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Environmental Impacts of Unconventional Natural Gas Development and Production

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List of Exhibits

Acronyms and Abbreviations

ADEQ	Arkansas Department of Environmental Quality
AEO	Annual Energy Outlook
amt	Amount
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
BLM	Bureau of Land Management
BMPs	Best management practices
Btu	British thermal unit
CAA	Clean Air Act
CAP	Criteria Air Pollutant
CAS	Chemical Abstract Services
CBM	Coalbed methane
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRS	Congressional Research Service
CWA	Clean Water Act
CWT	Centralized Waste Treatment
DOE	Department of Energy
DOI	Department of the Interior
EDF	Environmental Defense Fund
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ERP	Energy Resources Program
ESA	Endangered Species Act
ESPA	Energy Sector Planning and Analysis
EUR	Estimated ultimate recovery
ft	Foot
gal/mmBtu	Gallons per million British thermal units
GAO	Government Accountability Office
g CO_2e /MJ	Grams of CO_2 equivalent per megajoule
GHG	Greenhouse gas
GIS	Geographic Information Systems
GWP	Global warming potential
GWPC	Groundwater Protection Council
H_2S	Hydrogen sulfide
ha	Hectare
HAP	Hazardous air pollutant
IEA	International Energy Agency
IOGCC	Interstate Oil & Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
km^2	Square kilometers
lb	Pound
LCA	Life cycle analysis
LNG	Liquefied natural gas
M	Magnitude (Richter Scale)
Mcf, MCF	Thousand cubic feet
MMCF	Million cubic feet
mg/L	Milligram per liter
mi^2	Square mile
MIT	Massachusetts Institute of Technology
MJ	Megajoule
N/A	Not applicable
N_2O	Nitrous oxide
NAS	National Academy of Sciences
NASA	National Aeronautics and Space Administration
NEPA	National Environmental Policy Act
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive materials
NOV	Notices of violation
NO_x	Nitrogen oxides
NPS	National Park Service
NRC	National Research Council
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
ODNR	Ohio Department of Natural Resources
OGS	Oklahoma Geological Survey

OPA	Oil Pollution Act
OSHA	Occupational Safety and Health Administration
PADEP	Pennsylvania Department of Environmental Protection
PCT	Percent
PM	Particulate matter
POTW	Publically Owned Treatment Works
ppm	Parts per million
PXP	Plains Exploration & Production Company
R&D	Research and development
RCRA	Resource Conservation and Recovery Act
RECs	Reduced emission completions
RFF	Resources for the Future
RMA	Raw material acquisition
RMT	Raw material transport
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SEAB	Secretary of Energy Advisory Board
SO_2	Sulfur dioxide
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
STAR	Science to Achieve Results [EPA]
tcf	Trillion cubic feet
TDS	Total dissolved solids
TRI	Toxics release inventory
TSS	Total suspended solids
TWDB	Texas Water Development Board
UIC	Underground Injection Control
U.S.	United States
USDA	U.S. Department of Agriculture
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WRI	World Resources Institute
°C	Degrees Celsius
°F	Degrees Fahrenheit

Executive Summary

The recent growth in unconventional natural gas production has also produced a profusion of publications on the exploration, development, production, infrastructure, economics, uses, and environmental impacts of these resources. These publications build on a strong body of existing literature that traces the evolution of these resources from their conceptual stages in the 1970s to the technology advancements that started the shale gas boom in the early 2000s. Between 2009 and 2013, government, industry, academic, scientific, non-governmental, and citizen organizations have added a substantial body of literature on the environmental impacts that could result from the continuing development of shale gas, tight gas sands, and coalbed methane resources.

This report summarizes the current state of published descriptions of the potential environmental impacts of unconventional natural gas upstream operations within the Lower 48 United States. As a survey, this report is by no means exhaustive. The goal of this report is to ensure that the predominant concerns about unconventional natural gas development, as covered by current literature, are identified and described. The sources cited are publicly available documents. Multiple publications on similar topics are compared and contrasted based only on their technical and methodological distinctions. No opinion or endorsement of these works is intended or implied.

