Exhibit 11

Exhibit 11

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

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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.

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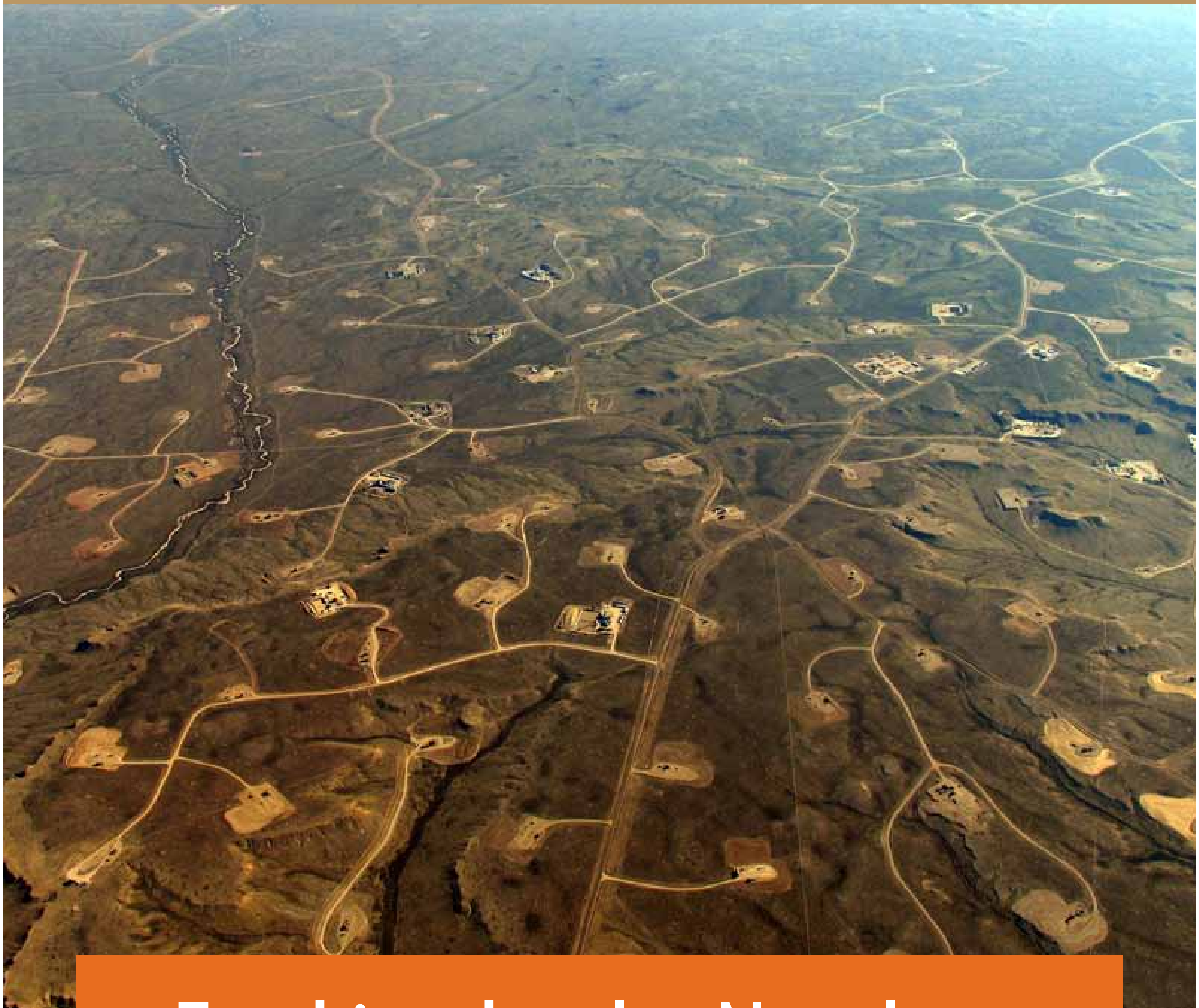
Exhibit 12



Fracking by the Numbers

Key Impacts of Dirty Drilling at the State and National Level

ENVIRONMENT AMERICA
RESEARCH & POLICY CENTER

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Executive Summary

Over the past decade, the oil and gas industry has fused two technologies—hydraulic fracturing and horizontal drilling—in a highly polluting effort to unlock oil and gas in underground rock formations across the United States.

As fracking expands rapidly across the country, there are a growing number of documented cases of drinking water contamination and illness among nearby residents. Yet it has often been difficult for the public to grasp the scale and scope of these and other fracking threats. Fracking is already underway in 17 states, with more than 80,000 wells drilled or permitted since 2005. Moreover, the oil and gas industry is aggressively seeking to expand fracking to new states—from New York to California to North Carolina—and to areas that provide drinking water to millions of Americans.

This report seeks to quantify some of the key impacts of fracking to date—including the production of toxic wastewater, water use, chemicals use, air pollution, land damage and global warming emissions.

To protect our states and our children, states should halt fracking.

Toxic wastewater: Fracking produces enormous volumes of toxic wastewater—often containing cancer-causing and even radioactive material. Once brought to the surface, this toxic waste poses hazards for drinking water, air quality and public safety:

- Fracking wells nationwide produced an estimated 280 billion gallons of wastewater in 2012.
- This toxic wastewater often contains cancer-causing and even radioactive materials, and has contaminated drinking water sources from Pennsylvania to New Mexico.
- Scientists have linked underground injection of wastewater to earthquakes.
- In New Mexico alone, waste pits from all oil and gas drilling have contaminated groundwater on more than 400 occasions.

Table ES-1. National Environmental and Public Health Impacts of Fracking

Fracking Wells since 2005	82,000
Toxic Wastewater Produced in 2012 (billion gallons)	280
Water Used since 2005 (billion gallons)	250
Chemicals Used since 2005 (billion gallons)	2
Air Pollution in One Year (tons)	450,000
Global Warming Pollution since 2005 (million metric tons CO_2-equivalent)	100
Land Directly Damaged since 2005 (acres)	360,000

Water use: Fracking requires huge volumes of water for each well.

- Fracking operations have used at least 250 billion gallons of water since 2005. (See Table ES-2.)
- While most industrial uses of water return it to the water cycle for further use, fracking converts clean water into toxic wastewater, much of which must then be permanently disposed of, taking billions of gallons out of the water supply annually.
- Farmers are particularly impacted by fracking water use as they compete with the deep-pocketed oil and gas industry for water, especially in drought-stricken regions of the country.

Chemical use: Fracking uses a wide range of chemicals, many of them toxic.

- Operators have hauled more than 2 billion gallons of chemicals to thousands of fracking sites around the country.
- In addition to other health threats, many of these chemicals have the potential to cause cancer.
- These toxics can enter drinking water supplies from leaks and spills, through well blowouts, and through the failure of disposal wells receiving fracking wastewater.

Table ES-2. Water Used for Fracking, Selected States

State	Total Water Used since 2005 (billion gallons)
Arkansas	26
Colorado	26
New Mexico	1.3
North Dakota	12
Ohio	1.4
Pennsylvania	30
Texas	110
West Virginia	17

Air pollution: Fracking-related activities release thousands of tons of health-threatening air pollution.

- Nationally, fracking released 450,000 tons of pollutants into the air that can have immediate health impacts.
- Air pollution from fracking contributes to the formation of ozone "smog," which reduces lung function among healthy people, triggers asthma attacks, and has been linked to increases in school absences, hospital visits and premature death. Other air pollutants from fracking and the fossil-fuel-fired machinery used in fracking have been linked to cancer and other serious health effects.

Global warming pollution: Fracking produces significant volumes of global warming pollution.

- Methane, which is a global warming pollutant 25 times more powerful than carbon dioxide, is released at multiple steps during fracking, including during hydraulic fracturing and well completion, and in the processing and transport of gas to end users.
- Global warming emissions from completion of fracking wells since 2005 total an estimated 100 million metric tons of carbon dioxide equivalent.

Damage to our natural heritage: Well pads, new access roads, pipelines and other infrastructure turn forests and rural landscapes into industrial zones.

- Infrastructure to support fracking has damaged 360,000 acres of land for drilling sites, roads and pipelines since 2005.
- Forests and farmland have been replaced by well pads, roads, pipelines and other gas infrastructure, resulting in the loss of wildlife habitat and fragmentation of remaining wild areas.

- In Colorado, fracking has already damaged 57,000 acres of land, equal to one-third of the acreage in the state's park system.
- The oil and gas industry is seeking to bring fracking into our national forests, around several of our national parks, and in watersheds that supply drinking water to millions of Americans.

Fracking has additional impacts not quantified here—including contamination of residential water wells by fracking fluids and methane leaks; vehicle and workplace accidents, earthquakes and other public safety risks; and economic and social damage including ruined roads and damage to nearby farms.

Defining "Fracking"

In this report, when we refer to the impacts of "fracking," we include impacts resulting from all of the activities needed to bring a shale gas or oil well into production using high-volume hydraulic fracturing (fracturing operations that use at least 100,000 gallons of water), to operate that well, and to deliver the gas or oil produced from that well to market. The oil and gas industry often uses a more restrictive definition of "fracking" that includes only the actual moment in the extraction process when rock is fractured—a definition that obscures the broad changes to environmental, health and community conditions that result from the use of fracking in oil and gas extraction.

To address the environmental and public health threats from fracking across the nation:

- States should prohibit fracking. Given the scale and severity of fracking's myriad impacts, constructing a regulatory regime sufficient to protect the environment and public health from dirty drilling—much less enforcing such safeguards at more than 80,000 wells, plus processing and waste disposal sites across the country—seems implausible. In states where fracking is already underway, an immediate moratorium is in order. In all other states, banning fracking is the prudent and necessary course to protect the environment and public health.
- Given the drilling damage that state officials have allowed fracking to incur thus far, at a minimum, federal policymakers must step in and close the loopholes exempting fracking from key provisions of our nation's environmental laws.
- Federal officials should also protect America's natural heritage by keeping fracking away from our national parks, national forests, and sources of drinking water for millions of Americans.
- To ensure that the oil and gas industry—rather than taxpayers, communities or families—pays the costs of fracking damage, policymakers should require robust financial assurance from fracking operators at every well site.
- More complete data on fracking should be collected and made available to the public, enabling us to understand the full extent of the harm that fracking causes to our environment and health.

Introduction

Many Americans have an image of the damage caused by fracking. Documentaries and YouTube videos have shown us tap water catching on fire and families experiencing headaches, dizziness, nausea and other illnesses while living near fracking operations. Plane trips over Texas or Colorado reveal the grids of wells across the landscape.

These snapshots illustrate the damage that fracking does to the environment and our health. But, until now, it has been difficult to comprehend the cumulative extent of that damage. Individual fracking wells, we know, can pollute the air and water of a neighborhood or town. But what does it mean now that the nation has not dozens or hundreds but tens of thousands of fracking wells in at least 17 states? What, for example, is the magnitude of the risk those wells present to drinking water? How many iconic landscapes are being damaged?

In this report, we have quantified several of the key impacts of fracking on water, air and land, at the state and national level, using the best available sources of information on the extent of fracking and the impacts of fracking on our environment and health.

Our analysis shows that damage from fracking is widespread and occurs on a scale unimagined just a few years ago. Moreover, three factors suggest that the total damage from fracking is far worse than we have tabulated here. Severe limitations in available data constrain our ability to see the full extent of the damage. Second, there are broad categories of fracking damage—such as the number of water wells contaminated—that would be difficult to ascertain under any circumstances. Finally, there remain major gaps in the scientific community's understanding of issues such as the long-term consequences of pumping toxic fluids into the ground.

Even the limited data that are currently available, however, paint an increasingly clear picture of the damage that fracking has done to our environment and health. It will take decisive action to protect the American people and our environment from the damage caused by dirty drilling.

Our analysis shows that damage from fracking is widespread and occurs on a scale unimagined just a few years ago.

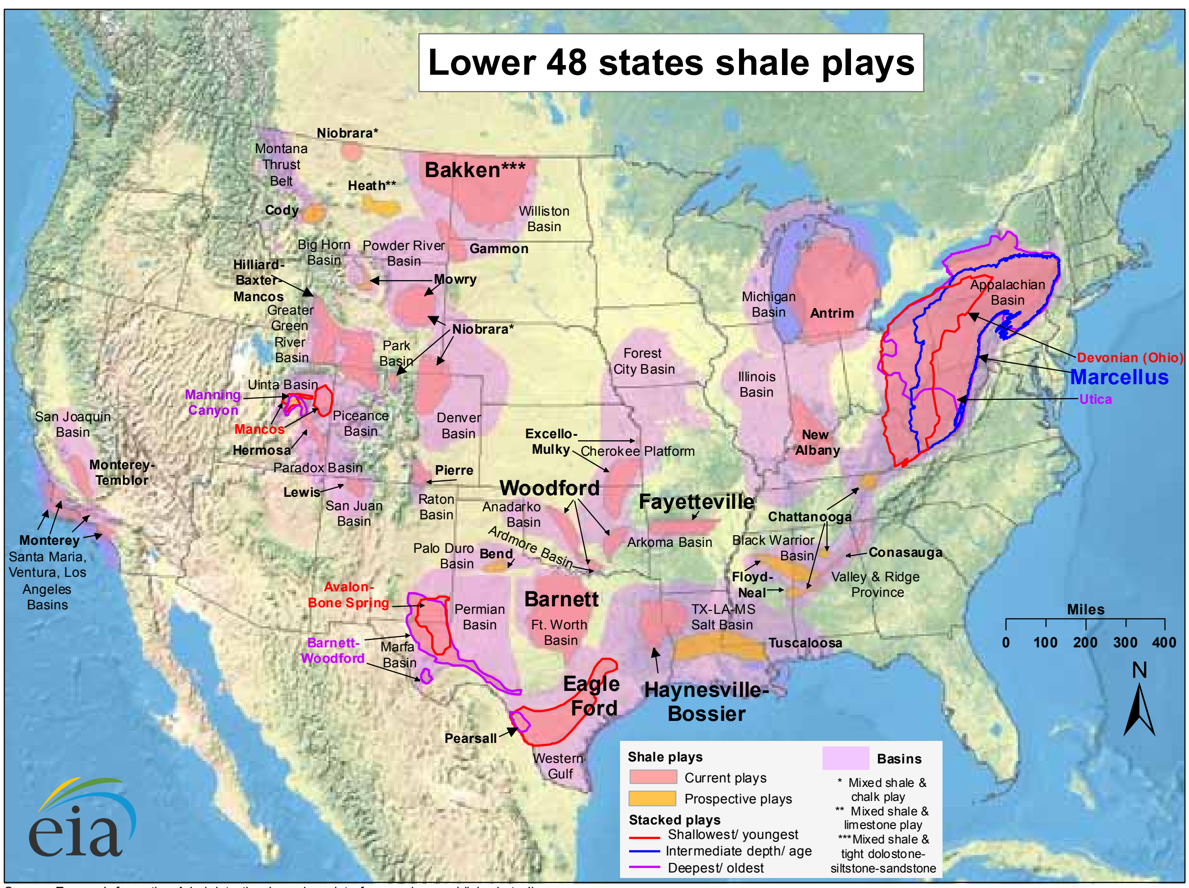
Fracking Poses Grave Threats to the Environment and Public Health

Over the past decade, the oil and gas industry has used hydraulic fracturing to extract oil and gas from previously inaccessible rock formations deep underground. The use of high-volume hydraulic fracturing—colloquially known as "fracking"—has expanded dramatically from its origins in the Barnett Shale region of Texas a decade ago to tens of thousands of wells nationwide today.

Roughly half of U.S. states, stretching from New York to California, sit atop shale or other rock formations with the potential to produce oil or gas using fracking. (See Figure 1.)

Fracking has unleashed a frenzy of oil and gas drilling in several of these shale formations—posing severe threats to the environment and public health.

Figure 1. Shale Gas and Oil Plays[1]



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Contaminating Drinking Water

Fracking has polluted both groundwater and surface waterways such as rivers, lakes and streams. Fracking pollution can enter our waters at several points in the process—including leaks and spills of fracking fluid, well blowouts, the escape of methane and other contaminants from the well bore into groundwater, and the long-term migration of contaminants underground. Handling of toxic fracking waste that returns to the surface once a well has been fracked presents more opportunities for contamination of drinking water. State data confirm more than 1,000 cases of water contaminated by dirty drilling operations. For example:

- In Colorado, approximately 340 of the leaks or spills reported by drilling operators engaged in all types of oil and gas drilling over a five-year period polluted groundwater;[2]
- In Pennsylvania, state regulators identified 161 instances in which drinking water wells were impacted by drilling operations between 2008 and the fall of 2012;[3] and
- In New Mexico, state records show 743 instances of all types of oil and gas operations polluting groundwater—the source of drinking water for 90 percent of the state's residents.[4]

Spills and Leaks of Fracking Fluids

Toxic substances in fracking chemicals and wastewater have been linked to a variety of negative health effects on humans and fish. Chemical components of fracking fluids, for example, have been linked to cancer, endocrine disruption and neurological and immune system problems.[5] Wastewater brought to the surface by drilling can contain substances such as volatile organic compounds with potential impacts on human health.[6]

There are many pathways by which fracking fluids can contaminate drinking water supplies. Spills from trucks, leaks from other surface equipment, and well blowouts can release polluted water to groundwater and surface water. For example, in September 2009 Cabot Oil and Gas caused three spills in Dimock Township, Pennsylvania, in less than a week, dumping 8,000 gallons of fracturing fluid components into Stevens Creek and a nearby wetland.[7]

Leaks of Methane and Other Contaminants from the Well Bore

A study by researchers at Duke University found that the proximity of drinking water wells to fracking wells increases the risk of contamination of residential wells with methane in Pennsylvania. The researchers pointed to faulty well casing as a likely source.[8] Data from fracking wells in Pennsylvania from 2010 to 2012 show a 6 to 7 percent well failure rate due to compromised structural integrity.[9]

Migration of Contaminants

A recent study of contamination in drinking water wells in the Barnett Shale area of North Texas found arsenic, selenium and strontium at elevated levels in drinking water wells close to fracking sites.[10] The researchers surmise that fracking has increased pollution in drinking water supplies by freeing naturally available chemicals to move into groundwater at higher concentrations or through leaks from faulty well construction.

Toxic Fracking Waste

The wastewater produced from fracking wells contains pollutants both from fracking fluids and from natural sources underground. It returns to the surface in huge volumes—both as "flowback" immediately after fracking and "produced water" over a longer period while a well is producing oil or gas. Yet fracking operators have no safe, sustainable way of dealing with this toxic waste. The approaches that drilling companies have devised for dealing with wastewater can pollute waterways through several avenues.

- Waste pits can fail. In New Mexico, substances from oil and gas pits have contaminated groundwater at least 421 times.[11] Moreover, waste pits also present hazards for nearby wildlife and livestock. For example, in May 2010, when a Pennsylvania fracturing wastewater pit owned by East Resources leaked into a farm field, the state Department of Agriculture was forced to quarantine 28 cattle exposed to the fluid to prevent any contaminated meat from reaching the market.[12]

- Discharge of fracking wastewater into rivers can pollute drinking water supplies. For example, after water treatment plants discharged fracking wastewater into the Monongahela River, local authorities issued a drinking water advisory to 350,000 people in the area.[13] In addition, fracking wastewater discharged at treatment plants can cause a different problem for drinking water: when bromide in the wastewater mixes with chlorine (often used at drinking water treatment plants), it produces trihalomethanes, chemicals that cause cancer and increase the risk of reproductive or developmental health problems.[14]

- Drilling companies deliberately spread wastewater on roads and fields. Pollutants from the water can then contaminate local waterways. Drilling operators sometimes spray wastewater on dirt and gravel roads to control dust, or on paved roads to melt ice. In some Western states, fracking waste is spread on farmland or used to water cattle.[15]

- Deep disposal wells are a common destination for fracking waste, but these wells can fail over time, allowing the wastewater and its pollutants to mix with groundwater or surface water.[16] For example,

Photo: The Downstream Project via SkyTruth/LightHawk.

Fracking wastewater is often stored in open waste pits such as these, near Summit, Pennsylvania. Leaks from pits can contaminate drinking water supplies.

wastewater injected into a disposal well contaminated the Cenozoic Pecos Alluvium Aquifer with 6.2 billion gallons of water near Midland, Texas.[17] In Pennsylvania, a disposal well in Bell Township, Clearfield County, lost mechanical integrity in April 2011, but the operator, EXCO Resources, continued to inject fracking wastewater into the well for another five months.[18] The U.S. Environmental Protection Agency (EPA) fined the company nearly $160,000 for failing to protect drinking water supplies. Nationally, routine testing of injection wells in 2010 revealed that 2,300 failed to meet mechanical integrity requirements established by the EPA.[19]

- Pressure from injection wells may cause underground rock layers to crack, accelerating the migration of wastewater into drinking water aquifers. For example, at two injection wells in Ohio, toxic chemicals pumped underground in the 1980s, supposedly secure for at least 10,000 years, migrated into a well within 80 feet of the surface over the course of two decades.[20] Investigators believe that excessive pressure within the injection well caused the rock to fracture, allowing chemicals to escape.

Despite the risk presented to drinking water supplies by fracking, the oil and gas industry is seeking to drill near sources of drinking water for millions of people, including George Washington National Forest in Virginia, White River National Forest in Colorado, Otero Mesa in New Mexico, Wayne National Forest in Ohio, and the Delaware River Basin.

