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

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U.S. DEPARTMENT OF ENERGY

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DRAFT REPORT

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List of Acronyms and Abbreviations

Acronym/Abbreviation	Definition
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
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, much the same as the conventional natural gas industry has for decades. Exporting natural gas may accelerate the timing of the development 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 including 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.

The analysis in this Addendum is not required by NEPA for the reasons described above. Nonetheless, DOE is making this draft Addendum available for public review and comment, and DOE will consider comments in finalizing this Addendum.

Public Comments

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, DOE's 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.

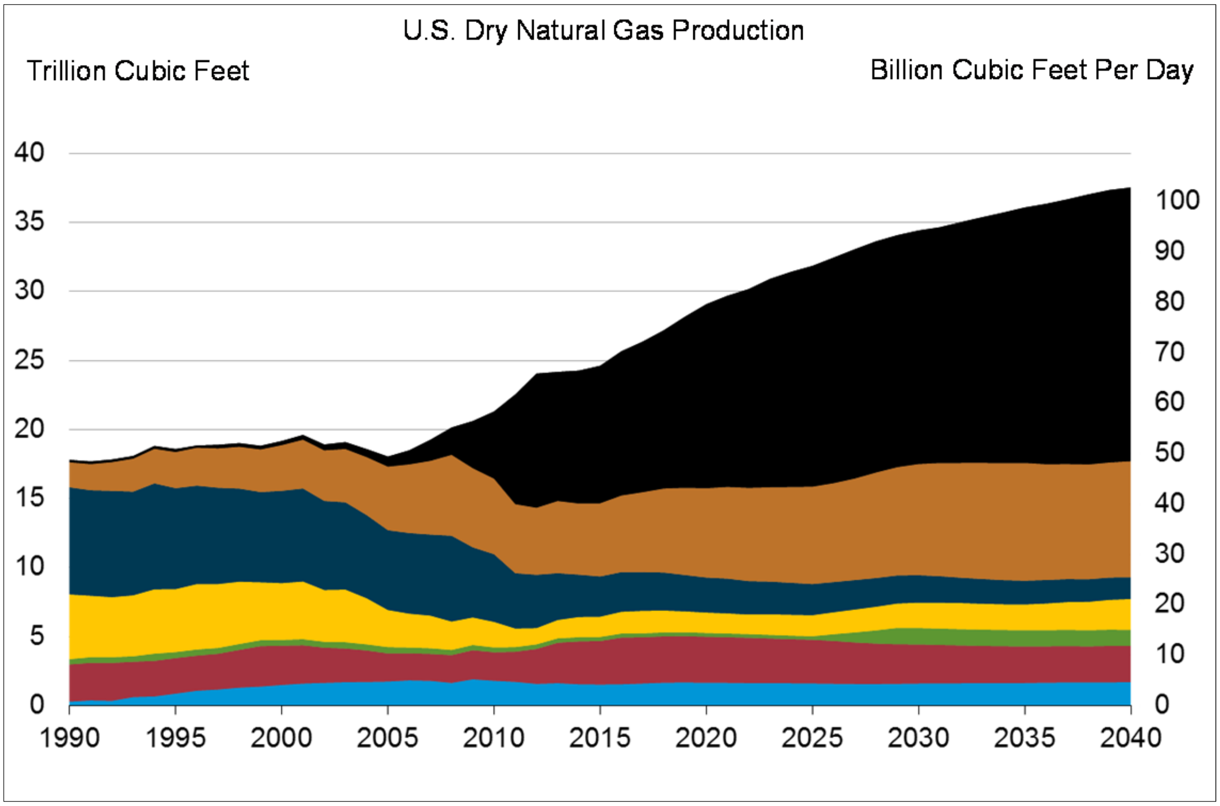


Figure 1: Natural Gas Production by Source (1990-2040) in Trillion Cubic Feet
(EIA, 2014b. AEO. Slide 6)

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.

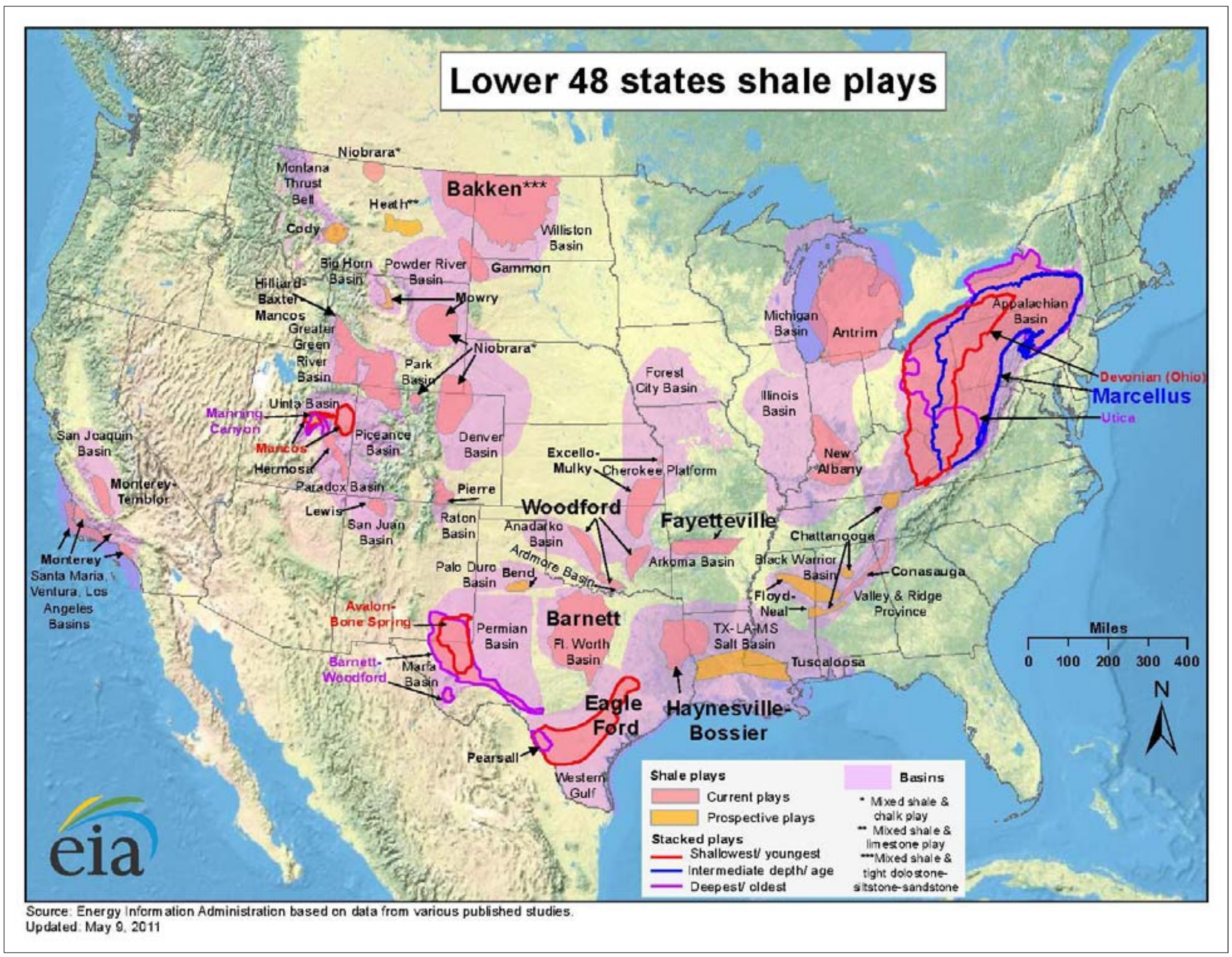


Figure 2: Approximate Locations of Current Producing Gas Shales and Prospective Shales

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.