Each chapter contains a separate section of references so that each type of impact can be explored further. The types of environmental impacts that are documented in the literature are described in the six following chapters:

Chapter 1 – Background

Recent innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States (U.S.), particularly in shale formations. Unconventional resources, including shale, tight sands, and coal beds, can be found in more than half of the lower 48 states, and overall production from these resources is forecast to continue growing in the coming decades so that by 2040 they may comprise half of domestic gas production. The combined effects of government policies, private sector entrepreneurship, and high natural gas prices spurred advances in horizontal drilling, hydraulic fracturing, and seismic imaging that have opened long-sought energy resources. Unconventional natural gas resources not only make up for declining conventional gas production, but increasing unconventional production is contributing to increased use of gas for power generation, manufacturing, transportation, and residential and commercial heating. These advances have swept domestic energy production so fast that in the last five years, U.S. companies have reversed plans to import liquefied natural gas (LNG), and many are now proposing exports. Continued increases in production are now most likely to come from the major shale plays, with stable production (as a percentage of total gas production) from tight sands and coal beds. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are conducting continuing research and development (R&D) to help develop best practices and minimize environmental impacts.

Chapter 2 – Greenhouse Gas Emissions and Climate Change

Greenhouse gas (GHG) emissions are released by the natural gas supply chain, and the extent to which these emissions contribute to climate change has been investigated by government and university researchers. There are five major studies that account for the GHG emissions from upstream natural gas, which include the construction and completion of gas wells, as well as subsequent production, processing, and transport steps. While a number of studies have been conducted on this topic, these five studies represent the breadth of all natural gas life cycle work and point to the methane emissions from unconventional well completions and workovers[1] as a key difference between the GHG profiles of conventional and unconventional natural gas. Other key emissions occur during steady-state operations, such as emissions from compressors and pipelines. The assumptions and parameters of the five studies vary, but, given their uncertainties, four of the five studies conclude that the GHG emissions from a unit of delivered unconventional natural gas are comparable to (if not lower than) those from a unit of conventional natural gas. The fifth study concludes that the high methane emissions from unconventional well completion and a lack of environmental controls at unconventional extraction sites translates to higher GHG emissions from unconventional natural gas than from conventional natural gas.

Chapter 3 – Air Quality

GHG emissions from natural gas systems have received significant attention in current literature; however, they are not the only type of air emission from natural gas systems. The two key sources of non-GHG emissions are:

- *Uncaptured Venting*: Releases natural gas, which is a source of volatile organic compound (VOC) emissions.
- *Engine Fuel Combustion*: Produces a wide variety of air emissions, including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM).

VOCs and NO_x react in the lower atmosphere to produce ground-level ozone, a component of smog that adversely affects human respiratory health. The reaction between VOCs and NO_x is unique, because it represents an interaction between two emission sources (in this case, uncaptured venting and fuel combustion). The other emissions from fuel combustion have a variety of human health and ecological impacts. CO affects human health by reducing the oxygen-carrying capacity of blood. SO_2 leads to soil or surface water acidification (via acid rain). PM is linked to poor heart and respiratory health. (EPA, 2012a; GAO, 2012)

Chapter 4 – Water Use and Quality

In the broadest terms, the literature describes water quality and the treatment and management of wastewaters as the central issue in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of fresh water, and deep underground injection wells for wastewater disposal are more readily available, the central issue is the availability of water for drilling and hydraulic fracturing and the impacts this could have on established users. Drilling and hydraulically fracturing a shale gas well can consume between 2 and 6 million gallons of water and local and seasonal shortages can be an issue, even though water consumption for natural gas production generally represents less than 1 percent of regional water demand. Water quality impacts can result from inadequate management of water and fracturing chemicals on the surface, both before injection and after as flowback and produced water. Subsurface impacts can result from the migration of fracturing fluids, formation waters, and

[1] "Workover" is a generic industry term for a variety of remedial actions to stimulate or increase production. As applied here to shale gas wells, it means hydraulic fracturing treatments after the initial drilling and first hydraulic fracturing of the well.

methane along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

Chapter 5 – Induced Seismicity

Induced seismicity is ground motion (earthquakes) caused by human activities. There is little question that energy extraction and fluid injection have the potential to cause seismic activity. Earthquakes have been detected in association with oil and gas production, underground injection of waste waters, and possibly with hydraulic fracturing. Hydraulic fracturing involves injecting large volumes of fluids into the ground. These injections are short-lived and are injected at lower pressures, so it is likely that they do not constitute a high risk for induced seismicity that can be felt at the surface. In contrast to hydraulic fracturing, wastewater disposal from oil and gas production, including shale gas production, is typically injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity. (NRC, 2012; GWPC, 2013)

Chapter 6 – Land Use and Habitat Fragmentation

Although not as extensively documented as other environmental impacts, like water quality and greenhouse gas emissions, land use and development impacts that have been discussed in the literature include property rights and use of public lands; local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations. Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species and can result in population declines. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells require spacing of 40 acres per well, the drill pads from which each horizontal well originates require spacing of 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6 to 8 wells. (NETL, 2009)