Consuming Scarce Water Resources

Each well that is fracked requires hundreds of thousands of gallons of water depending on the shale formation and the depth and length of the horizontal portion of the well. Unlike most industrial uses of water which return water to the water cycle for further use, fracking converts clean water into toxic wastewater, much of which must then be permanently disposed of, taking billions of gallons out of the water supply annually. Moreover, farmers are particularly impacted by fracking water use, as they must now compete with the deep-pocketed oil and gas industry for water, especially in the drought-stricken regions of the country.

In some areas, fracking makes up a significant share of overall water demand. In 2010, for example, fracking in the Barnett Shale region of Texas consumed an amount of water equivalent to 9 percent of the city of Dallas' annual water use.[21] An official at the Texas Water Development Board estimated that one county in the Eagle Ford Shale region will see the share of water consumption devoted to fracking and similar activities increase from zero a few years ago to *40 percent* by 2020.[22] Unlike other uses, water used in fracking is permanently lost to the water cycle, as it either remains in the well, is "recycled" (used in the fracking of new wells), or is disposed of in deep injection wells, where it is unavailable to recharge aquifers.

Already, demand for water by oil and gas companies has harmed farmers and local communities:

- In Texas, water withdrawals by drilling companies caused drinking water wells in the town of Barnhart to dry up. Companies drilling in the Permian Basin have drilled wells and purchased well water drawn from the Edwards-Trinity-Plateau Aquifer, drying up water supplies for residential and agricultural use.[23]

- Wells that provided water to farms near Carlsbad, New Mexico, have gone dry due to demand for water for drilling and years of low rainfall.[24]

Competition for limited water resources from fracking can increase water prices for farmers and communities—especially in arid western states. A 2012 auction of unallocated water conducted by the

Northern Water Conservation District in Colorado saw gas industry firms submit high bids, with the average price of water sold in the auction increasing from $22 per acre-foot in 2010 to $28 per acre-foot in the first part of 2012.[25] For the 25,000 acre-feet of water auctioned, this would amount to an added cost of $700,000.

Moreover, water pumped from rivers for fracking reduces the quality of the water remaining in the river because pollution becomes more concentrated. A 2011 U.S. Army Corps of Engineers study of the Monongahela River basin of Pennsylvania and West Virginia, where oil and gas companies withdraw water from the river for fracking, concluded that, "The quantity of water withdrawn from streams is largely unregulated and is beginning to show negative consequences."[26] The Corps report noted that water is increasingly being diverted from the relatively clean streams that flow into Corps-maintained reservoirs, limiting the ability of the Corps to release clean water to help dilute pollution during low-flow periods.[27] It described the water supply in the Monongahela basin as "fully tapped."[28]

Excessive water withdrawals undermine the ability of rivers and streams to support wildlife. In Pennsylvania, water has been illegally withdrawn for fracking numerous times, to the extent of streams being sucked dry. Two streams in southwestern Pennsylvania—Sugarcamp Run and Cross Creek—were reportedly drained for water withdrawals for fracking, triggering fish kills.[29]

Nationally, nearly half of all fracking wells are located in regions with very limited water supplies. A study by Ceres, a coalition of business and environmental interests, found that nearly 47 percent of wells fracked from January 2011 through September 2012 were located in areas with "high or extremely high water stress."[30]

Endangering Public Health with Air Pollution

Air pollution from fracking threatens the health of people living and working close to the wellhead, as well as those far away. Children, the elderly and those with respiratory diseases are especially at risk.

Fracking produces air pollution from the well bore as the well is drilled and gas is vented or flared. Emissions from trucks carrying water and materials to well sites, as well as from compressor stations and other fossil fuel-fired machinery, also contribute to air pollution. Well operations, storage of gas liquids, and other activities related to fracking add to the pollution toll.

Making Local Residents Sick

People who live close to fracking sites are exposed to a variety of air pollutants including volatile organic compounds (VOCs) such as benzene, xylene and toluene. These chemicals can cause a wide range of health problems—from eye irritation and headaches to asthma and cancer.[31]

Existing data demonstrate that fracking operations are releasing these pollutants into the air at levels that threaten our health. In Texas, monitoring by the Texas Department of Environmental Quality detected levels of benzene—a known cancer-causing chemical—in the air that were high enough to cause immediate human health concern at two sites in the Barnett Shale region, and at levels that pose long-term health concern at an additional 19 sites. Several chemicals were also found at levels that can cause foul odors.[32] Air monitoring in Arkansas has also found elevated levels of volatile organic compounds (VOCs)—some of which are also hazardous air pollutants—at the perimeter of hydraulic fracturing sites.[33] Local air pollution problems have also cropped up in Pennsylvania. Testing conducted by the Pennsylvania Department of Environmental Protection detected components of gas in the air near Marcellus Shale drilling operations.[34]

Residents living near fracking sites have long suffered from a range of acute and chronic health problems, including headaches, eye irritation, respiratory problems and nausea.[35] An investigation by the journalism website ProPublica uncovered numerous reports of illness in western states from air pollution from fracking.[36] In Pennsylvania, a homeowner in the town of Carmichaels described how she and her children began to suffer from a variety of symptoms after a compressor station was built 780 feet from her house.[37] Pam Judy explained to the nearby Murrysville Council that "Shortly after operations began, we started to experience extreme headaches, runny noses, sore/scratchy throats, muscle aches and a constant feeling of fatigue. Both of our children are experiencing nose bleeds and I've had dizziness, vomiting and vertigo to the point that I couldn't stand and was taken to an emergency room." Eventually, she convinced state officials to test air quality near her home. That testing revealed benzene, styrene, toluene, xylene, hexane, heptane, acetone, acrolein, carbon tetrachloride and chloromethane in the air.[38]

All indications are that these known stories just scratch the surface of health damage from fracking. In cases where families made sick from fracking have sought to hold drilling companies accountable in court, the companies have regularly insisted on gag orders as conditions of legal settlements—in a recent case even the children were barred from talking about fracking, for life.[39]

Workers at drilling sites also suffer from health impacts. A recent investigation by the National Institute for Occupational Safety and Health (NIOSH) found that workers at some fracking sites may be at risk of lung disease as a result of inhaling silica dust from sand injected into wells. The NIOSH investigation reviewed 116 air samples at 11 fracking sites in Arkansas, Colorado, North Dakota, Pennsylvania and Texas. Nearly half (47 percent) of the samples had levels of silica that exceeded the Occupational Safety and Health Administration's (OSHA) legal limit for workplace exposure, while 78 percent exceeded OSHA's recommended limits. Nearly one out of 10 (9%) of the samples exceeded the legal limit for silica by a factor of 10, exceeding the threshold at which half-face respirators can effectively protect workers.[40]

Over the past few years, health clinics in fracking areas of Pennsylvania have reported seeing a number of patients experiencing illnesses associated with exposure to toxic substances from fracking, all of whom have used false names and paid in cash. David Brown, a toxicologist with the Southwest Pennsylvania Environmental Health Project believes that these are mostly fracking workers, who are afraid that any record of their work making them sick will cost them their jobs.[41]

Regional Air Pollution Threats

Fracking also produces a variety of pollutants that contribute to regional air pollution problems. VOCs and nitrogen oxides (NO_x) in gas formations contribute to the formation of ozone "smog," which reduces lung function among healthy people, triggers asthma attacks, and has been linked to increases in school absences, hospital visits and premature death.[42]

Fracking is a significant source of air pollution in areas experiencing large amounts of drilling. A 2009 study in five Dallas-Fort Worth-area counties experiencing heavy Barnett Shale drilling activity found that oil and gas production was a larger source of smog-forming emissions than cars and trucks.[43] In Arkansas, gas production in the Fayetteville Shale region was estimated to be responsible for 5,000 tons of NO_x.[44] In Wyoming, pollution from fracking contributed to such poor air quality that, for the first time, the state failed to meet federal air quality standards.[45] An analysis conducted for New York State's revised draft environmental impact statement on Marcellus Shale drilling posited that, in a worst case scenario of widespread drilling and lax emission controls, shale gas production could add 3.7 percent to state NO_x emissions and 1.3 percent to statewide VOC emissions compared with 2002 emissions levels.[46]

Exacerbating Global Warming

Global warming is a profound threat to virtually every aspect of nature and human civilization—disrupting the functioning of ecosystems, increasing the frequency and violence of extreme weather, and ultimately jeopardizing health, food production, and water resources for Americans and people across the planet. Gas extraction produces enormous volumes of global warming pollution.

Fracking's primary impact on the climate is through the release of methane, which is a far more potent contributor to global warming than carbon dioxide. Over a 100-year timeframe, a pound of methane has 25 times the heat-trapping effect of a pound of carbon dioxide.[47] Methane is even more potent relative to carbon dioxide at shorter timescales, at least 72 times more over a 20-year period.

Intentional venting and leaks during the extraction, transmission and distribution of gas release substantial amounts of methane to the atmosphere. The U.S. Environmental Protection Agency revised downward its estimate of fugitive methane emissions from fracking in April 2013, citing improved practices by the industry.[48] A study conducted with industry cooperation and released in September 2013 found very low fugitive emissions of methane at the wells included in the study, though the findings may not be representative of standard industry practice.[49]

However, recent air monitoring by researchers at the National Oceanic and Atmospheric Administration and the University of Colorado, Boulder, near a gas and oil field in Colorado revealed fugitive methane emissions equal to 2.3 to 7.7 percent of the gas extracted in the basin, not counting the further losses that occur in transportation.[50] Recent aerial sampling of emissions over an oil and gas field in Uintah County, Utah, revealed methane emissions equal to 6.2 to 11.7 percent of gas production.[51]

The global warming impact of fracked natural gas is so great that electricity produced from natural gas may have a greater global warming impact than electricity from coal, especially when evaluated on a short timeline. An analysis by Professor Robert Howarth at Cornell and others found that, on a 20-year timescale, electricity from natural gas is more polluting than electricity from coal.[52]

Regardless of the fugitive emissions level from fracked gas, increased production of and reliance on gas is not a sound approach to reducing our global warming emissions. Investments in gas production and distribution infrastructure divert financing and efforts away from truly clean energy sources such as energy efficiency and wind and solar power. Gas is not a "bridge fuel" that prepares us for a clean energy future; rather, increasing our use of gas shifts our reliance from one polluting fuel to another.

Additionally, to the extent that fracking produces oil instead of gas, fracking does nothing to reduce global warming pollution: in fact, refining oil into useable products like gasoline and diesel, and then burning those products, is a huge source of global warming pollution.

Damaging America's Natural Heritage

Fracking transforms rural and natural areas into industrial zones. This development threatens national parks and national forests, damages the integrity of landscapes and habitats, and contributes to water pollution problems that threaten aquatic ecosystems.

Before drilling can begin, land must be cleared of vegetation and leveled to accommodate drilling equipment, gas collection and processing equipment, and vehicles. Additional land must be cleared for roads to the well site, as well as for any pipelines and compressor stations needed to deliver gas to market. A study by the Nature Conservancy of fracking infrastructure in Pennsylvania found that well pads average 3.1 acres and related infrastructure damages an additional 5.7 acres.[53] Often, this development occurs on remote and previously undisturbed wild lands.

As oil and gas companies expand fracking activities, national parks, national forests and other iconic landscapes are increasingly at risk. Places the industry is seeking to open for fracking include:

- **White River National Forest** – Located in Colorado, this forest draws 9.2 million visitors per year for hiking, camping and other recreation, making it the most visited national forest in the country.[54] The forest also hosts 4,000 miles of streams that provide water to several local communities and feed into the Colorado River.
- **Delaware River Basin** – This basin, which spans New Jersey, New York, Pennsylvania and Delaware, is home to three national parks and provides drinking water to 15 million people.[55]
- **Wayne National Forest** – Part of Ohio's beautiful Hocking Hills region, most of the acres in the forest are to be leased for drilling near the sole drinking water source for 70,000 people.[56]

Photo: Peter Aengst via SkyTruth/EcoFlight.

Wells and roads built to support fracking in Wyoming's Jonah gas field have caused extensive habitat fragmentation.

- **George Washington National Forest** – This area hosts streams in Virginia and West Virginia that feed the James and Potomac Rivers, which provide the drinking water for millions of people in the Washington, D.C., metro area.
- **Otero Mesa** – A vital part of New Mexico's natural heritage, Otero Mesa is home to pronghorn antelope and a freshwater aquifer that could be a major source of drinking water in this parched southwestern state.[57]

The disruption and fragmentation of natural habitat can put wildlife at risk. In Wyoming, for example, extensive gas development in the Pinedale Mesa region has coincided with a significant reduction in the region's population of mule deer. A 2006 study found that the construction of well pads drove away female mule deer.[58] The mule deer population in the area dropped by 50 percent between 2001 and 2011, as fracking in the area continued and accelerated.[59]

Concerns have also been raised about the impact of gas development on pronghorn antelope. A study by the Wildlife Conservation Society documented an 82 percent reduction in high-quality pronghorn habitat in Wyoming's gas fields, which have historically been key wintering grounds.[60]

Birds may also be vulnerable, especially those that depend on grassland habitat. Species such as the northern harrier, short-eared owl, bobolink, upland sandpiper, loggerhead shrike, snowy owl, rough-legged hawk and American kestrel rely on grassland habitat for breeding or wintering habitat.[61] These birds typically require 30 to 100 acres of undisturbed grassland for habitat.[62] Roads, pipelines and well pads for fracking may fragment grassland into segments too small to provide adequate habitat.

The clearing of land for well pads, roads and pipelines may threaten aquatic ecosystems by increasing sedimentation of nearby waterways and decreasing shade. A study by the Academy of Natural Sciences of Drexel University found an association between increased density of gas drilling activity and degradation of ecologically important headwater streams.[63]

Water contamination related to fracking has caused several fish kills in Pennsylvania. In 2009, a pipe containing freshwater and flowback water ruptured in Washington County, Pennsylvania, triggering a fish kill in a tributary of Brush Run, which is part of a high-quality watershed.[64] That same year, in the same county, another pipe ruptured at a well drilled in a public park, killing fish and other aquatic life along a three-quarter-mile length of a local stream.[65]

Imposing Costs on Communities

As with prior extractive booms, the fracking oil and gas rush disrupts local communities and imposes a wide range of immediate and long term costs on them.

Ruining Roads, Straining Services

As a result of its heavy use of publicly available infrastructure and services, fracking imposes both immediate and long-term costs on taxpayers.

The trucks required to deliver water to a single fracking well cause as much damage to roads as 3.5 million car journeys, putting massive stress on roadways and bridges not constructed to handle such volumes of heavy traffic. Pennsylvania estimates that repairing roads affected by Marcellus Shale drilling would cost $265 million.[66]

Fracking also strains public services. Increased heavy vehicle traffic has contributed to an increase in traffic accidents in drilling regions. At the same time, the influx of temporary workers that typically accompanies fracking puts pressure on housing supplies, thereby causing social dislocation. Governments respond by increasing their spending on social services and subsidized housing, squeezing tax-funded budgets.

Governments may even be forced to spend tax money to clean up orphaned wells—wells that were never properly closed and whose owners, in many cases, no longer exist as functioning business entities. Though oil and gas companies face a legal responsibility to plug wells and reclaim drilling sites, they have a track record of leaving the public holding the bag.[67]

Risks to Local Businesses, Homeowners and Taxpayers

Fracking imposes damage on the environment, public health and public infrastructure, with significant economic costs, especially in the long run after the initial rush of drilling activity has ended. A 2008 study by the firm Headwaters Economics found that Western counties that have relied on fossil-fuel extraction for growth are doing worse economically than their peers, with less-diversified economies, a less-educated workforce, and greater disparities in income.[68]

Other negative impacts on local economies include downward pressure on home values and harm to farms. Pollution, stigma and uncertainty about the future implications of fracking can depress the prices of nearby properties. One Texas study found that homes valued at more than $250,000 and located within 1,000 feet of a well site lost 3 to 14 percent of their value.[69] Fracking also has the potential to affect agriculture, both directly through damage to livestock from exposure to fracking fluids, and indirectly through economic changes that undermine local agricultural economies.

Fracking can increase the need for public investment in infrastructure and environmental cleanup. Fracking-related water demand may also lead to calls for increased public spending on water infrastructure. Texas, for example, adopted a State Water Plan in 2012 that calls for $53 billion in investments in the state water system, including $400 million to address unmet needs in the mining sector (which includes hydraulic fracturing) by 2060.[70] Fracking is projected to account for 42 percent of water use in the Texas mining sector by 2020.[71]

The cost of cleaning up environmental damage from the current oil and gas boom may fall to taxpayers, as has happened with past booms. For example, as of 2006, more than 59,000 orphan oil and gas wells were on state waiting lists for plugging and remediation across the United States, with at least an additional 90,000 wells whose status was unknown or undocumented.[72] Texas alone has more than 7,800 orphaned oil and gas wells.[73] These wells pose a continual threat of groundwater pollution and have cost the state of Texas more than $247 million to plug.[74] The current fracking boom ultimately may add to this catalog of orphaned wells.

Threatening Public Safety

Fracking harms public safety by increasing traffic in rural areas where roads are not designed for such high volumes, by creating an explosion risk from methane, and by increasing earthquake activity.

Increasing traffic—especially heavy truck traffic—has contributed to an increase in traffic accidents and fatalities in some areas in which fracking has unleashed a drilling boom, as well as an increase in demands for emergency response. In the Bakken Shale oil region of North Dakota for example, the number of highway crashes increased by 68 percent between 2006 and 2010, with the share of crashes involving heavy trucks also increasing over that period.[75] A 2011 survey by StateImpact Pennsylvania in eight counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years, largely due to an increase in incidents involving heavy trucks.[76]

Methane contamination of well water poses a risk of explosion if the gas builds up inside homes. In both Ohio and Pennsylvania, homes have exploded after high concentrations of methane inside the buildings were ignited by a spark.[77]

Another public safety hazard stems from earthquakes triggered by injection wells. For example, on New Year's Eve in 2011—shortly after Ohio began accepting increasing amounts of wastewater from Pennsylvania—a 4.0 earthquake shook Youngstown, Ohio. Seismic experts at Columbia University determined that pumping fracking wastewater into a nearby injection well caused the earthquake.[78] Earthquakes triggered by injection well wastewater disposal have happened in Oklahoma, Arkansas, Texas, Ohio and Colorado. The largest quake—a magnitude 5.7 temblor in Oklahoma that happened in 2011—injured two people, destroyed 14 homes and buckled highways. People felt the quake as far as 800 miles away.[79]

As fracking wastewater volumes have increased dramatically since 2007, the number of earthquakes in the central United States, where injection well disposal is common, has increased by more than 1,100 percent compared to earlier decades.[80] Scientists at the U.S. Geological Survey have concluded that humans are likely the cause.[81] After reviewing data on the Oklahoma quake, Dr. Geoffrey Abers, a seismologist at the Lamont-Doherty Earth Observatory, concluded that, "the risk of humans inducing large earthquakes from even small injection activities is probably higher" than previously thought.[82]

Quantifying the State and National Impacts of Fracking

Fracking imposes numerous costly impacts on our environment and public health. This report seeks to estimate several key impacts of fracking for oil and gas, with a primary focus on high-volume fracking.

There have been few, if any, efforts to quantify the cumulative impacts of fracking at a state or national scale. The task is made difficult, in part, by differing definitions and data collection practices for unconventional drilling used in the states. These variations in data make it difficult to isolate high-volume fracking from other practices. To address this challenge, we collected data on unconventional drilling targets (shale gas, shale oil, and tight-gas sands) and practices (horizontal and directional drilling) to ensure the comprehensiveness of the data. Where possible, we then narrowed the data to include only those wells using high-volume hydraulic fracturing involving more than 100,000 gallons of water.

Photo: The Downstream Project via SkyTruth/LightHawk.

More than 6,000 shale gas/liquids wells, such as this well site in Tioga County, have been drilled in Pennsylvania since 2005.

The data presented in the following sections come from multiple sources, including state databases, estimates from knowledgeable state employees, and information provided by oil and gas companies to a national website. As a result, the quality of the data varies and figures may not be directly comparable from state to state. Nonetheless, the numbers paint an initial picture of the extensive environmental and public health damage from fracking.

Table 1. Estimate of Fracking Wells[83]

State	Fracking Wells since 2005	Fracking Wells Drilled in 2012
Arkansas	4,910	719
Colorado	18,168	1,896
Kansas	407	236
Louisiana	2,327	139
Mississippi	9	Unavailable
Montana	264	174
New Mexico	1,353	482
North Dakota	5,166	1,713
Ohio	334	234
Oklahoma	2,694	Unavailable
Pennsylvania	6,651	1,349
Tennessee	30	Unavailable
Texas	33,753	13,540
Utah	1,336	765
Virginia	95	1
West Virginia*	3,275	610
Wyoming	1,126	468
TOTAL	**81,898**	**22,326**

"Unavailable" means information was not available to determine when wells were drilled. See methodology for complete details.

** Data for West Virginia is for permitted fracking wells, not wells that have been drilled. Data were not available on drilled wells.*

Wells Fracked by State

The most basic measure of fracking's scope is a tally of how many fracking wells have been drilled. In addition, having an accurate count of wells by state offers a basis for estimating specific impacts to water, air and land.

Fracking has occurred in at least 17 states (see Table 1), affecting approximately 82,000 wells. In the eastern U.S., Pennsylvania reports the most fracking wells since 2005, with 6,651 wells tapping into the Marcellus and Utica shales. More than 5,000 fracking wells have been drilled in North Dakota to produce oil from the Bakken formation. Western states with the most fracking include Colorado, New Mexico and Utah.

