have on air quality.[46] The cumulative effect shale oil and gas activities have on air quality will be largely determined by the amount of development and the rate at which it occurs, and the ability to measure this will depend on the availability of accurate information on emission levels. However, the number of wells that will ultimately be drilled cannot be known in advance—in part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. In addition, as we reported in 2010, data on the severity or amount of pollutants released by oil and gas development, including the amount of fugitive emissions, are limited.

Water Quantity

According to a number of studies and publications we reviewed, shale oil and gas development poses a risk to surface water and groundwater because withdrawing water from streams, lakes, and aquifers for drilling and hydraulic fracturing could adversely affect water sources.[47] Operators use water for drilling, where a mixture of clay and water (drilling mud) is used to carry rock cuttings to the surface, as well as to cool and lubricate the drill bit. Water is also the primary component of fracturing fluid. Table 3 shows the average amount of freshwater used to drill and fracture a shale oil or gas well.

Table 3: Average Freshwater Use per Well for Drilling and Hydraulic Fracturing

	Average freshwater used (in gallons)	
Shale play	**For drilling**	**For hydraulic fracturing**
Barnett	250,000	4,600,000
Eagle Ford	125,000	5,000,000
Haynesville	600,000	5,000,000
Marcellus	85,000	5,600,000
Niobrara	300,000	3,000,000

Source: GAO analysis of data reported by George King, Apache Corporation (2011).

Note: The amount of water required to hydraulically fracture a single well varies considerably as fracturing of shale oil and gas becomes dominated by more complex, multistaged fracturing activities.

[46] According to a 2008 National Park Service report, on a site-by-site basis, emissions may not be significant but on a regional basis may prove significant as states and parks manage regional ozone transport.

[47] An aquifer is an underground layer of rock or unconsolidated sand, gravel, or silt that will yield groundwater to a well or spring.

According to a 2012 University of Texas study,[48] water for these activities is likely to come from surface water (rivers, lakes, ponds), groundwater aquifers, municipal supplies, reused wastewater from industry or water treatment plants, and recycling water from earlier fracturing operations.[49] As we reported in October 2010, withdrawing water from nearby streams and rivers could decrease flows downstream, making the streams and rivers more susceptible to temperature changes—increases in the summer and decreases in the winter. Elevated temperatures could adversely affect aquatic life because many fish and invertebrates need specific temperatures for reproduction and proper development. Further, decreased flows could damage or destroy riparian vegetation. Similarly, withdrawing water from shallow aquifers—an alternative water source—could temporarily affect groundwater resources. Withdrawals could lower water levels within these shallow aquifers and the nearby streams and springs to which they are connected. Extensive withdrawals could reduce groundwater discharge to connected streams and springs, which in turn could damage or remove riparian vegetation and aquatic life. Withdrawing water from deeper aquifers could have longer-term effects on groundwater and connected streams and springs because replenishing deeper aquifers with precipitation generally takes longer.[50] Further, groundwater withdrawal could affect the amount of water available for other uses, including public and private water supplies.

Freshwater is a limited resource in some arid and semiarid regions of the country where an expanding population is placing additional demands on water. The potential demand for water is further complicated by years of drought in some parts of the country and projections of a warming climate. According to a 2011 Massachusetts Institute of Technology study,[51] the amount of water used for shale gas development is small in

[48]Charles G. Groat, Ph.D. and Thomas W. Grimshaw, Ph.D., *Fact-Based Regulation for Environmental Protection in Shale Gas Development* (Austin, Texas: The Energy Institute, The University of Texas at Austin, February, 2012).

[49]Operators are pursuing a variety of techniques and technologies to reduce freshwater demand, such as recycling their own produced water and hydraulic fracturing fluids. We recently reported that some shale gas operators have begun reusing produced water for hydraulic fracturing of additional wells (see GAO-12-156).

[50]GAO-11-35.

[51]Massachusetts Institute of Technology, *The Future of Natural Gas: An Interdisciplinary MIT Study* (2011) (web.mit.edu/mitei/research/studies/report-natural-gas.pdf).

comparison to other water uses, such as agriculture and other industrial purposes. However, the cumulative effects of using surface water or groundwater at multiple oil and gas development sites can be significant at the local level, particularly in areas experiencing drought conditions.

Similar to shale oil and gas development, development of gas from coalbed methane formations poses a risk of aquifer depletion. To develop natural gas from such formations, water from the coal bed is withdrawn to lower the reservoir pressure and allow the methane to desorb from the coal. According to a 2001 USGS report, dewatering coalbed methane formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation.[52]

The key issue for water quantity is whether the total amount of water consumed for the development of shale oil and gas will result in a significant long-term loss of water resources within a region, according to a 2012 University of Texas study. This is because water used in shale oil and gas development is largely a consumptive use and can be permanently removed from the hydrologic cycle, according to EPA and Interior officials. However, it is difficult to determine the long-term effect on water resources because the scale and location of future shale oil and gas development operations remains largely uncertain. Similarly, the total volume that operators will withdraw from surface water and aquifers for drilling and hydraulic fracturing is not known until operators submit applications to the appropriate regulatory agency. As a result, the cumulative amount of water consumed over the lifetime of the activity—key information needed to assess the effects of water withdrawals—remains largely unknown.

Water Quality

According to a number of studies and publications we reviewed, shale oil and gas development pose risks to water quality from contamination of surface water and groundwater as a result of spills and releases of produced water, chemicals, and drill cuttings; erosion from ground disturbances; or underground migration of gases and chemicals.

[52]USGS, *A Field Conference On Impacts of Coalbed Methane Development in the Powder River Basin, Wyoming,* Open-File Report 01-126 (Denver, CO: 2001).

Spills and Releases

Shale oil and gas development poses a risk to water quality from spills or releases of toxic chemicals and waste that can occur as a result of tank ruptures, blowouts, equipment or impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or operational errors. For example, tanks storing toxic chemicals or hoses and pipes used to convey wastes to the tanks could leak, or impoundments containing wastes could overflow as a result of extensive rainfall. According to New York Department of Environmental Conservation's 2011 Supplemental Generic Environmental Impact Statement, spilled, leaked, or released chemicals or wastes could flow to a surface water body or infiltrate the ground, reaching and contaminating subsurface soils and aquifers. In August 2003, we reported that damage from oil and gas related spills on National Wildlife Refuges varied widely in severity, ranging from infrequent small spills with no known effect on wildlife to large spills causing wildlife death and long-term water and soil contamination.[53]

Drill cuttings, if improperly managed, also pose a risk to water quality. Drill cuttings brought to the surface during oil and gas development may contain naturally occurring radioactive materials (NORM),[54] along with other decay elements (radium-226 and radium-228), according to an industry report presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition.[55] According to the report, drill cuttings are stored and transported through steel pipes and tanks—which the radiation cannot penetrate. However, improper transport and handling of drill cuttings could result in water contamination. For example, NORM

[53]GAO, *National Wildlife Refuges: Opportunities to Improve the Management and Oversight of Oil and Gas Activities on Federal Lands*, GAO-03-517 (Washington, D.C.: Aug. 28, 2003).

[54]Naturally occurring radioactive materials (NORM) are present at varying degrees in virtually all environmental media, including rocks and soils. According to a DOE report, human exposure to radiation comes from a variety of sources, including naturally occurring radiation from space, medical sources, consumer products, and industrial sources. Normal disturbances of NORM-bearing rock formations by activities such as drilling do not generally pose a threat to workers, the general public or the environment, according to studies and publications we reviewed.

[55]J. Daniel Arthur, Brian Bohm, David Cornue. "Environmental Considerations of Modern Shale Gas Development" (presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 2009).

concentrations can build up in pipes and tanks, if not properly disposed, and the general public or water could come into contact with them, according to an EPA fact sheet.[56]

The chemical additives in fracturing fluid, if not properly handled, also poses a risk to water quality if they come into contact with surface water or groundwater. Some additives used in fracturing fluid are known to be toxic, but data are limited for other additives. For example, according to reports we reviewed, operators may include diesel fuel—a refinery product that consists of several components, possibly including some toxic impurities such as benzene and other aromatics—as a solvent and dispersant in fracturing fluid. While some additives are known to be toxic, less is known about potential adverse effects on human health in the event that a drinking water aquifer was contaminated as a result of a spill or release of fracturing fluid, according to the 2011 New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement. This is largely because the overall risk of human health effects occurring from hydraulic fracturing fluid would depend on whether human exposure occurs, the specific chemical additives being used, and site-specific information about exposure pathways and environmental contaminant levels.

The produced water and fracturing fluids returned during the flowback process contain a wide range of contaminants and pose a risk to water quality, if not properly managed.[57] Most of the contaminants occur naturally, but some are added through the process of drilling and hydraulic fracturing. In January 2012, we reported that the range of contaminants found in produced water can include,[58] but is not limited to

- salts, which include chlorides, bromides, and sulfides of calcium, magnesium, and sodium;

[56]EPA, *Radioactive Waste from Oil and Gas Drilling*, EPA 402-F-06-038 (Washington, D.C.: April 2006).

[57]A 2009 report from DOE and the Groundwater Protection Council—a nonprofit organization whose members consist of state ground water regulatory agencies—estimates that from 30 percent to 70 percent of the original fluid injected returns to the surface.

[58]GAO-12-156.

- metals, which include barium, manganese, iron, and strontium, among others;
- oil, grease, and dissolved organics, which include benzene and toluene, among others;
- NORM; and
- production chemicals, which may include friction reducers to help with water flow, biocides to prevent growth of microorganisms, and additives to prevent corrosion, among others.

At high levels, exposure to some of the contaminants in produced water could adversely affect human health and the environment. For example, in January 2012, we reported that, according to EPA, a potential human health risk from exposure to high levels of barium is increased blood pressure.[59] From an environmental standpoint, research indicates that elevated levels of salts can inhibit crop growth by hindering a plant's ability to absorb water from the soil. Additionally, exposure to elevated levels of metals and production chemicals, such as biocides, can contribute to increased mortality among livestock and wildlife.

Operators must transport or store produced water prior to disposal. According to a 2012 University of Texas report, produced water temporarily stored in tanks (see fig. 12) or impoundments prior to treatment or disposal may be a source of leaks or spills, if not properly managed. The risk of a leak or spill is particularly a concern for surface impoundments as improper liners can tear, and impoundments can overflow.[60] For example, according to state regulators in North Dakota, in 2010 and 2011, impoundments overflowed during the spring melt season because operators did not move fluids from the impoundments—which

[59]GAO-12-156.

[60]The composition of pit lining depends on regulatory requirements, which vary from state to state.

were to be used for temporary storage—to a proper disposal site before the spring thaw.[61]

Figure 12: Storage Tank for Produced Water in the Barnett Shale

Source: GAO.

Unlike shale oil and gas formations, water permeates coalbed methane formations, and its pressure traps natural gas within the coal. To produce natural gas from coalbed methane formations, water must be extracted to lower the pressure in the formation so the natural gas can flow out of the coal and to the wellbore. In 2000, USGS reported that water extracted from coalbed methane formations is commonly saline and, if not treated

[61]In response, the state passed a new law that will significantly reduce the number of pits. Under the new law, operators can use pits for temporary storage of fluid from the flowback process but must drain and reclaim the pits no more than 72 hours after hydraulic fracturing is complete.

and disposed of properly, could adversely affect streams and threaten fish and aquatic resources.

According to several reports, handling and transporting toxic fluids or contaminants poses a risk of environmental contamination for all industries, not just oil and gas development; however, the large volume of fluids and contaminants—fracturing fluid, drill cuttings, and produced water—that is associated with the development of shale oil and gas poses an increased risk for a release to the environment and the potential for greater effects should a release occur in areas that might not otherwise be exposed to these chemicals.

Erosion

Oil and gas development, whether conventional or shale oil and gas, can contribute to erosion, which could carry sediments and pollutants into surface waters. Shale oil and gas development require operators to undertake a number of earth-disturbing activities, such as clearing, grading, and excavating land to create a pad to support the drilling equipment. If necessary, operators may also construct access roads to transport equipment and other materials to the site. As we reported in February 2005, as with other construction activities, if sufficient erosion controls to contain or divert sediment away from surface water are not established then surfaces are exposed to precipitation and runoff could carry sediment and other harmful pollutants into nearby rivers, lakes, and streams.[62] For example, in 2012, the Pennsylvania Department of Environmental Protection concluded that an operator in the Marcellus Shale did not provide sufficient erosion controls when heavy rainfall in the area caused significant erosion and contamination of a nearby stream from large amounts of sediment.[63] As we reported in February 2005, sediment clouds water, decreases photosynthetic activity, and destroys organisms and their habitat.

[62]GAO, *Storm Water Pollution: Information Needed on the Implications of Permitting Oil and Gas Construction Activities*, GAO-05-240 (Washington, D.C.: Feb. 9, 2005).

[63]In response, the state required the operator to install silt fences, silt socks, gravel surfacing of the access road, and a storm water capture ditch.

Underground Migration

According to a number of studies and publications we reviewed, underground migration of gases and chemicals poses a risk of contamination to water quality.[64] Underground migration can occur as a result of improper casing and cementing of the wellbore as well as the intersection of induced fractures with natural fractures, faults, or improperly plugged dry or abandoned wells. Moreover, there are concerns that induced fractures can grow over time and intersect with drinking water aquifers. Specifically:

Improper casing and cementing. A well that is not properly isolated through proper casing and cementing could allow gas or other fluids to contaminate aquifers as a result of inadequate depth of casing,[65] inadequate cement in the annular space around the surface casing, and ineffective cement that cracks or breaks down under the stress of high pressures. For example, according to a 2008 report by the Ohio Department of Natural Resources, a gas well in Bainbridge, Ohio, was not properly isolated because of faulty sealing, allowing natural gas to build up in the space around the production casing and migrate upward over about 30 days into the local aquifer and infiltrating drinking water wells.[66] The risk of contamination from improper casing and cementing is not unique to the development of shale formations. Casing and cementing practices also apply to conventional oil and gas development. However, wells that are hydraulically fractured have some unique aspects. For example, hydraulically fractured wells are commonly exposed to higher pressures than wells that are not hydraulically fractured. In addition, hydraulically fractured wells are exposed to high pressures over a longer period of time as fracturing is conducted in multiple stages, and wells may be refractured multiple times—primarily to extend the economic life of the well when production declines significantly or falls below the estimated reservoir potential.

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[64]Methane can occur naturally in shallow bedrock and unconsolidated sediments and has been known to naturally seep to the surface and contaminate water supplies, including water wells. Methane is a colorless, odorless gas and is generally considered nontoxic, but there could be an explosive hazard if gas is present in significant volumes and the water well is not properly vented.

[65]The depth for casing and cementing may be determined by state regulations.

[66]Ohio Department of Natural Resources, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio* (September 2008).

Natural fractures, faults, and abandoned wells. If shale oil and gas development activities result in connections being established with natural fractures, faults, or improperly plugged dry or abandoned wells, a pathway for gas or contaminants to migrate underground could be created—posing a risk to water quality. These connections could be established through either induced fractures intersecting directly with natural fractures, faults, or improperly plugged dry or abandoned wells or as a result of improper casing and cementing that allow gas or other contaminants to make such connections. In 2011, the New York State Department of Environmental Conservation reported that operators generally avoid development around known faults because natural faults could allow gas to escape, which reduces the optimal recovery of gas and the economic viability of a well. However, data on subsurface conditions in some areas are limited. Several studies we reviewed report that some states are unaware of the location or condition of many old wells. As a result, operators may not be fully aware of the location of abandoned wells and natural fractures or faults.

Fracture growth. A number of such studies and publications we reviewed report that the risk of induced fractures extending out of the target formation into an aquifer—allowing gas or other fluids to contaminate water—may depend, in part, on the depth separating the fractured formation and the aquifer. For example, according to a 2012 Bipartisan Policy Center report, [67] the fracturing process itself is unlikely to directly affect freshwater aquifers because fracturing typically takes place at a depth of 6,000 to 10,000 feet, while drinking water tables are typically less than 1,000 feet deep.[68] Fractures created during the hydraulic fracturing process are generally unable to span the distance between the targeted shale formation and freshwater bearing zones. According to a 2011 industry report, fracture growth is stopped by natural subsurface barriers

[67]Bipartisan Policy Center, *Shale Gas: New Opportunities, New Challenges* (Washington, D.C.: January 2012).

[68]Some coalbed methane formations are much closer to drinking water aquifers than are shale formations. In 2004, EPA reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing in coalbed methane formations. EPA found no confirmed cases linked to the injection of fracturing fluid or subsequent underground movement of fracturing fluids. The report states that, although thousands of coalbed methane formations are fractured annually, EPA did not find confirmed evidence that drinking water wells had been contaminated by the hydraulic fracturing process.

and the loss of hydraulic fracturing fluid.[69] When a fracture grows, it conforms to a general direction set by the stresses in the rock, following what is called fracture direction or orientation. The fractures are most commonly vertical and may extend laterally several hundred feet away from the well, usually growing upward until they intersect with a rock of different structure, texture, or strength. These are referred to as seals or barriers and stop the fracture's upward or downward growth. In addition, as the fracturing fluid contacts the formation or invades natural fractures, part of the fluid is lost to the formation. The loss of fluids will eventually stop fracture growth according to this industry report.

From 2001 through 2010, an industry consulting firm monitored the upper and lower limits of hydraulically induced fractures relative to the position of drinking water aquifers in the Barnett and Eagle Ford Shale, the Marcellus Shale, and the Woodford Shale.[70] In 2011, the firm reported that the results of the monitoring show that even the highest fracture point is several thousand feet below the depth of the deepest drinking water aquifer. For example, for over 200 fractures in the Woodford Shale, the typical distance between the drinking water aquifer and the top of the fracture was 7,500 feet, with the highest fracture recorded at 4,000 feet from the aquifer. In another example, for the 3,000 fractures performed in the Barnett Shale, the typical distance from the drinking water aquifer and the top of the fracture was 4,800 feet, and the fracture with the closest distance to the aquifer was still separated by 2,800 feet of rock. Table 4 shows the relationship between shale formations and the depth of treatable water in five shale gas plays currently being developed.

[69]George E. King, Apache Corporation, "Explaining and Estimating Fracture Risk: Improving Fracture Performance in Unconventional Gas and Oil Wells" (presented at the Society of Petroleum Engineers Hydraulic Fracturing Conference, The Woodlands, Texas, February 2012).

[70]Kevin Fisher, Norm Warpinski, Pinnacle—A Haliburton Service, "Hydraulic Fracture-Height Growth: Real Data" (presented at the Society of Petroleum Engineers Technical Conference and Exhibition, Denver, Colorado, October 2011).

