ADDENDUM TO ENVIRONMENTAL REVIEW DOCUMENTS CONCERNING EXPORTS OF NATURAL GAS FROM THE UNITED STATES

AUGUST 2014

U.S. DEPARTMENT OF ENERGY

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Table of Contents

List of Tables

List of Figures

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List of Acronyms and Abbreviations

Acronym/Abbreviation	Definition
API	**American Petroleum Institute**
BACT	Best Available Control Technology
BLM	Bureau of Land Management
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
Btu	British thermal units
C2ES	Center for Climate and Energy Solutions
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CEQ	Council on Environmental Quality
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide-Equivalent
CWA	Clean Water Act
DCNR	Department of Conservation and Natural Resources
DEQ	Department of Environmental Quality
DOE	U.S. Department of Energy
EGR	Enhanced Gas Recovery
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
FE	Office of Fossil Energy
FERC	Federal Energy Regulatory Commission
FTA	Free Trade Agreement
GHG	Greenhouse Gas
GWP	Global Warming Potential
GWPC	Ground Water Protection Council
H_2S	Hydrogen Sulfide
HAPs	Hazardous Air Pollutants
HNO_2	Nitrous Acid
HNO_3	Nitric Acid
IPCC	Intergovernmental Panel on Climate Change
LAER	Lowest Achievable Emissions Rate
LNG	Liquefied Natural Gas
M	Moment Magnitude Scale
MMI	Modified Mercalli Intensity
MMt	Million Metric Tons
N_2	Nitrogen Gas
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act

NESHAPs	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NO_2	Nitrogen Dioxide
NORM	Naturally Occurring Radioactive Materials
NO_X	Nitrous Oxides
NPDES	National Pollutant Discharge Elimination System
NRC	National Research Council
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
PM	Particulate Matter
ppb	Parts Per Billion
ppm	Parts Per Million
psi	Pounds Per Square Inch
RACT	Reasonably Available Control Technology
REC	Reduced Emissions Completion
ROW	Right-of-Way
scf	Standard Cubic Feet
SDWA	Safe Drinking Water Act
SIPs	State Implementation Plans
SO_2	Sulfur Dioxide
TDS	Total Dissolved Solids
Tg	Teragram (one trillion grams)
tpd	Tons Per Day
TPY	**Tons Per Year**
UIC	**Underground Injection Control**
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WRI	World Resources Institute

Introduction

Section 3(a) of the Natural Gas Act, 15 U.S.C. § 717b(a), directs the U.S. Department of Energy (DOE) to authorize proposed exports of natural gas to countries with which the United States does not have a Free Trade Agreement (FTA) requiring national treatment for trade in natural gas (non-FTA countries), unless DOE finds that the proposed exportation will not be consistent with the public interest.

DOE presently has before it numerous applications to export liquefied natural gas (LNG) to non-FTA countries. The project proponents in these applications also have applied to the Federal Energy Regulatory Commission (FERC) for approvals related to onshore LNG facilities. FERC is the lead federal agency for the preparation of environmental assessments (EAs) and environmental impact statements (EISs) required under the National Environmental Policy Act (NEPA) for the applications that are pending before both federal agencies. DOE is participating as a cooperating agency in these NEPA reviews.

Several parties and commenters to these proceedings have urged DOE to review the potential environmental impacts of natural gas production activities, particularly the hydraulic fracturing of shale formations. These parties and commenters reason that authorizing exports of LNG to non-FTA countries would induce additional natural gas production in the United States, and that the environmental impacts of the additional natural gas production should be considered as a factor affecting the public interest. (These comments are summarized below.)

Fundamental uncertainties constrain the ability to predict what, if any, domestic natural gas production would be induced by granting any specific authorization or authorizations to export LNG to non-FTA countries. Receiving a non-FTA authorization from DOE does not guarantee that a particular facility would be financed and built; nor does it guarantee that, even if built, market conditions would continue to favor export once the facility is operational. Numerous LNG import facilities were authorized by DOE, received financing, and were built, only to see declining use over the past decade.[1]

Nevertheless, assuming for the purpose of this document that LNG export proposals would result in additional export volumes, DOE believes those LNG export volumes would be offset by some combination of increased domestic production of natural gas (principally from unconventional sources), decreased domestic consumption of natural gas, and an adjustment to the U.S. net trade balance in natural gas with Canada and Mexico.

[1] From 2000 through 2010, more than 40 applications to build new LNG import facilities were submitted to federal agencies. Only eight new facilities were built, and the use of those facilities has declined substantially. In 2004, the United States imported 244 cargoes of LNG at the 4 terminals existing at that time. By comparison, in 2012, only 64 cargoes were imported at 7 of the 12 terminals then in existence. Five of the 12 existing terminals received no cargoes in 2012. *See Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 3282, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (May 17, 2013) at 64 n.79.

The current rapid development of unconventional natural gas resources will likely continue, with or without the export of natural gas. Potential impacts associated with unconventional natural gas will exist whenever it is produced, **just as is the case for** conventional natural gas **production**. Exporting natural gas may accelerate the timing of the development **of** unconventional resources and the associated potential impacts. However, it is not reasonable to assume that unconventional natural gas production and the associated potential impacts will not occur if natural gas exports to non-FTA countries are prohibited.[2]

Accordingly, to provide the public with a more complete understanding of potential impacts, DOE has prepared this discussion of potential environmental issues associated with unconventional gas production in the lower-48 states. By **preparing** this discussion of natural gas production activities, DOE is going beyond what NEPA requires. While DOE has made broad projections about the types of resources from which additional production may come, DOE cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced. Therefore, DOE cannot meaningfully analyze the specific environmental impacts of such production, which are nearly all local or regional in nature. Nor can DOE meaningfully consider alternatives or mitigation measures as they relate to natural gas production, given that DOE's regulatory jurisdiction extends only to the act of exportation. As DOE explained in *Sabine Pass Liquefaction, LLC,* DOE/FE Order No. 2961-A (Aug. 7, 2012), lacking an understanding of where and when additional gas production will arise, the environmental impacts resulting from production activity induced by LNG exports to non-FTA countries are not "reasonably foreseeable" within the meaning of the Council on Environmental Quality's (CEQ) NEPA regulations (40 CFR § 1508.7).

This Addendum is a review of existing literature and is intended to provide information only on the resource areas potentially impacted by unconventional gas production. With the exception of greenhouse gases (GHG) and climate change, potential impacts of expanded natural gas production and transport would be on a local or regional level. Appropriately, these activities are generally regulated on a State and local level. Each locale includes unique conditions, challenges, and environmental resources.

The discussions presented herein are based on existing regulations and best management practices. Over the course of the past decade, regulations have generally become more stringent. It is likely that this trend will continue in the future. Similarly, best management practices continue to evolve and improve through the course of time. It is likely that potential impacts will

[2] In a prescribed natural gas export study performed for DOE's Office of Fossil Energy (*Effect of Increased Natural Gas Exports on Domestic Energy Markets,* January 2012 **)**, the Energy Information Administration (EIA) found that increased natural gas exports would result in increased natural gas production that would satisfy about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, EIA stated that about three-quarters of this increased production would come from shale sources. In addition, EIA projected a decrease in the volume of gas consumed domestically. EIA stated that the electric power sector, by switching to coal and renewable fuels, would account for the majority of this decrease but indicates that there also would be a small reduction in natural gas use in all sectors from efficiency improvements and conservation. EIA states that the projections in the EIA report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used.

be less than represented herein, as regulations and best management practices continue to improve.

Purpose

The purpose of this Addendum is to provide additional information to the public regarding the potential environmental impacts of unconventional natural gas production activities. DOE has received many comments in related proceedings expressing concerns about the potential impacts from increased production of natural gas in the United States, particularly production that involves hydraulic fracturing, or fracking. While not required by NEPA, DOE has prepared this Addendum in an effort to be responsive to the public and provide the best information available.

Public Comments

DOE released a draft of this Addendum for public review and comment from June 4 through July 21, 2014. DOE received 40,745 comments in 18 separate submissions on the draft Addendum and has considered those comments in finalizing this Addendum. The comments received and DOE's responses are described in Appendix B. In this Addendum, bold text and vertical lines in the margin indicate where the Draft Addendum has been revised or supplemented (as exemplified by this paragraph). Deletions are not demarcated.

As part of a broader effort to further inform decisions related to LNG exports, DOE commissioned NERA Economic Consulting to conduct a study in order to gain a better understanding of how U.S. LNG exports could affect the public interest, with an emphasis on the energy and manufacturing sectors. On December 5, 2012, DOE's Office of Fossil Energy (FE) posted the final NERA report into the 15 export application dockets pending at that time, and invited the public to provide comment. Comments received were considered by DOE. Examples of representative comments are as follows:

> "Moving forward with the natural gas industry's plan to export this fuel would create problems nationwide, especially an increase in hydraulic fracturing or 'fracking' needed to supply this gas. While the gas industry profits, local communities are often left to deal with such consequences as poisoned drinking water, devastated coasts, and extreme air pollution. The fracking process is also a major source of global warming pollution, and the massive super-cooling process needed to create liquefied natural gas for export uses an incredible amount of energy, creating even more climate-disrupting pollution."

> "We pointed to putting water resources at risk, infrastructural degradation, as well as pollution from noise, light, and volatile emissions."

> "Getting the LNG to the coasts or rivers will do untold damage to the environment from laying the pipeline to destruction of a fragile coastline, particularly in Oregon."

> "Friends and neighbors of mine have suffered damage to their water supply and home values due to the extraction of natural gas. There are a few who benefit economically at the expense of many. In addition, methane is released into the atmosphere as a result of this process. Methane is a greenhouse gas far more dangerous than carbon. We should be moving full bore into a 21st century energy policy based on solar, wind, geothermal and other safe technologies not continuing a 19th century plan that depletes our fresh water supply."

> "Water withdrawals impact streams, aquatic life, wetlands and riparian areas. Water wells, ground water, ponds and the land itself have been contaminated. Forests may never recover from their fragmentation, loss of large trees (and their carbon sequestration), loss of animal habitat, the introduction of invasive species and the loss of biodiversity."

> "Shale gas development and its infrastructure induces or contributes to deforestation, land compaction, wetlands destruction, and increased earthquake potential, as well as creates increased potential for flooding and erosion of public and private lands that must be responded to and addressed by homeowners, communities and local, state and federal governments."

> "Different from other industrial processes hydraulic fracturing may (be) done in the midst of communities, forests, and ecologically sensitive areas."

> "The introduction of methane and other gases into our environment are a threat to our air quality and climate."

As demonstrated by this cross-section of comments, environmental concerns associated with unconventional natural gas production are of public interest. Recurring topics include water quality and quantity, air quality, climate change/ GHGs, land use, and induced seismicity. These comments and all others are available at: http://energy.gov/fe/services/natural-gas-regulation/lng-export-study.

Unconventional Natural Gas Production Activities in the United States

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial, and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

In August 2011, the DOE Office of Fossil Energy (FE) commissioned a study by the U.S. Energy Information Administration (EIA) that explored some of these possibilities. EIA's report, issued January 2012, modeled a variety of U.S. LNG export scenarios spanning a 25-year period. As a cautionary note, EIA warned that "projections of energy markets over a 25-year period are highly uncertain and subject to many events that cannot be foreseen, such as supply disruptions, policy changes, and technological breakthroughs" (EIA 2012). With these caveats, EIA projected that, across all cases, an average of 63 percent of increased export volumes would be accounted for by increased domestic production. Of that 63 percent, EIA projected that 93 percent would come from unconventional sources (72 percent shale gas, 13 percent tight gas, and 8 percent coalbed methane [CBM]) (EIA 2012).

Based on EIA's latest forecast (2014), natural gas production in the United States from all sources is expected to increase by 56 percent between 2012 and 2040, when production reaches 37.5trillion standard cubic feet (scf). This is an increase from 24.1 trillion scf in 2012 (Ibid.). As illustrated in Figure 1, this increase will primarily come from onshore unconventional plays, particularly shale plays.

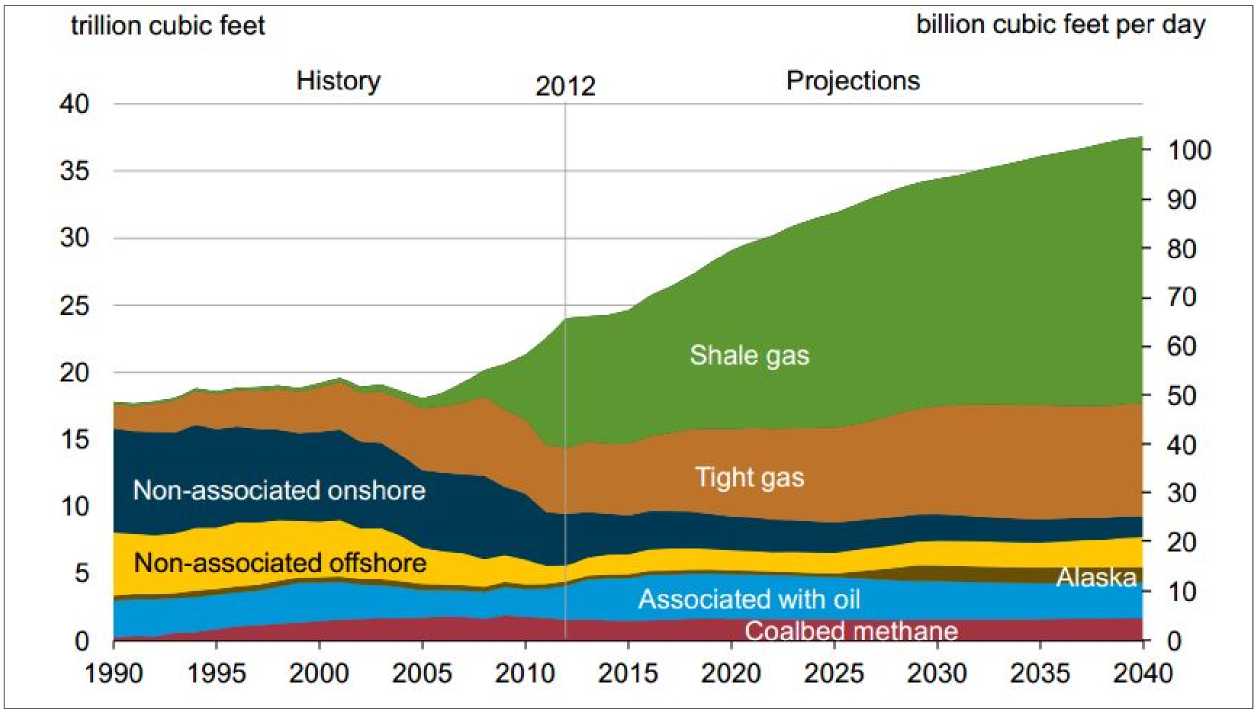


Figure 1: Natural Gas Production by Source (1990-2040) in Trillion Cubic Feet
(EIA, 2014b. AEO. Slide 8)

Natural gas production in the United States from unconventional sources, as indicated in Table 1, is expected to increase by 104 percent for shale plays, 73 percent for tight gas sands, and 8 percent for CBM by 2040, compared to the production in 2012 (EIA, 2014). By 2040, shale gas is expected to account for approximately 53 percent of the total natural gas production in the United States, compared to 40 percent in 2012 (Ibid.). For unconventional resources in aggregate, this is an increase from 16.2 trillion scf in 2012 to a production rate of 29.9 trillion scf in 2040 (Ibid.). EIA, which tabulates summary statistics for U.S. energy sources and makes forecasts, categorizes unconventional resources as: (1) natural gas from shales, (2) methane from coalbeds, and (3) natural gas from tight formations (mostly sandstones, chalks, siltstones).

Table 1: U.S. Natural Gas Production by Source (Trillion scf)

Year	Alaska	Coalbed Methane	Lower 48 Offshore	Lower 48 Onshore Conventional	Tight Sands	Shales	Total
2012	0.33	1.58	1.66	5.92[a]	4.86	9.72	24.06
2040	1.17	1.71	2.95	3.49[a]	8.41	19.82	37.54
EIA, 2014. Annual Energy Outlook 2014. a. Sum of “Associated-Dissolved” and “Other” gas.							

Shale gas is present across much of the lower 48 States. Figure 2 shows the approximate locations of current producing gas shales and prospective shales. Most of these plays co-produce some amount of heavier hydrocarbons in some areas. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different, and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

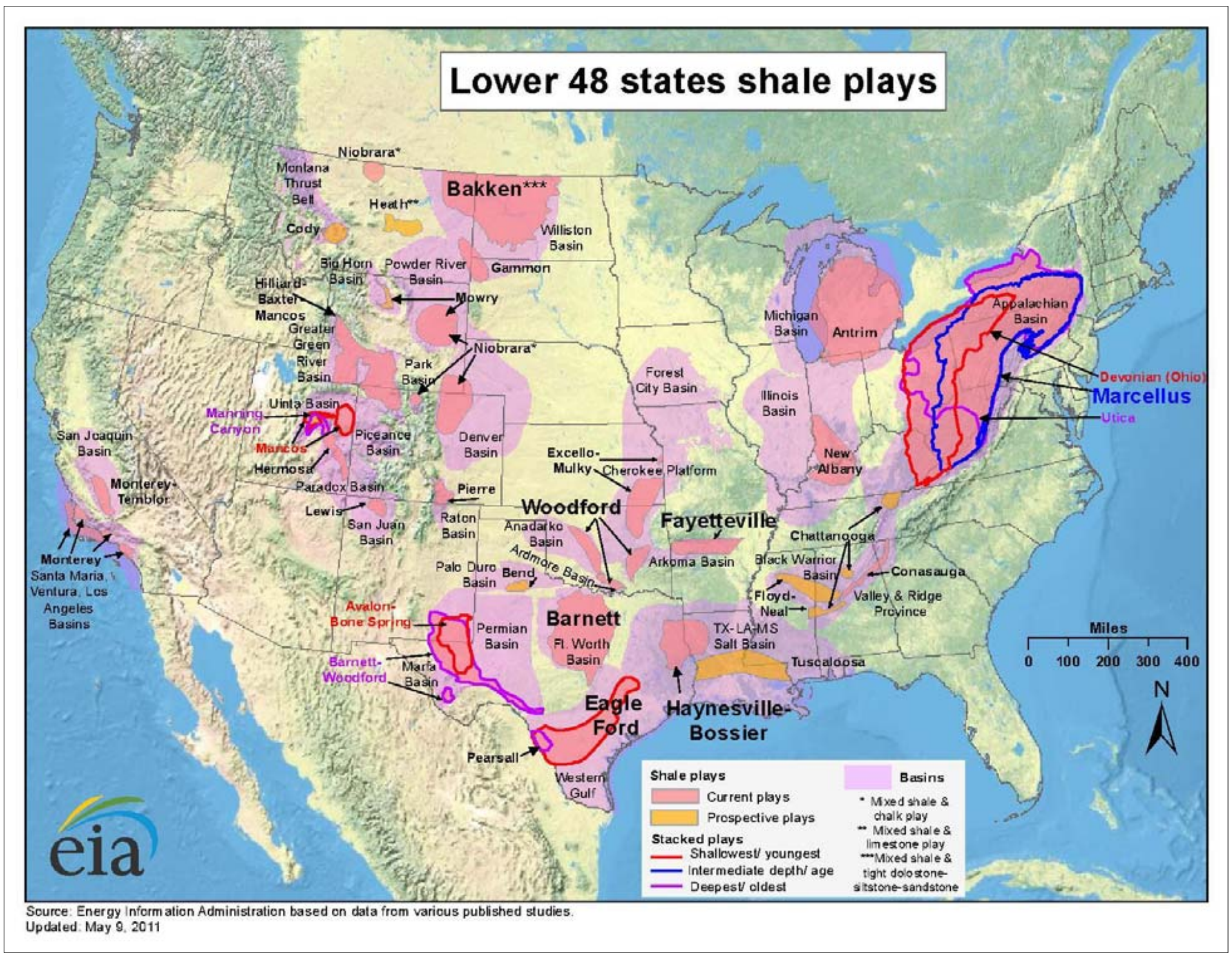


Figure 2: Approximate Locations of Current Producing Gas Shales and Prospective Shales

Gas-bearing low-permeability sandstones, chalks and siltstones and tight sand deposits are scattered across the lower 48 states wherever deep sedimentary basins are found (see Figure 3). The Rocky Mountain region has been a major development area for this resource. Development of these resources utilizes the same technologies currently applied to shale gas.

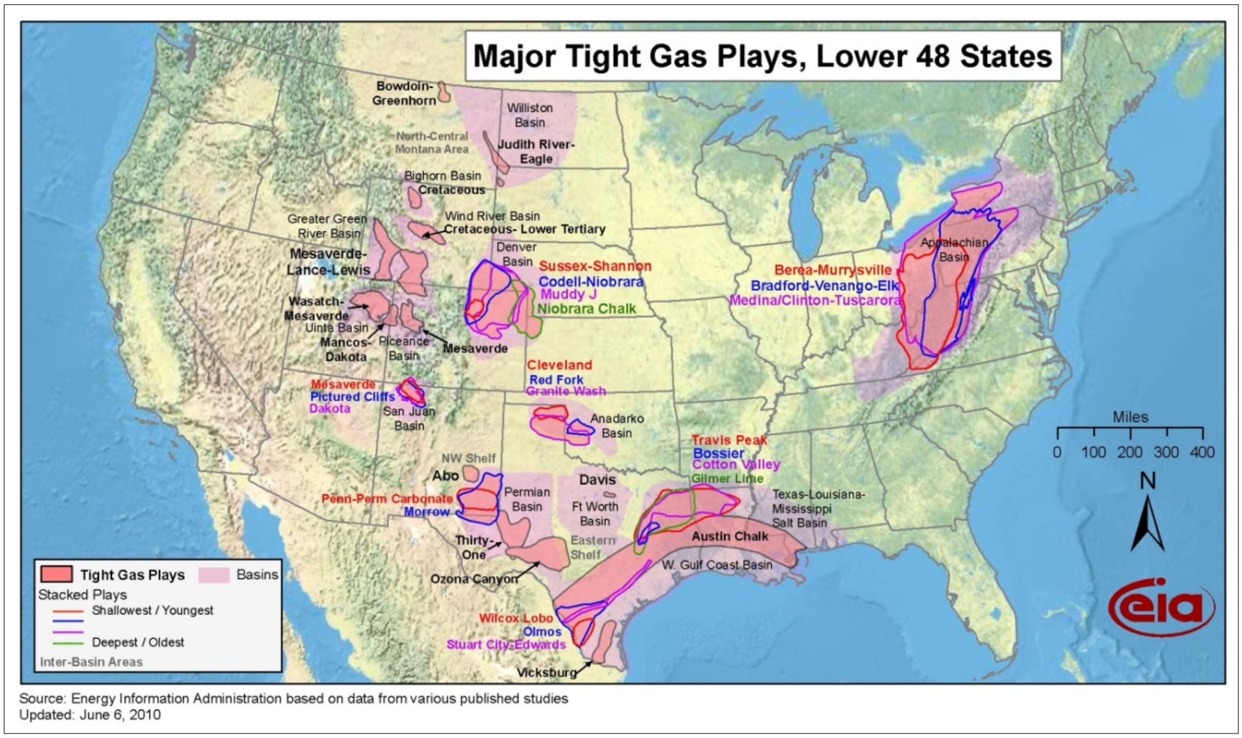


Figure 3: Location of Currently Active Areas for Tight Sand Development and Production

Methane is a natural constituent of coalbeds, resulting from the thermal and bacterial breakdown of the coal. It can be recovered using lower-cost vertical wells to remove water from the coal layers and then to recover the methane. Locations of productive coalbeds (Figure 4) nearly coincide with the locations of some tight sands and gas-bearing shales, but do not extend into the Gulf of Mexico coastal area or California.

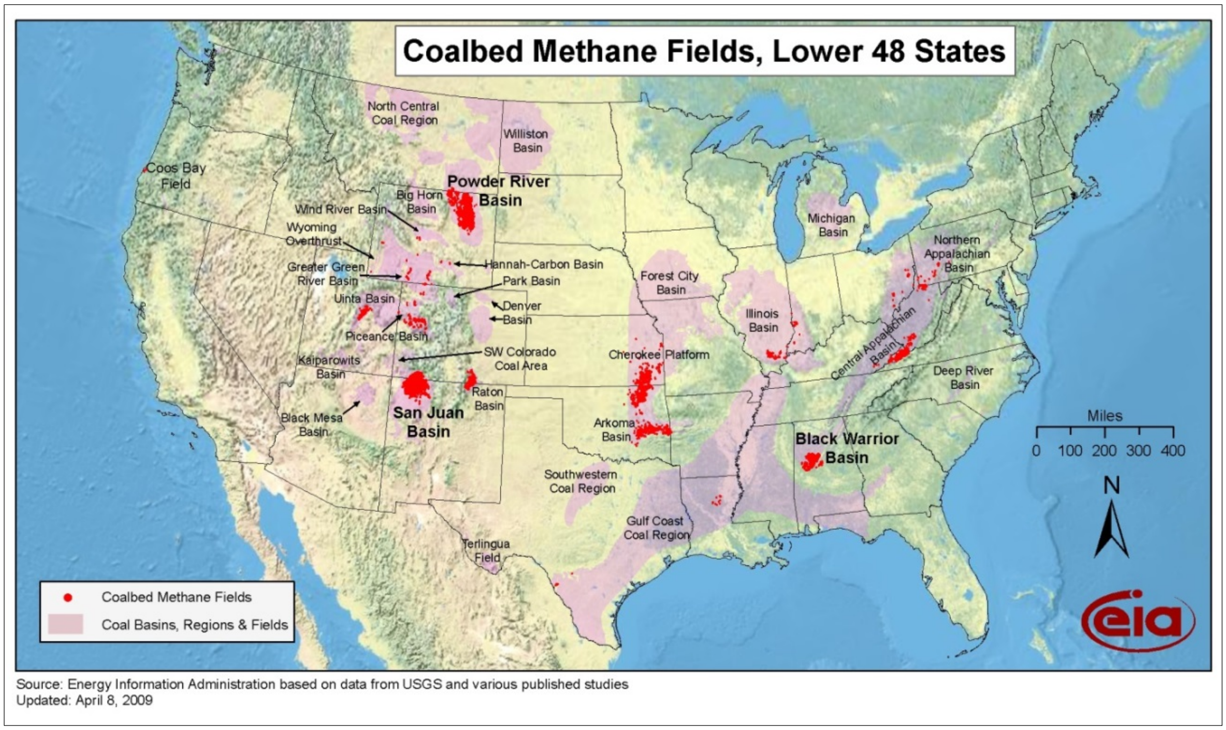


Figure 4: Location of Currently Active Areas for Coalbed Development and Production

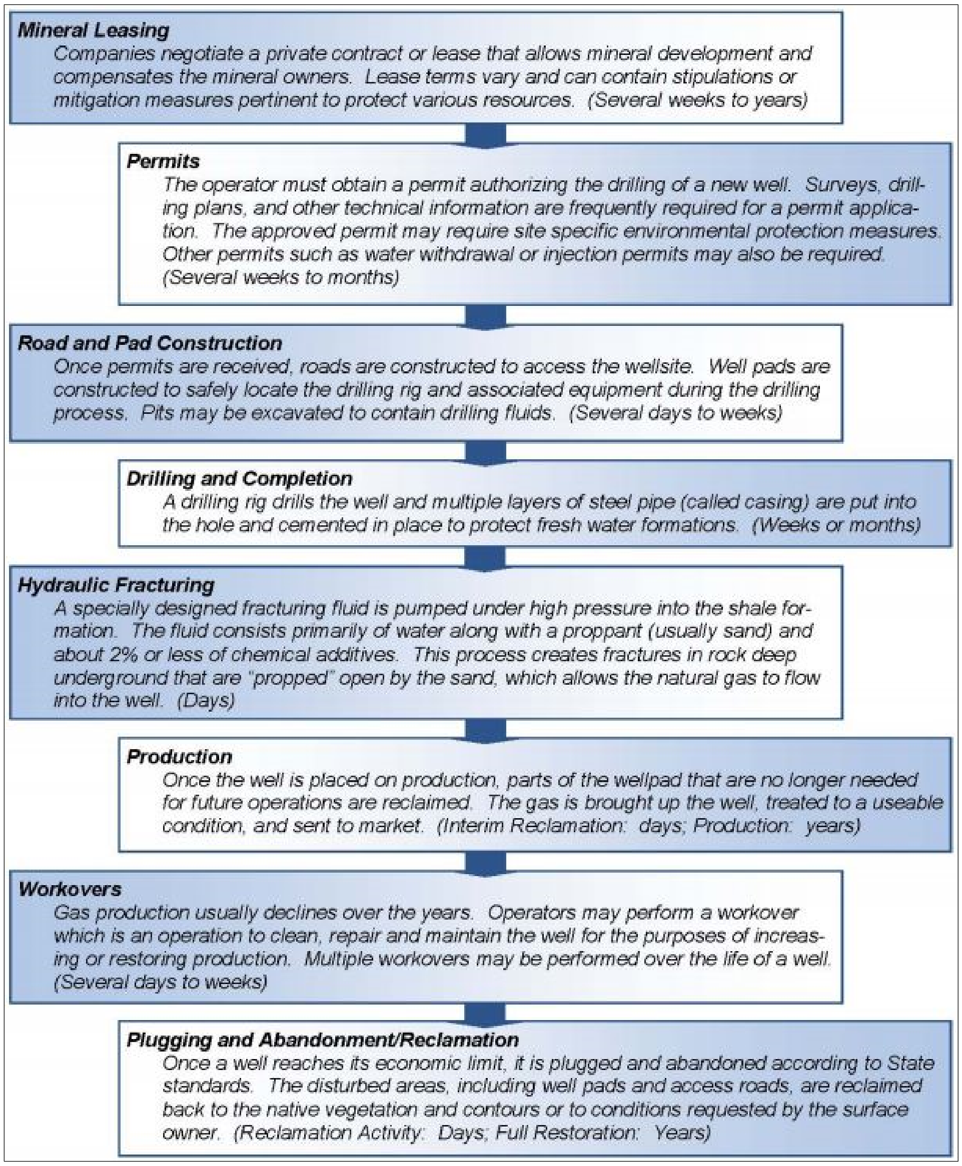


Figure 5: General Timeline Associated with Phases of Shale Gas Development
(*Modern Shale Gas Development in the United States: A Primer* [p. 44, exhibit 28])

A key element in the emergence of unconventional gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment, as well as on the quality of life in the communities in which shale gas production is located. For additional background information regarding the activities associated with shale gas development, the reader should refer to DOE's "Modern Shale Gas Development in the United States: A Primer" (http://energy.gov/fe/downloads/modern-shale-gas-development-united-states-primer).

Water Resources

Issues around water resources typically garner the most public attention with regard to unconventional natural gas production. The subject of hydraulic fracturing, or fracking, is often the focus of this discussion. As with the other resource areas, water considerations are unique for each location and may vary widely from well to well. Nonetheless, the two most fundamental concerns are water quantity and water quality.

Water Quantity

The availability of water varies widely across the United States. In general, water is less abundant in the drier climates of the west. The availability of fresh water in some areas is limited seasonally and may be exacerbated by drought conditions for extended periods. In the east, water is generally more abundant, especially when considered from a regional perspective. However, a regional perspective may not reveal potential impacts that could occur at more localized levels.

In 2011, Grand Prairie, Texas, restricted the use of municipal water for hydraulic fracturing. Similarly, operators in Kansas, Texas, Pennsylvania, and North Dakota faced higher water costs and denied access for at least six weeks due to drought conditions (DOE 2013). While water usage may not be an important factor for operations with facilities near the mouth of large watersheds, other operations may be limited by the availability of fresh water. Moreover, operations in these areas may have a higher potential to impact the human environment as the demand on this resource increases.

Unconventional natural gas production and transport requires water usage at various stages of development. For example, water may be used for:

- Controlling dust and fugitive emissions during times of heavy truck traffic.
- Hydrostatic pipeline testing.
- Making concrete.
- Make-up water for drilling.
- Hydraulic fracturing.

According to NETL 2014, hydraulic fracturing makes up approximately 89 percent of the water used by the shale gas industry. Drilling activities use another 10 percent and all other uses make up the final 1 percent. The water consumed is generally a function of:

- Geology – maturity of the shale and formation depth, thickness, and lateral extent.
- Technology – horizontal and vertical drilling, water recycling.
- Operations – operator decisions, availability of nearby fresh water.
- Regulatory – requirements for use and treatment of water.

Estimates from various sources cited by NETL 2014 put water usage at 1 to 6 million gallons per well for hydraulic fracturing activities each time a well is fracked. Shale gas wells can use 65,000 to 1 million gallons per well for drilling activities. While shale gas wells may be hydraulically fractured multiple times, the water usage will generally be confined to a discrete time period. Except during drilling and hydraulic fracturing, water usage is generally not a critical issue during phases of unconventional natural gas production. Shale gas wells may operate over the course of many years, while the drilling and hydraulic fracturing phases may take place over a matter of months.

To provide some context to the amount of water used by unconventional gas production, Table 2 found in NETL 2014 is included below. This table provides a comparison of water used for various energy sources and is presented in water intensity, or gallons of water used per million British thermal units (Btu).

Table 2: Water Intensity

Energy Source	Range in Water Intensity (gallons/mmBtu)
Conventional Natural Gas	~0
Shale Gas	0.6 – 1.8
Coal (no slurry transport)	2 – 8
Nuclear (uranium at plant)	8 – 14
Conventional Oil	1.4 – 62
Oil Shale Petroleum (mining)	7.2 – 38
Oil Sands Petroleum (*in situ*)	9.4 - 16
Synfuel (coal gasification)	11 - 26
Coal (slurry transport)	13 – 32
Oil Sands Petroleum (mining)	14 - 33
Synfuel (coal Fischer-Tropsch)	41 - 60
Enhanced Oil Recovery	21 – 2,500
Fuel Ethanol (irrigated corn)	2,500 – 29,000
Biodiesel (irrigated soy)	13,800 – 60,000

Despite the relatively small water intensity of shale gas production, water usage has the potential to impact specific areas. The potential varies from region to region, and even well to well. The context of water usage in the region must also be considered. For example, the Barnett Shale underlies the Dallas-Fort Worth metropolitan area. In this region, more than 80 percent of the water goes to public supplies. In the Marcellus Shale region, more than 70 percent of the water is used for power generation, and in the Fayetteville Shale region, more than 60 percent of the water is used for irrigation. Clearly, regions have very different water-use patterns and needs. Shale gas production is most likely to have some impact on water quantity in arid regions, such as the Eagle Ford, where shale gas production might be three to six percent of the region’s water demand. In most cases, shale gas production uses less than one percent of the total water demand.

Table 3: Water Usage in Shale Gas Regions

Play	Public Supply (%)	Industry & Mining (%)	Power Generation (%)	Irrigation (%)	Livestock (%)	Shale Gas (%)	Total Water Use (Bgals/yr)*
Barnett1	82.7	4.5	3.7	6.3	2.3	0.4	133.8
Eagle Ford[2]	17	4	5	66	4	3 – 6	64.8
Fayetteville[1]	2.3	1.1	33.3	62.9	0.3	0.1	378
Haynesville[1]	45.9	27.2	13.5	8.5	4.0	0.8	90.3
Marcellus[1]	12.0	16.1	71.7	0.1	0.01	0.06	3,570
Niobrara[3]	8	4	6	82		0.01	1,280

[*Bgal/yr = billion gallons per year]
Total water use for four major shale plays ([1]Arthur, 2009; [2]Chesapeake Energy, 2012a; [3]Chesapeake Energy)

In addition to shale gas production, CBM formations may also impact water resources. As these formations are dewatered to lower reservoir pressures and extract the methane in the coal, the groundwater table in these areas may be lowered and may reduce availability for other uses (NETL, 2014).

The potential impacts may include constraints on water usage for all activities in an area. In times of drought and low water supply, water usage is generally managed at a local level. In some areas, water availability is a concern even without the presence of unconventional natural gas production. Unconventional natural gas producers commonly withdraw water from local surface water and groundwater sources.

Withdrawals from surface water of limited capacity can impact the designated uses of the stream or river. Reduced downstream flows can alter the habitat in many ways. Lower flow rates generally leave smaller waterways susceptible to higher temperatures and less turbulence. This could lead to lower availability of dissolved oxygen in the stream. Some aquatic species require certain flow conditions and water temperatures for reproduction and development. Similarly, riparian vegetation and local wildlife may be negatively impacted.

Withdrawals from groundwater could also have potentially adverse impacts. Some smaller, shallower aquifers may be depleted or reduced **over time by cumulative withdrawals from all water users**. Such reductions may render these aquifers unavailable for residential drinking water wells or impact the hydraulic connections between these aquifers and local surface waters. These aquifers may be an important source of cool water in the local ecosystem, particularly in the warmest portion of the year. Deeper aquifers may also be impacted by significant withdrawals, as recharge from precipitation may take an extended period of time.

The impacts of water usage are a local issue. The degree of impact depends on the local climate, recent weather patterns, existing water use rates, seasonal fluctuations, and other factors. In many unconventional natural gas production areas, the timing of water usage may be the most critical factor to mitigating potential impacts. The severity of impacts may be exacerbated by prolonged drought conditions, shifts in land use, and expanding population centers. Impacts are most likely to be more prevalent in the arid western regions of the United States.

Water Quality

Water quality concerns may have received more attention than any other aspect of unconventional natural gas production. This stands to reason as water quality is vital to health, safety, and recreation. Further, the general public is still learning about aspects of drilling and hydraulic fracturing. **Recent studies have further investigated upward migration of hydraulic fracturing fluids (Flewelling & Sharma 2013).**

Construction

Water quality impacts generally begin with the construction of access roads and earth-disturbing activities. Storm water associated with these features is generally addressed using best management practices. In some cases, these discharges may be regulated by permit (the National Pollutant Discharge Elimination System [NPDES]). The goal is to reduce erosion and prevent sedimentation in local waterways. These discharges are long established and well understood. Impacts from these features are most likely to occur in areas with steep slopes and highly erodible soils. Nonetheless, when standard industry practices and preventative measures are deployed, only minor impacts are likely to result. Care must be exercised when work is planned in sensitive watersheds or areas of special concern. Similarly, linear features, such as roadways and pipelines, may cross wetlands or surface waters. Again, regulatory programs exist to protect water quality through standard industry practices and preventative measures. Potential impacts from construction activities are typically increases in turbidity and sedimentation in surface waters. Failure to employ preventative measures could result in negative impacts to aquatic life, critical habitat, and downstream water uses. The quality of groundwater could be impacted by construction activities as well. The most likely impacts would come from spills and leakage of fuels and fluids for the construction equipment. Again, best management practices associated with spill prevention, containment, and monitoring programs are well established.

The Clean Water Act (CWA) (Clean Water Act, 33USC § 1251 et seq.) and the Safe Drinking Water Act (SDWA) (Safe Drinking Water Act, 42 USC 300f et seq., 6939b; 15 USC 1261 et seq.) are Federal laws applicable to the regulation of shale gas development. Specifically, CWA regulates the surface discharge of flow back and other drilling water(s), stream crossings, fills into waters of the United States (including wetlands), and storm water runoff. The SWDA regulates the underground injection of wastewaters and is therefore an important consideration in hydraulic fracturing and drilling operations. The major portions of these two laws are generally administered and enforced at the State level.

Drilling

Drilling in unconventional natural gas regions requires water for purposes of removing cuttings from the borehole, cooling and lubricating the drill bit, stabilizing the wellbore, and controlling borehole fluid pressures. Drilling during unconventional natural gas production often requires penetrating shallower fresh water aquifers. Multiple layers of protective steel casing and cement are designed to protect fresh water aquifers. The casing is set while the well is being drilled and, before drilling any deeper, the new casing is cemented to seal the gap between the casing and the formations being drilled through. Each string of casing then serves to protect the subsurface environment by separating the drilling fluids inside and the formation fluids outside of the casing. Operators can check and repair the integrity of the casing and the cement bonding during and after drilling (DOE, 2009). The formations themselves also act as barriers and seals.

Many of the unconventional natural gas formations are thousands of feet below aquifers associated with public water supply or surface hydrologic connection. Nonetheless, failure of a casing or cement bond could cause contamination of an aquifer. Similarly, drilling can create connections with existing fractures or faults, or improperly plugged and abandoned wells, allowing contaminants to migrate through the subsurface. Potential impacts that may result due to such failures might include the migration of drilling fluids into groundwater supplies and surface waters.

Hydraulic Fracturing Fluids

Hydraulic fracturing is generally used to increase the productivity of a well. In addition to increasing permeability and fluid flow rates, fracturing can increase the amount of contact between the well and the formation and the area of drainage within the formation. This process can be used to manage pressure differences between the well and the target formation.

Water typically makes up more than 98 percent of the fluids used for hydraulic fracturing. In addition to sand, it is common for several chemical additives to be included in small quantities, depending on the local geologic and hydrologic conditions. Additives may vary among operators, but a representative list is presented in Table 4.

Table 4: Representative List of Fracking Fluids

Additive	Compound(s)	Purpose
Dilute acid	Hydrochloric or muriatic acid	Dissolve minerals and initiate cracks in rock.
Friction Reducer	Polyacrylamide or Mineral Oil	Minimizes friction between fluid and pipe.
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid.
KCl	Potassium Chloride	Creates a brine carrier fluid.
Gelling Agent	Guar gum or hydroxyethyl cellulose	Thickens water to suspend sand.
Scale inhibitor	Ethylene glycol	Prevents scale deposits in pipe.
pH Adjusting agent	Sodium or potassium bicarbonate	Maintains effectiveness of other components such as crosslinkers.
Breaker	Ammonium persulfate	Allows a delayed breakdown of the gel polymer chains.
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases.
Iron Control	Citric Acid	Prevents precipitation of metal oxides.
Corrosion inhibitor	N, n-dimethyl formamide	Prevents corrosion of pipe.

Additive	Compound(s)	Purpose
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts.
Oxygen Scavenger	Ammonium bisulfate	Removes oxygen from water to protect pipe from corrosion.
Clay control	Choline chloride, sodium chloride	Minimizes permeability impairment.
Water and proppant	Proppant: silica or quartz	Allows fractures to remain open.

Additional information on hydraulic fracturing fluids and methods is available in the DOE shale gas primer and on the FracFocus website (www.fracfocus.org), which provides public information via a national hydraulic fracturing chemical registry. The FracFocus website is managed by the Ground Water Protection Council (GWPC) and Interstate Oil and Gas Compact Commission. A large fraction of the reporting wells in FracFocus claim at least one trade secret exemption. The DOE Secretary of Energy Advisory Board (2011) favors full disclosure of all known constituents added to fracturing fluids with few, if any exceptions.

States have varying requirements for the disclosure of hydraulic fracturing fluids. Table 5 illustrates the differences in eight states with shale gas production. **States have continued to be active in addressing disclosure of the constituents of fracturing fluids. The following states have all adopted regulations concerning disclosure of the make-up of fracturing fluids since December 2011: Alabama, Alaska, California, Idaho, Indiana, Kansas, Michigan, Mississippi, North Carolina, Ohio, Oklahoma, South Dakota, Tennessee, Utah, and West Virginia. Pennsylvania is in the process of updating its disclosure regulations.**

Table 5: U.S. Oil- and Gas-Producing State-by-State Comparison of Hydraulic Fracturing Chemical Disclosure Regulations (KPMG, 2012)

	AR	CO	LA	MT	NM	ND	PA	TX	WY
Base Fluid Type	Yes	Yes	Yes	Yes	Yes (by reference to FracFocus template)	Yes	No	Yes	Yes
Base Fluid Volume	Yes	Yes	Yes	Yes	Yes (by reference to FracFocus template)	Yes	Yes	Yes	Yes
Additive Trade Name	Yes	Yes	Yes	Yes (trade secret only[1])	Yes (by reference to FracFocus template)	Yes	No	Yes	Yes
Additive Vendor	Yes	Yes	Yes	No	Yes (by reference to FracFocus template)	Yes	No	Yes	No
Additive Function	Yes	Yes	Yes	Yes	Yes (by reference to FracFocus template)	Yes	Yes	Yes	No
Additive Concentration	Yes	No	No	Yes	No	Yes	Yes	Yes	Yes
Chemical Names	Yes (unless trade secret)	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes	Yes (if subject to 29 CFR 1910.1200)	Yes	Yes

	AR	CO	LA	MT	NM	ND	PA	TX	WY
Chemical Concentration	No	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes	Yes (if subject to 29 CFR 1910.1200)	Yes (if subject to 29 CFR 1910.1200)	Yes
Chemical Abstract Services (CAS) Number	Yes (unless trade secret)	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes (unless trade secret)	Yes (if subject to 29 CFR 1910.1200 and unless trade secret)	Yes	Yes (if subject to 29 CFR 1910.1200)	Yes	No
Chemical Family CAS Number[2]	Yes (trade secret only)	Yes (trade secret only)	Yes (trade secret only)	Yes (trade secret only)	No	No	No	Yes (trade secret only)	No
Effective Date	January 16, 2011	April 1, 2012	October 20, 2011	August 27, 2011	February 15, 2012	Rulemaking in progress	February 6, 2011	February 1, 2012	October 17, 2010

[1] Montana exempts trade secrets from disclosure, but an operator may identify a trade secret chemical by trade name.