Absent policies to rein in fracking, fracking is likely to expand in these and other states. Tennessee currently has a handful of wells but more will soon be fracked in the Cumberland Forest.[84] One test well was fracked in Georgia in the past year.[85] Illinois recently adopted new regulations governing fracking, paving the way for the practice there.[86] Oil and gas companies are seeking to expand to states such as California, New York, Maryland and North Carolina where there has been no such activity to date. In New York, as many as 60,000 wells could be drilled.[87]

Wastewater Produced

One of the more serious threats fracking poses to drinking water is the millions of gallons of toxic wastewater it generates.

While there are many ways in which fracking can contaminate drinking water—including but not limited to spills of fracking fluid, well blowouts, leaks of methane and other contaminants from the well bore into groundwater, and the possible eventual migration of fluids from shale to the water table—one of the most serious threats comes from the millions of gallons of toxic wastewater fracking generates.

Table 2 shows how much wastewater has been produced from fracking wells in selected states. In some states, such as New Mexico, North Dakota, Ohio, Pennsylvania and Utah, well operators submit regular reports on the volume of wastewater, oil and gas produced from their wells. In some states where operators do not report wastewater volumes, we estimated wastewater volumes using state-specific data as described in the methodology. These estimates are for wastewater only, and do not include other toxic wastes from fracking, such as drilling muds and drill cuttings.

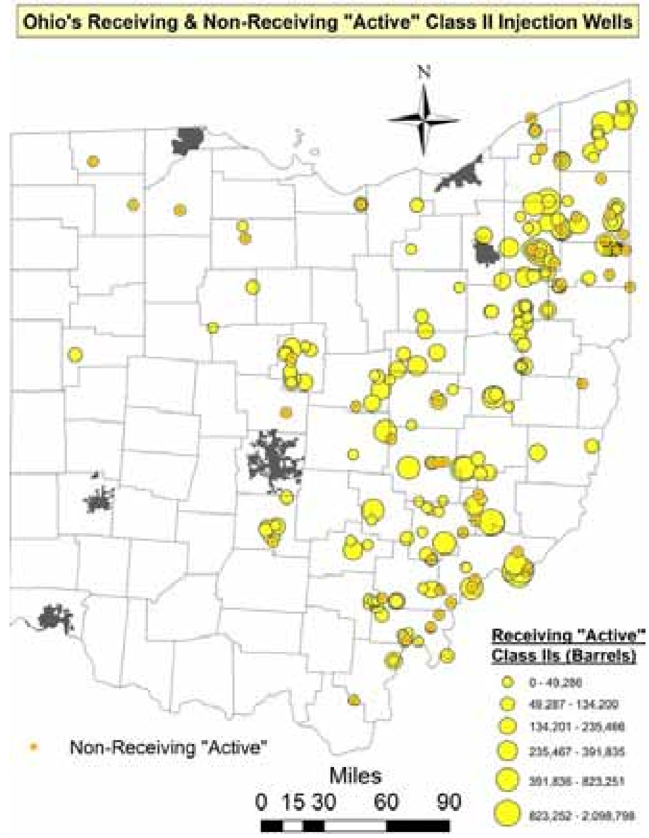
The rapid growth of fracking has caused wastewater volumes to increase rapidly. In the Marcellus Shale underlying Pennsylvania, West Virginia and Ohio, for example, wastewater production increased six-fold from 2004 to 2011.[89]

Table 2. Wastewater from Fracking in 2012[88]

State	Wastewater Produced (million gallons)
Arkansas	800
Colorado	2,200
Kansas	No estimate
Louisiana	No estimate
Mississippi*	10
Montana	360
New Mexico	3,000
North Dakota**	12,000
Ohio	30
Oklahoma	No estimate
Pennsylvania	1,200
Tennessee	No estimate
Texas	260,000
Utah	800
Virginia	No estimate
West Virginia	No estimate
Wyoming	No estimate
TOTAL	**280,000**

** Data for Mississippi are for 2012-2013.*

*** Data for North Dakota are cumulative to early 2013.*



Fracking wastewater is disposed into Class II injection wells in Ohio. "Receiving" wells currently accept fracking wastewater. "Non-receiving" wells are those wells that could receive fracking wastewater but haven't to date. Data mapped by the FracTracker Alliance on FracTracker.org. Original data source: *Bulk Transporter Magazine*, accessed at www.fractracker.org/2013/06/oh-waste-network, 23 July 2013.

In 2012 alone, fracking in Pennsylvania produced 1.2 billion gallons of wastewater, almost as much as was produced in a three-year period from 2009 to 2011.[90]

This huge volume of polluted wastewater creates many opportunities for contaminating drinking water. More wells and more wastewater increase the odds that the failure of a well casing or gasket, a wastewater pit or a disposal well will occur and that drinking water supplies will be contaminated. Moreover, as the sheer volume of wastewater generated exceeds local disposal capacity, drilling operators are increasingly looking to neighboring states as convenient dumping grounds. For example, in 2011, more than 100 million gallons of Pennsylvania's fracking waste were trucked to Ohio for disposal into underground injection wells.[91] (See map of Ohio disposal wells.)

As the volume of this toxic waste grows, so too will the likelihood of illegal dumping. For example, in 2013 Ohio authorities discovered that one drilling waste operator had dumped thousands of gallons of fracking wastewater into the Mahoning River.[92] And in Pennsylvania, prosecutors recently charged a different company with dumping fracking waste.[93]

For other industries, the threats posed by toxic waste have been at least reduced due to the adoption of the federal Resource Conservation Recovery Act (RCRA), which provides a national framework for regulating hazardous waste. Illegal dumping is reduced by cradle-to-grave tracking and criminal penalties. Health-threatening practices such as open waste pits, disposal in ordinary landfills, and road spreading are prohibited. However, waste from oil and gas fracking is exempt from the hazardous waste provisions of RCRA—exacerbating the toxic threats posed by fracking wastewater.

Chemicals Used

Fracking fluid consists of water mixed with chemicals that is pumped underground to frack wells. Though in percentage terms, chemicals are a small component of fracking fluid, the total volume of chemicals used is immense.

The oil and gas industry estimates that 99.2 percent of fracking fluid is water (by volume) and the other 0.8 percent is a mix of chemicals.[94] Assuming that this percentage is correct and has held true since 2005, that means oil and gas companies have used 2 billion gallons of chemicals.

These chemicals routinely include toxic substances. According to a 2011 congressional report, the toxic chemicals used in fracking include methanol, glutaraldehyde, ethylene glycol, diesel, naphthalene, xylene, hydrochloric acid, toluene and ethylbenzene.[95] More recently, an independent analysis of data submitted by fracking operators to FracFocus revealed that *one-third* of all frack jobs reported there use at least one cancer-causing chemical.[96] These toxic substances can enter drinking water supplies from the well, well pad or in the wastewater disposal process.

Water Used

Since 2005, fracking has used at least 250 billion gallons of water across the nation. Extrapolating from industry-reported figures on water use at more than 36,000 wells since 2011, we estimated total water use for all wells that were fracked from 2005 through mid-2013. (See Table 3.)

The greatest total water consumption occurred in Texas, at the same time the state was struggling with extreme drought. Other states with high water use include Pennsylvania, Arkansas and Colorado. The amount of water used for fracking in Colorado was enough to meet the water needs of nearly 200,000 Denver households for a year.[97]

Table 3. Water Used for Fracking[98]

State	Total Water Used since 2005 (million gallons)
Arkansas	26,000
Colorado	26,000
Kansas	670
Louisiana	12,000
Mississippi	64
Montana	450
New Mexico	1,300
North Dakota	12,000
Ohio	1,400
Oklahoma	10,000
Pennsylvania	30,000
Tennessee	130
Texas	110,000
Utah	590
Virginia	15
West Virginia	17,000
Wyoming	1,200
TOTAL	**250,000**

Air Pollution Created

Fracking created hundreds of thousands of tons of air pollution in 2012. As shown in Table 4, well-site operations during drilling and well completion generated approximately 450,000 tons of health-threatening air pollution. And that does not even include the significant emissions from ongoing operations, compressors, waste pits and truck traffic to and from drilling sites carrying supplies and personnel.

This air pollution estimate for all wells is based on emissions figures from wells in the Marcellus Shale. Different drilling targets and practices may lead to different results.[99] Additional research and improved data availability will help clarify the amount of pollution occurring in different regions.

The 2012 NO_x emissions from the early stages of fracking in Colorado were equal to 27 percent of the NO_x produced by power plants in the state, assuming fracking well emissions rates were similar to those in the Marcellus.[100] In Pennsylvania, fracking produced NO_x equal to 7 percent of that emitted in 2011 by electricity generation, a major source of smog-forming emissions.

Table 4. Estimated Air Pollution Produced from Early Stages of Fracking (Drilling and Well Completion) in 2012 (tons)

State	Particulate Matter	NO_x	Carbon Monoxide	VOCs	Sulphur Dioxide
Arkansas	400	5,300	8,100	700	20
Colorado	1,100	14,000	21,000	2,000	50
Kansas	100	1,700	2,700	200	6
Louisiana	80	1,000	1,600	100	3
Mississippi	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Montana	100	1,300	2,000	200	4
New Mexico	300	3,600	5,400	500	10
North Dakota	1,000	13,000	19,000	2,000	40
Ohio	100	1,700	2,600	200	6
Oklahoma	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Pennsylvania	800	10,000	15,000	1,000	30
Tennessee	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Texas	7,800	100,000	153,000	14,000	300
Utah	400	5,700	9,000	1,000	20
Virginia	1	7	11	1	0
West Virginia	400	4,500	6,900	600	20
Wyoming	270	3,500	5,300	500	12
TOTAL	**13,000**	**170,000**	**250,000**	**23,000**	**600**

Global Warming Pollution Released

Completion of fracking wells produced global warming pollution of 100 million metric tons of carbon dioxide equivalent from 2005 to 2012, equal to emissions from 28 coal-fired power plants in a year.[101]

Using the data on the number of fracking wells, we estimated emissions from well completion using an emissions rate from a recent study by researchers at MIT. The researchers calculated that the average fracked shale gas well completed in 2010 released 110,000 pounds of methane during the first nine days of operation.[102] The researchers assumed that 70 percent of wells were operated with equipment to limit emissions, that 15 percent of wells flared gas, and that 15 percent of wells vented gas. Their calculations did not include methane emissions after the first nine days, such as during processing, transmission and distribution, nor did they include carbon dioxide emissions from trucks and drilling equipment. We used data on the number of wells fracked since 2005 (as presented in Table 1 in "Estimate of Fracking Wells ") to estimate methane emissions. Table 5 presents estimated emissions from completion of fracking wells from 2005 to 2012.

In Texas, emissions from completion of fracking wells since 2005 are equal to those produced by 12 coal-fired power plants in a year.[103] Completion of wells in Pennsylvania produced emissions equal to the pollution from 1.7 million passenger vehicles in a year.[104]

Table 5. Global Warming Pollution from Completion of Fracking Wells

State	Based on Well Completion from 2005 to 2012 (metric tons of carbon dioxide-equivalent)
Arkansas	6,200,000
Colorado	23,000,000
Kansas	500,000
Louisiana	2,900,000
Mississippi	11,000
Montana	300,000
New Mexico	1,700,000
North Dakota	6,500,000
Ohio	420,000
Oklahoma	3,400,000
Pennsylvania	8,300,000
Tennessee	No estimate
Texas	40,000,000
Utah	1,700,000
Virginia	120,000
West Virginia	4,100,000
Wyoming	1,400,000
TOTAL	**100,000,000**

This estimate of emissions from well completion is both incomplete and includes several points of uncertainty. First and foremost, it does not include emissions from ongoing operation of wells. Second, in states where regulators do not have a firm estimate of the number of fracking wells, such as in Colorado and Texas, our conservative estimate of the number of fracking wells results in an underestimate of emissions. Introducing uncertainty, this estimate treats all wells as if they were the same and have the same emissions. In reality, some wells produce gas, some produce oil, and some wells produce gas that requires additional processing.[105] Finally, even those states that track the number of fracking wells typically don't track well type.

We believe this estimate of emissions from well completions understates total emissions from fracking wells. To compare this estimate of emissions from well completion to an estimate from ongoing emissions and to avoid the problem of uncertainty regarding emissions by well type, we estimated emissions based on gas production for a few states.

Researchers at Cornell have studied emissions from fracking in five unconventional gas formations.[106] The researchers estimated the methane emissions released from multiple steps in the fracking process—drilling, fracking and processing—and calculated emissions as a percentage of produced gas.[107] Using estimates of gas production by state, where available, we calculated statewide global warming pollution from fracking. For the two states where we have complete production data—Pennsylvania and North Dakota—the production-based emissions estimate is higher than the estimate based on the number of completed wells.

Using our production-based method, Pennsylvania, North Dakota and Colorado had the highest emissions. Pennsylvania produced the most global warming pollution from fracking for gas. In 2012, the state created 24 million metric tons of carbon dioxide-equivalent, as much pollution as produced by seven coal-fired power plants or 5 million passenger vehicles.[108]

Photo: Gerry Dincher/Flickr.

Storage tanks can be a significant source of fugitive methane emissions.

Acres of Land Damaged

Nationally, land directly damaged for fracking totals 360,000 acres. (See Table 6.) This estimate includes the amount of land that has been cleared for roads, well sites, pipelines and related infrastructure in each state. However, the total amount of habitat and landscape affected by fracking is much greater. In treasured open spaces, a single well-pad can mar a vista seen from miles around. A study of fracking development in Pennsylvania estimated that forest fragmentation affected more than twice as much land as was directly impacted by development.[109]

Fracking activity in Colorado damaged 57,000 acres, equal to one-third of the acreage in the state's park system.[110] In Pennsylvania, the amount of land directly affected by fracking-related development since 2005 is equal to all the farmland protected since 1999 through the state's Growing Greener land preservation program.[111]

Table 6. Land Damaged for Fracking[112]

State	Acres Damaged since 2005
Arkansas	24,000
Colorado	57,000
Kansas	No estimate
Louisiana	No estimate
Mississippi	No estimate
Montana	230
New Mexico	8,900
North Dakota	50,000
Ohio	1,600
Oklahoma	22,000
Pennsylvania	33,000
Tennessee	No estimate
Texas	130,000
Utah	9,000
Virginia	460
West Virginia	16,000
Wyoming	5,000
TOTAL	**360,000**

Photo: ©Dennis Dimick/Flickr.

A grid of drilling sites and roads, similar to those used in fracking, lies across the landscape near Odessa, Texas.

In the years to come, fracking may affect a much bigger share of the landscape. According to a recent analysis by the Natural Resources Defense Council, 70 of the nation's largest oil and gas companies have leases to 141 million acres of land, bigger than the combined areas of California and Florida.[113] Moreover, as noted earlier in this report, the oil and gas industry is seeking access to even more acres of land for fracking—including areas on the doorsteps of our national parks, and inside our national forests—some of which contain sources of drinking water for millions of Americans.

Policy Recommendations

As evidenced by the data in this report, fracking is causing extensive damage to the environment and public health in states across the country. States as disparate as Colorado, North Dakota, Pennsylvania and Texas suffer from air pollution, water pollution, habitat disruption and water depletion caused by widespread fracking. Wherever fracking has occurred, it has left its mark on the environment and our well-being.

Fracking has additional impacts not documented in this report. Environmental damage includes water pollution from spills of fracking fluids and methane leaks into groundwater, as well as air pollution from toxic emissions that causes both acute and chronic health problems for people living near wells. Economic and social damage includes ruined roads and damage to farm economies.

The scale of this threat is growing almost daily, with thousands of new wells being added across the nation each year. Given the scale and severity of fracking's myriad impacts, constructing a regulatory regime sufficient to protect the environment and public health from dirty drilling—much less enforcing such safeguards at more than 80,000 wells, plus processing and waste disposal sites across the country—seems implausible at best.

In states where fracking is already underway, an immediate moratorium is in order. In all other states, **banning fracking is the prudent and necessary course to protect the environment and public health.**

- At a minimum, state officials should allow cities, towns and counties to protect their own citizens through local bans and restrictions on fracking.
- Moreover, states bordering on the fracking boom should also bar the processing of fracking waste so that they will not become dumping grounds for fracking operations next door. Vermont has already banned fracking and its waste, and similar proposals are under consideration in other states.

Where fracking is already happening, the least we should expect from our government is to **reduce the environmental and health impacts of dirty drilling as much as possible**, including:

- The federal government should close the loopholes that exempt fracking from key provisions of our federal environmental laws. For example, fracking wastewater, which often contains cancer-causing and even radioactive material, is exempt from our nation's hazardous waste laws.
- Federal and state governments should protect treasured open spaces and vital drinking water supplies from the risks of fracking. In 2011, the Obama administration's science advisory panel on fracking recommended the "[p]reservation of unique and/or sensitive areas as off limits to drilling and support infrastructure."[114] In keeping with this modest directive, dirty fracking should not be allowed near our national parks, national forests or in watersheds that supply drinking water.

- Policymakers should end worst practices. Fracking operators should no longer be allowed to use open waste pits for holding wastewater. The use of toxic chemicals should not be allowed in fracking fluids. Operators should be required to meet aggressive water use reduction goals and to recycle wastewater.

To ensure that the oil and gas industry—rather than taxpayers, communities or families—pays the costs of fracking damage, states and the Bureau of Land Management should **require robust financial assurance from operators at every well site**.

While we conclude that existing data alone is sufficient to make the case against fracking, additional data will provide a more complete picture and is critical for local communities and residents to assess ongoing damage and liability where fracking is already occurring. As this report revealed, data available on fracking are inconsistent, incomplete and difficult to analyze. To remedy this, oil and gas companies should be required to report all fracking wells drilled, all chemicals used, amount of water used, and volume of wastewater produced and toxic substances therein. Reporting should occur into an accessible, national database, with chemical use data provided 90 days before drilling begins.

Methodology

This report seeks to estimate the cumulative impacts of fracking for oil and gas in the United States. We attempted to limit the scope of the data included in the report to wells using high-volume hydraulic fracturing with horizontal drilling, because that new technology has the greatest environmental impacts and its use is increasing rapidly. However, the definition of and data collection practices for unconventional drilling vary significantly from state to state, making it difficult—and in some cases impossible—to limit our study only to those wells that have been developed using high-volume fracking.

To ensure that our estimates included the most comprehensive data possible, we began by collecting—largely from state oil and gas regulators, as described below—data on all unconventional drilling targets and practices (excluding acidization). Where possible, we then narrowed the data to include only those wells using high-volume hydraulic fracturing involving more than 100,000 gallons of water and/or horizontal drilling. In many states, the information needed to identify these wells was lacking. In those states, we included all wells using unconventional drilling practices in the data. In the section "Number of Wells, Wastewater and Produced Gas," we explain what types of drilling are included in the data for each state.

For data on water use and for teasing apart state data on conventional and unconventional wells, we relied heavily on the work done by SkyTruth to make data reported by the fracking industry more accessible. Oil and gas drilling companies report some of their fracking activities to the FracFocus website, providing information on individual wells in separate PDF files. SkyTruth compiles these individual PDFs and extracts the data "as is," placing the data into a standard machine-readable database that can be downloaded and analyzed. We downloaded SkyTruth's *Fracking Chemical Database* from frack.skytruth.org/fracking-chemical-database/frack-chemical-data-download on 12 June 2013. References below to SkyTruth data or API numbers from SkyTruth refer to this database.

The data we were able to collect undercounts the scope of fracking and its damage, for several reasons. First, when the data were unclear, we made conservative assumptions and chose conservative methodologies. Second, the FracFocus data we drew upon for some of our calculations are incomplete (see text box "Problems with FracFocus Data").

Our analysis does not include data from several states where fracking is a subject of policy debates, including Michigan and California. In those states, the data show that little to no fracking has occurred using high volumes of water because oil and gas companies have not yet begun to combine horizontal drilling with fracking. In these states, hydraulic fracturing has taken place in vertical wells, which require far less water.

Problems with FracFocus Data

Data collected on the FracFocus website have several limitations: FracFocus does not include all fracking wells in the nation, the data that are provided can be of poor quality, and loopholes in reporting requirements enable companies to hide some information.

The FracFocus website does not include data on all fracking wells. The website came into operation in 2011, after thousands of wells had already been fracked and in most cases operators have not retroactively entered information on older wells. Furthermore, in many states, reporting to FracFocus is voluntary and therefore the website does not cover all wells fracked since 2011. Only Colorado, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Utah require reporting to FracFocus.[115] In most of those states, however, the reporting requirement was adopted in 2012 or later and therefore not all earlier fracking activity is included on FracFocus.

Table 7. FracFocus Contains an Incomplete Count of Fracking Wells (Using More than 100,000 Gallons of Water)

	Count from FracFocus		Count Based on State Data	
State	**Fracking Wells since 2005**	**Fracking Wells in 2012**	**Fracking Wells since 2005**	**Fracking Wells in 2012**
Arkansas	1,461	611	4,910	719
Colorado	4,996	2,308	18,168	1,896
Kansas	150	108	407	236
Louisiana	1,078	346	2,327	139
Mississippi	5	3	9	Unavailable
Montana	264	174	264	174
New Mexico	916	515	1,353	482
North Dakota	2,654	1,653	5,166	1,713
Ohio	156	121	334	234
Oklahoma	2,097	1,270	2,694	Unavailable
Pennsylvania	2,668	1,295	6,651	1,349
Tennessee	2	0	30	Unavailable
Texas	16,916	9,893	33,753	13,540
Utah	1,336	765	1,336	765
Virginia	5	3	95	1
West Virginia	280	170	3,275	610
Wyoming	1,126	468	1,126	468
TOTAL	**36,457**	**19,923**	**81,898**	**22,326**

We compared the data we collected from states with the data included in FracFocus. SkyTruth's database of FracFocus data contains records for approximately 36,000 unique wells that used more than 100,000 gallons of water. Based on data we collected directly from states, we tallied more than 80,000 wells from the beginning of 2005 through mid-2013. Table 7 shows the state-by-state differences between our figures and those derived from FracFocus.