Table 4: Shale Formation and Treatable Water Depth

Distance in feet

Shale play	Depth to shale	Depth to base of treatable water	Distance between shale and base of treatable water
Barnett	6,500- 8,500	1,200	5,300- 7,300
Fayetteville	1,000- 7,000	500	500- 6,500
Haynesville	10,500- 13,500	400	10,100- 13,100
Marcellus	4,000- 8,500	850	2,125- 7,650
Woodford	6,000- 11,000	400	5,600- 10,600

Source: GAO analysis of data presented in a report prepared at the request of the DOE.

Note: Depths to base of treatable water are approximate. According to the report, the depth to base of treatable water was based on data from state oil and gas agencies and state geological survey data.

Several government, academic, and nonprofit organizations evaluated water quality conditions or groundwater contamination incidents in areas experiencing shale oil and gas development. Among the studies and publications we reviewed that discuss the potential contamination of drinking water from the hydraulic fracturing process in shale formations are the following:

- In 2011, the Center for Rural Pennsylvania analyzed water samples taken from 48 private water wells located within about 2,500 feet of a shale gas well in the Marcellus Shale.[71] The analysis compared predrilling samples to postdrilling samples to identify any changes to water quality. The analysis showed that there were no statistically significant increases in pollutants prominent in drilling waste fluids—such as total dissolved solids, chloride, sodium, sulfate, barium, and strontium—and no statistically significant increases in methane. The study concluded that gas well drilling had not had a significant effect on the water quality of nearby drinking water wells.

- In 2011, researchers from Duke University studied shale gas drilling and hydraulic fracturing and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York. Sixty drinking water samples were collected in Pennsylvania and New York from bedrock aquifers that

[71]The Center for Rural Pennsylvania, *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies* (Harrisburg, Pennsylvania: October 2011).

overlie the Marcellus or Utica Shale formations—some from areas with shale gas development and some from areas with no shale gas development.[72] The study found that methane concentrations were detected generally in 51 drinking water wells across the region—regardless of whether shale gas drilling occurred in the area—but that concentrations of methane were substantially higher closer to shale gas wells. However, the researchers reported that a source of the contamination could not be determined. Further, the researchers reported that they found no evidence of fracturing fluid in any of the samples.

- In 2011, the Ground Water Protection Council evaluated state agency groundwater investigation findings in Texas and categorized the determinations regarding causes of groundwater contamination resulting from the oil and gas industry.[73] During the study period—from 1993 through 2008—multistaged hydraulic fracturing stimulations were performed in over 16,000 horizontal shale gas wells. The evaluation of the state investigations found that there were no incidents of groundwater contamination caused by hydraulic fracturing.

In addition, regulatory officials we met with from eight states—Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas—told us that, based on state investigations, the hydraulic fracturing process has not been identified as a cause of groundwater contamination within their states.

A number of studies discuss the potential contamination of water from the hydraulic fracturing process in shale formations. However, according to several studies we reviewed, there are insufficient data for predevelopment (or baseline) conditions for groundwater. Without data to compare predrilling conditions to postdrilling conditions, it is difficult to determine if adverse effects were the result of oil and gas development, natural occurrences, or other activities. In addition, while researchers

[72]Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, "Methane Contamination of Drinking Water Accompanying Gas-well Drilling and Hydraulic Fracturing," *Proceedings of the National Academy of Science* 108, no. 20 (2011).

[73]Ground Water Protection Council, *State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms: A Two-State Review: Ohio and Texas* (Oklahoma City, Oklahoma: August 2011).

have evaluated fracture growth, the widespread development of shale oil and gas is relatively new. As such, little data exist on (1) fracture growth in shale formations following multistage hydraulic fracturing over an extended time period, (2) the frequency with which refracturing of horizontal wells may occur, (3) the effect of refracturing on fracture growth over time,[74] and (4) the likelihood of adverse effects on drinking water aquifers from a large number of hydraulically fractured wells in close proximity to each other.

Ongoing Studies Related to Water Quality

Ongoing studies by federal agencies, industry groups, and academic institutions are evaluating the effects of hydraulic fracturing on water resources so that, over time, better data and information about these effects should become available to policymakers and the public. For example, EPA's Office of Research and Development initiated a study in January 2010 to examine the potential effects of hydraulic fracturing on drinking water resources. According to agency officials, the agency anticipates issuing a progress report in 2012 and a final report in 2014. EPA is also conducting an investigation to determine the presence of groundwater contamination within a tight sandstone formation being developed for natural gas near Pavillion, Wyoming, and, to the extent possible, identify the source of the contamination. In December 2011, EPA released a draft report outlining findings from the investigation. The report is not finalized, but the agency indicated that it had identified certain constituents in groundwater above the production zone of the Pavillion natural gas wells that are consistent with some of the constituents used in natural gas well operations, including the process of hydraulic fracturing. DOE researchers are also testing the vertical growth of fractures during hydraulic fracturing to determine whether fluids can travel thousands of feet through geologic faults into water aquifers close to the surface.

Land and Wildlife

Oil and gas development, whether conventional or shale oil and gas, poses a risk to land resources and wildlife habitat as a result of constructing, operating, and maintaining the infrastructure necessary to develop oil and gas; using toxic chemicals; and injecting waste products underground.

[74]According to research presented in the New York Department of Environmental Conservation's Supplemental Generic Environmental Impact Statement, refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.

Habitat Degradation

According to studies and publications we reviewed, development of oil and gas, whether conventional or shale oil and gas, poses a risk to habitat from construction activities. Specifically, clearing land of vegetation and leveling the site to allow access to the resource, as well as construction of roads, pipelines, storage tanks, and other infrastructure needed to extract and transport the resource can fragment habitats.[75] In August 2003, we reported that oil and gas infrastructure on federal wildlife refuges can reduce the quality of habitat by fragmenting it.[76] Fragmentation increases disturbances from human activities, provides pathways for predators, and helps spread nonnative plant species.

In addition, spills of oil, gas, or other toxic chemicals have harmed wildlife and habitat. Oil and gas can injure or kill wildlife by destroying the insulating capacity of feathers and fur, depleting oxygen available in water, or exposing wildlife to toxic substances. Long-term effects of oil and gas contamination on wildlife are difficult to determine, but studies suggest that effects of exposure include reduced fertility, kidney and liver damage, immune suppression, and cancer. In August 2003, we reported that even small spills may contaminate soil and sediments if they occur frequently.[77] Further, noise and the presence of new infrastructure associated with shale gas development may also affect wildlife. A study by the Houston Advanced Research Center and the Nature Conservancy investigated the effects of noise associated with gas development on the Attwater's Prairie Chicken—an endangered species. The study explored how surface disruptions, particularly construction of a rig and noise from diesel generators would affect the animal's movement and habitat.[78] The results of the study found that the chickens were not adversely affected by the diesel engine generator's noise but that the presence of the rig caused the animals to temporarily disperse and avoid the area.

[75]Habitat fragmentation occurs when a network of roads and other infrastructure is constructed in previously undeveloped areas.

[76]GAO-03-517.

[77]GAO-03-517.

[78]James F. Bergan, Richard Haut, Jared Judy, and Liz Price. "Living In Harmony—Gas Production and the Attwater's Prairie Chicken" (presented at the Society of Professional Engineers Annual Technical Conference, Florence, Italy, September 2010).

A number of studies we reviewed identified risks to habitat and wildlife as a result of shale oil and gas activities. However, because shale oil and gas development is relatively new in some areas, the long-term effects—after operators are to have restored portions of the land to predevelopment conditions—have not been evaluated. Without these data, the cumulative effects of shale oil and gas development on habitat and wildlife are largely unknown.

Induced Seismicity

According to several studies and publications we reviewed, the hydraulic fracturing process releases energy deep beneath the surface to break rock but the energy released is not large enough to trigger a seismic event that could be felt on the surface. However, a process commonly used by operators to dispose of waste fluids—underground injection—has been associated with earthquakes in some locations. For example, a 2011 Oklahoma Geological Survey study reported that underground injection can induce seismicity. In March 2012, the Ohio Department of Natural Resources reported that “there is a compelling argument” that the injection of produced water into underground injection wells was the cause of the 2011 earthquakes near Youngstown, Ohio. In addition, the National Academy of Sciences released a study in June 2012 that concluded that underground injection of wastes poses some risk for induced seismicity, but that very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

The available research does not identify a direct link between hydraulic fracturing and increased seismicity, but there could be an indirect effect to the extent that increased use of hydraulic fracturing produces increased amounts of water that is disposed of through underground injection. In addition, according to the National Academy of Science’s 2012 report, accurately predicting magnitude or occurrence of seismic events is generally not possible, in part, because of a lack of comprehensive data on the complex natural rock systems at energy development sites.

Extent of Risks Is Unknown and Depends on Many Factors

The extent and severity of environmental and public health risks identified in the studies and publications we reviewed may vary significantly across shale basins and also within basins because of location- and process-specific factors, including the location and rate of development; geological characteristics, such as permeability, thickness, and porosity of the formations in the basin; climatic conditions; business practices; and regulatory and enforcement activities.

Location and rate of development. The location of oil and gas operations and the rate of development can affect the extent and severity of environmental and public health risks. For example, as we reported in October 2010, while much of the natural gas that is vented and flared is considered to be unavoidably lost, certain technologies and practices can be applied throughout the production process to capture some of this gas, according to the oil and gas industry and EPA. The technologies' technical and economic feasibility varies and sometimes depends on the location of operations. For example, some technologies require a substantial amount of electricity, which may be less feasible for remote production sites that are not on the electrical grid. In addition, the extent and severity of environmental risks may vary based on the location of oil and gas wells. For example, in areas with high population density that are already experiencing challenges adhering to federal air quality limits, increases in ozone levels because of emissions from oil and gas development may compound the problem.

Geological characteristics. Geological characteristics can affect the extent and severity of environmental and public health risks associated with shale oil and gas development. For example, geological differences between tight sandstone and shale formations are important because, unlike shale, tight sandstone has enough permeability to transmit groundwater to water wells in the region. In a sense, the tight sandstone formation acts as a reservoir for both natural gas and for groundwater. In contrast, shale formations are typically not permeable enough to transmit water and are not reservoirs for groundwater. According to EPA officials, hydraulic fracturing in a tight sandstone formation that is a reservoir for both natural gas and groundwater poses a greater risk of contamination than the same activity in a deep shale formation.

Climatic conditions. Climatic factors, such as annual rainfall and surface temperatures, can also affect the environmental risks for a specific region or area. For example, according to a 2007 study funded by DOE, average rainfall amounts can be directly related to soil erosion.[79] Specifically,

[79] ALL Consulting and the Interstate Oil and Gas Compact Commission, *Improving Access to Onshore Oil and Gas Resources on Federal Lands* (a special report prepared at the request of the U.S. Department of Energy National Energy and Technology Laboratory, March 2007).

areas with higher precipitation levels may be more susceptible to soil compaction and rutting during the well pad construction phase. In another example, risk of adverse effects from exposures to toxic air contaminants can vary substantially between drilling sites, in part, because of the specific mix of emissions and climatic conditions that affect the transport and dispersion of emissions. Specifically, wind speed and direction, temperature, as well as other climatic conditions, can influence exposure levels of toxic air contaminants. For example, according to a 2012 study from the Sustainable Investments Institute and the Investor Responsibility Research Center Institute, the combination of air emissions from gas operations, snow on the ground, bright sunshine, and temperature inversions during winter months have contributed to ozone creation in Sublette County, Wyoming.[80]

Business practices. A number of studies we reviewed indicate that some adverse effects from shale oil and gas development can be mitigated through the use of technologies and best practices. For example, according to standards and guidelines issued jointly by the Departments of the Interior and Agriculture, mitigation techniques, such as fencing and covers, should be used around impoundments to prevent livestock or wildlife from accessing fluids stored in the impoundments.[81] In another example, EPA's Natural Gas STAR program has identified over 80 technologies and practices that can cost effectively reduce methane emissions, a potent greenhouse gas, during oil and gas development. However, the use of these technologies and business practices are typically voluntary and rely on responsible operators to ensure that necessary actions are taken to prevent environmental contamination. Further, the extent to which operators use these mitigating practices is unknown and could be particularly challenging to identify given the significant increase in recent years in the development of shale oil and gas by a variety of operators, both large and small.

Regulatory and enforcement activities. Potential changes to the federal, state, and local regulatory environment will affect operators' future

[80]Susan Williams, "Discovering Shale Gas: An Investor Guide to Hydraulic Fracturing," Sustainable Investments Institute and Investor Responsibility Research Center Institute (New York, NY: February 2012).

[81]United States Department of the Interior and United States Department of Agriculture. *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*. BLM/WO/ST-06/021+3071/REV 07 (Denver, CO: 2007).

activities and can therefore affect the risks or level of risks associated with shale oil and gas development. Shale oil and gas development is regulated by multiple levels of government—including federal, state, and local. Many of the laws and regulations applicable to shale oil and gas development were put in place before the increase in operations that has occurred in the last few years, and various levels of government are evaluating and, in some cases, revising laws and regulations to respond to the increase in shale oil and gas development. For example, in April 2012, EPA promulgated New Source Performance Standards for the oil and gas industry that, when fully phased-in by 2015, will require emissions reductions at new or modified oil and gas well sites, including wells using hydraulic fracturing. Specifically, these new standards, in part, focus on reducing the venting of natural gas and volatile organic compounds during the flowback process. In addition, areas without prior experience with oil and gas development are just now developing new regulations. These governments' effectiveness in implementing and enforcing this framework will affect future activities and the level of associated risk.

Agency Comments

We provided a draft of this report to the Department of Energy, the Department of the Interior, and the Environmental Protection Agency for review and comment. We received technical comments from Interior's Assistant Secretary, Policy, Management, and Budget, and from Environmental Protection Agency officials, which we have incorporated as appropriate. In an e-mail received August 27, 2012, the Department of Energy liaison stated the agency had no comments on the report.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of Energy, the Secretary of the Interior, the EPA Administrator, and other interested parties. In addition, the report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix IV.

Frank Rusco
Director, Natural Resources and Environment

List of Requesters

The Honorable Barbara Boxer
Chairman
Committee on Environment and Public Works
United States Senate

The Honorable Sheldon Whitehouse
Chairman
Subcommittee on Oversight
Committee on Environment and Public Works
United States Senate

The Honorable Benjamin L. Cardin
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Subcommittee on Water and Wildlife
Committee on Environment and Public Works
United States Senate

The Honorable Henry A. Waxman
Ranking Member
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House of Representatives

The Honorable Edward J. Markey
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Committee on Natural Resources
House of Representatives

The Honorable Diana DeGette
Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

The Honorable Robert P. Casey, Jr.
United States Senate

Appendix I: Scope and Methodology

Our objectives for this review were to determine what is known about (1) the size of shale oil and gas resources in the United States and the amount produced from 2007 through 2011—the years for which data were available—and (2) the environmental and public health risks associated with development of shale oil and gas.

To determine what is known about the size of shale oil and gas resources, we collected data from federal agencies, state agencies, private industry, and academic organizations. Specifically, to determine what is known about the size of these resources, we obtained information for technically recoverable and proved reserves estimates for shale oil and gas from the Energy Information Administration (EIA), the U.S. Geological Survey (USGS), and the Potential Gas Committee—a nongovernmental organization composed of academic and industry officials. We interviewed key officials about the assumptions and methodologies used to estimate the resource size. Estimates of proved reserves of shale oil and gas are based on data provided to EIA by operators. In addition to the estimates provided by these three organizations, we also obtained and presented technically recoverable shale oil and gas estimates from two private organizations—IHS Inc., and ICF International—and one national advisory committee representing the views of the oil and gas industry and other stakeholders—the National Petroleum Council. For all estimates we report, we conducted a review of the methodologies used in these estimates for fatal flaws; we did not find any fatal flaws in these methodologies.

To determine what is known about the amount of produced shale oil and gas from 2007 through 2011, we obtained data from EIA—the federal agency responsible for estimating and reporting this and other energy information. EIA officials provided us with estimated oil and gas production data, including data estimating shale oil and gas estimates from states and two private firms—HPDI, LLC and Lippman Consulting, Inc. To assess the reliability of these data, we examined EIA's published methodology for collecting this information and interviewed key EIA officials regarding the agency's data collection and validation efforts. We also interviewed officials from three state agencies, representatives from five private companies, and researchers from three academic institutions who are familiar with these data and EIA's methodology and discussed the sources and reliability of the data. We determined that these data were sufficiently reliable for the purposes of this report.

To determine what is known about the environmental and public health risks associated with the development of shale oil and gas[1], we identified and reviewed more than 90 studies and other publications from federal agencies and laboratories, state agencies, local governments, the petroleum industry, academic institutions, environmental and public health groups, and other nongovernmental associations. The studies and publications we reviewed included scientific and industry periodicals, government-sponsored research, reports or other publications from nongovernmental organizations, and presentation materials. We identified these studies by conducting a literature search and by asking for recommendations during our interviews with stakeholders. For a number of studies, we interviewed the author or authors to discuss the study's findings and limitations, if any. We believe we have identified the key studies through our literature review and interviews, and that the studies included in our review have accurately identified potential risks for shale oil and gas development. However, given our methodology, it is possible that we may not have identified all of the studies with findings relevant to our objectives, and the risks we present may not be the only issues of concern. The widespread use of horizontal drilling and hydraulic fracturing to develop shale oil and gas is relatively new. Studying the effects of an activity and completing a formal peer-review process can take numerous months or years. Because of the relative short time frame for operations and the lengthy time frame for studying effects, we did not limit the review to peer-reviewed publications.

The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse affects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many or where shale oil and gas drilling operations may be constructed. Second, operators' use of effective best practices to mitigate risk may vary. Third, based on the studies we reviewed, there are relatively few that are based on evaluating predevelopment conditions to postdevelopment conditions—making it difficult to detect or attribute adverse changes to shale oil and gas development. In addition, changes to the federal, state, and local

[1]Operators may use hydraulic fracturing to develop oil and natural gas from formations other than shale. Specifically, coalbed and tight sand formations may rely on these practices, and some studies and publications we reviewed identified risks that can apply to these formations. However, many of the studies and publications we identified and reviewed focused primarily on the development of shale formations.

regulatory environment and the effectiveness in implementation and enforcement will affect operators' future activities. Moreover, risks of adverse events, such as spills or accidents, may vary according to business practices, which in turn, may vary across oil and gas companies making it difficult to distinguish between risks that are inherent to the development of shale oil and gas from risks that are specific to particular business practices.

To obtain additional perspectives on issues related to environmental and public health risks, we interviewed a nonprobability sample of stakeholders representing numerous agencies and organizations. (See app. II for a list of agencies and organizations contacted.) We selected these agencies and organizations to be broadly representative of differing perspectives regarding environmental and public health risks. In particular, we obtained views and information from federal officials from the Department of Energy's National Energy Technical Laboratory, the Department of the Interior's Bureau of Land Management and Bureau of Indian Affairs, and the Environmental Protection Agency; state regulatory officials from Arkansas, Colorado, Louisiana, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas; tribal officials from the Osage Nation; shale oil and gas operators; representatives from environmental and public health organizations; and other knowledgeable parties with experience related to shale oil and gas development, such as researchers from the Colorado School of Mines, the University of Texas, Oklahoma University, and Stanford University. The findings from our interviews with stakeholders and officials cannot be generalized to those we did not speak with.