[2] Some states allow operators to report trade secret chemicals by chemical family.

Potential impacts associated with hydraulic fracturing fluids could come from spills and leakages during transport to the well pad, storage on the well pad, or during the chemical mixing process. Spills could contaminate surface water or groundwater if not appropriately controlled and remediated. Chemical additives may also contaminate groundwater should the integrity of the casing or cement seal be compromised. Hydraulic fracturing may also mobilize naturally occurring pollutants in the formation and introduce them to other water resources through the same mechanisms. Similarly, fracture growth may result when fractures propagate outside of the production zone. If a connection is established, contaminants may reach aquifers used for water supply if inadequate protections are not in place.

Flowback and Produced Waters

Produced water recovered **during flowback operations** from a hydraulic fractured well is **returned to the surface and** typically stored onsite in open pits or storage tanks **until reuse or disposal occurs**. Estimates on the percentage of original **hydraulic fracturing** fluids recovered vary widely, and may be from 20 to 80 percent (NETL 2014). **Produced** water **recovered during flowback operations** may contain elevated levels (as compared to State and Federal water quality standards) of total dissolved solids (TDS), salts, metals, organics, naturally occurring radioactive materials (NORM), and specific chemicals used in the hydraulic fracturing process.

Similarly, after natural gas production begins, formational fluids called produced waters are brought to the surface. These fluids are naturally found in oil- and gas-bearing formations and typically contain a variety of hydrocarbons and brines. The longer the fluids are in contact with shale, the more likely they are to exhibit higher concentrations of TDS, metals, and naturally occurring radioactivity. Produced water volumes and characteristics may vary throughout the producing lifetime of a formation.

The quality of recovered water is generally poor, and finding uses for this water is difficult without treatment. Conventional water treatment methods, such as physical and biological treatment, are generally not effective for recovered water. Elevated levels of TDS and salts form a complex matrix that can require reverse osmosis and ion exchange treatment.

Development companies have found more methods of recycling water and fluids to reduce final disposal quantities. Properly treating wastewater and fluids is elemental to protecting water quality and reducing impacts to water resources. Wastewater treatment is generally regulated under the NPDES Program for surface water discharges and under the **Underground Injection Control (**UIC**)** Program for subsurface discharge. **API has developed a series of industry standards (HF Series) to reduce water impacts from unconventional gas well developments.**

Operators tend to use a pollution prevention approach. This approach is typically:

- Minimization – mechanical and chemical alternatives to water use.
- Recycle/Re-use – reinjection for enhanced recovery or continued hydraulic fracturing, re-use for agriculture and industry, and treatment for drinking water.
- Disposal **–** underground injection, evaporation, or surface water discharge.

Potential impacts associated with recovered water include potential contamination of surface water and groundwater. The risks include spills, tank ruptures, blowouts, equipment and impoundment failure, overfills, vandalism, accidents, ground fires, operational errors, and contaminated storm water. The severity of potential impact would correlate to the volume and nature of the contamination, as well as the quality and use of the surface water or groundwater.

Conclusions

Water resources are important in all parts of the United States. Some locales already have stresses on the quantity and/or quality of water. Planning and monitoring at the local level are necessary to effectively manage water resources. Water demands in areas of unconventional natural gas development will increase and may need to be balanced with other water uses. This balance may become more critical during seasonal or prolonged drought conditions. Water quality may be impacted through additional discharges of pollutants to surface and groundwater. However, specific impacts to water resources cannot be predicted even on a regional level for the reasons described above.

Unconventional natural gas production, when conforming to regulatory requirements, implementing best management practices, and administering pollution prevention concepts, may have temporary, minor impacts to water resources. Conversely, like many other industries, improper techniques, irresponsible management, inadequately trained staff, or site-specific events outside of an operator's control could lead to significant impacts on local water resources.

Air Quality

The natural gas industry uses a variety of equipment, processes, and operations to develop natural gas resources, produce natural gas, and deliver natural gas to market. These activities and facilities include well pad and access road development, drilling, and completing wells; gas cleaning, dehydrating, and compressing facilities; storage tanks; and constructing and operating natural gas-gathering lines transmission and distribution pipelines. Many of these activities are often collectively referred to as upstream activities and produce air emissions that may contribute to air pollution in the area where they occur.

The oil and natural gas industry is the largest industrial source of volatile organic compound (VOC) emissions according to the U.S. Environmental Protection Agency (EPA). EPA estimated 2.2 million tons of VOC emissions from the oil and natural gas industry in 2008 **(EPA 2014b). EPA estimates the nationwide area source VOC emissions from oil & gas operations to be about 2.7 million tons per year (TPY), which represents about 21 percent of nationwide VOC emissions. For oil and gas operations non-point sources, three sources account for close to 70 percent of oil and gas operations non-point emissions, including: condensate tanks (~16 percent); crude oil tanks (more than 28 percent); and pneumatic devices (more than 24 percent).**

VOC and other pollutants **also** contribute to the formation of ground-level ozone. Ozone exposure is linked to a wide range of health effects, including aggravated asthma and increased emergency room visits and hospital admissions. The oil and natural gas industry is also a significant source of methane (CH_4) emissions. Methane is a greenhouse gas (GHG) more than 20 times as potent as carbon dioxide (CO_2) (EPA, 2014) (see GHG section for discussion). Oil and gas industry air emissions also include hazardous air pollutants (HAPs, or air toxics), as well as nitrogen oxides (NO_X), particulate matter (PM), and sulfur dioxide (SO_2) from the combustion of fossil fuels (EPA, 2014a**; EPA 2014d**).

Regulations

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for the six criteria pollutants – carbon monoxide (CO), nitrogen dioxide (NO_2), PM, ozone, sulfur dioxide (SO_2), and lead. The law also requires EPA to periodically review the standards and revise them if appropriate to ensure they continue to provide the requisite amount of health and environmental protection and to update those standards as necessary. The agency must also conduct technology reviews of these standards every eight years. Areas that do not meet the NAAQS are referred to as nonattainment areas. States must develop State Implementation Plans (SIPs) to bring nonattainment areas into compliance with the standards.

EPA also sets new source performance standards (NSPS) for industrial categories that cause, or significantly contribute to, air pollution that may endanger public health or welfare. The existing NSPS for VOCs and SO_2 were issued in 1985. EPA must also set standards for emissions of air toxics, also called HAPs. Air toxics are pollutants known or suspected of causing cancer and other serious health effects. EPA's existing air toxics standards for oil and natural gas production, as well as the standards for natural gas transmission and storage, were issued in 1999.

On April 17, 2012, EPA issued new regulations intended to reduce harmful air pollution from the oil and natural gas industry. The final rules include the first Federal air standards for hydraulically fractured natural gas wells. The rules also identify requirements for several other sources of air pollution in the oil and gas industry not currently regulated at the Federal level. Key changes to the NSPS rules for VOCs will be applied in two phases and is expected to ultimately yield a nearly 95 percent reduction in VOCs emitted from the estimated more than 11,000 new or reworked hydraulically fractured gas wells each year. This would be accomplished primarily through the use of the process known as reduced emissions completion (REC), or green completion. The REC process can greatly reduce the quantity of natural gas that would otherwise be vented or flared.

Figure 6: Flaring a Well in Pennsylvania
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Green completions use special portable equipment to separate the gas from the solids (e.g., sand) and liquids (e.g., water and hydrocarbons) from the flowback that comes from wells being prepared for production. The hydrocarbons are then treated and used locally to power equipment or delivered to the sales pipeline. Some states, such as Wyoming and Colorado, already require green completions, as do some cities, including Fort Worth and Southlake, Texas. Additionally, EPA's Natural Gas STAR Program reports that a number of companies are using green completions voluntarily (EPA 2011).

The anticipated VOC emission reductions from wells, combined with the reductions from storage tanks and other equipment, are expected to help reduce the formation of ground-level ozone in areas where oil and gas production occurs. In addition, the reductions would yield a significant co-benefit by reducing CH_4 emissions from newly developed and modified wells. Methane, the primary constituent of natural gas, is a potent GHG (more than 20 times as potent as CO_2 when emitted directly to the atmosphere). Oil and natural gas production and processing accounts for nearly 40 percent of all U.S. CH_4 emissions, making the industry the Nation's single largest CH_4 source. The final rules also would protect against potential cancer risks from emissions of several air toxics, including benzene.

EPA estimates the following combined annual emission reductions after full implementation of the rules in 2015:

- VOCs: 190,000 to 290,000 tons (Note: DOE estimates 7.6 to 11.6 percent of 2013 inventory).
- Air Toxics: 12,000 to 20,000 tons.
- Methane: 1.0 to 1.7 million short tons (about 19 to 33 million tonnes of CO_2 equivalents [CO_2e]) (Note: DOE estimates 15 to 25 percent of 2012 inventory).

On August 2, 2013, EPA updated its 2012 performance standards for oil and natural gas to address VOC emissions from storage tanks used by the crude oil and natural gas production industry. The updates will ensure the storage tanks likely to have the highest emissions are controlled first, while providing tank owners and operators time to purchase and install VOC controls. The amendments reflect recent information showing that more storage tanks will be coming online than the agency originally estimated. The new rule applies to storage tanks constructed after August 23, 2011, that have potential VOC emissions of six or more tons per year, and are used to store crude oil, condensate, or produced water (EPA, 2014b).

Air regulations and resulting air quality standards are implemented at the state level, provided EPA has approved the state program. States must prove that their respective programs can successfully implement the federal requirements. Some states directly adopt federal regulations and standards, but can also make the standards more stringent. **For example, in 2013 Pennsylvania revised the requirements associated with its General Permit for Air Pollution Control in Natural Gas Compression and/or Processing Facilities (GP-5), making it more stringent than some federal standards.**

On April 15, 2014, EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector. These emissions sources include completions and ongoing production of hydraulically fractured oil wells, compressors, pneumatic valves, liquid unloading, and leaks. The white papers focus on technical issues covering emissions and mitigation techniques that target methane and VOCs. As noted in the Obama Administration's Strategy to Reduce Methane Emissions (March 2014; http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf), EPA will use the papers, along with input from peer reviewers and the public, to determine how to best pursue additional reductions from these sources, possibly including the development of additional regulations (EPA, 2014j).

Emission Components and Sources

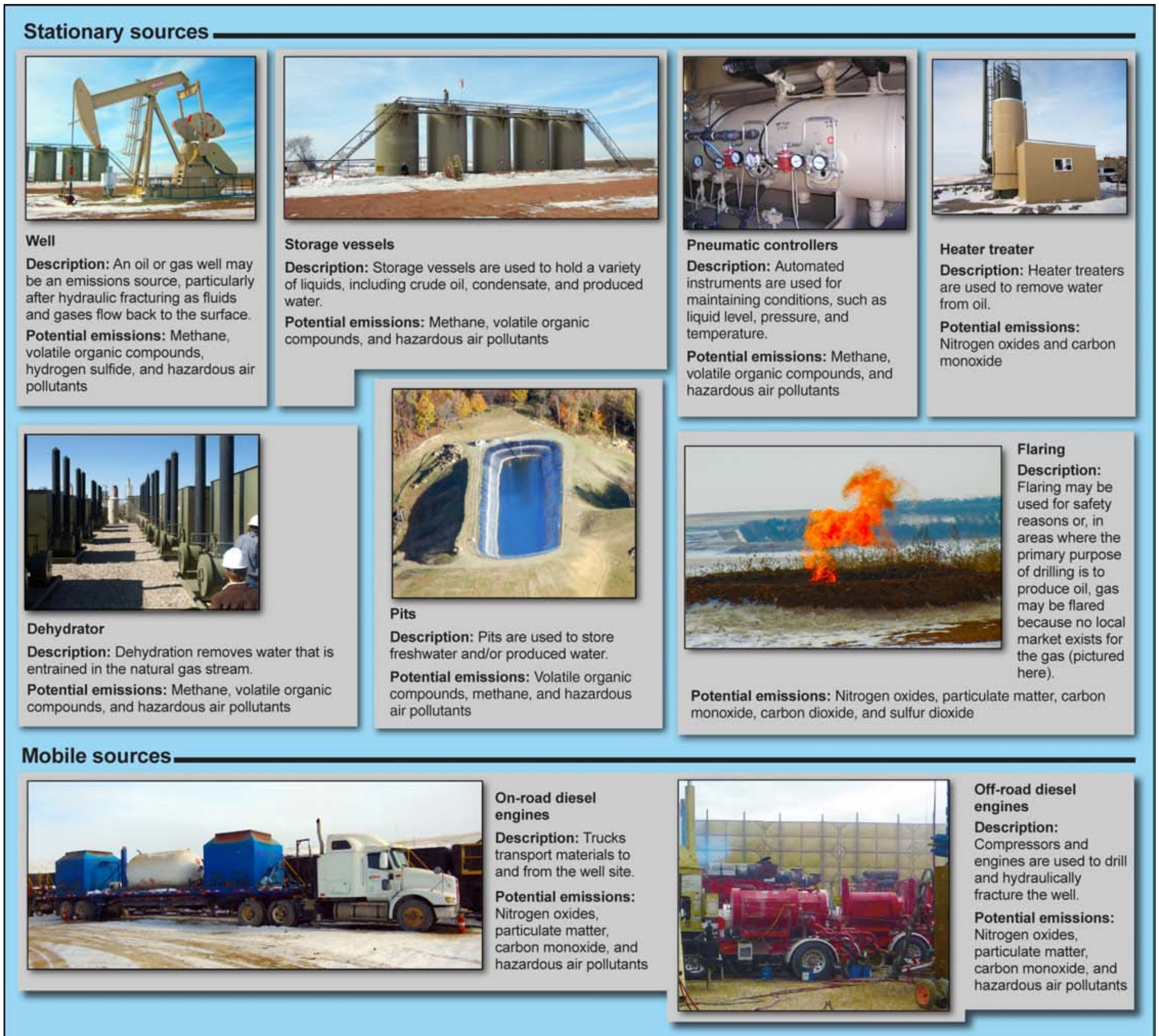
Sources of natural gas air emissions are commonly divided into three categories: (1) combustion emissions; (2) vented emissions; and (3) fugitive emissions. Other reviews of the environmental impacts of natural gas development combine vented and fugitive emissions to make two categories (the National Energy Technology Laboratory [NETL] 2014 and Lattanzio 2013).

NETL concluded that the air emissions generated by unconventional gas activities are similar to those generated by conventional gas activities. The biggest difference is related to whether the gas produced is considered a wet gas, producing both liquid (natural gas liquids) and gaseous hydrocarbons heavier than CH_4, or a dry gas (mostly CH_4).

Combustion emissions originate from the use of internal combustion engines during many natural gas activities. Sources of combustion emissions include on and off-road vehicles, drill rigs (mobile sources), and related equipment, as well as diesel or natural gas-powered pumps and compressors (stationary sources). These combustion sources produce a variety of emissions, including NO_X, SO_2, CO, CO_2, and PM. Flaring is controlled burning of combustible gases during certain phases of natural gas production. Flaring may reduce certain emissions by combusting vented gases at the source. **Vented emissions originate when natural gas is released during well completion and workover activities.** Venting also occurs during other processes related to the processing of natural gas, like dehydrating, sweetening, or compressing the gas for transmission and marketing. Vented emissions are dominated by CH_4 and VOCs. Fugitive emissions result from leaks through pipeline and storage tank valves, flanges, and seals, but also include the off-gas originating from produced water or wastewater holding pits. Fugitive emissions include CH_4, VOCs, and HAPs. PM released during construction clearing or other land disturbance activities is also considered a fugitive emission. Table 6 summarizes the types of emissions and the typical emissions sources for these three emissions categories.

Table 6: Source Categories of Airborne Emissions from Upstream Natural Gas Activities (EPA, 2013)

Category	Type of Emissions	Sources of Emissions
Combustion Emissions	NO_X and CO resulting from the burning of hydrocarbon (fossil) fuels. Air toxics, PM, un-combusted VOCs, and CH_4 are also emitted.	Engines, heaters, flares, incinerators, and turbines.
Vented Emissions	VOCs, air toxics, and CH_4 resulting from direct releases to the atmosphere.	Pneumatic devices, dehydration processes, gas sweetening processes, chemical injection pumps, compressors, tanks, well testing, completions, and workovers.
Fugitive Emissions	VOCs, air toxics, and CH_4 resulting from uncontrolled and under-controlled emissions.	Equipment leaks through valves, connectors, flanges, compressor seals, and related equipment and evaporative sources including wastewater treatment, pits, and impoundments.



Sources: GAO; photos from GAO except the pneumatic controllers and dehydrator are from BLM, and the pit is courtesy of www.marcellus-shale.us.

Figure 7: Examples of Air Emissions Sources Related to Oil and Gas Activities
(GAO, 2012)

Methane: Methane is the simplest alkane and the main component (60 to 90 percent) of natural gas (Gilman et al., 2013). In the upper atmosphere, CH_4 becomes a potent GHG, more than 20 times more powerful than CO_2 in breaking down the protective ozone layer in the upper atmosphere, although the CH_4 residence time is much less than CO_2. In the lower atmosphere, CH_4 is **also** an ozone precursor, contributing to ground-level ozone pollution**, especially in rural areas (EPA, 2011a)**. The oil and natural gas industry is the largest industrial source of CH_4 emissions in the United States (EPA, 2014). The main source of CH_4 emissions during natural gas activities occurs during venting of wells prior to completion. Emissions also occur as a result of vented and fugitive emissions from other equipment (e.g., storage vessels, compressors, dehydrators, valves, etc.). Methane emissions are not currently addressed by federal regulations, but **recent 2012** federal **VOC** regulations on the natural gas industry discussed above are expected to indirectly reduce CH_4 emissions as a co-benefit. In February 2014, Colorado adopted regulations targeting CH_4 emissions from the oil and gas industry (CDPHE, 2014). The new rules will take effect when published.

Volatile Organic Compounds (VOCs): VOCs are organic chemicals that have a high vapor pressure at ordinary room temperature, causing large numbers of molecules to evaporate or sublimate from the liquid or solid form of the compound (commonly referred to as off-gassing) and enter the surrounding air. There are many different VOCs, including both human-made and naturally occurring chemical compounds. Some VOCs are dangerous to human health or cause harm to the environment. Harmful VOCs typically are not acutely toxic, but have compounding long-term health effects. Many VOCs are also ozone precursors. The oil and natural gas industry as a whole (including conventional and unconventional resources) is the largest industrial source of VOCs in the United States. The VOCs emitted by natural gas operations vary by reservoir, but typically include alkanes (paraffins or saturated hydrocarbons), cycloalkanes (naphthenes), and aromatic hydrocarbons. Natural gas activities have many sources of VOC emissions, including vented wells, condensate tanks and other storage vessels, controllers, holding ponds or pits, etc. An assessment of emissions inventories for the Barnett Shale in Texas indicates that the top four sources of VOCs are: condensate tanks (58.2 percent), fugitives (21.5 percent), water tanks (6.8 percent), and engines (6.2 percent) (Allen, 2014).

Ground-Level Ozone: Ground-level ozone (or tropospheric ozone) is another of the six criteria pollutants. Ozone is not emitted directly into the air, but is created by chemical reactions between NO_X and VOCs, two common components of air emissions originating from natural gas industry activities. Ozone commonly reaches unhealthy levels on hot sunny days in urban environments, but can also be transported long distances by wind. High ozone concentrations have also been observed in cold months, where a few high-elevation areas in the western United States with high levels of local VOC and NO_X emissions have formed ozone in winter months. Ozone contributes to smog or haze formation (EPA, 2014c).

Hazardous Air Pollutants (HAPs): Also known as toxic air pollutants or air toxics, HAPs are air pollutants that are known or suspected to cause cancer or other serious health effects (i.e., reproductive effects or birth defects), as well as adverse environmental effects. EPA currently lists 187 pollutants as HAPs. Examples include benzene, which is found in gasoline; perchloroethylene, which is emitted from some dry cleaning facilities; and methylene chloride, which is used as a solvent and paint stripper by a number of industries. Examples of other listed air toxics include hydrogen sulfide (H_2S), dioxin, asbestos, benzene, toluene, and formaldehyde, and metals such as cadmium, mercury, chromium, and lead compounds. Natural gas production emits benzene, toluene, ethylbenzene, and xylenes (BTEX) from condensate tanks, dehydration units, diesel engines, and other sources. EPA set National Emission Standards for Hazardous Air Pollutants (NESHAPs), including some HAPs, which are regulated by requiring specific controls (40 CFR Parts 61 and 63) (EPA, 2014d).

Carbon Monoxide: Carbon monoxide is a colorless, odorless gas emitted from combustion processes. Nationally, and particularly in urban areas, the majority of CO emissions to ambient air come from mobile sources. Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues, and, at extremely high levels, can cause death. Carbon monoxide is released by the internal combustion engines supporting natural gas activities, and is one of the six criteria air pollutants regulated by NAAQS (EPA, 2014e).

Carbon Dioxide: The main human activity that emits CO_2 is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation, although certain industrial processes and land-use changes also emit CO_2. The main impact of CO_2 is as a GHG, but it can also cause asphyxia at higher concentrations in confined areas. Carbon dioxide is released by the internal combustion engines supporting natural gas activities (EPA, 2014f).

Particulate Matter: PM is a complex mixture of extremely small particles and liquid droplets, and is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles. PM is released by internal combustion engines, especially those burning diesel fuels, and is one of the six criteria air pollutants regulated by NAAQS under the Clean Air Act (EPA, 2014g).

Sulfur Dioxide: Sulfur dioxide is one of a group of highly reactive gasses known as "oxides of sulfur." The largest sources of SO_2 emissions are from fossil fuel combustion at power plants (73 percent) and other industrial facilities (20 percent). Sulfur dioxide is released by the internal combustion engines supporting natural gas activities. **Use of low sulfur diesel fuels has helped to reduce SO_2 emissions from such sources.** Sulfur dioxide **is linked with a number of adverse effects on the respiratory system, and** is one of the six criteria air pollutants regulated by NAAQS under the Clean Air Act (EPA, 2014h).

Nitrogen Oxides: Nitrogen oxides are a group of highly reactive gasses also known as "oxides of nitrogen." This group includes NO_2, nitrous acid (HNO_2), and nitric acid (HNO_3). EPA's NAAQS uses NO_2 as the indicator for the larger group of NO_X. Nitrogen dioxide forms quickly from the combustion emissions from cars, trucks and buses, power plants, and off-road equipment. In addition to contributing to the formation of ground-level ozone and fine particle pollution, NO_2 is linked with a number of adverse effects on the respiratory system. On and off-road vehicles, pumps, and compressors contribute to the NO_2 emissions resulting from natural gas activities (EPA, 2014i).

Discussion of Anticipated Impacts

Natural gas development leads to short-term increases in local and regional air emissions. Development activities at individual well sites are generally considered to be short-term activities. States issue air permits for new air emissions sources based on each individual source. Large-scale development within a shale basin may occur over a longer period of time, albeit at different locations within the field as new wells are drilled and developed and new pipelines and related infrastructure are constructed, bringing more natural gas into production and delivered to market. Short-term activities would include the vehicle emissions associated with well pad development and pipeline construction, well drilling and fracking, the venting or flaring of gas during well development, and related fugitive emissions from storage tanks and water pits. The impacts resulting from the aggregate of emissions within a region experiencing natural gas development**, coupled with emissions from other sources,** are not well understood. Even on a small scale, projecting impacts is a moving target. As new wells begin drilling, others begin venting or flaring, while others enter the phase of production with lower emissions on a continual basis. The dynamic nature of these short-term emissions makes quantitative analysis and modeling a challenge.

One study by Armendariz (2009) constructed an emissions inventory for the Barnett shale region in Texas and estimated air pollutant emissions. He estimated the following:

- Ozone and fine particle smog forming compounds (NO_X and VOC) of approximately 191 tons per day (tpd) on an annual average basis.
- During the summer, VOC emissions increase, raising the NO_X and VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the Dallas-Fort Worth metropolitan area.
- Emissions of air toxic compounds of approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

A recent study by Roy, et al. (2014) developed an air emissions inventory for the Marcellus shale gas region and estimated emissions through 2020. They concluded that development of the Marcellus shale will be an important source of regional NO_X and VOC emissions, and may contribute from 6 to 12 percent to regional emissions. They further concluded that these estimated emissions could complicate ozone management in the future.

Natural gas development may also lead to long-term increases in regional air emissions. Longer-term activities associated with natural gas development would be more associated with activities at the completed wells to clean and compress the produced natural gas and along the pipelines that deliver the gas to market. Well pad compressors, equipment designed to remove water (dehydrators) and clean gas to pipeline specifications for market use, storage tanks, and compressor stations along the pipeline routes would operate as long as the field economically produces natural gas. The emissions associated with these activities and any additional fugitive emissions would therefore be considered long-term, lasting well after the shorter-term drilling and development activities have ceased (Litovitz et al., 2013). As with short-term impacts, many of the individual sources are regulated by the states, but the impacts resulting from the aggregate of emissions within a region experiencing natural gas development**, coupled with emissions from other sources,** are not well understood.

Air emissions from natural gas development may create new or expanded ozone non-attainment areas and possibly complicate state implementation plans for bringing current non-attainment areas into compliance. Besides CH_4, the largest pollutant emissions associated with natural gas production are VOCs and engine emissions. Many of these pollutants are considered to be ozone precursors, contributing to the formation of ground-level ozone pollution. Often, areas of large-scale natural gas development occur where other pollution sources occur (e.g., industrial activities and vehicular traffic), and therefore where pre-existing pollution problems occur.

Areas that do not meet NAAQS for ground-level ozone are considered to be in nonattainment of the ozone standards. As shown in Figure 8, some of these ozone nonattainment areas occur near major natural gas development activities and large population centers, including the counties near Dallas-Fort Worth, Texas (Fort Worth Basin/Barnett Shale); Denver, Colorado (Denver Basin, Niobrara Shale); and Pittsburgh, Pennsylvania (Appalachian Basin/Marcellus Shale).

These nonattainment areas occur in proximity to large metropolitan areas with a variety of air emissions sources which have contributed to ozone problems for years, making it hard to specifically account for the impact of air emissions from natural gas activities. Colorado identified the oil and gas industry as the biggest source of VOC emissions in the state, and compressor engines and drill rigs used at oil and gas facilities as the biggest sources of oxides of nitrogen in the Front Range (Denver) ozone nonattainment area (EDF, 2013). Another example is illustrated in Figure 9, which shows the oil and gas wells located within or near the Dallas-Fort Worth, Texas, ozone nonattainment area.

Other ozone nonattainment areas occur in mostly rural areas where gas development is a major source of ozone precursors (e.g., Jamestown, New York, and Pinedale, Wyoming). For instance, in the area around Pinedale, Wyoming, the Wyoming Department of Environmental Quality (DEQ) inventory of emissions for the ozone nonattainment area and the surrounding counties shows that 94 percent of VOC emissions and 60 percent of NO_X emissions in the Upper Green River Basin are attributable to oil and gas production and development. All of the 11 major sources in the Upper Green River Basin are oil and gas related (Pinedale, 2009).

Generally, states where nonattainment areas **(listed by county or groups of counties)** occur must develop SIPs to **show how they plan to** get these areas into compliance with air standards (NAAQS). The rapid development of shale gas resources within or upwind of ozone nonattainment areas may make it difficult to successfully implement the SIPs. In nonattainment areas, **major emission sources** must use the lowest achievable emissions rate (LAER) standards, which are more stringent than Best Available Control Technology (BACT) and Reasonably Available Control Technology (RACT) standards, with no consideration of cost. In order for proposed new **major** sources to be permitted in a nonattainment area, companies must obtain offsets from existing emitters to compensate for the estimated new emissions. **However, most natural gas emissions do not fall within the category of major emissions when considered individually.**

Similarly, development of gas resources in or near areas currently in attainment of ozone standards could jeopardize the continued attainment status of these areas. For instance, in the Greater Green River Basin, new gas developments under consideration may impact the existing ozone nonattainment area near Pinedale, Wyoming, or potentially create new areas of ozone nonattainment. An analysis completed for the Continental Divide-Creston Natural Gas Project Draft Environment Impact Statement (EIS), prepared by the Bureau of Land Management (BLM) for a proposed project under consideration in southern Wyoming, estimated emissions and impacts for the life of the project, which would include 8,950 new natural gas wells, roads, and related production facilities. Far-field air modeling predicted that production facilities would have no significant contributions to modeled exceedances of air standards (national or Wyoming) for any criteria pollutants. Near-field air modeling predicted limited air standard exceedances at nearby receptors for NO_2 and PM, which may require BLM to implement additional mitigation measures for the project. Any updates to the analysis would be documented in the final EIS, anticipated in summer 2014 (BLM, 2012).

Another study evaluated the ozone impacts of natural gas development in the region of the Haynesville Shale play along the Texas-Louisiana border (Kemball-Cook et al., 2010). This study developed an emissions inventory for the area based on a number of sources and estimates of future production in the field. Projected emissions and ozone impact modeling indicated that Haynesville Shale development may impact future ozone levels in the region and potentially affect the ozone attainment status of the area as development proceeds.

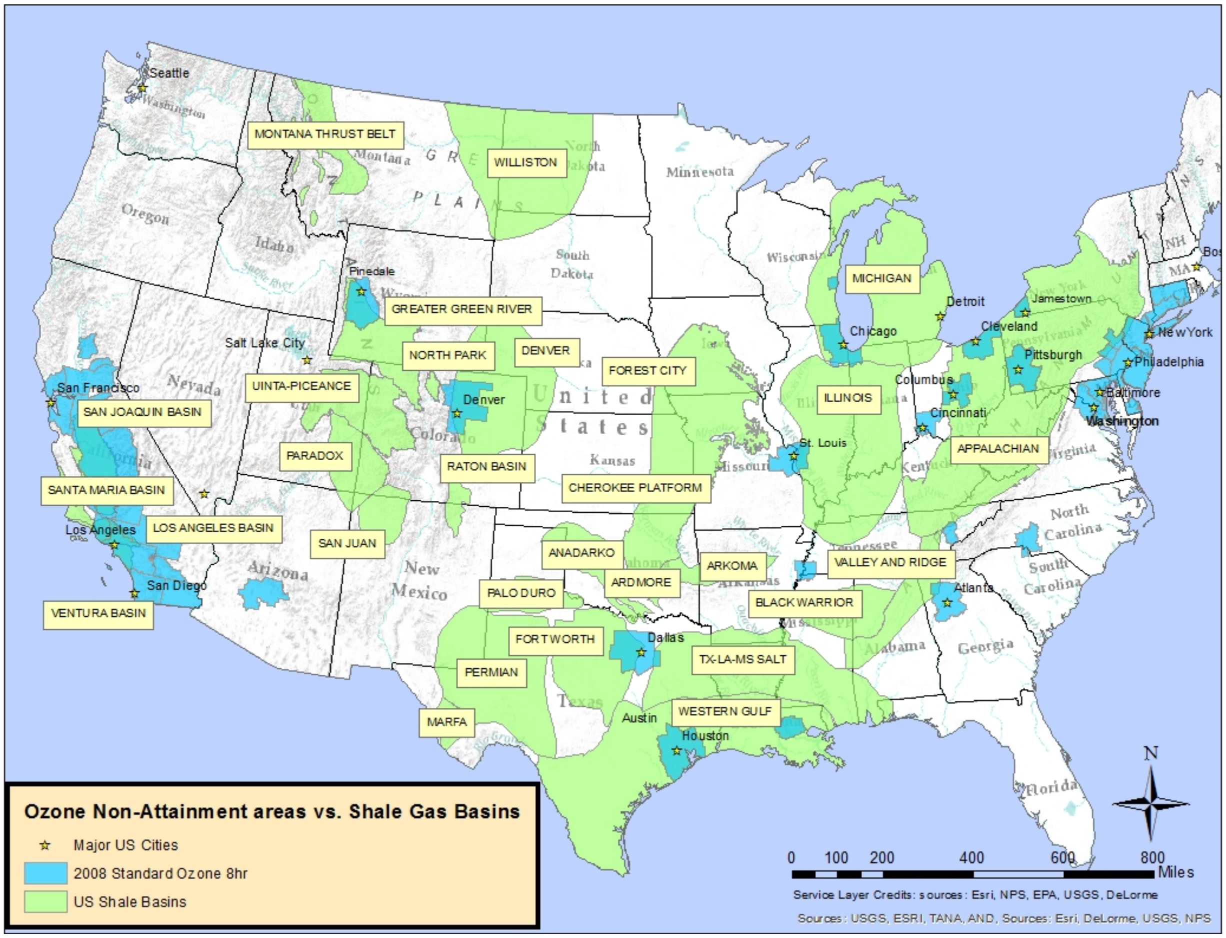


Figure 8: National Map Showing Ozone Nonattainment Areas Superimposed on Major Shale Gas Basins

Another possible impact of unconventional gas development is the reduction of visibility in Class I areas. The area classification system was established by Congress to facilitate implementation of some of the air quality provisions of the Clean Air Act, with Class I receiving the highest degree of protection. Class I federal areas include national parks, national wilderness areas, and national monuments. These areas are granted special air quality protections under Section 162(a) of the federal Clean Air Act. Visibility is mostly impacted by the formation of haze, caused when sunlight encounters pollution particles in the air, reducing the clarity and color of what a person sees. Since 1988 the federal government has been monitoring visibility in national parks and wilderness areas (i.e., in the Great Smoky Mountains National Park). Some groups are concerned with the rapid development of oil and gas resources adjacent to Class 1 areas (NPCA 2013). Some recent trends for national parks show general improvement in visibility while others show some level of concern overall, but more recent data is lacking and the data does not evaluate individual sources or source categories (EPA 2010; NPS 2013). However, it is important to note that in 2011 the Environmental Protection Agency, Department of Agriculture, and

Department of Interior signed a Memorandum of Understanding on air quality analysis and mitigation requiring an environmental review before drilling on federal lands, and would include an analysis of air quality impacts on Class I areas (<u>http://www.epa.gov/compliance/resources/policies/nepa/air-quality-analyses-mou-2011.pdf</u>).

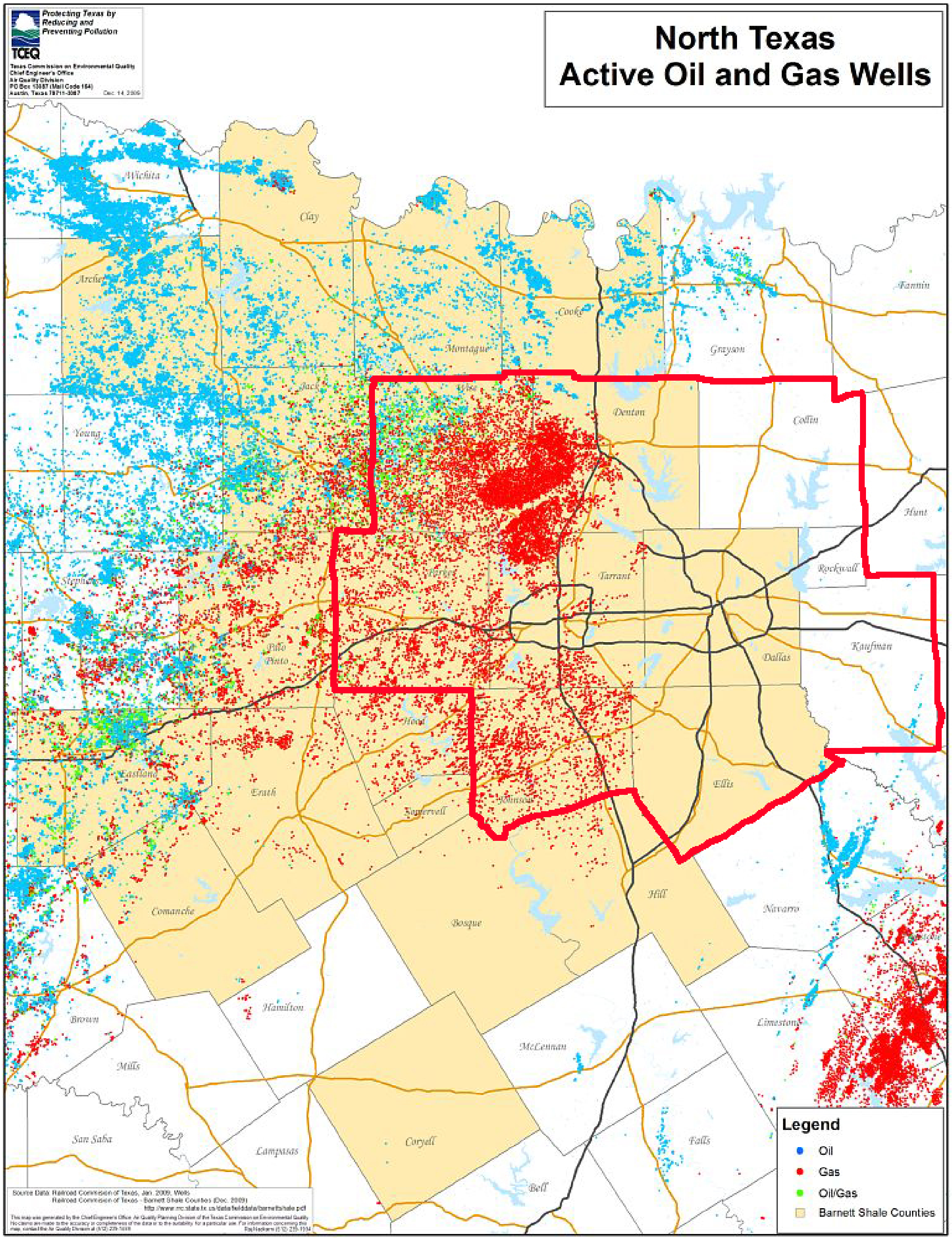


Figure 9: Dallas-Fort Worth Ozone Nonattainment Area (red outline) Superimposed on Map of Area Oil and Gas Wells from the Barnett Shale Play

Health Effects

The potential impact of natural gas development on human health has been a concern of many people. Claims of substantial impacts have been made in many of the regions experiencing natural gas development. Unfortunately, research into this topic is only now beginning to be reported. However, since natural gas development activities contribute measurable air emissions, including VOCs, air toxics, and criteria pollutants, some discussion is warranted.

The American Public Health Association (2014) provides the following policy statement regarding "The Environmental and Occupational Health Impacts of High-Volume Hydraulic Fracturing of Unconventional Gas Reserves":

> "Air pollution - Fugitive emissions of hydrocarbons from well heads, silica sand from open frac fluid mixing stations, particulate matter emissions from machinery at drill sites, incomplete combustion from flaring, gases (e.g., VOCs and other hazardous air pollutants) from compressor stations, and the cumulative impacts from diesel trucking may pose occupational health risks and contribute to local and regional air pollution" (American Public Health Association, 2014).

Bunch et al. (2014) evaluated the impact of shale gas operations on VOC emissions and health risks in the Barnett shale region of Texas. The Barnett shale is one of the more widely developed shale gas plays and where much of the more recent development began. Their analysis concluded that shale production activities have not resulted in community-wide exposures to VOC levels that would pose a health concern. The emission of VOCs, NO_X, and other pollutants common to natural gas development activities contribute to the formation of ground-level ozone. Ozone, even at relatively low levels, can cause human health effects. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone. Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma. Breathing ozone can trigger a variety of health problems, including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground-level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue.

HAPs, also known as air toxics, are known or suspected to cause cancer or other serious health effects (such as reproductive effects or birth defects), as well as adverse environmental effects. The 187 compounds currently listed as air toxics represent a wide range of chemicals and exposure pathways. People exposed to toxic air pollutants at sufficient concentrations and durations may have an increased chance of getting cancer or experiencing other serious health effects. Such health effects could include damage to the immune system, as well as neurological, reproductive (e.g., reduced fertility), developmental, respiratory, and other health problems (see: http://www.epa.gov/ttn/atw/allabout.html).

Only limited research has been conducted on the direct and indirect impacts of natural gas development on human health. McKenzie et al. (2012) collected air samples near well pads in

Garfield County, Colorado, and found a wide range of hydrocarbons present in the samples, including BTEX. Their risk assessment concluded that the closest residents were at an increased risk of acute and subchronic respiratory, neurological, and reproductive effects from exposure to these chemicals. Results also estimated cancer risks to be in a range of concern, but not at levels which would typically trigger any action.

Other contaminants of concern for workers and nearby residents include contaminated dust and direct radiation from naturally occurring radioactive materials and inhalation of silica dust from the sand used during fracking. Adgate et al. (estimated for 2014) provide a good overview of these and other contaminants related to unconventional natural gas development and the potential pathways for human exposure. They highlight that population-based studies of the potential health effects from airborne exposures have been limited and summarize the research needs.

Conclusions

Natural gas development leads to both short- and long-term increases in local and regional air emissions, especially methane, VOCs, and hazardous air pollutants (HAPs).

Air emissions from natural gas development**, coupled with existing or new emissions from other sources,** may create new or expanded ozone non-attainment areas**. Such emissions may also** complicate **existing** state implementation plans for bringing current ozone non-attainment areas into compliance and maintenance.

The intermittent nature of air emissions from sources such as wells makes it difficult to analyze impacts at the regional level. Many of the mobile and stationary emissions during well development activities are short-term, essentially ending after well completion. New emissions sources emerge as additional wells are drilled and completed, and gathering and transmission pipelines are developed. The dynamic nature of emissions sources, including the locations, timing, and numbers of sources, make a comprehensive impact analysis difficult, if not impossible. As more data become available to regulators and researchers, and new analyses are completed, a better understanding of trends in local and regional air quality and potential impacts will emerge. The DOE Secretary of Energy Advisory Board’s Shale Gas Production Subcommittee recommended the establishment of an emission measurement and reporting system at various points in the production chain as one way to accomplish this (DOE, 2011).

Greenhouse Gas Emissions from Upstream Natural Gas Industry

The natural gas industry has hundreds of thousands of wells, hundreds of gas processing facilities, and thousands of miles of transmission pipelines in the United States. Many greenhouse gases (GHGs) are emitted from various facilities and activities. Fortunately, most are emitted in relatively small quantities. Carbon dioxide (CO_2) and methane (CH_4) are the two most commonly associated with unconventional natural gas production and transport. Although CH_4 is emitted in much smaller quantities than CO_2, it has a greater capacity for heat retention in the atmosphere. While there are other potential GHGs associated with both conventional and unconventional natural gas production, CO_2 and CH_4 are clearly the two most important.

Based on 201**2** data, the natural gas industry's emissions of CH_4 accounted for **about 23 percent** of all U.S. CH_4 emissions and for approximately **two** percent of EPA's U.S. total inventory of GHG emissions on the basis of CO_2-e (see EPA **2014k4**). Upstream activities account for most of the industry's CH_4 emissions (**see e.g.,** Bradbury et al., 2013, p. 9). An overview of GHG emissions from natural gas systems in 2012 is presented in Table 7.