Further evidence of how much data are missing from FracFocus comes from a comparison of water use in all Texas wells reported to FracFocus by individual oil and gas companies versus water use calculated for the Texas Oil & Gas Association. This comparison shows that the figures in FracFocus in 2011 might be 50 percent too low. According to Jean-Philippe Nicot, et al., for the Texas Oil & Gas Association, *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report*, September 2012, fracking used 81,500 acre-feet of water in Texas in 2011 and consumed 68,400 acre-feet. In contrast, the data from SkyTruth's compilation of FracFocus data suggest total use was 46,500 acre-feet in 2011. Reporting by Texas operators was voluntary at this point, and in 2011 only half of Texas wells were reported to FracFocus, according to Leslie Savage, Chief Geologist, Oil and Gas Division of the Texas Railroad Commission, personal communication, 20 June 2013.

Second, the quality and scope of the data are inconsistent. Typographical errors and incorrect chemical identifying numbers mean some of the data are unusable.

Finally, companies are not required to report all the chemicals they use in the fracking process. Through a trade-secrets exemption, drilling companies can mask the identities of chemicals. In some states, up to 32 percent of the chemicals used are not disclosed because companies claim they are trade secrets, per SkyTruth, *SkyTruth Releases Fracking Chemical Database*, 14 November 2012.

Number of Wells, Wastewater and Produced Gas

We obtained most of our data on a state by state basis for the number of wells, the amount of wastewater produced, and the amount of gas produced.

Arkansas

Data on well completions in Arkansas came from Arkansas Oil and Gas Commission, *Fayetteville Well Completion Report*, downloaded from www.aogc2.state.ar.us/FayettevilleShaleInfo/regularly%20updated%20docs/B-43%20Field%20-%20Well%20Completions.pdf, 4 June 2013. Essentially all these wells are fracked, per James Vinson, Webmaster, Little Rock Office, Arkansas Oil & Gas Commission, personal communication, 4 June 2013. We included wells with no date listed for "Date of 1st Prod" when they had other remarks indicating they were drilled in the past few years.

Our calculation of the volume of flowback and produced water in Arkansas is based on a finding in J.A. Veil, Environmental Science Division, Argonne National Laboratory, for the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, *Water Management Practices Used by Fayetteville Shale Gas Producers*, June 2011. Veil reports that one producer in the Fayetteville Shale estimates that "the combined return volume of flowback water and subsequent produced water for the Fayetteville shale is … about 25%." We multiplied this by data on water consumed to frack Fayetteville shale wells in 2012.

Colorado

Colorado does not track fracking wells separately from other oil and gas wells. To estimate the number of fracking wells in the state, we counted the number of wells in Weld, Boulder, Garfield and Mesa counties with spud dates of 2005 or later. Data on well completions came from Colorado Oil and Gas Conservation

Commission, *2013 Production Summary*, accessed at cogcc.state.co.us/, 3 September 2013, and guidance on which counties to include came from Diana Burn, Eastern Colorado Engineering Supervisor, Colorado Oil and Gas Commission, personal communication, 4 September 2013. Many wells in Weld and Boulder counties use fracking to tap the Niobrara and Codell formations, while wells in Garfield and Mesa counties target the Piceance Basin. We excluded wells from all other counties because those wells use lower volumes of water due to shallower wells, foam fracking, or recompletion of existing wells.

Our estimate of gas production and produced water volumes came from Colorado Oil and Gas Conservation Commission, *2012 Annual Production Summary* (Access database), downloaded 25 June 2013. We selected for gas and water production data from all wells drilled in Weld, Garfield, Boulder and Mesa counties since 2005 as described above.

Kansas

We obtained data on all horizontal wells from Kansas Geological Survey, *Oil and Gas Well Database*, accessed at chasm.kgs.ku.edu, 30 May 2013. We counted only those wells with a listed spud date. We were unable to obtain an estimate of wastewater produced.

Louisiana

We obtained data on shale wells drilled in the Haynesville formation from Louisiana Department of Natural Resources, *Haynesville Shale Wells* (spreadsheet), updated 13 June 2013. We counted only those wells with a spud date. The majority of fracking in Louisiana is occurring in the Haynesville shale, per Michael Peikert, Manager, Environmental Section of Engineering Division at the Department of Natural Resource's Office of Conservation, personal communication, early June 2013.

Data on produced water are not available in Louisiana.

Mississippi

Mississippi began requiring permits for fracking wells only in March 2013. Therefore, we used data provided to FracFocus by oil and gas companies involved in fracking. We used the "Find a Well" function on the FracFocus website to search for wells in Mississippi as of 18 June 2013. Reporting to the FracFocus website is voluntary for companies in Mississippi, so the website likely undercounts fracking wells in the state.

Monthly data on produced water are available well by well from the Mississippi Oil and Gas Board's website (http://gis.ogb.state.ms.us/MSOGBOnline/) using individual API numbers. We looked up three wells, one of which has been abandoned, and used the volume of produced water to calculate a state average.

Montana

Our count of fracking wells came from the FracFocus database. We screened for wells that reported using more than 100,000 gallons of water, and counted 264 wells.

This estimate is conservative. A tally of new horizontal and recompleted horizontal wells in Montana Board of Oil and Gas Conservation, *Horizontal Well Completion Count*, accessed at www.bogc.dnrc.mt.gov, 29 May 2013 turned up 1,052 wells, which may include some coalbed methane wells.

To obtain an estimate of produced water, we downloaded the list of API numbers in Montana reported to FracFocus and compiled by SkyTruth. We provided that list of API numbers, which started in 2011, to Jim Halvorson, Petroleum Geologist, Montana Board of Oil and Gas, who queried the state's database for all produced water reports associated with those API numbers in a spreadsheet on 27 June 2013. We summed the produced water figures for the 12-month period ending 31 May 2013.

New Mexico

We calculated the total number of fracking wells in New Mexico in two different ways and chose to use the lower estimate to be conservative.

We counted 1,353 fracking wells by downloading a list of all permitted wells in the state from New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, *OCD Data and Statistics*, 12 June 2013. We selected all wells with an "H" (for hydraulically fractured) at the end of the well name, per a conversation with Phillip Goetze, New Mexico Oil Conservation Division, 25 June 2013. We further screened the wells to include just those with a status of "Active," "Plugged" or "Zone Plugged." We included wells that were identified as "New (Not drilled or compl)" if those records otherwise contained information suggesting the well has been completed (by listing days in production in 2011, 2012, or 2013). This count included a few wells started before 2005.

We counted 1,803 fracking wells by reviewing the list of hydraulic fracturing fluid disclosure forms submitted by drillers for approval before fracking a well. We obtained the list from New Mexico Oil Conservation Division, *Action Status Permitting Database*, 13 June 2013. The requirement to submit these forms began in 2012, so this count doesn't include wells from 2011 and earlier. This approach was based on a conversation with Laurie Hewig, Administrative Bureau Chief, New Mexico Oil Conservation Division, 13 June 2013.

To estimate produced water, we used water production data reported in New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, *OCD Data and Statistics*, 12 June 2013, and filtered as described above. We obtained gas production figures in the same manner.

North Dakota

We obtained data on fracking wells in North Dakota from North Dakota Oil and Gas Division, *Bakken Horizontal Wells by Producing Zone*, accessed at www.dmr.nd.gov, 29 May 2013. We assumed that all horizontal wells are fracked and that all fracking in the state happens in the Bakken Shale. We obtained data on produced water from this same data source. However, reported production data are cumulative by well and we could not calculate production by all fracking wells over a one-year period. Therefore, our tally of water includes multiple years of production.

Data on gas production from fracking wells comes from North Dakota Industrial Commission, Department of Mineral Resources, *North Dakota Monthly Gas Production and Sales*, accessed at www.dmr.nd.gov/oilgas/stats/Gas1990ToPresent.pdf, 9 August 2013. We tallied production in 2012 only.

Ohio

For Ohio, we included data for wells drilled in both the Marcellus and Utica shales from the Ohio Department of Natural Resources, Division of Oil & Gas Resources. The state separates shale well permit activity into Marcellus and Utica categories, and presents it in spreadsheets entitled *Cumulative Permitting Activity*, available at oilandgas.ohiodnr.gov/shale#SHALE, with well sites permitted through 2 May 2013.

Produced water and gas information for the Utica came from Ohio Department of Natural Resources, Division of Oil & Gas Resources, *2012 Utica Shale Production Report*, 16 May 2013. Data on production from the 11 drilled Marcellus wells came from Ohio Department of Natural Resources, Division of Oil & Gas Resources, *Ohio Oil & Gas Well Database*, accessed at http://oilandgas.ohiodnr.gov/well-information/oil-gas-well-database, 24 June 2013. We used the API numbers from Ohio Department of Natural Resources, Division of Oil & Gas Resources, *Marcellus Shale Horizontal Wells*, 6 July 2013.

Oklahoma

Our count of fracking wells in Oklahoma came from a database downloaded from FracTracker, *Oklahoma Shale Wells (3-18-2013)*, accessed at www.fractracker.org/downloads/, 28 June 2013. The database does not contain any date information.

Pennsylvania

We included data for all unconventional wells with spud dates of January 1, 2005 and later from Pennsylvania Department of Environmental Protection, *Oil and Gas Reports: SPUD Data Report*, www.portal.state.pa.us, 29 May 2013.

Data on gas and water produced in 2012 from Pennsylvania's fracking wells came from the Pennsylvania Department of Environmental Protection, *PA DEP Oil & Gas Reporting Website—Statewide Data Downloads by Reporting Period*, accessed at www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx, 24 June 2013. Our produced water tally included "Drilling Fluid Waste," "Fracing Fluid Waste" and "Produced Fluid."

Tennessee

Our estimate of the number of fracking wells came from Ron Clendening, Geologist, Oil & Gas Contacts, Division of Geology, Tennessee Department of the Environment and Conservation, personal communication, 8 July 2013. We were unable to obtain an estimate of wastewater or gas production.

Texas

Texas began keeping track of fracking wells in February 2012. To compile an estimate of fracking wells since 2005, we used several data sources.

- 2005-2009: We assume that from 2005 through 2009, the bulk of fracking activity in Texas occurred in the Barnett Shale and was barely beginning elsewhere. A total of 8,746 new horizontal wells were drilled in the Barnett Shale from 2005 through 2009, per *Powell Barnett Shale Newsletter*, 18 April 2010, as cited in Zhongmin Wang and Alan Krupnick, *A Retrospective Review of Shale Gas Development in the United States*, Resources for the Future, 2013. The Eagle Ford Shale was first drilled in 2008 and by 2009 there were 107 producing oil and gas wells, per Texas Railroad Commission, *Eagle Ford Information*, accessed at www.rrc.state.tx.us/eagleford/, 3 September 2013.
- 2010: Nearly 40 percent of wells drilled in 2010 were fracked using more than 100,000 gallons of water, per Table 7 of Jean-Philippe Nicot, et al., Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin, for the Texas Water Development Board, *Current and Projected Water Use in the Texas Mining and Oil and Gas Industry*, June 2011. We multiplied 39.7 percent times the 8,133 "new drill dry/completions" in 2010, per Railroad Commission of Texas, *Summary of Drilling, Completion and Plugging Reports,* accessed at www.rrc.state.tx.us/data/drilling/drillingsummary/index.php, 19 July 2013.
- January 2011 through January 2012: We calculated the number of fracking wells in this period by multiplying the number of wells drilled by an estimate of the percentage of those wells that were fracked. The number of "new drill dry/completions" came from Railroad Commission of Texas, *Summary of Drilling, Completion and Plugging Reports,* accessed at www.rrc.state.tx.us/data/drilling/drillingsummary/index.php, 3 September 2013. We interpolated between 2010 and February 2012 using the percentage of wells that were fracked using the 2010 estimate of 39.7 percent, described above, and the percent fracked from February 2012 to April 2013, described below.
- February 2012 through April 2013: Beginning in February 2012, drilling companies in Texas have been required to report their drilling activities

to FracFocus. Per SkyTruth, 19,678 wells were fracked in Texas in that period that used more than 100,000 gallons of water. This number of wells equals 82.5 percent of all "new drill dry/completions" in the same period in Railroad Commission of Texas, *Summary of Drilling, Completion and Plugging Reports,* accessed at www.rrc.state.tx.us/data/drilling/drillingsummary/index.php, 3 September 2013.

Texas does not require reporting of produced water volumes. However, the state does track the volume of water that is injected into disposal wells or for enhanced recovery in other wells. Our estimate of wastewater is based on the assumption that 99 percent of all produced water is reinjected, and therefore reinjected water volumes indicate wastewater production, per Leslie Savage, P.G., Chief Geologist, Oil & Gas Division, Railroad Commission of Texas, personal communication, 18 July 2013. Ms. Savage queried the Railroad Commission's *H10 Filing System* to return results on injected saltwater volumes in 2012, which we used as the basis of our estimate. This includes both flowback and produced water.

Utah

Our count of fracking wells came from the FracFocus database. We screened for wells that reported using more than 100,000 gallons of water, and counted 1,336 wells.

We calculated gas and produced water volumes from fracking wells in Utah from Utah Department of Natural Resources, Division of Oil, Gas and Mining, *Production Data*, accessed at http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm#download, 12 July 2013. To limit our tally to production from fracking wells, we used API numbers for all Utah wells included in SkyTruth's database from FracFocus data. Of the 1,607 wells with APIs in SkyTruth's database, we found 2012 production reports for 1,364 wells in Utah's data.

Virginia

We counted all horizontal wells included in Virginia Department of Mines, Minerals, and Energy Division of Gas and Oil Information System, *Drilling Report*, accessed at www.dmme.virginia.gov, 29 May 2013.

We were unable to obtain data on produced water. An estimated 15 to 30 percent of water and chemicals used to frack a well returns to the surface, per Virginia Department of Mines, Minerals, and Energy, Division of Gas and Oil, *Hydraulic Fracturing in Virginia and the Marcellus Shale Formation*, accessed at www.dmme.virginia.gov/DGO/HydraulicFracturing.shtml, 12 July 2013. However, we were unable to obtain data on how much formation water also is produced.

West Virginia

Our data for West Virginia includes all permitted wells targeting the Marcellus Shale. We were unable to narrow our count to drilled wells. We also chose to include wells without a listed permit date, on the assumption that any Marcellus drilling in West Virginia has occurred recently. Data is from West Virginia Department of Environmental Protection, *Resource Extraction Data Viewer*, http://tagis.dep.wv.gov/fogm/, 20 June 2013.

We tallied gas production from 2011 (the most recent year reported). We obtained 2011 production data from West Virginia Department of Environmental Protection, *Oil and Gas Production Data*, accessed from www.dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx, 12 July 2013. We looked up production from fracking wells by using the API numbers reported to FracFocus and compiled in SkyTruth's database. Our calculation of production is an underestimate because only 52 wells from FracFocus corresponded to wells in West Virginia's production database.

West Virginia does not collect water production data.

Wyoming

We used data on fracking wells reported to the FracFocus database to ensure we did not accidentally include coalbed methane wells. There are 1,126 wells in the FracFocus database that report using more than 100,000 gallons of water.

This figure from FracFocus is close to data we obtained through another approach. We tallied 1,273 horizontal wells since 2005 in Wyoming from FracTracker, *WY_horiz_06032013*, accessed at www.fractracker.org/data/, 28 June 2013. FracTracker obtained this list via a request to the Wyoming Oil and Gas Conservation Commission. This estimate excludes any wells that list a spud date before 2005, and includes wells with no date or that were flagged as coalbed.

Water Used

We multiplied the number of fracking wells per state since 2005 by average water use per well per state since 2011.

Average water use per well that reported using more than 100,000 gallons came from Skytruth, *Fracking Chemical Database*, accessed at http://frack.skytruth.org/fracking-chemical-database/frack-chemical-data-download, 12 June 2013. SkyTruth compiled data posted in PDFs on the FracFocus website into a database that includes water use, which can encompass freshwater, produced water and/or recycled water. The inclusion of recycled water may lead to some double-counting of water used. We included data beginning in 2011 through the most recent entries for 2013. In calculating average water consumption per well, we excluded wells that listed "None" for water use. We excluded what appeared to be duplicate entries, based on API numbers, frack date and reported water use. We also excluded two wells from Texas that reported using more than 1 billion gallons of water each, which we assumed was a data entry error by the reporting operator.

To estimate water use since 2005, we multiplied average water use per reporting well in each state by the number of fracking wells (using more than 100,000 gallons of water) in each state since 2005. The source of our well count is described in the previous section.

Air Pollution

We used data from New York State's assessment of air pollution from each well site to estimate the volume of particulate matter, smog precursors and other hazardous compounds from fracking. Though the U.S. Environmental Protection Agency recently studied air pollution from gas drilling, the data were compiled primarily from vertically rather than horizontally fracked wells and were limited to fewer types of pollutants (see EC/R, Inc., for U.S. Environmental Protection Agency, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards*, July 2011. New York State's pollution assessment was more complete and more relevant to high-volume fracking wells.

We assume that four wells per drilling site are drilled, fracked and completed each year, per New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, 7 September 2011, 6-105. We assumed that wells produce dry gas, not wet gas, and that operators flare flowback gas instead of simply venting it. This first assumptions means our air pollution estimate may understate the problem, since wet gas wells have higher emissions, while our second assumption changes the mix of pollutants released. We multiplied the tons-per-year emissions estimates from Table 6.7 of the *Revised Draft Supplemental Generic Environmental Impact Statement* by a recent year's well completion figure for each state.

This emissions estimate does not include the significant emissions from ongoing operations, compressors, and truck traffic to and from drilling sites carrying supplies and personnel.

Methane Emissions

We calculated methane emissions using two different approaches because neither approach alone provided a complete picture. The lack of data on wells drilled, gas produced and emissions per well makes it very hard to assess the extent of global warming damage from fracking. Our first approach multiplied emissions per well during completion by the number of fracking wells. Our second method multiplied emissions as a percentage of gas produced by the amount of gas produced from fracking wells.

In states with more comprehensive production data, the energy-based calculation may be more accurate because it is based on state-specific conditions. In addition, the energy-based method includes emissions from a wider range of activities involved in producing gas from fracking wells—from drilling to fracking to processing—and therefore better reflects the impact of fracking.

In states where we could obtain no or limited emissions data, the estimate based on per-well emissions during completion offers a rough emissions estimate. The per-well emission factor is conservative because it is based on a narrower definition of fracking activity (it excludes production and processing). However, it may overestimate emissions from wells that were drilled but produced little to no gas.

Emissions Based on Well Completion

We estimated methane emissions by multiplying an estimate of emissions per completion of a fracking gas well by the number of fracking wells in 2012 in each state. We estimated average emissions of 50,000 kilograms of methane per well, per Francis O'Sullivan and Sergey Paltsev, "Shale Gas Production: Potential Versus Actual Greenhouse Gas Emissions," *Environmental Research Letters*, 7:1-6, 26 November 2012, doi: 10.1088/1748-9326/7/4/044030. This estimate is a national average based on nearly 4,000 wells completed in 2010 and assumes 70 percent of wells undergo "green" completions in which fugitive emissions are captured. This likely overstates the green completions rate before 2010.

Our estimate has two limitations of note. First, it does not include methane emissions from pipelines, compressor stations, and condensate tanks, or carbon dioxide emissions from equipment used to produce gas. Second, it may not accurately reflect emissions from fracked shale wells that produce oil rather than gas. The data we obtained on well completions do not distinguish between wells fracked for oil versus gas production and therefore we have chosen to apply this estimate for shale gas wells to all wells. We spoke with two experts in the field who believe that, given the lack of better data on emissions from oil wells, is it reasonable to assume that fracked oil wells have substantial methane emissions.

We converted methane emissions to carbon dioxide equivalents using a 100-year global warming potential of 25 times that of carbon dioxide, per Federal Register, *Environmental Protection Agency, 40 CFR Part 98, 2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements; Proposed Rule*, 78(63): 19802-19877, 2 April 2013.

Emissions Based on Gas Production

We calculated methane emissions as a percentage of gas production. See the previous section for a description of how we estimated gas production in each state.

We converted cubic feet of gas production to megajoules of methane using the assumption that 78.8 percent of gas produced from unconventional wells is methane, per Robert Howarth, et al., "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change* 106: 679-690, 2011. (Note that other researchers have estimated the methane content of Marcellus Shale gas as high as 97.2 percent. See ICF International, Technical Assistance for New York State Department of Environmental Conservation, *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*, as cited in Mohan Jiang, et al., "Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas," *Environmental Research Letters,* 6, 034014, July-September 2011, doi:10.1088/1748-9326/6/3/034014, supplemental materials.)

We assume that 3.3 percent of the methane produced over the life of a well is lost as fugitive emissions, per Robert Howarth, et al., "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change* 106: 679-690, 2011, as presented in Robert Howarth, et al., *Methane Emissions from Natural Gas Systems; Background Paper Prepared for National Climate Assessment,* 25 February 2012. This estimate includes well-site and processing emissions from shale and tight-gas sands wells that produce gas. The estimate assumes significant venting of methane in the initial days after a well is fracked.