We conducted this performance audit from November 2011 to September 2012 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: List of Agencies and Organizations Contacted

Federal Agencies	Congressional Research Service Department of Energy's National Energy Technology Laboratory Department of Health and Human Services Department of the Interior's Bureau of Indian Affairs Department of the Interior's Bureau of Land Management Department of the Interior's U.S. Geological Survey Environmental Protection Agency
State Agencies	Arkansas Department of Environmental Quality Arkansas Oil and Gas Commission Colorado Oil and Gas Conservation Commission Louisiana Department of Natural Resources North Dakota Industrial Commission Ohio Department of Natural Resources Ohio Environmental Protection Agency Oklahoma Geological Survey Oklahoma Corporation Commission Texas Railroad Commission
Academic Institutions	Colorado School of Mines Oklahoma University Stanford University University of Texas at Arlington University of Texas Energy Center and Bureau of Economic Geology
Environmental Organizations	Clean Water Action Pennsylvania Earthworks Oil and Gas Accountability Project Environmental Defense Fund Subra Consulting Western Resource Advocates
Public Health Organizations	The Endocrine Disruption Exchange National Association of County and City Health Officials Southwest Pennsylvania Environmental Health Project
Industry	ALL Consulting American Exploration and Production Council American Petroleum Institute Apache Corporation

Chesapeake Energy
Colorado Oil and Gas Association
Devon Energy
Powell Shale Digest

Others

Ground Water Protection Council
Martin Consulting
Red River Watershed Management Institute
Osage Tribal Nation

Appendix III: Additional Information on USGS Estimates

The USGS estimates potential oil and gas resources in about 60 geological areas (called "provinces") in the United States. Since 1995, USGS has conducted oil and gas estimates at least once in all of these provinces; about half of these estimates have been updated since the year 2000 (see table 5). USGS estimates for an area are updated once every 5 years or more, depending on factors such as the importance of an area.

Table 5: USGS Estimates

Name of USGS province	Most recent assessment year
Northern Alaska	2006
Central Alaska	2004
Southern Alaska	2011
Western Oregon-Wash.	2009
Eastern Oregon-Wash.	2006
Northern Coastal	1995
Sonoma-Livermore	1995
Sacramento Basin	2006
San Joaquin Basin	2004
Central Coastal	1995
Santa Maria Basin	1995
Ventura Basin	1995
Los Angeles Basin	1995
Idaho-Snake River Downwarp	1995
Western Great Basin	1995
Eastern Great Basin	2004
Uinta-Piceance Basin	2002
Paradox Basin	1995
San Juan Basin	2002
Albuquerque-Sante Fe Rift	1995
Northern Arizona	1995
S. Ariz.-S.W. New Mexico	1995
South-Central New Mexico	1995
Montana Thrust Belt	2002
Central Montana	2001
Southwest Montana	1995
Hanna, Laramie, Shirley	2005

Name of USGS province	Most recent assessment year
Williston Basin (includes Bakken Shale Formation)	2008
Powder River Basin	2006
Big Horn Basin	2008
Wind River Basin	2005
Wyoming Thrust Belt	2004
Southwestern Wyoming	2002
Park Basins	1995
Denver Basin	2003
Las Animas Arch	1995
Raton Basin-Sierra Grande Uplift	2005
Palo Duro Basin	1995
Permian Basin (includes Barnett Shale)	2007
Bend Arch-Ft. Worth Basin	2004
Marathon Thrust Belt	1995
Western Gulf Coast (includes Eagle Ford Shale)	2011
East Texas Basin Province	2011
Louisiana-Mississippi Salt Basins Province	2011
Florida Peninsula	2000
Superior	1995
Cambridge Arch-Central Kansas	1995
Nemaha Uplift	1995
Forest City Basin	1995
Anadarko Basin	2011
Sedgwick Basin/Salina Basin	1995
Cherokee Platform	1995
Southern Oklahoma	1995
Arkoma Basin	2010
Michigan Basin	2005
Illinois Basin	2007
Black Warrior Basin	2002
Cincinnati Arch	1995
Appalachian Basin (includes Marcellus Shale)	2011
Blue Ridge Thrust Belt	1995
Piedmont	1995

Source: USGS.

Appendix IV: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the contact named above, Christine Kehr, Assistant Director; Lee Carroll; Nirmal Chaudhary; Cindy Gilbert; Alison O'Neill; Marietta Revesz, Dan C. Royer; Jay Spaan; Kiki Theodoropoulos; and Barbara Timmerman made key contributions to this report.

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LOOK BEFORE THE LNG LEAP:

Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start

BEYOND NATURAL GAS

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LOOK BEFORE THE LNG LEAP:

Why Policymakers and the Public Need Fair Disclosure Before Exports of Fracked Gas Start

By **Craig Segall,** Staff Attorney, Sierra Club Environmental Law Program. Thanks to legal fellow **Philip Goo** for very helpful research assistance.

EXECUTIVE SUMMARY

Exporting American natural gas to the world market would spur unconventional natural gas production across the country, increasing pollution and disrupting landscapes and communities. Deciding whether to move forward is among the most pressing environmental and energy policy decisions facing the nation. Yet, as the Department of Energy (DOE) considers whether to greenlight gas exports of as much as 45% of current U.S. gas production—more gas than the entire domestic power industry burns in a year—it has refused to disclose, or even acknowledge, the environmental consequences of its decisions. In fact, DOE has not even acknowledged that its own National Energy Modeling System can be used to help develop much of this information, instead preferring to turn a blind eye to the problem. DOE needs to change course. Even much smaller volumes of export have substantial environmental implications and exporting a large percentage of the total volume proposed would greatly affect the communities and ecosystems across America. The public and policymakers deserve, and are legally entitled to, a full accounting of these impacts.

Gas exports are only possible because of the unconventional natural gas boom which hydraulic fracturing ("fracking") has unlocked. DOE's own advisory board has warned of the boom's serious environmental impacts. DOE is charged with determining whether such exports are in the public interest despite the damage that would result. To do that, it needs a full accounting of the environmental impacts of increasing gas production significantly to support exports.

These environmental considerations include significant threats to air and water quality from the industry's wastes, and the industrialization of entire landscapes. Gas production is associated with significant volumes of highly-contaminated wastewater and the risk of groundwater contamination; it has also brought persistent smog problems to entire regions, along with notable increases in toxic and carcinogenic air pollutants. Regulatory measures to address these impacts have been inadequate, meaning that increased production very likely means increased environmental harm. Natural gas exports also have important climate policy implications on several fronts: Even if exported gas substitutes for coal abroad (which it may or may not do), it will not produce emissions reductions sufficient to stabilize the climate, and gas exports will increase our investment in fossil fuels. Moreover, the gas export process is particularly carbon-intensive, and gas exports will likely raise gas prices domestically, increasing the market share of dirty coal power, meaning that perceived climate benefits may be quite limited if they exist at all. The upshot is that increasing gas production comes with significant domestic costs.

The National Environmental Policy Act (NEPA) process is designed to generate just such an analysis. NEPA analyses, properly done, provide full, fair, descriptions of a project's environmental implications, remaining uncertainties, and alternatives that could avoid environmental damage. A full NEPA environmental impact statement looking programmatically at export would help DOE and the public fairly weigh these proposals' costs and benefits, and to work with policymakers at the federal, state, and local levels to address any problems. In fact, the U.S. Environmental Protection Agency has repeatedly called for just such an analysis.Without one, America risks committing itself to a permanent role as a gas supplier to the world without determining whether it can do so safely while protecting important domestic interests.

Equally troublingly, even as DOE has thus far failed to fulfill its obligation to protect the public interest by weighing environmental impacts, it risks losing its authority altogether. A drafting quirk in the export licensing statute intended to speed gas imports from Canada means that DOE must grant licenses for gas exports to nations with which the United States has signed a free trade agreement which includes national treatment of natural gas. This rubber-stamp applies even if the proposed exports would not otherwise be in the public interest. As the U.S. negotiates a massive trade agreement which may include nations hungry for U.S. exports, the Trans-Pacific Partnership, this mandatory rubber-stamp risks undercutting DOE's ability to protect the public.

The bottom line is that before committing to massive gas exports, federal decisionmakers need to ensure that they, and the public, have the environmental information they need to make a fair decision, and the authority to do so. That means ensuring that a full environmental impact statement discloses exports' impacts and develops alternatives to reduce them. It also means defending DOE's prerogatives against the unintended effects of trade pacts. Congress and the U.S. trade negotiators must ensure that agreements like the Trans-Pacific Partnership are designed to maintain DOE's vital public interest inquiry.

Gas exports would transform the energy landscape and communities across the country. We owe ourselves an open national conversation to test whether they are in the public interest. We need to look before we leap.

I. Introduction

For the first time ever, the United States has the ability to become a major natural gas exporter, but that possibility comes with substantial economic and environmental risks. The huge volumes of natural gas proposed for export as liquefied natural gas (LNG) would raise domestic energy prices and require a significant expansion of unconventional gas production using hydraulic fracturing ("fracking").

This shift in the energy landscape raises serious questions: What will export-induced production mean for people living in the gas fields? What will it mean for utilities weighing coal and gas prices as they chart the future of their generation fleets? What it will mean for environmental regulators seeking to manage risk? What will it mean for our air and water quality? What will it mean for climate policy if we increase the extraction and use of this fossil fuel? In the end, are exports worth higher prices and more pollution from fracked gas?

The policy debate continues, but without crucial information: Incredibly, neither the Department of Energy ("DOE")'s Office of Fossil Energy nor the Federal Energy Regulatory Commission ("FERC"), which share responsibility over LNG export proposals under the Natural Gas Act, have completed a full assessment of the environmental risks associated with export and the expanded gas production needed to support it. The agencies could do so using publicly available information and modeling systems, but have so far refused, implausibly insisting that it is impossible to predict *any* upstream impacts from expanded LNG exports.

For more than forty years, Congress has directed federal agencies to use the National Environmental Policy Act (NEPA)'s environmental impact statement process to address environmental decisions like this one. The NEPA process allows agencies to generate comprehensive data, weigh alternatives, and expose assumptions to public scrutiny, so they can base decisions on a fully developed analysis of the impacts of a proposed activity. Amidst the ongoing raucous public debate on export, the information NEPA can provide is not just legally required, but sorely needed.

DOE and FERC have failed to provide this critical analysis. Only one LNG export proposal, for a terminal at Sabine Pass on the Louisiana-Texas border, has moved most of the way through the federal licensing process. FERC, which focuses largely on terminal siting, refused to consider any of the upstream consequences of Sabine Pass's plan to export 2.2 billion cubic feet of gas every day.[2] It did so even though Sabine Pass's export application trumpets that the project intends to "play an influential role in contributing to the growth of natural gas production in the U.S." and relies substantially on this point to argue that the project is in the public interest.[3] DOE followed suit, adopting FERC's analysis to support its own public interest determination, while maintaining that the induced gas production necessary to support export is not

[2] FERC, *Order Granting Section 3 Authorization [to Sabine Pass]*, 139 FERC ¶ 61,039 (Apr. 16, 2012).
[3] Sabine Pass Export Application at 56, DOE/FE Docket 10-111-LNG (Sept. 7, 2010).

"reasonably foreseeable," and so warrants no consideration.[4] DOE recently announced that it would take time to consider whether to stand by this decision, but it has not yet reversed course.[5]

Thus, even while authorizing a proposal which, on its own, would increase U.S. gas exports by more than 50% annually,[6] and which explicitly relies on increased natural gas production to support itself, the federal decisionmakers charged with protecting the public interest were asleep at the switch. Even though export proponents themselves advertise that their projects will drive unconventional natural gas production, DOE and FERC are willfully blind to this major impact. This position is particularly untenable because the National Energy Modeling System (NEMS) which the Energy Information Administration ("EIA") within DOE administers, is designed to project changes in gas production caused by new demand, and could therefore predict precisely the production-level impacts which DOE and FERC insist cannot be foreseen at all.[7]

Instead, applications to export more than ten times the gas which was authorized in the Sabine Pass matter are moving forward in a piecemeal terminal-by-terminal licensing process which has not provided any meaningful analysis of the national and regional environmental challenges linked to export. This ongoing legal and policy failure warrants immediate correction.

Not only have DOE and FERC failed to provide a proper accounting, they may lose even their authority to do so if a controversial trade agreement now under negotiation is finalized. That deal, the Trans-Pacific Partnership ("TPP"), could further liberalize trade with much of the Pacific Rim, including major natural gas importers like Japan. Thanks to a little-known provision of the Natural Gas Act, it could also remove federal oversight of LNG exports. Twenty years ago, in an effort to speed Canadian gas *imports*, Congress provided that LNG shipments between countries with which the U.S. has a free trade agreement were to be automatically granted. Although Congress never anticipated massive LNG exports, that same provision could nonetheless remove DOE and FERC's discretion to weigh whether huge volumes of export are in the public interest, or to meaningfully regulate the process. Yet neither agency has insisted that TPP negotiators protect this critical federal authority.

For communities across the country, therefore, the future is in real question. If LNG export goes forward, they will experience a surge of unconventional new gas production, along with all

[4] DOE, *Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations*, FE Docket No. 10-111-LNG (Aug. 7, 2012).
[5] *See* DOE, *Order Granting Rehearing for Further Consideration*, FE Docket No. 10-111-LNG (Oct. 5, 2012).
[6] *See* EIA, *U.S. Natural Gas Imports & Exports 2011* (July 18, 2012). The U.S. now exports about 1,500 billion cubic feet "bcf" of natural gas annually, with the vast majority travelling by pipeline to Mexico and Canada. Sabine Pass would export 2.2 bcf/day, or 803 bcf annually.
[7] *See, e.g.*, EIA, *The National Energy Modeling System: An Overview* (2009) at 54-55 (explaining that NEMS contains "play-level" production models for each unconventional natural gas play and projects production based on demand); 59-62 (transmission and distribution module of NEMS allocates demand based through modeling the transmission network and can account for imports and exports).

the environmental burdens of the boom that are outlined below. If DOE and FERC do not analyze and disclose these impacts, neither they or state and local governments can weigh whether they are in the public interest, or take action to lessen them. And if the TPP and pacts like it are signed without due reflection and before a full NEPA environmental impact statement is available, the U.S. will be locked into a future of gas export without ever having considered the cost.

It is not yet too late to change course. DOE has committed not to release any more export licenses until an economic study has been finalized, which will not occur until this winter. Negotiations for the TPP have not concluded. FERC has not sited any more new terminals. So, although the United States has begun to edge into exports, that future has not yet been chosen. Cooler heads can still prevail, and decisionmakers can develop the information we and they so clearly need.

II. The Magnitude of the Export Boom

Even if only some of the 19 export projects now before DOE are approved, they would, once operational, transform the domestic energy market and greatly increase unconventional natural gas production. There is no domestic precedent for changes of the magnitude which DOE is now considering.

Before the shale gas boom began, the U.S. exported almost no gas beyond Canada and Mexico, and even those North American exports were not very large. In 2006, for instance, the U.S. exported a total of 723.9 bcf per year of natural gas, with 663 of that by pipeline.[8] Only the remaining approximately 60 bcf per year are exported as LNG, essentially all of it going to Japan from a single Alaskan terminal, with a few bcf to Mexico by truck.[9] Policymakers largely assumed that this pattern would continue, urging that the U.S. develop gas *import* capacity to accommodate growing domestic demand.[10]

The situation now is very different. Projections of abundant domestic natural gas from unconventional, largely shale, plays has dropped domestic gas prices to record lows while prices abroad remain high. As a result, U.S. pipeline exports have risen, pushing total exports over 1,500 bcf per year (or about 4 bcf per day), and investors have flooded DOE with an ever-growing number of export proposals. As of late October 2012, the 19 different export projects before DOE proposed to export as much as 28.39 bcf *per day* of LNG.[11] Of this, 23.71 bcf per day was proposed for export to countries with which the U.S. has not signed a free trade

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[8] EIA, U.S. Natural Gas Exports by Country, *available at*: http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm.
[9] *See id.*
[10] *See, e.g.*, National Petroleum Council, *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy* at 36-40 (2003)
[11] Department of Energy Office of Fossil Energy, *Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of October 26, 2012)*, available at http://www.fossil.energy.gov/programs/gasregulation/reports/Long_Term_LNG_Export_10-26-12.pdf. Other proposals to export at least 2.5 bcf/d of LNG have also been reported, but have not yet been filed with DOE.

agreement providing for national treatment of natural gas; DOE has clear authority to disapprove such proposals if they are not in the public interest.

How much gas is 28.39 bcf per day? It is equivalent to 10,362 bcf per year. By comparison, the entire country produced just 23,000 bcf in 2011, meaning that exports equivalent to about 45% of domestic production are now before DOE.[13] Exporting this much gas would be bound to strongly affect domestic gas production and consumption patterns. For example, the country consumed 24,316 bcf of gas last year – slightly more than it produced, with imports making up much of the difference.[14] Dedicating forty percent of U.S. gas production to export would, therefore, cause big shifts in the domestic market. The amount of gas slated for export is considerably more than the 7,602 bcf that the entire electric power sector used last year, and nearly twice as much gas as was used for electricity by every home in the country.[15] If this amount of gas is exported, the United States must produce more gas, use less, or do both.

The Energy Information Administration ("EIA") has come to just that conclusion in a DOE-commissioned January 2012 report, which estimated that about two-thirds (63%) of export demand will be met by increased production, rather than by decreases in gas consumption elsewhere in the economy.[16] That new production, in turn, will come almost entirely (93%) from unconventional gas plays, and so will be produced by fracking.[17]

Thus, if the DOE authorizes all of the 10,362 bcf of exports now before it, about 63% of that exported gas, or 6,5282 bcf, would likely be from new production, and 6,397 bcf of that new production would be fracked gas. Total domestic gas production would increase by 27%.