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1 Background

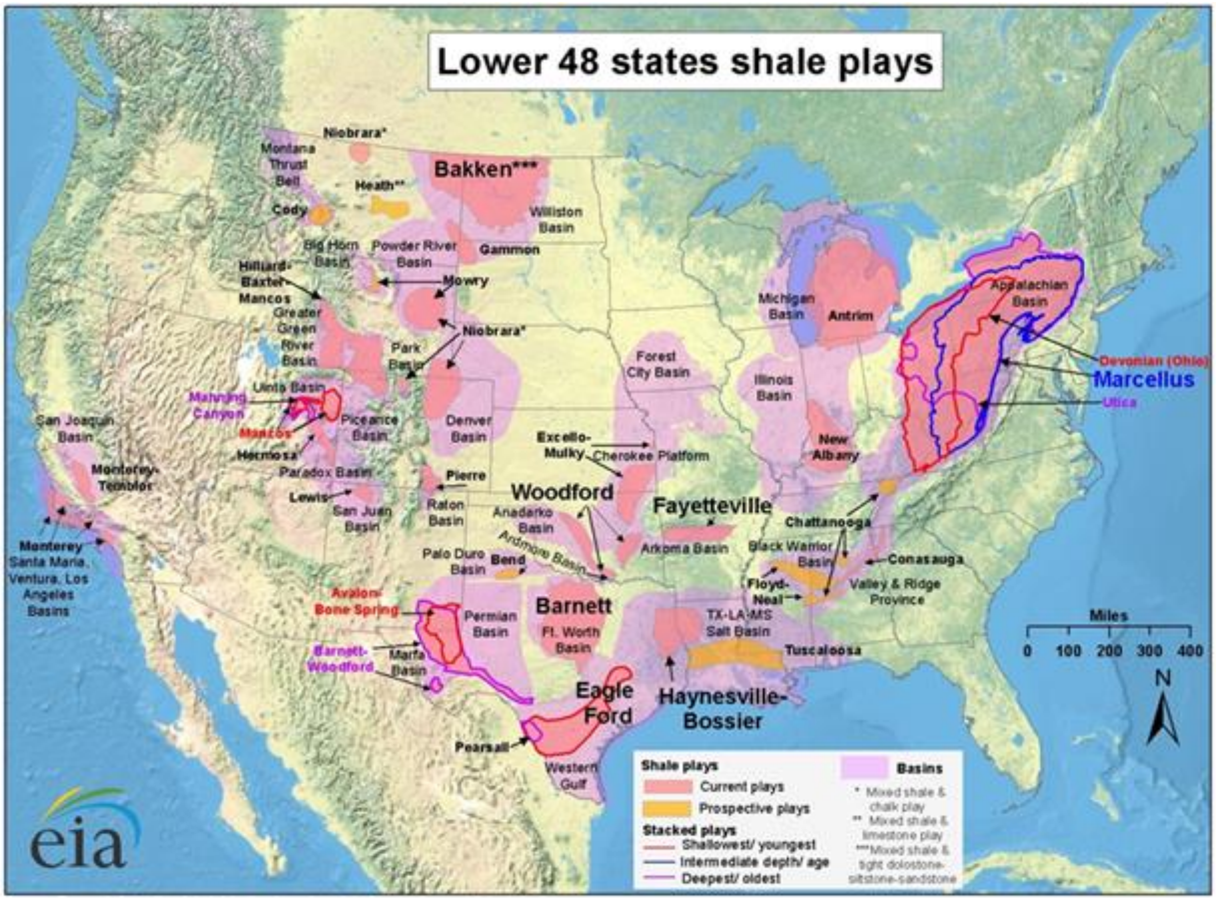
Recent innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States (U.S.), particularly in shale formations. Unconventional resources, including shale, tight sands, and coal beds, can be found in more than half of the lower 48 states, and overall production from these resources is forecast to continue growing in the coming decades so that by 2040 they may comprise half of domestic gas production. The combined effects of government policies, private sector entrepreneurship, and high natural gas prices spurred advances in horizontal drilling, hydraulic fracturing, and seismic imaging that have opened long-sought energy resources. Unconventional natural gas resources not only make up for declining conventional gas production, but increasing unconventional production is contributing to increased use of gas for power generation, manufacturing, transportation, and residential and commercial heating. These advances have swept domestic energy production so fast that in the last five years, U.S. companies have reversed plans to import liquefied natural gas (LNG), and many are now proposing exports. Continued increases in production are now most likely to come from the major shale plays, with stable production (as a percentage of total gas production) from tight sands and coal beds. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are conducting continuing research and development (R&D) to help develop best practices and minimize environmental impacts.