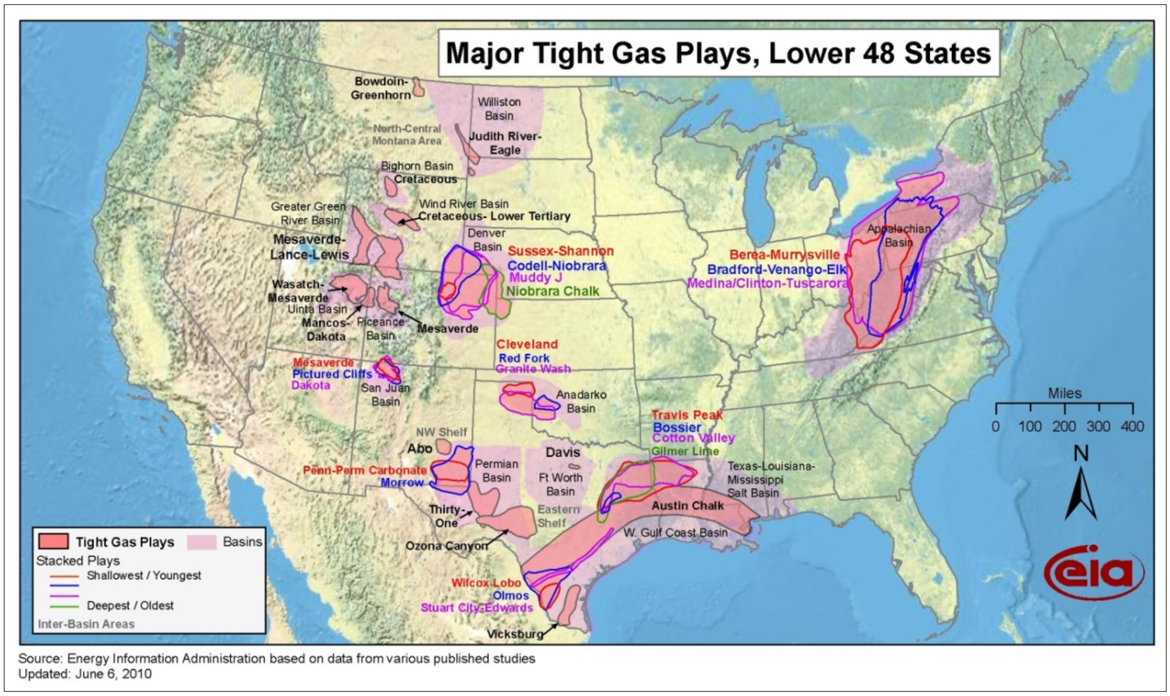


Figure 3: Location of Currently Active Areas for Tight Sand Development and Production

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.

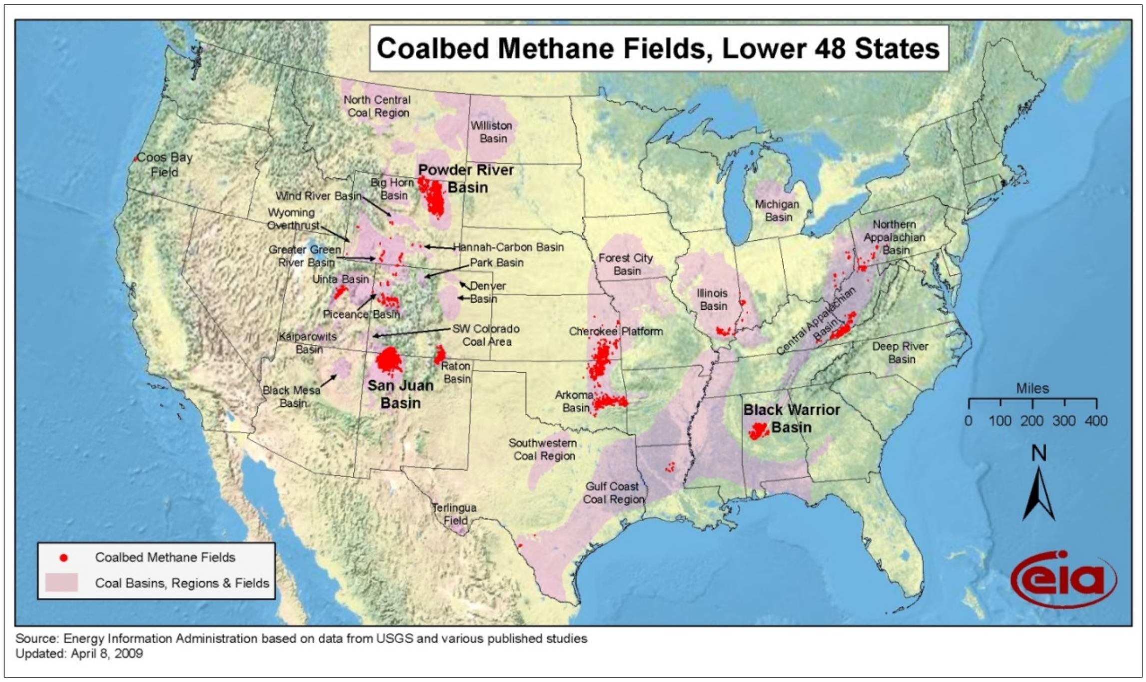


Figure 4: Location of Currently Active Areas for Coalbed Development and Production