Table 7: GHG Emissions from Upstream U.S. Natural Gas Systems in Year 2012

Gas Species	Mass (Gg)	Intensity (Tg CO_2-e)
CH_4	4,**955**	**104.0**
"Non-Combustion" CO_2	35,**195**	35.2
CO_2 from Combusted CH_4	**2,281**	**47.9**
Sum	**42,431**	**187.1**
Percent of U.S. GHG emissions from all sources (6,**525.6** Tg CO_2-e)		2.9%

Sources:

1. EPA (**2014k**) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. Tables: 3-43 **to** 3-47.

Notes:

- EPA (2014) defines "Natural Gas Systems" to include: "field production," "processing," "transmission & storage," and "distribution." **Values reported above do not include "distribution."**
- "Non-combustion" CO_2 emissions represent the natural CO_2 released; CO_2 derived from combustion of CH_4 (in engines or flares) in the upstream sector is **shown in the next row**.
- "Intensity" = GWP weighted emissions as measured in TgCO_2-e, applied to an effective time period of 100 years.
- EPA (2014) applies of factor of 21 CO_2 atoms equals the GWP of 1 CH_4 atom in the atmosphere (GWP = 21 for CH_4).
- Tg = 1.0 teragram = 1.0 MMt = one million metric tonnes.
- Gg = 1.0 gigagram = 1.0 Mt = one thousand metric tonnes.

As a fraction of total natural gas production, EPA's methane emissions inventories (including distribution of gas to customers) for the years 2008 through 2011 ranged from less than 1 percent to 2.1 percent with a recent estimate of 1.3 percent, according to Allen (2014, p. 60). Allen notes that other researchers have claimed leakage rates higher than two percent (as high as eight percent). The most recent EPA and EIA data are used to calculate 0.8 percent of the natural gas produced was released as methane in 2012, as shown in Table 8. The amount of produced natural gas that is released to the atmosphere as methane is important because it relates to the choice among alternative sources of energy. For example, Alvarez et al. (2012, as cited in Allen, 2014) claim a benefit in reduced GHG emissions resulting from the increased use of natural gas to produce electricity in Natural Gas Combined-Cycle (NGCC) power plants (compared to using coal) if the upstream losses of methane are less than 2.9 percent. These analyses depend on the time period of concern, given the global warming potential varies with the time period of analysis and the details of the scenarios for switching from coal to natural gas. Losses in the upstream sector of one to four percent of the methane could change the GHG footprint of natural gas relative to other fuels, depending on the type of use and the time period of consideration for GHG impacts (Allen, 2014).

Table 8: GHG Emissions Expressed as Percent of Natural Gas Production in Year 2012

Gas Species	Mass (Gg)	Percent of Production
CH_4	4,**955**	0.8%
"Non-Combustion" CO_2	35,**195**	5.9%
Sum	40,**150**	6.7%
U.S. Natural Gas Production (24.06 trillion scf)	601,500	

Sources:
1. EPA (**2014k**) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. Tables: 3-43, 3-44, 3-46, 3-47.
2. EIA (2014) Annual Energy Outlook 2014: Early Release Overview and data tables.

Notes:
- EPA (2014) defines "Natural Gas Systems" to include: "field production," "processing," "transmission & storage," and "distribution." **Values reported above do not include "distribution."**
- "Non-combustion" CO_2 emissions represent the natural CO_2 released; CO_2 derived from combustion of CH_4 (in engines or flares) in the upstream sector is not shown here.
- Gg = 1.0 gigagram = 1.0 Mt = one thousand metric tonnes.
- Natural gas production converted to mass using gas density = 25 g/scf (after Allen, 2014).

A recent draft document from the Intergovernmental Panel on Climate Change (IPCC) describes the context for considering GHG emissions of all types, including those associated with changes in the natural gas industry:

> "Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased…. The atmospheric concentration of the greenhouse gases carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) have all increased since 1750 due to human activity. In 2011 the concentrations of these greenhouse gases were 391 [parts per million (ppm)], 1803 [parts per billion (ppb)], and 324 ppb, and exceed the pre-industrial levels by 40%, 150%, and 20%, respectively. Concentrations of CO_2, CH_4, and N_2O now substantially exceed the highest concentrations recorded in ice cores during the past 800,000 years. The mean <u>rates of increase</u> in atmospheric concentrations over the past century are, with very high confidence, unprecedented in the last 22,000 years." (IPCC, 2013. p. 4 and 11, citing numerous references) [emphasis added]

Changes in the composition of the atmosphere as a result of GHG emissions have changed its heat retention capacity as indicated in Figure 10. Emissions of CO_2 correlate to the greatest increase in heat-trapping capacity, followed by CH_4. Comparisons are made relative to the year 1750, which is assumed to represent the pre-industrial era.

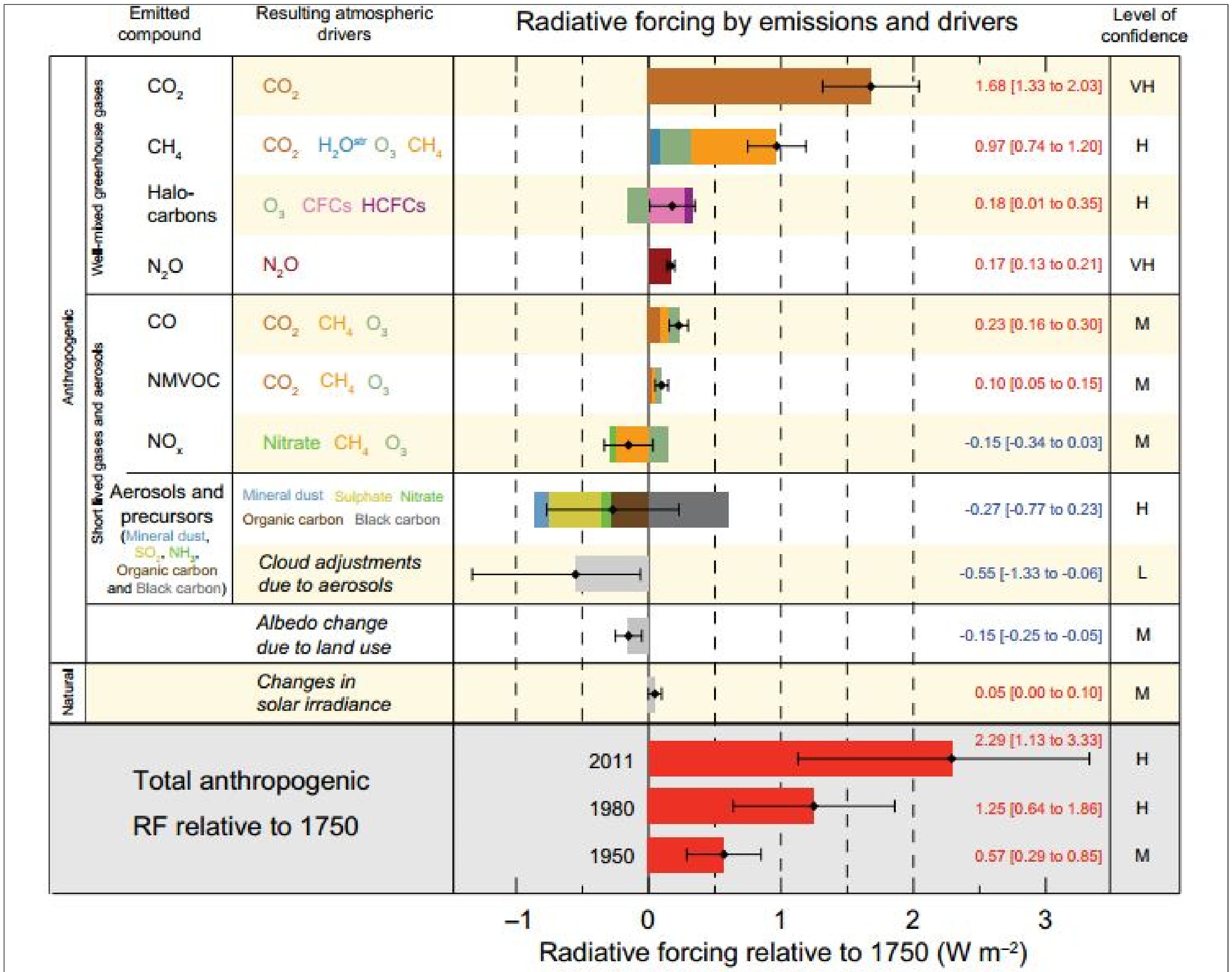


Figure SPM.5 | Radiative forcing estimates in 2011 relative to 1750 and aggregated uncertainties for the main drivers of climate change. Values are global average radiative forcing (RF[14]), partitioned according to the emitted compounds or processes that result in a combination of drivers. The best estimates of the net radiative forcing are shown as black diamonds with corresponding uncertainty intervals; the numerical values are provided on the right of the figure, together with the confidence level in the net forcing (VH – *very high*, H – *high*, M – *medium*, L – *low*, VL – *very low*). Albedo forcing due to black carbon on snow and ice is included in the black carbon aerosol bar. Small forcings due to contrails (0.05 W m^{-2}, including contrail induced cirrus), and HFCs, PFCs and SF_6 (total 0.03 W m^{-2}) are not shown. Concentration-based RFs for gases can be obtained by summing the like-coloured bars. Volcanic forcing is not included as its episodic nature makes is difficult to compare to other forcing mechanisms. Total anthropogenic radiative forcing is provided for three different years relative to 1750. For further technical details, including uncertainty ranges associated with individual components and processes, see the Technical Summary Supplementary Material. {8.5; Figures 8.14–8.18; Figures TS.6 and TS.7}

Figure 10: Relative Impact of Various Greenhouse Gases
(IPCC, 2013, p. 14)

GHGs Associated with Upstream Natural Gas Industry

Methane is the primary component of natural gas. Natural gas is a naturally occurring mixture of gases and vapors (mostly methane, with lesser amounts of ethane, propane, butanes, pentanes, nitrogen gas [N_2], carbon dioxide [CO_2], water vapor [H_2O], and hydrogen sulfide [H_2S], and even lesser amounts of numerous other compounds). The natural gas industry uses gasseparation plants to remove certain constituents from raw natural gas so that the gas going into transmission pipelines meets sales specifications. Well site condensers and the gas processing plants may also recover higher-value products (natural gas liquids) for separate sales.

When released to the atmosphere, CH_4 has a much greater GHG effect than that of CO_2. Its lifespan in the atmosphere, however, is much shorter than that of CO_2 on average. When released to the atmosphere, CH_4 oxidizes to CO_2 and H_2O over a period of time measured in years to decades. Both oxidation products are GHGs. Although water vapor is short-lived, water vapor produced in the stratosphere does affect global warming (see, e.g., IPCC, 2013. p. 666).

The CH_4 in the atmosphere has a heat retention (or warming) effect that is approximately 100 times greater than that of CO_2. Because CH_4 oxidizes to CO_2 and H_2O, the effect of a quantity released to the atmosphere decreases over time. It is reported to have a 20-year average CO_2-e of 72. After 100 years, only a trace amount of the CH_4 will remain un-oxidized, with the result that the 100-year average CO_2-e is around 25 (excluding indirect effects of reactions with aerosols in the atmosphere) (IPCC, 2007). The draft of IPCC's upcoming assessment report (see IPCC, 2013. Table 8.7) indicates that the global warming potential (GWP) values attributed to methane are being increased (e.g., from 25 up to 28 or 34 [depending on what is being assessed] for the 100-year effect, and from 72 up to 84 or 86 for the 20-year effect) (but see Shindell et al., 2009, who estimates the GWP at 105 for 20 years, and 33 for 100 years, accounting for indirect effects with aerosols).

Natural gas includes CO_2 as a natural constituent. Consequently, CO_2 is emitted with CH_4 wherever natural gas is released. It is also considered to be a contaminant of natural gas that is removed prior to sale if the concentration of methane does not meet specifications.

Anthropogenic CO_2 is a product of the combustion of CH_4 and therefore is released wherever natural gas is burned, such as in pipeline compressors. It also is a primary combustion product emitted from motor vehicles and equipment (e.g., drilling rigs, hydraulic pumps – mostly diesel fueled) used in the upstream sector of the industry.

Sources of Emissions

The upstream natural gas industry emits CH_4 and CO_2 regularly at various points in the system and episodically during some activities. Steady state and episodic emissions are best described in the context of the phases of industry activity:

- Drilling and well completion.
- Well production.
- Well **recompletions,** workovers**,** and maintenance.
- Gas processing.
- Transmission and storage.

The descriptions in this section are from Bradbury et al. (2013), NETL (2014), the New York State Department of Environmental Conservation (NYSDEC, 2011), and EPA (2014).

Emissions estimates are generally uncertain because direct measurements are lacking, industry practices are evolving for unconventional resources, and practices are not standard across the industry. Service providers and field operators use different approaches and techniques, especially from one play to another, which makes estimating emissions at the industry level a challenge.

Phases of Industry Activity and GHG Sources

Well Drilling and Completion

This phase covers equipment mobilization, site preparation, drilling, well completion and stimulation activities, and well testing. In some studies, this phase includes CO_2 emissions from diesel engines on heavy equipment (e.g., bulldozers, drill rigs). Natural gas (mostly CH_4) is released from drilling fluids and produced water at multiple steps. In many cases, much of the natural gas coming up the well during well completion is diverted to a flare where it is burned. Flaring is an important health and safety practice, and it reduces the GWP of the emissions by converting the methane and other organic compounds to CO_2. After drilling or hydraulic fracturing activities stop, fluids in the well and the surrounding rock are allowed to flow back through the well to the surface, pushed by gas pressure in the reservoir. The flowback of hydraulic "fracking" fluids or drilling fluids may continue for 3 to 10 days (some operators claim the average is only 3 to 4 days), during which time a large amount of natural gas emerges from the well and is either vented or flared (Bradbury et al., 2013, p. 19). Some reports claim wells in unconventional resources have higher emissions of natural gas compared to wells in conventional resources (see e.g., Howarth et al., 2011). This may occur because venting or flaring of natural gas may be prolonged for unconventional resource wells compared to conventional resource wells (see e.g., Bradbury et al., 2013, p. 19). Recently, more focus has been on reduced emissions completions (RECs) that capture a large portion of these releases for use or sale; however, this depends on the availability of a nearby pipeline, regulations, and other factors. RECs are required by new regulations starting in 2015 (see 40 CFR Parts 60 and 63, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule 77 FR 159, 16 August 2012, 49490-49600).

Gas Production

In this phase, natural gas is allowed to flow from the reservoir (propelled by pressure of the gas in the reservoir) through the well and into small pipelines that convey the gas to a central station or processing plant or to a major transmission pipeline. Fluids flowing up the well often include water vapor, part of which condenses at the ground surface and must be removed. Liquid hydrocarbons condensing in the pipeline may also be removed at the well site and stored temporarily in tanks. GHG emissions consist of methane and other VOCs, and natural CO_2. Releases occur through small tank vents and various leaks. Some vents may have a flare installed to burn the vented hydrocarbons.

Well Recompletions, Workovers, and Maintenance

When production of natural gas slows to very low rates, wells are typically cleaned or re-**completed**. A maintenance operation that occurs frequently in some plays or fields is the removal of water and liquid hydrocarbons that build up in the bottom of wells and obstruct the flow of natural gas through the well. When this liquid is brought to the surface, substantial amounts of natural gas may come with it, depending on the technique used. **If not captured and sent to market, t**his natural gas **is** either vented or flared and can account for relatively large emissions. **An increased use of plunger lifts is lowering emissions from liquids unloading, according to EPA (2014k).** Some natural gas fields are "dry" and do not accumulate liquids in the wellbore, so liquid removal is not necessary in these fields.

Workovers are done less frequently and are accomplished with small service rigs **or drill rigs. Workovers are an invasive maintenance procedure whereby well flow is stopped, and the well is inspected and repairs made. The well head is removed, and often the production tubing and packer is pulled from the well and replaced. Any valves, pumps, or other components in the well would be removed and inspected or replaced.**

In connection with a workover, wells are sometimes recompleted. For wells in both unconventional and conventional resources, hydraulic fracture jobs **may be** redone**,** either using the existing perforations through the casing or newly created perforations**, often in different zones**. After fracturing the rock in the reservoir, hydraulic fluids bearing dissolved natural gas and entrained with natural gas are allowed to flow from the well, resulting in emissions. During this flowback period (which lasts 3 to 10 days), the gas is either flared, vented to the atmosphere, or piped to market, depending on well-site circumstances and applicable regulations (see section below on Regulatory Issues). **RECs are increasingly used to capture emissions from recompletions, according to EPA (2014k).**

Some studies of GHG emissions include CO_2 from diesel engines on the service rig, pumps, and other service equipment.

Gas Processing

Processing plants prepare natural gas for sale and transmission through mainlines. If needed, an acid gas scrubber removes H_2S and converts the sulfur into elemental form. Excess natural CO_2 is also removed at this step. The natural gas is then dried in a dehydrator; mercury is removed in a filter; nitrogen gas is removed; and ethane and other hydrocarbons may be removed and separated, and the methane is sent to the transmission mainline for sale. Some of these steps require energy (e.g., heat for an amine scrubber recovery unit), and the cleaned natural gas must be compressed to meet pipeline pressures. These activities are accomplished by burning a portion of the natural gas for power, which results in emissions of CO_2, water vapor, and small quantities of hydrocarbons. Some VOCs may be vented from the acid gas scrubber. Leakage of natural gas also occurs through compressor seals and other connections in the plant. Compressors account for the largest GHG source in this phase. Generation of electricity to run pumps and equipment accounts for a small amount of CO_2 emissions. GHG emissions from processing and transmission do not differ much between conventional and unconventional resources.

Gas Transmission and Storage

After natural gas enters transmission mainlines, it flows to points of sale or export facilities. As the gas flows through mainlines, very small amounts leak from seals; larger amounts leak from compressor bushings. Natural gas not immediately needed is sent to a storage facility until demand increases, usually in the winter months. Most gas storage facilities are abandoned oil or gas fields. At a storage field, there will be additional minor leakage from distribution lines and wells in the field. A portion of the gas is used to fuel re-processing plants (perhaps only a dehydrator) and compressors that pressurize the gas for shipment from the storage field.

Figure 11 shows the percent of total GHG emissions from various elements of the upstream industry in a shale play (the Marcellus, in this example), as calculated by NETL (2014). This figure highlights the fact that unlike other industries where most of the GHG emissions are in the form of CO_2, emissions from the upstream natural gas industry include a large percentage as CH_4. Figure 11 also highlights the fact that pipeline gas compressors are a major source of GHG emissions. Longer pipelines require more compressor stations and therefore generally result in greater GHG emissions. These compressors typically use combustion engines fueled by natural gas from the pipeline.

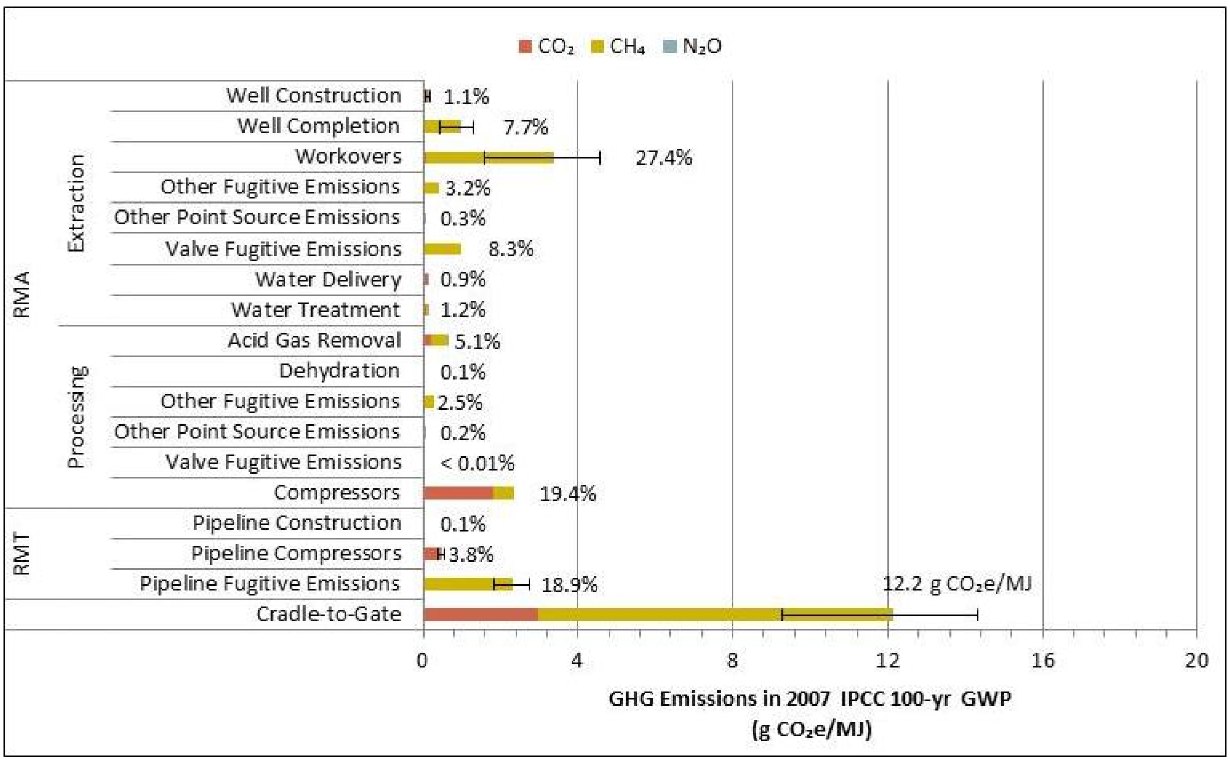


Figure 11: Detailed GHG Results for Marcellus Shale Natural Gas Extraction, Processing, and Transport
(NETL, 2014)

Estimates of GHG Emissions

As indicated in Table 9, the most recent estimates (2012) of CO_2 emissions from the upstream natural gas industry in the United States are less than or equal to 83.2 million metric tons (MMt) of CO_2-e/year (CH_4 "captured/combusted" plus "non-combustion" CO_2 emissions), amounting to approximately 1.3 percent of the EPA's draft GHG inventory for 2012 (6,**525.6** MMt CO_2-e) (EPA, **2014k**). EPA (**2014k**) does not show emissions data separated by natural gas source.

Recent estimates of CH_4 emissions from the upstream U.S. natural gas industry are approximately 4.**96** MMt/year or **104** MMt CO_2-e/year in 2012, amounting to approximately 1.6 percent of EPA's GHG inventory for 2012 (EPA, **2014k**).

Table 9: U.S. Emissions of GHGs from Upstream Natural Gas Systems in 2012 (TgCO_2-e or MMt CO_2e)

	Well Site	Processing	Transmission and Storage	Total
CH_4 Emissions	**41.8**	18.7	43.5	**104.0**
CH_4 "Captured/Combusted"	36.4	3.3	8.2	47.9
"Non-Combustion" CO_2 Emissions	13.7	21.5	0.1	35.2
EPA, **2014k**. Inventory … 1990-2012 (**Final**), Tables 3.45 & 3.46 100-year basis used for the CO_2-e.				

Most studies (e.g., Bradbury et al., 2013; NETL 2014) suggest that emissions of GHGs from the upstream industry are of similar magnitude for both conventional and unconventional resources. For natural gas brought out of the ground (both conventional and unconventional resources), approximately 92 percent on average reaches the end of the transmission mainline (the city gate or the export facility), and approximately 8 percent is leaked, vented, flared, or consumed (to power equipment) (NETL, 2014). Approximately two percent of these emissions go into the atmosphere in the form of methane, according to NETL (Ibid.). One notable exception (Howarth et al., 2011) concludes that hydraulic fracturing in shale gas plays releases much higher volumes of natural gas than most other unconventional production methods. This latter study estimates that 3.6 to 7.9 percent of the ultimate recovery of gas from a well is vented, releasing methane to the atmosphere. Table 10 shows the range of estimates of methane leakage rates (as a percentage of the ultimate recovery of natural gas from a well).

Table 10: Comparison of Leakage Rates from Upstream U.S. Natural Gas Industry

Author	Methane Leakage Rate (percent of ultimate recovery from a well)	
	Unconventional Resources	Conventional Resources
Weber (Science and Technology Policy Institute)	2.42%	2.80%
Burnham (Argonne National Laboratory)	2.01%	2.75%
Howarth (Cornell University)	5.75%	3.85%
EPA GHG Inventory Data (2012)	2.27%	
EPA GHG Inventory Data (2013)	1.54%	
NETL (2014)	1.4%	1.3%
From: NETL (2014), after Bradbury et al., 2013; and C2ES, 2013.		

The differences in GHG emissions and methane leakage rates among natural gas analyses are driven by different data sources, assumptions, and scopes.

Figure 12 illustrates the results of several assessments of emissions from the upstream industry in shale plays. The results are shown by major phases, as described above, except that gas production**, recompletions,** and workovers plus maintenance are combined under the heading of "production." All except one of these studies suggest that most of the emissions occur in the production phase (including **recompletions,** workovers**,** and maintenance activities) and processing phase. The "pre-production" phase (i.e., drilling, well completion, and initial hydraulic fracturing) does not have the highest emissions. The "production" phase has higher emissions because of the assumed number of **recompletions** that include new hydraulic fracture jobs and because of the assumed number of maintenance operations to remove liquids from wells (without using devices that greatly reduce emissions). The processing phase has high emissions because of compressor systems that both burn and leak natural gas.

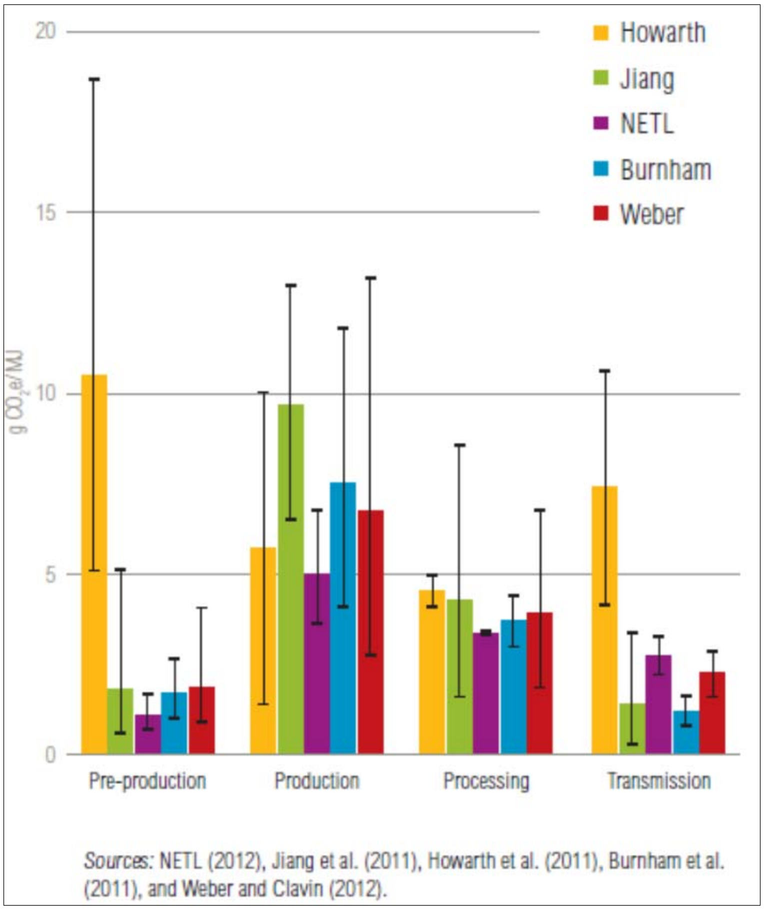


Figure 12: Upstream GHG Emissions from Shale Gas by Life Cycle Stage[3] (Bradbury et al., 2013, p. 3, Figure S-1)

Projections of Future GHG Emissions

The World Resources Institute (WRI) assessed future GHG emissions from the upstream sector of the U.S. natural gas industry based on data from EIA's (2012) "Annual Energy Outlook"; EPA's (2012) "Inventory of Greenhouse Gas Emissions and Sinks: 1990-2010"; and EPA's estimates of (or goals for) the effectiveness of new regulations. WRI's goal was to assess the impacts of new regulations, given EIA's projections for natural gas production from several resource types. Its projections of GHG emissions from the upstream U.S. natural gas industry

[3] Sources: All data presented in this figure are derived from the referenced studies, with only unit conversions and minor adjustments for heating rates. See Figure 9 of Bradbury et al., 2013 for complete study references and more detailed discussion.

Sources: NETL (2012), Jiang et al. (2011), Howarth et al. (2011), Burnham et al. (2011), and Weber and Clavin (2012).
Notes: All data presented in this figure are derived from the referenced studies (in some cases through personal communication with the authors), with only unit conversions and minor adjustments for heating rates. However, not all studies calculate emissions for each of the four life cycle stages shown here; therefore, the authors of this study occasionally allocated a single emissions estimate over more than one life cycle stage. Since Howarth et al. generally do not calculate a central, or base case, life cycle emissions estimate, the top of each gold bar on the chart represents a mid-point between their high- and low-range estimates (the exception to this is in the preproduction stage, for which Howarth et al. present an average value for the methane emissions from well completions in five separate basins). Howarth et al. is the only study that does not use the IPCC (2007) GWP numbers for converting methane emissions to CO2e. They instead rely on Shindell et al. (2009). This partially explains why Howarth has larger upstream emission estimates than the rest of the studies shown here. Uncertainty ranges for each study have different meanings; for some studies, the range represents a range of scenarios explored by authors (e.g., Jiang et al.), while others only represent emissions data uncertainties (e.g., NETL).

activities (all resource types) are 250 MMt CO_2-e/year or less for each year between 2015 and 2035 (Bradbury et al., 2013, p. 27), amounting to approximately 3.8 percent of EPA's (**2014k**) most recent GHG inventory. This assumes that the recently effective NSPS rules have the intended and expected effects. Without these regulations, the emissions are expected to climb to 335 MMt CO_2-e/year by year 2035. Shale gas CO_2-e emissions are expected to stay below 89 MMt CO_2-e/year if the regulations have the expected results, but could climb to 159 MMt CO_2-e/year otherwise (Bradbury et al., 2013, Figure 10). Bradbury et al. (2013) did not report their forecasts for emissions of CH_4 and CO_2 separately.

EIA's "Annual Energy Outlook 2014 Early Release Overview" projects U.S. exports of liquefied natural gas to increase to 3.5 trillion scf in 2029 and remain constant through year 2040. Pipeline exports to Mexico would grow from 0.6 trillion scf in 2012 to 3.1 trillion scf in 2040, while pipeline transports to and from Canada would go from 2.0 trillion scf net imports in 2012 to 0.7 trillion scf net imports in 2040. EIA's "Annual Energy Outlook 2014 Early Release Overview" includes an assessment of U.S. energy-related CO_2 emissions that are expected to stay below 2005 emissions between the years 2012 and 2040. These values relate to the entire U.S. energy industry and do not relate specifically to emissions from the upstream natural gas industry or LNG exports. These values merely provide context.

Regulatory Issues

Currently, there are no Federal regulations that directly limit emissions of GHGs from the upstream natural gas industry. However, recent NSPS rules (promulgated under the Clean Air Act) finalized by EPA in April 2012 (effective in October 2012 for some rules and in 2015 for others; 40 C.F.R. 60, Subpart OOOO [2012]; 40 C.F.R. 63, Subpart HH [2012]; 77 Fed. Reg. 49490 [2012]) will indirectly reduce methane emissions as a collateral result of rules that aim to reduce emissions of toxic air pollutants and VOCs (see Lattanzio, 2013, p. 17-20). The rules aim to curb emissions from flowback after hydraulic fracture jobs on natural gas wells, and they aim to reduce emissions from pneumatic devices, storage tanks, and certain compressors. They will not affect **liquids** removal, which is claimed to be another significant source of methane emissions, and they do not apply to wells that produce primarily oil (**see generally,** Bradbury et al., 2013). Other new rules issued under NESHAPs will reduce emissions from glycol dehydration units (used to remove water from natural gas) and establish thresholds and requirements for leak detection and repair for both gas and oil systems (see Lattanzio, 2013, p. 19).

WRI forecasts that the new rules will reduce upstream emissions of GHGs (as measured in CO_2-e, 100-year basis), primarily methane, 32 percent initially and 37 percent by 2035 compared to its baseline projection of emissions for shale gas plays (Bradbury et al., 2013, p. 23). Without the rules, WRI forecasts that GHG equivalents would increase 79 percent between 2012 and 2035 in the shale gas plays (Ibid.). WRI forecasts much smaller benefits for conventional resource plays. Its forecasts relied upon EIA's 2012 "Annual Energy Outlook" for future natural gas production and therefore did not account for greater gas production that could be stimulated by proposed increases in LNG exports.

State regulation of GHGs from the upstream sector of the natural gas industry is presently lacking, except in Wyoming and Colorado, where regulations on emissions of VOCs have been issued (see generally, Bradbury et al., 2013, p. 31-34). These regulations indirectly reduce methane emissions from the upstream industry in these states.

NSPS rules, if fully implemented across the industry, could reduce the upward trend in GHG emissions. At least one study (Bradbury et al., 2013. p. 5) indicates the trend could level out and that additional opportunities for mitigation may be available (Ibid. p. 6). Bradbury et al. (2013) had the following insight into the importance of mitigating methane emissions:

> "Though methane accounted for only 10 percent of the U.S. greenhouse gas (GHG) emissions inventory in 2010, it represents one of the most important opportunities for reducing GHG emissions in the U.S. (Bianco et al., 2013). In addition to the scale and cost-effectiveness of the reduction opportunities, climate research scientists have concluded that cutting methane emissions in the near term could slow the rate of global temperature rise over the next several decades (NRC, 2011)." (Bradbury, et al., 2013 p. 10)

On April 15, 2014, EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector. These emissions sources include completions and ongoing production of hydraulically fractured oil wells, compressors, pneumatic valves, liquid unloading, and leaks. The white papers focus on technical issues covering emissions and mitigation techniques that target methane and VOCs. As noted in the Obama Administration's Strategy to Reduce Methane Emissions (March 2014; http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf), EPA will use the papers, along with input from peer reviewers and the public, to determine how to best pursue additional reductions from these sources, possibly including the development of additional regulations (EPA 2014j).

Conclusions

Increased unconventional natural gas production will increase GHG emissions from upstream activities. These emissions may contribute to climate change. However, the science of climate change has not advanced to the point that allows a conversion from tons of GHGs to a discrete change in global temperatures. Further, the net change in global emissions is dependent on the fuels that may be replaced by increased natural gas production.

To the extent that unconventional natural gas production replaces the use of other carbon-based energy sources, there may be a net positive impact in terms of climate change.

Incremental GHG Emissions

Increased production of unconventional gas resources will result in increased GHG emissions. Each incremental increase in natural gas production of 1 trillion scf/year is expected to increase upstream GHG emissions by an estimated **6.8** teragrams (Tg) of CO_2-e/year initially to **5.8** Tg CO_2-e by 2035, assuming new NSPS rules are fully implemented and have their intended effect.

Induced Seismicity Associated with Unconventional Gas and Oil Activities

Various activities associated with production of natural gas, gas condensates, and oil from currently targeted unconventional plays can induce seismicity at levels that can cause public alarm and damage to property. These plays are scattered across the United States. The recent development of these plays over the past 8 to 10 years means that statistical data on the frequency, magnitudes, and other characteristics of induced seismicity is limited. The National Research Council (NRC) (2013) describes events caused by or likely related to energy development in at least 13 states involving oil and gas extraction, secondary recovery, wastewater injection, geothermal energy extraction, and hydraulic fracturing for shale gas. However, NRC notes that proving human activity caused a particular event can be difficult because such conclusions depend on local data, records of prior seismicity, and the scientific literature.

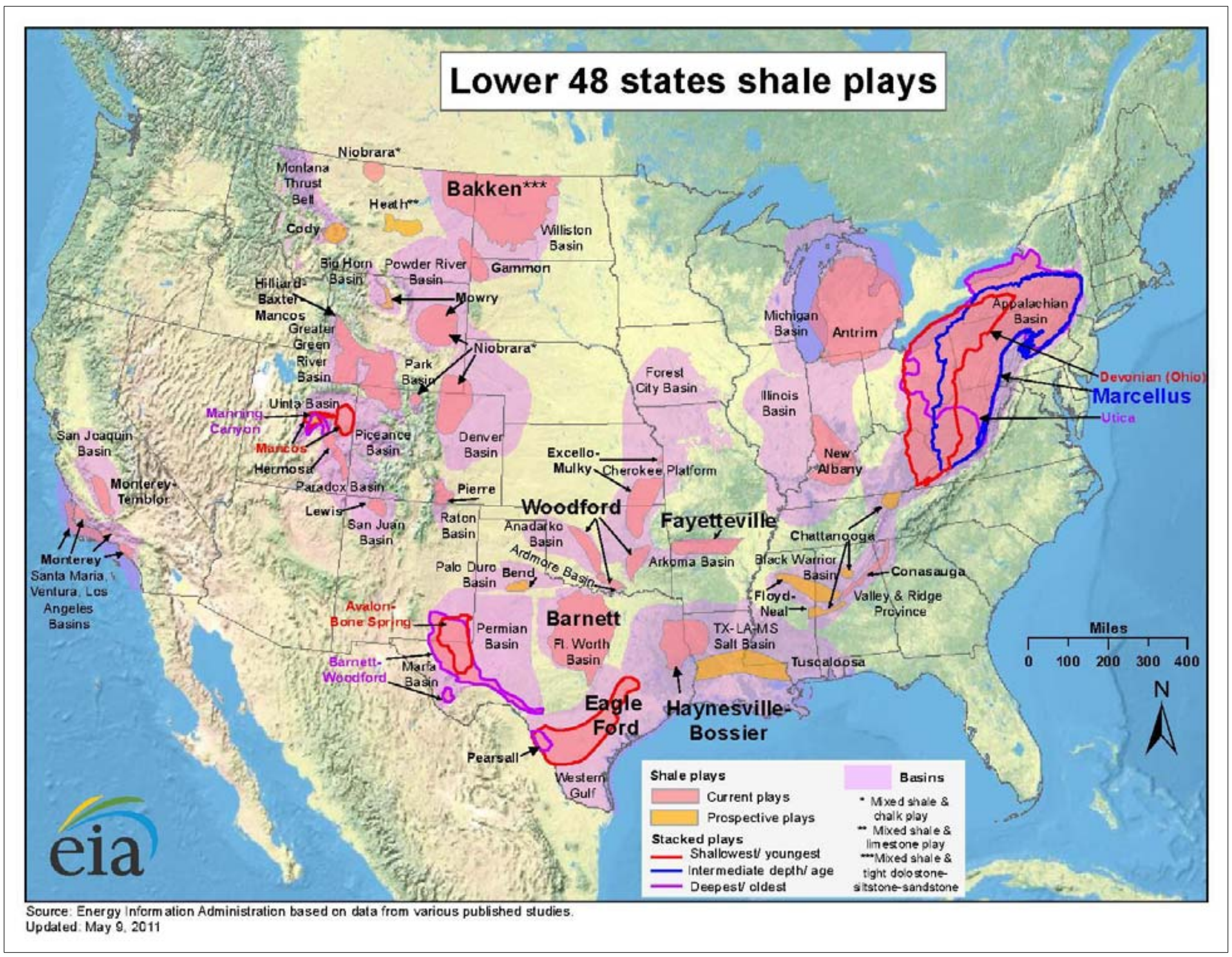


Figure 13: Lower 48 States' Shale Plays
(EIA, 2011)

Seismicity

Natural Seismicity

Natural seismicity is a phenomenon of rapid earth movements (e.g., vibration, displacements) resulting from natural events. For the stronger seismic events, the common name is "earthquakes." When an abrupt slippage or rupture occurs in rock, some of the energy is released and dissipated in the surrounding earth materials in the form of radiating energy waves or "seismic waves."

Most people are familiar with the magnitude or intensity of earthquakes as gaged in terms of peak vibration amplitude (e.g., Richter scale) or resulting effects (e.g., Modified Mercalli Intensity [MMI]), respectively. The most commonly reported scale is the Richter scale, which ranges up to 9.5+ (the strongest earthquake ever measured). Similar to the Richter scale, is the Moment Magnitude Scale (M), which is currently widely used by scientists. Values on the M scale are very similar to those on the Richter scale, but they have a different meaning. The M scale relates to force and area of slippage, whereas the Richter scale relates to amplitude of waves as recorded on a seismograph. MMI is more of a descriptive scale related to damages that can be seen or felt. It relates more directly to people's perceptions and is commonly used to describe damages observed at various locations. Seismic events with a magnitude less than 2.0 (either Richter or M scale) generally are not felt by people, but those with magnitude greater than about 4.0 are felt by most people in the vicinity of the epicenter and cause widespread public concern. Seismic events with magnitude values greater than 5.0 tend to damage buildings. Table 11 shows two of the scales relative to each other. **For a given magnitude (M) earthquake, the felt vibration intensity and damage done (and the MMI value assigned) at a specific location is a function of the distance to the slipping fault plane (including the vertical distance into the Earth), the density and integrity of the intervening rock, the consolidation and fluid pressures of the soils at the specific location, and the structural quality of the features (buildings, bridges, etc.) on the land surface at the specific location.**

Table 11: Modified Mercalli Intensity vs. Richter Scale

Category	Effects	Richter Scale (Approximate)
I. Instrumental	Not felt.	**1-2**
II. Just Perceptible	Felt by only a few people, especially on upper floors of tall buildings.	**3**
III. Slight	Felt by people lying down, seated on a hard surface, or in the upper stories of tall buildings.	**3.5**
IV. Perceptible	Felt indoors by many, by few outside; dishes and windows rattle.	**4**
V. Rather Strong	Generally felt by everyone; sleeping people may be awakened.	**4.5**
VI. Strong	Trees sway, chandeliers swing, bells ring, some damage from falling objects.	**5**
VII. Very Strong	General alarm; walls and plaster crack.	**5.5**
VIII. Destructive	Felt in moving vehicles; chimneys collapse; poorly constructed buildings seriously damaged.	**6**
IX. Ruinous	Some houses collapse; pipes break.	**6.5**

Category	Effects	Richter Scale (Approximate)
X. Disastrous	Obvious ground cracks; railroad tracks bent; some landslides on steep hillsides.	7
XI. Very Disastrous	Few buildings survive; bridges damaged or destroyed; all services interrupted (electrical, water, sewage, railroad); severe landslides.	7.5
XII. Catastrophic	Total destruction; objects thrown into the air; river courses and topography altered.	8

(USGS, 2014)

Natural earthquakes of widespread public concern come from the abrupt slippage of rock along fractures, called faults, after stresses have built up sufficiently or after the resistance to slippage has been reduced. There are thousands of small seismic events every day, and almost all are too small to be felt. More than 1.4 million earthquakes greater than magnitude 2.0 (Richter scale) are measured worldwide each year.

Figure 14 shows relative seismic risks from natural earthquakes, as estimated for the United States by the U.S. Geological Survey (USGS).

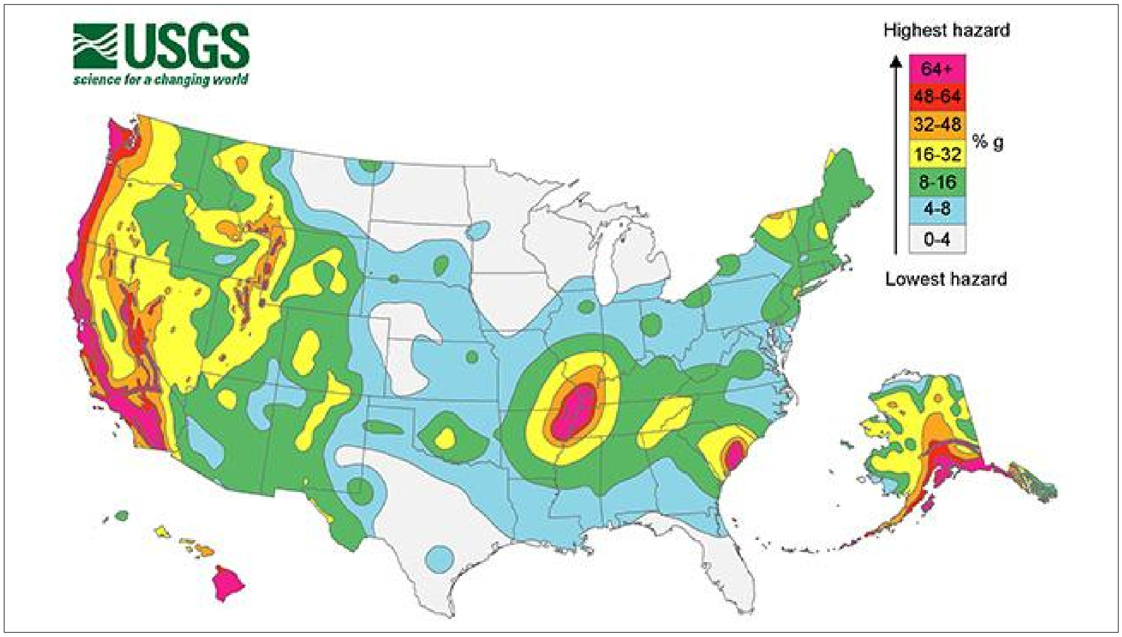


Figure 14: Seismic Risks from Natural Earthquakes, as Estimated for the United States
(USGS, 2008)

Induced Seismicity

Induced seismicity is seismic activity caused directly or indirectly by humans. Examples are earth vibrations caused by blasting, mine collapses, settling around new large impoundments, fault slippage related to wastewater injection, nuclear explosions, and so on. Table 12 summarizes observed seismicity related to the development of energy resources across the U.S.