1.1 Unconventional Natural Gas Resources

A precise definition for "unconventional" resources is somewhat difficult, being in part a function of the technological and economic environments in which energy resources are produced. Some oil and gas resources are recognized, by historical convention, as unconventional, others because they are "outside the range of combinations of oil/gas price, available technology, and industry risk tolerance that would enable them to be widely produced today." (DOE, 2011) In current usage, three types of reservoirs comprise unconventional natural gas resources and a fourth, methane hydrates, is included, but viewed currently as outside the range of currently available technology. The first and most important of these is shale gas, the second is "tight" (low-permeability) sandstones, and the third is coalbed methane (CBM). (DOE, 2011) The Energy Information Administration (EIA) has produced a map depicting unconventional gas plays (Exhibit 1-1).

The dispersed nature of these resources is one of the reasons for calling them unconventional. The gas (and oil) in these reservoirs is less concentrated than conventional reservoirs where the gas has accumulated in geologic traps, and the lower permeabilities make unconventional gas more difficult to extract. Among the implications for this are greater scales of operations and the need for more wells to contact the larger areas of production in target formations. Hydraulic fracturing involves more complex and intensive preparation, and introduces additional environmental risks. (IEA, 2012)

Exhibit 1-1 Unconventional natural gas plays in the lower 48 states (EIA, 2011)



Shale is a sedimentary rock composed mainly of clay and clay-sized particles. The crystalline structures of clay minerals form in thin, parallel sheets, somewhat like the skin of an onion. Small flakes of clay carried by streams and rivers settle out in low-energy geologic environments like tidal flats and in deep ocean basins where they fall flat and parallel to one another. As these sediments are covered and buried, they are compacted into thin layers with low permeabilities. Like pages in a book, these layers restrict fluid flow, especially vertically across the layers. At the same time, microscopic bits of organic matter, plant and animal debris that were deposited with the clay flakes, decay, and under the heat and pressure of deep burial, form natural gas and liquid hydrocarbons. The low permeability traps the gas and hydrocarbons in the shale, so the shale must be fractured to increase the permeability to allow the gas to flow into wells. (NETL, 2009a)

Shale may be considered an unconventional resource, but it is not unknown in the industry. In fact, organic-rich shale formations are wide-spread and well-known in most parts of the world, because shale is found in all sedimentary basins and can make up 80 percent of the sediments in a basin. In many cases, enough is already known about shale formations that little precision exploration is needed; operators may already understand that shale gas reserves exist at a given location. At the same time, operators may not be able to estimate the technically and economically recoverable reserves until wells have been drilled and tested. Shale formations each have unique geologic characteristics; within each formation there are differences that create "sweet spots" for production. Variables include the amount of organic material deposited with the shale, the presence of natural fractures, and the amount of liquid hydrocarbons. (IEA, 2012)

Dozens of gas-bearing shale formations are located in sedimentary basins across the U.S. Some areas like the Appalachian Basin, the Michigan Basin, and the Illinois Basin have long histories of natural gas production. With improvements in unconventional technologies such as horizontal drilling and hydraulic fracturing, plays like the Barnett, Fayetteville, Haynesville, Marcellus, and Woodford have seen the development and growth of unconventional wells in addition to their existing conventional wells. Others, including the Eagle Ford and Pearsall, have started development since improvements in horizontal drilling and hydraulic fracturing have occurred. In terms of reserves, the "Big Five" plays are now considered to be the Barnett, Fayetteville, Haynesville, Marcellus, and Woodford. (DOE, 2011)

"Tight gas" reservoirs were defined in the 1970s by the federal government as having a permeability to gas flow less than 0.1 millidarcy (a unit to measure the permeability of rock) to determine which gas wells would be eligible for tax credits to encourage production. They are not necessarily deposited differently than conventional sandstone reservoirs, but may have lower permeabilities due to more intensive cementing by mineral precipitates. A more technical definition might be "a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, by a horizontal wellbore, or by use of multilateral wellbores." (Holditch, 2006)

Like conventional sandstone gas reservoirs, tight gas sands form as gas from organic-rich source rocks (like shales) migrates into the sands, and is trapped there. Like shale gas formations, the low permeabilities mean that tight sand formations must be stimulated to produce commercial quantities of gas. However, once drilled and stimulated, tight sands tend to have better production factors than shales. (IEA, 2012) These plays are less extensive than the shale plays, with half of the estimated reserves in the Green River, Piceance, and Uinta Basins in Colorado and Utah, and the East Texas Basin. (DOE, 2011)