The 3.3 percent pollution rate from Howarth, et al., is higher than reported in EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 to 2011*, 12 April 2013. However, it is in the range of one recent study that measured fugitive emissions over a gas and oil field in Colorado, finding fugitive methane emissions of 2.3 to 7.7 percent of gas produced (Gabrielle Pétron, et al., "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study," *Journal of Geophysical Research*, 117, D04304, 2012, doi:10.1029/2011JD016360, and Jeff Tollefson, "Air Sampling Reveals High Emissions from Gas Field," *Nature*, 483(7384): 139-140, 9 February 2012, doi: 10.1038/482139a). A second recent study in the same area measured methane emissions equal to 6.2 to 11.7 percent of production (Anna Karion, et al., "Methane Emissions Estimate from Airborne Measurements over a Western United States Natural Gas Field," *Geophysical Research Letters*, 27 August 2013, doi: 10.1002/grl.50811).

We used a slightly different method to calculate emissions for North Dakota, where a large portion of gas is flared rather than sold. We calculated emissions for the flared gas and emissions for the remaining gas separately. Because of lack of infrastructure to get gas to market, 29 percent of all gas produced in North Dakota is flared, per Lynn Helms, North Dakota Industrial Commission, Department of Mineral Resources, *Director's Cut*, 15 July 2013. We estimated emissions from this gas based on New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, 7 September 2011, 6-194. We calculated emissions from the remaining wells using Robert Howarth, et al., "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change* 106: 679-690, 2011, as presented in Robert Howarth, et al., *Methane Emissions from Natural Gas Systems; Background Paper Prepared for National Climate Assessment*, 25 February 2012.

Landscape Impacts

We calculated landscape impacts based on the number of wells in each state. We divided the number of wells drilled (or permitted, if only that figure was available) since the beginning of 2005 by the average number of wells per pad to obtain the number of well pads. We then multiplied the number of well pads by the size of each well pad and the roads and pipelines servicing it. Where possible, we used state-specific estimates about the number of wells per pad and the acreage damaged by pads and supporting infrastructure.

For states where most drilling is into the Marcellus Shale (**Pennsylvania** and **West Virginia**), we assumed that land disruption patterns are comparable to those in Pennsylvania, where existing drilling practices place an average of 1.8 wells per well pad. Well pads average 3.1 acres and associated infrastructure disturbs 5.7 acres. Pennsylvania data were presented in New York State Department of Environmental Conservation, *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, 7 September 2011, 6-76. We assumed **Ohio** and **Virginia** follow the same land disturbance patterns.

In **Oklahoma**, we assumed 1.1 wells per pad, and the same wellpad size and road and pipeline impacts as in Ohio and Pennsylvania.

For **Texas**, we assumed two wells per pad because the sources we consulted suggest that there are some multi-well pads but that the number of wells per pad remains small. In the Barnett, well pads hold anywhere from one to eight wells, per George King, GEK Engineering, *Multi-Well Pad Operations for Shale Gas Development, Draft Document*, 5 May 2010. In the Eagle Ford Shale, Chesapeake Energy, as of early 2013, was drilling only half of its wells on multi-well pads, per Jennifer Hiller, "Chesapeake Thinks It Has 342 Million Barrels in Eagle Ford," *Eagle Ford Fix* (blog operated by *San Antonio Express-News*), 6 May 2013. We assumed pad size is the same as in Pennsylvania (which has an average of 1.8 wells per pad). We assume road and pipeline infrastructure occupies 4.75 acres, the same as on public land in western Colorado.

For **New Mexico**, we estimated the number of wells per pad after mapping the location of fracking wells reported to FracFocus in 2012. We used the API number of those wells to obtain the latitude and longitude for each well from New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, *OCD Data and Statistics*, 12 June 2013. A small number of 2012 wells appear to be on multi-well pads. Given that in neighboring Texas, few wells before 2012 were drilled on multi-well pads, we assumed that New Mexico wells average 1.1 wells per pad. We assumed pad size for a single-well pad is 2.47 acres, based on the average pad size and wells per pad in Weld County, Colorado (see below). We assumed road and pipeline infrastructure occupies 4.75 acres, the same as on public land in western Colorado.

We made the same assumption for **Utah**, based on mapping the location of fracking wells and finding few multi-well pads.

For **Colorado**, we obtained estimates for acres damaged by wells in Weld County and on public land in western Colorado. By looking at the Form 2A documentation for 20 fracking wells across Weld County, we found that an average of 2.25 wells are drilled per pad and that well pads disturb an average of 5.56 acres. We could not obtain an estimate of land disturbed for roads and pipelines. We obtained this data from Colorado Oil and Gas Conservation Commission, *GISOnline*, accessed at http://dnrwebmap-gdev.state.co.us/mg2012app/, 11 July 2013. Leases on federal land in western Colorado average eight wells per pad, with 7.25 acres of land disturbed per pad and an additional 4.75 acres for roads and other infrastructure, per U.S. Department of the Interior, Bureau of Land Management, Colorado State Office, Northwest Colorado Office, White River Field Office, *Draft Resource Management Plan Amendment and Environmental Impact Statement for Oil and Gas Development*, August 2012. For our calculation, we used the Weld County data for Weld and Boulder wells, and the western Colorado estimates for Garfield and Mesa wells. We used the western Colorado estimate of acreage for supporting infrastructure.

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Exhibit 13

Exhibit 13

The New York Times
http://www.nytimes.com/2016/01/21/science/earth/2015-hottest-year-global-warming.html?_r=0

2015 Was Hottest Year in Historical Record, Scientists Say

By Justin Gillis
Jan. 20, 2016

Clockwise from top left: A family sleeping on the roof of a house in New Delhi last May; people navigating a flooded street in a canoe in Arnold, Mo., on Dec. 31; tourists in a haze-shrouded Singapore last September; the drought-stricken Molatedi Dam in South Africa in November.
Clockwise from top left; Tsering Topgyal/Associated Press, Jeff Roberson/Associated Press, Edgar Su/Reuters, Stuart Graham/Associated Press

Scientists reported Wednesday that 2015 was the hottest year in the historical record by far, breaking a mark set only the year before — a burst of heat that has continued into the new year and is roiling weather patterns all over the world.

In the contiguous United States, the year was the second-warmest on record, punctuated by a December that was both the hottest and the wettest since record-keeping began. One result has been a wave of unusual winter floods coursing down the Mississippi River watershed.

Scientists started predicting a global temperature record months ago, in part because an El Niño weather pattern, one of the largest in a century, is releasing an immense amount of heat from the Pacific Ocean into the atmosphere. But the bulk of the record-setting heat, they say, is a consequence of the long-term planetary warming caused by human emissions of greenhouse gases.

“The whole system is warming up, relentlessly,” said Gerald A. Meehl, a scientist at the National Center for Atmospheric Research in Boulder, Colo.

It will take a few more years to know for certain, but the back-to-back records of 2014 and 2015 may have put the world back onto a trajectory of rapid global warming, after a period of relatively slow warming dating to the last powerful El Niño, in 1998.

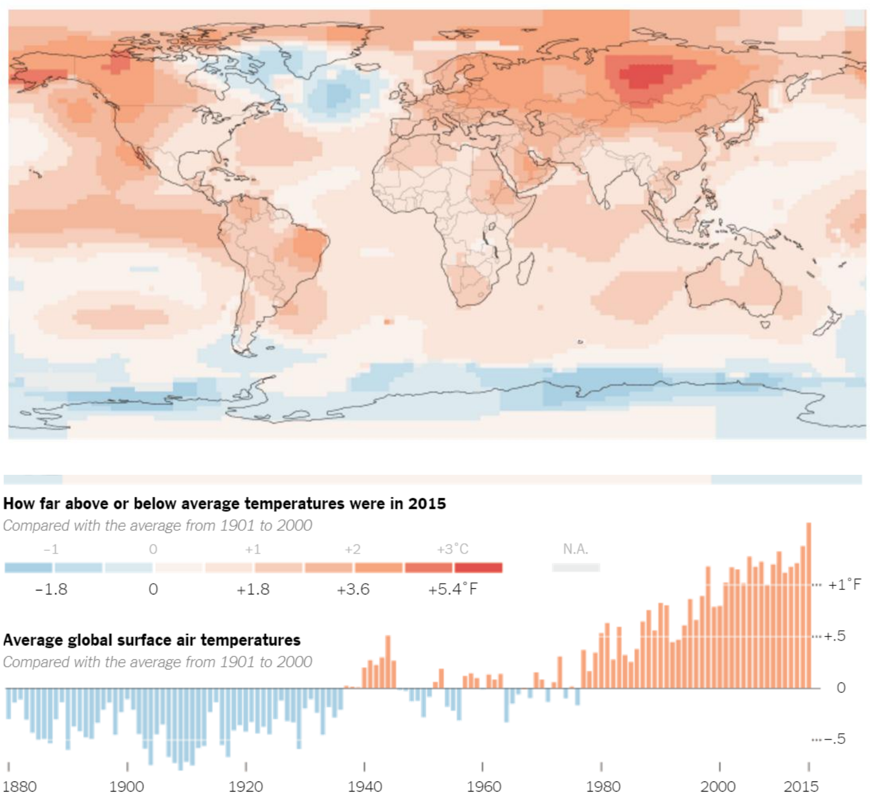
Politicians attempting to claim that greenhouse gases are not a problem seized on that slow period to argue that “global warming stopped in 1998,” with these claims and similar statements reappearing recently on the Republican presidential campaign trail.

Statistical analysis suggested all along that the claims were false, and that the slowdown was, at most, a minor blip in an inexorable trend, perhaps caused by a temporary increase in the absorption of heat by the Pacific Ocean.

“Is there any evidence for a pause in the long-term global warming rate?” said Gavin A. Schmidt, head of NASA’s climate-science unit, the Goddard Institute for Space Studies, in Manhattan. “The answer is no. That was true before last year, but it’s much more obvious now.”

The Hottest Year on Record

Globally, 2015 was the warmest year in recorded history.



Source: NASA Goddard Institute for Space Studies

By The New York Times

Michael E. Mann, a climate scientist at Pennsylvania State University, calculated that if the global climate were not warming, the odds of setting two back-to-back record years would be remote, about one chance in every 1,500 pairs of years. Given the reality that the planet is warming, the odds become far higher, about one chance in 10, according to Dr. Mann’s calculations.

Two American government agencies — NASA, the National Aeronautics and Space Administration, and NOAA, the National Oceanic and Atmospheric Administration — compile separate analyses of the global temperature, based upon thousands of measurements from weather stations, ships and ocean buoys scattered around the world. Meteorological agencies in Britain and Japan do so, as well. The agencies follow slightly different methods to cope with problems in the data, but obtain similar results.

The American agencies released figures on Wednesday showing that 2015 was the warmest year in a global record that began, in their data, in 1880. British scientists released figures showing 2015 as the warmest in a record dating to 1850. The Japan Meteorological Agency had already released preliminary results showing 2015 as the warmest year in a record beginning in 1891.

On Jan. 7, NOAA reported that 2015 was the second-warmest year on record, after 2012, for the lower 48 United States. That land mass covers less than 2 percent of the surface of the Earth, so it is not unusual to have a slight divergence between United States temperatures and those of the planet as a whole.

The end of the year was especially remarkable in the United States, with virtually every state east of the Mississippi River having a record warm December, often accompanied by heavy rains.

A warmer atmosphere can hold more water vapor, and an intensification of rainstorms was one of the fundamental predictions made by climate scientists decades ago as a consequence of human emissions. That prediction has come to pass, with the rains growing more intense across every region of the United States, but especially so in the East.

The term global warming is generally taken to refer to the temperature trend at the surface of the planet, and those are the figures reported by the agencies on Wednesday.

Some additional measurements, of shorter duration, are available for the ocean depths and the atmosphere above the surface, both generally showing an inexorable long-term warming trend.

Most satellite measurements of the lower and middle layers of the atmosphere show 2015 to have been the third- or fourth-warmest year in a 37-year record, and scientists said it was slightly surprising that the huge El Niño had not produced a greater warming there. They added that this could yet happen in 2016.

When temperatures are averaged at a global scale, the differences between years are usually measured in fractions of a degree. In the NOAA data set, 2015 was 0.29 degrees Fahrenheit warmer than 2014, the largest jump ever over a previous record. NASA calculated a slightly smaller figure, but still described it as an unusual one-year increase.

The intense warmth of 2015 contributed to a heat wave in India last spring that turns out to have been the second-worst in that country's history, killing an estimated 2,500 people. The long-term global warming trend has exacted a severe toll from extreme heat, with eight of the world's 10 deadliest heat waves occurring since 1997.

Only rough estimates of heat deaths are available, but according to figures from the Center for Research on the Epidemiology of Disasters, in Brussels, the toll over the past two decades is approaching 140,000 people, with most of those deaths occurring during a European heat wave in 2003 and a Russian heat wave in 2010.

The strong El Niño has continued into 2016, raising the possibility that this year will, yet again, set a global temperature record. The El Niño pattern is also disturbing the circulation of the atmosphere, contributing to worldwide weather extremes that include a drought in southern Africa, threatening the food supply of millions.

A version of this article appears in print on January 21, 2016, on page A1 of the New York edition with the headline: 2015 Far Eclipsed 2014 as World's Hottest Year, Climate Scientists Say.

Exhibit 14

Exhibit 14

http://www.huffingtonpost.com/2015/04/06/oregon-drought_n_7014406.html

Oregon Governor Expands Drought Declaration

Reuters
Posted: 04/06/2015
By Courtney Sherwood

PORTLAND, Ore., April 6 (Reuters) - Oregon Governor Kate Brown declared a drought emergency on Monday in three southern and central Oregon counties, expanding upon earlier drought declarations the Democrat made in March, as the state faces record low snowpack levels.

Continuing drought has caused "natural and economic disaster conditions" in Oregon's Crook, Harney and Klamath counties, heightening wildfire risk, and threatening wildlife and agriculture, Brown said in her declaration.

"Oregon's unusually warm and dry winter has potentially dire consequences," Brown said on Monday.

The drought declarations in Oregon come as below-average rain and snow levels have threatened agriculture in parts of the U.S. West.

A spring storm was expected to bring several inches (cm) of rain to some areas of drought-parched California and up to two feet (60 cm) of snow to mountains beginning late on Monday, just days after Governor Jerry Brown ordered sweeping cuts in water use.

In Washington, Governor Jay Inslee last month declared drought emergencies for regions of his state, north of Oregon.

Brown has placed Malheur and Lake counties in southeastern Oregon under drought emergency since mid-March.

According to Oregon's Water Resources Department, snowpack statewide is at less than 50 percent of its normal level, and a number of lakes and reservoirs are nearly empty, posing threats to endangered fish within the region.

In some cases, the drought has also uncovered long-buried historic sites.

The town of Klamath Junction, which was abandoned in 1960 to make way for an irrigation project and had been under water for more than half a century, has been gradually re-emerging since late last year.

Building foundations and scattered debris are now visible on a muddy plain that is normally under water. (Reporting by Courtney Sherwood; Editing by Sandra Maler)

Exhibit 15

Exhibit 15

http://www.oregonlive.com/opinion/index.ssf/2015/05/oregon_must_avoid_californias.html

Oregon must avoid California's water plight (OPINION)

Farmer Gino Celli climbs out of an irrigation canal May 18 that is covered in dried salt on a field he farms near Stockton, California. *(AP Photo/Rich Pedroncelli)*

By Guest Columnist Rep. Dan Rayfield
May 22, 2015

California is in a state of emergency. Mountain snowpack is at a record low, and many of its lakes and streams are at all-time lows. Mandatory water use restrictions have been put into place for the first time in California's history, and communities have been ordered to cut water use by an average of 25 percent. Outside the cities, farmers left more than 500,000 acres unplanted last year due to lack of water. That number will grow this year. In the Sierras, more than 12 million trees have died, with millions more expected to die this summer.

Here in Oregon, extreme drought is creeping north from California. Gov. Brown has already declared drought emergencies in 15 counties. It may look green outside today, but that creek in your community is probably running at levels typical of August. These problems, in combination with heat and no snow, suggest our water challenges are just beginning.

We have an opportunity to learn from the drought afflicting California, but it's going to require two things: raising awareness of water policy at every level in Oregon and investing in conservation and storage projects. It's time to roll up our sleeves and get to work before we end up in California's shoes.

Oregonians care deeply about water. Our forests and rivers define how we see ourselves – and our plentiful waters help sustain the farms and forests that support our communities. Keep in mind that Oregon's agriculture industry, which relies on steady access to quality water, supports more than 400,000 jobs and represents a $22.8 billion industry. Water also creates the critical habitat that sustains Oregon's abundant fisheries and ecosystems.

Oregon already faces challenges concerning water. In most parts of the state, our water resources are fully allocated. At the same time, our progress toward clean water has stagnated. Decreasing snowpack, increasing temperatures, and changing precipitation patterns only add to these challenges. Oregon needs to address these issues now. Further delay will negatively impact our economy, communities and the environment.

Oregon is beginning to tackle these challenges, but funding is needed to move the efforts forward. Oregon's natural resources agencies currently receive about 1 percent of the state's general fund. Water management receives even less. Other western states spend dramatically more than Oregon has historically spent on water infrastructure and quality. We don't have the resources that California has to address our water challenges, but by beginning to invest strategically, we can leverage public and private investment to protect our communities and the quality of life we care so deeply about.

Oregon is currently considering a $56 million package for planning and implementation of water conservation, management and storage projects. There are also a number of proposals to improve water quality – primarily through non-regulatory programs. These investments are just a drop in the bucket, but it's a start. If we're going to avoid California's water woes, we need your help to move the topic of "water" to the forefront of the conversation. The situation certainly demands nothing less.

Democrat Dan Rayfield, of Salem, represents the 16th District in the Oregon House of Representatives.

Exhibit 16

SCIENTIFIC AMERICAN™

SUSTAINABILITY

Drought Takes $2.7-Billion Toll on California Agriculture

Scientists say the current drought will cost big in lost crops

By Andrea Thompson, Climate Central on June 3, 2015

The California drought is devastating agriculture across the state.
Luca Cerabona/Flickr

The record-breaking drought in California—brought about by a severe lack of precipitation, especially mountain snows—has exacted a $2.7 billion toll on the state's economy because of agricultural losses, researchers said Tuesday.

During a briefing for the California Department of Food & Agriculture, scientists from the University of California, Davis, told officials that based on their preliminary research and modeling, the drought is resulting in a harder economic pinch this year than it was in 2014.

The drought, they found, will lead this year to 32 percent more acres of land laid fallow, an increase in groundwater pumping to make up for the lack of water in rivers and reservoirs, and total job losses of 18,600.

The losses from this drought aren't spread out evenly across the state, the researchers added, with areas like the Tulare Lake Basin in the southern San Joaquin Valley bearing much of the brunt.

Californians are hoping that an El Nino event that seems to be gaining strength will finally change weather patterns and bring a wet winter that could spell an end to the drought, though a full recovery will likely take many years. Scientists also are studying whether climate change could mean more such deep droughts in the future and whether it made the current one worse.

The drought in California has been building for more than four years, as winter precipitation deficits slowed streams to a trickle and sent reservoir levels dipping, while unusually warm temperatures increased water demand. Now, more than two-thirds of the state is in the worst two categories of drought established by the U.S. Drought Monitor.

The drought particularly metastasized over the past two years, which saw dismal winter precipitation. At the end of this winter, the state recorded its all-time lowest snowpack, which measured only 6 percent of normal on April 1.

That number recently dropped to 0 percent of normal, meaning there is virtually no snow left to help replenish reservoirs during the summer months.

The terrible snowpack and low reservoir levels prompted Gov. Jerry Brown in April to call for the first statewide mandatory water restrictions for cities and towns. Farmers in the Sacramento-San Joaquin River Delta recently volunteered to cut their water entitlement by 25 percent this year, with the understanding that the state government won't ask for further reductions beyond that amount.

Farmers will have about 33 percent less surface water available to them this year than they would in a normal year, and is more than the shortage faced last year, the UC Davis team said. About 70 percent of that will be made up for with groundwater pumping, which will mean extra costs to farmers, to the tune of about $600 million statewide.

So much groundwater pumping raises issues, though, as it pushed the water table lower and lower, causing shallower wells to dry up and deeper and deeper wells to be drilled. There is also the problem of not knowing just how much groundwater the state has and exactly how much is being pumped, which the state just last year instituted measures to better monitor.

Another way farmers are dealing with the water shortage is by leaving land unused. The amount of cropland not planted this year is expected to increase 33 percent over last year, the UC Davis researchers said, to cover about 564,000 acres.

Drought Impact	Loss Quantity
Water Supply	
Surface water reduction	8.7 million acre-feet
Groundwater pumping increase	6.2 million acre-feet
Net water shortage	2.5 million acre-feet
Statewide Costs	
Crop revenue loss	$856 million
Additional groundwater pumping cost	$595 million
Livestock revenue loss	$100 million
Dairy revenue loss	$250 million
Total direct agricultural costs	**$1.8 billion**
Total statewide economic cost	**$2.7 billion**
Total job losses	**18,600**

ESTIMATES OF ECONOMIC LOSSES RELATED TO AGRICULTURE IN CALIFORNIA FOR 2015. *CREDIT: HOWITT RE, MEDELLÍN-AZUARA J, MACEWAN D, LUND JR AND SUMNER DA. 2015. "PRELIMINARY ANALYSIS: 2015 DROUGHT ECONOMIC IMPACT STUDY," UC DAVIS CENTER FOR WATERSHED SCIENCES.*

The dairy industry will be particularly hit this year as the higher milk prices that buffered losses last year have dropped.

The combined costs from crop, livestock and dairy revenue losses and groundwater pumping amount to $1.8 billion. When indirect costs to the economy are included the costs statewide amount to $2.7 billion. Updated numbers will be released in July.