To be sure, there are legitimate questions as to the real scope of the export boom. The global LNG market may be hungry for U.S. gas, but limits on near-term demand and regasification capacity may mean that not every export terminal will be built, or operate at capacity. On the other hand, the scramble for export licenses shows no signs of diminishing. In fact, the pace and intensity of this export boom seems to have caught decisionmakers by surprise. In January 2012, DOE and the EIA assumed that exports of 12 bcf/d were at the high end of possible export futures.[18] Export applications for more than double that volume have now been lodged with DOE. The "high end" scenario now looks decidedly mid-range compared to pending applications.[19]

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[13] EIA, Natural Gas Monthly November 2012, Table 1 (volume reported is dry gas).
[14] *Id.*, Table 2.
[15] *Id.* (electric power sector gas use in 2011 was 7,602 bcf; residential use was 4,730 bcf).
[16] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* (Jan. 2012) at 6, 10-11.
[17] *Id.* at 11.
[18] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 1.
[19] In its Annual Energy Outlook for 2012, EIA very conservatively projects that only 2.2 bcf/d of LNG will be exported by 2035, noting that this projection is subject to considerable regulatory uncertainty. *See* EIA, *Annual Energy Outlook* (2012) at 94. This amount would correspond to about a 470 bcf annual increase in unconventional natural gas production – about a 2% national increase. Notably, the 2.2 bcf of annual LNG export EIA conservatively projects are equivalent to the export proposed by the Sabine Pass facility which DOE has already all

Moreover, even a much smaller gas export increase would still mean major changes in the U.S. gas market. If only one-quarter of the proposed projects move forward, about 6 bcf/d of gas would still be exported – the equivalent of 2,190 bcf annually. That demand would, in turn, be accompanied by about 1,172 bcf of new unconventional gas production if the EIA is correct, increasing U.S. gas production overall by 5%.

Proposed export terminal sites are on all three U.S. sea coasts. Most applications are focused on the Gulf Coast, but applicants have also filed to export from Atlantic coastal sites in Maryland and Georgia and from Pacific coastal sites in Oregon. Between the terminals themselves, the pipelines required to feed them with gas, the barge traffic they will engender and, of course, the fracking boom they will support and extend, few regions of the United States will be untouched by LNG export.

III. Environmental Implications of Export

Producing and exporting large volumes of natural gas will have significant environmental implications that are best evaluated in the NEPA process with an Environmental Impact Statement. The urgency of a comprehensive look is clear from an examination of a subset of those effects: impacts associated directly with increasing gas production, impacts from changes in the gas market associated with export, and impacts associated with export itself, particularly its implications for climate change.

A. The Environmental Impacts of Increased Unconventional Gas Production

While the DOE's Office of Fossil Energy continues to consider pending export applications, the Secretary of Energy Advisory Board has been sounding the alarm about the fracking process on which export depends. Its Shale Gas Production Subcommittee issued a detailed set of recommendations in late 2011, emphasizing that a substantially enhanced regulatory and research effort is needed to ensure that unconventional natural gas production can move forward safely.

The Subcommittee, composed of nationally-regarded independent experts, wrote that it "believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity."[20] As of late 2011, the Subcommittee warned that "progress to date is less than the Subcommittee

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but approved. The EIA projection thus functionally assumes that *none* of the other projects now before DOE are built. While that might occur, it is obviously prudent to consider the impacts of other projects.

[20] Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB"), *Second-Ninety Day Report* (Nov. 18, 2011) at 10.

hoped."[21] It cautioned 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."[22]

As the Subcommittee recognized, the impacts of unconventional gas production stretch across multiple mediums and contexts. Its recommendations identify areas for improvement in managing air pollution, water pollution, subsurface contamination, land use, and community impacts.[23] The Subcommittee also issued an urgent call for improved transparency and disclosure throughout the process, and for greatly enhanced research and development to better understand and improve production processes.[24]

Significant environmental impacts associated with unconventional natural gas production, and hence with export, include the following:

Air Pollution

Natural gas production has significant air quality impacts. As the DOE's Shale Gas Subcommittee summarized the matter last August:

> Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.
>
> As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[25]

The tight link between gas production and ground-level ozone, or smog, is a particularly pressing problem. The gas industry is a major source of two major ozone precursors: VOCs and NO_x.[26] Smog harms the respiratory system and has been linked to premature death, heart

[21] *Id.*
[22] *Id.*
[23] *Id.* at Annex C.
[24] *Id.*
[25] SEAB, *First Ninety Day Report* (August 18, 2011) at 15.
[26] *See, e.g.,* Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf (hereinafter "Barnett Shale Report").

failure, chronic respiratory damage, and premature aging of the lungs.[27] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[28]

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of July 2012, there were 16,213 gas wells and another 2,764 wells permitted.[29] Of the nine counties surrounding the Dallas Fort Worth area that EPA has designated as in "nonattainment" with national air quality standards for ozone, five contain significant oil and gas development.[30] A 2009 study found that summertime emissions of smog-forming pollutants from gas production in these counties were roughly comparable to emissions from all the cars in those same areas.[31] These nonattainment designations are particularly striking because the current ozone standard is set below the level EPA's own scientific advisors recommend as adequate to protect public health.[32] That gas production emissions can cause violations even of this relatively *lax* standard underlines their severity.

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[33] On March 12, 2009, the governor of Wyoming recommended that EPA designate Wyoming's Upper Green River Basin as an ozone nonattainment area under EPA's current ozone.[34] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[35] In the winter of 2010-2011, the residents of Sublette County suffered thirteen

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[27] *See, e.g.*, Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop.
[28] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html; EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html.
[29] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf (Accessed Sept. 25, 2012).
[30] Barnett Shale Report at 1, 3.
[31] *Id.* at 1, 25-26.
[32] *See,e.g.*, Elizabeth Shogren, NPR, *EPA Seeks to Tighten Ozone Standards* (July 24, 2011) (when EPA set the current standards it "ignored the advice of its own panel of outside scientific advisers"). EPA has since opted not to immediately update the out-dated standards, but revisions may be forthcoming next year.
[33] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415.
[34] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf.
[35] Wyoming Nonattainment Analysis at viii.

days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone levels exceeded the worst days of smog pollution in Los Angeles.[36]

As oil and gas production moves into new areas ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone air quality standards.[37] Experts also anticipate air quality problems associated with development of the Marcellus shale in the Mid-Atlantic region.[38]

Ozone pollution is not the only danger associated with natural gas production, however. Toxic air emissions are also a significant concern. Emissions from gas fields contain carcinogenic compounds, including benzene, which are associated with significant increases in cancer risk. In fact, Colorado researchers sampling the air near a field there recently determined that residents living within half a mile of from wells were at increased risk of cancer, compared to those living further away, due to long-term exposure to toxic leaks.[39] As the industry expands, this toxic problem will come with it.

In addition to these serious problems, the industry poses a significant threat to the global climate. The natural gas industry is also among the very largest sources of methane pollution in the country. Methane is a potent greenhouse gas, and these emissions rank the industry as the second largest industrial greenhouse gas source, second only to power production.[40] Because fracking operations tend to produce substantially more methane, and are also supporting new well development across the country, unconventional natural gas production is increasing these emissions. EPA has recently estimated annual industry methane emissions as the equivalent of 328 million metric tons of CO_2.[41]

This pollution will remain a serious danger even though EPA has recently finalized its first attempt at comprehensive air pollution controls for the industry.[42] While these standards will

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[36] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode&msaorcountyValue=56035&poll=44201&county =56035&msa=-1&sy=2011&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas.; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1.

[37] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (Nov. 18, 2010).

[38] Elizabeth Shogren, *Air Quality Concerns Threaten Natural Gas's Image*, National Public Radio (June 21, 2011), *available at* http://www.npr.org/2011/06/21/137197991/air-quality-concerns-threaten-natural-gas-image.

[39] *See generally* Lisa McKenzie *et al.*, *Human health risk assessment of air emissions from development of unconventional natural gas resources*, Sci. Total Environment (May 2012), *abstract available at*: http://www.ncbi.nlm.nih.gov/pubmed/22444058.

[40] *See* EPA, Inventory of US Greenhouse Gas Emissions and Sinks 1990-2010 (2012).

[41] *See* 74 Fed. Reg. 52,738, 52,756 (Aug. 23, 2011).

[42] *See* 77 Fed. Reg. 49,490 (Aug. 16, 2012).

play a significant role in reducing air pollution from new infrastructure, many new sources and existing infrastructure escape regulation. Moreover, the standards do not regulate methane directly. As a result, air pollution from production will continue to be a serious problem, despite this important first regulatory effort.

Water Pollution

Much public concern over expanded fracking operations has focused on water pollution, and with good reason. Significant water resource impacts can occur throughout the production process.

Fracking requires large volumes of water per well. While operators have sought to reduce their water demands in some areas, numerous sources indicate that fracturing a single well requires at least 1 to 5 million gallons of water.[43] Water withdrawals can harm aquatic ecosystems and human communities by reducing instream flows—especially in small headwaters streams -- and by harming aquatic organisms at water intake structures.[44] Where water is withdrawn from aquifers rather than surface sources, withdrawal risks permanent depletion.[45] Withdrawals for fracking pose a greater risk than other withdrawals, because fracking is a consumptive use. Fluid injected during the fracking process is ideally deposited below freshwater aquifers and into sealed formations, so much of it never returns to the surface.

The well-site management of fracking fluid and wastes, including flowback water, poses water quality risks throughout the process. Spills at the surface, leaks through well casings, and contaminant migration from the fracking site itself can all contaminate ground and surface water.

Fracturing fluid itself contains many chemicals that present health risks. Diesel fuel and similar compounds pose particularly pressing risks. The DOE Subcommittee singled out diesel for its harmful effects and recommended that it be banned from use as a fracturing fluid additive.[46] The minority staff of the House Committee on Energy and Commerce determined that despite diesel's risks, between 2005 and 2009, "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[47]

Fracking fluids are not the only source of potential contamination.[48] Fluid naturally occurring in the target formation "may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds." [49] Inadequate

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[43] *See, e.g.*, SEAB, *First Ninety-Day Report* at 19; NY RDSGEIS 6-10.
[44] NY RDSGEIS at 6-3, 6-4.
[45] *Id.* 6-5; SEAB, *First Ninety Day report* at 19 ("[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.").
[46] *Id.* at 25.
[47] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2011) at 1.
[48] NY RDSGEIS at 5-75 to 5-78
[49] SEAB *First Ninety-Day Report* at 21.

well cementing, among other faults, can allow these substances to contaminate groundwater resources.[50] Storage, transport, and treatment of produced water on the surface create risks of spills and inadequate disposal, providing another vector for contamination of surface and groundwater resources.[51]

Properly treating these waste products, and other production waste, is essential to protecting water quality. Limited treatment capacity and the challenges of safely using underground injection as an alternative disposal method for large volumes of waste are pressing problems. Treating and discharging extremely salty, highly-contaminated wastewater is energy-intensive and technically difficult, and can put surface streams at risk. Meanwhile, injection also faces challenges, as not all regions have substantial injection capacity and injection wells themselves have been associated with earthquakes of up to 4.0 on the Richter scale.[52]

Finally, sediment contamination associated with the significant land disturbance and construction activities needed to construct and manage a well field is a persistent challenge. Run-off from production sites can readily contaminate streams without careful management.

Incidents of water contamination from various phases of the production process have been widely reported. Although EPA, other federal agencies and some states have begun to move forward with regulatory responses, many of these challenges remain unresolved. Thus, increased gas production for export will be accompanied by increasing risks of water pollution.

Land and Community Impacts

Intense gas production can transform entire regions. The gas boom means hundreds of thousands of new wells, along with the vast infrastructure of roads, pipelines, and support facilities they require. This landscape-level industrialization can transform formerly rural areas into vast construction sites, with thousands of trucks moving down an expanding webwork of gravel roads. This landscape change, too, is a significant environmental impact of increasing gas production.

The scope of potential change is great. Each well pad alone occupies roughly 3 acres, and associated infrastructure (roads, water impoundments, and pipelines) more than doubles this figure.[53] Many of these acres remain disturbed through the life of the well, estimated to be 20 to 40 years.[54] This directly disturbed land is generally no longer suitable as wildlife habitat. *Id.* at 6-68. In addition to this direct disturbance, indirect habitat loss occurs as areas around the directly disturbed land lose essential habitat characteristics. As New York regulators, for

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[50] *Id.* at 20.
[51] *See* NY RDSGEIS at 1-12 (describing risks of fluid containment at the well pad).
[52] *See, e.g.*, Columbia University, Lamont-Doherty Earth Observatory, *Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists* (Jan. 6, 2012); Alexis Flynn, *Study Ties Fracking to Quakes in England*, Wall Street Journal (Nov. 3, 2011).
[53] NY RDSGEIS at 5-5.
[54] *Id.* at 6-13.

instance, report, "[r]esearch has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge."[55]

These effects will harm rural economies and decrease property values, as major gas infrastructure transforms and distorts the existing landscape. United States Geological Survey researchers, reviewing recent patterns of unconventional gas extraction, combined with coalbed methane projects, report that these activities create "potentially serious patterns of disturbance on the landscape."[56]

Pennsylvania presents a particularly striking example of the many ways in which gas production can transform a landscape. A recent state study of drilling in Pennsylvania's hitherto relatively undisturbed forest lands found that the forests have been so thoroughly fragmented and disrupted by the influx of gas activity that "zero" remaining acres of the state forests are suitable for further leasing with surface disturbing activities.[57]

Increased gas production for export can be expected to intensify and extend these impacts to new regions as drilling continues to meet increased demand.

Summary

The environmental impacts of increasing gas production of course extend well beyond those captured by this short summary. There are real environmental risks inherent in every phase of gas's life-cycle, from site preparation to drilling to waste disposal. Greatly increasing gas demand will increase the scope and intensity of these risks. The DOE's Shale Gas Subcommittee has already found that our regulatory infrastructure is not adequate to manage these risks at their current level of intensity. The United States is even less prepared for a greater and more rapid expansion of natural gas extraction.

B. Environmental Impacts Due to Fuel Market Shifts

Increasing demand for gas will necessarily raise gas and energy prices. These price effects have important environmental impacts as well because changing gas prices and availability affects the domestic fuel market. If natural gas is relatively more expensive, utilities, in particular, may be more likely to use competing fuels and generation technologies, each of which has its own environmental implications.

The prospect that LNG exports could incentivize domestic coal-fired generation is particularly important to understand. Coal-fired generation is a major source of many air pollutants,

[55] *Id.* at 6-75.
[56] E.T. Slonecker *et al.*, USGS, *Landscape Consequences of Natural Gas Extraction in Bradford and Washington Counties, Pennsylvania, 2004–2010* (2012) at 1.
[57] PA DCNR, *Impacts of Leasing Additional State Forest for Natural Gas Development* (2011).

including asthma-inducing SO_2, and among the very largest sources of combustion-related CO_2. Thus, LNG-induced market changes could have important implications for domestic air quality.

The EIA has modeled this fuel-shifting effect for gas exports of up to 12 bcf/d.[58] It reports that as exports rise, domestic gas consumption falls. Utilities largely switch to coal, while also making up a bit of the displaced gas generation with energy efficiency and renewable energy.[59] On balance, this shift results in increased emissions because the bulk of the new energy (72% of the total) comes from coal generation.[60]

More coal generation means greater carbon dioxide emissions from combustion, which are more than sufficient to balance out any emissions savings from greater use of efficiency and renewable energy in most of the scenarios that the EIA considered.[61] In fact, even in the few scenarios where the EIA predicted a larger market share for low carbon sources, LNG exports still resulted in a net increase in CO_2 emissions nationally, once emissions from the liquefaction process itself were accounted for.[62] The size of this increase depends upon the volume and size of exports, and the baseline price of gas and coal under various scenarios, so the EIA analysis estimates it within a broad range of 187 to 1,587 million metric tons of CO_2 over the next twenty years. These are large amounts. Even at the low end, 187 million metric tons is equivalent to the CO_2 emitted in a year by roughly 44 coal-fired power plants.[63] These emissions have the potential to increase as more LNG is exported with commensurate impacts on the market. They would be accompanied by corresponding increases in other coal-generation-related air pollutants, like SO_2.

This market-linked pollution effect could work to disrupt important policy work at the national and local level. Many utilities, public service commissions, and environmental regulators increasingly assume that coal generation's market share will steadily fall, in favor of gas, renewable energy, and energy efficiency. These entities are planning accordingly. Indeed, the EPA's recent proposed carbon pollution standards for fossil-fired generation are premised on EPA's understanding that "in light of a number of economic factors, including the increased availability and significantly lower price of natural gas … few, if any, new coal-fired power plants will be built in the foreseeable future."[64] As policymakers adapt to a world of more readily-available natural gas, export's tendency to make gas *less* available and more expensive will have important environmental implications throughout the country.

C. Impacts from Export Itself: Focus on Climate

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[58] EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 17-19.
[59] *Id.*
[60] *Id.* at 18.
[61] *See id.* at 18-19.
[62] *Id.*
[63] Calculated with EPA's *Greenhouse Gas Equivalencies Calculator*, available at http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results.
[64] *See* 77 Fed. Reg. 22,392, 22,399 (Apr. 13, 2012).

Finally, exports themselves have substantial environmental impacts.

Export terminals are large industrial sites. The liquefaction facilities needed to chill natural gas until it condenses into a liquid well below zero are energy-intensive and can produce substantial amounts of air and water pollution. Likewise, the pipeline and compressor networks needed to transport gas to the terminal, and the international shipping system needed to carry it onward all have significant impacts on the environments they traverse. The highly explosive nature of LNG means that carefully mapping out the potential for serious accidents around terminals and ships is an ongoing and important exercise in worst-case scenario analysis.

Looking more broadly, the use of LNG itself has environmental impacts, both positive and negative. Examining the climate implications of LNG is particularly important because LNG proponents have touted the fuel for its supposed potential to substantially reduce greenhouse gas pollution by displacing coal.

This claim is not well-supported. Because of the energy used to liquefy, transport, and re-gasify LNG, its life-cycle climate footprint is greater than that of most gas sources. Indeed, at least one peer-reviewed study has found LNG's life-cycle greenhouse gas emissions approach the low-end of coal life-cycle emissions.[65] Notably, that study was based on emissions from conventionally-produced natural gas, which are considerably lower than those from unconventional gas. Other studies, though concluding that LNG emissions are still lower than those of coal, have likewise documented that LNG life-cycle emissions are on the order of 30% greater than those of ordinary gas.[66] Whichever figures ultimately turn out to be correct, it is clear that LNG is among the most carbon-intensive forms of natural gas.

Further, whether or not LNG produces as much greenhouse gas pollution as coal, increased use of *any* fossil fuel is not consistent with preventing dangerous climate change. Recent climate studies show that increased natural gas use (from whatever source), without aggressive additional carbon control efforts, will not prevent dangerous increases in global temperature. The International Energy Agency, for instance, recently considered a future in which global gas use (including LNG use) sharply increases because of the unconventional gas boom.[67] In this scenario, despite gas's presumed life-cycle emissions advantage over coal, atmospheric CO_2 concentrations nonetheless rise on a trajectory towards 650 ppm, up from near 400 ppm today, pushing towards a 3.5°C temperature increase.[68] As a result, even if LNG emits less greenhouse gas pollution than coal, and even if it displaces some amount of coal power (which may or may not occur), it will not put on a path towards safe climate.

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[65] Jaramillo et al., *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, 41 Environ. Sci. Technol. 6,290, 6,295 (2007).

[66] *See* European Commission Joint Research Centre, *Liquefied Natural Gas for Europe – Some Important Issues for Consideration* (2009) at 16-17; European Commission Joint Research Centre, *Climate impact of potential shale gas production in the European Union* (2012).