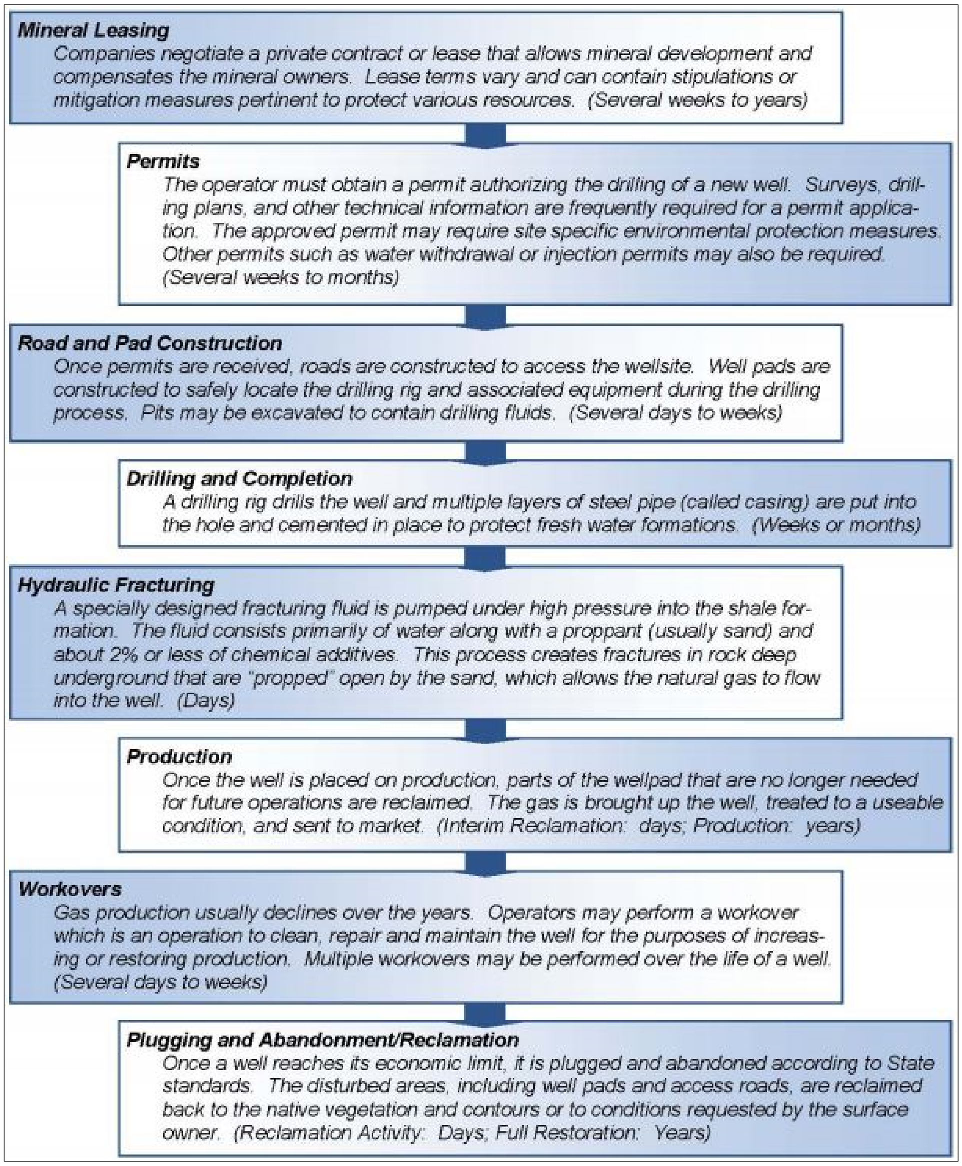


Figure 5: General Timeline Associated with Phases of Shale Gas Development
(*Modern Shale Gas Development in the United States: A Primer* [p. 44, exhibit 28])

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/FE'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. 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.

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.
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts.

Additive	Compound(s)	Purpose
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.

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

Flowback water recovered from a hydraulic fractured well is typically stored 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 fluids recovered vary widely, and may be from 20 to 80 percent (NETL 2014). 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.

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 UIC Program for subsurface discharge.

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), and contributes to the formation of ground-level ozone. EPA estimated 2.2 million tons of VOC emissions from the oil and natural gas industry in 2008. VOC and other pollutants 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 [http://www.epa.gov/ttn/atw/allabout.html]), as well as nitrogen oxides (NO_X), particulate matter (PM), and sulfur dioxide (SO_2) from the combustion of fossil fuels (EPA, 2014a).

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 change 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. This occurs after well drilling and prior to well completion. 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.

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. Vented emissions originate when natural gas is flared at well sites or vented during well completion and workover activities. 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. 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.

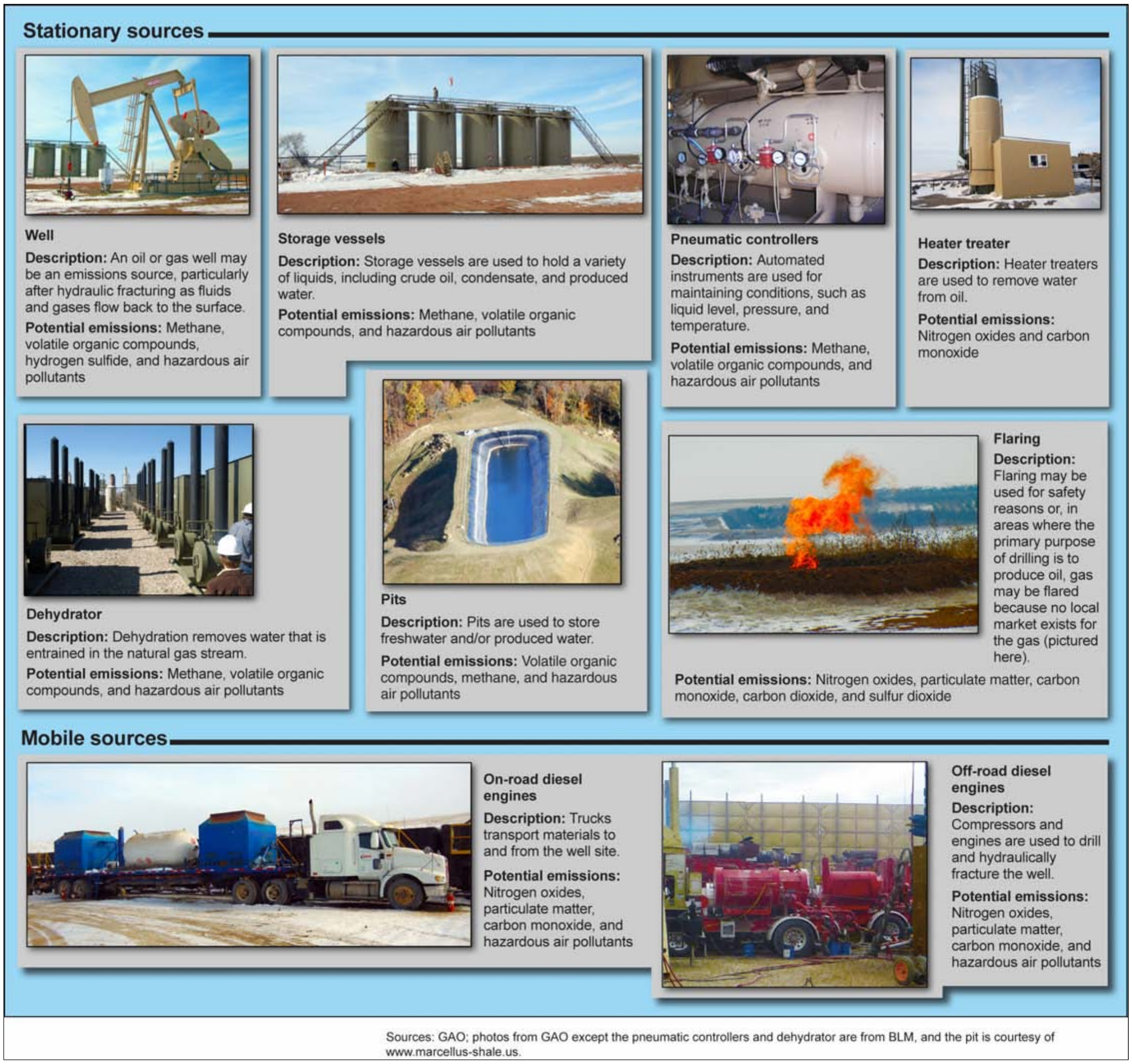


Figure 7: Examples of Air Emissions Sources Related to Oil and Gas Activities
(GAO, 2012)

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 an ozone precursor, contributing to ground-level ozone pollution. 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 the new federal 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 linked with a number of adverse effects on the respiratory system, and is released by the internal combustion engines supporting natural gas activities. Sulfur dioxide 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 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 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).

States where nonattainment areas occur must develop SIPs 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, companies 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 sources to be permitted in a nonattainment area, companies must obtain offsets from existing emitters to compensate for the estimated new emissions.

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.