Coal seams typically form in low-energy swampy environments where organic matter and sediment accumulate. Natural gas can be produced from thermogenic alteration of the coal as it is buried, compressed, and heated, or by the biogenic action from microbes on the coal. (NETL, 2009a) As plant material is buried and converted to coal, natural gas is generated, while the increasing pressure from trapped water forces the gas to adsorb onto the coal. The amount of gas that can be produced is a function of the hardness (or "rank") of the coal. Softer coals (peat and lignite) have higher porosities and water contents, and produce some biogenic methane; higher-rank anthracite coals have lower porosities and water contents with little methane. The preferred coals for CBM production are mid-rank bituminous coals that have matured enough to generate thermogenic methane. (EPA, 2010)

As with the other types of unconventional gas reservoirs, CBM formations have low permeabilities and most of the permeability in a coal bed is created by natural fractures, or cleats. Pumping out the water found in CBM formations releases the gas from the coal and allows it to flow into the well. CBM typically contains fewer liquid hydrocarbons (natural gas liquids [NGL]) than other types of natural gas wells. This affects the economics of production, since the NGL market value is tied to oil prices rather than gas prices, making any gas produced with NGLs essentially free. (IEA, 2012)

CBM is produced in 15 basins in eight states (Alabama, Colorado, Illinois, Montana, Pennsylvania, West Virginia, Wyoming, and Virginia). Production of CBM started in the early 1980s in the Black Warrior Basin in Alabama, and the San Juan Basin in New Mexico and Colorado. (EPA, 2010) The two major basins for CBM production now are the Powder River Basin in Wyoming and Montana, and the San Juan Basin. (DOE, 2011) Together, these two basins account for nearly 70 percent of CBM production. The Powder River Basin accounts for most of the recent growth, having grown from 10 percent to almost one-third of U.S. production between 2000 and 2008. (EPA, 2010)