[67] International Energy Agency, *Golden Rules for a Golden Age of Gas* (2012).

[68] *Id.* at 91.

We can only avoid the worst impacts of climate change if emissions fall sharply. As IEA explains, "reaching the international goal of limiting the long-term increase in global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone."[69] Thus, expanded natural gas exports may, at best, very slightly slow the pace of warming. In the worst case, they will maintain the status quo, while deepening a national and global investment in climate-disrupting fossil fuels and delaying the transition to renewable energy sources.

D. Conclusions on Environmental Impacts

In sum, the environmental impact of LNG export is large, and stretches from local effects near individual gas wells to significant cumulative impacts on the country as gas production increases and gas prices rise to significant shifts in the international energy market. Some of these impacts are better understood than others, but all are worthy of careful analysis.

That analysis has not been forthcoming. DOE and FERC have prepared no environmental reports studying the impacts of export and, worse, have so far declined to do so, as is explained below. Export proponents, who generally trumpet production increases as a central benefit of their projects, are silent on the environmental costs of these production shifts.

The policy community has not yet seriously engaged these questions either. Two much-discussed recent LNG export papers, which generally favor exports, devote almost no attention to the environmental impacts of exports and the increased gas production that would accompany them. A report from the Brookings Institution, titled *Liquid Markets*, cites the DOE's Shale Gas Subcommittee's serious concerns and reviews ongoing regulatory initiatives, but makes no effort to quantify the likely environmental impacts of increased production.[70] Instead, it settles for predicting only that the "current regulatory environment" – the one which DOE has judged to be inadequate – should not put any insuperable hurdles in the way of new drilling.[71]

A second report, from Michael Levi of the Council on Foreign Relations and the Hamilton Project, also lacks a detailed treatment of these issues.[72] The environmental portion of that analysis also largely considers whether public backlash over environmental damage will be sufficient to derail exports, warning that the EIA projects "that a large part of increased production spurred by export demand would be in the Northeast, where opposition to shale gas development has been strongest."[73] Levi views this possibility as an argument for improved regulation, such as the DOE has called for. He implies, however, that because LNG exports will

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[69] *Id.* at 100.
[70] Brookings Energy Security Initiative, *Liquid Markets: Assessing the Case for U.S. exports of Liquefied Natural Gas* (May 2012) at 6-12.
[71] *Id.* at 11.
[72] Michael Levi, The Hamilton Project, *A Strategy for U.S. Natural Gas Exports* (June 2012).
[73] *Id.* at 20-21.

not commence "for several years," there will be time to put the necessary rules in place before hand.[74] Suffice to say that this is back-to-front thinking: There is no guarantee that rules will be in place to manage a wave of increased fracking. On the contrary, with billions of dollars sunk into export terminals, one might expect export proponents to oppose new regulation.

These two recent reports are representative: There has been a great deal of discussion of the economic potential of LNG exports, but the environmental discussion has lagged dangerously behind. Mere assertions that environmental impacts will not be sufficiently disturbing as to cause a massive public backlash, or that regulations will doubtless be in place by the time exports occur, are not enough to support careful consideration of these transformative changes. The decision to allow substantial LNG exports requires a thorough accounting of the likely impacts and how they can best be managed.

To be sure, a great deal of useful information is being developed on the environmental impacts of unconventional gas production generally, as state and federal regulators grapple with the implications of the boom. That information, however, has not been integrated into an analysis of the impacts of LNG exports or used to inform export decisions. If DOE or FERC began that study, they would find a rich and developing literature to draw upon and synthesize. The export licensing system, supported by the NEPA process, should produce just an analysis. That information is long overdue.

IV. The Regulatory Infrastructure

The Natural Gas Act and NEPA provide a framework under which DOE and FERC must weigh the environmental impacts of export, and then ensure that exports, if any, are regulated to protect the public interest. Thus far, this fundamental oversight machinery has not been fully used.

Natural gas imports and exports have been regulated under the Natural Gas Act since the late 1930s. Until very recently, however, large-scale exports of LNG were not in the picture. The two core regulatory bodies, DOE's Office of Fossil Energy, and FERC, dealt largely with pipeline shipments to Canada and Mexico and with LNG import terminals. Although they occasionally handled periodic permit renewals for a sole, small, LNG export terminal in Alaska that has served the Asian market off and on since the 1960s, this minor project does not remotely compare to the enormous export proposals now before them. This striking shift underlines the importance of proceeding carefully now.

A. The Public Interest Determination and Siting Process

The Natural Gas Act provides that "no person" may export or import natural gas without a license.[75] Such a license will be granted unless the proposal "will not be consistent with the

[74] *See id.* at 21.
[75] 15 U.S.C. § 717b(a).

public interest."[76] This public interest standard is broad and invites careful analysis. Among other points, it includes "the authority to consider conservation, environmental, and antitrust questions."[77] The Supreme Court has made clear that environmental considerations, in particular, are due close attention in this analysis.[78] DOE has recently affirmed that it is required to examine a "wide range of criteria" to best understand the public interest, "including… U.S. energy security… [i]mpact on the U.S. economy… [e]nvironmental considerations… [and] [o]ther issues raised by commenters and/or interveners deemed relevant to the proceeding."[79]

DOE and FERC share responsibility for Natural Gas Act determinations, with DOE taking, in many ways, the more fundamental role. Under their current division of authority, FERC is charged with location-specific concerns: Its primary responsibility is to investigate how to safely site and operate export and import terminals themselves.[80] DOE, by contrast, is charged with more broadly considering whether the project should move forward at all: It must make the public interest determination, and so must survey the information before it in order to discern how a given export or import proposal will affect the many considerations relevant to the public interest.[81] Although DOE reads its governing statute to afford export applicants a rebuttable presumption that their project is in the public interest, this presumption is not dispositive and a detailed public interest analysis is required in each case.[82]

NEPA analysis supports this public interest determination by providing the environmental information which DOE must weigh under the Natural Gas Act. The NEPA process, described in detail below, is the joint responsibility of DOE and FERC, and must be completed before either one issues a final order. Since 2005, FERC has been charged by statute as the "lead" agency for NEPA compliance, meaning that it coordinates the environmental assessment process.[83] DOE, however, must contribute to and review the documents which FERC prepares, and must independently determine whether they are sufficient to support its public interest determination, or whether more analysis is needed.[84] Only once DOE determines that it has NEPA documents which fully analyze the environmental impacts of the decision before it does it weigh those impacts and make its final public interest decision.

This process applies to all the export applications now before FERC and DOE with one important exception, which is discussed in more detail in the final section of this paper. In the 1992

[76] *Id.*
[77] *Nat'l Ass'n for the Advancement of Colored People v. Federal Power Commission*, 425 U.S. 662, 670 n.4 & n.6 (1976).
[78] *See Udall v. Federal Power Comm'n*, 387 U.S. 428, 450 (1967).
[79] Testimony of Christopher Smith, Deputy Assistant Secretary of Oil and Gas Before the Senate Committee on Energy and Natural Resources (Nov. 8, 2011).
[80] Department of Energy Delegation Order No. 00-004.00A § 1.21 (May 16, 2006).
[81] *See* Department of Energy Redelegation Order No. 00-002.04E § 1.3 (Apr. 29, 2011).
[82] *See Panhandle Producers and Royalty Owners Ass'n v. Economic Regulatory Administration*, 822 F.2d 1105, 1110-1111 (D.C. Cir. 1987).
[83] *See* 15 U.S.C. § 717n.
[84] *See* 40 C.F.R. § 1501.6.

Energy Policy Act, Congress amended DOE's Natural Gas Act authority to provide that DOE *must* grant applications for export to (or import from) nations with which the United States has signed a free trade agreement providing for national treatment in natural gas.[85] In those cases, FERC still oversees terminal siting, but DOE loses its broad oversight role as to whether export is wise in the first place. This loophole was created to support natural gas imports from Canada – rather than massive LNG *exports* from the U.S. – but it has been relatively unimportant until recently. Significant export projects generally must go through the usual public interest process because the United States does not have free trade agreements with most major LNG importers. The 2010 free trade agreement with South Korea, a large LNG importer, changed this picture somewhat, but the South Korean market is still relatively limited and the free-trade "loophole" has not short-circuited DOE's usual process in most cases. That situation highlights, however, the importance of maintaining the public interest determination process as trade negotiations continue with other importers.

Accordingly, though most exporters do secure the "free" license to export to free-trade-agreement nations, the license to export to non-free-trade-act nations remains more valuable, and is often essential to doing business. Of the 19 projects now before DOE, only 4 rely exclusively on a free-trade-agreement license.[86] The remaining proposals are proceeding through the full public interest determination process.

B. The NEPA Process

The NEPA phase of this process must provide DOE and the public with a full and fair understanding of the environmental implications of export.

NEPA is our bedrock environmental statute.[87] It is rooted in democratic decisionmaking informed by excellent information. NEPA directs federal agencies to look before they leap: by requiring the preparation of environmental impact statements (EISs) for major federal actions, it helps ensure sound decisions before bulldozers roll. Policymakers have a pressing need for the information the NEPA process can provide as they consider whether and how to permit LNG export. NEPA analysis, accordingly, is not just a legal mandate but a prudent measure.

NEPA requires all federal agencies to "utilize a systematic, interdisciplinary approach" to make decisions, ensuring that their decisions are fully informed before they act with a goal of maintaining "the environment for succeeding generations."[88] The core of this obligation is the EIS, which must be prepared for every major Federal action which could significantly affect "the quality of the human environment."[89]

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[85] *See* 15 U.S.C. 717b(c).
[86] Those four are the SB Power Solutions, Golden Pass Productions, Main Pass Energy Hub, and Waller LNG Services proposals.
[87] It is codified at 42 U.S.C. §§ 4321 *et seq.*
[88] 42 U.S.C. §§ 4332(A) & 4331(b)(1).
[89] 42 U.S.C. § 4332(C).

An EIS is designed to develop information describing the environmental impact of a proposed action, alternatives to the proposal, and the relationship between the short-term proposal and "the maintenance and enhancement of long-term [environmental] productivity."[90] NEPA, in other words, helps prompt agencies to look more broadly than the immediate matter at hand, to understand how their actions fit within a larger environmental context. As the first court to review the statute explained, "NEPA, first of all, makes environmental protection a part of the mandate of every federal agency and department."[91]

This is not a paper exercise. The Council on Environmental Quality, the high-level body which administers NEPA across the government, explains in its regulations that "[u]ltimately, of course, it is not better documents but better decisions that count. NEPA's purpose is not to generate paperwork--even excellent paperwork--but to foster excellent action."[92] This means that "[t]he NEPA process is intended to help public officials make decisions that are based on an understanding of environmental consequences, and take actions that protect, restore, and enhance the environment."[93]

This process proceeds in several steps, designed to build a strong platform for the final decision. It is to begin as early as possible in order to ensure that the EIS can "serve practically as an important contribution to the decisionmaking process and will not be used to rationalize or justify decisions already made."[94] After an initial "scoping" phase during which the agency gathers comments from stakeholders to identify key issues,[95] the agency prepares a draft and then a final EIS.

The "heart of the environmental impact statement" is a careful discussion of the proposal and all relevant alternatives, "sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public."[96] With regard to each option, the agency must develop a careful description of its environmental consequences.[97]

These consequences are generally divided between direct, indirect, and cumulative impacts.[98] Direct impacts are simply those immediately caused by the action at issue; indirect impacts are those which may occur a bit further afield, but which are still causally linked to the federal action.[99] The agency must cast a wide net, analyzing all "reasonabl[y] foreseeable" impacts, including those "induced" by its action – think, for instance, of the "growth inducing" impacts of building a highway, or, for that matter, an export terminal inducing drilling with its attendant

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[90] *Id.*
[91] *Calvert Cliffs' Coordinating Committee, Inc. v. U.S. Atomic Energy Comm'n*, 449 F.2d 1109, 1112 (D.C. Cir. 1971).
[92] 40 C.F.R. § 1500.1(c).
[93] *Id.*
[94] 40 C.F.R. § 1502.5.
[95] 40 C.F.R. § 1501.7.
[96] 40 C.F.R. § 1502.14.
[97] 40 C.F.R. § 1502.16.
[98] 40 C.F.R. §§ 1508.7 & 1508.8.
[99] 40 C.F.R. § 1508.8.

effects on "air and water and other natural systems."[100] The analysis must also include the "cumulative" impacts of federal action – the "incremental impact of the action when added to other past, present, and reasonably foreseeable future actions."[101] For instance, in the LNG context, the cumulative production inducing effects of all relevant LNG terminals should be considered together. It would also make sense to consider the cumulative impact of new production from export along with the impact of existing gas production.

The EIS, in short, ultimately presents a full accounting of all the reasonably foreseeable impacts of the agency's proposed course of action, along with alternatives to that course of action. It is designed to bring information to light and to generate syntheses of formerly scattered information.

Congress recognized, in this regard, that some uncertainty will always be present in any prediction of environmental impacts. Such uncertainty does not excuse agencies from complying with NEPA – if it did, NEPA analyses would never succeed in developing the new research agencies need to inform their decisions. Rather, the NEPA process is designed to limit uncertainty, while carefully characterizing remaining questions. Where information is incomplete, the agency must gather it (expending reasonable funds to do so) to fill in key aspects of the picture.[102] If costs are truly exorbitant, or it is very difficult to generate a particular piece of information, an agency must still do its best, providing a careful description of what it believes to be missing from its evaluation, a "summary of existing credible scientific evidence" relevant to its problem, and the agency's best "evaluation" of the impacts before it based upon what it knows.[103] In all cases, the goal is to develop the best-informed analysis possible, advancing the public's understanding, even of uncertainties, before the final decision is made.

Uncertainties can also be managed by beginning at a higher level of generality with a special form of EIS known as a "programmatic" environmental impact statement, and then filling in more specific information down the road as individual projects are considered. As the name suggests, programmatic EISs are intended to provide a broad overview of entire programs, or classes of activity.[104] Such documents are particularly useful as road maps. They provide an overview of how a class of decisions – such as granting many different export applications – will affect the environment. As the D.C. Circuit Court of Appeals has explained, this process has "a number of advantages" which recommend it here:[105] A programmatic EIS, the court explained, "provides an occasion for a more exhaustive consideration of effects and alternatives than would be practicable in a statement on an individual action. It ensures consideration of

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[100] *See id.*
[101] 40 C.F.R. § 1508.7.
[102] 40 C.F.R. § 1502.22(a).
[103] 40 C.F.R. § 1502.22(b)(1).
[104] *See* 40 C.F.R. § 1502.14(b)-(c).
[105] *Scientists' Institute for Public Information, Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1087 (D.C. Cir. 1973).

cumulative impacts that might be slighted in a case-by-case analysis. And it avoids duplicative reconsideration of basic policy questions."[106]

To facilitate this broad overview, the NEPA regulations in turn explain that agencies can structure programmatic EISs by looking, for instance, geographically at "actions occurring in the same general location"; generically, by looking at actions with, for instance, "common timing, impacts, alternatives, methods of implementation, media, or subject matter"; or even by "stage of technical development" as processes and technologies mature.[107] Once such an overview is in hand, an agency is free to rely upon it to guide more specific analyses of particular projects, thereby saving work and time down the road.[108]

Whether an EIS is programmatic or project-specific, as the Supreme Court has explained, by ensuring that agencies take a "hard look" at the environmental consequences of their decisions, NEPA is "almost certain to affect the agency's substantive decision."[109] In this sense, NEPA reflects a fundamentally democratic approach to decisionmaking, a faith that putting the best information forward transparently will help policymakers and the public navigate uncertainty and make difficult choices. The Supreme Court identifies these two purposes this way:

> First, [NEPA] ensures that the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts. Second, it guarantees that the relevant information will be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision.[110]

With this process in place, the goal is that "the most intelligent, optimally beneficial decision will ultimately be made."[111]

There is a pressing need for such careful, deliberate, decisionmaking in the LNG export context.

V. Applying NEPA to LNG Exports

DOE affirms in its governing regulations that it will "follow the letter and spirit of NEPA" and will "apply the NEPA review process early in the planning stages" of its projects.[112] These rules are clear that DOE must base its final decisions on matters with significant environmental impacts on a carefully developed environmental impact statement.[113] But DOE has refused to prepare

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106 *Id.* (internal quotations and citation omitted).
107 40 C.F.R. § 1502.14(c)(1)-(3).
108 *See*, *e.g.*, 40 C.F.R. § 1502.20
109 *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989).
110 *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 767 (2004) (internal quotations omitted).
111 *Calvert Cliffs*, 449 F.2d at 1114.
112 10 C.F.R. § 1021.102.
113 *See, e.g.*, 10 C.F.R. §§ 1021.210 (affirming that DOE will complete NEPA review "before making a decision"); 1021.214 (affirming that this standard applies for adjudicatory proceedings, such as licensing processes).

an environmental impact statement to help it wrestle with the weighty export decisions now before it. Worse, it has refused even to acknowledge that it has the tools to do so, even though its own modeling system could go far to help answer the vital questions now before it.

DOE *should* have approached NEPA compliance in a far more considered way. It should have begun by preparing a national programmatic environmental impact statement – either on its own or as a partner with FERC, the usual NEPA lead agency -- that would have considered the cumulative effect of the export proposals before it and ways to mitigate those effects. Such an analysis would be a natural counterpart to a national economic study it is now preparing. In fact, the U.S. Environmental Protection Agency (EPA) has now twice filed formal comments making clear that just such an analysis is necessary.[114] With both such studies in hand, DOE and FERC could then have developed shorter, subsidiary studies for each proposal before it, considering their particular circumstances in the context of its comprehensive public disclosures.

The unwise course the agencies have thus far taken in the environmental arena contrasts sharply with DOE's far wiser commitment to consider national economic impacts before moving forward on any further export applications. These two approaches are irreconcilable. DOE must undertake a full EIS for LNG export, including the effects of increased gas production, if it is to make prudent decisions and satisfy its legal mandates.

A. DOE's Failure to Properly Apply NEPA Thus Far

DOE has assured Congress that it recognizes that the cumulative impact of "future LNG export authorizations could affect the public interest."[115] Unfortunately, though DOE is attempting to better understand some of the economic implications of LNG export, it has thus far actively refused to consider the environmental implications.

The only nearly-complete example of DOE's deliberative process thus far is its handling of the Sabine Pass LNG export project proposed for southern Louisiana. Sabine Pass was the first LNG export application filed in the current wave of proposals, and proposed to export 803 bcf of gas annually. This volume of export, alone, would increase *total* U.S. gas exports by more than 50%.[116] One might have expected DOE to analyze this historic application in detail, but it did not.