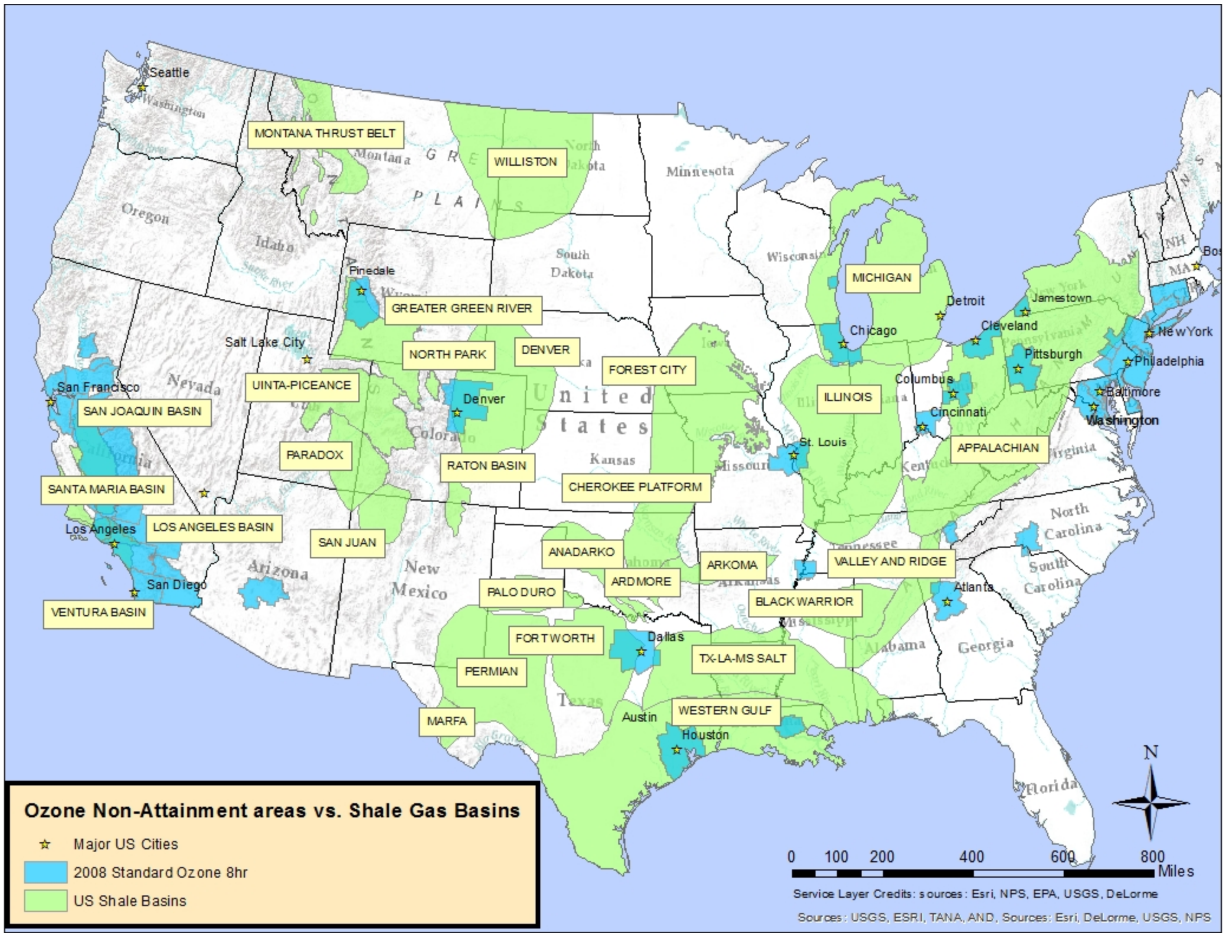


Figure 8: National Map Showing Ozone Nonattainment Areas Superimposed on Major Shale Gas Basins

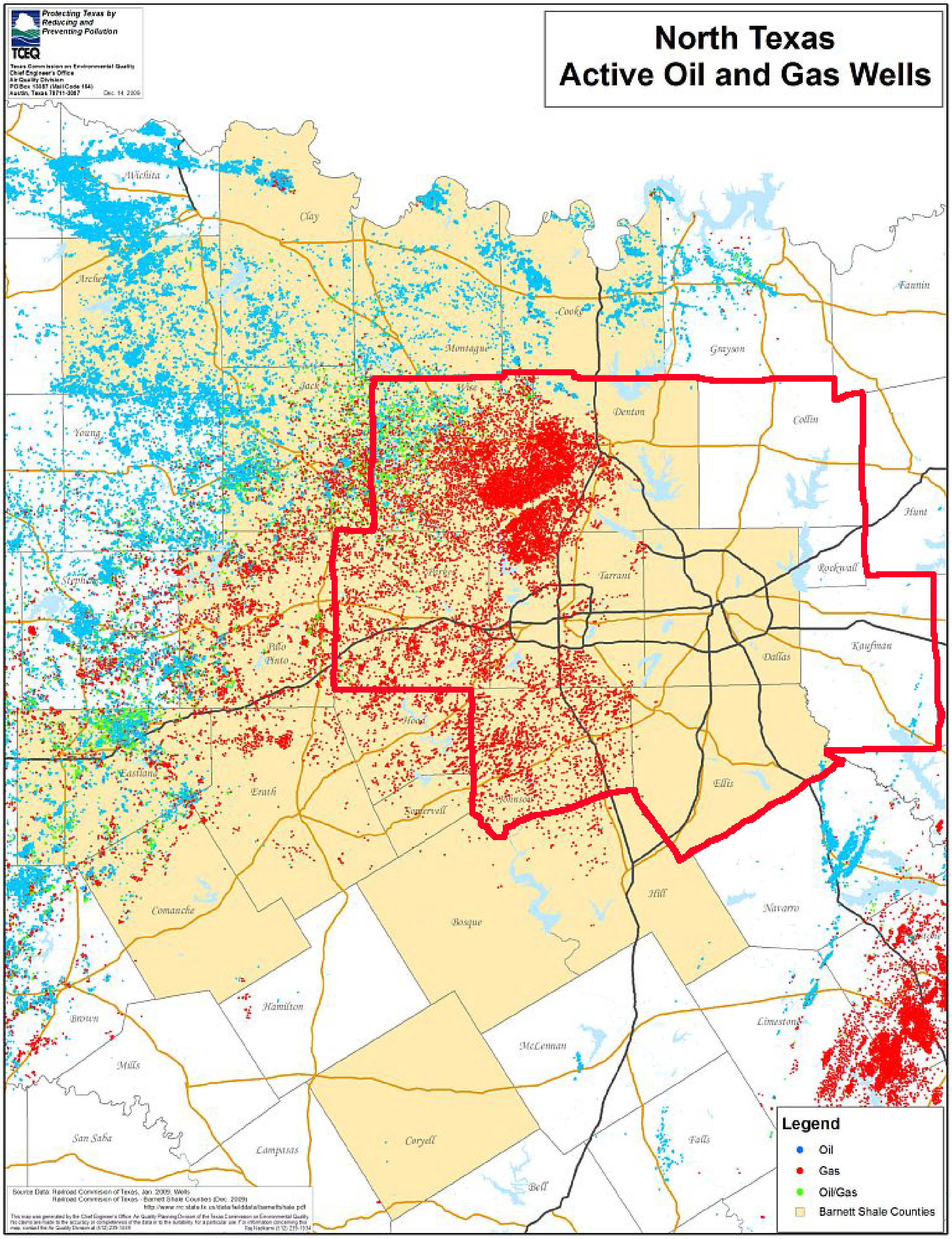


Figure 9: Dallas-Fort Worth Ozone Nonattainment Area (red outline) Superimposed on Map of Area Oil and Gas Wells from the Barnett Shale Play

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. This 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 may create new or expanded ozone non-attainment areas and possibly complicate 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 2010 data, the natural gas industry's emissions of CH_4 accounted for one-third of all U.S. CH_4 emissions and for approximately three percent of EPA's U.S. total inventory of GHG emissions on the basis of CO_2-e (see e.g., Bradbury et al., 2013. p. 9, citing EPA 2012a). Upstream activities account for most of the industry's CH_4 emissions (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	4,821	101.2
"Non-Combustion" CO_2	35,191	35.2
Sum	40,012	136.4
Percent of U.S. GHG emissions from all sources (6,501.5 Tg CO_2-e)		2.1%

Sources:

1. EPA (2014) DRAFT Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. Tables: 3-43, 3-44, 3-46, 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 not shown here.
- "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	4,821	0.8%
"Non-Combustion" CO_2	35,191	5.9%
Sum	40,012	6.7%
U.S. Natural Gas Production (24.06 trillion scf)	601,500	

Sources:
1. EPA (2014) DRAFT 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 rates of increase 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.