Table 12: Comparison of Induced Seismicity Associated with Energy Resource Activities in the U.S.
After NRC (2013), Table S-1, p. 10-11

Energy Technology	Number of Projects	Number of Felt Induced Events	Maximum Magnitude of Felt Event	Number of Events M ≥ 4.0
Vapor-Dominated Geothermal	1	300 – 400 per year since 2005	4.6	1 to 3 per year
Liquid-Dominated Geothermal	23	10 – 40 per year	4.1	Possibly one
Enhanced Geothermal Systems	~8 pilot projects	2 – 5 per year	2.6	0
Secondary Oil and Gas Recovery (Waterflooding)	~108,000 (wells)	One or more felt events at 18 sites across the country	4.9	3
Tertiary Oil and Gas Recovery (EOR)	~13,000	None known	None known	0
Hydraulic Fracturing for Shale Gas Production	35,000 wells total	1	2.8	0
Hydrocarbon Withdrawal	~6,000 fields	20 sites	6.5	5
Wastewater Disposal Wells	~30,000	9	4.8	7
Carbon Capture and Storage (Small Scale)	2	None known	None known	0
Carbon Capture and Storage (Large Scale)	0	None	None	0

Various oil and gas industry activities are widely thought to cause felt earthquakes, although the evidence for any particular earthquake arising from a specific activity is mostly based on proximity in location and time. Case studies have been done on some of the larger induced earthquakes in Ohio, Texas, Colorado, Oklahoma, and Arkansas. Figure 15 shows the geographic locations of several earthquakes that are believed to result from gas and oil industry practices. The strongest earthquake believed to have come from oil and gas industry practices in the United States is around 5.6 M. Most seismicity from gas and oil industry activities is too small to be felt beyond the local occurrence. Cosmetic and structural damage to buildings can occur from the largest induced earthquakes.

According to U.S. Geological Survey (USGS) scientists, "[t]he number of earthquakes has increased dramatically over the past few years within the central and eastern United States. Nearly 450 earthquakes of magnitude 3.0 and larger occurred in the four years from 2010-2013, over 100 per year on average, compared with an average rate of 20 earthquakes per year observed from 1970-2000… USGS scientists have found that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells." (Ellsworth, et al. 2014) See Figure 16. According to USGS seismologist, Bill Leith, "We've statistically analyzed the recent earthquake rate changes and found that they do not seem to be due to typical, random fluctuations in natural seismicity rates." He further observed that the recent increase in earthquake rates "require significant changes in both the

background rate of events and earthquake triggering properties… in contrast to what is typically found when modeling natural earthquake swarms." (quoted in Ellsworth, et al., 2014).

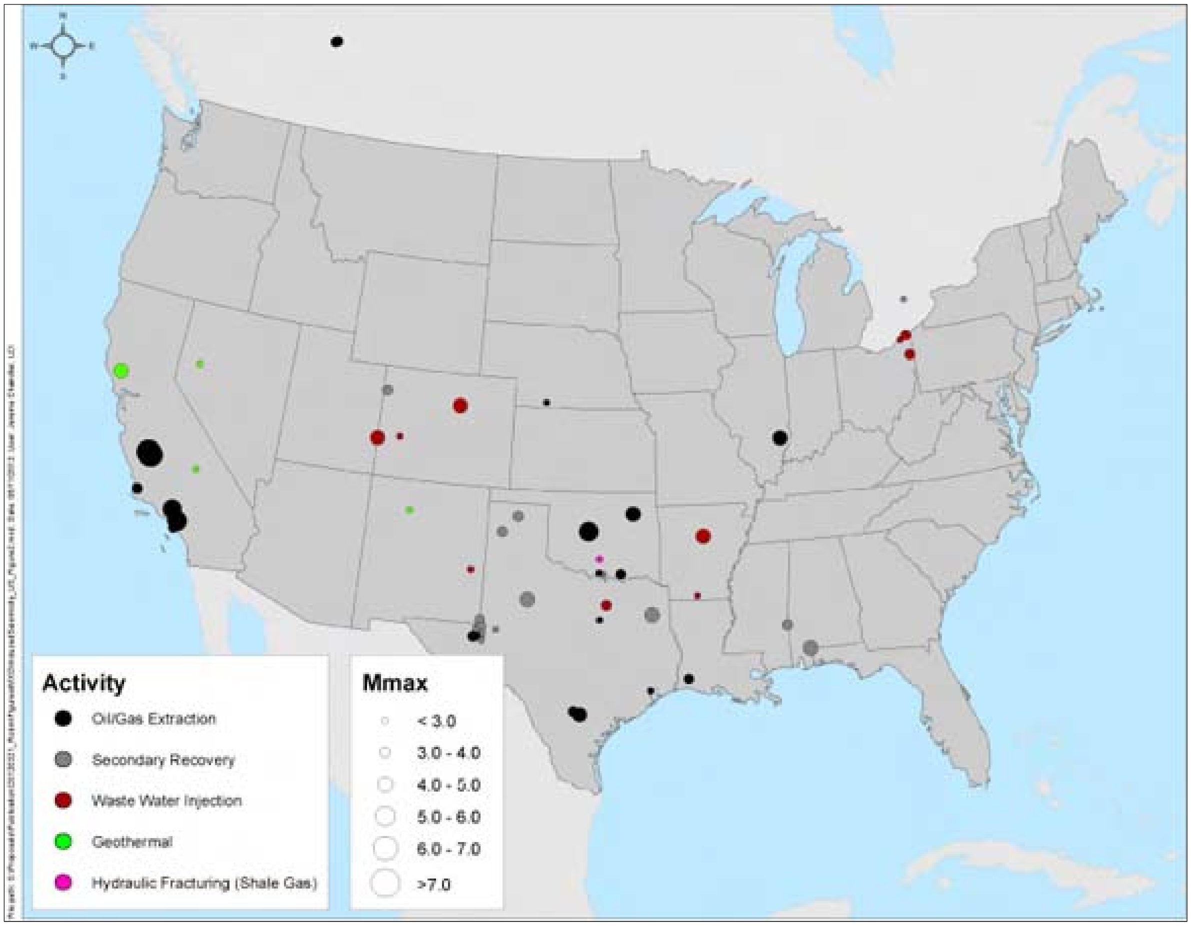


Figure 15: Geographic Locations of Earthquakes Believed to Result from Gas and Oil Industry Practices (NRC, 2013, *Induced Seismicity Potential in Energy Technologies*. Reprinted with permission from the National Academy of Sciences, Courtesy of the National Academies Press, Washington, D.C.)

Causes of Induced Seismicity Associated with Oil and Gas Industry Activities

Primary Gas and Oil Production

Production of gas and oil from underground reservoirs has the potential to induce seismicity, especially when an equal volume of fluids is not injected into the reservoir to maintain original fluid pressures. Because the extraction of gas, oil, and associated water from the reservoirs reduces the fluid pressures in the pore spaces of the reservoir material, unconsolidated materials (such as some of the sand reservoirs along the Gulf Coast of the United States) can compact, causing settlement of the overlying rock and sediment along with certain types of faulting. In this situation, abrupt slippage along faults is less frequent because the overlying rock and sediment tend to be poorly consolidated such that abrupt breaks (brittle failure) occur less frequently. The chance of this type of seismicity is considered to be low for currently targeted tight sand and shale plays in the United States (see discussion in Suckale, 2010).

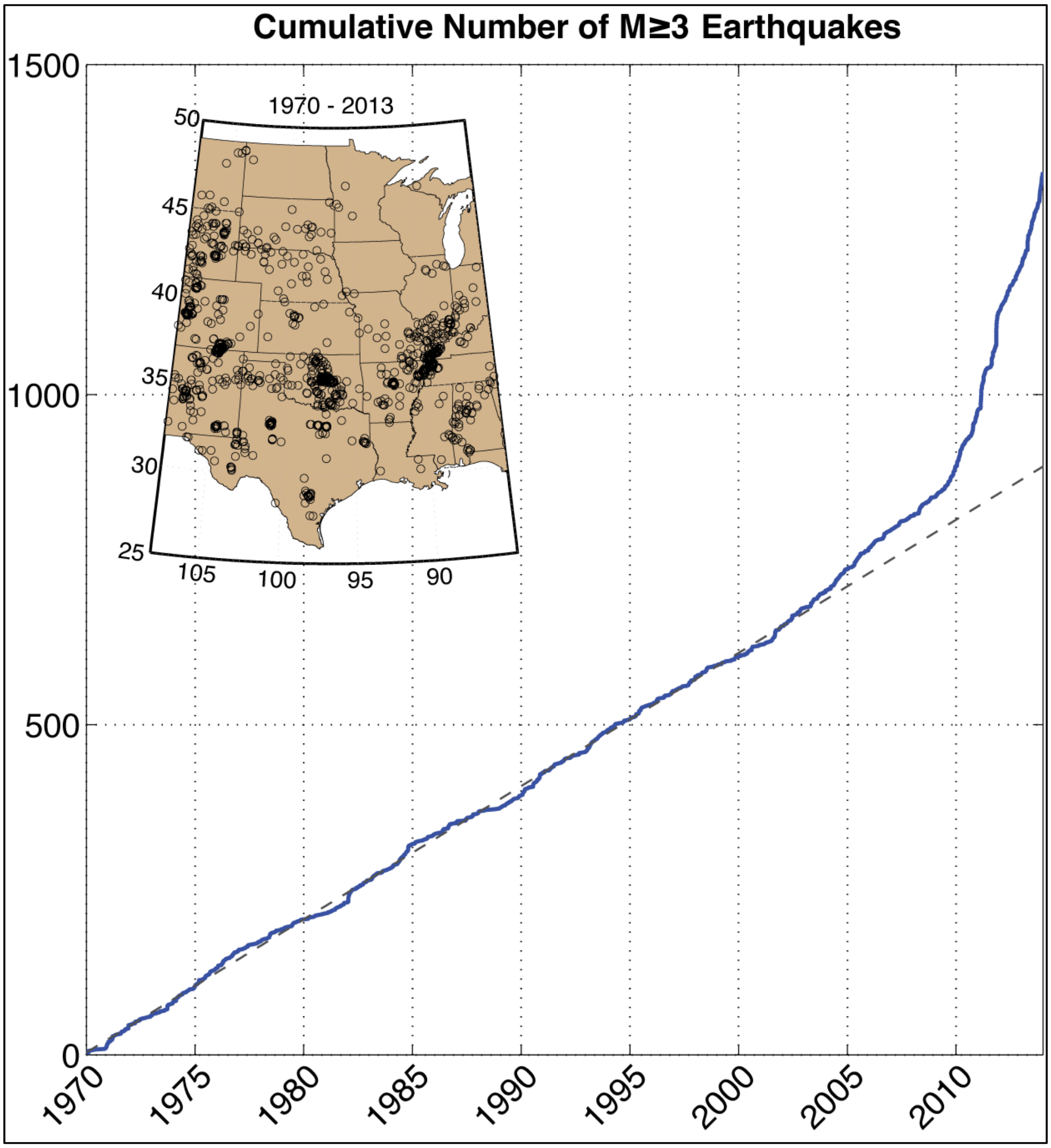


Figure 16: "Cumulative count of earthquakes with a magnitude >= 3.0 in the central and eastern United States, 1970-2013. The dashed line corresponds to the long-term rate of 20.2 earthquakes per year, with an increase in the rate starting around 2009." Ellsworth, et al., 2014. *Man-Made Earthquakes Update*. USGS, Science Features. http://www.usgs.gov/blogs/features/usgs_top_story/man-made-earthquakes/

Depending on the shape or configuration of the reservoir body, slight contraction of the reservoir as a result of fluid withdrawal can cause stresses in the rock surrounding the reservoir to undergo a significant change in principal stress directions and magnitudes, potentially encouraging movement on faults or creating faults.

Furthermore, the unloading of weight that occurs when a large mass of fluids is removed changes the stresses in the rock beneath the reservoir, potentially inducing slippage and earthquakes in the rock beneath the reservoir.

Hydraulic Fracturing in Unconventional Natural Gas Production

The hydraulic fracturing process creates fractures to increase flow pathways immediately surrounding the wellbore. The fractures extend outward from the well at points of fracture initiation, usually where the casing has been perforated to allow reservoir fluids to flow into the well. The fractures are typically perpendicular to the minimum principal stress direction. Fractures extend radially outward from the well (sometimes exceeding 1,000 feet) within the reservoir strata (see Fisher and Warpinski, 2011). Increases in hydraulic pressure at the fracture tip are required to force growing fractures to cross rock beds of differing materials. For this reason, the vertical extent of fracture growth tends to be much less than the horizontal extent (Ibid.). Fracturing fluids are pumped in at high pressure to grow the hydraulic fractures an optimal distance and to open natural fractures that are connected to the hydraulic fractures. There is incentive to discontinue injecting liquids when an optimal fracture size is reached because much of the fluid flows into inter-granular pore spaces where it obstructs the flow of natural gas (or oil) into the created fractures. Operators also attempt to keep fractures from propagating upwards beyond the target formation to prevent intersection with an aquifer, whereby water would flow into the gas reservoir. At depths shallower than about 2,000 feet, hydraulically created fractures will tend to grow horizontally (Ibid.).

As the hydraulic fractures grow, the breaking rock releases micro-seismicity, which is usually too small to feel. This is sometimes monitored by the well developer to track where the fractures grew. Seismicity coming from the breaking rock is weak and usually not felt at the surface. If the fractures intersect a natural fault, the risk of inducing a felt earthquake increases. The same risk exists when a series of natural fractures connect into a nearby natural fault. Fisher and Warpinski (2011, p. 3 and 15) noted that hydraulic fractures occasionally intersect faults and larger magnitude seismic events can be generated as a result of the large fault surface area available to move. Induced micro-seismicity within faults has been observed to extend upwards nearly 2,000 feet from the wellbore (Ibid., Fig. 4).

When the operator stops injecting, the flow back of liquids to the surface relieves the fluid pressures within the fracture zone and reduces the risk. The duration of injection is generally minutes or hours and the quantity of injected fluids is relatively small. Therefore, the probability of injecting enough fluid into a natural fault to trigger a felt earthquake is low. The GWPC report (2013, p. 17, citing Holland) noted the possibility of cases of hydraulic fracture jobs in two fields in Oklahoma causing seismic events ranging up to a maximum of 2.9 M. The GWPC report also summarized the statements of several presenters regarding a couple of felt earthquakes (maximum = 2.3 M) in the United Kingdom and another case in Canada. The National Research Council (NRC, 2013) report notes that EPA (2011) estimated about 35,000 wells had been fractured in shale gas plays in the United States, with NRC identifying only a few cases of possible felt seismicity.

Wastewater Disposal Via Injection

Water produced from a reservoir is often a large quantity. Produced water usually has high concentrations of salt and contains residues of oil and gas. Frequently, it is gathered and re-injected. In some cases the water is piped or trucked to wells that inject the water into other strata. Wastewater disposal wells are installed into porous and permeable strata thought to have suitable characteristics for accepting the wastewater. This technique of wastewater disposal has been used for many decades by the oil and gas industry and also has been used for disposal of both industrial wastewater and municipal sewage treatment plant effluent.

There have been a number of cases of induced seismicity associated with wastewater injection into formations used only for disposal. Figure 15 (above) shows the locations of some of these cases. The incidence of felt earthquakes is higher for wastewater disposal via injection wells because a large volume of water is injected without any withdrawal of fluids, with the result that fluid pressures can be increased within a large area surrounding the injection well. Such large-scale injection increases the chance of elevating fluid pressures in a natural fault that is already under stress. The GWPC report (2013, p. 18, citing Holland) briefly describes an episode of approximately 1,800 earthquakes ranging in magnitude up to 4.0 M at a location in Oklahoma, about 8 to 12 miles from disposal wells thought to have possibly triggered the events. In a more thoroughly studied case located in the Paradox Basin of Colorado, the injection of natural brines (not from oil and gas industry activities) triggered earthquakes up to 9.9 miles away from the injection well (see NRC, 2013, p. 90, citing Block, 2011). The largest earthquake possibly induced by disposal of wastewater in the United States was a 4.7 M event in central Arkansas. It was one of 1,300 earthquakes, all located within the vicinity of several active disposal wells and showing temporal and spatial correlation with the wells (GWPC, 2013. p. 19-20, citing: Ausbrooks). In a recent case, small earthquakes ranging up to 4.0 M were correlated with a nearby deep disposal well near Youngstown, Ohio (GWPC, 2013, p. 21-22, citing Tomastik). The GWPC report mentions other cases in Texas and West Virginia, apparently related to disposal of produced water from shale plays.

Industry Practices and Regulations

The following are a few facts relevant to understanding and considering the potential for induced seismicity associated with expansion of industry activity in the shale and tight sand gas (and oil) plays onshore in the United States:

1) Typical quantities of water injected during shale and tight sand hydraulic fracture jobs are 1 to 6 million gallons per well; typical quantities of flowback water are 1 to 3 million gallons.
2) Typical quantity of production-related water to be disposed from a well or reservoir is approximately 10 barrels of water per 1 barrel of oil produced; comparatively, little water is produced per million cubic feet of natural gas produced (see NRC 2013, Table 3.2).
3) The geographic distribution of conventional resources (Figure 17) and the distribution of unconventional resources (Figures 1, 3, and 4) cover a large portion of the co-terminus United States (and Alaska), including large metropolitan areas and areas of manufacturing.
4) Industry practices and resource attributes vary among the unconventional resource plays such that the potential for impacts and preventative operational measures may differ for each play (see Table 13 for comparison of attributes of the major plays).
5) Underground injection wells along with gas and oil wells are allowed in almost all states. Neither Federal nor State regulations directly address induced seismicity (GWPC, 2013, p. 14, citing: McGuire). The one exception is that Ohio issued regulations in October

2012 to directly address the risks of induced seismicity associated with disposal wells (GWPC, 2013, p. 33-34, citing: Tomastik). Lesser controls and permit application procedures are in place in Colorado and Arkansas (Ibid., p. 34-35, citing Ellsworth, Ausbrooks). These regulations provide the authority to stop injection when necessary to protect public welfare.

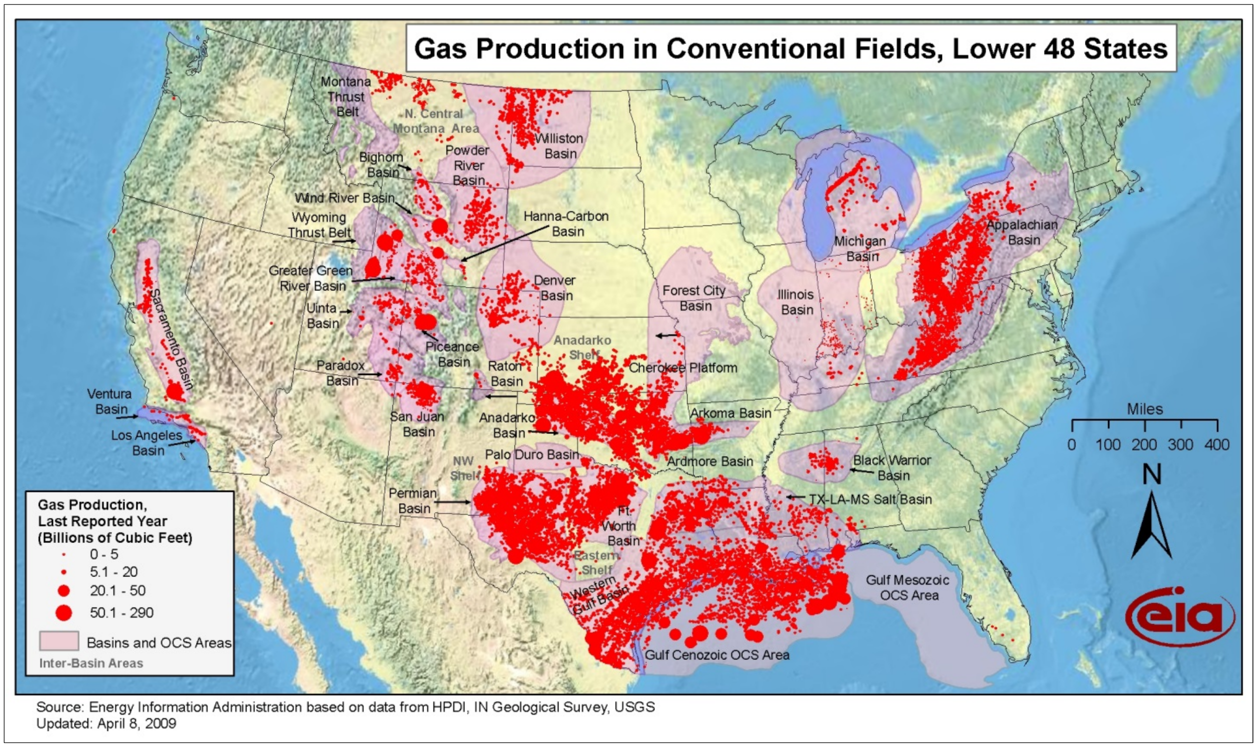


Figure 17: Lower 48 States' Conventional Gas Plays
(EIA, 2009)

Table 13: Attributes of Major Shale Gas Plays in the United States

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area (mi^2)	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth (ft)	6,500 – 8,500	1,000 – 7,000	10,500 – 13,500	4,000 – 8,500	6,000 – 11,000	600 – 2,200	500 – 2,000
Net Thickness (ft)	100 – 600	20 – 200	200 – 300	50 – 200	120 – 220	70 – 120	50 – 100
Depth to Base of Treatable Water (ft)	~1,200	~500	~400	~850	~400	~300	~400
Rock Column Thickness Between Top of Pay and Bottom of Treatable Water (ft)	5,300 – 7,300	500 – 6,500	10,100 – 13,100	2,125 – 7,650	5,600 – 10,600	300 – 1,900	100 – 1,600
Total Organic Carbon (%)	4.5	4.0 – 9.8	0.5 – 4.0	3 – 12	1 – 14	1 – 20	1 – 25
Total Porosity (%)	4 – 5	2 – 8	8 – 9	10	3 – 9	9	10 – 14
Gas Content (scf/ton)	300 – 350	60 – 220	100 – 330	60 – 100	200 – 300	40 – 100	40 – 80
Water Production (barrels water/day)	N/A	N/A	N/A	N/A	N/A	5 – 500	5 – 500
Well Spacing (acres)	60 – 160	80 – 160	40 – 560	40 – 160	640	40 – 160	80
Original Gas-In-Place (tcf)	327	52	717	1,500	23	76	160
Technically Recoverable Resources (tcf)	44	41.6	251	262	11.4	20	19.2

(GWPC and ALL Consulting, 2009, Exhibit 11)

Opportunity for Harm

Overlying the current shale plays and tight sand plays are areas of various levels of development, including urban areas (such as Dallas, Fort Worth, and Pittsburgh), industrial areas, rural areas, forests, and arid land. Prior events of induced earthquakes have garnered more attention in areas that historically have been aseismic in recent history. Earthquakes in shale play areas have been below the magnitudes that would cause structural damage. The potential exists for stronger earthquakes, most likely in association with deep well disposal of wastewater from unconventional plays. As more injection wells are used, more instances of induced earthquakes are possible.

Assessment of Environmental Impacts

NRC examined the scale, scope, and consequences of seismicity induced during fluid injection and withdrawal related to energy technologies, including shale gas recovery, and concluded that "the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events" (NRC, 2013).

The relative risks associated with further expansion of the unconventional natural gas industry activities may be summarized as follows:

1) Wastewater disposal via injection wells presents the highest risk of induced seismicity. In contrast, oil/gas production is expected to be low-risk. Hydraulic fracturing seems to cause few felt earthquakes, based on current industry practices and the frequency of reported events.
2) Industry practices generate wastewater in proportion to the number of wells developed and in proportion to the amount of natural gas produced. Wastewater may be dealt with in a number of ways, but underground injection through disposal wells is a low-cost approach that is likely to continue for some period of time. In some states, facilities are now being specially designed and constructed to treat this waste water for reuse or safe release.
3) Faults in proximity to points of fluid injection relate to higher risks. For wastewater disposal wells, earthquakes may be triggered up to 10 miles away (see GWPC, 2013, p. 12; NRC, 2013, p. 90, citing Block, 2011). Avoidance of known faults can reduce risks when siting injection wells.
4) Injection of large volumes of fluid tends to elevate pore pressures longer distances from wells. This results in a higher probability of triggering a susceptible fault. Disposal practices could be considered such that injection of wastewater occurs in strata where fluids of equal volume are currently being removed or where fluids of equal volume have been removed in the past (such as depleted oil fields).
5) As the number of wells increases, so will the chance of wells being in close proximity to susceptible faults. Risks also increase from the cumulative effect on fluid pressures of having multiple wells injecting large volumes of fluid into a single stratum or a small region.
6) Most of the economic risk relates to the potential for damage to buildings and infrastructure if a larger earthquake is triggered. Structural damage can occur but very rarely does. Generally, the potential for harm to people is very low.

Concerning the assessment of impacts from induced seismicity, NRC (2013) noted the following in its summary:

> "Recently, several induced seismic events related to energy technology development projects in the United States have drawn heightened public attention. Although none of these events resulted in loss of life or significant structural damage, their effects were felt by local residents, some of whom also experienced minor property damage. Particularly in areas where tectonic (natural) seismic activity is uncommon and energy development is ongoing, these induced seismic

events, though small in scale, can be disturbing to the public and raise concern about increased seismic activity and its potential consequences." (p. 5)

Land Use Impacts

All energy sources create some impact on land use, and most have substantial land requirements when the whole supply chain is included (Sathaye et al 2011). The development of unconventional natural gas resources clearly includes direct and indirect changes to the land, as discussed below. Some impacts are short-term in nature, while others may be more permanent. While no single authority appears to have compiled comprehensive information on the intensity of land use impacts on a comparative basis, there have been various efforts to estimate land use associated with energy sectors, with more emphasis on electricity generation. For instance, biomass energy can utilize 460,000 m^2/GWh/yr (Nicholson 2013)**. A** typical hydroelectric reservoir utilizes 250,000 m^2/GWh/yr**, with g**eothermal plants impact**ing** up to 900 m^2/GWh/yr (MIT 2006)**, and land-based natural gas impacting 250-320 m^2/GWh/yr (Fthenakis and Kim 2009). W**ind energy may impact approximately 1,100 m^2/GWh/yr (Ong et al 2009). Larger solar plants, which vary in size and technology employed, can impact up to 15,000 m^2/GWh/yr (Ong et al 2013). Photovoltaic arrays deployed on existing structures would be substantially less. **A comparative analysis prepared for the Natural Gas Supply Association (2014) made a similar comparison of impacts and other factors by fuel type for electricity generation. The results for land use are presented in the table below, showing natural gas to have one of the smaller footprints**.

Table 14: Comparison of Land Use for Different Fuel and Power Plant Types (Data from Leidos, 2014)

Fuel/Plant Type	Typical Plant Capacity	Land Use Per 1,000 Households
Natural Gas – Combined Cycle	400 MW	0.30 acres
Coal – with Advanced Pollution Control	650 MW	0.48 acres
Coal – with Carbon Capture and Sequestration	650 MW	0.95 acres
Advanced Nuclear	2,234 MW	0.74 acres
Biomass – Waste	50 MW	0.06 acres
Biomass – Wood	50 MW	0.11 acres
Solar – Photovoltaic	20 MW	43.30 acres
Solar – Thermal	100 MW	43.30 acres
Wind – Onshore	100 MW	15.46 acres

The available comparisons do not clearly detail what is or is not included in their respective land use or footprint estimates. Additionally, it is difficult to compare such land use impacts with those associated with unconventional gas, which may be used for more than electricity generation. The following discussion highlights the land use impacts that may result from the development of unconventional natural gas resources.

Natural gas development generally occurs on undeveloped land that may be privately or publicly owned. These lands may be currently used for residential, agricultural, light industrial, timber management, wildlife management, or recreational uses. Land use impacts would occur as a result of surface disturbances mainly associated with the construction and development of new access roads, well pads, and pipeline Rights-of-Way (ROWs), as well as the other ancillary infrastructure that may be needed during gas exploration and production activities (e.g., lay-down areas, compressor stations). Additional development as a result of natural gas exploration and production activities may also include the construction of new housing, office buildings, equipment yards, raw material supply storage, and other related infrastructure to support the workforce and material needed for the myriad of activities associated with natural gas development (e.g., land clearing, well drilling, well completion and stimulation [hydraulic fracturing], gas production, and pipeline construction).

Description of Disturbances

The following section discusses land requirements and activities for the two main components associated with natural gas production: well drilling/production and pipeline construction/operation.

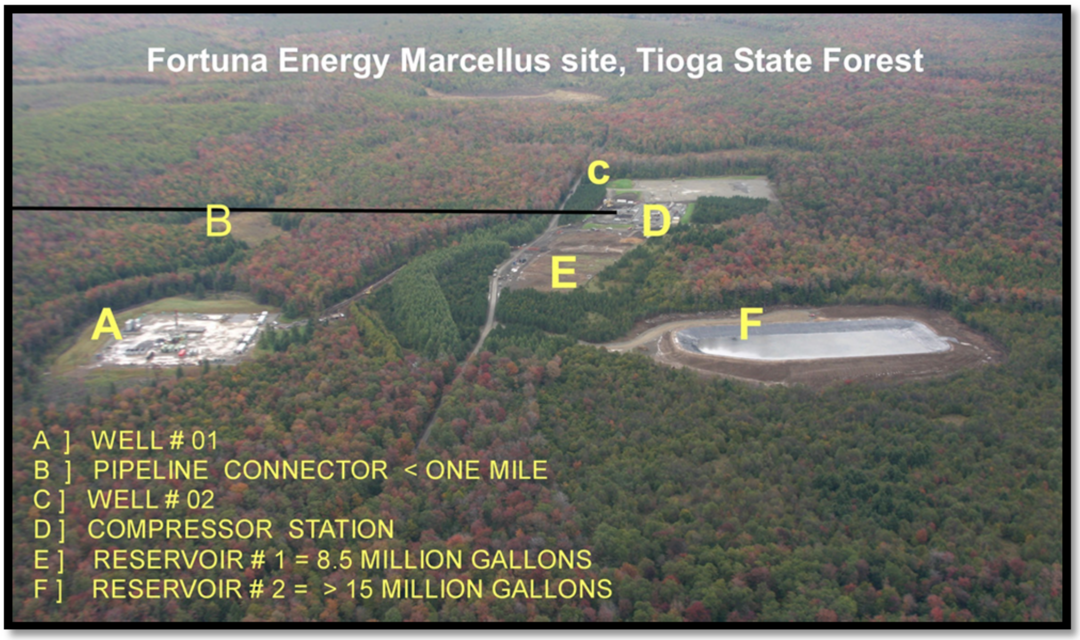


Figure 18: Example of Well Pad Development in a Wooded Location
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Well Drilling (Exploration/Fracking/Production)

Access Roads: These are typically needed to provide entry to leased properties for the purposes of exploration activities, development of well pads, drilling and completion of wells, and well stimulation prior to production. The length of access roads varies depending on topography, proximity to existing roads, and other location-specific requirements. Access roads need to be wide enough to accommodate large trucks carrying heavy equipment and large quantities of materials to and from the well pads. As development and production operations proceed, local residents can be confronted with increased truck traffic, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Utilities may also follow the same corridor.

Well Pad Size/Components: A well pad is a prepared area that provides a stable base for drilling rigs, retention ponds, water storage tanks, piping and pumps, and other related equipment. After well completion, the pad also serves as the location of the wellhead. Pad preparation includes clearing and leveling several acres of land which is usually leased from the landowner. Typical well pads are 3-5 acres, but may be as large as 7-10 acres for locating multiple horizontally drilled wells. Horizontal directional drilling, combined with high-volume hydraulic fracturing, allows multiple wells (up to 8-12) to be drilled from one well pad (Clark et al. 2012).

Well Pad Spacing: Typical well spacing starts at one well pad per square mile. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6 to 8 wells (NETL, 2009). **As horizontal drilling capabilities increase, well pad spacing has also increased, reducing impacts to land resources.** The need for additional well pads is determined by characteristics of the local geology and production status.

Figure 19: Example Well Pad in Pennsylvania
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Pipelines

New gathering and transmission pipelines will be constructed as a result of increased unconventional gas development. Widths of ROWs for construction vary from 75 to 100 feet. Gathering pipelines run between individual well sites, compressor units, and metering stations. Transmission pipelines (interstate pipelines) move gas between two or more states. Pipelines usually require the pipeline company to acquire ROW to private or public lands. A pipeline ROW is a strip of land over and around natural gas pipelines where some of the property owner's legal rights have been granted to a pipeline operator. An ROW agreement between a pipeline company and a property owner is also called an easement and is usually filed in the appropriate county office with property deeds. ROWs provide a permanent, limited interest in the land, allowing the pipeline company to install, operate, test, inspect, repair, maintain, replace, and protect one or more pipelines within the designated easement (Penn State Extension, 2014).

Pipeline easements may also be obtained by eminent domain. **Eminent domain is the power to acquire land or access to that land for public use (or public benefit) upon payment of fair compensation to the landowner. This power resides with Federal, State, and local governments and can be granted to certain private companies (e.g., utilities) by state legislatures to, among other things, prevent a single individual from unduly disrupting an activity deemed to be in the best interest of the state or Nation's citizens. Applicable state and federal laws, and the Fifth and Fourteenth Amendments of the U.S. Constitution, contain protections for landowners, requiring due process and payment of market value for any property rights taken. Pipeline companies have been granted the power of eminent domain since the Natural Gas Act (NGA) was enacted in the 1930s. The use of eminent domain for linear features like pipelines varies based on the purpose of the pipeline, location, and the regulating agencies involved. In the case of interstate pipelines, if an easement cannot be negotiated with a landowner and the pipeline has been certified by the Federal Energy Regulatory Commission (FERC), pipeline operators may use the right of eminent domain granted to it under state laws to obtain rights-of-way and temporary extra work areas. However, in most cases, eminent domain is used as the last resort.**

For gathering lines, the laws governing exercise of eminent domain vary by state. As an example, in New York State, the Commonwealth of Pennsylvania, and the State of West Virginia, the option to use the power of eminent domain generally only applies to transmission pipelines. Therefore, for individual gathering lines, pipeline operators must negotiate easements with each individual landowner along the anticipated pipeline route.

<u>Access/Maintenance Roads</u>: Like well pads, the construction and operation of pipelines require access roads to facilitate the movement of workers, equipment, and materials to the job site as construction activities progress along the pipeline route and to allow for inspection and maintenance activities after completion.

<u>Construction ROW</u>: Construction of pipelines requires a wider ROW to allow access to heavy equipment and the staging of removed soils and other materials (pipe, gravel) needed to complete the pipeline installation. The width varies depending on the size of the pipeline and the terrain to be crossed, but would typically be between 75 to 100 feet for larger pipelines. Larger widths may be necessary to accommodate site-specific challenges, like the use of horizontal directional drilling to avoid impacts to sensitive or unique resources. Considering localized topography of the pipeline project, this area in general represents between 9.1 and 12.1 acres of disturbance per mile of pipe (Oil & Gas Journal).

Figure 20: Example of Eastern U.S. Natural Gas Pipeline Construction
(Photos courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Lay-Down Areas: During pipeline construction, open areas are needed along the pipeline route to stage equipment and materials to facilitate efficient management of construction activities.

Final ROW: Individual ROW agreements may vary, but generally, the pipeline company's final ROW extends 50 feet total width (established at 25 feet from each side of the installed pipeline). Special conditions may cause deviations from this typical case. An ROW is usually mowed periodically, and cleared of trees, high shrubs, and other obstructions on an annual basis. Easements also restrict land owners from certain activities within the ROW that could impact the integrity of the pipeline.

Figure 21: Typical Pipeline Right-of-Way Cross-Section
(https://www.aogc.com/beawarepipelinesinyourcommunity_en.aspx)

Compressor Stations: Similar to well pads, compressor stations require stabile flat areas.

Figure 22: Examples of Natural Gas Compressor Stations
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Other Ancillary Infrastructure

The development of gas exploration and production infrastructure (wells and pipelines) requires a substantial workforce and a variety of raw materials. This leads to the development of ancillary infrastructure with additional but similar potential impacts to land use (sewer lines, water lines, utility lines, etc.). However, much of this development may occur in areas that are less rural or remote, where access to highways or other transportation modes can be provided.

Housing: New hotels/motels, especially extended-stay motels; temporary worker bunkhouses or worker villages; RV campgrounds; or other housing developments constructed for the purpose of housing shale gas field workers.

Commercial Space: Office buildings to provide space for the management support and technical teams associated with gas development spring up around the area of well development and pipeline activities. These are needed for the myriad of companies providing well drilling services, well operation support, pipeline construction, well-field services, and their subcontractors. Warehouses and equipment storage yards provide space for staging equipment and materials, or maintaining equipment (example below).

Figure 23: Typical Construction Staging and Equipment Areas
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Supporting Businesses: The rapid development associated with unconventional gas exploration and production often leads to an increase in the businesses indirectly supporting the work force. Office and field workers need food, fuel, raw materials, and other supplies to complete their work. Convenience stores and gas stations provide easy access to such necessities for the field workers. Vendors provide the raw materials, like pipe, sand, cement, and chemicals. Often, larger facilities develop near rail or barge lines where bulk goods transportation can be accessed (examples from Texas and Pennsylvania below).

Figure 24: Pipe Storage Facility in Pennsylvania
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Typical land use impacts **may** include the following:

- Conversion of agricultural (crops and grazing) and forested lands to open disturbed, semi-industrial uses. **Some lands in ROW may revert back to agricultural uses, but soil compaction or drainage changes may be issues (Penn State 2014, Cornell 2010).**
- Conversion of lands to maintained ROWs for access roads and pipelines. Loss of lands for public recreational use/access.
- **Decreased property values and the inability to obtain mortgage loans or insurance in areas adjacent to gas development activities and infrastructure (Radow 2014, Throupe et al 2013).**
- Increased ease of **unwanted** access to lands via new access roads. Many may be gated, but walk-in accessibility **could** be increased.
- Cumulative impact of development on public and private lands, such as increased deterioration of local and secondary roadways due to repetitive high axle load truck traffic.

The real issue with land use impacts is not the minor impacts related to each well pad, access road, or pipeline. When the impacts from these individual components of shale gas development are considered in aggregate, or cumulatively, the impacts become magnified on an ecosystem **or** regional scale. Aerial photographs taken from areas with major shale gas development illustrate this, showing the extensive numbers of well pads and networks of access roads and pipelines that have resulted. In the rural areas where much of this development occurs, it is easy to see that such widespread development can carve up the land once used for agricultural, grazing, timber management, wildlife management, and recreational purposes. While these land uses can still occur, the patchwork that results from shale gas development undoubtedly leaves a mark on the quantity of land consumed, quality of recreational use, and the quality of habitat available to many important wildlife and plant species. It must be noted, however, that some of these changes may be a benefit to certain wildlife species.

Figure 25: The Effect of Landscape Disturbance on Non-Forest Habitat (Wyoming, USA)
(USGS 2013)

Figure 26: Aerial Picture of Gas Development Near Odessa, Texas
(Dennis Dimick/Flickr)

Shale gas development on forested lands results in the removal of core forest lands within large contiguous tracts of forest. The result is the creation of more edge forests and a reduction of the few vast tracts of forested lands left, especially in the eastern United States (NPR 2014). **New forest edges create an environment where increased risks of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species (TNC 2010).**

When shale gas development occurs on public land, Federal and State resource managers need to identify areas that may require special protection, setting them aside from further development. These areas could represent important habitat for protected species, special recreational use areas, or other areas with unique resources that need to be protected (e.g., historical, cultural). Such protection can also occur at the local or municipal level when development is planned on or near municipal parks or other multiple-use lands.

Associated impacts from development:

- Increased traffic – Pipeline construction and well development activities require deliveries of various raw materials and an army of workers that **may result in increased** traffic, **raised** accident rates, and increased road wear and tear (see Traffic and Roadway Impacts).
- Increased noise and vibration – Pipeline construction and well development activities increase noise levels.
- Habitat fragmentation – Pipeline construction and well development activities result in a loss of land and landscape/vegetation changes. The overall result is a patchwork of well pads and pipeline corridors that changes the regional landscape, breaks up large tracts of undisturbed land, and fragments the habitats for many species.
- **Protected species – Land disturbance and related impacts have the potential to impact state and federally protect species (Johnson 2010). Species with limited distribution or special habitat requirements may be especially vulnerable (Gillen and Kiviat 2012).**
- Invasive species – Pipeline construction and well development activities **may** cause disturbance of land that can provide access to invasive species. **Federal and state guidelines exist to regulate reclamation efforts in an effort to minimize this impact.**
- View shed alteration – Pipeline construction and well development activities cause at least temporary visual changes to the landscape. During the peak of activities, nuisance lighting can also be an issue.
- Reflective Light Pollution – During the peak of activities, nuisance lighting can also be an issue.

Figure 27: Example of Eastern Shale Gas Viewshed Alteration
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Figure 28: NPR – Satellite Imagery of Bakken Shale/Oil Play Area (January 2013)

Land Use Mitigation Measures

Mitigation measures to avoid or reduce impacts to land use from oil and gas production.

The following are examples of mitigation measures that could be applied to reduce land use impacts of a project depending upon site- and project-specific conditions. Since most land use impacts are related to the project footprint (e.g., land disturbance, habitat destruction, erosion, changes in runoff patterns, and hydrological alterations), many impacts can be reduced or avoided when considered during the siting and design phase.

Siting and design considerations that mitigate impacts include:

- Identify sensitive resources, existing land uses, and local plans and ordinances.
- Provide adequate public notice of planned exploratory activities.
- Site the project on previously disturbed or altered landscapes whenever possible.
- Consolidate infrastructure requirements (e.g., well pads, pipelines, transmission pipelines, roads) for efficient use of land. Consider the reclamation requirements for the site during initial development of well pads and roads.
- Establish reclamation plans to addresses both interim and final reclamation requirements. Ensure that interim reclamation of disturbed areas is conducted as soon as possible.

- Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009).

Many State and Federal agencies that manage large tracts of land have developed processes to permit natural gas development activities on their lands. For example, BLM has published "The Gold Book – Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development" (USDOI/BLM 2007), and the Pennsylvania DCNR has issued its "Guidelines for Administering Oil and Gas Activity on State Forest Lands" (PADCNR, 2013).

Traffic and Roadway Impacts

Traffic Impacts

Increased traffic causes potential noise, as well as visual and air quality impacts. Trucking demands related to transportation of materials, water, and waste lead to concerns over large volumes of traffic, as well as large vehicles. Local concerns typically include safety and increased road maintenance.

Throughout the shale play regions, increases in truck traffic will occur on federal, state, county, and other roadways. Truck traffic in certain locations could significantly increase, although most of the projected trips would be short. The largest volume of truck traffic for horizontal drilling is for water deliveries during fracking, and these typically involve short trips between the water supply and the well pad.

Traffic impacts can vary significantly, depending on the type of roadway and whether it's located near a heavily populated community or in proximity to heavily traveled intersections and/or interchanges. Traffic on arterials and major collectors would not be anticipated to be adversely impacted, as these roads are designed for high volumes of vehicle traffic. Anticipated increases in the level of traffic associated with nearby wells may only represent a small, incremental change in existing conditions. However, certain local roads may experience congestion during certain times of the day, or during certain phases of well development. Vehicles associated with fracking operations may exceed 1,000 truck trips. Table 15 lists the approximate truck traffic that can be expected throughout a typical unconventional Marcellus shale gas well development.