While the overall job losses from the drought come primarily in contract farm labor, the overall employment picture for the state is better, with an overall employment increase of 2 percent last year, according to the Employment Development Department.

The drought has prompted louder and louder calls for California to rethink how it handles and allocates its water supply, particularly in a climate that is warming and changing and could bring more such droughts in the future.

The relationship between climate change and any drought is a complex one, as many factors feed into creating and perpetuating drought conditions. The clearest impact of warming on drought is when higher temperatures cause more evaporation and increase water demand, as has happened with this drought. California, in fact, recorded its warmest year on record in 2014, followed by its warmest winter ever this year.

One way the state could get a better handle on its water situation would be to better use the technology available to it to understand things like how much groundwater it has and more detailed information on crops, said Richard Howitt, a professor emeritus, with UC Davis Agricultural & Resource Economics. While the state has one of the epicenters of technological innovation in Silicon Valley, when it comes to “one of our absolutely critical resources, water, we’re running in the blind,” he said.

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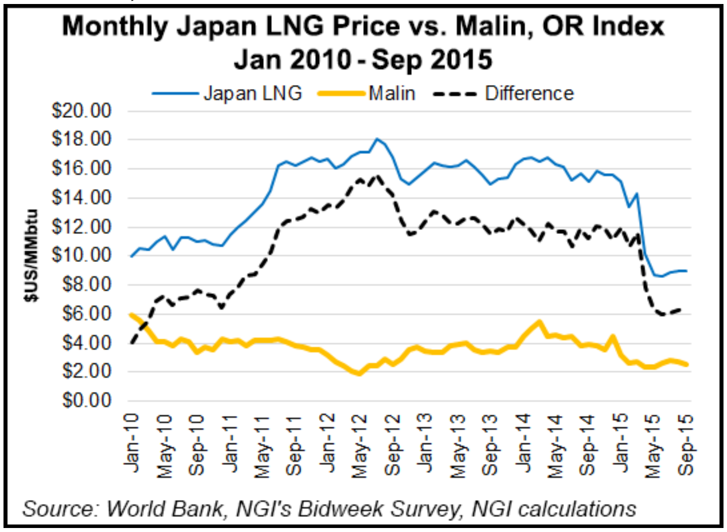
Exhibit 17

http://www.naturalgasintel.com/articles/103968-west-coast-lng-export-projects-doubtful-in-current-environment-analysts-say

West Coast LNG Export Projects Doubtful in Current Environment, Analysts Say

By Richard Nemec
October 9, 2015



In the current oversupplied global energy market, a liquefied natural gas (LNG) export terminal on the U.S. West Coast is unlikely to become a reality anytime soon, according to several industry analysts speaking at a natural gas forum in Los Angeles.

The consensus at the LDC Gas Forum Rockies & the West conference is that the five terminals now under construction or about to start on the Gulf and East Coasts are the only ones likely to be operating by 2020. Combined, they represent incremental demand growth of 10.5 Bcf/d in the world market, which is somewhat saturated already.

That scenario leaves out the two proposed export projects in Oregon -- Jordan Cove and Oregon LNG -- which are in the midst of the permitting process at the Federal Energy Regulatory Commission.

"There is debate about how much U.S. LNG can make it into the global market," said David Braziel, director of finance and fundamental analysis at RBN Energy LLC. "If all the U.S. LNG export facilities that have been proposed were built (45 Bcf/d), the capacity would dwarf the global market." There are other significant LNG exporters worldwide, including Canada, Australia, Indonesia, East Africa and Russia, he said.

RBN thinks 33% of the global market for U.S. LNG is a reasonable assumption, Braziel said, but that leaves no room for the West Coast facilities. "Thirty percent would be about 12 Bcf, and there is already 13.2 Bcf/d of capacity being built, so that's how we get to our [one-third] estimate and there is nothing beyond the five terminals [Sabine Pass, Freeport, Cameron, Corpus Christi and Cove Point, MD]."

Separately at the LDC Forum, a further complication was mentioned by a consultant talking about Mexico's energy market reforms when he said that longer term, Mexico hopes to transform all three of its LNG receiving terminals into export facilities to serve Asian markets.

Noting the first exports out of the U.S. will come from the Sabine Pass facility around the start of next year at about 150 MMcf/d, Genscape Inc.'s Rick Margolin, senior analyst, said Genscape estimates there will be about 10 Bcf/d of export capacity built, concentrated in Maryland, Louisiana and Texas.

"We currently don't include Jordan Cove in our forecasts, although that would lead to a lot of increased demand in the U.S. West," Margolin said. Rockies producers would love to see the terminal in Oregon built, he said. "Jordan Cove has yet to receive any contracts with Asian buyers at all at this point, and we're certainly not going to put it in our forecast until they have a serious deal, and that is looking increasingly unlikely given what is happening in the global market."

In response to an inquiry from *NGI*, Oregon LNG Project Manager Peter Hansen acknowledged the global market is "a bit oversupplied" but cautioned that it must be remembered that LNG is a global commodity, "and accordingly, there will always be a market for low-cost LNG." Hansen said his project "will be among the lowest-cost suppliers to Asia and should have no difficulty finding a market." However, he did not respond to questions about his prospects for contracts with Asian buyers.

Thad Walker, an energy analyst with Bentek Energy, said his firm's analysis doesn't see much likelihood of any West Coast greenfield LNG export terminals being built.

"Jordan Cove is not in our forecast right now, although it received a positive EIS [environmental impact statement] from FERC [see *Daily GPI*,Sept. 30], because the facility has yet to receive any contracts, and until they have contracts, it is very unlikely they will make a final investment decision to move the project forward," Walker said.

"I think it is going to take more time to see where the global LNG market is going. Certainly with depressed oil prices all the projects indexed to crude oil improve and we're going to see a flood of Australian LNG on the Asian market, so we have a pretty depressed outlook for Jordan Cove, although it is well positioned on the West Coast to serve Asian markets, relative to the other U.S. projects."

Steve Piper, research director at SNL Energy, said the crash in global crude oil prices last year and the linking of many contracts outside the United State to crude oil has "hurt the competitiveness" of U.S. LNG projects. But to a large extent, U.S. LNG seems to remain competitive on a global basis, he said. Piper thinks an initial 4 Bcf/d of U.S. exports in 2017 will be "enough to influence global markets."

He thinks West Coast projects "could be demand drivers going forward," but not until 2020 at the earliest. Collectively, LNG exports from the projects now under construction will have "a noticeable impact" on Gulf Coast gas prices -- "not a huge impact, but in the 7- to 10-cent[/Mcf] range. So it won't be trivial."

Exhibit 18

http://business.financialpost.com/news/energy/window-of-opportunity-for-new-lng-projects-is-gone-because-of-supply-glut-consultancy-says?

‘Window of opportunity’ for new LNG projects is gone because of supply glut, consultancy says

By Yadullah Hussain | September 3, 2015 |

The window to build liquefied natural gas projects in Canada and elsewhere has closed amid a global supply glut, says global energy consultancy Wood Mackenzie.

“There is a clear reluctance by companies to stand down, but the reality is that the window of opportunity closed over six months ago for everyone, not just for Canada,” Noel Tomnay, vice-president global gas and LNG research for Wood Mackenzie said in an interview.

Qatar and Australia led the first two waves of LNG development with the U.S. spearheading the third wave, even as Canadian and East African proposals were stalled.

“Canada’s biggest competitor is not the U.S. — it is probably Mozambique,” Tomnay said, noting that these two regions would probably the play the role of niche, “strategic resources” for investors in the next wave of development that will cater to demand after 2022.

Proposed LNG projects are under pressure as prices are stuck in the US$7-US$8 per million British thermal unit range, compared to the US$11-US$12 needed long-term to make project economics work.

LNG deliveries to the key markets of China, Japan and South Korea are also falling at the same time that 140 million tonnes per annum of new LNG capacity is being built, to add to the 250 million tonnes per annum already on stream.

“The outlook for longer-term incremental LNG demand growth in China is also being negatively affected. And with lower industrial output and power generation competition increasingly characterising other key Asian LNG markets, like South Korea, Asian buyers are not in a hurry to finalise new LNG contracts,” Tomnay said in a report.

British Columbia has attracted as many as 20 LNG proposals, but none has committed to a positive final investment decision (FID) yet.

Malaysia' state-owned Petronas and its partners gave a conditional approval to their $11-billion Pacific NorthWest LNG on Lelu Island near Prince Rupert, but the consortium faces stiff opposition from some First Nations. It has also not secured an environmental certificate from the Canadian Environmental Assessment Agency — one of two conditions necessary to secure a final approval from the consortium.

An unprecedented global supply glut could hurt projects proposed by Petronas' and Shell Plc.'s LNG Canada project, both of whom boast Asian investors.

"Some of the partners may not be in big hurry to see the projects executed as quickly," given the number of other developments already under way, Tomnay said.

Malaysia is also in the middle of a political storm with Prime Minister Najib Razak under fire for a financial scandal that would likely make the Malaysian government more cautious in moving quickly with its proposed LNG project.

"Najib's priority at the moment is to stay away from more controversies particularly given the level of public scrutiny on public finance," Ambika Ahuja, Asia analyst at risk management consultancy Eurasia Group, said in an email.

While the B.C. project has not been elevated to a major controversy in Malaysia, it could spark a debate about Petronas' priorities as it's a major source of government revenue, and a collapse in crude and LNG prices could see it cutting back on capital expenditure, Ahuja said.

A Pacific Northwest LNG spokesman declined to comment.

Wood Mackenzie's Tomnay says the two B.C. frontrunners, Petronas and Shell, are playing a "game of chicken" as neither wants to concede and hand over victory to the other, as the project that goes second would likely suffer from cost inflation.

"A very likely outcome though is that both projects say 'let's take a pause.' And you don't get FID from either of these large projects in the next couple of years," Tomnay said.

LNG Canada did not respond to a request for comment. The consortium has maintained an FID decision is expected in the middle of the decade.

Chevron Corp.'s Kitimat LNG project has already missed its initial window, and serves as a "cautionary tale" for other LNG producers, according to Citibank.

In 2009, Kitimat LNG owners at the time had announced the possibility of exporting gas by 2014, but environmental concerns, inability to secure offtake contracts and prolonged negotiations with various levels of government and First Nations dragged out its progress, Citibank said in a report published Thursday.

"Meanwhile, U.S. LNG and other projects globally zoomed ahead. Hence, if Kitimat were to export LNG at all in the future, it may not do so until well after 2020, or nearly 10 years or more after the original date," analyst Anthony Yuen said in a report.

Chevron did not respond to a request for comment.

yhussain@nationalpost.com
YAD_FPEnergy

Exhibit 19

WorldOil.Com

Wood Mackenzie: Where are all the LNG project postponements?

9/4/2015

EDINBURGH, United Kingdom -- In a new global gas analysis, Wood Mackenzie remarks that despite the outlook for global LNG demand looking increasingly subdued, the number of LNG projects proposed to take a Final Investment Decision (FID) in 2015 and 2016 has not reduced significantly, in contrast to the 45 upstream oil & gas projects, which have been postponed FID so far in 2015.

If there are no postponements, Wood Mackenzie says the market could see an additional 100 MMtpa of LNG sanctioned in the next six to 18 months, extending the likelihood of an oversupply of LNG in Asia to 2025.

Noel Tomnay, V.P. Global Gas & LNG Research for Wood Mackenzie says, "With the LNG market facing a wall of new supply just as China's gas demand growth has faltered, it is surprising how few new projects chasing a final investment decision (FID) have been postponed."

Tomnay outlines the current market conditions, which are shaping the global LNG market, "Global LNG supply is presently around 250 MMtpa and there is a further 140 MMtpa under construction. Recognizing that the global market will struggle to absorb such a large supply uptick, for some time now we've been forecasting a soft global market. However that bearish prognosis is now being exacerbated by a demand downturn."

Wood Mackenzie points to Asia and China, in particular, as being key to its revised outlook. Tomnay elaborates, "China's LNG import commitments are set to rise by 17% year-on-year (yoy) between 2015 and 2020, from 20 to 41 MMtpa, but China will struggle to take all this LNG so quickly. In contrast, China's LNG imports fell by almost 4% yoy in the first half of 2015, as a consequence of subdued industrial output and fuel competition, which was driven by relatively low priced oil.

"The outlook for longer term incremental LNG demand growth in China is also being negatively affected. And with lower industrial output and power generation competition increasingly characterizing other key Asian LNG markets, like South Korea, Asian buyers are not in a hurry to finalize new LNG contracts," adds Tomnay. Wood Mackenzie's view remains that the market opportunity for new LNG into Asia does not open up significantly until after 2022, with the key implication being that new project FIDs are not required until 2017 at the earliest.

So have we seen any indications that companies are reassessing investment decisions on LNG projects in light of reduced demand? Tomnay points to an example from February this year, "Recognising this oversupply BG deferred its proposed U.S. LNG export project at Lake Charles. But BG's postponement has been an exception."

Wood Mackenzie says that thus far most companies are continuing to push ahead with their new LNG projects. "Major project operators including Shell, PETRONAS, ENI, Anadarko, BP, ExxonMobil and Woodside maintain that their projects will take FID before the end of 2016," Tomnay qualifies.

So why haven't more companies followed BG's suit if the market is unlikely to be able to absorb new LNG in the medium to long term? Tomnay explains some of the drivers behind the decision to press ahead, " Postponement could invalidate contracts for the portion of project LNG sold so far, and jeopardise hard-won stakeholder support, including from local communities. Some developers may be worried that a loss of momentum could favour their competitors and that a project postponement may be tantamount to a cancellation."

Wood Mackenzie warns that if company statements are to be believed, we will see FID on some 50 MMtpa of LNG from the U.S. and a further 50 MMtpa from outside the U.S. within the next six to 18 months. "Development of even half of this proposed supply could prolong the Asian oversupply to 2025. Wood Mackenzie's view is that the global LNG market does not need all this LNG at the pace proposed and, as companies confront this reality, a raft of project postponements will follow," Tomnay offers in closing.

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Exhibit 20

BROOKINGS

BROOKINGS ENERGY SECURITY AND CLIMATE INITIATIVE
NATURAL GAS TASK FORCE

NATURAL GAS ISSUE BRIEF #4:

An Assessment of U.S. Natural Gas Exports

JULY 2015

Tim Boersma
Charles K. Ebinger
Heather L. Greenley

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ABOUT THE BROOKINGS ENERGY SECURITY AND CLIMATE INTITIATIVE

The Energy Security and Climate Initiative (ESCI) at Brookings is designed to encourage the development, discussion, and dissemination of high-caliber energy security and climate research. ESCI, through its research and convening efforts, seeks to examine three key substantive aspects of energy security: the geopolitics of energy; the economics of energy; and the growing environmental imperative of balancing increasing global economic prosperity in a carbon-constrained context.

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PREFACE

In May 2011, the Brookings Institution Energy Security and Climate Initiative (ESCI) assembled a Task Force of independent natural gas experts, whose expertise and insights inform its research on various issues regarding the U.S. natural gas sector. After the first series of meetings, Brookings released a report in May 2012 analyzing the case and prospects for exports of liquefied natural gas (LNG) from the United States. The Task Force now continues to meet periodically to discuss important issues facing the gas sector more broadly. With input from the Task Force, Brookings will continue to release periodic issue briefs for policymakers.

The conclusions and recommendations of this report are those of the authors and do not necessarily reflect the views of the members of the Task Force.

An Assessment of U.S. Natural Gas Exports

Tim Boersma
Charles K. Ebinger
Heather L. Greenley[1]

Introduction

Increased natural gas production in the United States has fueled a lively debate on the future of natural gas exports. This debate has focused so far predominantly on exports of liquefied natural gas (LNG). At the same time, the debate is clouded with many confusing statements about the regulatory regime related to natural gas exports with many foreign nations and even some domestic observers having the erroneous belief that the United States has severe restrictions on exports, when in fact no project has to date ever been rejected. In addition, estimates about the amount of U.S. natural gas that will be competitive in global markets vary widely, in part because a number of new supply sources are expected to enter the market in the coming years. There are also many uncertainties regarding global demand for LNG going forward. Finally, declining natural gas sales to the United States have incentivized Canada's provincial and federal authorities to search for opportunities to market its product elsewhere in the world, though unconventional gas development in Canada trails U.S. production, and in some parts of the country gas infrastructure is less developed than in most parts of the United States.

This policy brief provides an assessment of U.S. natural gas exports in the coming years, as well as its competitive position vis-à-vis other suppliers that are emerging worldwide. It does so by briefly outlining the existing regulatory framework related to LNG exports from the United States. It then proceeds with a timeline for LNG export projects that are being developed.[2] The policy brief then turns to what are currently considered major (potential) rivals of U.S. LNG, before it concludes with some final observations regarding the competitive position of U.S. LNG as of June of 2015.

This paper builds on extensive discussions within the Brookings Institution's Natural Gas Task Force (NGTF), along with our analysis of available literature on existing natural gas production trends, price formation, and legal and infrastructural limitations. We are grateful for the rich debates that have occurred in our NGTF. Despite the generosity and valuable contributions of all our speakers and participants, this policy brief reflects solely our views, and any errors remain our own.

[1] The authors are all members of the Energy Security and Climate Initiative at the Brookings Institution. Tim Boersma is a fellow and acting director; Charles K. Ebinger is a senior fellow; and Heather L. Greenley is a senior research assistant.
[2] We have used data that were available in early June 2015, or before.

The global LNG market

For many years, the outlook for natural gas has been very positive, and the outlook for LNG was similarly optimistic. A golden age for natural gas was near, according to the International Energy Agency in 2011. Today, that same agency reports that the outlook may still be bright, but is not set in stone.[3] Falling oil prices have knock-on effects on gas production worldwide, and, perhaps more importantly, demand for natural gas in 2014, particularly in Asia, proved to be substantially more moderate than anticipated.

Recent high regional prices, in both Europe and Asia, have incentivized the construction of significant additional LNG capacity additions. By 2020 additional LNG capacity additions totaling 164 billion cubic meters (bcm) will have come into the market, of which 90 percent will come from Australia and the United States. This, combined with slowing demand, has led to a situation of oversupply, which is expected to last until at least 2017.[4] It is against this background that we write our report. **Table 1** shows some key characteristics of global LNG markets, before we turn to the U.S. regulatory framework.

United States regulatory framework

The evolution of the U.S. LNG export licensing process

All U.S. LNG export projects must receive approvals from both the Department of Energy's Office of Fossil Energy as well as the Federal Energy Regulatory Commission (FERC) per the statutory provisions of the 1938 Natural Gas Act (NGA) Section 3(15 USC§717b).[5] Prior to 2014, this process required an initial application to the Department of Energy (DOE) and a national interest determination finding that LNG exports were within the public interest. This process was then followed by a FERC review after which if the project met all regulatory considerations an approval for the construction of an export facility followed.

Exports to countries holding free trade agreements (FTA) with the U.S. are automatically deemed in the public interest, and therefore licensable by the DOE. For exports to countries without an FTA with the United States, the Office of Fossil Energy was still required to issue an export permit unless, after publishing the application in the Federal Register, seeking public comments, and receiving protests against the sale or notices of intervention by parties opposed to the sale, such exports could be detrimental to the public interest. However, a major shortcoming of this process was the very vague grounds used to determine what was meant by the "public interest." Additionally, under the regulatory process, DOE had the ability to issue permits up to a certain cumulative volume of LNG exports and then to deny subsequent applications if it perceived that tight market conditions made such additional exports in contravention of the public interest. Finally, the DOE's low-cost, undemanding application process soon became bogged down with dozens of export applications.

Following DOE's approval, authorization by FERC was (and still is) also necessary for any LNG export facilities requiring the siting, construction, or operation of those facilities, or to amend an existing FERC authorization. Certain additional regulatory

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[3] International Energy Agency (IEA), Gas: Medium-Term Market Report 2015, by Costanza Jacazio et al. Paris: OECD/IEA, 2015.
[4] Ibid., 94.
[5] For a more in-depth assessment of the process for approval for LNG exports prior to 2014, see: Charles Ebinger et al., "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution, May 2012, http://www.brookings.edu/~/media/research/files/reports/2012/5/02%20lng%20exports%20ebinger/0502_lng_exports_ebinger.pdf.

TABLE 1. THE GLOBAL LNG MARKET[6]

KEY CHARACTERISTICS OF THE GLOBAL LNG MARKET
LNG has been the fastest growing source of gas supply, averaging 7 percent annual growth since 2000. However, over the last three years, LNG trade has been stable at just below the peak of 241.5 million metric tons per annum (mtpa) reached in 2011. LNG in 2013 met 10 percent of global gas demand.
In 2013, the Middle East supplied 42 percent of global LNG supplies, while the Asia Pacific supplied 30 percent. Around 65 percent of the world's liquefaction capacity is held in just five countries: Qatar, Indonesia, Australia, Malaysia, and Nigeria.
Most LNG demand growth has been in the Asia Pacific region, particularly due to increased consumption in China and South Korea. Japan remains the world's dominant importer, utilizing 37 percent of global imports.
Though interregional trade patterns have intensified in recent years, a single price structure for global LNG does not exist. In fact, current investments in the sector are based largely on the premise that these price differentials will remain in place (and incentivize arbitrage).
Historically, LNG trade was based on long-term contracts and oil-indexation, in order to manage risks associated with high upfront costs of liquefaction, transport in specialized tankers, and regasification. However, in 2013, 33 percent of global trade was not long-term (referring to cargoes that are not supported by 5+ years Sales and Purchase Agreements, cargoes diverted from their original/planned destination, and cargoes above take-or-pay commitments). Several factors have contributed to this trend, including the growth of contracts with destination flexibility, and the lack of domestic production or pipeline imports in Japan, Korea, and Taiwan (as a result, sudden changes in demand following for instance a phase out of nuclear capacity have to be covered in the spot market). In addition, the continued price differentials between various regions, and the fact that LNG volumes have been freed up due to a loss of competitiveness vis-à-vis coal (Europe) and shale gas (United States) has facilitated shorter-term trade.
Re-exports of LNG likely remain an important feature of global LNG markets, as described above. In 2013, re-exports grew for the fourth year in a row, to 4.6 megatons (MT) and continues to grow today. Another market development has been the introduction of new pricing formulas by U.S. firms (based on North American spot market prices, instead of oil-indexation). Even though U.S. pricing formulas are currently unique, and low oil prices may take away the immediate incentive for more widespread change, it seems likely that in due time hub-based pricing will become more common. Next to these developments, a number of technological innovations may drive further changes in global LNG markets going forward, such as floating LNG, small scale LNG, high-efficiency liquefaction plants, and LNG ice breakers which would facilitate Arctic transportation.

approvals for offshore facilities involving the export of LNG are on occasion also needed from the Coast Guard as well as the Department of Transportation. If a favorable verdict was made by these agencies, then applications were issued a Certificate of Public Convenience and Necessity allowing the project to proceed to construction and operation.