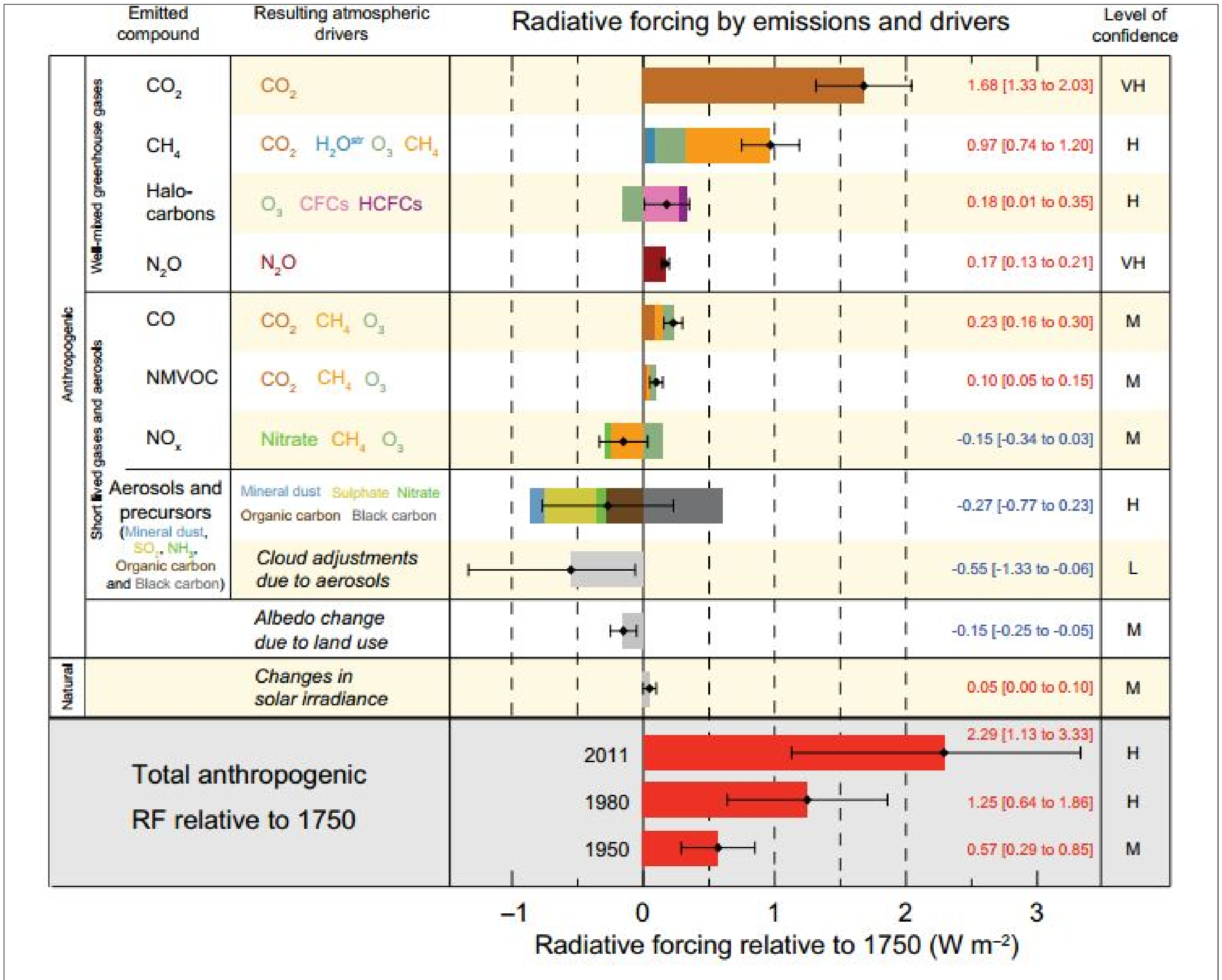


Figure SPM.5 | Radiative forcing estimates in 2011 relative to 1750 and aggregated uncertainties for the main drivers of climate change. Values are global average radiative forcing (RF[14]), partitioned according to the emitted compounds or processes that result in a combination of drivers. The best 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 gas-separation 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 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 Workovers and Maintenance

When production of natural gas slows to very low rates, wells are typically cleaned or re-worked. 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. This natural gas may be either vented or flared and can account for relatively large emissions. 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. For wells in both unconventional and conventional resources, hydraulic fracture jobs are redone as part of the workover, either using the existing perforations through the casing or newly created perforations. 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). 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.

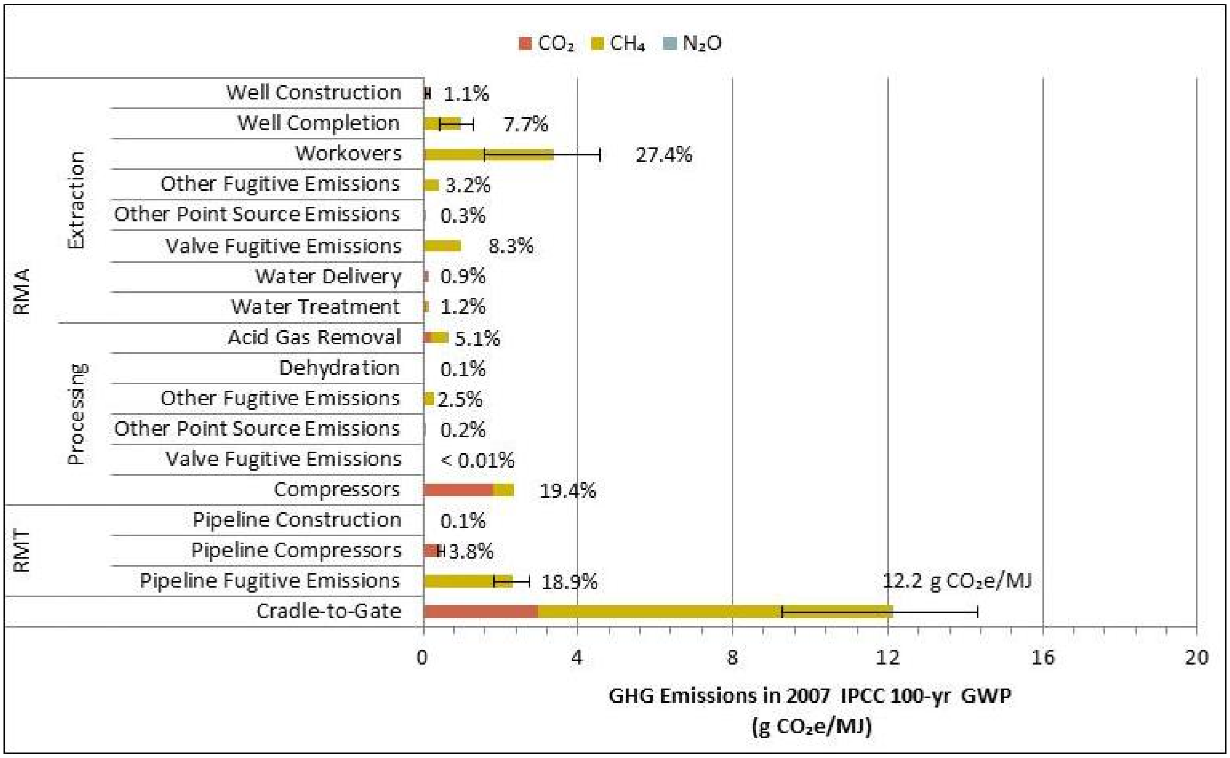


Figure 11: Detailed GHG Results for Marcellus Shale Natural Gas Extraction, Processing, and Transport (NETL, 2014)

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 (sum of 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 (6,502 MMt CO_2-e) (EPA, 2014). EPA (2014) 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 4.8 MMt/year or 101.2 MMt CO_2-e/year in 2012, amounting to approximately 1.6 percent of EPA's GHG inventory for 2012 (EPA, 2014).