Table 15: Truck Traffic Expected Throughout Typical Unconventional Marcellus Shale Gas Well Development

Purpose	Truck Trips			
	Per Well		Per Pad	
	Low	High	Low	High
Drill pad and road construction equipment			10	45
Drilling rig			30	30
Drilling fluid and materials	25	50	150	300

Drilling equipment (casings, drill pipe, etc.)	25	50	150	300
Completion rig			15	15
Completion fluid and materials	10	20	60	120
Completion equipment (pipe, wellhead)	5	5	30	30
Hydraulic fracture equipment (pump trucks, tanks)			150	200
Hydraulic fracture water	400	600	2,400	3,600
Hydraulic fracture sand	20	25	120	150
Flowback water removal	200	300	1,200	1,800

(Supplemental Generic EIS on the oil, gas, and solution mining regulatory program, published in 2009 by the NYSDEC Division of Mineral Resources).

As with other resources, traffic impacts must be evaluated on a local level. The potential for impacts will correlate with the number of additional vehicles and the capacity and existing level of service of the roadways. Extra truck traffic would generate increased maintenance for other local road structures, such as bridges, traffic devices, and storm water and drainage structures.

Roadway Infrastructure Impacts

Shale gas extraction requires many heavy truck trips for equipment and materials, which can damage state and local roads that do not normally experience high volumes of heavy truck traffic. As a result of the anticipated increase in truck traffic, roads in the vicinity of the well pads may be damaged. Many of the areas affected by well development are rural in nature and do not have the proper roadways for the larger size and volume of vehicles that come with unconventional natural gas well developments. Many rural local roadways typically began as unpaved farm cartways having the least amount of bearing capacity (pavement thickness). Over the years, these local rural roadways have gradually developed through multiple layers or tarring and chipping; however, many are still without a true subbase, or proper drainage features. These types of local roadways are damaged the most by high axle load vehicles. Road damages can begin with minor fatigue cracking (i.e., alligator cracking), leading to significant delamination (potholes, rutting, and pumping) to complete failure of the roadway pavement and subgrade. Shale development firms, through agreements with state and local municipalities, often reconstruct visibly damaged roads; however, these reconstructions vary greatly from one developer to another, as well as from one local municipality to another.

Typically, the different classifications of roads are constructed to accommodate different levels of service and weight, defined by vehicle trips or vehicle class. Normally, the higher the road classification, the more stringent the design standards and the higher levels of bearing capacity and safety are designed into the road. The design of roads and bridges is based on the weight of vehicles that use the infrastructure. Local roads are not typically designed to sustain a high level of vehicle trips or loads and thus oftentimes have weight restrictions. The increased levels of maintenance and repair of roadway infrastructures in Pennsylvania and other major shale play locations will place strains on already limited budgets along with the county and local agencies responsible for local roads. According to a recent study, assuming an average of 20 miles travel distance one way, the range of consumptive road use costs per well is between approximately \$13,000 and \$23,000, depending on the number of heavy truck trips assumed to be associated with shale gas development. Heavy trucks generally cause more damage to roads and bridges than cars or light trucks due to the weight of the vehicle. When performing calculations for a detailed pavement design, a single large truck is generally equivalent to the passing of 9,000 to 10,000 automobiles (Alaska Department of Transportation and Public Facilities 2004; Army Corps of Engineers Pavement Design, Waterways Experiment Station, Vicksburg, MS).

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Appendix A: Calculations from Greenhouse Gas Section

Natural Gas Production in Year 2012 (EIA, 2014):

24.**06** Tscf/year x 25 g/scf x 1,000 Gg/Tg = 60**1,500** Gg/year

Estimation of unit methane emissions:

1.0 Tscf/year x (4**955** Gg CH_4/24.**06** Tscf) = **205,943** Gg CH_4/year

Estimation of unit emissions of CH_4 plus "non-combusted" CO_2:

1.0 Tscf/year x (**42,431** CH_4+CO_2/ 24.**06** Tscf) = **1763.55** Gg CH_4+CO_2/year

1763.55 Gg CH_4+CO_2/year x (**187.1** TgCO_2-e CH_4 + CO_2/**42,431** Gg CH_4 + CO_2) = **7.78** Tg CO_2-e / year

Assuming reductions in CO_2-e emissions as estimated by Bradbury et al. (2013) for all resource types subjected to the recent NSPS (13 percent lower initially, 25 percent lower by 2035), the unit emissions (estimated above) would be reduced to:

7.78 Tg CO_2-e/year x (1.0 – 0.13) = **6.8** Tg CO_2-e/year (current production levels from shales)

7.78 Tg CO_2-e/year x (1.0 – 0.25) = **5.8** Tg CO_2-e/year (increased production levels from shales)

Appendix B: Public Comments

The U.S. Department of Energy (DOE) announced the availability of the Addendum for public review and comment in the *Federal Register* Vol. 79, No 107, on Wednesday, June 4, 2014. By email dated May 29, 2014, each of the parties in several pending proceedings involving applications for authorization to export liquefied natural gas were notified of the announcement and the opportunity to comment.[4]

The announcement initiated a 45-day comment period which closed July 21, 2014. Commenters submitted documents to DOE either by a dedicated online form or by delivery to DOE's Office of Oil & Gas Global Security & Supply in Washington, D.C. All comments filed in response to the Notice were made publicly available on the DOE/Office of Fossil Energy (FE) website (http://energy.gov/fe/Draft-Upstream-Addendum), and an electronic link to the comments was posted to the docket in each of the pending proceedings in which parties had previously been notified of the announcement.

DOE received comments from individuals, industrial stakeholders, and several organizations. DOE did not receive comments from any regulatory or resource agencies. No comments were received from state agencies or elected officials.

Comment Process

All comments were identified, categorized, reviewed, and carefully considered. DOE processed the comments by first reviewing each unique comment submission and delineating them into individual comments. The review identified repetitive comments and removed any inappropriate language. Individual comments were then categorized. Similar comments were grouped and consolidated to develop thematic comments. DOE then prepared responses to the thematic comments as appropriate.

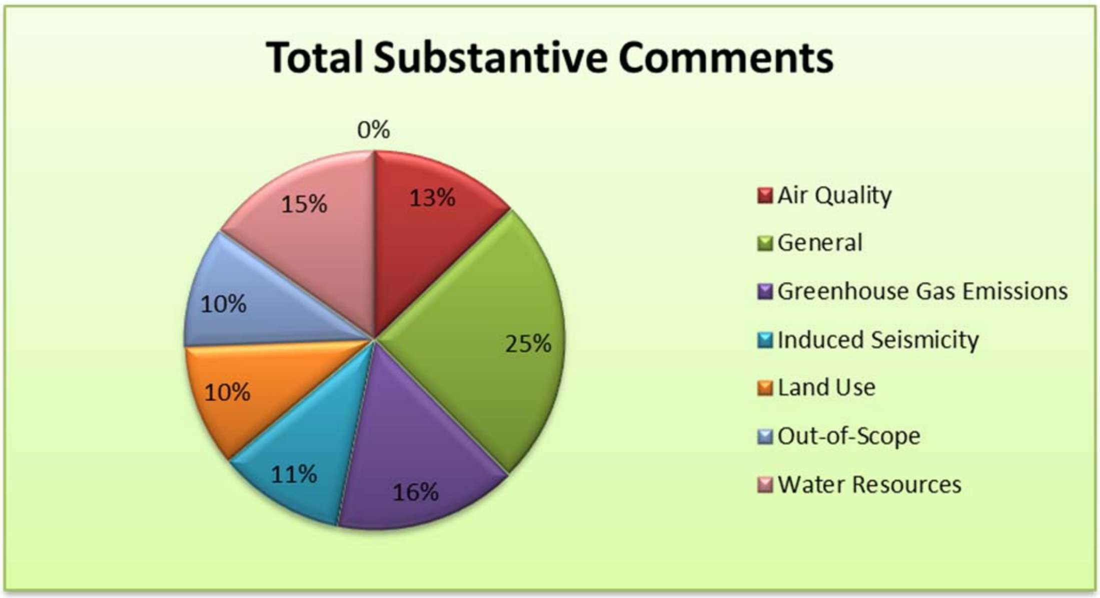
All of the thematic comments are presented in table form herein. Thematic comments are listed within sections titled Air Quality, Induced Seismicity, Greenhouse Gas, Land Use, Water Resources, General Comments, and Out of Scope comments. All individual comment submissions are available to the public at: https://app.fossil.energy.gov/app/GPC-Public/Forms/ViewForm.aspx.

[4] The email notification was directed to parties in the following proceedings: Freeport LNG Expansion, L.P.(10-161-LNG); Dominion Cove Point LNG, LP (11-128-LNG); Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (11-161-LNG); Cameron LNG, LLC (11-162-LNG); Gulf Coast LNG Export, LLC (12-5-LNG); Jordan Cove Energy Project, L.P. (12-32-LNG); LNG Development Company, LLC d/b/a Oregon LNG (12-77-LNG); Cheniere Marketing, LLC (12-97-LNG); Southern LNG Company, L.L.C. (12-100-LNG); Gulf LNG Liquefaction Company, LLC (12-101-LNG); CE FLNG, LLC (12-123-LNG); Excelerate Liquefaction Solutions I, LLC (12-146-LNG); Golden Pass Products LLC (12-156-LNG); Pangea LNG (North America) Holdings, LLC (12-184-LNG); Trunkline LNG Export, LLC (13-4-LNG); Freeport-McMoRan Energy LLC (13-26-LNG); Sabine Pass Liquefaction, LLC (13-30-LNG); Sabine Pass Liquefaction, LLC (13-42-LNG); Venture Global LNG, LLC (13-69-LNG); Eos LNG LLC (13-116-LNG); Barca LNG LLC (13-118-LNG); Sabine Pass Liquefaction, LLC (13-121-LNG); Magnolia LNG, LLC (13-132-LNG); and Delfin LNG LLC (13-147-LNG).

Summary of Comments on the Addendum

DOE received a total of 40,745 comments in 18 separate submissions during the 45-day comment period. These comments are summarized in themes and presented in the following table.

The figure below presents a breakdown by issue category of all the unique substantive comments received on the Addendum.



Thematic Comment	Comment Excerpt	DOE Response
Air Quality		
Subcategory: Air Quality Emissions		
Comments express concern that the Addendum downplays the importance of the contribution of natural gas development to increased ozone levels (in aggregate from numerous wells). Concerns include jeopardizing ozone attainment status and worsening non-attainment status, consequently threatening human health and harming air quality and visibility in national parks and wilderness areas (i.e., Class I areas).	(SC 143) As DOE recognizes, "Air emissions from natural gas development may create new or expanded ozone non-attainment areas and possibly complicate implementation plans for bringing current non-attainment areas into compliance," and "development of gas resources in or near areas currently in attainment of ozone standards could jeopardize the continued attainment status of those areas." (SC 143) DOE appears to inappropriately downplay the importance of these impacts by stating that "Development activities at individual well sites are generally considered to be short-term activities" and by identifying pollution control requirements generally do not apply to gas production. While development of an individual well may be short term, LNG exports would induce additional production requiring development of thousands of wells throughout the life of the projects. Numerous studies have demonstrated that the "short term" impacts of developing individual wells, in aggregate, lead to significant impacts on ozone levels. Several studies have specifically modeled significant gas development's contributions to 8-hour ozone levels: … Wyoming Department of Environmental Quality ("WDEQ") found that ozone pollution was "primarily due to local emissions from oil and gas ... development activities: drilling, production, storage, transport, and treating." …The Utah Department of Environmental Quality has determined that "Oil and gas operations were responsible for 98-99 percent of volatile organic compound (VOC) emissions and 57-61 percent of nitrogen oxide (NOx) emissions," the primary chemical contributors to ozone formation. The Bureau of Land Management (BLM) has similarly identified the multitude of oil and gas wells in the region as the primary cause of the ozone pollution. …Colorado Department of Public Health and Environment concluded that the smog-forming emissions from oil and gas operations exceed vehicle emissions for the entire state. (AAF 112) Although the Addendum acknowledges that emissions from gas development could result in more nonattainment areas, it improperly downplays these concerns, stating that drilling and fracking often occurs in areas where pre-existing pollution exists. This ignores the fact that gas development would make those problem areas worse, and that so far gas	The Addendum addressed these topics and the associated potential impacts, including the potentially serious issue of ozone levels and worsening nonattainment status in some locations. However, the Addendum was not intended to be an in-depth analysis of location-specific issues, but rather a general discussion on the impacts that may occur as a result of the development of unconventional gas resources across the United Sates. A short discussion of potential impacts on visibility was added in the air resources discussion.

Thematic Comment	Comment Excerpt	DOE Response
	production has occurred mainly in rural areas.	
Subcategory: Air Quality Health Effects		
Comments express concern that the Addendum does not adequately acknowledge the health impacts from gas production adversely affecting persons living in close proximity to wells, particularly related to increased ozone levels and hydrocarbons. Commenters stated that DOE must take a harder look at these impacts.	(SC 143) DOE does not fully address the extent to which gas production is likely to contribute to unhealthy levels of ground-level ozone pollution, and DOE does not acknowledge recent science regarding the harmful effects of proximity to gas wells on fetal health. (SC 143) In addition to the regional effects on ozone pollution, gas production has been found to emit air pollutants adversely affecting persons living in close proximity to wells. As DOE recognizes, research from the Colorado School of Public Health found that residents living within a half mile of wells "were at an increased risk of acute and subchronic respiratory, neurological, and reproductive effects" from exposure to hydrocarbons, including BTEX compounds, emitted by gas production. This same study also found that nearby residents suffered elevated cancer risks. (UHLC 84) At least one study of air sampling has concluded that the greatest potential for health impacts from airborne chemicals occurs during the well completion period, when condensate tanks are vented during filling, and methane flared off. The estimated potential for health risks, based on exposures to air pollutants, was found to be grater for people living closest to the site. (AAF 112)… respiratory and neurological damage, cancer, miscarriages, and birth defects. Far more research has occurred than is discussed in the Addendum and numerous cases of harm have been documented which the Addendum fails to address. (ANGA 100) The discussion of potential pollutants and health effects is broad and not specific to relevant pollutants or pathways (for example, the entirety of the hazardous air pollutants - HAPs - section includes EPA's generic overview of HAPs and is not specific to natural gas). Instead of quoting the scientific literature, DOE opens the section with unattributed, speculative statements about "[c]laims of substantial impacts". The literature that DOE does quote is inconclusive.	The Addendum discusses the negative health effects that may result from the air emissions associated with the development of unconventional natural gas resources in the U.S. However, at this time, there are few detailed studies available that can directly link the possible effects to these emissions, while dismissing other possible contributing factors.
A comment stated that the air quality	(HESI 78) HESI believes that the section on "Air Quality" would be more	The Addendum indicates that states may elect

Thematic Comment	Comment Excerpt	DOE Response
section of the Addendum would be more comprehensive if it discussed current developments in some state regulations to limit air emissions associated with unconventional natural gas production, and the Addendum should acknowledge that these regulations could serve as a template for other states. Another comment expressed concern that a more objective assessment is required in the Addendum regarding the green completion program (e.g., the Addendum assumes unrealistic full compliance and enforcement, and fails to address the exemption for loosely-defined "exploratory" wells).	comprehensive if it referenced how state regulations are also currently being developed to address air quality issues associated with unconventional natural gas production. For example, Colorado recently adopted regulations to limit air emissions from unconventional natural gas production. Colorado adopted a statewide limit on emissions from natural gas HF operations, including methane, on February 23, 2014. Under these rules, components of unconventional natural gas production are required to control air emissions from hydrocarbons by 95% under certain phase-in schedules.23 These rules could serve as a template for other states seeking to reduce air emissions from unconventional natural gas production. (AAF 112) The Addendum implies that green completion requirements scheduled to take effect in 2015 will significantly reduce emissions associated with drilling and fracking activity, but ignores deficiencies in the rule which limit its effectiveness, such as exemptions for loosely-defined "exploratory" wells. The Addendum also unrealistically describes optimal outcomes, assuming full compliance and enforcement. Even on public lands, federal regulators usually inspect only a small fraction of wells, and failure of regulatory inspections and controls are known to be rampant. An objective assessment of the green completion program is needed.	to develop regulations that are more stringent than federal regulations. The Addendum provides a general discussion of potential impacts and related issues, and was not meant to provide an in-depth evaluation of individual issues. At the federal level, green completions are a recent requirement; therefore, it is too soon to evaluate the actual benefit or effectiveness of this initiative. As with any regulation, the effectiveness will clearly be influenced by compliance and enforcement efforts. Some states have already implemented regulations that require green completions, but DOE is unaware of any assessments of their success rates.
Some comments recommend specific changes and edits to the text.	(ANGA 121) On page 23 of the Addendum, DOE states, "[v]ented emissions originate when natural gas is flared at well sites or vented during well completion and workover activities." This definition conflicts with the definition of vented emissions in Table 6, which, correctly, does not include flared emissions. In venting, natural gas is released directly to the atmosphere. In flaring, it is combusted and the byproducts are released to the atmosphere. Fugitive emissions are similar to vented emissions in composition, with the difference being that vented emissions are intentional while fugitive emissions likely are not. (Page 23 cont)… the document describes the six criteria air pollutants without indicating which are and are not emitted from natural gas production in meaningful quantities. For example, the SO2 paragraph notes that the "largest sources of SO2 emissions are from fossil fuel combustion at power plants (73 percent) and other industrial facilities (20 percent)." However, these statistics refer to coal-fired power plants. As EPA notes, "[e]missions of sulfur dioxide … from burning natural gas are negligible." (API 100) Page 20: The report states that the oil and natural gas industry is the largest industrial source of VOC emissions according to the U.S. EPA, but no reference is provided for this statement.	DOE considered the recommendations provided by many of the comments on the Addendum. This resulted in a number of corrections, clarifications, and other changes to the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	Based on the 2011 National Emission Inventory for criteria pollutants4 EPA is estimating that the nationwide area source VOC emissions from Oil & Gas operations is about 2.7 million tons per year (TPY) which represents about 21% of nationwide VOC emissions. For Oil and Gas operations non-point sources three sources account for close to 70% of the emissions, including: Condensate Tanks (~ 16% of VOC emissions for a sectoral total of 448,021 TPY); Crude Oil Tanks (over 28% of VOC emissions for a sectoral total of 769,805 TPY); and Pneumatic Devices (over 24% of VOC emissions for a sectoral total of 669,340 TPY). Page 21: The report states that oil and natural gas production and processing account for nearly 40% of all U.S. CH4 emissions, making the industry the nation's single largest CH4 source. This statement is not supported by emissions data from EPA's latest national inventory. As shown in the following table, all oil and natural gas operations combined contribute just over 28% of the total CH4 emissions. Methane emissions from oil and natural gas production and processing operations are the third highest source, behind enteric fermentation and landfills. Page 24: The last sentence notes "Methane emissions are not currently addressed by federal regulations, but the new federal regulations on the natural gas industry discussed above are expected to indirectly reduce CH4 emissions as a co-benefit." Since the EPA rulemaking was finalized and in effect since 2012, this sentence should be reworded to more accurately read: "Methane emissions are not currently directly addressed by federal regulations, but recent 2012 federal VOC regulations on the natural gas industry discussed above are indirectly reducing CH4 emissions as a co-benefit." Page 26: With regard to the discussion on sulfur dioxide, mention should be made that SO2 levels have been greatly reduced by the use of low sulfur fuels. Page 27: API recommends that the *red text* be added to discussion on aggregate emissions. As written, the statement is too broad and ignores other contributing sources. As with short-term impacts, many of the individual sources are regulated by the states, but the impacts resulting from the aggregate of emissions within a region experiencing natural gas development *coupled with emissions from other sources* are not well understood. Air emissions from natural gas development *may create new or expanded ozone non-attainment areas* and	

Thematic Comment	Comment Excerpt	DOE Response
	possibly complicate state implementation plans for bringing current non-attainment areas into compliance. Page 27: API recommends that the report be specific to the types of engine emissions in the sentence below and further explain the pollutants considered to the be ozone precursors. "Besides CH4, the largest pollutant emissions associated with natural gas production are VOCs and engine emissions. Many of these pollutants....." Page 28: With regard to the discussion on nonattainment areas, API offers that states with marginal nonattainment are not required to develop SIPs and operators in nonattainment areas must use LAER only if a designated major source. Page 32: Under the conclusions section, API recommends that the *red text* below be added: Air emissions from natural gas development *and other sources* may create new or expanded ozone nonattainment areas and possibly complicate state implementation plans for bringing current ozone nonattainment areas into compliance and maintenance.	
Greenhouse Gases		
Subcategory: Greenhouse Gases – Emissions		
Comments on methane's potency in regard to its global warming potential. Methane's life-cycle GHG impacts arising from upstream natural gas industry activities as well as from export to and use in other countries as compared to burning coal.	(CALNG 128) In February 2014 an article that appeared in Politico written by Bill McKibben and Mike Tidwell stated the following:…The industry bombards the public with ads saying natural gas is 50 percent cleaner than coal. But the claim is totally false. Gas is cleaner only at the point of combustion. If you calculate the greenhouse gas pollution emitted at every stage of the production process— drilling, piping, compression—it's essentially just coal by another name. Indeed, the methane (the key ingredient in natural gas) that constantly and inevitably leaks from wells and pipelines is 84 times more powerful at trapping heat in the atmosphere than CO2 over a 20-year period, according to the Intergovernmental Panel on Climate Change… When you add it all up, using numbers from the EPA, the International Energy Agency and the U.S. gas industry itself, the final climate impact of fracked-and-liquified-and-exported Appalachian gas is	The Addendum acknowledges the greater heat retention effect of methane, compared to CO_2, and the effect over 20 years and 100 years as the methane slowly oxidizes to CO_2. The NETL (2014) life-cycle assessment addresses greenhouse gas emissions from production to end use. It considers methane and CO_2 emissions associated with natural gas production in the U.S., liquefaction, and transportation to Asia or Europe for end use. By comparison, the Addendum is intended to

Thematic Comment	Comment Excerpt	DOE Response
	basically as bad as burning coal in Asia. (UHLC 84) The Howarth Study evaluated the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. That study found that 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the life-time of a well and that these methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The study further found that the higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. The study noted that methane is a powerful greenhouse gas with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. As a result, the study found that the greenhouse gas footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20- year horizon and is comparable when compared over 100 years.	focus only on the upstream emissions (drilling, production and pipeline transport of natural gas) from unconventional gas plays, primarily shale plays. It presents a synopsis of findings from several recent (2010 to 2014) studies. The Addendum illustrates the variability in findings of different research groups looking at emissions of greenhouse gases from upstream natural gas industry activities in the U.S. This includes the findings of Howarth et al. (2011), which some have criticized (e.g., Cathles, L., L. Brown, M. Taam, and A. Hunter, 2012. A commentary on "The Greenhouse-Gas Footprint of Natural Gas in Shale Formations" by R.W. Howarth, R. Santoro, and A. Ingraffea". Climatic Change, Vol. 113, No. 2, pp. 525-535. Summary at: http://cce.cornell.edu/EnergyClimateChange/NaturalGasDev/Documents/PDFs/FINAL%20Short%20Version%2010-4-11.pdf).
Comments dispute the use of the Howarth study in the Addendum, stating that it has been characterized as inherently flawed by the scientific community.	(UHLC 84) It should be noted that the Howarth study has been refuted by other studies including a commentary that is widely cited by the industry that disagreed with the underlying assumptions in the Howarth study (ANGA 157) Figure 12 on page 41 should be modified so that it does not include data from the Howarth study. The Howarth study has been characterized as inherently flawed by the scientific community, and more reputable studies, including DOE's own lifecycle emissions study released at the same time as the Addendum, have found that upstream natural gas systems produce significantly fewer methane emissions	See last paragraph in the response to the comment above. Figure 12 was taken directly from Bradbury et al. (2013). Along with showing the variability in estimates between various research groups, Figure 12 shows the lumping of emissions estimates into a small number of broad categories (e.g., "production", "processing", "transmission"). When challenged, Howarth et al. have defended their estimates, so these will remain in the Addendum.
Comments identify concerns regarding calculation of methane emissions, noting	(AAF 112) In calculating greenhouse gas emissions, the Addendum applies an outdated global warming potential (GWP) factor of 21 for methane.	The Addendum includes methane's CO_2-equvalency factors from the IPCC 2007

Thematic Comment	Comment Excerpt	DOE Response
the Addendum's use of outdated data for methane's global warming potential (GWP) and the difference between the use of 100-yr vs 20-yr GWP. These calculations are said to result in mis-statements of GHG-equivalents of methane emissions.	According to current data from the Intergovernmental Panel on Climate Change (IPCC), methane is at least 34 times more potent as a greenhouse gas than carbon dioxide over 100 years, and at least 86 times more potent over 20 years. (See Compendium, p.53.) Climate scientists agree that major greenhouse gas reductions are essential in the near term to avoid the worst impacts of climate change, therefore the GWP of methane over twenty years must not be ignored. Even the DOE's lifecycle report of greenhouse gas emissions for the export of LNG considers the 20-year GWP of methane. The Addendum should be revised to reflect the global warming potential of methane too. (See also Compendium, pp. 50-55.) (ANGA 157) The Addendum's description of the Global Warming Potential ("GWP") for methane is confusing and should be clarified. On page 36 the Addendum states that methane's GWP "is approximately 100 times greater than that of CO2", but provides no timescale. In the same paragraph, methane is listed as having a 20-year GWP of 72. The Addendum needs to be clear and should explain the difference between 20- and 100-year GWP and how they are applied. The Addendum should also note that the 100-year GWP is the value used in U.S. and global policy discussions. For example, EPA's annual GHG Inventory submitted to the United Nations uses the 100-year GWP to convert methane to CO2 equivalents. And, EPA's GHG Reporting Program similarly uses the 100-year GWP. (API 100) Page 36: Different global warming potential values are discussed in this portion of the report. (SC 145) DOE also understates the impact of each ton of methane emitted, by understating the global warming potential of methane, and by focusing on the 100-ycar, rather than 20-year, timeframe. .. .. The **DOE Addendum**, Gas LCA, and **Unconventional Production Report** all use, at times, older methane global warming potentials.' **(REFERENCES ADDENDUM at 20)** These analyses must be updated to consistently rel1cct the best available science.	reports, as used in recently published studies, plus those from a draft (2013) version of the next set of IPCC reports. Calculations in Table 7 use the older CO_2-equvalency value of 21 for the 100-year effect to maintain consistency with the EPA's Inventory reports and to allow usage of EPA's estimate for total greenhouse gas emissions from all sources. Using the older factor also provides consistency with other reports issued over the past several years. DOE's statement about CH_4 in the atmosphere having a heat retention effect that is approximately 100 times greater than that of CO_2 is followed by explanations of the reduced global warming impacts over time as a result of the gradual oxidation of CH_4 to CO_2. Because the statement in question is referring to the inherent differences in CH_4 itself versus CO_2, a time scale is not needed. Below this statement, the Addendum explains the environmental impacts over time considering the conversion of one chemical species to another. Both U.S. and global policy discussions refer to 20-year and 100-year weighted average impacts of CH_4 emitted.
Comments dispute method of assessing methane leakage rates associated with unconventional natural gas production.	(AAF 112)The Addendum grossly underestimates methane leakage rates, comparing a limited set of sources to suggest that the 5.75 percentage rate estimated by Howarth, et al., is an outlier that should be discarded. (p.40.) However, as explained by Howarth in his recent publication A Bridge to Nowhere, this estimate is consistent with several other independent studies (Brandt, Miller, Karion, Petron)--some of which indicated even higher leakage rates. (See also Compendium, pp. 50.) Monitoring of actual well fields in production confirm high leakage rates that clearly refute EPA greenhouse gas inventory estimates. Unlike leakage estimates by EPA, which are based on a "bottom up" calculation of predicted emissions from various sources, these "top down" studies reflect real-world measurements	The Addendum shows a range of findings from among the studies published. DOE is mindful that the findings of these studies vary as a function of differences in sources of information, assumptions used, and scopes of analyses. See also responses to two previous comments

Thematic Comment	Comment Excerpt	DOE Response
	of air quality. The Addendum also disputes data by Howarth, et al., that unconventional wells leak more than conventional wells and that the pre-production fracking phase has higher emissions. However this leakage, which occurs during the flowback period of an unconventional well, has also been confirmed by several sources, including the EPA. Leakage rates discussed in the Addendum must be revised. (API 100) The section on the natural gas industry, beginning on page 37, presents a very simplistic view of GHG emissions associated with the natural gas industry, and of operations associated with natural gas production. In fact, only well drilling, completion, and workovers are discussed in any detail, and much of the background information from these operations is technically incorrect.	above. DOE acknowledges technical deficiencies in the Addendum's summary description of industry practices and has revised the text. However, the technical deficiencies derive from the fact that information is being taken from a number of studies by different authors who aggregated the data into different groups and used differing descriptions (or definitions) for the aggregated information they present.
There are four environmental documents covering, for example, methane emissions, but these documents present different information and conclusions. The Addendum acknowledges the more recent data but uses older data in tables expressing methane emissions in CO_2e. Comments dispute the methods used to calculate life-cycle emissions from unconventional natural gas production and export. While these comments predominantly focused on content in the Life-Cycle GHG reports, the commenters purposefully stated that these comments also pertain to the Addendum and the "Unconventional NG Development and Production" Report (NETL UPR 2014).	(SC 145) In discussing the lifecycle impacts of U.S. LNG, DOE understates the amount of methane that is emitted during the gas lifecycle (the "leak rate"), DOE improperly omits consideration of emissions from pipeline transportation in LNG's end-use markets, and DOE understates the impact of the methane that is emitted. These errors cause DOE to understate the lifecycle impacts of US LNG, and similarly apply to the broader analyses DOE must undertake, such as evaluation of the net impact on U.S. greenhouse gas emissions. (SC 145) Despite this confusion as to the inputs for NETL's leak rate estimates, it's clear that NETL's ultimate answer is too low. One line of evidence indicating that actual emissions are higher comes from recent direct measurements of gas production emissions. The Gas LCA, like the EPA estimates summarized above, uses a "bottom-up" method of estimating emissions. That is, it uses an estimate of tbe average emissions for each type of individual piece of equipment or individual event, such as a high-bleed pneumatic device or a well completion, and multiplies that per-component value by an estimate of the total number of components or events of !hat type. DOE acknowledges that this method of analysis has significant limits, explaining that "Emissions estimates are generally uncertain because direct measurements are lacking, industry practices are evolving for unconventional resources, and practices are not standard across the industry"**(REFERENCES the ADDENDUM at 36-37) ..** ... The NETL lifecycle leak rate estimates, l.3 and 1.4%, are lower even the l.54% lifecycle leak rate DOE derives from EPA's 2013 GHG Inventory **(REFERENCES ADDENDUM at 40)** Allen therefore indicates that the NETL estimates of natural gas lifecycle leak rates are too low.	Particular comments about the LCA studies are outside the scope this Addendum. The LCA studies and environmental report have different purposes than the Addendum. Collectively, all of these provide a substantial breath of analysis and review on various environmental concerns raised by the public on previous occasions. The Addendum, in particular, is a review of recent publications covering a set of issues most often raised in public forums regarding the upstream natural gas industry activities. Older data are presented in some tables and figures because the data or figures are taken from prior assessments, as cited. While these data are older, they are not without merit. The tables and figures from previous assessments, collectively, show both the diversity and agreement among findings between the research groups. These older assessments have publication dates ranging from 2011 to 2013.

Thematic Comment	Comment Excerpt	DOE Response
	(SC 145) Another indication that NETL's leak rate estimates are too low is that NETL's estimate is lower than all of the other life-cycle leak rate estimates NETL cited. NETL states that, including NETL's own work, "[t]here are five major studies that account for the GHG emissions from upstream natural gas .... While a number of studies have been conducted on this topic, these five studies represent the breadth of all natural gas lifecycle work ... ."'**(REFERENCES NETL UPR 2014 at 2)**, Three of the nonNETL studies provide estimates of methane leak rates **(REFERENCES ADDENDUM at 40 and NETL UPR 2014 at 52).** NETL provides an extensive discussion of one of these studies, explaining why NETL's leak rate estimates differ from those provided by Robert Howarth of CornelI **(REFERENCES NETL UPR 2014 at 52-54).**° For a second study, work led by Burnham, while NETL identifies several differences between NETL and Burnham in the inputs used to estimate leak rates, it appears that differences in inputs alone should lead to Burnham to estimate a lower leak rate, but Burnham's estimated leak rate is higher than NETL's, including an estimate of 2.01% for unconventional production (**REFERENCES NETL UPR 2014 at 55)** For the third "major study" to provide a leak rate, led by Weber, NETL offers no explanation whatsoever for the discrepancy between NETL's estimates and Weber's estimate of2.8 and 2.42 percent leak rates for conventional onshore and unconventional production, respectively (**REFERENCES NETL UPR 2014 at 52)**. Thus, the DOE package of materials provides no basis for concluding that the NETL estimate of the leak rate is more accurate than the estimates provided by Burnham and Weber **(REFERENCES ADDENDUM at 33-34)** (SC 145)The Export LCA does not acknowledge any of this recent science. The Gas LCA and **Unconventional Production Report** briefly acknowledge the Brandt **(REFENCES NETL UPR 2014 at 56)** and earlier Colorado study (Petron 2012), but it does not discuss the other studies, and it offers no argument as to why the estimates adopted by the Gas LCA are superior to those provided by atmospheric studies. **NETL's Unconventional Production Report** argues that the Colorado Study is not applicable to shale gas, because it concerned production in tight sandstone. Yet this report does not identify any difference between shale and tight sandstone that would limit the study's applicability to shale. Moreover, EIA predicts that some production induced by LNG exports will come from tight sandstone **(REFENCES NETL UPR 2014 at 65)**. Because methane is an extremely potent greenhouse gas, increases in the methane leak rate drastically increase the lifecycle greenhouse gas emissions of LNG. The Export LCA acknowledges this sensitivity, and thus the importance of this issue, but	

Thematic Comment	Comment Excerpt	DOE Response
	numerous lines of evidence indicate that DOE gets this important issue wrong.	
Comments state that DOE should explain the effect of GHG emissions on the relevant social and policy contexts.	(SC 145) DOE must do more than merely quantify the likely increase in greenhouse gas emissions that would result from U.S. LNG exports. DOE must also explain the effect of these emissions in relevant social and policy contexts. U.S. LNG exports will hinder, if not preclude, U.S. attainment of the administrations' stated emission targets and international commitments. U.S. LNG exports are inconsistent with the U.S.'s policy of encouraging other nations to reduce greenhouse gas emissions. Finally, the social and environmental cost of these emissions must be incorporated into DOE's assessment of the economic impact of LNG exports. ….. Copenhagen in 2009, .. Cancun in 2010, and the 2020 goal in the Climate Action Plan announced in 2013. (SC 145) Finally, DOE must evaluate the social cost of exports' greenhouse gas emissions. DOE has used economic analyses, including cost benefit analysis, to weigh the nonenvironmental impacts of exports. DOE cannot base its decisions on exports on a projection of economic benefit without also giving weight to the impact of exports' environmental impact. At a minimum, DOE's cost/benefit analysis must consider the available estimates of the social cost of carbon dioxide and methane, the primary greenhouse gases that would be emitted by export approvals.	While these issues are outside the scope of the Addendum, the comments have been noted.
Comments mention that the Addendum should be updated to reflect current regulations and industry practices regarding flare methane emissions and emissions from workovers and maintenance.	(ANGA 157) The Addendum's assessment of GHG emissions from the different phases of natural gas production should be updated to reflect current regulations and industry practices. The section on well drilling and completion incorrectly asserts that all gas during flowback is either vented or flared and claims that unconventional wells may have higher emissions due to longer flowback periods. Currently, federal regulations require all hydraulically fractured wells to flare methane emissions – venting is allowed only under specific safety-related circumstances. By 2015, all hydraulically fractured gas wells will be required to use reduced emission completions (REC). However, many operators have been employing RECs for several years. For example, the 2014 GHG Inventory shows that 49 percent of hydraulically fractured wells used RECs in 2012.21 Overall, the paragraph contains information on emissions during well completion that does not provide an accurate reflection of actual or potential emissions. It should be updated to characterize emissions from current work practices and supported by scientifically sound data. (ANGA 157) The paragraph on well workovers and maintenance does not accurately portray emissions from liquids unloading and fails to differentiate workovers from recompletions. The Addendum states that emissions from	The purpose of the Addendum is not to identify all applicable regulations and practices but rather to give the public an overview of environmental impacts and the causes of these impacts. The Addendum reflects current practices and further acknowledges that reduced emissions completions (RECs) have been used recently and will be required under certain circumstances starting in 2015 as a result of new regulations. DOE has added text to the Addendum clarifying the differences between workovers and recompletions. Descriptions of plunger lifts and other means of removing water from well bores were not explained in the

Thematic Comment	Comment Excerpt	DOE Response
	liquids unloading are either vented or flared, but provides no data and does not describe control technologies, such as plunger lifts, that are commonly used to increase recovered natural gas. The 2012 ANGA/API survey found that a significantly higher numbers of wells were using plunger lifts and artificial lifts than EPA accounted for in its GHG Inventory. After accounting for this new information, EPA dramatically reduced its estimate of 2010 emissions from liquids unloading from 85.6 million metric tons CO2e (mmtCO2e) in the 2012 GHG Inventory to 5.4 mmtCO2e in the 2013 GHG Inventory, a reduction of 94 percent. This information should be included as part of a broader discussion on control technologies to provide a more accurate understanding of emissions from liquids unloading. This section also conflates workovers and recompletions, describing them as one and the same. While the first full paragraph on page 38 explains the recompletion process, it is incorrectly labeled as a workover. Workovers involve a well kill to stop production, followed by an examination and cleaning, repair or replacement of the wellbore. A recompletion often follows a workover, but they are distinct, separate events. This paragraph should be edited to differentiate the two procedures.	Addendum because the focus of the Addendum was on environmental impacts and the causes of these impacts, rather than listing control technologies. Reports on GHG emissions from upstream natural gas activities, such as NETL's 2014 report on this topic, lump emissions from liquids unloading together with emissions from recompletions and workovers. Figure 11 in the Addendum was taken from NETL's 2014 report and shows the category labeled as "workovers" having emissions that sum to 27.4 percent of the total GHG emissions (CO_2e) for the Marcellus Shale play. This category lumps emissions from liquids unloading events, recompletions and well workovers.
Commenter disagrees with the Addendum's statement that the science is unable to translate greenhouse gas emissions into changes in global temperature.	(AAF 112) The Addendum also includes misleading forecasts by the World Resources Institute of "reduced" greenhouse gas emissions in 2035. These are relative to baseline projections that assume greater emissions from increased gas production and do not account for LNG exports. Disturbingly, the Addendum states that science is unable to translate greenhouse gas emissions to changes in global temperature (p.43.); however models have in fact been developed to do this. The International Energy Agency (IEA) has determined that a large natural gas boom--even with improvements in place to reduce leakage--would lead to a temperature rise of 3.5 degrees Celsius, far exceeding the 2 degree threshold necessary to avoid the most severe effects of climate change. (See Compendium, p.54)	The Addendum is not based on new analyses but rather is a synopsis of information from previous analyses that are relevant to an understanding of the upstream impacts. Comment noted.
Subcategory: Greenhouse Gases – Climate Change		
Comments presented for and against the Addendum's claim that there may be a net positive impact to climate change if unconventional natural gas production replaces use of other carbon-based energy sources.	(API 100) Page 43: The section concludes with the following statements: "Increased unconventional natural gas production will increase GHG emission from upstream activities" and "To the extent that unconventional natural gas production replaces the use of other carbon-based energy sources, there may be a net positive impact in terms of climate change". API agrees with this statement. (AAF 112) Discounting the global warming potential of methane and leakage rates, the Addendum mistakenly concludes that replacing other	DOE's statement in the Addendum is consistent with a number of studies on this topic. (see, e.g., general discussions in Bradbury et al., 2013)

Thematic Comment	Comment Excerpt	DOE Response
	carbon-based energy sources with natural gas could have a positive benefit on climate change. (p.43.)	
Comment suggests that Addendum should reference a study exhibiting economic benefits of tackling climate change.	(CALNG 128) On the 26th of September 2012 – the most comprehensive assessment ever of the current global impact of climate change was released by Daily Mail Reporter (DARA). (See Exhibits 4-6) governments commissioned the independent report, the first of its kind to show that tackling the global climate crisis would reap significant economic benefits for world, major economies and poor nations alike.	Comment noted.
Suggested changes to clarify Figures and Tables in Addendum.	(API 100) Page 39: Figure 11 in the draft Addendum presents GHG emissions from NETL modeling of natural gas operations in the Marcellus Shale. Marcellus Shale is the modeling parameter chosen in the NETL report titled Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States (May 29, 2014), as being representative of U.S. natural gas industry operations for comparison to the other scenarios modeled. · The terminology used in this figure are not defined and not commonly used in the natural gas sector. For example, the figure presents emissions data for "valve fugitive emissions" and "other fugitive emissions." (API 100) The figure (Figure 11) presents emission data for "water delivery" and "water treatment." These are not GHG emission sources that are accounted for in the national GHG inventory or in EPA's GHG reporting program for the natural gas sector. Page 42 indicates that water removal is "claimed to be another significant source of CH4 emissions". While it is true that water management adds to the lifecycle of GHG emissions due to pumping, transportation and processing of water, the use of the word "significant" is unclear and inaccurate. · The figure presents emissions associated with "transport" operations, but it is not clear if this is activity upstream or downstream of gas processing operations. (API 100) Page 40: Table 9 presents CH4 emissions in additional to CH4 "Captured/Combusted" and "non-Combustion" CO2 emissions, referencing the draft 2012 national GHG inventory report, Tables 3.45 and 3.46. The row labeled "CH4 Emissions" in Table 9 appears to be the net CH4 emissions from the national GHG inventory (draft 2012 version). However, Table 9 implies that these emissions are additive, when in fact the CH4 emissions "Captured/Combusted" as presented in the national inventory report are meant to reflect emission reductions and are netted from the calculated potential emissions presented in the inventory report. This row should be removed from the table.	DOE acknowledges technical deficiencies in the Addendum's summary description of industry practices as well as the deficiencies in the figures taken from other sources. However, DOE believes that presenting figures from other sources is the best way to portray the nature of the information and findings in these reports. No change. The values in Table 9 show the emissions of CH_4 and CO_2 in units of CO_2 equivalents. The emissions reported as CH_4 "Captured/Combusted" are emissions of CO_2 and are counted as such. No Change.