Instead, applying the rebuttable presumption-based approach to export, DOE did not develop significant independent analyses when considering the application. It relied almost entirely on Sabine Pass's own assertions. In spring 2011, it "conditionally" approved the Sabine Pass's request to export up to 2.2 bcf/d of natural gas, largely on the ground that no opposing party

[114] Letter from Christine B, Reichgott, EPA Region 10 to FERC (Oct. 29, 2012) at 12-13; Letter from Jeffrey D. Lapp, EP Region 3 to FERC (Nov. 15, 2012) at 2.
[115] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 3.
[116] *See* n. 3, *supra*.

had shown that the project was *not* in the public interest.[117] DOE thus approved the beginning of the export boom largely on the export proponents' say-so, without preparing its own analysis.

The "conditional" part of the approval referred in large part to DOE's decision to defer its consideration of environmental matters pending FERC's work on NEPA documents for Sabine Pass as the lead agency for NEPA compliance. Because FERC had not yet prepared an environmental analysis or environmental impact statement, DOE opted not to weigh any environmental factors in its public interest analysis. Instead, it stated that FERC, with DOE's cooperation, would undertake the environmental study for both agencies as part of FERC's facility siting process.[118] DOE stated that it would review FERC's final product before finally signing off on Sabine Pass.

But FERC did not prepare an EIS for Sabine Pass and did not consider the national implications of the application, including its implications for production. FERC recognized that Sabine Pass itself identified the purpose and need of the facility as to "provide a market solution to allow the further development of unconventional (particularly shale gas-bearing formation) sources in the United States."[119] Nonetheless, it instead prepared only a more limited document called an environmental assessment (an "EA"), which focused only on the environmental impacts of the facility siting decision before it.[120]

FERC justified this decision on the grounds that the impacts from increased gas development were not "reasonably foreseeable" because "no specific shale-gas play is identified."[121] It did so even though Sabine Pass itself affirmed that the "most likely" sources of supply for its project were "the historically prolific Gulf Coast Texas and Louisiana onshore gas fields, the gas fields in the Permian, Anadarko, and Hugoton basins, and the emerging unconventional gas fields in the Barnett, Fayetteville, Woodford, and Bossier basins."[122] FERC apparently felt that the applicant's own assurances that export would spur production, and would likely do so in specific places, provided no ground for analysis. Because FERC believed that it could not identify precisely where Sabine Pass would catalyze gas production, it refused to consider these impacts at all.[123]

But NEPA analyses are not dependent on this sort of location-specific analysis. Instead, a programmatic EIS, for instance, could readily have presented the environmental choices before DOE on a national level, with particular attention to potential production patterns in prolific shale plays. Even a project-specific EIS could have addressed pressing environmental issues directly. FERC could have evaluated the sorts of pollution risks and ecosystem threats

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[117] DOE, Order 2961 (May 20, 2011) at 42.
[118] *Id.* at 40-41.
[119] *Id.* at 1-10.
[120] *See* FERC, *Environmental Assessment for the Sabine Pass Liquefaction Project* (December 2011).
[121] FERC, Order Granting Section 3 Authorization, 139 FERC ¶ 61,039 at ¶¶ 96-97 (Apr. 16, 2012).
[122] Sabine Pass Export Application (Sept. 7, 2010) at 16.
[123] *Id.* at ¶¶ 98-100.

associated with increased fracking. It could have described the likely cumulative impacts of the many proposed LNG projects, including those at Sabine Pass, and could have estimated the scale of environmental disruption that they may cause. Instead, FERC provided none of this information. Perversely, because it concluded that Sabine Pass might promote gas production "in any of the numerous shale plays that exist in most of the eastern United States," and hence could have nationwide impacts, FERC decided that these impacts swept too broadly to be analyzed.[124]

DOE did not have to accept this blinkered view, but it nonetheless did so, declaring, on its review of FERC's EA, that FERC had "examined all reasonably foreseeable impacts" of the project.[125] DOE therefore accepted FERC's EA as a "complete picture for purposes of meeting DOE's NEPA responsibilities and fulfilling its duty to examine environmental factors as a public interest consideration under the [Natural Gas Act]."[126] In doing so, DOE also accepted FERC's reasoning that because it was "impossible" to know precisely how much new production Sabine Pass would cause, or exactly where this production would occur, there was no way to discuss these impacts at all.[127]

Thus, though DOE affirmed that it was "fully aware of concerns of the environmental effects of shale gas production," it insisted that it could not provide a "meaningful analysis" of Sabine Pass – or of the cumulative impacts of LNG export as a whole.[128] Sierra Club petitioned for rehearing of this decision, and DOE has announced that it continues to consider whether its decision was correct.[129]

DOE has not moved forward on any other LNG export applications (with the exception of licenses for export to countries with which the U.S. has a free trade agreement, discussed below), so the Sabine Pass order stands as its current word on the subject. If DOE does not change course, huge volumes of natural gas will be produced and exported without any consideration of how this massive production increase will affect communities across the country. Far from working to protect the public interest, DOE will not acknowledge, much less address, the challenge before it.

B. How NEPA Should Be Applied to LNG Exports

The Sabine Pass decisions made a bad beginning, but they need not determine the rest of the story. DOE may yet reconsider its Sabine Pass order. Moreover, many other LNG export applications have been filed with DOE and, as it considers them, it may still treat this environmental challenge with the seriousness it deserves. Before granting any further licenses,

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[124] FERC, Order Denying Rehearing and Stay, 140 FERC ¶ 61,076 at ¶ 12 (July 26, 2012).
[125] DOE, Order 2961-A (Aug. 7, 2012) at 27.
[126] *Id.*
[127] *Id.* at 28.
[128] *Id.*
[129] DOE, *Order Granting Rehearing for Further Consideration*, FE Docket No. 10-111-LNG (Oct. 5, 2012).

DOE should ensure that the NEPA process develops the information it needs to make a sound public interest determination.

For purposes of this discussion, DOE or FERC could undertake the tasks described below. FERC would be the most likely coordinator, given its lead agency role under the Natural Gas Act, but it is ultimately DOE's responsibility to ensure that the final NEPA analysis is sufficient to support a careful public interest determination, whether it is prepared entirely by FERC or later supplemented by DOE. For ease of reference, this section therefore refers to "DOE" as conducting the analysis, though FERC would play an important coordinating role.

In this context, a programmatic EIS makes a great deal of sense. By looking first at the common questions inherent in export, DOE could help develop a fundamental shared understanding of their impacts before turning to the particular impacts of specific proposals.

i. Determining Foreseeable Production Associated with Export

The most important first question for DOE is to determine a "reasonably foreseeable" range of natural gas which may be exported and the corresponding range of reasonably foreseeable increases in production. So far, DOE and FERC have insisted that *no* production impacts are reasonably foreseeable, as the Sabine Pass decisions state. This conclusion is simply wrong. The DOE's own NEMS program can forecast these production impacts. DOE's failure to develop such projections is unjustifiable.

NEMS is a very well-established modeling system designed to model the economy's energy use through a series of interlocking "modules" that represent different energy sectors on regional and national levels.[130] Relevant here, NEMS has an "Oil and Gas Supply Module"[131] and a "Natural Gas Transmission and Distribute Module."[132] Rhese modules jointly represent the entire domestic natural gas sector, and describe how production responds to demand across the country. They can be used, therefore, to model the effects of increased export demand on gas production. In fact, they *have* been used for this purpose by DOE already: The January 2012 EIA special report on LNG, which included production forecasts, relies on NEMS, as does the summer 2012 Annual Energy Outlook, which contains LNG projections.[133]

EIA's formal documentation for NEMS is available online, and thoroughly describes the system. That documentation demonstrates that DOE/FE is in error when it states that the implications of LNG export demand for the production and supply of domestic gas are not foreseeable. In fact, NEMS's natural gas sub-models are explicitly designed to project how supply will respond to demand on a national and a regional basis; indeed, they *must* do so for the model to

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[130] *See* EIA, *The National Energy Modeling System: An Overview* (2009) at 1-2 ("NEMS Overview").
[131] *See* EIA, *Documentation of the Oil and Gas Supply Module* (2012 ("OGSM Documentation").
[132] *See* EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System* (2012) (TDM Documentation).
[133] *See, e.g.*, EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 3 (EIA used NEMS for this forecast); EIA, . *See* EIA, *Annual Energy Outlook* (2012) at App. E (describing NEMS).

generate predictions. As such, NEMS could (and in fact has) be used to project likely production increases in response to increased demand caused by LNG exports. NEMS therefore provides the analysis of "when, where, and how shale-gas development will be affected" that the DOE has so far stated it would be impossible to produce.

To begin with, the Supply Module is built on detailed state-by-state reports of gas production across the country.[134] These reports allow the EIA to develop regionally differentiated models of the costs of production in each gas field, and how readily production can be increased in those fields. As the EIA explains, "production type curves have been used to estimate the technical production from known fields" as the basis for a sophisticated "play-level model that projects the crude oil and natural gas supply from the lower 48."[135] The module reports its results for regions throughout the United States, including the Northeast, the Gulf Coast, and areas in Texas and Arkansas with large gas plays.[136] It also distinguishes coalbed methane, shale gas, and tight gas from other resources, allowing for specific predictions distinguishing unconventional gas production from conventional natural gas production.[137] The module further projects the number of wells drilled each year, and their likely production; these are important figures for estimating environmental impacts.[138]

In short, this module "includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision."[139] Thus, for each play in the lower 48 states, the EIA is able to predict future production based on existing data. Importantly, the EIA makes clear that "the model design provides the flexibility to evaluate … environmental, or other policy changes in a consistent and comprehensive manner."[140] Those policy changes include permitting LNG export.

LNG export creates new demand and transmission needs. The next NEMS module, the Transmission and Distribution Module, can address these impacts. It integrates supply projections with regional and national demand to help determine how gas will flow to areas experiencing increased demand. As EIA explains, the module "represents the transmission, distribution, and pricing of natural gas" using a national module of the transmission system, which, in turn, is divided by region.[141] The module "links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural

[134] *See* OGSM Documentation at 2-2.
[135] *Id.* at 2-3.
[136] *Id.* at 2-4.
[137] *Id.* at 2-7.
[138] *See id.* at 2-25 -2-26
[139] *Id.*
[140] *Id.*
[141] TDM Documentation at 2.

gas and the regional market clearing prices between suppliers and end-users."[142] Because the Transmission Module represents demand regionally, it can distinguish, for instance, between LNG export demand on the Gulf Coast and demand in the Northeast.[143] For each region, the module then links supply and demand annually, taking transmission costs into account, in order to project how demand will be met by the transmission system.[144] Thus, it interacts with the Supply Module to develop projections for how supply in each production region will evolve in response to demand.[145]

Importantly, the Transmission Module already is designed to model LNG imports and exports, and contains an extensive modeling apparatus to do so.[146] The Module includes import/export pipelines and the sole existing LNG export terminal in Alaska.[147] There is, thus, no technical barrier to modeling increased export demand going forward.[148] One source of demand is much like any other, so additional export terminals can simply be modeled as additional demand centers in the regions in which terminals are proposed. The Module could, for instance, readily model additional demand along the Gulf Coast or other coasts, and translate that demand back to the Supply Module. Again, this process is essentially what the EIA already did in the context of its January 2012 LNG export study, which relied on NEMS to forecast the production and price impacts of export.

In short, NEMS is already set up to do the sort of work which DOE needs to do here.[149] In response to a given demand in a particular region, it projects transmission system flows and

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[142] *Id.*
[143] *See id.* at 12-14.
[144] *See id.* at 15-16.
[145] *See id.* at 16-20.
[146] *See id.* at 22-32.
[147] *Id.* at 3.
[148] *See id.* at 30-31.
[149] As are several models used by private consultants. For instance, the Deloitte consultancy regularly makes such predictions. *See, e.g.*, Deloitte, *Made in America: The Economic Impact of LNG Exports from the United States* (2011) at 6 (explaining that if LNG is "exported from one particular geographic point, the entire eastern part of the United States reorients production and flows and basis differentials change substantially"); *see also id.* at 6 (explaining that the reference case for the model predicts increased production in the Marcellus and Haynesville shales) & 8 (explaining that Deloitte considers how producers will "develop more reserves in anticipation of demand growth, such as LNG exports" and forecasting different prices depending on where exports occur).

According to Deloitte, its "World Gas Model" and its component "North American Gas Model" are designed precisely to provide this sort of finer-grained analysis. Deloitte explains that "[t]he North American Gas Model is designed to simulate how regional interactions of supply, transportation, and demand determine market clearing prices, flowing volumes, storage, reserve additions, and new pipelines throughout the North American natural gas market." *See* Deloitte, *Natural Gas Models.* The model "contains field size and depth distributions for every play, with a finding and development cost model included. This database connects these gas plays with other energy products such as coal, power, and emissions." *Id.* According to Deloitte, its modeling thus allow it to predict how gas production, infrastructure construction, and storage will respond to changing demand conditions, including those resulting from LNG export: "The end result is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate." *Id.* The point here is that linking exports to production is plainly possible.

production responses at the level of individual plays across the country. Thus, DOE is fully capable of analyzing the production impacts of particular levels of LNG export. Its failure to do so – and its insistence that such projections are somehow impossible to make – is inexplicable.

Given this capability, DOE should look at a range of possible export volumes and timing, just as the EIA did in the economic study that DOE commissioned. It should then consider the amount of natural gas (either produced or diverted from other uses) necessary to meet this demand, and can, using the same analysis EIA applied, predict how much of this gas is likely to come from new production.

Because NEPA is rooted in the alternatives analysis, DOE should also develop alternative approaches to the range of possible exports. It might, for instance, look at the impacts of allowing the maximum and minimum volumes of exports it thinks are plausible, along with its projection of the most likely scenario. It also makes sense to look at variations in export timing and volume driven by public interest concerns. For instance, DOE could consider permitting exports only after the environmental safeguards the Shale Gas Subcommittee identified are in place, or only permitting exports at a volume that would not cause serious price disruptions or economic harm domestically. And, of course, DOE must consider a "no action" alternative baseline, in which exports do not move forward at all. The point of the analysis, as always, is to ensure that the agency thoroughly explores the possible solution space, rather than simply pursuing its preconceived plans.

DOE, in short, has many options before it open for analysis. The only option which it simply may not pursue, however, is the one that it has picked: It cannot and must not refuse to use its *own models* to help inform the public as to the vital choices ahead.

ii. Estimating the Impacts of Production

With this array of options in mind, the next task for DOE is to identify the environmental impacts associated with each of the reasonable alternatives it has developed. EPA has twice instructed FERC (in its role as the lead agency) that just such an analysis is necessary.

EPA's formal comments put the matter well. As EPA explained in comments on a proposal to export LNG from Oregon:

> The 2012 report from the Energy Information Administration states that[] "natural gas markets in the United States balance in response to increased natural gas exports largely through increased production." That report goes on to say that about three-quarters of that increase[d] production would be from shale resources. We believe it is appropriate to consider available information about the extent to which drilling activity might be stimulated

> by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion.[150]

EPA made a similar point in comments on another, Maryland-based, export facility. It wrote:

> We also recommend expanding the scope of analysis to include indirect effects related to gas drilling and combustion. … Th[e EIA] report also indicated that about three-quarters of that increase[d] production would be from shale gas resources and that domestic natural gas prices could rise by more than 50% if permitted to be exported. We believe it is appropriate to consider the extent to which implementation of the proposed project, combined with implementation of other similar facilities nationally, could increase the demand for domestic natural gas extraction and increase domestic nautral gas prices.[151]

EPA, in short, recognizes that the important national debate needs to be informed by careful environmental analysis. Because this analysis may best be done at the programmatic level, DOE should look at the impacts of export-linked production across the country, before applying this programmatic analysis to informed consideration of particular project proposals. The NEMS system and similar models will help DOE to project national impacts and to regionalize them. As it considers these options, it will need to answer several key questions. These include, but are certainly not limited to, the following:

> *What is the magnitude and timing of the increased natural gas production associated with a range of export scenarios?*
>
> This is the most fundamental question that the NEPA process should answer. The EIA has already developed models linking export to increased production. A NEPA analysis could use this starting point to investigate the magnitude of production needed to support a range of export volumes. This inquiry, on its own, would meaningfully assist decisionmakers. If they know, for instance, that permitting 1 bcf/d of export means that some dozens, hundreds, or thousands, of additional wells will need to be drilled, that consideration should be balanced transparently in the public interest analysis. Again, NEMS should be able to supply this analysis and, indeed, to do so on play-by-play and regional levels, as well as nationally.
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> *What incremental air pollution risk is associated with increased natural gas production generally, and with increased unconventional gas production in particular?*
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> The air pollution impacts of both conventional and unconventional gas production are serious and need to be better understood – especially if exports significantly increase production, as they are likely to do. The DOE can use the NEPA process to better describe these impacts. For instance, the Environmental Protection Agency has developed

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[150] Letter from Christine B, Reichgott, EPA Region 10 to FERC (Oct. 29, 2012) at 12.
[151] Letter from Jeffrey D. Lapp, EP Region 3 to FERC (Nov. 15, 2012) at 2.

increasingly accurate emissions figures corresponding to processes through the natural gas production system, from well drilling to gas transport.[152] By estimating the amount production is likely to increase, DOE can evaluate the approximate range of new air pollution likely to be associated with increased production. Likewise, it can assess the likely emissions associated with any upgrades to pipeline transmission networks required to get natural gas to export terminals. DOE can, in other words, forecast whether a given export scenario is likely to be associated with many thousands of tons of additional air pollution, or a more limited amount.

Going further, DOE can predict where this pollution is most likely to occur. Although exported gas can be produced in many places, some natural gas basins are declining or stable, while others – such as those near the Texas Gulf coast and the Marcellus shale of the east coast -- are rapidly growing and are near proposed export terminal sites, reducing transportation costs. DOE can and should forecast the most likely targets for additional development in response to increasing gas demand; these locations are, in turn, the most likely to suffer from increased air pollution and to have to invest in appropriate control efforts. NEMS will it allow it do so.

In short, DOE can map out the air pollution control challenge ahead under various export scenarios. It can also forecast which regions are most likely to have to manage this increased pollution, and some of its likely public health and environmental impacts.

What incremental water pollution risk is associated with increased natural gas production generally, and with increased unconventional gas production in particular?

As with air pollution, water pollution risk increases with increased gas production. Here, too, an overview of pollution risk and response needs with substantially higher production will assist policymakers and the public. Although many other questions should be answered here, two areas of investigation within this general field jump out for investigation at the programmatic level.

First, increased gas production will generate a predictable amount of waste for treatment. Looking at the national scale, a proper EIS would consider the adequacy of treatment available for this increase in wastewater and other substances. Does existing treatment plant capacity correspond to the likely increased volume and can those plants properly treat all pollutants from the industry? Do injection wells appear ready to take up the slack? If not, where is waste likely to go? Before licensing exports, it makes sense to make sure that the nation is ready to handle the waste they leave behind.

Second, water *quantity* issues also deserve a close look. A substantial increase in fracking means a substantial increase in water use. Even though water use varies among gas

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[152] *See generally*, EPA, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry* (Apr. 2012).

fields, DOE can calculate a range of water demand likely to be associated with increased gas production. That range will help to determine whether gas export will add substantially to water stress in the nation's gas fields.