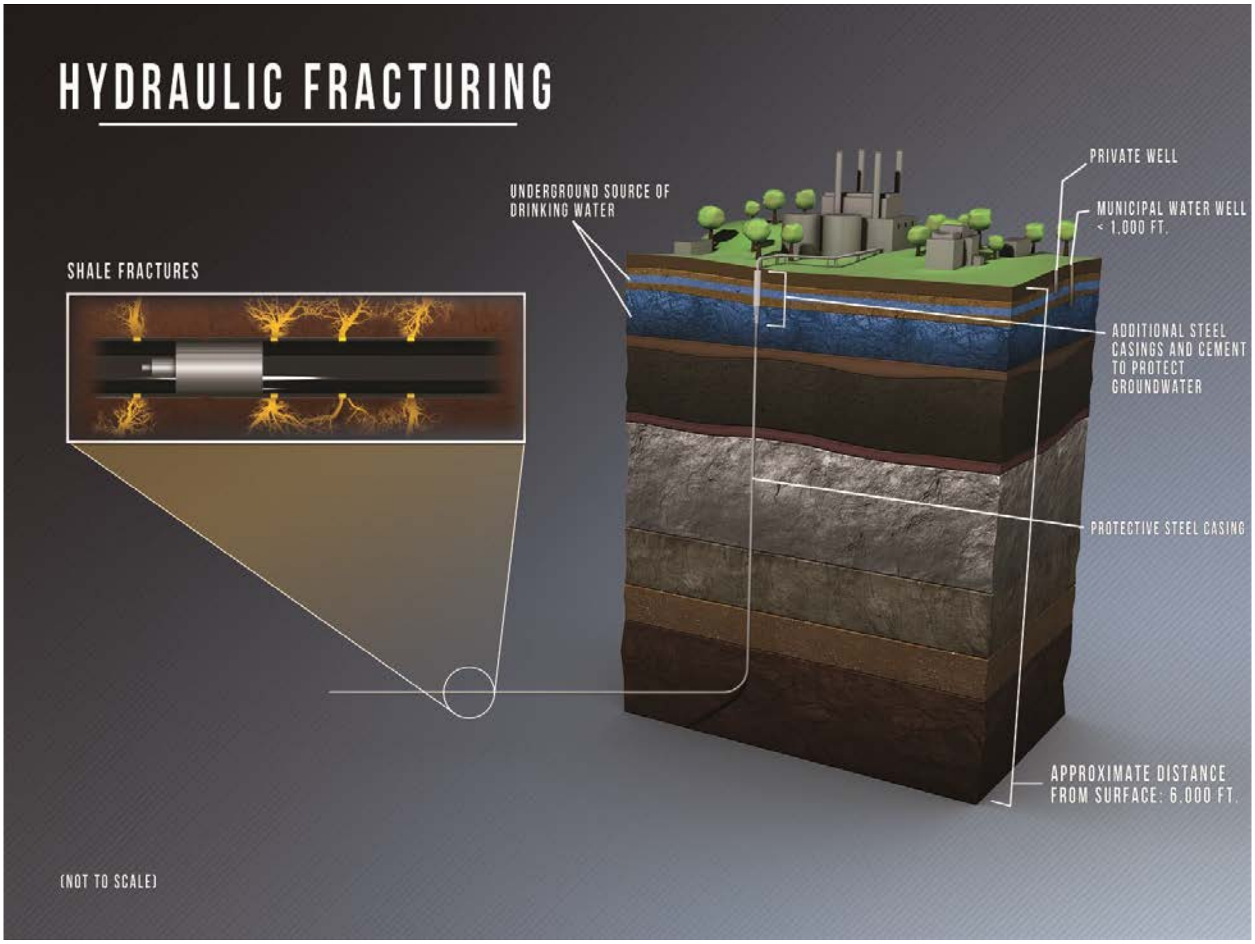
1.2 Technology Advances and Adaptation

Wang and Krupnick recount the history of the economic, policy, and technology developments that led to large-scale U.S. shale gas production. (2013) Their explanation (for international stakeholders) of the advent of the U.S. shale gas boom offers a case study of the interactions among government policies, private sector entrepreneurship, technology innovations, land and mineral rights ownership structures, and high gas prices that helped create the boom. In the late-1970s, the U.S. faced supply shortages, high prices, and declining prospects for conventional gas production. The federal government recognized that private corporations lacked incentives to make large, high-risk R&D investments. To compensate for the difficulty in protecting and patenting new technologies in the oil and gas industry, the federal government funded R&D programs, and provided tax credits to promote the development of unconventional resources. Shale gas production was first assessed in the Barnett Shale region in Texas between the early 1980s and late 1990s, after Mitchell Energy invested a large amount of money in the area. The Barnett Shale was not included in early assessments of potential gas resources prior to this timeline. As a nation, the U.S. offered favorable geology, water availability, private land and mineral ownership rights, structured energy markets, and existing infrastructure to translate the success in the Barnett into greatly increased natural gas production from shale plays. (Wang and Krupnick, 2013)

The production of natural gas from unconventional resources became economically viable due to advances in development and production technologies, leading to large-scale utilization of a resource that had historically been uneconomic to extract. (Jackson *et al*., 2011) Advances in horizontal drilling equipment and hydraulic fracturing techniques allowed greater access to unconventional reservoirs. A key innovation for shale formations was the addition of very fine grains of sand, known as proppants, to hold the fractures open to allow the trapped gas to flow into the well. (CRS, 2009) Jackson *et al*. estimated that a single horizontal well is two to three times more productive than a single vertical well, and can reach resources two miles away from the well pad. (2011) In the hydraulic fracturing process, fluid is pumped into the reservoir from the well, stimulating production by opening fractures in the reservoir.

However, neither of these technologies is new or unique to unconventional gas production. Horizontal drilling has been used since the 1930s, originally to drill from land out into formations under the seabed, and with advancements in the early 1980s became more commercially viable. Hydraulic fracturing was developed in the 1950s, and has been applied to shale gas wells since the mid-1980s. (NETL, 2009a) The Interstate Oil & Gas Compact Commission (IOGCC) estimates that 90 percent of oil and gas wells in the U.S. use hydraulic fracturing, though unconventional gas wells use a much larger volume of water than conventional gas wells. (Jackson *et al*., 2011) Estimates from industry data indicate that hydraulic fracturing has been used in more than a million wells in all of the 33 states that produce oil and gas. (Horinko, 2012) Exhibit 1-2 illustrates these processes in a representative shale gas well.

Exhibit 1-2 Horizontal drilling, hydraulic fracturing, and well construction (Source: NETL)