Thematic Comment	Comment Excerpt	DOE Response
Comments states that the Addendum's section on GHG emissions from natural gas production is flawed as it relies on outdated information for methane emissions.	**<u>Outdated Data for GHG Emissions</u>** (ANGA 157) The section on greenhouse gas (GHG) emissions from natural gas production is flawed as it relies in large part on outdated information. i. GHG Inventory Data Parts of the Addendum contain outdated GHG emission data that should be replaced with current data. Page 33 of the draft includes information from EPA's 2012 GHG Emissions Inventory (2010 data). This paragraph should be updated based on 2012 emissions data from the 2014 GHG Inventory. The resulting paragraph would read: Based on 2012 data, CH4 emissions from upstream natural gas systems accounted for 18 percent of all U.S. CH4 emissions and for approximately 1.8 percent of EPA's U.S. total inventory of GHG emissions on the basis of CO2-e.. Table 7, which is currently based on data from the draft 2014 GHG Inventory, should also be updated with data from the final 2014 GHG Inventory. These changes provide consistency and represent the most recently available data. (API 100) Page 33: The report indicates the natural gas industry's emissions of CH4 account for one-third of all U.S. CH4 emissions and approximately 3% of the EPA's U.S. total inventory of GHG emissions on a CO2e basis. However, this is based on data from the 2010 national GHG inventory. Data from EPA's latest national GHG inventory indicates that the natural gas systems contribute 23% of the total CH4 emissions in the U.S., and 2% (129.9 million tonnes CO2e from natural gas systems out of 6,525.6 million tonnes CO2e GHG emissions total) of the national GHG emissions. (API 100) Page 33: Table 7 presents a summary of the 2012 GHG emissions data for natural gas systems in the U.S., however, this table is based on a draft version of the 2012 national GHG inventory report, and not the final version released in April 2014. The final emissions data are shown in Table 2 below…. ……Table 3 below presents GHG emissions from natural gas systems relative to total national natural gas withdrawals, based on 2012 national GHG inventory data from EPA and natural gas production information from EIA.	The Addendum did include the most recent information available from EPA at the time of drafting the Addendum. For example, Table 7 on page 33 of the draft Addendum showed numbers from EPA's most recent DRAFT Inventory, which is based on EPA's 2012 annual data. The final Addendum reports values from EPA's 2014 FINAL GHG Inventory.
Induced Seismicity		
Subcategory: Causes of Seismicity		
The Addendum relies on outdated	(UHLC 84) To date, the most significant research pertaining to hydraulic	The Addendum summarizes information

Thematic Comment	Comment Excerpt	DOE Response
information from 2010 to conclude the chances of seismicity are low. Commenters point to examples of seismic activity, including earthquakes (in US and UK), that should be acknowledged and identify controls the UK Government has concluded can be used to manage seismic risks associated with fracking.	fracturing and induced seismicity comes from the experiences of the United Kingdom (UK) and United States. In April and May of 2011, two earthquakes with magnitudes 2.3 and 1.5 occurred in the UK in an area where Cuadrilla Resources was hydraulically fracturing for shale gas at their Preese Hall site in Lancashire. Operations were suspended and Cuadrilla submitted a geotechnical report, which concluded that the tremors were caused by fracking. The UK suspended all shale gas activity pending review of the incident. Following a detailed study and further analysis by an independent panel of experts, the UK Government ultimately concluded that the seismic risks associated with fracking can be managed effectively with proper controls in place. These controls include: • A prior review before fracking begins must be carried out to assess seismic risk and the existence of faults; • A fracking plan must be submitted to DECC showing how seismic risks will be addressed; • Seismic monitoring must be carried out before, during and after fracking; and • A new traffic light system to categorize seismic activity and direct appropriate responses, including a trigger mechanism, which will stop fracking operations in certain conditions. (AAF 112) The Addendum relies on outdated information from 2010 to conclude that the chances of seismicity are low for tight sand and shale plays in the United States. (p. 49.) Since 2010, however, a growing swarm of seismic activity, including felt earthquakes, have been recorded in gas production areas. (See Compendium, pp. 37-42.) Table 12 and other statements dismissive of risks within the Addendum conflict with current data--including Figure 15 which documents the location and magnitude of seismic activity from gas development. In Oklahoma more than 200 quakes have already been recorded this year, a dramatic--indeed unprecedented--increase; and in Ohio, a recent drilling moratorium was enacted because of a surge in seismic activity. (See Compendium, pp. 37-38.) Recently the Seismological Society of America warned that the risks of earthquakes induced by fracking and injection wells is much greater than previously thought. (See Compendium, pp. 37-38.) In fact the USGS and Oklahoma Geological Survey has issued joint public advisories about earthquake danger, warning that the dramatic increase in smaller seismic activity significantly increases the chance of a damaging quake in central Oklahoma. (See Compendium, p.37.) Despite a dramatic increase in reports of seismic activity in areas that have had virtually none in the past, the Addendum offers only vague assurances that structural damage is rare and the potential for harm to people is generally low. (p.54.)	from publications dated within the past several years but mostly from year 2013. The Addendum's section on induced seismicity was drafted taking into account the seismicity associated with Cuadrilla Resources' hydraulic fracturing activities in the United Kingdom and the recent upswing in seismic activity in Oklahoma and Arkansas. The section notes that wastewater disposal via injection wells presents the highest risks of induced seismicity, as also suggested by the synopses printed in the Compendium submitted along with the comments of AAF. The Addendum further notes that stronger earthquakes (stronger than those previously observed in the U.S.) are possible, most likely in association with deep well disposal of wastewater. As more injection wells are used, more instances of induced earthquakes are possible. With more information coming available on the recent seismic activity in Oklahoma, the Addendum's section on induced seismicity has been amended to acknowledge this topic.

Thematic Comment	Comment Excerpt	DOE Response
The Addendum does not provide a fair assessment of induced seismicity and should include more robust and balanced discussion of relative risks, including steps undertaken by industry in recent years to better understand the risks and hazards of fracking and the design approaches to mitigate those risks.	(ANGA 121) The Addendum correctly notes that the National Research Council, an arm of the National Academies concluded that current hydraulic fracturing techniques for shale gas recovery do not pose a high risk for inducing felt seismic events. However, the Addendum proceeds to identify a range of relative risks associated with further expansion of the unconventional natural gas industry activities. Some of these risks are not correctly referenced and cited (for example, page 54, bullet number 4). (API 100) Page 48: DOE includes the data from the NRC 2013 report Induced Seismicity Potential in Energy Technologies – showing the low probability of seismic occurrence. API recommends that DOE also include the information from the "Executive Summary" of that same report in this section, which would provide much better context on risk. In addition, DOE misses the opportunity to explicitly state that only a handful of events have been attributed to the 10's of thousands of injection wells; and hundreds of thousands of hydraulically fractured wells. (API 100) Page 45: The introduction section does a very poor job in providing clear information on the risk level associated with potential induced seismicity associated with unconventionals. Specifically, the third sentence "The National Research Council (NRC) (2013) describes numerous events caused by or likely related to energy development in at least 13 states involving oil and gas extraction, secondary recovery, wastewater injection, geothermal energy extraction, and hydraulic fracturing for shale gas" implies that induced seismicity is a frequent occurrence. While the sentence is not false; it does not provide the right context that induced seismicity is rare. (API 100) Page 54: The discussion of relative risks provided is not robust or balanced. The discussion is lacking in a thorough and clear explanation of the 3 key elements to consider when assessing relative risk: (a) whether a critically stressed fault is present; (b) whether a subsurface pathway for hydraulic communication from the injection point to the fault is present; and (c) whether the intended scope of injection operations is likely to result in a sufficient subsurface stress perturbation in sufficiently close proximity to a fault, to cause the fault to slip. The wording provided does not contrast critically-stressed faults to "benign" faults. This may result in the public becoming unnecessarily concerned with the presence of any fault in the area; when, in fact, the key concern should be with larger faults which are critically stressed. The report should be much more descriptive and clear on this matter, thereby enhancing the observation that this combination of factors is only encountered in rare and unique circumstances. (ANGA 121) The Addendum implies an association between unconventional oil and gas development activities with increased incidents	Generally: The Addendum presents only a summary explanation of induced seismicity and some of the causes of induced seismicity associated with the oil and gas industry. Much of the U.S. experience with possible induced seismicity has been in association with energy resource activities other than natural gas extraction. Several investigators at universities and regulatory agencies, as well as USGS scientists, are attempting to better understand the risks and triggers. Industry has monitored seismicity associated with some hydraulic fracture jobs, primarily as part of their efforts to understand the extent and location of hydraulic fracture growth and natural fracture enhancement. Relative risks, as this topic is currently assessed, is indicated directly by Table 12 and Figure 15 in the Addendum and is indicated indirectly by Figure 14 to the extent that regions at higher risk of natural seismicity are also at higher risks for induced seismicity (i.e., the faults are critically stressed). As noted in the Introduction of the Addendum, DOE prepared this document for a specific purpose. Discussion in the Addendum focuses on relative risks among various types of upstream natural gas industry activities and it presents the most important factors, generally. It does not present the factors for assessing risks at a specific site. DOE notes that it is usually very difficult and costly to identify all significant faults at most sites, to assess which faults are critically

Thematic Comment	Comment Excerpt	DOE Response
	of induced seismicity, yet notes that existing data is limited and thus proving human activity caused a particular event can be difficult. We believe that the Addendum does not provide a fair or concise assessment of induced seismicity nor provide sufficient citations throughout. For example, the section begins asserting induced seismicity can cause damage to public property but later notes that most seismicity from gas and oil industry activities is too small to be felt beyond the local occurrence. In fact, the Addendum creates a point of confusion by more broadly referencing "energy development," which has implications beyond oil and gas operations. (API 100) Page 54: Within the seismicity section of the draft Addendum, it is unfortunate that DOE fails to include any discussion on the steps undertaken by industry, particularly in the past few years, to better understand the risks and hazards and design approaches to mitigate those risks. In addition, a discussion on the research being pursued by many universities on the induced seismicity topics is also missing. Through this combined understanding, use of risk assessment and mitigation techniques will help to reduce the likelihood of induced seismicity and mitigate potential consequences should an induced seismic event occur. (ANGA 121) In considering industry practices, it is important to clarify that companies take into account local conditions when conducting an assessment for potential seismic events and identifying preventative operational measures. As currently drafted the text does not appear to provide sufficient insight into why industry practices may differ among various shale plays. (UHLC 84) In the United States, a recent report by the National Research Council (NRC) noted that induced seismicity can be caused by a range of activities that involve disposal or storage by injection deep into the ground and that this has been known since the 1920s with respect to geothermal energy and carbon capture and storage. That report concluded that the process of hydraulic fracturing poses a low risk for inducing earthquakes and notes that over 35,000 wells have been hydraulically fractured for shale gas in the US. The NRC report, as well as some recent work done by the US Geological Survey, concluded that there is a greater risk of earthquakes from the use of injection wells used for the disposal of wastewater in oil and gas development. In the US, there are approximately 150,000 Class II injection wells, which include about 40,000 waste fluid disposal wells for oil and gas operations. A small number of these disposal wells have induced earthquakes that are large enough to be felt and could cause damage – these are generally earthquakes of magnitude 4.0 or higher. There has also been an uptick in seismic activity in the US in areas with significant shale gas development, such as Oklahoma, and additional research is being	stressed, to determine whether subsurface hydraulic connection exists between a well location and a particular fault, and to gauge the magnitude of fluid pressure change in a fault as a result of an injection well. Usually, these things are not determined at specific well sites, and the time, effort and costs of determining these things with adequate reliability is prohibitive.

Thematic Comment	Comment Excerpt	DOE Response
	undertaken.	
Subcategory: Regulatory Issues		
The Addendum fails to evaluate the absence of policies at the federal or state level to address induced seismicity.	(AAF 112) Although virtually no policies exist at the federal or state level to address induced seismic activity, the Addendum fails to evaluate this deficiency, recommend the development of regulations, or suggest a limit to fracking and wastewater injection in areas at risk. The Addendum must be revised to address these issues.	The purpose of the Addendum is not to identify all applicable regulations and practices but rather to be responsive to the public and provide information on the potential environmental impacts of unconventional natural gas activities.
Specific changes requested.	(API 100) Page 45: While "most people" may be aware of the magnitude of a seismic event based on the Richter scale, "most people" do not have a true comprehension of how it works or a clear understanding of the Modified Mercalli Intensity. This sentence should be deleted.	No change has been made in response to this comment.
Specific changes requested.	(API 100) Page 46: In reference to Table 11, it is not scientifically precise or adequately descriptive of the limits of application or appropriate qualifiers. It provides an interpretation of USGS information to correlate Modified Mercalli Scale and Richter Scale without suitable discussion of the qualifiers associated with its use. For example, a distance from hypocenter (or event depth) can have significant influence on felt ground shaking. This fact is not discussed effectively in the report. As a stand-alone table/reference; this will continue to create confusion across the public, where Richter magnitudes may be considered in stoplight systems, without discussion of factors that affect the actual felt ground shaking for a given magnitude event. The public would be much better informed if the report were edited to clearly emphasize that the use of Richter magnitudes (or other magnitude scales) are not adequately 1) descriptive of ground shaking values or 2) valid for identifying hazardous ground shaking conditions without considering event location and seismic attenuation.	DOE has amended the text to add a brief listing of the factors that cause differences between Richter scale magnitude values and observed or felt effects as presented in the Modified Mercalli Intensity scale.
Specific changes requested.	(API 100) Page 50: API recommends adding the *text* below to the discussion on industry practices: 4) Industry practices and resource attributes vary among the unconventional resource plays*, as a direct result of the differing local conditions,* such that the potential for impacts and preventative operational measures may differ from each play (see Table 13 for a comparison of attributes of the major plays).	No change has been made in response to this comment.
Specific changes requested.	(API 100) Page 53: API recommends that the *text* below be added to the discussion on wastewater disposal via injection wells: 1) Wastewater disposal via injection wells presents a relatively low but recognized ~~the highest~~ risk of induced seismicity. In contrast, oil/gas production is expected to be *a very* low-risk. Hydraulic fracturing ~~seems to~~ *causes few felt seismic events*, based on current industry practices and the	No change has been made in response to this comment.

Thematic Comment	Comment Excerpt	DOE Response
	frequency of reported events.	
Specific changes requested.	(ANGA 121) The Addendum identifies a range of relative risks associated with further expansion of the unconventional natural gas industry activities. Some of these risks are not correctly referenced and cited (for example, page 54, bullet number 4).	Comment noted. The bullets on page 54 are DOE's summary of relative risks.
Land Use		
Subcategory: Land Use Impacts – General		
Comments indicate that the description of land use impacts is not properly sourced or cited and provides prejudicial information with respect to unconventional natural gas development and operations. The discussion does not give sufficient weight to the regulatory mechanisms in place to minimize environmental impacts nor does it appear to be representative of the entire industry.	(ANGA 121) The Addendum's description of land-use impacts is not properly sourced or cited and provides prejudicial information with respect to unconventional natural gas development and operations. (API 100) Page 62: API questions the use of a news article (NPR 4) as an appropriate resource for a "scientific report" such as the draft Addendum. (ANGA 121) Natural gas has the least land-use impact of any electric generating option, including renewables. However, this information is not reflected in the Addendum. Instead, the draft simply notes that it is difficult to compare land use impacts associated with electricity generation to land use impacts associated with unconventional gas because the recovered gas may be used for more than electricity generation. Data is needed to reflect the scale of natural gas electric generation from unconventional sources and the associated land use impacts of these operations relative to other electricity generating options. SAIC/RW Beck shows that to serve 1,000 households per year, natural gas generation only needs 0.4 acres (including land needed for fuel production). This is the smallest footprint of any major generation source. (ANGA 121) Furthermore, this section [Land Use Impacts] does not appear to be representative of the entire industry. For example, Figure 17, Typical Well Pad Development in a Wooded Location [Description of Disturbance], implies that the use of large-scale reservoirs is a typical industry practice. Additionally, Figures 24 and 25, The Effect of Landscape Disturbance on Non-Forest Habitat and Aerial Picture of Gas Development Near Odessa, Texas, respectively, do not appear to be representative examples of land use impacts associated with unconventional natural gas development.	DOE made a number of editorial changes, clarifications, and other modifications to the sections related to these comments. Additional references were added where appropriate to support statements made. DOE added an estimate for natural gas to the comparative analysis of land use by fuel type for electricity generation. DOE also included an additional comparative analysis brought to its attention by the National Gas Supply Association (NGSA). The Figure mentioned in the comment was intended to be used as an example for the public to get a visual understanding of the issues being talked about. The caption for this figure was changed accordingly.
One commenter questions the accuracy of information and some of the sources cited, with examples provided. Another commenter points out that the study does	(ANGA 121) As currently drafted, this section contains significant inaccurate information not credibly sourced. For example, information on soil compaction is not cited (page 60). Further, an NPR news article is used as a source to describe the implications of shale gas development on forested	DOE made a number of editorial changes, clarifications, and other modifications to the sections related to these comments. Additional discussion and references for soil

Thematic Comment	Comment Excerpt	DOE Response
not identify the total land requirements for natural gas development and infrastructure, or explain that land impacts from natural gas increase over time as new wells and infrastructure must be perpetually added.	lands (page 62). This is not scientific source of information for a policy document of this nature. (AAF 112) Although the Addendum estimates the aggregate amount of land required for other sources of energy generation as a function of energy produced, it provides no such estimates for natural gas development and infrastructure. (p.55.) A comprehensive evaluation would require a build-out analysis, accounting for not only the size of well pads, but also land required for infrastructure including water impoundments, staging areas, pipelines, compressor stations, processing plants, access roads, gas-fired power plants, and facilities for the production and storage of LNG. Furthermore, unlike renewable sources of energy, land impacts from natural gas increase over time because fracked wells are highly productive for only a couple of years--new wells and infrastructure must be perpetually added. Likewise, drilling and fracking is an intense industrial activity spread across large landscapes, which degrades the environmental value and usability of affected or interspersed lands.	compaction and forest impacts were added where appropriate. The Addendum was not meant to be an in-depth analysis of specific issues, but rather a general discussion on the impacts that may occur as a result of the activities associated with the development of unconventional gas resources across the United Sates. DOE added an estimate for natural gas to the comparative analysis of land use by fuel type for electricity generation. DOE also included an additional comparative analysis brought to its attention by the National Gas Supply Association (NGSA).
Subcategory: Well Drilling (Exploration/Fracking/Production)		
One commenter points out the Addendum's erroneous comparison of a single unconventional multi-well pad to conventional well pads, and the need for a comprehensive build-out analysis of land use impacts. Another commenter points out the Addendum's failure (in assessment of "Pipelines") to address issues such as those associated with Jordan Cove and its potential threat to eminent domain.	(AAF 112) The Addendum also erroneously compares a single unconventional multi-well pad within a square mile to 16 conventional well pads over the same area, despite the fact that such a pattern of conventional wells is not economically viable for shale gas extraction. (p.56.) In the absence of fracking and horizontal drilling, there is little danger of this imagined scenario. The Addendum should include a comprehensive build-out analysis of anticipated land use impacts. (CW 125) Other issues associated with the LNG export proposal we are familiar with, Jordan Cove, were not addressed in the Addendum. For instance, the impact of the 230-mile pipeline across southern Oregon (called the Pacific Connector Pipeline) was not reflected in the Addendums' assessment of "Pipelines" starting on page 56. Our pipeline will threaten eminent domain of over 300 Oregon families. The initial offers from the Company for easement purchases were ridiculously low. They were accompanied by information on "Eminent Domain", appearing to threaten Oregonians with swift legal action if the low offers were not accepted. If FERC grants eminent domain to enhance the profits of a Canadian natural gas company, the ability to engage in fair negotiations is taken away from U.S. Citizens. The Addendum failed to consider these impacts.	The Addendum addressed these topics and the associated potential impacts. The Addendum was not meant to be an in-depth analysis of specific issues, but rather a general discussion on the impacts that may occur as a result of the activities associated with the development of unconventional gas resources across the United Sates. With respect to the commenter's eminent domain concerns, DOE is unsure of the specific impacts the commenter is referring to. However, additional information was added to the discussion of eminent domain in the Land Use section of the Addendum. Eminent domain is the power to acquire land or access to that land for public use (or public benefit) upon payment of fair compensation to the landowner. This power resides with Federal, State, and local governments and can be granted to certain private companies (e.g.,

Thematic Comment	Comment Excerpt	DOE Response
		utilities) by state legislatures to, among other things, prevent a single individual from unduly disrupting an activity deemed to be in the best interest of the state or Nation's citizens. Applicable state and federal laws, and the Fifth and Fourteenth Amendments of the U.S. Constitution, contain protections for landowners, requiring due process and payment of market value for any property rights taken. Pipeline companies have been granted the power of eminent domain since the Natural Gas Act (NGA) was enacted in the 1930s. The use of eminent domain for linear features like pipelines varies based on the purpose of the pipeline, location, and the regulating agencies involved. In the case of interstate pipelines, if an easement cannot be negotiated with a landowner and the pipeline has been certified by the Federal Energy Regulatory Commission (FERC), pipeline operators may use the right of eminent domain granted to it under state laws to obtain rights-of-way and temporary extra work areas. However, in most cases, eminent domain is used as the last resort.
Subcategory: Public Lands		
Commenters express concern about reference to the leasing of public lands	(API 100) Page 62: The example of Pennsylvania's Department of Conversation (DCNR) leasing of state forest lands should be omitted from the report. On May 23, 2014 Governor Corbett issued an Executive Order that prohibits the leasing of state forest and park land which would result in additional surface disturbance on state forest or state park lands. The Executive Order is effective immediately (see: http://www.oa.state.pa.us/portal/server.pt/community/executive_orders/708). (ANGA 121) Further, the Addendum implies that state and local governments are leasing public lands at increasing rates in order to generate additional revenues without providing examples or citations of this actually	DOE has made several revisions to the text referenced by these comments to reflect updated information or the current state of affairs. As for declining oil and gas production on federal lands, a number of large projects in the Western U.S. are pending environmental reviews.

Thematic Comment	Comment Excerpt	DOE Response
	occurring, and is in direct conflict with declining oil and gas production on federal lands.	
Subcategory: Other Ancillary Infrastructure		
Comments identify other areas of impact that have not been considered in the Addendum, including ecological and socioeconomic impacts, including ecological impacts on public lands, and the need to analyze these issues.	(AAF 112) From an ecological standpoint, the impacts of well pads, pipelines, access roads, and other related infrastructure must be considered together. Although the Addendum includes aerial photos of widespread fracking and acknowledges that cumulative environmental impacts such as loss of wildlife habitat, forest fragmentation, and invasive species are significant, it fails to analyze the profound consequence of this on biodiversity, the integrity of ecosystems, are large-landscape connectivity. (pp. 60-62.) Although more research is needed, several reports and studies have been conducted by organizations like The Nature Conservancy to evaluate these impacts. While the Addendum discusses forest fragmentation caused by gas development, it ignores other habitat which could be threatened such as wetlands, prairie, or scrub. The Addendum also neglects edge effects which extend into adjacent habitat such as noise and light, invasives, and predation. Other issues not adequately considered include air, water, and soil contamination; wildlife exposure to toxic flowback and emissions; or light and noise impacts including flaring which threatens migratory birds and other wildlife. Pipeline easements also require perpetual maintenance involving pesticides and suppression of natural regrowth. Furthermore, regardless of gates, linear corridors invite trespassing and environmental harm from ATVs, dirt-bikes, and other vehicles. Finally, the Addendum makes the extremely misleading statement that gas development may benefit certain wildlife species. The fact is that open areas created by gas development are often fragmenting linear corridors which divide interior forests and lead to the spread of invasive species. A few animal species that utilize edge habitat occasionally benefit, but these are usually common species adapted to impacted environments and which often prey upon more rare native species. The Addendum must be revised to meaningfully analyze these issues, evaluate the extent of impacts nationally, and assess the widespread ecological impacts of increased gas development. (AAF 112) Disturbingly, the Addendum also provides no analysis of the large-scale ecological impacts of widespread fracking on public land, or discusses the need to restrict gas development on certain public lands to ensure the integrity of sensitive habitat, pristine areas, and wilderness. The Addendum must include an objective assessment of existing and projected impacts to public land and the inadequacy of protections in place. (AAF 112) The Addendum provides no discussion of the significant	The purpose of the Addendum is to provide additional information to the public. The Introduction and Purpose sections of the Addendum provide DOE's purpose in more detail. DOE chose not to address ecological effects tied to the development of unconventional natural gas resources because it cannot meaningfully do so. Such effects must be very project specific, with avoidance or other mitigation requirements determined on a case-by-case basis. The Addendum was not meant to be an in-depth analysis of issues, but rather a general discussion on the impacts that may occur as a result of the development of unconventional gas resources across the United Sates. DOE also added some additional discussion about possible impacts to property values.

Thematic Comment	Comment Excerpt	DOE Response
	negative impacts of gas development on private property, residences, and existing businesses. Intense industrial activities, noise, emissions, and pollution from gas development often intrude upon communities and directly conflict with other land uses such as agriculture, outdoor recreation, and tourism. (See Compendium, pp. 35-37.) The Addendum refers to housing for temporary workers, but fails to discuss the pervasive problem that "man camps" and the influx of out-of-area workers create with respect to increased prostitution, violent crime, and drug use. Land use impacts on property values, mortgages, and insurance are not addressed either. Moreover, the Addendum mentions businesses which are supported by gas development (p.59), but fails to address displaced activities, such as organic farming and tourism which rely on a clean, unspoiled environment; or the negative consequences of the boom-bust economy typical of extractive industries, including fracking. (See Compendium, pp. 55-62.) These serious issues must be discussed.	
Subcategory: Siting and Design		
Two commenters indicate that the Addendum does not give enough weight to regulatory mechanisms in place to reduce land use impacts. Conversely, other commenters indicate that the Addendum fails to assess the efficacy of federal and state rules or guidelines pertaining to drilling and fracking, with examples of their ineffectiveness. Other concerns relating to land use mitigation include the Addendum's erroneous assertion that many impacts can be reduced or avoided by siting and design, and the omission of problems with the Jordan Cover mitigation measures.	(ANGA 121) Not enough weight is given to the regulatory mechanisms in place at the state and federal level to minimize environmental impacts and disturbances. (ANGA 121) Addendum does not address common mitigation measures or practices required by law or commonly utilized by industry to reduce land use impacts until the end of the section. Each state has regulatory agencies that enforce federal law and administer state rules. State regulations include the review and approval of permits for all aspects of drilling activities, such as well design, location, spacing, operation, water management and disposal, waste management and disposal, air emissions, wildlife impacts, surface disturbance and worker health and safety. State-led enforcement, in conjunction with current federal oversight, is considered critical because drilling practices are customized to the unique geological characteristics of different parts of the country, making state-level expertise essential to the oversight process. While states may adopt their own standards, by law they must be at least as protective as federal standards. (AAF 112) The Addendum fails to assess the efficacy of federal and state rules or guidelines pertaining to drilling and fracking on public lands. (p.64.) There is no discussion in the Addendum of what the BLM "Gold Book" requires or any objective assessment of its effectiveness and related enforcement. Federal regulators typically inspect only a fraction of wells that are drilled and fracked on public land. Regarding state land, the Addendum refers only to guidelines of one state: Pennsylvania. Impacts to	DOE has noted these comments. No changes were made to the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	state forests in Pennsylvania have been some of the most catastrophic in the nation. Clearly, the PA-DCNR guidelines are not effective. (AAF 112) The Addendum erroneously asserts that many impacts of gas development can be reduced or avoided by siting and design. (p.63.) This dismisses the major unavoidable industrial footprint and operational characteristics of gas production on a site-specific and regional scale. Drilling and fracking is an intense industrial activity involving around-the-clock disturbance, traffic, noise and pollution. Some impacts can be reduced, but it is disingenuous to suggest that many can be. (See Compendium, pp. 35-37.) The Addendum includes a vague set of siting and design considerations to "mitigate" impacts but fails to evaluate the extent to which any of these have been effectively applied, or the extent to which any are required and enforced. (p.63.) Contrary to mitigations identified, impacts often occur within previously undisturbed areas, and infrastructure is difficult or impossible to consolidate since gas development occurs on a grid pattern across large regions. The Addendum also fails to acknowledge that in many jurisdictions, the public has little or no legal recourse to oppose projects. Environmental damage, forest fragmentation, and other land use impacts which have already occurred during the first few years of shale gas development demonstrate that existing "mitigation" measures are woefully inadequate. Other considerations which the Addendum ignores include the need for setbacks to neighboring residences, business, and land uses; setbacks and restrictions relating to sensitive natural resources, surface waters, wetlands, and aquifers; security such as fencing to secure hazardous materials and prevent access by the public, wildlife, or livestock; and operational restrictions, such as limits on drilling, fracking, or flaring during wildlife migration times and other sensitive periods. The Addendum must be revised to address these many issues and objectively evaluate the inadequacy of current mitigation requirements. (CW 125) The Land Use Mitigation Measures described on page 63 of the Addendum also did not reflect the problems with the Jordan Cove Mitigation Measures, such as the lack of adequate mitigation measures offered for the pipeline. Other problems include the demands that the federal agencies cut short their review of the impacts on 28 species protected under the Endangered Species Act that could be impacted by the Jordan Cove Project.	
Subcategory: Traffic and Roadway Impacts		
Comments from industry indicate that the impacts on traffic and roadways are either redundant and have already been	(ANGA 121) The impacts highlighted throughout this section are redundant throughout the Addendum. The issues of truck traffic and impact on road infrastructure have been addressed proactively in many shale development	The purpose of the Addendum is to provide additional information to the public. The Introduction and Purpose sections of the

Thematic Comment	Comment Excerpt	DOE Response
addressed through the utilization of road maintenance agreement (RUMA) or state approved road management plans, or that the section should be deleted. Another commenter requests more context on impact fees on the industry provided for by state statutes. Another commenter takes the opposite position stating that the Addendum improperly downplays concerns of traffic and road damage caused by drilling and fracking activity.	areas through the utilization of a road maintenance agreement (RUMA) or state approved road management plans. A RUMA is an agreement between a governing body - typically at the local level such as county or a township- and a gas exploration company. RUMAs are entered into prior to the development of well pad sites and before any drilling or hydraulic fracturing take place. In many jurisdictions a RUMA is required to be obtained prior to the issuance of any permits associated with development activities. RUMAs establish the parameters by which a gas producer will use the local road infrastructure. Typically the agreements are between a producer and a locality that cover road repairs, upgrades and bonding. These agreements often stipulate designated travel routes for heavy equipment to ensure safety and minimize impact. They also take into account school bus routes and travel schedules as well as other issues of local concern that can be mitigated through effective transportation planning and government/operator collaboration. Additionally, the advent and wide utilization of water recycling and reuse programs has dramatically reduced truck traffic. The construction of centralized fresh water impoundments and temporary over surface water lines that deliver water for well stimulation without the need for vehicular transport is further minimizing impacts on local transportation infrastructure. In Pennsylvania alone between 2008 and 2011 according to a Marcellus Shale Coalition operator survey, gas producers invested over $411 million on construction of new roadways, upgrades and repairs since development began in earnest. (API 100) Page 64: API recommends deleting the Traffic Impacts section. The same points are raised several times in the preceding associated impacts section. (API 100) Page 66: It is necessary to provide context on impact fees on the industry provided for by state statutes. These fees finance infrastructure and environmental repairs and upgrades, improve public safety, and provide tax relief. They also help to finance certain state government agencies. (AAF 112) The Addendum improperly downplays concerns of traffic and road damage caused by drilling and fracking activity, asserting that increased traffic caused by gas production may only represent a “small, incremental change” in existing conditions, or is limited to certain local roads at certain times. (p.64.) Communities in and around areas of gas production have experienced significant problems caused by the high volume of large trucks needed to transport water, chemicals, construction supplies, and drilling or fracking waste--often on roads which are not	Addendum provide DOE’s purpose in more detail. State and local road maintenance plans or impact fees are not within the scope of the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	designed to support the volume and weight of vehicles involved. Arterial and major collectors may also be impacted depending on prior levels of service. Although the Addendum acknowledges that damage to roads and bridges can strain government budgets, it fails to evaluate the cumulative impact of this problem. (See Compendium, pp. 56, 58-61.) The Addendum also fails to address how this impacts public safety. A surge in traffic-related deaths have been reported in heavily drilled areas of six states, including counties in North Dakota where traffic fatalities have jumped 350 percent. (See Compendium. pp.56.) The Addendum should be revised to address these issues.	
Specific changes requested.	(API 100) Page 56: API recommends omitting Figure 17: Typical Well Pad Development in a Wooded Location. The text with this photo inaccurately depicts the use of very large reservoirs of water as typical for unconventional development across the country.	The Figure mentioned in the comment was intended to be used as an example for the public to get a visual understanding of the issues being talked about. The caption for this figure was changed accordingly.
Specific changes requested.	(API 100) Page 56: The well pad spacing reference (NETL 2009) is out of date as the reach of horizontal drilling has continually increased.	DOE has noted the comment. No changes were made to the Addendum.
Specific changes requested.	(API 100) Page 60: In the discussion on land use impacts, DOE states: “Some lands may revert back to agricultural uses, but soil compaction may be an issue.” API recommends providing a reference for this statement or deleting it.	DOE made a number of editorial changes, clarifications, and other modifications to the sections related to this comment. Additional discussion and references for soil compaction were added where appropriate.
Specific changes requested.	(API 100) Page 62: API recommends the following changes to the discussion on the associated impacts from development: Associated impacts from development: · Increased traffic – Pipeline construction and well development activities require deliveries of various raw materials and an ~~army~~ increase in workers that *may result in* increase*d* traffic, ~~raise~~ accident rates, and ~~cause increased~~ road wear and tear (see Traffic and Roadway Impacts). · Invasive species – Pipeline construction and well development activities *may cause* a disturbance of land that can provide access to invasive species. *However, is it important to note that there are strict federal and state regulations governing reclamation efforts to prevent invasive species issues.* View shed alteration – Pipeline construction and well development activities cause at least temporary visual changes to the landscape. ~~During the peak of activities, nuisance lighting can also be an issue.~~ · Reflective Light Pollution – During the peak of activities, nuisance lighting can also be an issue.	DOE made a number of editorial changes, clarifications, and other modifications to the sections related to these comments. Additional references were added where appropriate to support statements made.

Thematic Comment	Comment Excerpt	DOE Response
Water Resources		
Subcategory: Water Use and Quantity/Consumption and Source Water		
Commenters expressed concern that the Addendum understates the quantity of water required, misuses the comparisons with water use for fracking and other forms of energy production, and fails to adequately address the context and impact of unconventional gas development's water use on local water supplies. Conversely, commenters representing the oil and gas industry offer support for DOE's comparison to other forms of energy production to show the smaller water footprint associated with shale gas production, and point out the industry's commitment to environmental stewardship. However, they also think there are some misleading statements that imply production is depleting freshwater sources and that the Addendum should be amended to clarify the factors companies consider while sourcing water and to better reflect the range of private sector initiatives underway to alleviate concerns about access to water.	(SC 143) As DOE acknowledges, shale gas production is a water-intensive process, with drilling and hydraulically fracturing a well requires an average of 2 to 6 million gallons of water. DOE likely understates this quantity: the author of the more recent of the two studies informing DOE's estimates, Jean-Philippe Nicot, has published more recent work that concludes increased estimates of water consumption. (SC 143) The Addendum nonetheless fails to adequately discuss the context and impact of unconventional gas development's water use, for two reasons. The Addendum's discussion of the impact of water use begins by comparing shale gas with other forms of energy in terms of water intensity, i.e., gallons of water demand per mmBtu. DOE concludes that after conventional gas, shale gas is the least water intensive fossil fuel. For purposes of assessing the water impacts of proposed LNG exports, however, this comparison is potentially misleading. The increased gas production that will be induced by LNG exports will occur in addition to, rather than in place of, production of other energy. The key question is whether American communities and ecosystems will be able to tolerate the additional water demand created by the added gas production. If the answer is no, then there will be little comfort in the fact that, if an equivalent amount of some other energy production had been added instead, the water demand would have been even higher. (SC 143) The Addendum further obscures the water impact of shale production by comparing it with less consumptive uses. The Addendum emphasizes that the water volumes needed for shale gas production are smaller than those used for municipal, irrigation, and electricity generation purposes, such that "In most cases, shale gas production uses less than one percent of the total water demand." Shale gas's water demand is significantly different than these other uses, however, in that shale gas extraction is largely a consumptive use that removes water from the usable water cycle. After water has been used for irrigation or municipal purposes, for example, much of that water is treated and redischarged into surface water or percolates through the soil and recharges usable groundwater aquifers. The majority of water used for shale gas production, however, either remains in the shale formation or, after it is returned to the surface, is disposed of in underground injection wells where it is permanently removed from the	DOE's estimate of between 2 to 6 million gallons of water used to hydraulically fracture an unconventional gas well is based on currently available information and represents a range from well to well. Localized geology of the well, length and depth of the well, and number of fracture stages will determine the specific water usage per well. DOE water usage quantities provided are reasonable within the context of the Addendum. Further, regionally water usage varies greatly from one shale gas formation to another (Marcellus/east, Barnett/west). DOE is fully aware that unconventional gas plays are increasing supplies of natural gas nationally; however, as stated in the Addendum, it cannot be fully determined where this new gas will be produced locally, as it relates to LNG exportation in other areas. DOE clearly stated the Addendum was not required by NEPA and simply cannot provide detailed analysis for specific local issues. The Addendum was not intended to be an alternatives analysis, nor was it intended to be a comprehensive evaluation. However, as with any other studies, reports, or publications, this document may be referenced or considered by DOE or others.

Thematic Comment	Comment Excerpt	DOE Response
	usable water cycle. NETL explains that "By far, the preferred [water] disposal method for the oil and gas industry as a whole is underground injection," and that "In 2007," the only year for which NETL provides a nationwide estimate, "more than 98 percent of produced water from on-shore wells was injected underground." The SEAB Shale Gas Subcommittee has recognized "significant concerns about consumptive water use for shale gas development." Thus, the water withdrawn from the aquifer will be used in a way that provides no opportunity to percolate back down to the aquifer and recharge it. Because shale gas development uses water more consumptively than other forms of water demand, the impact of shale gas development on local water supplies is greater than the mere percentages provided by DOE acknowledges. (AAF 112) The Addendum's comparison of water use for fracking to other forms of energy production is misleading because a significant amount of fracking water remains underground or is later disposed of by underground injection. Unlike water needed for other forms of energy production such as hydro-power, geothermal, biofuels or nuclear power, this water is permanently removed from the Earth's hydrologic cycle. As with water contamination, the Addendum dismisses water consumption as a "local" issue (p.12), ignoring cumulative regional impacts and failing to address real conflicts occurring between the gas industry and other water consumers such as farmers and residents in drought prone areas. The Addendum should be revised to address these issues. (UHLC 84) By far one of the most critical issues related to shale gas development pertains to what the US Environmental Protection Agency (EPA) has called the water lifecycle. At the request of the US Congress, the US EPA is conducting a study to better understand any potential impacts of hydraulic fracturing on drinking water and ground water. The scope of the EPA's research includes the full lifecycle of water use in hydraulic fracturing, from acquisition of the water, through the mixing of chemicals and actual fracturing, to the post-fracturing stage, including the management of flowback and produced water and its ultimate treatment and disposal. This study is significant because to date, it is the most comprehensive study being undertaken on the impact of hydraulic fracturing on water and the findings may be useful to inform decisions around the world. A final draft report is expected to be released for public comment and peer review in 2014. (UHLC 84) With many countries facing acute water shortages, concerns have been raised pertaining to the large volumes of water needed during the	DOE does not consider this document as the sole justification for any determination or agency action. DOE has added further references to the Addendum regarding fracking water migration and potential health effects. Additional references have been included in the Addendum citing more current peer-reviewed studies and modeling pertaining to upward migration of hydraulic fracturing fluids and potential contamination of shallow potable groundwater aquifers. Available water varies greatly from one area to another. Consultation with the appropriate water management and State regulatory agencies is essential.

Thematic Comment	Comment Excerpt	DOE Response
	hydraulic fracturing process. According to a report issued by the U.S. Geological Survey (USGS) pertaining to water resources and gas production in the Marcellus Shale, "many regional and local water management agencies [in the Marcellus shale region] are concerned about where such large volumes of water will be obtained, and what the possible consequences might be for local water supplies." Chesapeake Energy Corp., one of the most active drillers in the Marcellus shale, candidly admits water is an essential component of its deep shale gas development. According to the company, "fracturing a typical Chesapeake Marcellus horizontal deep shale gas well requires an average of five and a half million gallons per well." Industry generally maintains that water resources are protected through stringent state, regional and local permitting processes and in comparison to other uses, deep shale gas drilling and fracturing uses a small amount of water. Nonetheless, whether or not a particular location has the water resources to support shale gas development is a critical issue and consultation with the appropriate water management agencies is essential. (ANGA 121) An important part of the natural gas industry's commitment to environmental stewardship revolves around our ability to use water wisely and to be attuned to community water needs. As the Addendum correctly points out, conventional natural gas and shale gas production have a relatively small water footprint with shale gas production typically using less than one percent of total water demand in a region or metropolitan area. (ANGA 121) Recognizing concerns associated with the availability of water and restrictions associated with municipal water use, our members have adopted a number of recycling initiatives to be better stewards of the communities in which they operate [references 4 examples – see below] These efforts take into account the local climate, weather patterns, existing water use rates and needs. Accordingly, we urge the DOE to amend the Addendum to reflect the range of private sector initiatives underway to alleviate concerns around access to water and promote responsible development of natural gas. • In the Marcellus Shale, Anadarko's water management and well completion strategies help to reduce truck traffic and associated emissions, while minimizing earth disturbance and conserving available water resources. Additionally, a piping system using two lines, one for natural gas and one for fresh water (located in the same trench to reduce surface disturbance) provides water to well sites for the completion process. The closed-loop system moves	The Addendum addressed some of the issues of flowback water and its treatment. Gas developers continue to utilize new technologies and recycling techniques to reduce amounts of flowback water requiring further treatment. DOE recognizes that technological improvements are continually evolving to find innovative methods to conserve water and reduce environmental impacts. Addendum has been modified to cite flowback water subject to the EPA's New Source Performance Standards (NSPS).

Thematic Comment	Comment Excerpt	DOE Response
	water from a pre-determined and approved source through pipelines to containment facilities for use in the hydraulic fracturing process. • Range Resources has been successfully recycling 100% of its flow-back water in their core operating area in southwestern Pennsylvania since 2009. • Cabot Oil and Gas has recognized that processes such as water recycling are essential to the long-term viability of modern natural gas and oil production. In its Marcellus Shale operations, which accounted for 60% of Cabot's wells drilled in 2012, they currently recycle virtually all of the water generated through drilling, completion and production operations. • To reclaim produced water as a way to conserve water, Chesapeake Energy developed Aqua Renew® in 2006 as a logical evolution of its involvement with the Barnett Shale Water Conservation and Management Committee in North Texas. (ANGA 121) The Addendum makes broad assertions about stream and aquifer usage with no substantive discussion around sourcing of water or the quality of sourced water. Some of these statements seem to suggest that oil and gas operations are depleting fresh water sources, which is misleading. It should be noted that many states require water management plans that ensure water withdrawals will not harm the watershed by adversely affecting stream flow, aquatic life or sensitive environments. A more robust discussion is necessary to clarify the factors that companies weigh while sourcing water for their operations. (API 100) With regard to the discussion on withdrawals from surface waters and groundwater, more context is needed. As written, the reader is left with the impression that industry only uses drinking water or water of drinking water quality to carry out operations. [specific language offered for Page 12, see below]	
Subcategory: Water Contamination – Drilling Impacts		
Commenters expressed concern that despite DOE's optimism about the possibility of minimizing risks, numerous studies demonstrate that contamination occurs in practice. The Addendum fails to assess or even	(SC 143) Shale gas production can introduce harmful contaminants into surface and groundwater through a number of pathways: spills and leakages at the well pad, failure of well casing or cement, or through other underground migration. For underground migration, DOE describes contamination occurring through the assistance of some conduit such as existing well or natural fault. One geological model, however, concluded that even in the absence of such a conduit, hydraulic fracturing could drive	References have been added to the Addendum to reflect recent "frack" fluid disclosure requirements. The main focus of the Addendum is not to identify all applicable State and Federal Regulations and industry practices but rather to give the public an

Thematic Comment	Comment Excerpt	DOE Response
acknowledge the numerous reported cases of surface and groundwater contamination. Also, the Addendum asserts that best practices and other measures can minimize risk of contamination; it provides no analysis of the rate of industry adherence to these practices or the residual risk that exists despite the exercise of due care.	contaminants into aquifers in less than 10 years. DOE concludes best practices can minimize risk of contamination through other pathways but provides no analysis of the rate of industry adherence to these practices or the residual risk that exists despite the exercise of due care. (SC 143) Despite DOE's optimism about the possibility of minimizing risks, numerous studies demonstrate that contamination occurs in practice. In addition to the studies cited in the NETL Unconventional Production report, a review of drilling in Colorado found that gas drilling correlated with increasing thermogenic methane and chloride levels in groundwater wells. In addition, EPA has concluded that unconventional production likely led to groundwater contamination in Pavillion, Wyoming and Dimock, Pennsylvania. [Commenter goes into great detail about EPA study and findings (draft) regarding chemicals found in wells surrounding Pavillion as well as EPA's assessment and findings in homes near Dimock, PA. Commenter also references records obtained by the Scranton Times-Tribune which further document that oil and gas development damaged at least 161 Pennsylvania water supplies between 2008 and the Fall of 2012, although the evidence may paint only a partial picture because some instances are not made public. (AAF 112) The Addendum fails to assess or even acknowledge the numerous reported cases of surface and ground water contamination. (See Compendium, pp. 16-27, 30-32.) Many residents around the country are now forced to rely on water buffaloes (portable water tanks) or bottled water because drilling and fracking operations have contaminated drinking water supplies. Inexcusably, the EPA abruptly halted investigations of wells contaminated in Dimock, PA and Pavilion, WY although significant levels of toxins in well water were revealed. Likewise, hundreds of cases of water contamination have now been documented by the Pennsylvania DEP. Providing no assessment of vaguely referenced regulations, best management practices, and "pollution prevention concepts," the Addendum asserts without authority that if these measures are followed, only temporary, minor impacts to water resources are likely to occur. (p.19.) Furthermore, the Addendum states that even if they are not followed, significant impacts would only be "local." Clearly, regional water resources are at risk too. In fact, it is out of concern for a major regional watershed--the watershed of New York City--that the NYS-DEC has said it will not permit fracking within southeast New York. These defects and omissions in the analysis of risks to water resources must be corrected. (UHLC 84) Cites other studies in addition to those cited in the NETL	overview of environmental impacts. Potential contamination would be a very local issue. While DOE is aware that leakage can occur through improper casing and construction and grouting techniques, the Addendum is not incorrect by stating that multiple casings are utilized during the construction of an unconventional shale gas well.