Environmental review and assessment

The approval of the Office of Fossil Energy and of FERC additionally required an Environmental Impact Statement (EIS) under the National Environmental Policy Act (NEPA of 1970). All projects were to have an EIS for every proposed major federal action that

[6] Based on International Gas Union, *World LNG Report – 2014 Edition* (Fornebu, Norway: International Gas Union, 2014), 23, http://igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf.

was thought to have a significant impact on the environment, in accordance with NEPA's requirements. Even projects with less significant impacts still required documentation. For example, even if the environmental impacts were indeterminable, an EIS would have to be done in order to conclude if an EIS was necessary. If the ensuing EIS determined that the proposed project had no significant environmental impacts, then a Finding of No Significant Impact (FONSI) report was provided. Finally, projects perceived to have no significant impacts on the environment could be processed as Categorical Exclusions alleviating any requirement to provide either an EIS or a less robust Environmental Assessment (EA). In preparing all the documentation required by NEPA, both the Department of Energy and the FERC were also charged with identifying any other compliance requirements pertinent to the project such as the Clean Air Act, the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act, as well as any approvals under these or state-related requirements that fell under these federal statutes. In addition to the environmental requirements, LNG export projects can be subject to the oversight requirements of other agencies such as the Department of Transportation's Office of Pipeline Safety, the National Fire Protection Association, and the Federal Emergency Management Agency.

This seemingly simple, but realistically complex regulatory approval process was made more convoluted by the uncertainty of how long it would take, particularly for those applying to export to non-FTA countries. Again, prior to 2014, the DOE reviewed applications to export LNG to countries without a free trade agreement in the order in which they were received, resulting in a cumbersome and painstakingly time-consuming process. This provided industry with little or no certainty that their projects would be approved if they were way down the applicant list, even if they had excellent technical partners, sound balance sheets, committed customers, and strong prospects for certain financing. While the DOE, per its legal mandate, intended to process these applications in a timely manner (at an average of one every eight weeks), by March 2014 the escalating number of applications had prolonged the approval process by nearly four years, regardless of the project's environmental complexities or lack thereof. "The result was that projects which might make it through the environmental review, led by the Federal Energy Regulatory Commission (FERC) or the U.S. Maritime Administration (MARAD) depending on jurisdiction, might not be considered until they came up in the queue, possibly years later, or might be rejected altogether because they exceeded the soft cap of 12 billion cubic feet per day (Bcf/d)."[7]

On May 29, 2014, the DOE announced a modification of the application process for LNG exports to countries without a U.S. free trade agreement. First, the DOE effectively terminated conditional verdicts to export to non-FTA countries without a NEPA review. "DOE typically issued these conditional authorizations after completion of the notice and

[7] David L. Goldwyn, "DOE's New Procedure for Approving LNG Export Permits: A More Sensible Approach," Brookings Institution, June 10, 2014, www.brookings.edu/research/articles/2014/06/10-doe-approving-lng-export-goldwyn-hendrix. The existence of the so-called soft cap grew out of a study commissioned in 2012 by the DOE with the goal of determining how much LNG could be exported from the United States within the public interest. Finally issued in 2014, the DOE's study, authored by NERA, found inter alia that the more LNG the United States exports, the greater the public interest, thus in effect depriving the DOE of any stopping point, based on its own required criteria and its own study. Because the highest volume scenario NERA examined was 12 Bcf/d of exports, this justified a "soft cap" of 12 Bcf/d in the eyes of some observers. The cap was, indeed, soft because NERA soon privately updated its study, finding public interest in a 19 Bcf/d scenario.

comment process, but before completion of NEPA review."[8] As discussed earlier, prior to this time many projects had to wait in queue in the order in which they were received; some of these were still undergoing environmental review because this assessment could be highly complex, while other projects that had no environmental impact still waited in line. Following the change in policy, the DOE only issues public interest approval for projects that have secured their NEPA requirement, streamlining the DOE approval process. Furthermore, the DOE eliminated the queue system and now approves applications based on when an application "has completed the pertinent NEPA review process and when DOE has sufficient information on which to base a public interest determination."[9]

Despite this attempt to clarify and streamline the approval process, industry still remains a bit concerned over how the changes will work in actuality. Moreover, the issue of what criteria DOE uses and what weight each criterion is given in determining what constitutes the "public interest" is not fully guaranteed by the issuing of an export permit. The United States government still reserves the full right to withdraw export permits determined not to be in the public interest.[10] Unfortunately, this determination is outside the DOE's jurisdiction and can only be changed or clarified by an act of Congress. Nonetheless, with the change in policy, DOE has made a vast improvement in the approval process providing industry with noticeably more confidence in the approval timeline, once they have undergone their NEPA review.

Current trade flows and North American export projects under construction

Since 2007, Canadian gas pipeline exports to the United States have been in a sluggish decline as new U.S. domestic supplies, largely from unconventional gas, and the construction of new pipelines to distribute them are quickly obviating the need for Canadian gas imports. In 2013, virtually all U.S. imports of natural gas came from Canada, totaling 2,785 Bcf.[11] Given these market trends and the absence of new export markets, Canadian gas production likely will remain stagnant, serving only the domestic economy and some select niche U.S. regional markets. It is worth noting however, that those niche markets also may evaporate for two reasons. First, U.S. domestic infrastructure investments continue to expand, bringing previously stranded gas supplies to market. To give an example, in 2013 Canadian imports into the northeastern United States dropped by almost 12 percent, due to the increase in production from the Marcellus shale and expanded pipeline capacity.[12] Second, gas market growth in California, a highly important niche market for Canadian gas, is in decline as large renewable energy projects increasingly dominate electricity generation capacity, gradually pushing out gas.

In response to this Canadian "existential" gas market crisis and the perception that the United States is a "low cost" gas producer, the Canadian gas industry has embarked on ambitious schemes

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[8] Procedures for Liquefied Natural Gas Export Decisions, 79 Fed. Reg. 32262 (proposed June 4, 2014), https://federalregister.gov/a/2014-12932.
[9] Ibid.
[10] The right to withdraw export permits due to the determination of not being in the public interest is unlikely to be exercised. This issue becomes moot once natural gas export prices reach the point of no longer being in the public interest, the price of exporting U.S. natural gas becomes too expensive and therefore uneconomic.
[11] U.S. Energy Information Administration, "U.S. Natural Gas Imports & Exports 2013," May 28, 2014, http://www.eia.gov/naturalgas/importsexports/annual/.
[12] Ibid.

to ship Canadian gas to Asian markets where gas prices have historically been high. Currently, there are no fewer than 19 proposed LNG projects along the coast of British Columbia.[13] There are also two more in Oregon that, if built, would be supplied by gas from Western Canada, and several liquefaction plants have been proposed in Canada's Maritime Provinces on its Atlantic coast.

To date, however, no final decision has been made for any Canadian LNG export project and none have been built. Malaysia's Petronas has decided to continue to move forward with its project in British Colombia, yet final investments are still waiting for federal and provincial approval.[14] Much of the delay in Canada relates to the relatively long distances over which wholly new gas pipelines have to be constructed to enable LNG exportation. These long pipeline routes (e.g., over 600 miles in British Columbia) have drawn significant environmental backlash, complicated by protracted negotiations with the First Nations and recent revisions to the tax regime in British Columbia. Recently, several First Nations, including the Lax Kw'alaams, have voted against LNG plans in British Columbia as it interferes with traditional territories, leaving significant environmental and ecological concerns which need to be addressed.[15] With these delays possibly curbing potential investment, Ottawa has announced a federal tax break for proposed LNG terminals in British Columbia, which intends to spur investment by making British Columbian LNG more competitive and to alleviate some economic uncertainty.[16]

In the United States, the euphoria brought on by the unconventional gas revolution has been astounding as estimates of technically recoverable natural gas resources have ascended to over 2,200 trillion cubic feet (Tcf), an amount in excess of 87 years supply at current consumption levels.[17] The magnitude of these resources has led to FERC's approval of several LNG export terminals, five of which are under construction (**Figure 1**).[18] Furthermore, there are 21 additional proposed projects in the continental United States and one in Alaska pending review by U.S. regulatory authorities, including several existing import terminals that are requesting to be converted into export facilities, i.e., for which substantial gas infrastructure components are already in place. In addition, it is estimated that there could be 11 more potential facilities in terms of available sites.[19]

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[13] For a list of British Columbian projects see: "Explore B.C.'s LNG Projects," Government of British Columbia, http://engage.gov.bc.ca/lnginbc/lng-projects/. For a list of Canadian projects applying for an LNG export terminal license with the Government of Canada, see: "Canadian LNG Projects," Natural Resources Canada, last modified September 23, 2014, http://www.nrcan.gc.ca/energy/natural-gas/5683.

[14] Chester Dawson, "Shell-Led Natural Gas Export Project in Canada Clears Environmental Hurdles," *The Wall Street Journal*, June 17, 2015, http://www.wsj.com/articles/shell-led-natural-gas-export-project-in-canada-clears-environmental-hurdles-1434584827.

[15] Justine Hunter, "Lacklustre Support from B.C. First Nations Signals Trouble for LNG Facility," *The Globe and Mail*, May 10, 2015, http://www.theglobeandmail.com/news/british-columbia/lacklustre-support-from-bc-first-nations-signals-trouble-for-lng-facility/article24361708/.

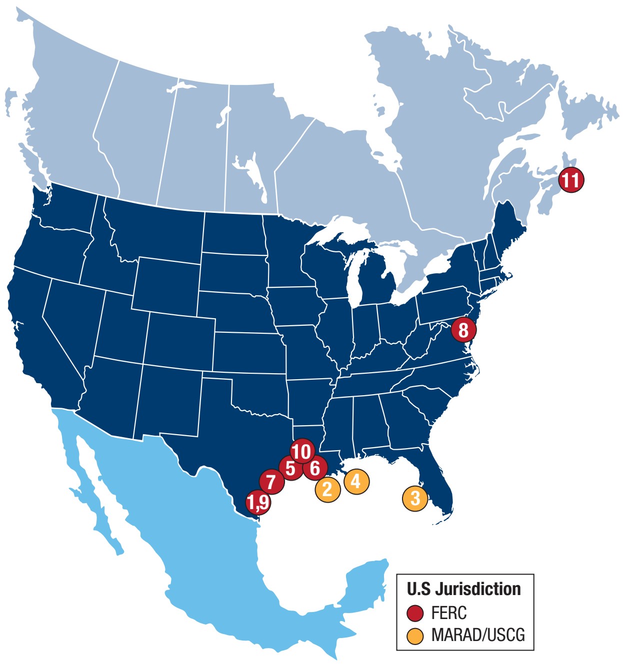
[16] Brent Jang and Ian Bailey, "Ottawa Grants Tax Breaks for LNG Sector in BC," *The Globe and Mail*, February 19, 2015, http://www.theglobeandmail.com/news/british-columbia/harper-announces-tax-breaks-for-lng-industry-in-bc-to-spur-job-growth/article23106853/.

[17] "Frequently Asked Questions: 'How much natural gas does the United States have and how long will it last?,'" U.S. Energy Information Administration, last modified December 3, 2014, http://www.eia.gov/tools/faqs/faq.cfm?id=58&t=8.

[18] Likewise, proved U.S. gas reserves have reached record levels of 354 trillion cubic feet as of year-end 2013: U.S. Energy Information Administration, "U.S. Crude Oil and Natural Gas Proved Reserves," December 19, 2014, http://www.eia.gov/naturalgas/crudeoilreserves/.

[19] "LNG," Federal Energy Regulatory Commission, last modified June 18, 2015, http://www.ferc.gov/industries/gas/indus-act/lng.asp.

FIGURE 1. NORTH AMERICAN LNG IMPORT/EXPORT TERMINALS APPROVED



As of June 18, 2015

Import Terminal

APPROVED - UNDER CONSTRUCTION

U.S. – FERC

1. **Corpus Christi, TX:** 0.4 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)

APPROVED – NOT UNDER CONSTRUCTION

U.S. – MARAD/Coast Guard

2. **Gulf of Mexico:** 1.0 Bcfd (Main Pass McMoRan Exp.)
3. **Offshore Florida:** 1.2 Bcfd (Hoëgh LNG – Port Dolphin Energy)
4. **Gulf of Mexico:** 1.4 Bcfd (TORP Technology–Bienville LNG)

Export Terminal

APPROVED – UNDER CONSTRUCTION

U.S. – FERC

5. **Sabine, LA:** 2.76 Bcfd (Cheniere/Sabine Pass LNG) (CP11-72 & CP14-12)
6. **Hackberry, LA:** 1.7 Bcfd (Sempra – Cameron LNG) (CP13-25)
7. **Freeport, TX:** 1.8 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction) (CP12-509)
8. **Cove Point, MD:** 0?82 Bcfd (Dominion – Cove Point LNG) (CP13-113)
9. **Corpus Christi, TX:** 2.14 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)

APPROVED – NOT UNDER CONSTRUCTION

U.S. – FERC

10. **Sabine Pass, LA:** 1.40 Bcfd (Sabine Pass Liquefaction) (CP13-552)

APPROVED – NOT UNDER CONSTRUCTION

Canadian

11. **Port Hawkesbury, NS:** 0.5 Bcfd (Bear Head LNG)
12. **Kitimat, BC:** 3.23 Bcfd (LNG Canada)

Source: Federal Energy Regulation Commission, U.S. Department of Energy

While the projected number of North American LNG export facilities is massive, closer examination of the projects' financial realities offer a more nuanced story. Almost all of the existing analysis and forecasts have been based on three central tenants. First, that spot market prices at Henry Hub will continue to be at record low levels. However, in reality, Henry Hub prices, while remaining relatively low, are projected in most forecasts to rise steadily in the coming years, albeit gradually. Unless the costs of the liquefaction process, transportation, and regasification of natural gas can be reduced, and there are currently few indications that they can, those marginal differences in hub prices may become more significant in determining how attractive U.S. LNG exports will be.[20] The second supposition is that prices in Asia and Europe will remain high, creating ample room for arbitrage. Currently, Henry Hub prices have remained low at around $3/Mcf. Meanwhile, spot prices in Asia (roughly $6-7/mmBtu for 2015-2016)[21] and Europe have tumbled over the course of 2014 (because they have been tied to world oil prices, which declined precipitously, because of a slowdown in economic growth, and because natural gas faces stiff competition from other fuel sources, negatively impacting demand) to levels where it would be increasingly difficult for North American LNG to be considered profitable. The third supposition is the continued

[20] International Gas Union, *World LNG Report - 2014 Edition*.

[21] Osamu Tsukimori, "Japan Feb LNG Spot Price Falls a Quarter to $7.60/mmBtu," Reuters, March 10, 2015, http://www.reuters.com/article/2015/03/10/lng-japan-spot-idUSL4N0WC1JL20150310.

practice outside the United States of indexing the price of LNG to the oil price, coupled with the general assumption that oil prices will remain high. Consequently, when oil prices fell by 50 percent after October 2014, many LNG projects' fiscal solvency were called into question. Even with prices having slightly rebounded, investors remain increasingly cautious about new projects. U.S. projects that are currently under construction are unique in that their pricing formulas are based on spot-market prices at Henry Hub, unlike other LNG projects around the world which are in some form indexed to oil or oil-related products. With the fall in oil prices, rivals to U.S. LNG projects, in particular those in Australia (which are discussed in more detail later in this brief) have become more competitive than they were just one year ago, but it is uncertain how the oil price will develop going forward.

In addition, there are many other uncertainties worth considering:

1. The pace at which China ramps up pipeline imports, particularly from Russia;
2. The rate at which many countries with large shale gas resources (China, Argentina, South Africa, and Algeria, to name a few) successfully develop them;
3. Inter-fuel competition from other sources such as coal and renewables with LNG, especially in the Asian power market;
4. Whether or not Russia will also initiate large scale pipeline exports to Japan and the Koreas, owing partially to the pace and scale of Russian LNG exports from its Arctic regions, as well as how much Russian LNG from Yamal and Sakhalin will continue to flow;
5. The speed and degree to which Japan determines whether or not to bring its nuclear reactors back online, and to what extent nuclear outages in South Korea continue to spur LNG imports;
6. To what extent Japan will continue its support schemes for renewable electricity and significantly expand in particular its solar capacity;
7. The ability to utilize LNG as a transportation fuel, particularly in the Chinese and Indian markets where pollution and health concerns are growing;
8. Whether the United Nations Framework Convention on Climate Change meeting in Paris in late 2015 reaches a global agreement on reducing CO_2 emissions and the nature of that agreement; and,
9. To what extent the major economies in Asia, in particular China and India, decide to reduce the share of coal in their electricity generation, especially if there is no serious agreement to reduce CO_2 at the Conference of the Parties meeting. In such a scenario coal will remain very competitive with LNG.[22]

Faced with the foregoing uncertainties, U.S. LNG export projects are actually poised to compete favorably with new LNG projects coming to the world market from other locations. U.S. construction costs are comparatively low, especially for brown-field liquefaction projects, i.e., that will convert existing import terminals that have already secured environmental approvals for existing facilities. Additionally, low U.S. energy prices provide a construction cost edge, and the United States offers significant skilled labor at a reasonable cost.[23] Finally, depending on global oil prices, the U.S. LNG pricing structure,

[22] Brian Songhurst, "LNG Plant Cost Escalation," The Oxford Institute for Energy Studies, February 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/02/NG-83.pdf.

[23] Leonardo Maugeri, "Falling Short: A Reality Check for Global LNG Exports," Harvard Kennedy School, December 2014, 21, http://belfercenter.ksg.harvard.edu/files/Falling%20Short-LNG%202014.pdf.

based on Henry Hub spot market prices, may give U.S. projects a competitive advantage going forward by providing buyers with lower cost LNG and price index diversity.

Yet the success of U.S. projects is not guaranteed. First, capacity costs are not fixed and can rise with an increased demand for material and skilled labor, as the overall economy improves.[24] Second, the oil price level plays an important role. Leonardo Maugeri of Harvard's Kennedy School makes a compelling case that U.S. LNG projects are likely less competitive at an oil price (Brent) level of $80/bbl compared to $100/bbl. With other LNG projects indexed to the price of crude, the current price level would make LNG from Australia more competitive vis-à-vis U.S. LNG in Asia.[25] It is worth noting that Australian projects that are competitive are not per definition profitable. Some estimates suggest that Australian LNG projects break even at around $85/bbl, though of course every case is unique.[26] Third, with respect to Europe in general, LNG producers have to wonder what will be the absorptive capacity of the market. In Europe, LNG competes with cheap coal, support mechanisms for renewables, and very competitive pipeline gas from Russia, Norway, and Algeria (notwithstanding declining domestic production from the Netherlands, for example). It is not unlikely that, even if large amounts of U.S. LNG make it to the European market, traditional suppliers would start a price war rather than give up market share.[27] There is some empirical evidence that U.S. LNG could be very competitive in the more liquid parts of the European market, in particular the UK and Netherlands. Fourth, given all these uncertainties, possible constraints, and the fact that a significant amount of projects are permeating the market in the coming years, it may be increasingly difficult to finance additional projects going forward.

For all proposed LNG projects worldwide, timing is crucial. According to M.C. Moore et al., of the University of Calgary, "delays beyond 2024 risk complete competitive loss of market entry for Canadian companies. Already British Columbia is behind schedule on the government's goal of having at least one terminal in operation by 2015."[28] Moore et al. argue that if Canadian facilities lag behind the projected entry of U.S. LNG facilities, they are at considerable risk for losing out on market share competitiveness by 2024 because of their relatively high delivered-product costs. Thus, it is still highly uncertain what amount of North American LNG will actually make it to the market. We observe that at this point in time, the number of firm export projects in the United States can be counted on one hand, while in Canada there are currently no projects under construction. We also note that even full regulatory approval from FERC and DOE does not guarantee that a project will eventually be built. In addition to regulatory approval, a project requires financing, and at current price levels with more LNG (particularly from Australia and the U.S.) coming on stream, we believe that it is increasingly unlikely that new projects other than fully licensed and financed ones will make it to the market before the early 2020s. Even for the five U.S. projects that have received all green lights over the course of 2014, it is important to keep in mind that

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[24] Ibid., 23.
[25] Ibid., 33.
[26] Bob Lamont, "Falling Oil Prices Set to Hit Future LNG Price," *The Observer*, November 4, 2014, http://m.gladstoneobserver.com.au/news/cheap-oil-to-hit-lng-price/2441170/.
[27] Tim Boersma et al., "Business as Usual: European Gas Market Functioning in Times of Turmoil and Increasing Import Dependence," The Brookings Institution, October 2014, 22, http://www.brookings.edu/~/media/Research/Files/Papers/2014/10/european-gas-market-import-dependence/business_as_usual_final_3.pdf?la=en.
[28] M.C. Moore et al., "Risky Business: The Issue of Timing, Entry and Performance in the Asia-Pacific LNG Market," *The School of Public Policy SPP Research Papers* 7, no. 18, July 2014, http://policyschool.ucalgary.ca/sites/default/files/research/moore-lng-onl.pdf.