DOE's task here, as in the air pollution analysis, will thus generally be to forecast the likely scope of increased threats to water quantity and quality. Because both waste and water can be transported significant distances, this analysis does not depend on knowing precisely which fields will increase their production, but such forecasts will be helpful in assessing the most likely impacts. That said, where DOE can localize these impacts, as NEMS allows, it will be able to provide extremely important information to policymakers working to protect particular watersheds and aquifers.

What degree of land and community disturbance will be associated with increased gas production for export?

A given volume of export will be associated with an approximate number of new wells, well pads, roads, and associated infrastructure. In some gas fields, this infrastructure is already causing serious conflicts and challenges for communities and for wildlife. For instance, DOE might answer questions like these: What acreage of new disturbance is necessary to meet the increased demand for gas? How many new truck trips and how many new miles of pipeline are likely to be necessary? How many people are living in areas likely to see increased production? And how able are the already disrupted communities and ecosystems in the most likely areas for new production to absorb these impacts without excessive damage? This area of inquiry should prompt DOE to think seriously about the degree of landscape transformation that export will drive.

What are the domestic energy and environmental policy implications of export?

As we have discussed above, gas exports will likely raise gas and energy prices. These market shifts have the potential to change the electrical generation mix and also have implications for domestic industry. DOE is already analyzing these economic questions and is beginning to chart their implications. EIA's initial look at shifts in CO_2 emissions from the utility sector is a good example of this analysis. DOE should extend it to consider, at a range of export volumes and timings, what changes in emissions from other sources are likely. If price increases from export, for instance, prompt increased use of highly polluting coal plants, DOE should carefully address the impacts resulting from that shift.

What are the international energy and environmental policy implications of export?

The atmosphere does not respect national boundaries. Accordingly, if LNG exports lead to changes in climate-disrupting pollution – by replacing either cleaner or dirtier energy sources or simply by increasing the load of carbon in the atmosphere – the United States will feel the effects. The country will also experience changes in transboundary transport

> of other chemicals and pollutants. To the extent possible, DOE can help forecast these impacts by considering which energy sources LNG is most likely to replace, and the extent of any such replacement.
>
> *What alternatives are available to reduce these impacts?*
>
> The alternatives analysis is the heart of the EIS. Developing a range of export policies – from permitting all exports, to only a subset of exports; from giving the green light now to waiting until protective regulations are in place – will allow DOE to test these alternatives against their impacts. The EIS should produce a map of possible trade-offs, showing how export decisions affect the environment and which export plans will best protect communities and ecosystems.

With answers to these and other questions in hand, DOE will be far better placed to understand the trade-offs inherent in LNG export and to decide whether export are in the public interest (and, if so, the proper volumes and timing which can best protect the public). This information is, in fact, necessary to properly conclude that process. Moreover, if the NEPA process reveals pressing risks from LNG export, DOE will be able to address them in advance or help other federal or state agencies do so. It will also have contributed to a crucial public conversation on a matter of vital national importance. When and if DOE does license exports, in this future, it will do so with its eyes wide open and will able to develop appropriate mitigation strategies.

Not all of the questions above are easy to answer. Many of them are difficult to address with complete precision, though DOE modeling and publicly available data will provide useful projections and estimates. But residual uncertainty is not a reason to shirk the task. The alternative, after all, is not safe inaction: It is blindly permitting a major change in the nation's energy system, committing to billions of dollars in LNG export infrastructure, and licensing a major increase in fracking activity across the country without any proper analysis. That course should not be undertaken casually. The nation will discover the answers to these questions with or without NEPA compliance, but without NEPA, the answers will come directly from suffering communities and ecosystems. NEPA ensures that decision-makers instead discover them in advance, "at a stage where real environmental protection may come about [rather] than at a stage where corrective action may be so costly as to be impossible."[153]

Forecasts of this sort are thus extraordinarily helpful, even if they are not entirely precise. As the D.C. Circuit Court of Appeals explained in a seminal NEPA case, the statute is designed to help outline crucial questions and answers early on, in order to guide continued decisionmaking and inquiry:

> The agency need not foresee the unforeseeable, but by the same token neither can it avoid drafting an impact statement simply because describing the environmental effects of and alternatives to particular agency action involves some degree of forecasting. And

[153] *Calvert Cliffs*, 449 F.2d at 1129.

> one of the functions of a NEPA statement is to indicate the extent to which environmental effects are essentially unknown. *It must be remembered that the basic thrust of an agency's responsibility under NEPA is to predict the environmental effects of proposed action before the action is taken and those effects are known.*[154]

The point is not that NEPA analysis at this phase will answer every question about export definitively and completely. Instead, "[r]easonable forecasting and speculation is… implicit in NEPA."[155] What DOE can, at a minimum, do now is to map out the fundamental environmental implications of LNG export. It can identify the scope and magnitude of likely impacts, and it can point to key unknowns that warrant more research. It can underline key concerns (such as the availability of treatment capacity to manage the waste associated with increased production for export) and offer alternatives that could address them. It can consider which regions are most likely to bear the costs of export, and where the benefits are most likely to fall. It can offer the sort of well-balanced, comprehensive, projections for which NEPA is designed.

Such an analysis, at an appropriate level of generality, is plainly required. There is absolutely no serious question that increased unconventional gas production is a "reasonably foreseeable" consequence of licensing LNG exports. Export proponents themselves predict such production increases; indeed, they premise their arguments that their projects are in the public interest in large part on the economic growth which they contend will follow from increased gas production.

For instance, Sabine Pass's promoters promised that their project would "play an influential role in contributing to the growth of natural gas production in the U.S."[156] The proponents of the Freeport project, likewise affirmed their project was "positioned to provide the Gulf Coast region and the United States with significant economic benefits by increasing domestic gas production."[157] Likewise, the Lake Charles project's backers maintained that their export would "spur[] the development of new natural gas resources that might not otherwise make their way to market."[158] The Gulf Coast LNG project's supporters asserted that their project will "allow the U.S. to benefit now from the natural gas resources that may not otherwise be produced for many decades, if ever."[159]

The litany goes on: In Oregon, the investors behind the Jordan Cove project assured DOE that it would be "instrumental in providing the increased demand to spur exploration and development of gas shale assets in North America."[160] And in Maryland, the Dominion Cove Point's project's supporters proclaimed that "[t]he most basic benefit of the proposed LNG exports will be to encourage and support increased domestic production of natural gas…. The

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[154] *Scientists' Institute*, 481 F.2d at 1092 (emphasis added).
[155] *Id.*
[156] Sabine Pass Application at 56 (Sept. 7, 2010).
[157] Freeport LNG Application at 14-15 (Dec. 19, 2011).
[158] Lake Charles Application at 20 (May 6, 2011).
[159] Gulf Coast Application at 11 (Jan. 10, 2012).
[160] Jordan Cove Application at 19 (Mar. 23, 2012).

steady new demand associated with LNG exports can spur the development of new natural gas resources that might not otherwise be developed."[161]

The bottom line is that increased domestic gas production is a necessary consequence of export. It is not just foreseeable: It is a principal *justification* for gas export projects. As such, its environmental impacts must be disclosed under NEPA and weighed in the Natural Gas Act public interest determination.[162]

Programmatic analyses of this sort are not unfamiliar to DOE. DOE, in fact, recognizes the importance of the NEPA process as a support for its decisionmaking, and has deep experience with programmatic EISs. Secretary Chu has written that he "cannot overemphasize the importance" of building NEPA compliance into DOE project management.[163] DOE has regularly done so. Over the years, the department has prepared draft and final programmatic EISs and environmental assessments for a nationwide effort to promote energy efficiency,[164] a solar energy promotion program in six western states,[165] energy "corridors" in 11 different states,[166] a global program supporting nuclear power,[167] and a national coal power research and development initiative.[168] Plainly, DOE has had no difficulty developing national-level environmental surveys of large-scale energy decisions, even when the precise location and nature of all site-specific impacts were not yet known. Instead, such broad overviews informed policy. An EIS for LNG export would fit well into this tradition and is certainly entirely possible using DOE's own modeling capacity, as is discussed above.

The courts have made clear, as well, that NEPA requires agencies to take a hard look at the upstream consequences of their decisions. In one recent decision, the Ninth Circuit Court of Appeals rejected the Surface Transportation Board's assertion that, when permitting a new train line serving a coal-producing area, it did not need to consider the coal production the line would doubtless make possible.[169] The agency insisted that such development was not "reasonably foreseeable," even though it relied on the coal production to determine that the train line would be financially viable.[170] The court rightly held that the agency could not permit an infrastructure project justified in large part on increasing fossil fuel production without considering those impacts in a NEPA analysis. The same analysis applies here. LNG export

[161] Dominion Cove Point Application at 35 (Oct. 3, 2011).
[162] *See also Center for Biological Diversity v. National Highway Traffic and Safety Administration*, 538 F.3d 1172, 1200 (9th Cir. 2008) (where the impact of an agency action is uncertain, agency may not simply given that impact zero weight and fail to address it).
[163] DOE Memorandum, "Improved Decisionmaking Through the Integration of Program and Project Management with [NEPA] Compliance" (June 12, 2012).
[164] *See* DOE, Programmatic Environmental Assessment for the State Energy Conservation Program (1996).
[165] *See* 77 Fed. Reg. 44,267 (July 27, 2012).
[166] *See* 73 Fed. Reg. 72,477 (Nov. 28, 2008).
[167] *See* 73 Fed. Reg. 61,845 (Oct. 17, 2008).
[168] *See* DOE, Final Programmatic Environmental Impact Statement Clean Coal Technology Demonstration Program (1996).
[169] *Northern Plains Resource Council v. Surface Transportation Board*¸668 F.3d 1067, 1081-82 (9th Cir. 2011).
[170] *Id.*

terminals will drive new gas production and, in fact, depend upon that new production to justify their existence.

In the end, it should come as no surprise that DOE's own NEPA regulations provide that large LNG export projects will "normally require EISs."[171] When a project involves either "major operational changes (such as a major increase in the quantity of liquefied natural gas imported or exported)" or the "construction of major new facilities or the significant modification of existing facilities," an EIS is appropriate.[172] These rules, which have been in place since DOE first issued its NEPA regulations,[173] set a clear course for the agency. The applications before it now uniformly involve major increases in the quantity of LNG set for export – by many times over – and also require multi-billion dollar construction projects to create new facilities to support these facilities. An EIS, in these circumstances, is plainly mandated by DOE's own regulations.

C. DOE's National Economic Analyses Demonstrate That It Can Approach Environmental Impacts On A National Level

DOE's abdication of its environmental responsibilities is illegal and unwise. It is unjustifiable based on DOE's own modeling capabilities. It is also strikingly inconsistent with DOE's own approach to the national *economic* implications of LNG export. There, DOE has invested considerable effort in developing a comprehensive general understanding of the economic implications of LNG export, including the impacts of new production. That it can generate such an analysis at a national scale demonstrates that it can pursue the same course for environmental considerations. It should do so to ensure that policymakers and the public have a balanced view of *both* the economic and environmental impacts of exports.

The national economic analysis began, as DOE has explained to Congress, with DOE's realization, after the Sabine Pass conditional approval had issued and more LNG export applications were flooding in, that LNG exports could have real effects on the public interest.[174] DOE did not attempt to avoid grappling with these impacts just because it did not know with complete certainty exactly where production would occur. But, unlike in the environmental context, DOE correctly recognized that such uncertainties were not fatal to a proper national overview.

Instead, DOE immediately and responsibly embarked on two national studies, which were intended to help bring the national economic impacts of export into sharper focus. The first of these was the EIA report discussed above. At DOE's behest, EIA modeled a range of possible export and production scenarios, exploring combinations of different exports rate and timing

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[171] 10 C.F.R. Pt. 1021 App. D to Subpart D, § D8 & D9.

[172] *Id.*

[173] *See* 45 Fed. Reg. 20,694, 20,700 (Mar. 28, 1980).

[174] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 3.

and possible variations in gas supply and economic demand.[175] As a result, EIA was able to generate a range of well-supported impact predictions for these varying scenarios. This analysis uncovered important effects for DOE's consideration, including the prospect of sharp domestic gas and electricity price increases with some export scenarios. Rather than allowing uncertainty to defeat the analysis, EIA considered a range of reasonable outcomes to help better inform policy – just as NEPA requires in the environmental context.

The second study will build further on these results. According to DOE, it will look at sixteen different hypothetical export scenarios to investigate:

> (1) [t]he potential impacts of additional natural gas exports on domestic energy, consumption, production, and prices; (2) the cumulative impact on the U.S. economy, including the effect on gross domestic product, job creation balance of trade; and (3) the impact on the U.S. manufacturing sector (especially energy intensive manufacturing industries).[176]

Rather than dismissing this analysis as "impossible" because it involves some degree of uncertainty, DOE sensibly embraced the task of investigating likely national impacts under varying production scenarios. Although there is, of course, some uncertainty as to the precise effects a particular proposal will have on the economy, the major wave of export proposals will have a predictable effect which can be investigated despite uncertainty as to particular production patterns. Indeed, as noted above, export proponents rely upon induced gas production to help justify their projects.

It is thus not at all surprising that DOE felt it to be both possible and necessary to analyze the economic ramifications of these changes. Of course, such an analysis is appropriate. The surprising point, instead, is that DOE nonetheless has blinded itself to the environmental impacts of the very same production increases it is analyzing.

D. DOE Must Look at Environmental Impacts With the Same Rigor With Which It Examines Economic Impacts

This double-vision – with economics in sharp focus and environmental impacts blurred to invisibility – impermissibly skews the choice before DOE. Both economic impacts and environmental costs weigh in the public interest determination. If DOE is only willing to look at one side of the ledger, it cannot properly fulfill its obligations because it cannot understand the all the aspects of the public's interest which are implicated by export. Without a full NEPA analysis, it cannot make a sound final decision.

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[175] *See* EIA, *Effects of Increased Natural Gas Exports on Domestic Energy Markets* at 1-2.

[176] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey at 4.

The courts have made this point clear. Very early in NEPA's history, the Atomic Energy Commission insisted that it could not forecast the environmental impacts of a power plant research program for which it had already developed an economic analysis.[177] The D.C. Circuit Court of Appeals held this position had a "hollow ring" given that the Commission was happy to use its economic analyses in "convincing Congress" to support its plans.[178] As the court held, if economic analyses can be prepared, then "in turn … parallel environmental forecasts would be accurate for use in planning how to cope with and minimize the detrimental effects attendant upon" the course the agency wishes to pursue, "and in evaluating the program's overall desirability."[179] Agencies cannot skew their analyses, or mask the costs of their actions, by examining only one side of a problem while refusing to consider the other.

The Ninth Circuit Court of Appeals corrected the same error in its coal train line case, discussed above. There, too, while insisting that coal mines triggered by a new train line were too speculative to analyze under NEPA, the agency nonetheless "relied on the coal mine development … to justify the financial soundness of the proposal" which it approved.[180] Once again, the court held that an agency may not rely on economic predictions while simultaneously refusing to acknowledge the environmental impacts of the economic activity it is permitting.

The same analysis applies, with great force, to DOE's situation here. The agency has proven willing and able to analyze the economic impacts of LNG export and is in the process of expending considerable funds to improve its forecasting. Further, in individual licensing proceedings, it is clearly open to relying on predictions of increased economic activity from gas production to justify the licensing export. The very same drilling and production forecasts it is now working up in that context could, and should, inform an analysis of the environmental impacts of those decisions. There is nothing inherently harder in saying that ten thousand new wells will produce *x* dollars in tax revenue or *y* tons of pollution than in predicting they will produce *z* new jobs. DOE cannot conduct one analysis while neglecting the other.

DOE cannot embrace sunny economic predictions while ignoring real environmental costs. Such a course is not only contrary to NEPA, but will render the public interest determination process fundamentally unreliable. DOE must tally up the benefits of export, but it must also count the costs.

E. The Need for NEPA

DOE has thus far refused to give any weight to the landscape-level changes large-scale LNG export would produce. This error is serious. Uncorrected, it will distort policy by masking the domestic consequences of export.

177 *See Scientists' Institute*, 481 F.2d at 1096-97.
178 *Id.* at 1097.
179 *Id.*
180 *Northern Plains*, 668 F.3d at 1082.

Export proponents would, of course, prefer that these consequences go unremarked. Even as they tout the large increases in fracking that their projects will support, they insist that DOE must not and cannot even begin to account for the environmental consequences of their projects. But even if DOE ignores these impacts, American communities will feel the impacts of this production as exports ramp up. Rather than proceeding blindly while locking in these future harms, NEPA charges DOE with accounting for those impacts now, and the Natural Gas Act makes clear that it must take these harms into account as it considers the public interest.

DOE has the time it needs to do the right thing. It has already committed to Congress not to issue any further export licenses for export to non-free-trade-agreement nations until its second economic study is complete.[181] (Its decision to nonetheless finalize the in-process Sabine Pass license is a disturbing anomaly). DOE has recently announced that this economic study, originally slated for release in spring 2012, will not be released until this coming winter. It is taking the time it needs to gather meaningful economic information. It can and should do the same for environmental information.

There is no statutory deadline to issue licenses, and every reason to ensure that DOE's final decisions are as well-reasoned as possible. LNG export terminals represent billions of dollars in investment capital, and export licenses often last for decades. Before committing to this near-irrevocable investment, DOE owes it to itself and the public to take the time it needs to develop as full and careful analysis as possible.

VI. Preserving DOE's Authority to Protect the Public Interest

DOE must use its authority to prepare a proper EIS for LNG export. But, thanks to ongoing trade negotiations, this is not the only challenge DOE faces in order to protect the public interest. It must also act quickly, in coordination with Congress and the Executive, to ensure that its regulatory ability to protect the public is not inadvertently destroyed.

The problem confronting DOE is an unintended consequence of Congress's 1992 decision to speed LNG imports from Canada. To protect those imports, Congress directed that DOE *must* license LNG imports *and exports* from nations with which the U.S. has signed a free trade agreement providing for national treatment of natural gas.[182] Up to this point, this rubber stamp process has not been at issue, but that may be about to change.

The proposed Trans-Pacific Partnership (TPP) is a massive trade agreement currently under negotiation between the United States and ten other Pacific Rim nations.[183] Its influence could be even broader, however. The TPP is intended to be a "docking station" for new signatories,

[181] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey at 4.
[182] *See*15 U.S.C. § 717b(c).
[183] *See* http://www.ustr.gov/tpp.

permanently open for expansion, so it could establish an ever-expanding web of countries to which LNG *must* be exported if the market can sustain the demand.