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	39.0	18.7	43.5	101.2
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, 2014. Inventory … 1990-2012 (Draft), 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 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 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 workovers 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.

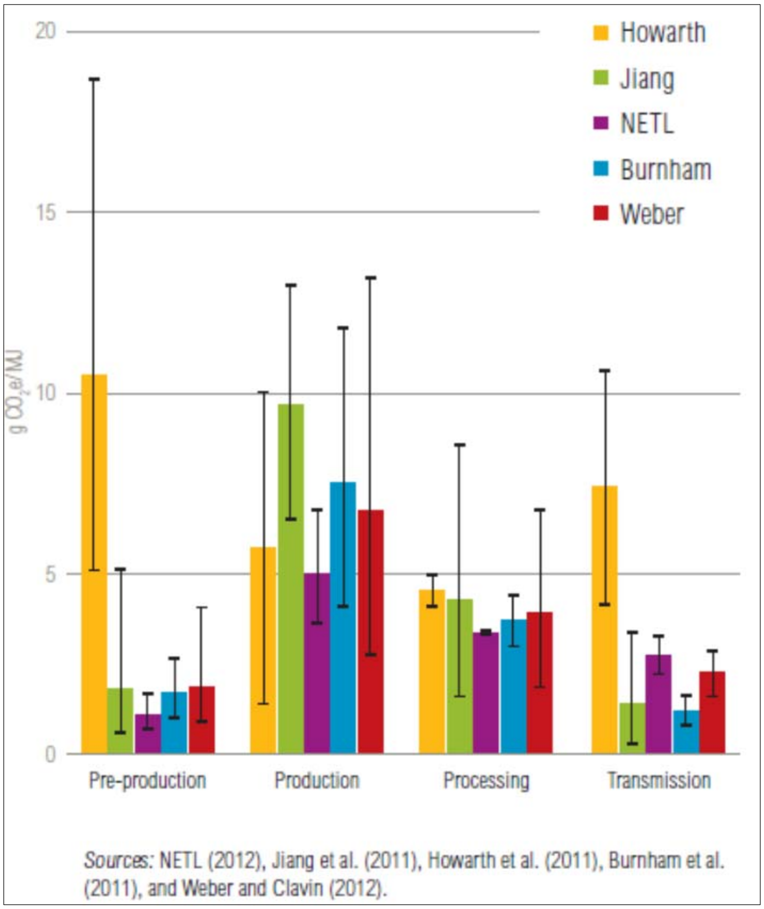


Figure 12: Upstream GHG Emissions from Shale Gas by Life Cycle Stage[3]
(Bradbury et al., 2013, p. 3, Figure S-1)

[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).

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 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 (2014) 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 water removal, which is claimed to be another significant source of methane emissions, and they do not apply to wells that produce primarily oil (Bradbury et al., 2013, p. 23). 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.

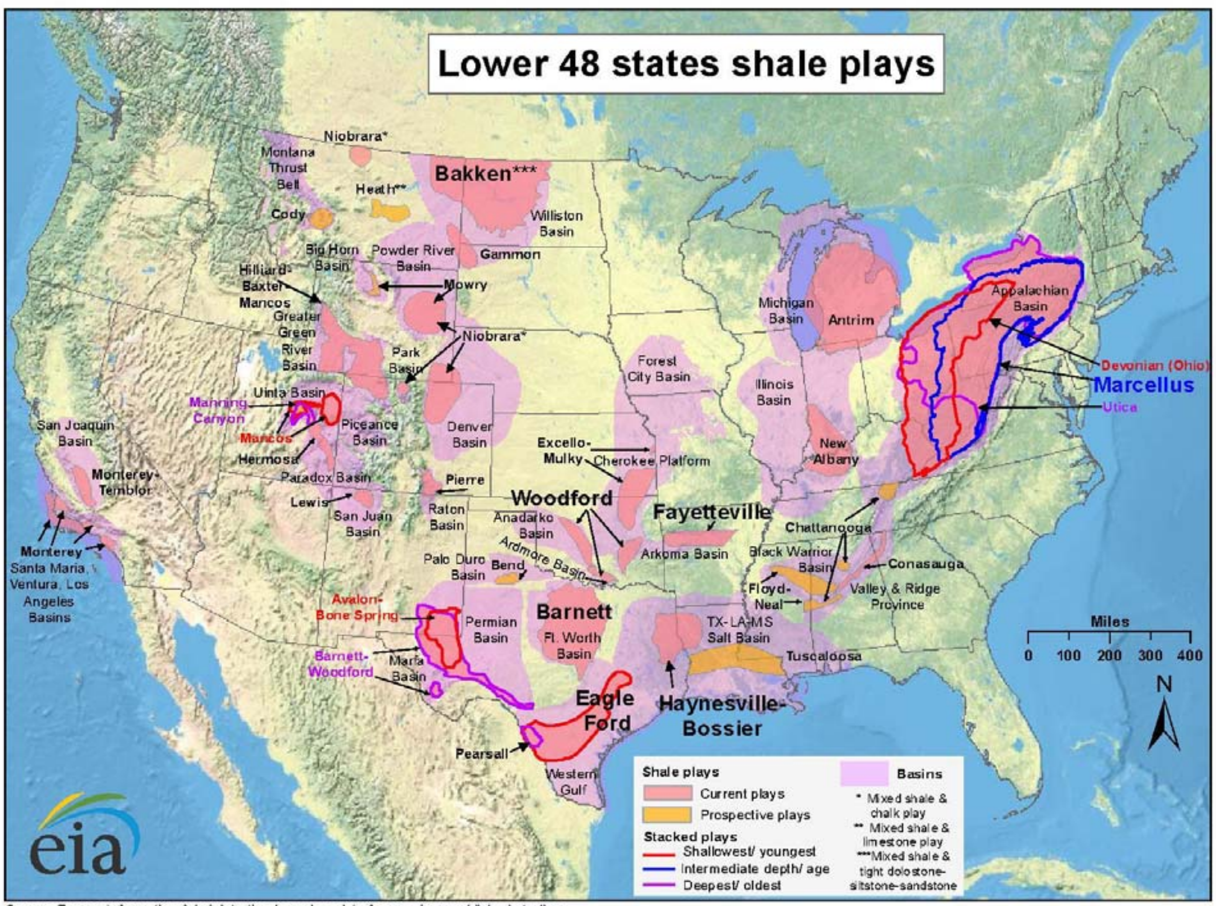
To the extent that unconventional natural gas production replaces the use of other carbon-based energy sources, there may be a net positive impact in terms of climate change.

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 4.9 teragrams (Tg) of CO_2-e/year initially to 4.2 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 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. 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.



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

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.

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**
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**

Category	Effects	Richter Scale (Approximate)
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).