Thematic Comment	Comment Excerpt	DOE Response
	Report – with primary reference to Draft EPA study – that concluded unconventional production likely led to groundwater contamination in Pavillion, Wyoming and Dimock, PA (contamination at Pavillion also supported by studies from USGS and WY DEQ); case now under review by State of Wyoming. The sampling data obtained throughout EPA's groundwater investigation will be considered in Wyoming's further investigation, and EPA will have the opportunity to provide input to the State of Wyoming and recommend third-party experts for the State's consideration. The State intends to conclude its investigation and release a final report by September 30, 2014.	
Subcategory: Water Contamination – Drilling Impacts		
Commenters are concerned that the Addendum inaccurately describes the use of "multiple layers" of steel casing and cement as protective of freshwater aquifers; inaccurately claims that the surrounding rock formation will act as a seal; and fails to include any assessment of gas well leakage or failure rates. Conversely, an industry commenter doesn't think the discussions of risk of aquifer contamination provide context or sufficient citations to justify the broad claims made.	(AAF 112) The Addendum inaccurately describes the use of "multiple layers" of steel casing and cement as protective of freshwater aquifers. (p.13.) Various studies, including those by industry, have shown that 5 percent of oil and gas wells typically leak immediately, and that 40 to 60 percent leak over time. (See Compendium, pp. 27-29.) Further, the additional stress associated with high-volume fracking, which may be repeated several times for a single well, can compromise casing integrity. The Addendum also inaccurately claims that the surrounding rock formation will act as a seal. In actuality, leakage very often occurs through the vertical movement of methane gas and other volatile compounds between the pipe and casing, and between the casing and formation. This is a problem that the gas industry cannot solve, and long-term requirements for monitoring and repair are lacking. The Addendum fails to include any assessment of gas well leakage or failure rates. These issues must be addressed. (UHLC 84) While the Pavillion case remains under review by the state of Wyoming, the general consensus that seems to have emerged is the greater risk for groundwater contamination is related to the process of developing a natural gas or oil well (drilling through an overlying aquifer, and casing, cementing and completing the well). Incidents of well water contamination attributed to hydraulic fracturing, typically have been found to be caused by problems with the well casing or cementing. In some states, such as Pennsylvania, regulators have confirmed that methane had migrated to water wells and that the gas migration was caused by improperly cased and cemented wells, as well as excessive pressures in some cases. The challenge of sealing off the groundwater and isolating it from possible contamination is common to the development of any oil or gas well, not only those that rely on hydraulic fracturing. Nonetheless, given the higher pressures and large volumes of water used in hydraulic fracturing, a number of states have revised well casing, cementing, pressure testing and other requirements to	See response above.

Thematic Comment	Comment Excerpt	DOE Response
	protect water resources. (ANGA 121) The Addendum makes statements about the risks associated with development of unconventional resources but provides neither context nor sufficient citations to justify such broad claims. For example, the Addendum notes that failure of a casing or cement bond could lead to aquifer contamination and identifies contamination risks associated with improper drilling practices but provides no contextual data related to regulations that minimize risk, actual incidents or the probability of occurrence.	
Subcategory: Hydraulic Fracturing Fluids – Pathways and Risk		
Commenter points out that a number of peer-reviewed papers and other studies demonstrate that the risk of contamination of shallow aquifers through subsurface migration of fluids is minimal, and cite a number of peer-reviewed papers that should be referenced in the Water Quality Section, Hydraulic Fracturing Fluids subsection, to provide more comprehensive and accurate information on this subject.	(HESI 78) The Draft Addendum states that "fracture growth may result when fractures propagate outside of the production zone. If a connection is established, contaminants may reach aquifers used for water supply if "adequate protections are not in place." However, a number of peer-reviewed papers and other studies demonstrate that the risk of contamination of shallow aquifers through subsurface migration of fluids from shales or other tight formations via induced fractures or existing faults is minimal. Commenter cites and summarizes several peer-reviewed papers that should be referenced in the Water Quality Section, Hydraulic Fracturing Fluids subsection, to provide more comprehensive and accurate information on this subject, including: • A peer-reviewed paper by researchers at the Lawrence Berkeley National Laboratory reports on some of the results of modeling being conducted for EPA's study of the impacts of HF on drinking water and concludes that the possibility of hydraulically induced fractures at great depths causing activation of faults and creation of a new flow path that can reach shallow groundwater resources is "remote." • Gradient's 2013 National Human Health Risk Evaluation evaluates whether it is possible for fluids pumped into a tight formation during the HF process to migrate upward to reach drinking water aquifers and determines that once the fracturing fluids are pumped into a tight formation, it is "simply not plausible" that the fluids would migrate upwards from the target formation through several thousand feet of rock to contaminate drinking water aquifers. • A peer-reviewed paper by Gradient discusses the physical constraints on upward fluid migration from black shales to shallow aquifers and concludes that upward migration of frac fluid and brine as a result of HF activity does not appear to be physically	Addendum has been modified to cite several recent studies on fracture propagation outside of production zones. These studies found that the likelihood of upward migration of fracture fluids is minimal.

Thematic Comment	Comment Excerpt	DOE Response
	possible. These conclusions are confirmed by a review of an extensive microseismic database that includes over 12,000 HF stages throughout the US. • Another peer-reviewed paper by Gradient and a HESI expert concludes that it is not physically plausible for induced fractures – either alone or through activation of existing faults – to create a hydraulic connection between tight formations at depth and overlying drinking water aquifers. This conclusion is again supported by extensive microseismic data. • An October 2012 report regarding HF operations in the Inglewood Oil Field in the Baldwin Hills area of Los Angeles County showed that, based on actual groundwater monitoring results, the groundwater quality in the area was not affected by hydraulic fracturing activities. • MIT 2011 study on the potential risks of hydraulic fracturing to groundwater aquifers and found that "no incidents of direct invasion of shallow water zones by fracture fluids during the fracturing process have been recorded."	
Subcategory: Hydraulic Fracturing Fluids – Health Effects of Chemical Additives		
Gas production and unconventional gas production in particular can harm water quality primarily by contaminating surface and ground water with chemicals added to fracturing fluids or chemicals naturally occurring in the formation.	(SC 143) DOE provides examples of chemical additives and their purpose but does not include any discussion of the chemicals' safety. Many of the chemicals used present health risks. Many of these compounds are also regulated in other industries under the Safe Drinking Water Act (SDWA) and the Clean Water Act (CWA) as hazardous water pollutants... Many of the chemical compounds used in the process lack scientifically based maximum contaminant levels (MCLs), which render a quantification of their public health risks more difficult... At certain concentrations or doses, more than 75% of the chemicals identified are known to negatively impact the skin, eyes, and other sensory organs, the respiratory system, the gastrointestinal system, and the liver; 52% have the potential to negatively affect the nervous system; and 37% of the chemicals are candidate endocrine disrupting chemicals. (SC 143) One of most troubling additives is diesel, which has been singled out for its harmful effects by SEAB Shale Gas Subcommittee and a ban has been recommended. (SC 143) In addition to chemicals added to fracturing fluid, harmful chemicals naturally occur in the target formations, and these chemicals can be mobilized by the shale gas production process. DOE generally states that, in addition to chemicals introduced into the fracturing fluid, wastewater can	References have been added to the Addendum to reflect recent fracture fluid disclosure requirements. References to recent medical studies have been added to the Addendum. Many states no longer allow diesel fuel as an additive to fracture fluids.

Thematic Comment	Comment Excerpt	DOE Response
	contain "total dissolved solids (TDS), salts, metals, organics, [and] naturally occurring radioactive materials (NORM)." DOE does not acknowledge that the organic chemicals can include particularly handful compounds such as benzene, toluene, ethylbenzene, and xylene. Unconventional gas production can also introduce methane into water supplies, creating a safety hazard. (AAF 112) The Addendum mischaracterizes the amount of chemicals added to fracking fluid as “small” because it represents about two percent of the liquid solution. Chemists understand that concentrations measured in parts-per-thousand and parts-per-million are very significant to the properties of a fluid and its toxicity to human health. The Addendum compares the chemical disclosure requirements of only nine states although fracking occurs in many more. The Addendum also fails to address how industry secrecy prevents doctors, patients, and medical researchers from accessing information important to public health. The Addendum must acknowledge the need for disclosure of all fracking chemicals and call for study of the combined impacts of chemicals used in fracking--many of which are known human carcinogens--on public health. (API 100) Main risks related to public health include [air emissions] and indirect impacts in terms of potential water pollution, some being recognized as carcinogens. Water contamination can also lead to contamination of live animals, food and feed. (API 100) Conversely to the comments above, the American Petroleum Institute comments that the Addendum fails to report that there has been no peer reviewed “exposure pathway” (via air, water or otherwise) that has been proven to connect the industrial process with any health issues.	
Subcategory: Hydraulic Fracturing Fluids – Identification of Chemicals		
Commenter references growing trend to disclose chemicals used in hydraulic fracturing because the chemical additives could be hazardous.	(UHLC 84) The chemical additives used include “common chemicals which people regularly encounter in everyday life” as well as “chemical additives that could be hazardous, but are safe when properly handled.” The service companies that provide these additives have developed a number of different combinations to be used depending on the well characteristics. As shale gas development increased in the United States, there were growing calls for the industry to disclose the chemicals used in hydraulic fracturing fluids. In addition to public calls for disclosure, various members of the US Congress through the US Subcommittee on Energy and Environment also requested this information from oil and gas companies with companies ultimately complying. More recently, there is a growing trend in the US towards requiring	DOE recognizes that technological improvements are continually evolving to find innovative methods to conserve water and reduce environmental impacts.

Thematic Comment	Comment Excerpt	DOE Response
	companies to disclose the chemicals used in hydraulic fracturing with a number of states now requiring disclosure and more states likely to follow this trend. Some states require or allow for the disclosure via FracFocus, which is a web-based national registry where companies can disclose the chemical additives used in the hydraulic fracturing process on a well-by-well basis. Canada has a similar website and other countries are considering something similar for disclosure which is likely to be required in most countries.	
Subcategory: Water Contamination – Construction Impacts from Sediment Loading		
Commenter thinks DOE overstates the extent to which federal authority limits potential stormwater pollution from gas production.	(SC 143) Under the Clean Water Act, "industrial" activity-including land clearing, excavation, and ground-disturbing activity-requires a water permit that includes a Stormwater Pollution Prevention Plan. But because of exemptions enacted in 1987 and expanded in 2005, gas production is largely exempt from this rule. As EPA interprets this loophole, gas exploration and production does not require a stormwater permit for stormwater discharges containing only sediment. Although gas production still requires a permit when its stormwater discharge carries oil, hazardous substances, or other pollutants, the loophole for sediment means that often, there is no permit in place and no mechanism for monitoring whether stormwater is carrying these other substances. Thus, DOE overstates the extent to which federal authority limits potential stormwater pollution from gas production.	While exemptions do exist for certain activities, many other activities are still covered under the CWA.
Subcategory: Flowback and Produced Waters – Water Disposal Issues		
The Addendum needs to include an assessment of the existing disposal methods for fracking flowback water, and the adequacy of state regulations and their enforcement, including impacts associated with the spreading of "brine" and impacts to livestock and wildlife caused by containment ponds, spills and soil contamination. The Addendum also needs to include a corrected definition for "flowback" that is consistent with the definition in EPA's Oil and Gas New Source Performance Standards.	(UHLC 84) The Addendum contains a cursory description of fracking flowback and produced water, but fails to assess disposal methods, the adequacy of state regulations and their enforcement, or the significant problem of illegal dumping. The Addendum mischaracterizes certain methods of disposal as a "pollution prevention approach" (p.18), although injection wells have caused groundwater contamination, evaporation results in concentrated effluent and the release of toxic compounds into the atmosphere, and surface discharges contribute to water pollution. Impacts associated with the spreading of "brine" that contains toxic and radioactive material on roads are not mentioned, nor are impacts to livestock and wildlife caused by containment ponds, spills, and soil contamination. (See Compendium, pp. 48-49.) The Addendum must be revised to address these issues. (AAF 112) The Addendum contains a cursory description of fracking flowback and produced water, but fails to assess disposal methods, the adequacy of state regulations and their enforcement, or the significant problem of illegal dumping. Typical wastewater treatment plants are not	The purpose of the Addendum is clearly stated. Determining the adequacy of state regulations or enforcement is outside of the scope of this document. The Addendum addressed issues of flowback water and concerns involved with the treatment and disposal of it. State by State regulatory changes and modifications to sewage treatment plants are ongoing in order to allow or dis-allow treatment at respective plants. Many gas developers continue to

Thematic Comment	Comment Excerpt	DOE Response
	able to treat or remove chemicals contained in fracking wastewater. Thus, fracking wastewater not disposed of by injection wells is simply diluted and released into drinking water sources. The Addendum mischaracterizes certain methods of disposal as a "pollution prevention approach" (p.18), although injection wells have caused groundwater contamination, evaporation results in concentrated effluent and the release of toxic compounds into the atmosphere, and surface discharges contribute to water pollution. Impacts associated with the spreading of "brine" that contains toxic and radioactive material on roads are not mentioned, nor are impacts to livestock and wildlife caused by containment ponds, spills, and soil contamination. (See Compendium, pp. 48-49.) The Addendum must be revised to address these issues. (ANGA 121) The Addendum incorrectly states that flowback occurs after well drilling and before completion. Flowback is from well completion, and is accurately defined in EPA's Oil and Gas New Source Pollution Standards. This definition should be corrected in the Addendum to ensure that it aligns with the definition given in EPA's regulations. (UHLC 84) Another commenter acknowledges that the method of disposal for the flowback water is also an important issue and given the potential large quantities involved, is a significant challenge for many reasons. This commenter identifies and briefly describes each of the disposal methods used in the US today (Underground injection, wastewater discharges to treatment facilities, recycling of wastewater, and surface impoundments (pits or ponds) und and references EPA's current examination of the various disposal methods to ensure there are regulatory and permitting frameworks in place to provide for safe disposal of flowback.	utilize new technologies and recycling techniques to reduce amounts of flowback water requiring treatment. The Addendum has been modified to reflect EPA's definition of flow back water.
Subcategory: Regulatory Issues		
Commenter thinks the Draft Addendum should reference / describe some additional state regulatory developments that have occurred since the State of Louisiana's December 2011 review.	(HESI 78) Draft Addendum's description of U.S. state regulatory requirements regarding HF chemical disclosure in Table 5 is derived from a chart originally created by the Louisiana Department of Natural Resources on December 30, 2011.2 While this chart originally provided a comprehensive snapshot of certain aspects of state regulation, the Draft Addendum should also reference/describe some additional state regulatory developments that have occurred since the state of Louisiana's December 2011 review over two and a half years ago. The following states have all adopted regulations concerning disclosure of the make-up of fracturing fluids since December 2011: Alabama, Alaska, California, Idaho, Indiana, Kansas, Michigan, Mississippi, North Carolina, Ohio, Oklahoma, South Dakota, Tennessee, Utah and West Virginia. Pennsylvania is in the	The purpose of the Addendum is to provide information to the public. A detailed review of state regulations is outside the scope of the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	process of updating its disclosure regulations that were in place when table 5 was created to reflect changes in its oil and gas law that were adopted in 2012.	
Specific changes requested.	(API 100) Page 12: API recommends that DOE include the following phrasing *(red text)* to the groundwater withdrawal discussion: Withdrawals from groundwater could also have potentially adverse impacts. Some smaller, shallower aquifers may be depleted or reduced *over time by cumulative withdrawals from all water users*. Such reductions may render these aquifers unavailable for residential drinking water wells or impact the hydraulic connections between these aquifers and local surface waters. These aquifers may be an important source of cool water in the local ecosystem, particularly in the warmest portion of the year. Deeper aquifers may also be impacted by significant withdrawals, as recharge from precipitation may take an extended period of time.	DOE has made minor modifications to the Addendum based upon these concerns.
Specific changes requested.	(API 100) Page 14: API recommends that DOE delete the unnecessary sentence noted below: Hydraulic fracturing is generally used to increase the productivity of a well. In addition to increasing permeability and fluid flow rates, fracturing can increase the amount of contact between the well and the formation and the area of drainage within the formation. This process can be used to manage pressure differences between the well and the target formation."	These statements in the Addendum are factually correct. DOE attempted to summarize existing literature in several areas and these sources have unique assumptions or methods.
Specific changes requested.	(API 100) Page 18: API recommends that the first paragraph be rewritten, to include the red text, to more accurately reflect the management of produced water: Produced water recovered during flowback operations water recovered from a hydraulic fractured well is returned to the surface and typically stored, until reuse or disposal occurs, onsite in open pits or storage tanks. Flowback water is the fluid returned to the surface after hydraulic fracturing. Estimates on the percentage of original hydraulic fracturing fluids recovered vary widely, and may be from 20 to 80 percent (NETL 2014).Produced water recovered during flowback operations. Flowback water may contain elevated levels (as compared to State and Federal water quality standards) of total dissolved solids (TDS), salts, metals, organics, naturally occurring radioactive materials (NORM), and specific chemicals used in the hydraulic fracturing process.	DOE has made changes to the Addendum to more clearly explain flowback operations and produced water management.
General, Document, or Procedural Comments		
The Addendum does not adequately assess existing policies and regulations and their efficacy, particularly with	(AAF 112) "Significantly, the Addendum fails to perform any meaningful assessment of policies and regulations in place at the federal and state levels, or their efficacy. For example, it is well known that the oil and gas industry has been granted broad exemptions from landmark environmental laws, such	As previously stated, the purpose of the Addendum was very specific. DOE was not attempting to provide an assessment of

Thematic Comment	Comment Excerpt	DOE Response
regard to the exemptions to such regulations for some aspects of hydraulic fracturing.	as the Clean Air Act and Safe Drinking Water Act. However, nowhere in the Addendum are the ramifications of these exemptions discussed. The Addendum instead assumes--without evidence--that regulations have become stricter (p.2). Growing accounts of pollution, accidents, and illness caused by widespread drilling and fracking activities throughout the United States are indicative of a system of lax regulatory oversight--refuting claims regarding the adequacy of rules in place, and demonstrating a clear need for stronger protections and the repeal of special interest exemptions.	regulatory frameworks, nor recommend a compilation of industry standards.
Commenters submitted 70 reports and articles to support their comments on various aspects of the Addendum.	Summary of Attachments Received: • *Compendium of Scientific, Medical, and Media Findings Demonstrating Risks and Harms of Fracking (Unconventional Gas and Oil Extraction)* prepared by the Concerned Health Professionals of New York in July 2014 (AAF 108 and AAF 112) • Article from the journal, *Environmental Practice* entitled "Hydraulic Fracturing Threats to Species with Restricted Geographic Ranges in the Eastern United States."(AAF 112) • Article from the journal, *Energy Science and Engineering* entitled "A Bridge to Nowhere: Methane Emissions and the Greenhouse Gas Footprint of Natural Gas." (AAF 112) • *An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources.*" Nature Conservancy, December 2011 (AAF 112) • Article from the newspaper, *The World* (Coos Bay) titled, "Money Starts Flowing, Jordan Cove Parent Company Looks at Financing, Ownership Options, Expansion" (March 28, 2014) (CALNG 128) • Citizens Against LNG, Inc. Notice of Intervention, Protest and Comments in Response to FE Docket No. 12-32-LNG (CALNG 128) • Letter from Citizens Against LNG to DOE Docket Manager (Sept 12, 2012) (CALNG 128) • Article from *Daily Mail Reporter* titled "Ignore Climate Change and 100M People Will Die by 2030, Shocking New Report Claims." (Sept 26, 2012) (CALNG 128) • Article titled "Report: Climate Crisis Already Causing Unprecedented Damage to World Economy; Human Impact on Large-Scale (Sept 26, 2012) (CALNG 128) • *Climate Vulnerability Monitor. A Guide to the Cold Calculus of a Hot Planet, Second Edition* prepared by DARA (CALNG 128) • *The National Energy Modeling System: An Over view 2009.* Energy Information Administration, Office of Integrated Analysis and Forecasting. U.S. Department of Energy, 2009. (SC 143,	Additional studies and references submitted to DOE have been incorporated by reference into the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	Exhibit 1) • *Model Documentation, Natural Gas Transmission and Distribution Module of the National Energy Modeling System.* U.S. Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis. U.S. Department of Energy, February 2012. (SC 143, Exhibit 2) • *Documentation of the Oil and Gas Supply Module (OGSM).* U.S. Energy Information Administration, Office of Energy Analysis. U.S. Department of Energy, July 2011. (SC 143, Exhibit 3) • *Analysis of Economic Impact of LNG Exports from the United States.* Deloitte MarketPoint LLC (DMP). Prepared for Excelerate Energy L.P, (SC 143, Exhibit 4) • *Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report.* Prepared for Texas Oil & Gas Association. September 2012. (SC 143, Exhibit 5) • Article from the Journal, *Environmental Health Perspectives* entitled "Environmental Public Health Dimensions of Shale and Tight Gas Development." Published with support from the National Institute of Environmental Health Sciences, National Institutes of Health, U.S. Department of Health and Human Services, April 2014. (SC 143, Exhibit 6) • A letter to the U.S. EPA Administrator, sent from the Congress of the United States, House of Representatives, Committee on Energy and Commerce Democrats, October 2011. (SC 143, Exhibit 7) • Article from the National Ground Water Association's Journal, *Ground Water*, entitled "Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers." By Tom Meyers. (SC 143, Exhibit 8) • *Review of Phase II Hydrogeologic Study.* SBS, LLC. Prepared for Garfield County, by Geoffrey Thyne, December 2008. (SC 143, Exhibit 9) • *DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming. Part 1.* U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, December 2011. (SC 143, Exhibit 10-A) • *DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming. Part 2.* U.S. Environmental Protection Agency, Office of Research and Development, National Risk Management Research Laboratory, December 2011. (SC 143,	

Thematic Comment	Comment Excerpt	DOE Response
	Exhibit 10-B) • *Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming.* U.S. Department of the Interior, U.S. Geological Survey, in cooperation with the Wyoming Department of Environmental Quality, April and May 2012. (SC 143, Exhibit 11) • TECHNICAL MEMORANDUM: Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey. Prepared by Tom Myers, Ph.D., September 2012. (SC 143, Exhibit 12) • News & Comment article from *Nature,* entitled, "Is fracking behind contamination in Wyoming groundwater?" Jeff Tollefson, October 2012. (SC 143, Exhibit 13) • TECHNICAL MEMORANDUM: Review of *DRAFT: Investigation of Ground Water Contamination near Pavillion, Wyoming.* Prepared by the Environmental Protection Agency, by: Tom Myers, Ph.D., April 2012. (SC 143, Exhibit 14) • U.S. Environmental Protection Agency, Region 8, Pavillion Draft Report. July 2013. (SC 143, Exhibit 15) • U.S. Environmental Protection Agency, Region III. *Action Memorandum - Request for funding for a Removal Action at the Dimock Residential Groundwater Site…*, to Dennis P. Carney from Richard M. Fetzer, January 2012. (SC 143, Exhibit 16) • News Release from the U.S. Environmental Protection Agency, entitled, "EPA Completes Drinking Water Sampling in Dimock, Pa." July 2012. (SC 143, Exhibit 17) • Article from *The Times Tribune,* entitled, "Sunday Times Review of DEP Drilling records reveals water damage, murky testing methods." By Laura Legere, May 2013. (SC 143, Exhibit 18) • Article from the journal, *Environmental Science and Technology*, entitled,*"Ozone Impacts of Natural Gas Development in the Haynesville Shale."* ENVIRON International Corporation, June 2010. (SC 143, Exhibit 19) • Article from the *Journal of the Air & Waste Management Association,* entitled, "The potential near-source ozone impacts of upstream oil and gas industry emissions." Eduardo P. Olaguer, May 2012. (SC 143, Exhibit 20) • Rule from the Federal Register, "Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards." 40 CFR Part 81, Environmental Protection Agency, May 2012. (SC 143, Exhibit 21)	

Thematic Comment	Comment Excerpt	DOE Response
	• *Rapid photochemical Production of A Ozone at High Concentrations in a Rural Site During Winter*. NOAA, Earth System Research Laboratory and Wyoming Department of Air Quality. (SC 143, Exhibit 22) • Letter from the State of Wyoming - Office of the Governor, to Ms. Carol Rushin - Acting Regional Administrator, USEPA Region 8. “RE: Wyoming 8-Hour Ozone Designation Recommendation.” March 2009. (SC 143, Exhibit 23) • Graph, *Daily Ozone AQI Levels in 2011, Sublette County, Wyoming.* Environmental Protection Agency Air Explorer, November 2012. (SC 143, Exhibit 24). • Article from *USA TODAY*, entitled, “Wyoming’s smog exceeds Los Angeles’ due to gas drilling.” By Wendy Koch, March 2011. (SC 143, Exhibit 25) • *Associations of Short-Term Exposure to Ozone and Respiratory Outpatient Clinic Visits – Sublette County, Wyoming, 2008-2011*. State of Wyoming, Department of Health, March 2013. (SC 143, Exhibit 26) • Pinedale Online, *2011 DEQ Ozone Advisories – Ozone Calendar*. Pinedale, Wyoming. 2011. (Sc 143, Exhibit 27) • Pinedale Online, *Ozone Advisory for Monday, Feb.28 – by Wyoming Department of Environmental Quality*. Pinedale, Wyoming. February 2011. (SC 143, Exhibit 28) • Pinedale Online, *DEQ plans for the 2014 winter ozone season. Forecasting January-March for the Upper Green River Basin.* Pinedale, Wyoming. December 2013. (SC 143, Exhibit 29) • Article by *Utah Department of Environmental Quality*, entitled, “Utah’s Environment 2013: Planning and Analysis: Uinta Basin Ozone Study.” February 2013. (SC 143, Exhibit 30) • Article by *Utah Department of Environmental Quality*, entitled, “Uinta Basin: Ozone in the Uinta Basin.” February 2013. (SC 143, Exhibit 31) • *Colorado Air Quality Control Commission, Agenda Item Summary*. Agenda Item Control Sheet, 2013 Summer Ozone Season Review, October 2013. (SC 143, Exhibit 35) • *Colorado Air Quality Control Commission, Agenda Item Summary*. Agenda Item Control Sheet, 2013 Forecasting Air Quality in Colorado, April 2013. (SC 143, Exhibit 36) • *Four Corners Air Quality Task Force Report of Mitigation Options.* Drafted by members of the Four Corners Air Quality Task Force, November 2007. (SC 143, Exhibit 37) • *The Association between Ambient Air Quality Ozone Levels and*	

Thematic Comment	Comment Excerpt	DOE Response
	Medical Visits for Asthma in San Juan County. Environmental Health Epidemiology Bureau, Epidemiology and Response Division, New Mexico Department of Health, August 2007. (SC 143, Exhibit 38) • *Shale Gas Development and Infant Health: Evidence from Pennsylvania.* Working Paper. Elaine Hill, Cornell University, December 2013. (SC 143, Exhibit 39) • Technical Paper from the *Journal of the Air & Waste Management Association*, entitled, "Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States." Volume 59. September 2009. (SC 143, Exhibit 40) • *Asian Coal & Power: Less, Less, Less...The Beginning of the End of Coal.* Bernstein Research, June 2013. (SC 145, Exhibit 1) • *Wind at parity with new coal in India, solar to join by 2018: HSBC.* Reneweconomy.com.au. Sophie Vorrath, July 2013. (SC 145, Exhibit 2) • *The Rising Sun - Grid parity gets closer. A point of view on the Solar Energy sector in India.* KPMG International, September 2012. (SC 145, Exhibit 3) • *Wind in Power: 2013 European Statistics.* The European Wind Energy Association, Febuary 2014. (SC 145, Exhibit 4) • *Sierra Club* news release, entitled, "Leaked Trade Document Exposes Dangerous European Union Energy Proposal." July 2014. (SC 145, Exhibit 5) • Article from the *Proceedings of the National Academy of Sciences* Journal, entitled, "Anthropogenic emissions of methane in the United States." www.pnas.org. Miller et al., December 2013. (SC 145, Exhibit 6) • *A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin.* Corresponding author Gabrielle Pétron of the NOAA Earth System Research Laboratory, 2014. (SC 145, Exhibit 7) • Article from *Geophysical Research Letters*, entitled, "Methane emissions estimate from airborne measurements over a western United States Natural Gas Field." American Geophysical union, August 2013. (SC 145, Exhibit 8) • *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Chapter 4: Fugitive Emissions,Volume 2: Energy. 2006. (SC 145, Exhibit 9) • Letter sent to the Executive Secretary of the United Nations	

Thematic Comment	Comment Excerpt	DOE Response
	Framework Convention on Climate Change, from the United States Department of State, Office of the Special Envoy for Climate Change. January 2010. (SC 145, Exhibit 10) • *Compilation of economy-wide emission reduction targets to be implemented by Parties included in Annex I to the Convention.* United Nations Framework Convention on Climate Change, June 2011. (SC 145, Exhibit 11) • *2014 U.S. Climate Action Report***.** Chapter 5: Projected Greenhouse Gas Emissions. U.S. Department of State, 2014. (SC 145, Exhibit 12) • *2014 U.S. Climate Action Report.* First Biennial Report of the United States of America. U.S. Department of State, 2014. (SC 145, Exhibit 13) • *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Chapter 8: Reporting Guidance and Tables,Volume 1: General Guidance and Reporting. 2006. (SC 145, Exhibit 14) • *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* Interagency Working Group on Social Cost of Carbon, United States Government, May 2013. (SC 145, Exhibit 15) • Comments regarding the Office of Management and Budget's (OMB) request for comments on the *Technical Support Document entitled Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866*. Comments submitted by the Sierra Club, February 2014. (SC 145, Exhibit 16) • Comments regarding the Office of Management and Budget's (OMB) request for comments on the *Technical Support Document entitled Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866*. Comments submitted by the Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, and Union of Concerned Scientists. February 2014. (SC 145, Exhbiit 17) • *Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide.* NCEE Working Paper Series, Alex L. Marten and Stephen C. Newbold, January 2011.(SC 145, Exhibit 18) • *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* Interagency Working Group on Social Cost of Carbon, United States Government, May 2013. (SC 145, Exhibit 19)	

Thematic Comment	Comment Excerpt	DOE Response
The analysis presented in the document overlaps with and is inconsistent with the analyses presented in the other documents that have been released to the public in support of DOE's analysis of the environmental impacts of unconventional natural gas production.	(SC 143) We offer comments on these materials in this document and in the related comment addressing air emissions and climate impacts. We note, however, that while DOE has invited comment on this package of materials, DOE has structured the package in a way that complicates public review and participation. These four documents provide overlapping, and often inconsistent, analyses. For example, all four of these documents discuss the greenhouse gas emissions of natural gas production, but they draw on different data sources and rest on different assumptions. Estimates of methane's global warming potential provide one example of this inconsistency: the Export LCA uses estimates from the most recent Intergovernmental Panel on Climate Change ("IPCC") report, but the Gas LCA and Unconventional Production Report uses earlier and outdated estimates, and the DOE Addendum, although it acknowledges the recent data, appears to use older data in tables expressing methane emissions in carbon dioxide equivalents. Commenters have no way of knowing which of these conflicting documents represents the agency's conclusion on the matter. DOE has not, for example, identified any one of these documents as controlling. In other circumstances commenters might assume that the most recent agency publication represented the agency's current opinion, but all four of these documents have the same date. DOE must resolve these inconsistencies by presenting a clear statement of its analysis, the supporting evidence, and its conclusions. DOE could provide this clarification by unifying the analysis into a single document, or by using separate documents with more clearly delineated roles and interrelationships. (SC 143) As noted in the introduction above, the discussion of the air emissions from gas production (both conventional and unconventional production) is fragmented between the four May 29, 2014 documents. We provide comments on the amount of air pollution caused by gas production, and the climate impact of that pollution, in our separate comment focused on the Export LCA and Gas LCA. Those comments focus on quantities of methane pollution, but as DOE notes, methane emissions are significantly correlated with emissions of other pollutants. (SC 143) Even where these documents are not inconsistent with one another, their fragmented analysis makes public comment difficult For example, NETL states that, including NETL's own work, there are "five major studies that ... represent the breadth of all natural gas lifecycle [greenhouse gas emission] work." Yet the discussion of these "five major [life cycle] studies" does not occur in either of the package's two documents that have "life cycle" in their titles and that specifically address climate impacts, nor do the two life cycle documents indicate that this issue is discussed in the other	DOE acknowledges these documents have some degree of overlap. These documents were prepared for unique purposes and the methods and assumptions may vary among them. DOE regrets any confusion, but has provided references for the information contained in each. Specifically for the Addendum, DOE attempted to summarize existing literature. Many of these sources have unique assumptions or methods.

Thematic Comment	Comment Excerpt	DOE Response
	documents. Indeed, only two of the four non-NETL "major" lifecycle studies are even cited in the two NETL life cycle reports. Because DOE invited public comment on each document individually, a member of the public concerned with climate impacts might review the two climate documents without realizing that those documents represented only a portion of DOE's analysis of this issue.	
The analysis presented in the Addendum is inadequate because it relies on the assertion that the environmental impacts resulting from production activity induced by LNG exports to non-FTA countries are not "reasonably foreseeable." DOE should perform a more detailed analysis that estimates impacts based on the modeling of typical build-out scenarios.	(SC 143) The DOE Addendum recognizes two obvious facts: that LNG exports would induce additional gas production and that gas production has severe environmental consequences. Although DOE's survey of the literature documenting the latter requires some additions and corrections, the primary flaw in DOE's analysis is the refusal to link these two obvious facts and take a hard look at extent to which authorizing LNG export applications will cause significant marginal increases in each of these environmental harms. DOE's assertion that uncertainty prevents meaningful discussion of this linkage is factually and legally implausible. (AAF 112) The Addendum asserts that a meaningful analysis of environmental impacts cannot be performed or that the impacts of increased gas production are not "reasonably foreseeable" because the precise location of future wells and infrastructure is unknown. (p.2.) Hiding behind this rationale, the Addendum provides only a cursory description of fracking practices and possible impacts--a far cry from the meaningful cumulative environmental review that is needed. The precise location of infrastructure is not necessary to estimate impacts based on the modeling of typical build-out scenarios. A much more comprehensive analysis should be performed.	The purpose of the Addendum was to provide additional information to the public regarding the potential environmental impacts of unconventional natural gas production activities. While not required by NEPA, DOE prepared this Addendum in an effort to be responsive to the public and provide the best information available.
The Addendum conflicts with current DOE policy, as both FERC and DOE have concluded that the environmental impacts of natural gas production should not be considered in the context of LNG exports.	(API 100) DOE recognizes its shortcomings in analyzing natural gas production activities and assessing specific environmental impacts in a NEPA context. API questions the purpose of the draft Addendum. As DOE explained in Sabine Pass Liquefaction, LLC, DOE/FE Order No. 2961-A (Aug. 7, 2012), lacking an understanding of where and when additional gas production will arise, the environmental impacts resulting from production activity induced by LNG exports to non-FTA countries are not "reasonably foreseeable" within the meaning of the Council on Environmental Quality's (CEQ) NEPA regulations (40 CFR § 1508.7). (ANGA 121) This Addendum is in some measure duplicative of the existing LNG application process and in other ways conflicting. Under the permitting process for applications to export LNG to non-FTA countries, both DOE and the Federal Energy Regulatory Commission ("FERC") have addressed environmental concerns. For example, in its review of the Sabine Pass	Same as previous response.

Thematic Comment	Comment Excerpt	DOE Response
	export proposal, FERC explicitly discussed a broad range of potential environmental concerns including direct environmental impacts and potential cumulative environmental impacts.3 In its final order, FERC appropriately concluded that NEPA does not require evaluation of potential impacts from induced shale gas development.4 FERC based this decision on the principles of the Council on Environmental Quality (CEQ), which establish limits on NEPA review.5 The fourth CEQ principal states, "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."6 FERC found that "impacts which may result from additional shale gas development are not 'reasonably foreseeable' as defined by the CEQ regulations. Nor is such additional development, or any correlative potential impacts, an 'effect' of the project, as contemplated by the CEQ regulations, for purposes of a cumulative impact analysis."7 This determination is supported by DOE in its approval of the Sabine Pass facility. Therefore, the Addendum conflicts with current DOE policy, as both FERC and DOE have concluded that the environmental impacts of natural gas production should not be considered in the context of LNG exports. In addition to the fact that the Addendum conflicts with the stated scope of the LNG export review process, the Addendum itself highlights the numerous 'uncertainties' related to LNG exports and natural gas production which call into question the need and usefulness of the document. For example, the Addendum states "fundamental uncertainties constrain the ability to predict what, if any, domestic natural gas production would be induced by granting any specific authorization or authorizations to export LNG to non-FTA countries."8 Furthermore, DOE concedes that it "cannot meaningfully analyze the specific environmental impacts of such production." In light of such a finding, the purpose of this Addendum remains in question.	
The Addendum does not adequately address current (i.e., created/implemented since 2011) federal and state regulations related to unconventional natural gas production.	(AAF 108) Rather than performing a comprehensive assessment of impacts associated with gas production, the Addendum relies on an extremely limited set of information to make broad generalizations about impacts to water, air, climate change, seismic activity, and land use. The result is a document that is inaccurate, and only useful insofar as it highlights how much remains unknown. Moreover, the report fails to perform any meaningful assessment of policies and regulations in place at the federal or state level, or the efficacy of those measures. These concerns are elevated by the fact that the oil and gas industry enjoys exemptions from key provisions of landmark environmental law. (HESI 78) HESI believes that the Draft Addendum (and the NETL report)	As previously stated, the purpose of the Addendum was very specific. DOE was not attempting to provide an assessment of regulatory frameworks, nor recommend a compilation of industry standards. Additional studies and references submitted to DOE have been incorporated by reference into the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	could be improved by recognizing and including the following: · In the past few years, the legal landscape regulating unconventional natural gas development and production activities has evolved as state legislatures and regulatory agencies have continued to develop and update HF disclosure regulations. The Draft Addendum should reference these important recent developments, rather than rely solely on a summary of state regulations created in 2011. · Several reports and studies, including peer-reviewed papers, have concluded that there is no risk of migration of HF fluids to sources of drinking water. The Draft Addendum should acknowledge these findings and include a reference to these materials. HESI believes that the inclusion of this information in the Draft Addendum will provide a more accurate and comprehensive report on the potential environmental impacts of unconventional natural gas production activities. (ANGA 121) Figure 5 in the Addendum (page 9) is an incomplete assessment of the timeline associated with shale gas development. For a more complete representation, the figure should include a list of all regulations required at every stage of the natural gas production process. It is ANGA's view that inclusion of the table below (Figure 1), from the 2011 National Petroleum Council 2011 Prudent Development Report provides a more comprehensive example of natural gas production and associated regulations with which the industry must comply. (ANGA 121) (API 100) API would argue that in the case of the draft Addendum, a balanced approach is lacking. Specifically, DOE states that the discussions presented within the draft Addendum are based on existing regulations and best management practices. And yet, no mention is made of the work undertaken by API, and released publically in 2011, regarding best practices directly related to hydraulic fracturing. We believe this to be a serious oversight. As stated above, API is the worldwide leading standards-making body for the oil and natural gas industry. In our on-going effort toward continued improvement of oil and natural gas operations, in May of 2011, API completed a series of industry guidance documents specific to hydraulic fracturing: Ø HF1, Hydraulic Fracturing Operations—Well Construction and Integrity; Ø HF2, Water Management Associated with Hydraulic Fracturing Guidance; Ø HF3, Practices for Mitigating Surface Impacts Associated With Hydraulic Fracturing; Ø Standard 65-Part 2, Isolating Potential Flow Zones During Well Construction; and Ø RP 51R, Environmental Protection for Onshore Oil and Gas production	

Thematic Comment	Comment Excerpt	DOE Response
	Operations and Leases. We believe this series provides the blueprint for the environmentally sound development of oil and natural gas. API immediately sent a full set of the series to the state regulators with oil and gas operations oversight in over 20 oil and natural gas producing states. The documents were made available free of charge on the API website. In addition, a succession of workshops was held in 15 locations across the country to educate state legislators, regulators, non API members, and interested stakeholders on the valuable content of the documents. As part of our ANSI accreditation process -- requiring openness, balance, consensus and due process -- API's Standards Program demands that industry specifications, recommended practices, and guidance documents be reviewed and updated on a regular basis to ensure they remain current. In 2013, HF1, HF2, and HF3 underwent a review process. All three documents are expected to be released as revised recommended practices by the fall of 2014. Finally, during this review, a new document, focusing on community engagement, was developed. It will serve as a gold standard for good neighbor policies that address community concerns, enhance the long-term benefits of local development, and ensure a two-way conversation regarding mutual goals for community growth. Released on July 9, 2014, the standard provides a detailed list of steps that oil and natural gas companies can take to help local leaders and residents prepare for energy exploration, minimize interruption to the community, and manage resources. (API)	
The addendum only summarizes public comments on the NERA Report and does not provide context or alternative views. The comments that are summarized are biased and not germane to the NERA report. These comments should be omitted from the addendum.	(ANGA 121) The public comments section of the Addendum contains comments on a NERA Economic Consulting report on the impact of LNG exports on the U.S. economy. The purpose of this study was to evaluate the macroeconomic impact of LNG exports, and the report does not include any discussion or analysis of the indirect environmental impacts of natural gas production. Despite the fact that this was an economic impact report, numerous comments were submitted regarding alleged and potential environmental impacts of natural gas production. The Addendum only summarizes these comments, which are decidedly in opposition to natural gas development on environmental grounds, and does not provide context or any alternative views. Understandably, many commenters focused solely on the economic impacts of LNG exports and did not comment on possible indirect impacts as they were not included in the NERA report. Therefore, the inclusion in the Addendum of environmental impact-related comments in opposition to natural gas development unfairly excludes stakeholder comments positive toward natural gas development simply because the comments they submitted were relevant to the NERA report. ANGA objects	DOE provided some representative comments so the reader could understand the broad categories of concerns DOE was attempting to address. The summarized comments were not intended to be exhaustive. The purpose of the Addendum was to provide additional information to the public based on comments similar to those shown in the Addendum. No change has been made to the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	to this section in its current form as the comments are not germane to the NERA report, and are not in context without a broader discussion of the NERA report. Furthermore, the comments cited do not contain or reference any data or facts; instead, they consist only of broad, unsubstantiated statements. The Addendum does not list the comments' authors and the comments are not based in science. For the above-stated reasons, the comments should be omitted from the Addendum. Beyond our primary objection to the inclusion of comments on environmental issues that were made in response to an economic report, the comments cited are not representative of all comments submitted and could have a prejudicial effect regarding natural gas development. For example, ANGA submitted reply comments referencing the wide range of state and federal regulations that apply to gas production.9 If DOE chooses to proceed with this report, we urge DOE to include comments by industry and other supporters of natural gas development and to provide references to the sources of all included comments. (API 100) Pages 3-4: API has additional report-balance concerns with the "examples of representative comments." Those included are not only anecdotal and pejorative, but all in opposition to natural gas development. This section should be deleted.	
UIC	(API 100) Page 18: API recommends that DOE add a clarification for the acronym use "UIC" as shown below. This acronym should also be added to the abbreviation list on Page V of the draft Addendum. Wastewater treatment is generally regulated under the NPDES Program for surface water discharges and under the underground injection control (UIC) Program for subsurface discharge.	DOE agrees and has made this change in the Addendum.
Reference to NETL 2014.	(SC 143) Finally, because all of these documents save the DOE Addendum were authored by DOE's National Energy Technology Laboratory ("NETL") and published on the same date, the documents' practice of simply using "NETL 2014" to refer to one another creates needless confusion. The DOE Addendum refers to the Unconventional Production Report as "NETL 2014," but the Unconventional Production Report and the Export LCA both use "NETL 2014" to refer to the Gas LCA. Public review of this integrated package of documents would have been aided had DOE and NETL taken the simple measure of adopting and consistently using unique shorthand names for the individual documents constituting this package.	DOE regrets any confusion among the references. Although no changes are made in the Addendum regarding this issue, DOE has noted a unique shorthand notation for each document would have been helpful for readers.
The 45-day public comment period is	(UH Law Center/Sakmar 4) I intend to comment on all three issues but the 45-comment period for all three issues is not enough time to review and	DOE did not grant an extension to the public

Thematic Comment	Comment Excerpt	DOE Response
not long enough to allow the public to review all of the materials released by DOE.	analyze all of the complex issues involved. I respectively request that DOE extend the comment period to 90-days for the Draft Addendum which would allow time for the public to review the large volume of information DOE has released and make useful and relevant comments.	comment period.
The Addendum should not be used to support the decision making process for export permit applications approvals pending before DOE.	(CLNG/Cooper 6) It appears that the Addendum is merely for public information and not for use by DOE in making decisions on the applications pending before it…CLNG respectfully requests that DOE not consider the Addendum or the report entitled Environmental Impacts of Unconventional Natural Gas Development and Production (May 29, 2014) (Upstream Report), prepared by the National Energy Technology Laboratory, a DOE laboratory, for any purpose when issuing decisions on above-referenced applications pending before it. (CLNG/Cooper 99) If DOE "cannot meaningfully estimate where, when, or by what method any additional natural gas would be produced", then attempts to assess the environmental effects would not be "meaningful" within the CEQ requirements, which govern the NEPA review process. Therefore, the Addendum has no place in the decision-making process for the export applications pending before DOE. CLNG respectfully requests that DOE not consider the Addendum…for any purpose when issuing decisions on above-referenced applications pending before it." (LoBaugh 106) The public interest determinations required under Section 3 of the Natural Gas Act ("NGA") have been already been made, namely the two proposed non-FTA exports are not inconsistent with the public interest; the only remaining issue being the satisfactory completion of the National Environmental Policy Act ("NEPA") review. That environmental review has already been completed and is only waiting the issuance by DOE of the final orders for those non-FTA export authorizations. Therefore, the Addendum and the comments filed to the Addendum should not be applicable to FLEX and its applications to export domestically sourced LNG. In addition, DOE/FE has already determined that the Addendum and its submaterial, and consideration of such, is beyond the requirements of NEPA…Therefore, the Addendum and its sub-material may be an interesting scholastic exercise, but they can have no application to the FLEX authorizations. (LoBaugh 111) The Addendum and its subsections are not applicable to the FLEX application. The potential environmental impacts discussed in that material are not reasonably related to the FLEX export applications. Any alleged connection between the FLEX proposed exports and those alleged potential environmental impacts is, at best, speculative and not the proper basis of a NEPA analysis It is requested that DOE expeditiously issue its	The purpose of the Addendum is to provide additional information to the public regarding the potential environmental impacts of unconventional natural gas exploration and production activities. DOE clearly stated the material was not required by NEPA. However, as with any other studies, reports, or publications, this document may be referenced or considered by DOE or others. DOE does not consider this document as the sole justification for any determination or agency action.