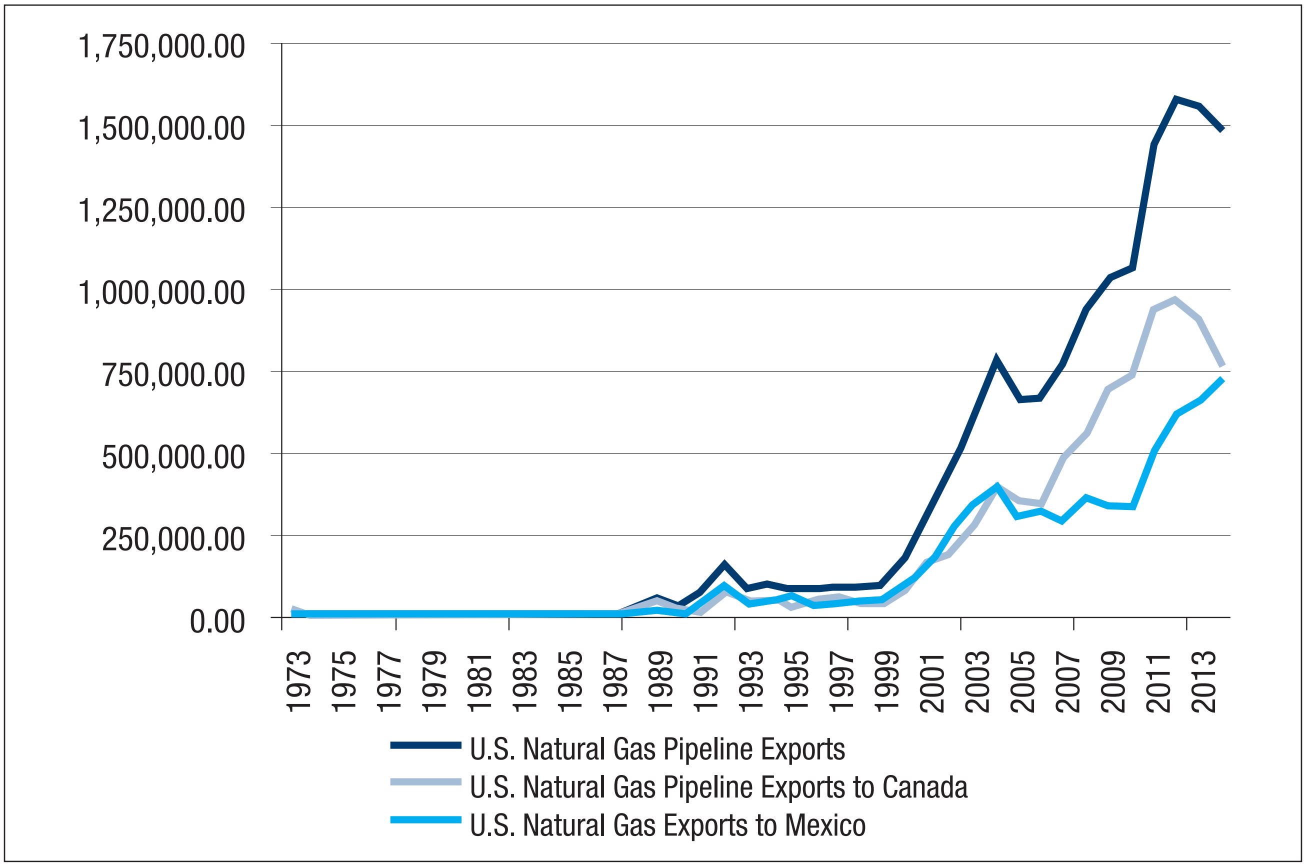
with an estimated brownfield construction time of four years, the earliest achievable start dates will be in late 2018/early 2019,[29] other than the initial four trains (2.2 Bcf/d) of the Sabine Pass LNG export project, which are nearing completion and expected to enter service beginning November 2015. We believe that the trend of increased regional pipeline gas exports will continue however, resulting in particular in vastly increased pipeline exports from the United States to Mexico (**Figure 2**), and a further erosion of Canadian–U.S. gas trade. This leaves an open question where Canadian producers can market their gas going forward.

Competition for U.S. LNG: The cases of Australia and East Africa

Australia

Australia has moved fast to break into the LNG market. With three major facilities already in operation and seven more prepared to go online in the next couple of years, Australia is poised to exceed Qatar as the world's largest LNG exporter in terms of export volumes. However, the Australian projects face significant cost increases, amongst others because production costs turned out higher than anticipated,

FIGURE 2. U.S. NATURAL GAS EXPORTS AND RE-EXPORTS BY COUNTRY



Source: U.S. Energy Information Administration

[29] Ibid.; International Gas Union, *World LNG Report – 2014 Edition, 23.*

and labor costs rose significantly. Because of that, combined with the fact that Australian LNG prices have been linked to oil, it remains to be seen how competitive Australian LNG will be. Regardless of their competitiveness, with huge sunk costs, the Australian projects are still expected to compete in the global market space.

Australia has approximately 43 Tcf of proven natural gas reserves with an additional 437 Tcf of technically recoverable shale gas reserves.[30] Much of the domestic need for natural gas was previously provided by Eastern Australia, but recently there has been a shift and the eastern market has begun exporting LNG. This increase in exports has had an upward effect on domestic prices. As a result, populist voices have emerged, calling to keep natural gas in the country in order to keep domestic prices low. However, the Australian government does not support this policy, arguing that reserving natural gas for domestic use will inhibit innovation, limit diversity of supply, and discourage new investment opportunities.[31] Furthermore, the domestic Australian natural gas market is small, with coal currently dominating the electricity sector at about 64 percent of generation capacity.[32] In addition, foreign investment in the development of the Australian natural gas export market has been beneficial to the Australian economy. The new LNG export facility in Queensland alone has provided the country with 30,000 construction jobs and 12,000 permanent positions through at least 2020.[33] The Queensland Curtis LNG plant is the world's first large scale plant to convert coal-bed methane to LNG. In January 2015, it sent its first tanker carrying LNG to Singapore, Chile, China, and Japan.

Notwithstanding the economic benefits, the Australian projects have generated public concern. A shortage of skilled labor has resulted in delays and cost increases. The projects require skilled labor and Australia's labor pool is limited. However, labor unions in Australia and governmental restrictions over temporary work visas have made it difficult to bring in foreign workers. The labor unions in Australia are powerful and have been able to interrupt the construction of a project under the "right-of-entry" provision.[34] Additionally, labor unions have negotiated for higher wages, on top of already high salaries due to a strong Australian dollar. That strong currency also contributed to skyrocketing prices for construction materials, such as steel, in the early stages of the development of some of these projects. All of these issues contributed to delays in expected completion times as well as significant cost overruns. For example, the Gorgon project, with a capacity of 15.6 mtpa, has been delayed from an original completion date of 2014 to late 2015, while its costs have increased by 40 percent.[35]

Australian LNG projects target Asian markets. They have a major advantage vis-à-vis North American exports in terms of proximity, as transportation costs are lower. Conversely, Australian projects have

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[30] "Australia Overview," U.S. Energy Information Administration, last modified August 28, 2014, http://www.eia.gov/beta/international/analysis.cfm?iso=AUS.

[31] Australian Government Department of Industry and Science, *2015 Energy White Paper*, (Canberra, Australia Capital Territory: Canberra ACT Department of Industry and Science, April 2015), http://ewp.industry.gov.au/sites/test.ewp.industry.gov.au/files/EnergyWhitePaper.pdf.

[32] Ibid.

[33] Ibid.

[34] David Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?" Oxford Institute for Energy Studies, Oxford University, September 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/09/NG-90.pdf.

[35] Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?"

negotiated contracts based on the price of oil, a formula that may lose its competitive edge in comparison to U.S. projects if oil prices start to rise again. In addition, low Henry Hub prices have sparked a debate amongst Asian buyers whether oil-indexation should still be the preferred pricing method for LNG. There have also been discussions about the development of an Asian benchmark, a stance that is actively supported by the U.S. Department of State. The drop in oil prices has eroded some of the urgent needs of Asian buyers to address the oil-indexation of LNG cargoes, though we do not expect that desire for changes in pricing formulas to disappear. At the same time, it is too early to claim that non-oil based contracting practices marks a widespread disruption of the current system.[36]

Australian LNG faces uncertainties regarding Asian demand. Japan is currently determining how many nuclear power plants it can bring back online since the shutdown of its nuclear fleet after the disaster in Fukushima. In 2013, 80 percent of Australian LNG exports went to Japan, and in 2012 Australia was the largest source of LNG for Japan.[37] Next to the more mature markets in Japan and South Korea, most growth in LNG demand is expected in China and India. However, growth in China in 2014 was weaker than anticipated due to the overall economic slowdown.[38]

Nevertheless, Australia is still on schedule to takeover Qatar to become the world's primary LNG supplier before 2020. One major contributing factor has been that Australia secured contracts before the U.S. shale gas revolution took off in full. Australia's potential for exports is enormous: "LNG exports rose in 2013 to 22.3 mtpa (30.5 Bcm), up by 9% from 2012 and by 2018 the proportion of Australian produced gas exported for LNG is projected to rise to 81%."[39] However, new investments have become uncertain, with other projects coming on stream and global demand in the nearby future possibly being weaker than expected.

East Africa

Over the past decade, both Tanzania and Mozambique have made significant offshore natural gas discoveries. With reports indicating discovered gas at over 140 Tcf in Mozambique and another 46 Tcf in Tanzania, East Africa can become a major competitor in the world LNG market. Although these two countries can produce LNG at relatively competitive rates due to largely conventional deposits and East Africa's close proximity to Asian markets, both Tanzania and Mozambique have substantial barriers to overcome concerning domestic regulations and political stability as well as the lack of available infrastructure to get this natural gas to market.

Both Tanzania and Mozambique must develop infrastructure in order to secure financial investment. The governments of Tanzania and Mozambique have worked with LNG project developers to design a "unitization initiative" in order to cut costs by sharing LNG production facilitates while also effectively curbing construction time.[40] The infrastructure issue becomes even more compounded with the remote

[36] Ibid.; International Gas Union, *World LNG Report – 2014 Edition*, 14.
[37] "Australia Overview," U.S. Energy Information Administration.
[38] BG Group, "Global LNG Market Outlook 2014-15," BG Group, http://www.bg-group.com/480/about-us/lng/global-lng-market-overview-2013-14/.
[39] Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?"
[40] International Energy Agency, The Asian Quest for LNG in a Globalising Market, by Anne-Sophie Corbeau et al. Paris: OECD/IEA, 2014, http://www.iea.org/publications/freepublications/publication/PartnerCountrySeriesTheAsianQuestforLNGinaGlobalisingMarket.pdf.

location of many of these LNG facilities. In Tanzania, LNG project completion is currently estimated anywhere from 2021 to 2023 with expected international investments of $20 to 30 billion. While Mozambique LNG is officially still estimated to come to the market by around 2018 to 2019, there is a growing consensus that delays could move the completion date back to the mid-2020s. Companies working in the area, such as Eni and BG, have expressed their concerns over the infrastructure challenge being resolved in time to meet the 2018 target.[41]

Additionally, both countries are struggling to attract an adequate, skilled labor force to develop this infrastructure, with the local median age hovering around 17 years. Mozambique has attempted to quell this issue by instituting the Decree Law of December 2014, which outlines specific qualifications for bringing in skilled foreign workers. This decree, among other things, eases restrictions on hiring foreign workers, yet stresses the need to give job priority first to qualified Mozambicans. Additionally, the decree suggests that foreign workers should not be hired for unskilled jobs or those that are not technically complex as these should be reserved for the local population.

Tanzania and Mozambique have also considered using these natural gas resources to meet their domestic needs. The Tanzanian government has made it clear that it will prioritize the domestic market over exports. According to the Natural Gas Policy of Tanzania 2013, "Tanzania aims to have a reasonable share of the resource for domestic applications as a necessary measure to ensure diversification of the gas economy before [development of an] export market."[42] While the Tanzanian domestic market for natural gas is relatively small in comparison to its reserves, this policy could pose a significant barrier to investment. In Mozambique, the new Petroleum Law introduced by Parliament established a 25 percent domestic supply obligation.[43] The national market of Mozambique will not be able to absorb this amount in the long term; therefore, an open question is whether to allow South Africa to be part of this "national market."

East Africa faces the stigma of historic political instability, which could influence both future investments as well as physically impact production. While Tanzania has been a peaceful nation for over 50 years, Mozambique ended a nearly 20-year civil war in 1992 with the signing of a peace agreement. Despite the formal peace, there have been new periods of unrest. Starting in October 2012 and continuing throughout 2013, new skirmishes warranted a second peace deal, which has been in place since September 2014. Still, there continues to be concerns over the ability of the government to maintain political stability and protect against uprisings that could impact future investment in Mozambique.

Despite this uncertainty, at this point Mozambique is comparatively better positioned to export LNG than Tanzania. Mozambique has developed a much more specific regulatory framework and does not have any qualms with exporting the majority of its natural gas. The government recognizes the need for strong regulation and control over how energy resources are managed within the country in order to guarantee domestic revenues. Responsible planning and the reorganization of tax and regulatory poli-

[41] International Energy Agency, *Medium-Term Gas Market Report: Market Analysis and Forecasts to 2019*, Paris: OECD/IEA, 2014.
[42] The United Republic of Tanzania, *The Natural Gas Policy of Tanzania – 2013*, Dar es Salaam: October 2013, 14, http://www.tanzania.go.tz/egov_uploads/documents/Natural_Gas_Policy_-_Approved_sw.pdf.
[43] William Felimao, "Mozambique Passes Petroleum Law and Tax Break for Eni, Anadarko," *Bloomberg Business*, August 15, 2014, http://www.bloomberg.com/news/articles/2014-08-15/mozambique-passes-petroleum-law-and-tax-break-for-eni-anadarko.

cies are necessary in order for Mozambique's natural gas resources to be developed. The government recognizes that Mozambique has the ability to come out of poverty through the development of its energy resources. Standard Bank estimates that LNG could add 15,000 direct jobs and $39 billion in gross domestic product per annum to the Mozambique economy by 2035.[44] The government of Mozambique has issued documentation considering issues such as transparency, regulatory clarity, revenue usage, infrastructure, education, and environmental protection to be priorities when determining the future development of their local natural gas resources.[45] While these are indeed noble intentions, there is still much work to be done in order to overcome rampant corruption, such as rent seeking, which could undermine development.[46]

Even amidst these challenges, there still remains significant interest from Asian investors in developing this LNG. Together both Tanzania and Mozambique make East Africa an attractive investment opportunity. Their location makes their export potential to India and South Asia viable. Companies that operate in Mozambique, such as Eni and Anadarko, plan to have LNG projects online around 2018 with an estimated capacity of 27.2 bcm/year.[47] Even though completion of these projects before the end of the decade may be optimistic, if these plans are implemented and successful, in due time they could result in making Mozambique and Tanzania significant LNG exporters.

Final observations

From this brief overview, we reach the following conclusions:

Though the U.S. regulatory processes for LNG exports to countries with which the United States does not have a free trade agreement are convoluted, lengthy, expensive, and could be further streamlined, there is no outright ban to sell natural gas to any country. To date, no project has been rejected by either DOE or FERC. Thus, it is essentially up to the market to figure out how much room there is for exports of natural gas from the U.S.

We believe that the U.S. LNG projects that are currently under construction, totaling close to 10 Bcf/d in capacity, will make it to the market by 2020, but additional projects are at this point increasingly uncertain. As noted, factors that are important to consider are alternative suppliers of LNG about to enter the market, as well as competition from existing suppliers, such as Qatar, and pipeline supplies from Russia, Norway, and Algeria, and perhaps by the mid-2020s, Iran. Demand in Asia will be affected by the success or failure of additional intercontinental pipeline projects. Russia continues to expand to new markets in Asia, particularly in China, the Koreas, and Japan. Additionally, Central Asian countries continue to add new production and pipelines to the Asian power and industrial markets. Demand will also be affected by the likelihood of at least some

[44] Standard Bank and Conningarth Economists, *Mozambique LNG: Macroeconomic Study*, (Johannesburg, South Africa: Standard Bank, 2014), http://www.mzlng.com/content/documents/MZLNG/LNG/Development/2014-MozambiqueLNGReport-ENG.pdf.

[45] ICF International, *The Future of Natural Gas in Mozambique: Towards a Gas Master Plan* (Washington, DC: Public-Private Infrastructure Advisory Facility, December 20, 2012): ES-17, 18, http://www.ppiaf.org/sites/ppiaf.org/files/publication/Mozambique-Gas-Master-Plan-executive-summary.pdf.

[46] Anne Frühauf, "Mozambique's LNG Revolution: A Political Risk Outlook for the Rovuma LNG Ventures," The Oxford Institute for Energy Studies, April 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/04/NG-86.pdf.

[47] International Energy Agency, *Medium-Term Gas Market Report: Market Analysis and Forecasts to 2019*.

countries tapping into their own unconventional gas reserves in the coming years. If a country like China is successful in this endeavor, this will likely have a downward effect on LNG demand. Prices would also be affected. If, for example, a country like Argentina or Algeria is successful with new quantities of gas beyond their domestic requirements, then more supplies will reach at least regional markets putting a downward pressure on prices. Furthermore, the degree to which Japan (and to a lesser extent, South Korea) utilizes its nuclear capacity, can have a dramatic impact on LNG demand and the availability of supplies in the next couple of years. Finally, it remains to be seen whether there will be a global agreement to curb carbon emissions, as many energy forecasts seem to assume, and if so, what kind of agreement emerges, e.g., carbon pricing and GHG restrictions tend to favor natural gas and LNG, although outright requirements for or subsidies to renewables may have the opposite effect. Absent such an agreement, coal remains very competitive against LNG, especially in Asia's burgeoning electricity market. And then there are uncertainties in the LNG market itself, most prominently to what extent arbitrage between the different pricing regions in the market remains attractive, and whether promising technological advances like floating LNG facilities, small scale LNG, and usage of LNG in marine and transportation sectors become more widely dispersed.

Owing to strong environmental opposition by First Nations groups, leading local and international environmental organizations, and fishing interests, less rapid unconventional gas extraction, and less developed infrastructure, it is unlikely that Canada will have a LNG terminal up and running before the end of the decade. Canadian projects are opposed on a number of grounds (siting, impact on fisheries, adding to CO_2 emissions, pipelines serving the projects crossing wilderness areas in British Columbia), and in the current market constellation we believe it will be increasingly difficult to finance new projects, because demand in the coming years can likely be met by existing capacity in combination with those plants that are currently under construction.

In terms of foreign competition, Australia with early market entrance will be paving the way for the future shape of LNG exports. Despite budgetary and project setbacks, Australia's LNG exports are coming online before most of the North American projects. In the coming years we expect to see fierce competition between different LNG suppliers, as supplies outgrow demand, turning the LNG market into a buyers' market. In addition, in areas such as electricity generation, LNG competes with pipeline gas and other fuel sources. As described, there are many different factors that will determine the amount of the future growth of LNG demand, and we would be cautious to take the unprecedented growth figures that we have seen until 2011 for granted.

The jury is out on whether or not Tanzania and in particular Mozambique can become significant producers of natural gas, though there is enormous potential. With many investors interested in developing this region, the lack of infrastructure, rent-seeking, and the ability to complete construction are among the greatest risks to East African LNG market development in the short term. It is worth noting that in the current market environment, and keeping in mind the local challenges in East Africa, constructing greenfields may be increasingly challenging. At the same time, it has been done before, recently, for instance, in Papua New Guinea. LNG coming out of East Africa in due time may well have the ability to compete cost-effectively against North American LNG exports.

The U.S. projects that are currently under construction are unique in their price setting. Even though in the current modest oil price environment the immediate imperative for a more widespread adoption of this pricing formula may have faded, we believe that in the longer run it is likely that more gas producers will abandon the traditional model of oil-indexation. In northwestern Europe in 2008 and 2009 we saw a shift away from oil-indexation, incentivized by oversupply, and the supply glut that is anticipated in the coming years may well have similar effects. For major buyers of natural gas it is important to keep in mind though that spot-price indexation does not equal guaranteed lower prices, and more volatility is certainly one possible outcome.

In sum, the United States is poised to become a major global supplier of LNG, but its operators will face significant competition from a variety of suppliers, in terms of alternative LNG, pipeline gas, domestic production, and alternative energy sources. A number of Australian and U.S. projects are ahead of the curve and will come to the market in the coming years. In combination with slowing demand for LNG these developments will lead to a situation of oversupply, which is expected to last at least until 2017. Therefore, going forward, despite the presence of abundant resources worldwide, we believe it will be increasingly difficult to finance new LNG projects, due to high upfront costs in combination with a substantial number of uncertainties which influence supply and demand. That does not prohibit some of the aforementioned projects in for instance Canada or Mozambique to come to the market, as in due time surely we expect a new investment cycle that results in new liquefaction and regasification capacity coming on-stream.

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