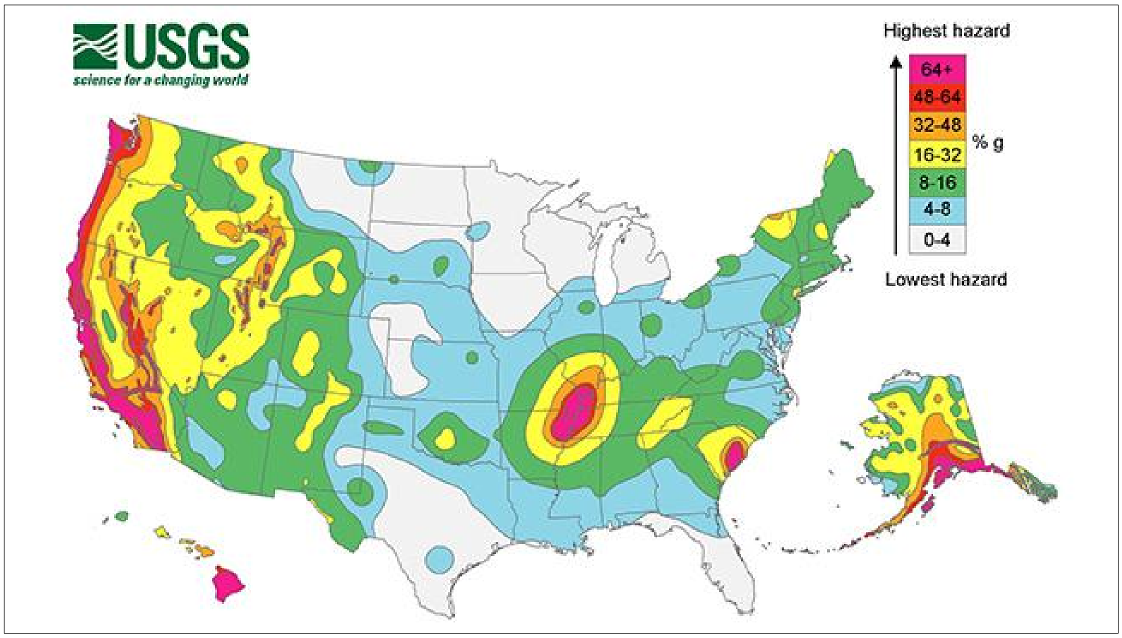


Figure 14: Seismic Risks from Natural Earthquakes, as Estimated for the United States
(USGS, 2008)

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.

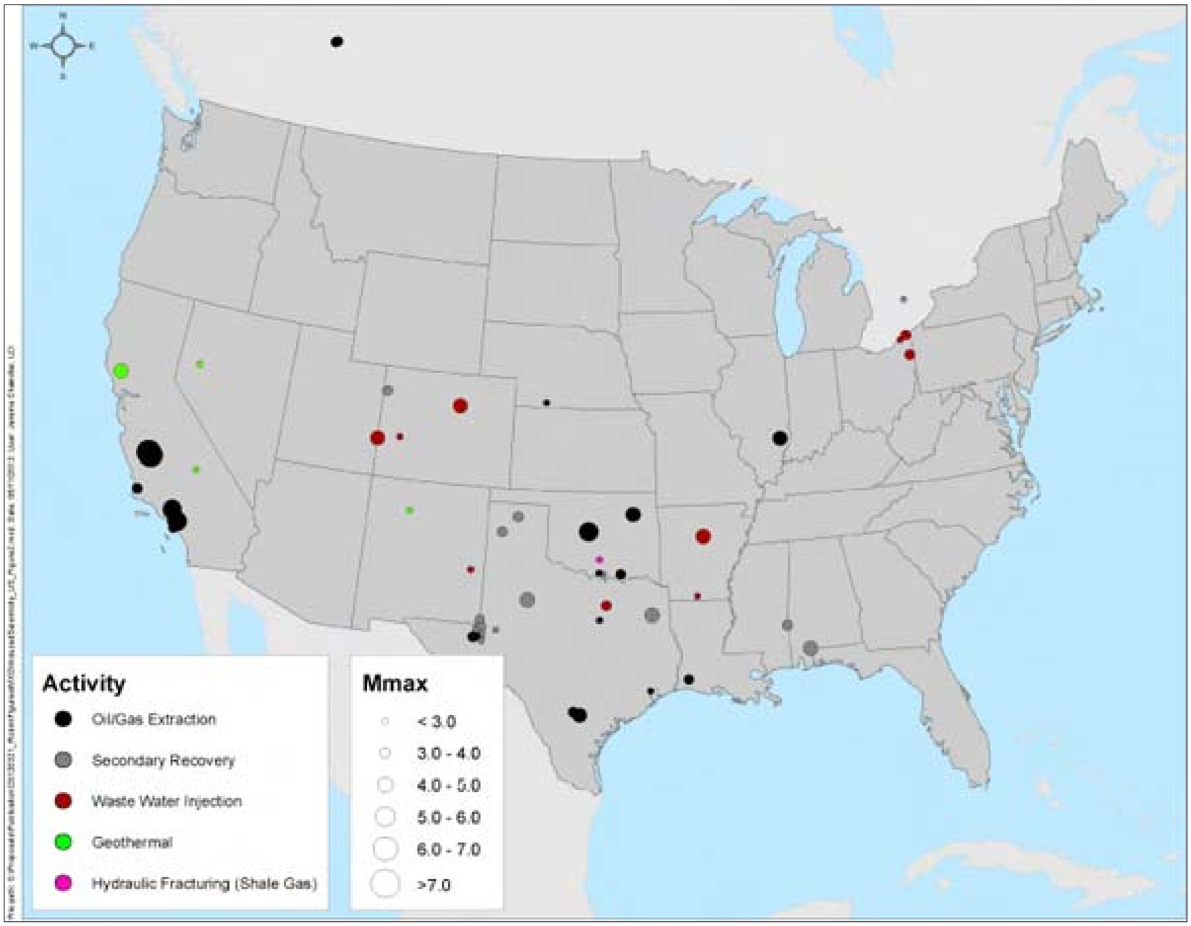


Figure 15: Geographic Locations of Earthquakes Believed to Result from Gas and Oil Industry Practices
(NRC, 2013, *Induced Seismicity Potential in Energy Technologies*. Reprinted with permission from the National Academy of Sciences, Courtesy of the National Academies Press, Washington, D.C.)

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).

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 from 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 16) 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.