Thematic Comment	Comment Excerpt	DOE Response
	final decisions approving the pending FLEX requests for authorization to export LNG to non-FTA countries.	
The impacts from natural gas production induced by increased exports must be assessed under NEPA as there are tools that can be utilized to forecast future production.	(Sierra Club/Matthews 9) These documents understate the impacts of natural gas production and of potential U.S. exports, and they fail to provide the full analysis of the impacts of LNG exports that the National Environmental Policy Act ("NEPA") and the Natural Gas Act require. (Sierra Club/Matthews 14) Most importantly, examination of the environmental impacts of LNG exports, including effects of induced gas production, must occur within the NEPA framework. In addition, absent formal programmatic environmental review under NEPA, DOE must ensure that these materials are included in the individual dockets for every export application. (Sierra Club/Matthews 16) The environmental review required by NEPA must include discussion of "indirect" and "cumulative" effects. LNG exports' inducement of gas production, the environmental impacts of that production, and the other environmental impacts described in these comments all plainly fall within these rubrics. DOE's assertions that by discussing these issues it "is going beyond what NEPA requires," and that "The analysis in this Addendum is not required by NEPA" are wrong on both the law and facts. …DOE's mistaken contention that the Addendum and related reports go beyond what NEPA requires rests solely on foreseeability. (Sierra Club/Matthews 17) When confronted with an application to export specific volumes of LNG, DOE must consider the environmental consequences of the proposed volume of exports…If exports do occur, they will induce significant additional natural gas production, as DOE concedes…The professed impossibility of meaningfully predicting "by what method" additional gas would be produced flies in the face of DOE's own statements on the previous page, to say nothing of the EIA predictions of the breakdown of particular unconventional types…We simply note that multiple tools exist which allow predictions of how and where production will respond to exports. DOE offers no explanation as to why the predictions available through use of these models are so "meaningless" as to fall outside the scope of NEPA analysis. (Sierra Club/Matthews 18) Finally, as DOE acknowledges, uncertainty as to the location of induced gas production provides minimal impediment to assessment of the climate impact of export-induced gas production. (Sierra Club/Matthews 43) The environmental harms exports would cause	DOE's position on these matters remains clearly stated in the Introduction and Purpose sections of the Addendum.

Thematic Comment	Comment Excerpt	DOE Response
	must be weighed in DOE's Natural Gas Act evaluation of whether the proposed exports are consistent with the public interest. The analysis provided here, whether on its own or in conjunction with analyses previously provided by DOE, falls short of what these statutes require.	
Out of Scope		
Comment requests DOE establish new procedures for assessing cumulative impacts of LNG export projects.	(UH Law Center/Sakmar 45) DOE should establish detailed procedures that address the unique and complex public interest concerns associated with LNG exports. A transparent and comprehensive procedure will ensure DOE fulfills its legal duty to "monitor the cumulative impacts" of each approved LNG export project. At the same time, a comprehensive procedure would provide greater regulatory certainty for the market and ensure that America is taking advantage of its newfound abundance of shale gas in the most beneficial manner.	While these comments were not within the scope of the Addendum, DOE noted the content and nature of each. In cases where these submissions provided comments on other documents, these comments were provided to authors of those documents.
Commercial viability should not be the primary determining factor for decision making regarding permit applications.	(UH Law Center/Sakmar 46) Theoretically, all of the proposed LNG projects could be commercially viable and the majority of America's natural gas could be exported. It is doubtful that exporting most or all of America's natural gas is in the public's interest since this would foreclose other important opportunities to use more natural gas at home in manufacturing, transportation and power generation. It would also mean much higher energy costs for average American's. In this regard, I urge DOE to consider commercial viability as BUT one potential factor in the public interest analysis.	
DOE should state that the four May 29, 2014 documents, the documents cited as references therein, and the public comments received thereon will all be treated as part of the administrative record for all pending LNG export applications.	(Sierra Club/Matthews 21) DOE must clarify the relationship between the various materials released on May 29 and the dozens of individual LNG export dockets…While DOE includes the climate lifecycle analysis in 25 dockets, the Federal Register notice for the DOE Addendum lists only thirteen. These issues, however, are plainly pertinent to all LNG export applications, and should be included in each export docket…DOE should state that the four May 29, 2014 documents, the documents cited as references therein, and the public comments received thereon will all be treated as part of the administrative record for all pending LNG export applications and for further applications received in the foreseeable future.	
There is no need to expedite LNG exports since the DOE has already approved most of U.S. gas for export.	(UHLC 84) There Is No Need to Expedite LNG Exports Since the DOE Has Already Approved Over Half of Current U.S. Gas Production for Export A. Free Trade Agreement (FTA) v. Non-FTA Countries At the outset, it is important to note that under existing U.S. law, export applications to export to most free trade agreement (FTA) countries are deemed to be in the public interest and such applications are quickly authorized by the Department of Energy, Office of Fossil Energy (DOE/FE). Most, though not all, countries	

Thematic Comment	Comment Excerpt	DOE Response
	that have an FTA with the U.S. require national treatment for trade in natural gas, including Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Republic of Korea, Singapore and Panama. With the exception of the Republic of Korea, Chile, and Singapore, which is trying to establish an LNG trading hub, most of the FTA countries are not likely to be significant importers of LNG so the real prize for a company is the authorization to export LNG to any country, which the DOE refers to as "non-FTA" countries. Applications for export authorization to non-FTA countries involve greater scrutiny and under Section 3(a) of the Natural Gas Act (NGA), 15 U.S.C. § 717b, DOE performs a thorough public interest analysis before acting and is authorized to attach terms or conditions to orders that are necessary or appropriate to protect the public interest. (UHLC 84) The DOE Has Already Approved A Significant Amount of Exports After Making A "Public Interest" Determination Subsequent to the release of the NERA LNG Study, the DOE resumed its approval of LNG export applications to non-FTA countries (the applications for FTA approval had not been delayed by the NERA study). Consistent with the public interest requirement, the DOE continued to process the pending non-FTA application on a case-by-case basis, following the order of precedence previously established. While the DOE's case-by-case process has resulted in slower approvals than the industry would like and many have called for "expediting" even more exports,5 the DOE has in fact already approved over half of current U.S. natural gas production for export. As of June 11, 2014, the DOE has approved long-term applications to export over 37 Bcf/d of natural gas to FTA countries. To put this in perspective, 37 Bcf/d is 290 million metric tonnes per annum (MTPA) of LNG (using the DoE's conversion factor of 1 Bcf/d = 7.82 mtpa). This is around 50 MTPA more than was produced worldwide in 2012. Perhaps most significant is the fact that 37 Bcf/d represents over half of current U.S. production of natural gas of approximately 70 Bcf/d. In terms of non-FTA approvals, the DOE crossed the psychologically significant 6 Bcf/d threshold when it approved Dominion's Cove Point Project, thereby cumulatively authorizing non-FTA exports totaling 6.4 Bcf/d. The 6 Bcf/d of non-FTA approvals was significant because most of the economic studies analyzing the impact of exports on the domestic price of natural gas have used a 6 Bcf/d minimum and 12 Bcf/d maximum.6 In addition to Dominion (.77 Bcf/d), the non-FTA approvals are Cheniere's Sabine Pass (2.2 Bcf/d), Freeport's first application (1.4 Bcf/d), Lake Charles Exports (2.0 Bcf/d), Freeport's second application, (0.4 Bcf/d), Cameron (1.7 Bcf/d) and most recently, Jordan Cove (0.8 Buff/d). As of June 11, 2014, the amount of non-FTA export approval is 9.27 Bcf/d or approximately 72 MTPA, which is a massive amount of	

Thematic Comment	Comment Excerpt	DOE Response
	LNG.8 To put this in perspective, the world's largest LNG exporter is Qatar, with current export capacity of 77 MTPA. Australia has numerous LNG export projects under construction and is expected to meet or exceed Qatar's LNG export capacity by the end of the decade. Even if just a fraction of the proposed U.S. LNG export capacity came to fruition, the U.S. will rival both Qatar and Australia in terms of exports. Under DOE's prior policy framework, DOE had signaled and the market had largely accepted there would be a "soft cap" of 12 Bcf/d of non-FTA approvals, after which a pause might take place. While DOE has never announced a cap of any kind, the NERA study focused on exports of 12 Bcf/d maximum, which gives rise to the assumption that once this threshold is reached, new studies are warranted. DOE's current announcement that it planes to undertake an economic study to assess the impact of exports between 12 and 20 Bcf/d is therefore a positive development. The DOE has also indicated it will use more recent data from the EIA. While these studies are underway, the DOE has indicated it will continue to act on applications. Since the new studies are critical to the public interest analysis, the proper course of action would be for DOE to suspend review of all remaining pending applications subject to the release of the new studies. DOE has already conditionally approved 9.27 Bcf/d but has issued final approval for just one project - Cheniere's Sabine Pass Liquefaction project (2.2 Bcf/d). Suspending review of the remaining projects would ensure that the 12 Bcf/d threshold is not exceeded pending the outcome of the new studies. Alternatively, DOE should clarify exactly how it intends to proceed on the conditionally approved and pending applications while awaiting the release of the new economic studies. DOE should also provide a time frame for the studies.	
DOE should consider either a more exhaustive review of the literature or substantially reduce the content of the report. DOE should review NREL's approach for the LCA Harmonization Project.	(API 100) Further, the Executive Summary of the NETL report describes the body of work as one that: "summarizes the current state of published descriptions of the potential environmental impacts of unconventional natural gas upstream operations within the Lower 48 United States. As a survey, this report is by no means exhaustive. The goal of this report is to ensure that the predominant concerns about unconventional natural gas development, as covered by current literature, are identified and described. The sources cited are publicly available documents. Multiple publications on similar topics are compared and contrasted based only on their technical and methodological distinctions. No opinion or endorsement of these works is intended or implied." In reviewing the content of the report, and the cited references, it is clear the authors have attempted to assemble a listing and discussion of many diverse	

Thematic Comment	Comment Excerpt	DOE Response
	and publicized studies with a broad range of potential impacts. While we acknowledge the stated intent was not to screen the literature for technical soundness and technical validity, nor was there an intent to provide an “exhaustive” survey of the literature. As a result, API cannot support this document, in its current version, as an adequate summary of the current state of potential environmental impacts. We would expect that NETL would provide a document that is technically sound; rather than a compilation of information without suitable technical vetting. Without an exhaustive literature assessment, whereby such literature is also screened for technical quality and rigor, the report will continue to drive confusion and misunderstanding by the broad general public and stakeholders. DOE should consider either a more exhaustive review of the literature, that also includes a robust technical screening (performed by appropriate experts in each topic) or substantially reduce the content of the report, whereby the concerns are listed and briefly summarized, but detailed discussion of individual cited references are eliminated." (API 100) A final option offered to DOE is to follow the approach of the National Renewable Energy Laboratory (NREL). While specific to greenhouse gas emissions, NREL understands that the most comprehensive and accurate information on GHG emissions from various sources of energy is essential to informing policy, planning, and investment decisions. NREL recently led the Life Cycle Assessment (LCA) Harmonization Project, a study that gives decision makers and investors more precise estimates of life cycle GHG emissions for renewable and conventional generation, clarifying inconsistent and conflicting estimates in the published literature, and reducing uncertainty. API strongly urges DOE to review the NREL activity and consider following a similar harmonization approach when looking at the number of studies available on the environmental impacts of unconventional development. API’s more detailed comments on the draft Addendum follow in Attachment 1 to this letter. We urge the DOE to consider this input fully as the agency debates moving forward with any procedural changes to exporting natural gas from the United States. Please do not hesitate to contact us if we can be of further assistance."	

Thematic Comment	Comment Excerpt	DOE Response
A deeper understanding of the amount of supply under contract for non-FTA projects should be obtained before more exports are approved.	(UHLC 84) The Market Has Responded and a Significant Amount of LNG Exports is Under Contract. It is my understanding that most, if not all, of the volumes authorized for the non-FTA projects have already been contracted out to buyers, or "off takers" although Cheniere's Sabine Pass project is the only project currently under construction. The significance of committed off takers should not be overlooked since this means it is likely that ALL of the approved non-FTA projects will take final-investment decision (FID) and move forward. The fact that all of the current non-FTA projects, with the exception of Jordan Cove, are already existing import terminals also makes it more likely that the project will move forward since these projects will be less expensive than new Greenfield projects. A deeper understanding of the amount of supply under contract for non-FTA projects should be obtained before more exports are approved. While the larger non-FTA projects have garnered the most attention in the media, a deeper understanding of whether the numerous FTA only projects are likely to be viable should also be obtained. Many of these FTA only projects are seeking to ship LNG via ISO container and as a result, do not require the massive infrastructure and capital expenditures as the larger non-FTA projects. While the volumes for the FTA only projects are small on an individual basis, the cumulative volume is significant and could be a surprise to the upside in terms of exports if more go forward than realized. (UHLC 84) The "Public Interest" Test Must Be Maintained to Achieve the Primary Purpose of the Natural Gas Act – To Protect Consumers. With a large volume of LNG exports already approved and under contract, I commend DOE for now taking the time to focus on the potential impacts of exporting a much greater volume of LNG exports than previously contemplated and analyzed. There is no doubt that regulation of natural gas in the United States has experienced many years of regulatory evolution. But the primary purpose of the Natural Gas Act (NGA) has essentially remained the same for decades – "protection of consumers against exploitation at the hands of natural-gas companies. In the context of U.S. LNG exports, the protection of consumers is delegated to the DOE who has indicated that it will continue to take a "measured approach" in reviewing the pending export applications and will continue to assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals. Going forward, the DOE should continue to proceed with caution in approving additional export projects for several valid reasons that the DOE has articulated:	

Thematic Comment	Comment Excerpt	DOE Response
	1. The LNG Export Study, like any study based on assumptions and economic projections, is inherently limited in its predictive accuracy, 2. Applications to export significant quantities of domestically produced LNG are a new phenomena with uncertain impacts, and 3. The market for natural gas has experienced rapid reversals in the past and is again changing rapidly due to economic, technological, and regulatory developments. In short, the DOE has correctly recognized that "The market of the future very likely will not resemble the market of today." As such, it is paramount that DOE maintain the current public interest determination since this is the best way to ensure vigilant protection of the public's interest in times of significant market fluctuations, which seems to characterize the U.S. natural gas markets. Numerous parties have already raised concerns about allowing unlimited LNG exports, including industrial users of natural gas and consumer focused trade associations such as APGA and America's Energy Advantage (AEA). With such significant volumes of gas now approved for exports, these concerns should be prioritized since the overarching policy goal is to harness America's new found abundance of shale gas not JUST for export, but for other opportunities in manufacturing, transportation and domestic consumption. (UHLC 84) For the reasons stated above, I urge DOE to continue to apply its public interest determination on a case-by-case basis and to incorporate the comments it receives into its future analysis of the pending LNG export projects. The DOE has already approved half of America's natural gas production for export so there is no compelling reason to expedite even more exports without waiting for the new economic studies and after careful consideration of all of the comments submitted. Caution is particularly warranted since the export of U.S. LNG is merely an arbitration opportunity for energy companies and energy traders. As trading companies have emerged from relative obscurity to become formidable players in global energy markets, there is a growing need for policy makers to understand the full implications of who owns the natural gas production in the U.S., how it will be traded and by whom, and where America's natural gas is likely to go if unfettered LNG exports are permitted. It should be abundantly clear that energy companies and energy traders have every incentive to export every single drop of America's natural gas to the highest bidder. If this is the outcome, as I believe it could be if LNG exports are expedited and allowed without any limits, then policy makers should be prepared to explain to American voters why this is in the	

Thematic Comment	Comment Excerpt	DOE Response
	"public's interest" or why they failed to miss the warning signs.	
Commenters provided comments on NETL's report entitled "Environmental Impacts of Unconventional Natural Gas Development and Production."	(Labadia 16) Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6 to 8 wells. (NETL, 2009)". How do you rationalize this statement with your chosen depiction in Exhibit 6-1 of what is clearly a County that is heavily populated with the outdated and less-commonly (currently) employed vertical wells? By your own admission... "For example, 6-to-8 horizontal wells can be drilled from a single pad and equal the production of 16 vertical wells developed on 16 pads to cover an	

Thematic Comment	Comment Excerpt	DOE Response
	area of 1 mile by 1 mile (259 hectares)". If this is true, why have you chosen to display images (i.e., Exhibits 6-1 and 6-2) depicting conventional drilling methods that do not enlighten the reader with visual references to the way that unconventional (i.e., the majority of the Marcellus Shale Play) technology is reducing impacts? At least, you should have shown two aerial photos from the same area; one illustrating the effects of conventional drilling versus one showing the greatly reduced effects of unconventional. This would have been the more intellectually stimulating thing to do. Another point...you state "Locally, each well pad covers about three acres with an equivalent amount for infrastructure, and much of this area remains disturbed through the life of the well, as long as 20 to 40 years". Again, intellectual integrity and verification of aerial photography from wells drilled many years ago dictates that this statement is not true. The greatest land impacts derived from well activities occur during the drilling stage. This stage usually occupies a small fraction of the well cycle (perhaps a few months). After drilling activities are complete, most companies greatly reduce the areal impact of well pad activities and commence the restoration phase. Resource extraction activities require a greatly reduced Project footprint (thereby reducing impacts on the environment); a conclusion that can be applied to pipeline operations as well since pipeline operation (the much longer phase) allows for revegetation and return to previous vegetative conditions (including forest) for approximately 97% of pipeline rights-of-way.. (HESI 78) In addition, HESI would like to call DOE's attention to the NETL report's broader discussion of state developments in its section on the "U.S. Statutory and Regulatory Framework," which has also omitted recent state regulatory developments. It is important for the NETL report to recognize that states have not only adopted comprehensive regulations to govern unconventional natural gas operations, but have also continued to revise and update their regulations to address new developments and/or continuing issues. This important concept is missing in the NETL report's current description of U.S. state regulations. Examples include the following: • Colorado: Colorado was the first state to adopt HF disclosure requirements in 2008. The state updated its HF disclosure regulations in late 2011 and has adopted other oil and gas requirements multiple times since then to address various other issues associated with unconventional natural gas development and production. In early 2013, Colorado adopted a statewide groundwater baseline sampling rule that requires oil and gas operators to sample nearby water wells before and after drilling	

Thematic Comment	Comment Excerpt	DOE Response
	activities. In addition, as described below, Colorado recently adopted air emissions requirements for oil and gas operations, including a statewide limit for methane emissions from these operations. • California: Following the September 2013 adoption of a comprehensive law addressing the environmental impacts of well stimulations, including HF, the state is in the process of developing regulations to implement the new law. The state Division of Oil, Gas and Geothermal Resources adopted emergency regulations in mid-December 2013, which were revised in late June 2014 that will be in place until final regulations are adopted to implement the new law. The interim regulations include requirements for obtaining authorization to perform well stimulation treatments, well construction and casing, HF disclosure, notice to landowners and local/state agencies, and groundwater testing. Most recently, the state issued revised proposed regulations for public comment on June 13, 2014. • Alaska: Alaska adopted new regulations on April 2, 2014 that require the make-up of HF fluids used in the state to be disclosed to the Alaska Oil and Gas Conservation Commission and on the public FracFocus website registry. In addition, the rules require a plan for baseline sampling of nearby water wells prior to HF operations. • Texas: Texas adopted HF disclosure regulations in early 2012. More recently, Texas adopted updated regulations in May 2013 to strengthen well construction requirements in the state. • Pennsylvania: Pennsylvania is in the process of updating its regulations to implement the state's new oil and gas law, Act 13, which was signed into law in February 2012.13 The Pennsylvania Department of Environmental Protection issued proposed regulations to implement the new law in December 2013; the rules are currently going through a state regulatory approval process. The new rules will address environmental standards for unconventional natural gas operations, including updated requirements for disclosure of the make-up of HF fluids used in the state. HESI realizes that a reference to these developments would not be tied to any published material, unlike the majority of the NETL report as currently drafted. However, acknowledgement of these state regulatory developments are important to provide a comprehensive survey, similar to the NETL	

Thematic Comment	Comment Excerpt	DOE Response
	report's reference to the federal New Source Performance Standards adopted by the U.S. Environmental Protection Agency ("EPA"). (CLNG 75) Report: Environmental Impacts of Unconventional Natural Gas Development and Production, May 29, 2014. The report under this heading has been released contemporaneously with the Addendum. It is unclear how this report relates to the various Federal Register notices published by DOE on June 4, 2014,6 if at all. In various public settings, DOE officials have indicated that this report feeds into the report entitled Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States. However the Notice published in the Federal Register for the Addendum noted that the report under this heading was a "key resource in preparing the Addendum." For the reasons set forth herein, CLNG respectfully requests that it not be considered for any purpose related to those applications.	
Commenters provided comments on NETL's report entitled "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied NG from the United States."	(DCPLNG 115) The GHG Perspective, prepared by DOE's National Energy Technology Laboratory, estimates the "life cycle" greenhouse gas ("GHG") emissions of U.S. LNG exports to Europe and Asia to produce electric power, compared to alternative means of production. Specifically, the report provides an analysis of four energy transportation and usage scenarios to contrast and compare the estimated GHG emissions of LNG exports with both regionally produced natural gas and coal. The analysis reflects an example of U.S. unconventional production transported to a liquefaction terminal in New Orleans and LNG exported to regasification terminals in (a) Rotterdam, Netherlands to represent European markets and (b) Shanghai, China to represent Asian markets. This type of well-founded, science-based approach may be helpful in promoting understanding of the expected environmental impacts of LNG exports as well as contributing to an increased understanding of the impacts of maintaining existing practices. Such understanding can contribute to policy decisions promoting an overall energy strategy that addresses the need for a stable, reliable international energy value chain while considering the environmental impacts of these decisions. The conclusions in the GHG Perspective are supportive of LNG exports. For a vast majority of scenarios in both the European and Asian regions, the generation of power from imported natural gas has lower life cycle GHG emissions than power generation from regional coal. The results show that the LNG and Russian natural gas cases produce similar amounts of GHG emissions on a 100-year basis, with LNG comparing favorably to piped Russian gas when comparing the scenarios on a 20-year basis. At a minimum, the analysis shows that exporting U.S. LNG will not increase GHG emissions on a life cycle basis compared to the likely alternatives.	

Thematic Comment	Comment Excerpt	DOE Response
	The GHG Perspective emphasizes that its "results should be interpreted as general guidance to provide perspective on trends only and not as perspective, scenario-specific results." Further, the specific scenarios chosen for modeling do not correspond to particular LNG exports from any specific proposed project: e.g., they do not reflect exports from our terminal on the Chesapeake Bay to export customers based in Japan and India. Most importantly, this type of life cycle GHG analysis is in no way required as part of the environmental review of LNG exports. DOE has recognized that, just like the Upstream Addendum, the GHG Perspective goes "beyond what is required by NEPA." Just as DOE explained regarding the Upstream Addendum, the GHG impacts of the life cycle from natural gas production to power generation overseas are not "reasonably foreseeable." Moreover, life cycle GHG emissions are not "caused" by DOE's authorization of LNG exports within the meaning of NEPA. For an agency action to be considered responsible for an effect, NEPA requires a "reasonably close causal relationship" between the environmental effect and the alleged cause. In no sense can DOE's authorization of LNG exports be considered the cause of GHG emissions ranging all the way from the well-head (wherever that may be for particular feed gas) to the burner-tip (wherever the exported LNG may be burned after regasification under whatever regulatory rules may apply in that country). Therefore, our fundamental concern regarding the GHG Perspective is the same as our main concern regarding the Upstream Addendum. DOE's effort to explain various potential environmental impacts associated in some general way with LNG exports, including by considering public comments on the life cycle GHG analysis, should not delay or impede DOE's action on individual export applications, such as our application in FE Docket No. 11-128-LNG. " (UHLC 84) Life Cycle Greenhouse Gas Perspective of LNG Exports. The Department also released the Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States. The LCA GHG Report and public comments received in response thereto will be considered by the Department in its public interest determinations in connection with applications to export LNG to non-FTA countries. The purpose of the LCA GHG is to inform the public and DOE on the life cycle greenhouse gas (GHG) emission of U.S. LNG exports for use in electric power generation. The LCA GHG Report compares the life cycle GHG emission from U.S. LNG exports to regional coal and other imported natural gas for electric power generation in Europe and Asia. The study is problematic for several reasons. As a preliminary issue, it is not clear how or	

Thematic Comment	Comment Excerpt	DOE Response
	why the study questions were limited to the following: 1) Does export liquefied natural gas (LNG) from the U.S. to European or Asian markets for power production result in increased global GHG emissions from a life cycle analysis perspective compared to power production from regional coal? 2) How do these results compare with natural gas sourced from Russia and delivered to the same European and Asian markets via pipeline? There seems to be no basis for the assumption that exported U.S. LNG would necessarily displace coal in Europe or Asia. In fact, in some cases, exported U.S. LNG might actually displace nuclear or renewables, which would certainly make U.S. LNG the higher emissions fuel source. This is precisely what has happened in Japan, the world's largest LNG importer. After the Fukushima tragedy that led to the shutdown of virtually all of Japan's nuclear power, Japan imported record amounts of LNG. A more relevant study might be to compare Japan's emissions both before and after Fukushima. Similarly, Germany and other countries have backed away from nuclear power after Fukushima and the impact on emissions from switching to natural gas should be considered. In addition to the flaw in the study questions, it is far from clear whether emissions should be measured on a global basis or not. In my recently published book on the global LNG industry, Energy for the 21st Century: Opportunities and Challenges for LNG, I addressed this question but found there was very little research on this issue. Most of the research pertaining to emissions from LNG is related to the massive LNG project underway in Australia. These projects should be reviewed and emissions data incorporated into DOE's analysis. My research revealed one study from Worley Parson's referenced in the Wheatstone Draft EIA. The study, entitled, "Greenhouse Gas Emissions Study of Australian LNG, "provides a comparison of Australian LNG versus Australian black coal in terms of lifecycle greenhouse gas emissions, which includes the entire process from extraction and processing in Australia through to an end use of combustion in China for power generation.43 In general, the study found that the displacement of coal with LNG for use for power generation in China results in substantial reductions globally in greenhouse emissions, albeit at the expense of some additional Australian greenhouse emissions. While the measurement of emissions on a global basis has some merit, it is far from clear that this is the consensus view. In addition, it is clear from several prominent studies, such as the IEA's Golden Age of Gas Report, that absent additional actions, the world's increased use of natural gas will not result in the globally agreed upon reduction of greenhouse gas emissions.	

Thematic Comment	Comment Excerpt	DOE Response
	(AAF 108) One of two draft reports released by DOE is an analysis of lifecycle greenhouse gas emissions resulting from the export of LNG overseas (Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States). First, the lifecycle report is seriously flawed because it rests on a false set of choices: that countries in Europe and Asia will meet their energy needs either by relying on LNG exported from the United States, other sources of natural gas, or coal. This limited analysis neglects other energy options, including renewables—the 21st century choice that nations of the world, including the United States, ought to pursue instead of creating a greater dependency on fossil fuels. Secondly, the lifecycle report significantly underestimates methane leakage associated with the production, processing, and transport of natural gas. A key finding in recent peer-reviewed articles is that methane leakage amounts to more than 3 percent of consumed natural gas, and potentially more than 7 percent. Without justification, the report uses a range of 1.1 to 1.6 percent. This low range leads DOE to significantly understate the greenhouse gas footprint of natural gas. LNG further exacerbates these impacts due to additional leakage and the tremendous amount of energy required for liquefaction, shipping, and regasification. Yet, despite grossly underestimating greenhouse gas emissions, the DOE's life-cycle report is still unable to decisively conclude that replacing coal in Europe and Asia with LNG from the United States would be better from a greenhouse gas perspective. The next few decades are crucial to avoiding a critical tipping point for the planet. The best science indicates that a swift and dramatic reduction in greenhouse gas emissions is absolutely necessary to limit global warming to no more than 2 degrees Celsius—a threshold beyond which the worst impacts of climate change cannot be avoided. This can only be achieved through the swift and dramatic transition away from fossil fuels. If instead, the Administration promotes greater world dependency on natural gas through the approval of numerous multi-billion dollar export terminals, it will condemn future generations to climate catastrophe. (SC 145) DOE Must do More than Compare The Lifecycle Emissions of US. LNG with Other Fossil Fuels. As explained in the comment incorporated above, NEPA and the Natural Gas Act require DOE to consider the environmental impacts of the proposed LNG exports. DOE's "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States" provides some useful information regarding the climate impacts of proposed LNG exports. Full consideration of the climate impacts of LNG exports, however, requires much more than mere comparison of the	

Thematic Comment	Comment Excerpt	DOE Response
	lifecycle emissions of LNG with those of other fossil fuels. In DOE's words, The primary questions addressed by the [Export LCA] are: • I-low docs exported liquefied natural gas (LNG) from the U.S. compare with regional coal (or other LNG sources) for electric power generation in Europe and Asia, from a life cycle greenhouse gas (GHG) perspective? • How do those results compare with natural gas sourced from Russia and delivered to the same European and Asian markets via pipeline?' This comparison of the greenhouse gas intensity of U.S.-sourced LNG with other fossil fuels for purposes of electricity generation does not reflect the climate impacts of proposed exports, because U.S. LNG exports will not simply and exclusively displace other fossil fuels. End use markets in Europe and Asia are rapidly investing in clean energy infrastructure like wind, solar, and efficiency. U.S. LNG exports would likely displace these energy investments in addition to, or instead of; displacing use of other fossil fuels. In addition, U.S. LNG exports will affect U.S. greenhouse gas emissions in ways not captured by this lifecycle analysis. As modeled by the EIA over two years ago, LNG exports will raise U.S. natural gas prices, which will likely shift some electricity generation from gas to coal, with EIA predicting a net increase in carbon dioxide emissions from U.S. electricity generation. We discuss both of these issues below. (SC 145) As reported by the International Energy Agency's (""IEA""), renewables are projected to become the world's second-largest source of power generation by 2015, and are expected to close in on coal as the primary source by 2035. Other sources of information similarly predict an increasing role for renewables in likely import markets. For example, a June 2013 report by Bernstein Research predicts that in China, ""wind and solar will expand from roughly 61 GW and 8.3GW of installed capacity currently to 250GW and 200GW, respectively, by the end of the decade. In combination, wind and solar will account for roughly half of incremental power generation over the rest of the decade." Forecasts for India are similar, with HSBC concluding that wind power is already at "parity," or cost competitiveness, with new coal fired generation3 and HSBC and KPMG predicting that photovoltaic power will reach parity between 2016 and 2018.4 In Europe, renewables constitute 55% of new electric generating capacity installed since 2000, and 72% of new capacity installed in 2013, with wind power the single most installed power source in 2013.European environmental interest groups agree that U.S. LNG exports to Europe would likely frustrate Europe's transition to clean renewable energy.6 Thus, energy infrastructure in the regions DOE identifies as likely markets for U.S. LNG	

Thematic Comment	Comment Excerpt	DOE Response
	exports is strongly trending toward renewables. In light of this trend toward clean energy, there is no reason to assume that countries importing U.S. LNG would use that fuel exclusively in lieu of other fossil fuels. On the contrary, the IEA predicts that international trade in LNG and other measures to increase global availability of natural gas will cause natural gas to displace use of wind, solar, or other renewables that would otherwise occur in many countries, and that these countries may also increase their overall energy consumption beyond the level that would otherwise occur. Even within DO E's frame of looking at the lifecycle impacts of energy used in end use countries, if even a small fraction of LNG imported from the U.S. is used without displacing other sources of fossil fuels, this profoundly affects the net climate impact of U.S. LNG exports. Even using the most skewed of DOE's emission estimates (i.e., the estimates DOE provides that are most favorable to LNG),8 U.S. LNG would need to displace at least twice as much coal as renewable energy to show any climate benefit. As we explain below, however, DOE significantly underestimates U.S. LNG's lifecycle emissions. Based on methane leakage rates indicated by atmospheric studies (e.g., 3% or more), U.S. LNG's lifecycle emissions approach will likely exceed coal's, applying 100-year and 20-year methane global warming potentials, respectively. Adding in the fact that U.S. LNG will also compete with regional LNG, which DOE estimates to have lower lifecycle emissions than U.S. LNG, makes it even less likely that U.S. LNG exports would decrease importing countries' aggregate lifecycle energy emissions. Thus, using realistic estimates of the lifecycle greenhouse gas emissions of U.S.-sourced LNG, if even a small fraction of U.S. LNG exports are used in lieu of renewables and efficiency, this will significantly impact the overall effect on end use markets' lifecycle energy emissions." (SC 145) DOE's lifecycle analysis assumes that 1.3 and 1.4 percent of extracted conventional and unconventional gas, respectively, is released as methane between the well and liquefaction facility. 14 DOE's maximum emission rate for both forms of production is 1.6 percent. 15 This estimate is almost certainly too low, as demonstrated by, inter alia, recent studies measuring methane in the atmosphere, which indicate that the methane leak rate for domestic onshore gas is 3 percent or higher. As a threshold matter, DOE has failed to adequately explain the basis for its leak rate estimates. The Export LCA states that these estimates arc derived from the Gas LCA. The Gas LCA discussion of emissions from gas production, in turn, relies almost exclusively on documents simply cited as	

Thematic Comment	Comment Excerpt	DOE Response
	EPA 201 la, EPA 2011 b, EPA 201lc, and EPA 2012c. 16 The Gas LC A's references section, however, contains errors that prevent commenters from identifying or retrieving these documents. The references section identifies EPA 201la as "Background Technical Support Document - Petroleum and Natural Gas Industry." The URL provided, however, points to a different document, "Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document." This document describes EPA's Subpart W Greenhouse Gas Reporting Program. The title of this particular document, retrieved from the EPA 2011 a URL, is the title the Gas LCA ascribes to both EPA 201lb and EPA 201le (but not EPA 20 I la). Neither the URL for EPA 2011b nor the URL for 2011c, however, leads to a document with this title. Nor does NETL appear to have simply transposed the titles or URLs for 201lb or 201lc with201la, because neither of the URLs for 2011b or 2011c leads to the document named in EPA 2011a. Thus, the supporting materials only actually identify one of the three EPA 2011 documents they rely upon, and they do not indicate which of EPA 20 l la, 20 l I b, or 20llc this is. This confusion limits the public's ability to evaluate or comment upon the inputs DOE uses. Different EPA documents provide different estimates of gas production emissions (for example, in documents related to Clean Air Act rules for oil and gas production, the subpart W reporting program, and the annual greenhouse gas inventories), and these different EPA documents often rely on different estimates for individual source emissions. While Sierra Club and other environmental commenters criticized these EPA's estimates in their associated EPA dockets, here, because DOE has not revealed which particular source of estimates it is using, we cannot offer commentary on the validity of the particular estimates used by DOE. Even for the ""Greenhouse Gas Emissions Reporting"" document we were able to retrieve, because we cannot determine which of 20 l la, 2011 b, and 20llc this is supposed to be, we cannot determine which sources are ones for which DOE drew estimates from this document. (SC 145) Once LNG is delivered to an import terminal and regasified, it must be transported by pipeline to the end user. As DOE acknowledges in discussing U.S. pipeline transportation elsewhere, pipeline transportation of gas emits methane as a result of li.1gitive emissions and carbon dioxide as a result of combustion in compressors and other equipment along the pipeline route: DOE, however, explicitly omits emissions from this stage of the LNG lifecycle from DOF's analysis. DOE bases this omission on the "assumption that the natural gas power plant in each of the import destinations is existing and located close to the LNG port."· DOE docs not, however, provide any basis for this assumption.	

Thematic Comment	Comment Excerpt	DOE Response
	Pipeline emissions in end-use markets are potentially significant. DOE's Export LCA identifies U.S. pipeline transportation emissions as a significant source of emissions. Although the journey from regasification lo end use may be shorter than the journey from the well to the liquefaction terminal, the emissions per pipeline mile may be higher in some end use markets. The Intergovernmental Panel on Climate Change's (IPCC) most recent "Guidelines for National Greenhouse Gas Inventories" explains that, measured against emissions in North America and Western Europe, "in developing countries and countries with economies in transition ... there are [generally] much greater amounts of fugitive emissions per unit of activity." (SC 145) Extracting, transporting, and burning natural gas-whether through domestic pipelines or through international trade in LNG--releases harmful climate pollution. The Export LCA and Gas LCA demonstrate that LNG is even more carbon intensive than domestic pipeline gas, although DOE understates the lifecycle emissions of both. Yet neither document examines the climate impact that US LNG exports would have. To avoid catastrophic global warning, the U.S. must drastically reduce domestic emissions, and we must do everything we can to aid others in doing the same. LNG exports are inconsistent with these goals, because LNG exports will induce increases in U.S. gas production and associated emissions and LNG exports will displace investments in renewable energy and efficiency in importing markets. Instead of building LNG export infrastructure that will entrench high emission levels for decades to come, the U.S. must adopt and promote carbon free clean, renewable energy.	
Commenters provided comments on NETL's report entitled "Proposed Procedures for LNG Export Decisions."	(DCPLNG 115) In light of changing market conditions, DOE proposes to suspend its practice of issuing conditional decisions on applications for non-FTA export authorizations and to eliminate its prior practice of acting on the applications in the published order of precedent. Instead, DOE will act on non-FTA applications only after the completion of the NEPA process. As Deputy Assistant Chris Smith explained in the statement accompanying the announcement: By removing the intermediate step of conditional decisions and setting the order of DOE decision-making based on readiness for final action, DOE will prioritize resources on the more commercially advanced projects. The public notice further explained four reasons for the DOE's proposed change in procedures: first, because conditional decisions no longer appear necessary for FERC or the majority of applicants to devote resources to NEPA review; second, because doing so will prioritize acting upon applications that are otherwise ready to proceed; third, because doing so will facilitate decision making informed by better and more complete	

Thematic Comment	Comment Excerpt	DOE Response
	information; and fourth, because doing so will better allocate agency resources. DOE explained that its new proposed procedures: would not affect the continued validity of the conditional orders the Department has already issued. For those applications, the Department will proceed as explained in the conditional orders: When the NEPA review process for those projects is complete, the Department will reconsider the conditional authorization in light of the information gathered in the environmental review and take appropriate final action. Accordingly, the new procedures would not be applicable to DCP's Liquefaction Project because it has already received a conditional non-FTA authorization. Nevertheless, we support DOE's goal of prioritizing, and devoting its resources to, the commercially-advanced LNG export projects that are most ready to proceed. We believe that the new procedures proposed by DOE are an improvement over the pre-existing procedures and commend DOE for proposing the change. Accordingly, we support the adoption of the proposed new procedures. DCP's wishes to emphasize, however, that DOE's proposed new procedures should in no way impede or delay our Liquefaction Project, including the issuance of the final non-FTA approval needed from DOE. This is a major, important project for the nation that is ready to move forward, and it will be one of the very first U.S. LNG export projects to go into operation. The export capacity is fully subscribed by major energy companies based in Japan and India, and we are ready to proceed with construction of the Project as soon as we are authorized to do so. As DOE has repeatedly recognized, including in its non-FTA order for DCP, LNG exports will have major public benefits, including creating jobs, expanding tax revenues, improving the country's balance of trade, and helping U.S. allies around the world with an attractively priced, reliable new source of natural gas. Our Liquefaction Project is the epitome of the sort of LNG export project for which DOE has announced it will prioritize its resources. No new procedures concerning LNG exports generally, or related comment periods, should delay the benefits of the project any longer." (AAF 108) Exports of the scale sought by industry—an amount equivalent to over 60 percent of the U.S. natural gas produced in 2013—would dramatically accelerate the pace of drilling and fracking for natural gas,	

Thematic Comment	Comment Excerpt	DOE Response
	exposing Americans to greater danger. Given FERC's reluctance to recognize the clear cause-and-effect relationship between LNG exports and more fracking, we are concerned that this could lead to a train of project approvals with a proliferation of negative impacts to match. The DOE's initial economic analysis determined that typical households "might not participate in benefits" of LNG exports. While the gas industry and its investors would undoubtedly profit from exports, the many risks and harm of drilling and fracking mean that those benefits shared by few will come at the expense of many. We urge you to recognize that the widespread approval of LNG exports are not in the public interest."	

Acronyms Used in Summary Tables

Acronym	Full Name of Organization	Submittal #	
AAF	Americans Against Fracking, et al.	108	MacMillan
	Americans Against Fracking, et al.	112	Schue
ANGA	America's Natural Gas Alliance	121	
API	American Petroleum Institute	100	
CALNG	Citizens Against LNG	128	
CLNG	Center for Liquefied Natural Gas	75	
CW	Cascadia Wildlands	125	
DCPLNG	Dominion Cove Point LNG, LP	115	
HESI	Halliburton Energy Services, Inc.	78	
Labadia	General Public	16	
LoBaugh	Freeport, LNG, et al.	127	
SC	Sierra Club	143	Comments to Addendum
	Sierra Club	145	Comments on LCA GHG Report
UHLC	University of Houston Law Center	84	

Other Groups not included in the Summary Table Comment Excerpts:

Edes	Citizens for Huerfano County	20
Wurth	Food and Water Watch (duplicate of MacMillan Attachment)	138