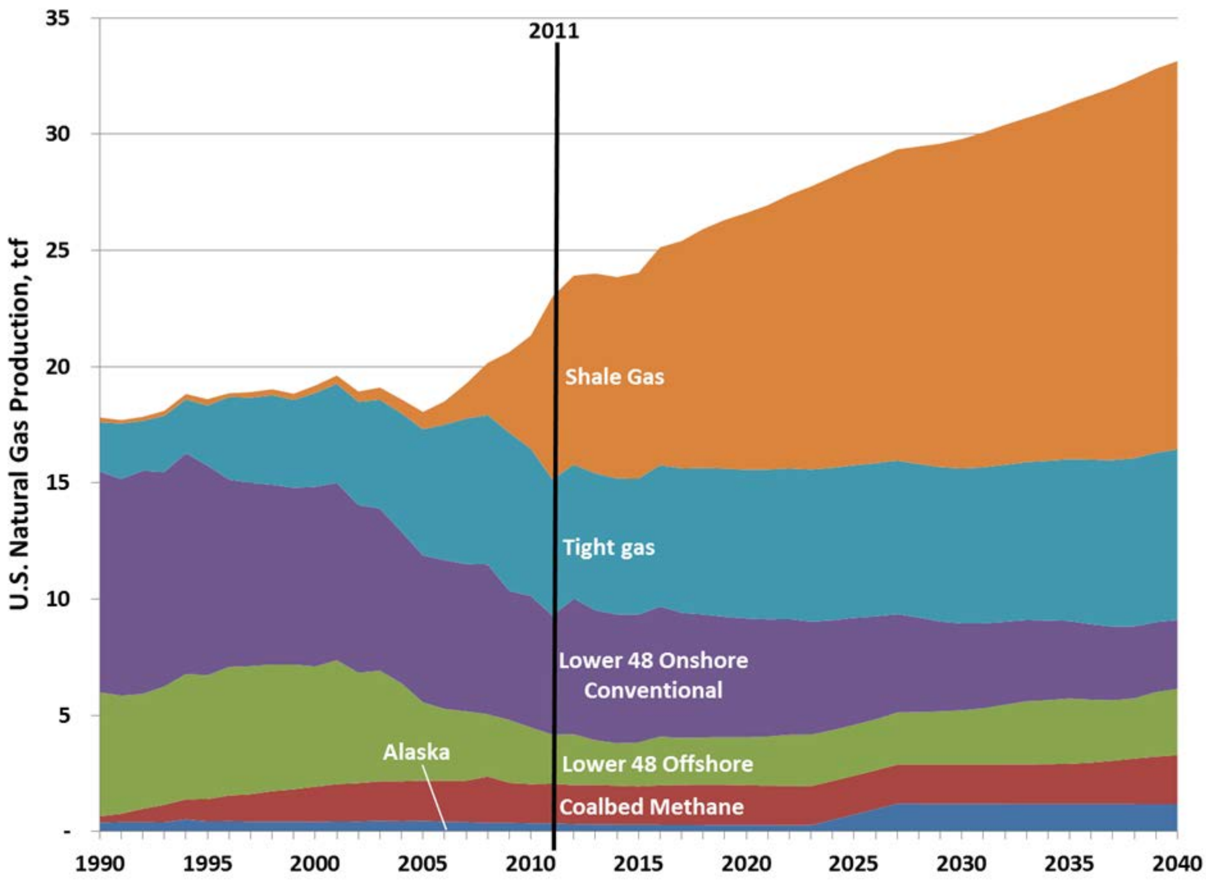
Fracturing fluids commonly consist of mostly water and sand along with other chemicals and additives. (NETL, 2009a) The specific additives, and the proportion of each, depend on the formation that is being fractured. These additives function as friction reducers, biocides, oxygen scavengers, stabilizers, and acids, all of which are necessary to optimize shale gas production. (NETL, 2009a) The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4, Water Use and Quality.

1.3 Unconventional Reserves and Production

There remain significant uncertainties in the estimates of the total technically recoverable natural gas reserves in the lower 48 states. Recent estimates range from 1,758 trillion cubic feet (tcf) in the EIA's Annual Energy Outlook 2013 [Early Release], to 2,129 tcf in the Colorado School of Mines' Potential Gas Committee, to 3,263 tcf ICF International's North American Shale Resource Assessments. Differences in these estimates represent combinations of data and assumptions about policies, technologies, future demand, prices, and macroeconomic conditions. For example, some states may continue to limit access to these resources. On the other hand, continuing technology advancements could increase recovery rates and lower production costs. (BPC, 2013)

The GAO analyzed EIA data and concluded that actual shale gas production grew from 1.6 tcf to 7.2 tcf between 2007 and 2011, over 75 percent of which came from the Barnett, Fayetteville, Marcellus, and Haynesville Shale plays. (GAO, 2012a) With increasing development, the EIA (2013a) forecasts a 44 percent net increase in natural gas production between 2011 and 2040 from increased development of unconventional resources: shale gas, tight gas, and CBM. The EIA estimates that the largest contribution to this growth will come from shale gas, where production is expected to increase by 113 percent, and which will grow from 34 percent to 50 percent of total production by 2040. Tight gas and CBM production will each increase by about 25 percent but their contributions to total production will decrease slightly, overshadowed by shale. Growth in CBM production is not expected to materialize until after 2035, when prices and demand levels raise enough to promote further drilling. But EIA estimates that, by about 2020, U.S. production will eliminate the need for net imports, and position the U.S. to become an exporter of natural gas. (EIA, 2013a) Exhibit 1-3 indicates that any significant increases in U.S. gas production will likely come from shale.