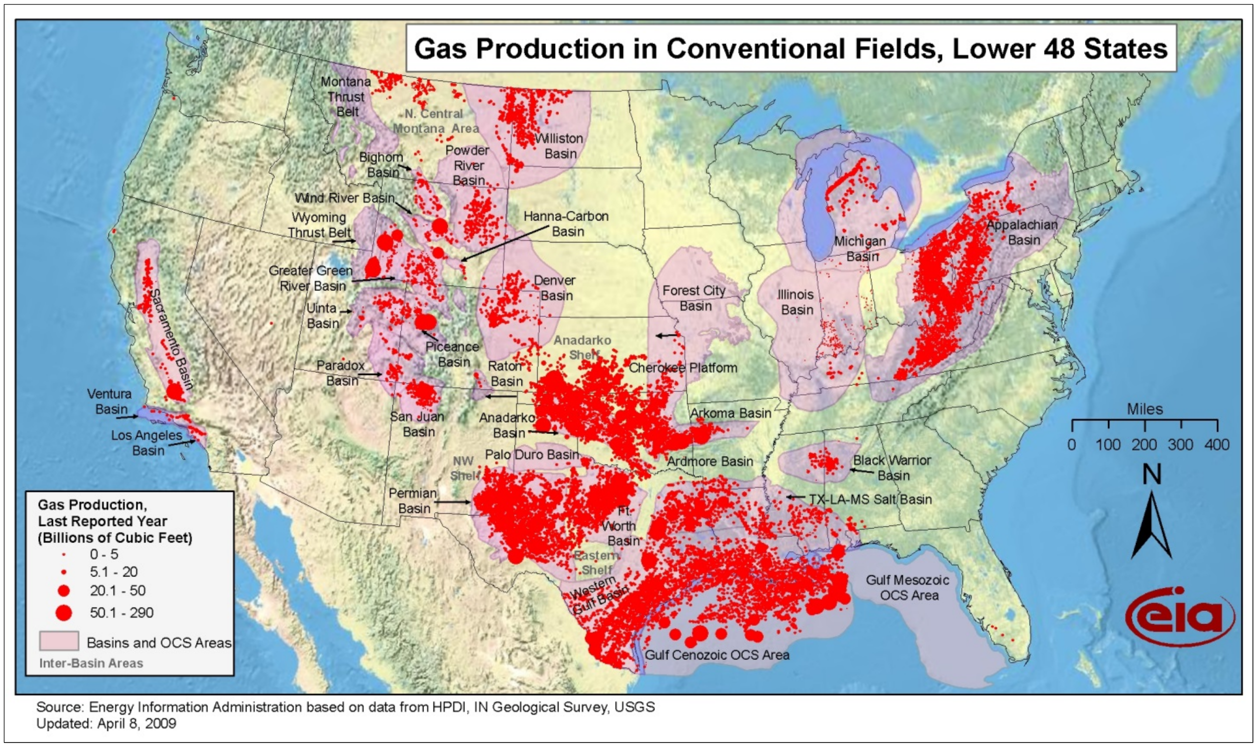


Figure 16: Lower 48 States' Conventional Gas Plays
(EIA, 2009)

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

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
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), while a typical hydroelectric reservoir utilizes 250,000 m^2/GWh/yr (Fthenakis and Kim 2009). Geothermal plants may impact up to 900 m^2/GWh/yr (MIT 2006); and wind 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. Unfortunately, it is difficult to compare these 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.

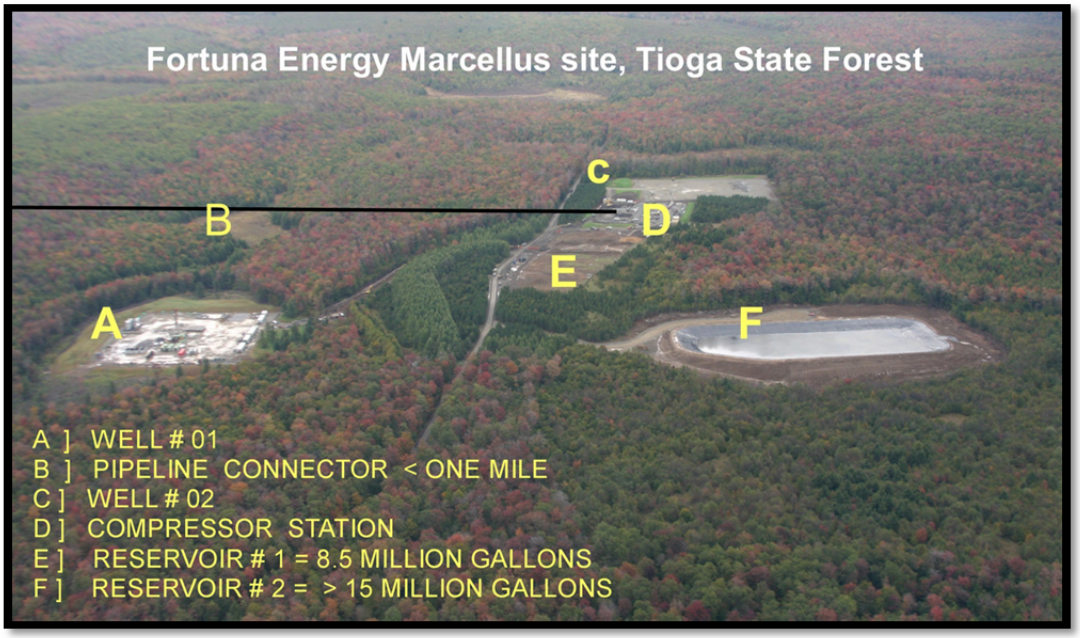


Figure 17: Typical Well Pad Development in a Wooded Location
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

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). The need for additional well pads is determined by characteristics of the local geology and production status.

Figure 18: A Typical 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. For gathering lines, the laws governing exercise of eminent domain vary by state. As an example, in New York, Pennsylvania, and West Virginia, eminent domain generally only applies to transmission pipelines. Therefore, for individual gathering lines, the pipeline operator must negotiate easements with each individual landowner along the anticipated pipeline route.

Access/Maintenance Roads: 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.

Construction ROW: 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 19: Typical 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 20: 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 21: 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 22: 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 23: Pipe Storage Facility in Pennsylvania
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Typical land use impacts include the following:

- Conversion of agricultural (crops and grazing) and forested lands to open disturbed, semi-industrial uses.
- Conversion of lands to maintained ROWs for access roads and pipelines. Some lands in ROW may revert back to agricultural uses, but soil compaction may be an issue.
- Loss of lands for public recreational use/access.
- Increased ease of access to lands via new access roads. Many may be gated, but walk-in accessibility would 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 of 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 24: The Effect of Landscape Disturbance on Non-Forest Habitat (Wyoming, USA)
(USGS 2013)

Figure 25: 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).

As State and local governments continue to seek increased methods to generate revenue, state parks and other public open space areas are increasing the leasing of their public lands for shale gas development. The Pennsylvania Department of Conservation and Natural Resources (DCNR) estimates that almost 700,000 (31 percent) of the 2.2 million acres of state forest lands are available for natural gas development. If all these acres were developed, the Pennsylvania DCNR estimates that more than 3,000 miles of new edge forest would be created. Additionally, the Pennsylvania DCNR predicts a major loss of primitive and semi-primitive forest lands as gas development proceeds, as well as a disruption to many of the recreational trails in its vast motorized and un-motorized trail system.

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 increase traffic, raise accident rates, and cause 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.
- Invasive species – Pipeline construction and well development activities cause disturbance of land that can provide access to invasive species.
- 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 26: Typical Eastern Shale Gas Viewshed Alteration
(Photo courtesy of Robert M. Donnan, http://www.marcellus-shale.us/)

Figure 27: 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 14 lists the approximate truck traffic that can be expected throughout a typical unconventional Marcellus shale gas well development.

Table 14: 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

Calculations from Greenhouse Gas Section

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

24.12 Tscf/year x 25 g/scf x 1,000 Gg/Tg = 603,000 Gg/year

Estimation of unit methane emissions:

1.0 Tscf/year x (4821 Gg CH_4/24.12 Tscf) = 199.876 Gg CH_4/year

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

1.0 Tscf/year x (40,012 CH_4+CO_2/ 24.12 Tscf) = 1658.87 Gg CH_4+CO_2/year

1658.87 Gg CH_4+CO_2/year x (136.4 TgCO_2-e CH_4 + CO_2/40,012 Gg CH_4 + CO_2) = 5.66 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:

5.66 Tg CO_2-e/year x (1.0 – 0.13) = 4.9 Tg CO_2-e/year (current production levels from shales)

5.66 Tg CO_2-e/year x (1.0 – 0.25) = 4.2 Tg CO_2-e/year (increased production levels from shales)