Already, several potential signatories, including Chile and Singapore, are LNG importers and so would be able to take imports from the United States without any public interest oversight. And, critically, there is a very real possibility that Japan may join the talks and the final agreement.[184] Japan is the largest LNG importer in the world.[185]

If Japan is included in the TPP, with national treatment of natural gas, DOE will lose its discretion to condition any exports to Japan on the public interest. Such exports would be automatically licensed. Because Japan has the potential to absorb large amounts of U.S. gas, the loss of DOE's ability to carefully examine the consequences of those exports before licensing them is a serious concern. Regardless of the results of the NEPA analysis we recommend here, or of the economic studies DOE is conducting, exports would be legally mandated.

This result is not what Congress intended when it inserted the free-trade-agreement exception language in 1992. At that time, LNG export from the United States was neither possible nor contemplated. Instead, Congress was focused on removing barriers to natural gas imports from Canada.

The 1992 amendments, in fact, did not even reference export when proposed. Congressman Phil Sharp (D-IN), Chairman of the House Subcommittee on Energy and Power (and H.R. 776's original sponsor) stated that the amendments' purpose was only "deregulating Canadian natural gas imports."[186] Likewise Congressman Norman Lent (R-NY), Ranking Member of the House Committee on Energy and Commerce, explained that the amendments were "vital to assuring that U.S. regulators do not interfere with the importation of natural gas to customers in the United States."[187]Congressman Edward Markey (D-OR), who is a current skeptical voice on export, strongly supported the provisions, describing them as "important new statutory assurances that U.S. regulators will not discriminate against *imported* natural gas."[188]

Language providing for automatic approval of export applications as well as import applications in the free trade context was added in the final conference on the bill, with no recorded debate. The conference report does not justify this discussion, noting only that the final bill "includes an

[184] *See, e.g.*, Paul McBeth, National Business Review, "Pressure on Japan as Canada joins TPP talks" (June 20, 2012); ICIS Heren, "Japan Warms to U.S. Liquefaction Prospects" (Mar. 12, 2012).
[185] *See* EIA Country Statistics for Japan, http://www.eia.gov/countries/country-data.cfm?fips=JA#ng.
[186] 138 Cong. Rec. 32,075 (Oct. 5, 1992).
[187] 138 Cong. Rec. 32,083 (Oct. 5, 1992)
[188] Extension of Remarks, Cong. Rec. (Oct. 9, 1992), "Concerning Gas Import Provisions in H.R. 776, The Energy Policy Act of 1992) (emphasis added).

amended section… regarding fewer restrictions on certain natural gas imports and exports."[189] Whatever the justification for this expansion, it seems very clear that large-scale LNG exports were not on Congress's mind. The debate to this point had focused on Canadian imports, and, large-scale LNG exports were, in any event, not possible at the time. Indeed, Chairman Sharp described the final amended language as concerning "exports of natural gas *to Canada* from the United States" and affirmed (despite the seemingly open-ended final language) that "as drafted, the new fast task track process would not be available for LNG exports to, for example, Pacific rim nations other than Canada."[190]

At bottom, as DOE explained in a recent letter to Congress, "Congress's attention [in 1992] was focused on North American trade, not on the potential impact of the amendment on United States trade with other countries overseas."[191] Yet, the TPP, and the prospect of other such agreements, threatens to expand this exemption into a wholesale roll-back of DOE's regulatory discretion to protect the public interest. Should this occur, both the careful NEPA process and the public interest determination themselves would be suddenly and inappropriately truncated. In essence, the U.S. would see as much fracking activity as is necessary to support exports for the Asian market, with no direct domestic oversight of these exports.

This serious unintended consequence argues for swift remedial action. Several courses could be available. It may, first, be possible for the U.S. Trade Representative to draft the TPP to include exceptions for national treatment in natural gas, which could preserve DOE's authority. Second, Congress could certainly modify the provision to remove fast track authority for exports. Third, at a minimum, agreements that would remove DOE's discretion to regulate exports certainly should not be concluded until a full environmental impact statement for export has been completed. That report will help policymakers determine how exports should be managed – critically important information for U.S. trade negotiators before they finalize any deal that would commit the nation to exports without any further oversight.

So far, however, DOE has not taken any of these steps, and neither has the U.S. Trade Representative. In meetings and phone conversations with the Sierra Club, the Trade Representative has insisted that DOE, not the Representative, must address the issue. DOE, in turn, has placed responsibility for protecting the public interest review process back on the Trade Representative. The result is that both agencies are pointing fingers at each other, and neither is taking responsibility for addressing this serious matter. Unless they change course,or Congress or the Executive act to insist that they do so, the result may be that the U.S. gives up its ability to manage LNG exports without even thinking about it.

VII. Conclusion: A Full EIS is Needed to Inform Policymakers and the Public

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[189] H.R. Conf. Rep. 102-1018, 1992 USCCAN 2472, 2477 (Oct. 5, 1992); *see also* 138 Cong. Rec. 34,043 (Oct.8. 1992) (statement of conferees, explaining only that the final bill "has been expanded to include fewer restrictions on exports of natural gas to countries with which the United States has a Free Trade Agreement.").

[190] 38 Cong. Rec. 32,076 (Oct. 5, 1992) (emphasis added).

[191] Letter from Christopher Smith, Deputy Assistant Secretary of Oil and Gas to Representative Edward Markey (Feb. 24, 2012) at 1.

The United States is sleepwalking through one of the biggest energy policy decisions of our time. Even as billions of dollars in investment capital are marshaled to support an ever-growing wave of export proposals, the federal agencies in charge of protecting the public interest have failed even to consider the environmental implications of exporting a large amount of the domestic gas supply – including the intensified fracking needed to support exports. Meanwhile, trade negotiators risk stripping away DOE's discretion ever to properly manage these problems, even if it does finally analyze and disclose them.

No matter where one stands on the ultimate wisdom of LNG exports, it is clear that this sort of blind, piecemeal, decisionmaking is what NEPA was designed to prevent. For more than 40 years, NEPA has reflected a national commitment to transparent, democratic, and careful decisionmaking to protect communities and our environment. That commitment applies with great force to DOE's decisionmaking now, and the agency should honor it. The possible conversion of the United States into one of the world's largest LNG exporters is a matter of national importance and a key shift in environmental and economic policy. If a full NEPA analysis of all the consequences, upstream and downstream, of an agency's decisions were ever appropriate for any agency action, then an EIS is surely appropriate now, when the nation's energy future is profoundly implicated by DOE's decisions. It is time for a full programmatic environmental impact statement for LNG export.

DOE has the time and the duty to do the right thing and begin the open, public, environmental impact statement process it should have initiated at the outset. It must retreat from its dereliction of duty in the Sabine Pass environmental process, and instead extend its national review process from the economic studies it has already begun to the environmental studies it also plainly needs. Before issuing another license on a piecemeal basis, it should change course, acknowledge its responsibilities, and begin the national conversation we urgently need to have.

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http://www.resilience.org/stories/2012-10-22/gas-bubble-leaking-about-to-burst

Gas Bubble Leaking, About to Burst

by Richard Heinberg, originally published by Post Carbon Institute | Oct 22, 2012

For the past three or four years media sources in the U.S. trumpeted the "game-changing" new stream of natural gas coming from tight shale deposits produced with the technologies of horizontal drilling and hydrofracturing. So much gas surged from wells in Texas, Oklahoma, Louisiana, Arkansas, and Pennsylvania that the U.S. Department of Energy, presidential candidates, and the companies working in these plays all agreed: America can look forward to a hundred years of cheap, abundant gas!

Some environmental organizations declared this means utilities can now stop using polluting coal—and indeed coal consumption has plummeted as power plants switch to cheaper gas. Energy pundits even promised that Americans will soon be running their cars and trucks on natural gas, and the U.S. will be exporting the fuel to Europe via LNG tankers.

Early on in the fracking boom, oil and gas geologist Art Berman began sounding an alarm (see example). Soon geologist David Hughes joined him, authoring an extensive critical report for Post Carbon Institute ("Will Natural Gas Fuel America in the 21st Century?"), whose Foreword I was happy to contribute.

Here, one more time, is the contrarian story Berman and Hughes have been telling: The glut of recent gas production was initially driven not by new technologies or discoveries, but by high prices. In the years from 2005 through 2008, as conventional gas supplies dried up due to depletion, prices for natural gas soared to $13 per million BTU (prices had been in $2 range during the 1990s). It was these high prices that provided an incentive for using expensive technology to drill problematic reservoirs. Companies flocked to the Haynesville shale formation in Texas, bought up mineral rights, and drilled thousands of wells in short order. High per-well decline rates and high production costs were hidden behind a torrent of production—and hype. With new supplies coming on line quickly, gas prices fell below $3 MBTU, less than the actual cost of production in most cases. From this point on, gas producers had to attract ever more investment capital in order to maintain their cash flow. It was, in effect, a Ponzi scheme.

In those early days almost no one wanted to hear about problems with the shale gas boom—the need for enormous amounts of water for fracking, the high climate impacts from fugitive methane, the threats to groundwater from bad well casings or leaking containment ponds, as well as the unrealistic supply and price forecasts being issued by the industry. I recall attempting to describe the situation at the 2010 Aspen Environment Forum, in a session on the future of natural gas. I might as well have been claiming that Martians speak to me via my tooth fillings. After all, the Authorities were all in agreement: The game has changed! Natural gas will be cheap and abundant from now on! Gas is better than coal! End of story!

These truisms were echoed in numberless press articles—none more emblematic than Clifford Krauss's New York Times piece, "There Will Be Fuel," published November 16, 2010.

Now Krauss and the Times are singing a somewhat different tune. "After the Boom in Natural Gas," co-authored with Eric Lipton and published October 21, notes that ". . . the gas rush has . . . been a money loser so far for many of the gas exploration companies and their tens of thousands of investors." Krauss and Lipton go on to quote Rex Tillerson, CEO of ExxonMobil: "We are all losing our shirts today. . . . We're making no money. It's all in the red." It seems gas producers drilled too many wells too quickly, causing gas prices to fall below the actual cost of production. Sound familiar?

The obvious implication is that one way or another the market will balance itself out. Drilling and production will decline (drilling rates have already started doing so) and prices will rise until production is once again profitable. So we will have less gas than we currently do, and gas will be more expensive. Gosh, whoda thunk?

The current Times article doesn't drill very far into the data that make Berman and Hughes pessimistic about future unconventional gas production prospects—the high per-well decline rates, and the tendency of the drillers to go after "sweet spots" first so that future production will come from ever-lower quality sites. For recent analysis that does look beyond the cash flow problems of Chesapeake and the other frackers, see "Gas Boom Goes Bust" by Jonathan Callahan, and Gail Tverberg's latest essay, "Why Natural Gas isn't Likely to be the World's Energy Savior".

David Hughes is working on a follow-up report, due to be published in January 2013, which looks at unconventional oil and gas of all types in North America. As part of this effort, he has undertaken an exhaustive analysis of 30 different shale gas plays and 21 shale/tight oil plays—over 65,000 wells altogether. It appears that the pattern of rapid declines and the over-stated ability of shale to radically grow production is true across the U.S., for both gas and oil. In the effort to maintain and grow oil and gas supply, Americans will effectively be chained to drilling rigs to offset production declines and meet demand growth, and will have to endure collateral environmental impacts of escalating drilling and fracking.

No, shale gas won't entirely go away anytime soon. But expectations of continuing low prices (which drive business plans in the power generation industry and climate strategies in mainstream environmental organizations) are about to be dashed. And notions that the U.S. will become a major gas exporter, or that we will convert millions of cars and trucks to run on gas, now ring hollow.

One matter remains unclear: what's the energy return on the energy invested (EROEI) in producing "fracked" shale gas? There's still no reliable study. If the figure turns out to be anything like that of tight "fracked" oil from the North Dakota Bakken (6:1 or less, according to one estimate), then shale gas production will continue only as long as it can be subsidized by higher-EROEI conventional gas and oil.

In any case, it's already plain that the "resource pessimists" have once again gotten the big picture just about right. And once again we suffer the curse of Cassandra—though we're correct, no one listens. I keep hoping that if we're right often enough the curse will lift. We'll see.

Exhibit K

The New York Times
http://www.nytimes.com/2013/01/05/business/energy-environment/exports-of-us-gas-may-fall-short-of-high-hopes.html?_r=1&

Exports of American Natural Gas May Fall Short of High Hopes

By CLIFFORD KRAUSS

Published: January 4, 2013

HOUSTON — Only five years ago, several giant natural gas import terminals were built to satisfy the energy needs of a country hungry for fuels. But the billion-dollar terminals were obsolete even before the concrete was dry as an unexpected drilling boom in new shale fields from Pennsylvania to Texas produced a glut of cheap domestic natural gas.

Now, the same companies that had such high hopes for imports are proposing to salvage those white elephants by spending billions more to convert them into terminals to export some of the nation's extra gas to Asia and Europe, where gas is roughly triple the American price.

Just like last time, some of the costly ventures could turn out to be poor investments.

Countries around the world are importing drilling expertise and equipment in hopes of cracking open their own gas reserves through the same techniques of hydraulic fracturing and horizontal drilling that unleashed shale gas production in the United States. Demand for American gas — which would be shipped in a condensed form called liquefied natural gas, or L.N.G. — could easily taper off by the time the new export terminals really get going, some energy specialists say.

"It will be easier to export the technology for extracting shale gas than exporting actual gas," said Jay Hakes, former administrator of the Energy Department's Energy Information Administration. "I know the pitch about our price differentials will justify the high costs of L.N.G. We will see. Gas by pipeline is a good deal. L.N.G.? Not so clear."

Even the terminal operators acknowledge that probably only a lucky few companies will export gas because it can cost $7 billion or more to build a terminal, and then only after a rigorous federal regulatory permitting process. The exploratory process to find a suitable site for a new terminal alone can take a year and cost $100 million, operators say, and financing can be secured only once long-term purchase agreements — 20 years or more — are reached with foreign buyers.

"It's a monumental effort to put a deal together like this, and you need well-heeled partners," said Mark A. Snell, president of Sempra Energy, which is based in San Diego and is applying for permits to turn around a Hackberry, La., import terminal for export. "There are only a handful of people who can do this kind of thing."

At least 15 proposed terminal projects have filed regulatory applications to export gas, and if all were approved, they could export more than 25 billion cubic feet a day, equivalent to more than a third of domestically consumed natural gas.

Environmental advocates say that kind of surge in demand would produce a frenzy of shale drilling dependent on hydraulic fracturing of hard rocks, an industrial method they say endangers local water supplies and pollutes the air. Dow Chemical, a big user of natural gas, and some other manufacturers express concerns that an export boom could threaten to raise natural gas prices for factories and consumers and, ultimately, kill jobs.

Opponents are already lobbying the Obama administration to reject most of the planned terminals, and protests have already occurred. Sempra, Exxon Mobil, Cheniere Energy and others have already built import terminals on the Gulf of Mexico. With docking facilities and giant gas tanks already built on land they had acquired and received permits for, they have a huge advantage over companies that have not yet built terminals. Cheniere, the only company to secure an export license, already has entered long-term purchase agreements for its L.N.G., and several other companies are only a few steps behind.

Dominion Power, which operates a nearly idle import terminal near Cove Point on Chesapeake Bay in Maryland, is also expected to proceed with a conversion to exports, since it is strategically located near the mid-Atlantic gas fields of the Marcellus Shale.

"You have got to be able to change, adapt as changes take place in the world," said Michael E. Gardner, manager of the Cove Point plant.

The companies with import terminals now wanting to export won a victory in December when an Energy Department report said exports of L.N.G. could produce $30 billion a year in export earnings without driving up domestic gas prices significantly.

Many energy specialists expect the Obama administration to approve several export license applications in the next couple of years, and exports could begin as soon as 2015.

The plans for a gas export boom are based on the theory that cheap American gas will remain cheap for decades while Asian and European gas supplies remain tight and expensive. Global demand for natural gas is expected to expand for decades as nations seek a replacement for coal, nuclear energy and increasingly expensive oil, energy specialists say.

If the American terminals could be built tomorrow, they would have a perfect market opportunity. The production glut in the United States has reduced natural gas prices in this country by more than two-thirds since 2008.

Gas prices in most other places around the world are much higher because they are linked to oil, which has remained comparatively expensive. Gas prices in the United States are around $3.30 per thousand cubic feet, compared with $10 to $11 in Europe and over $15 in Asia.

But analysts say that the price spread could quickly shrink as a host of factors converge. Gas prices in the United States will face upward pressure as exports rise, electric utilities switch to gas-fired plants from coal, and companies use more natural gas in manufacturing and for fleet vehicles.

"With rising U.S. gas prices, U.S. L.N.G. could be priced out of the market," said Noel Tomnay, head of global gas research at the consultancy Wood Mackenzie. "Even without L.N.G. exports, the price of gas will go up."

The indexing of Asian and European gas to oil prices is beginning to erode. At the same time, huge natural gas pipelines are being built around Asia to supply China, while new gas finds around Australia, East Africa and the eastern Mediterranean are likely to flood the markets with more L.N.G. Russia, a major global gas producer, is also moving aggressively to protect its markets.

And the cost of shipping and processing liquefied gas will cut into American suppliers' competitiveness.

Nikos Tsafos, a gas analyst at PFC Energy, said if the current gas price of slightly less than $3.30 per thousand cubic feet rose to $6, "by the time it gets to Asia, it's double that price and that means there is no arbitrage." The biggest threat, over the long term, is the spread of the American shale boom overseas. The United States has a big lead; shale drilling has been slow to get started in Europe, South Africa and South America because of environmental concerns, water shortages and political obstacles.

But China, which potentially has more shale resources than the United States, is poised for development. And Poland, Britain and Argentina are moving forward with more shale drilling.

Resistance from environmental groups like the Sierra Club could help stop some export projects, especially outside the Gulf of Mexico region, which has long been comfortable with the oil and gas industry. And manufacturers like Dow Chemical are campaigning against unfettered exports to keep their costs down.

Over all, these factors will make it challenging for export projects to raise enough financing. L.N.G. terminal developers note that more than 20 import terminals proposed a decade ago were never built because of local opposition or lack of government permits and financing.

"Can all these projects get financed? That's a good question," said Marvin Odum, president of Shell Oil Company, which is looking at various possible L.N.G. terminal sites to invest in. "The outcome of this is not likely to be unlimited L.N.G. exports."

Charif Souki, Cheniere's chief executive, predicted that by 2018, the country would manage to export only one billion to two billion cubic feet of gas a day, or roughly 2 percent of current domestic consumption. In 10 years, after two to four projects have received permits and have been built, he said he expected exports to grow to three billion to five billion cubic feet a day. The total global production of L.N.G. is about 40 billion cubic feet a day, and growing rapidly.

George Biltz, Dow Chemical's vice president for energy and climate change, said that exports that come near Mr. Souki's projections would ease Dow's concerns. "That is a range that I think will maintain a competitive advantage for the United States," he said.

Eric Lipton contributed reporting from Washington.

A version of this article appeared in print on January 5, 2013, on page B1 of the New York edition with the headline: Reversal of Fortune for U.S. Gas.