Exhibit 1-3 U.S. natural gas production by source, 1990 – 2040 (EIA, 2013a)



1.4 Overview of the Major Shale Plays

The EIA reports that 15 states produced shale gas in 2011: Arkansas, California, Colorado, Kentucky, Louisiana, Michigan, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming. Between 2007 and 2011, U.S. dry natural gas production increased by 19 percent, from approximately 19.3 to 22.9 tcf. In the same period, gross withdrawals from shale gas wells grew by 427 percent, from 1.99 to 8.50 Tcf, while CBM production fell by 11 percent, to 1,779,055 from 1,999,748 MMcf. In 2011, about 30 percent of U.S. natural gas production came from shale gas wells and about 6 percent from CBM wells with the remainder coming from other gas wells and oil wells (EIA does not differentiate tight gas sands production). (EIA, 2013b)

Of the states producing shale gas, Texas is the largest, accounting for 36 percent of 2011 production. Louisiana and Pennsylvania also each produced more than 1 million MMcf and together account for over 39 percent of 2011 shale gas production. Arkansas, Oklahoma, and Colorado round out the top states for shale gas production, and together make up over 17 percent of total production. Together, these 6 states produce about 92 percent of U.S. shale gas. (EIA, 2013b) Data characterizing some of the major shale plays in these states are tabulated in Exhibit 1-4.

Shale gas wells are marked by a rapid decline in production after strong initial production. Exhibit 1-5 below depicts the 30-day average production rate of shale gas wells in the Haynesville, Marcellus, and Barnett Shale plays. (MIT, 2011) In the early life of the well, much of the free natural gas is recovered in a short period of time. The sharp decline in productivity gradually slows, and the gradual decline generally lasts for a longer period. The production rate of an unconventional gas well over a long period of time depends greatly on the location of the fracture as well as the geologic makeup of the formation. (MIT, 2011)

Though shale gas wells are generally depleted more quickly than conventional gas wells, they also have the advantage of requiring less surface space than conventional gas wells. To develop a one square mile (mi^2) area for natural gas production using conventional vertical wells would require sixteen individual well pads for sixteen individual wells. If a number of horizontal wells were drilled to reach the same amount of space, only a single well pad and six-to-eight horizontal wells (each originating from that single well pad) would be required. (NETL, 2009a) Whereas vertical wells require spacing of 40 acres per well, the drill pads can be drilled from a single pad, so they require spacing of 160 acres per well. (NETL, 2009a)

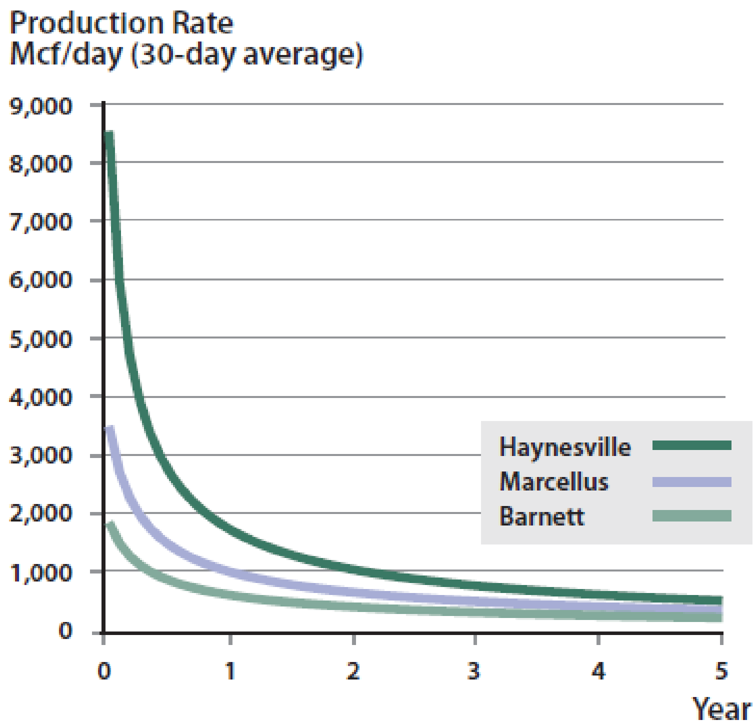
Exhibit 1-4 Data for shale gas formations in the U.S. (NETL, 2009a)

Parameter	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim
Location	Texas	Arkansas	Texas & Louisiana	Ohio, New York, Virginia, Pennsylvania, West Virginia,	Texas & Oklahoma	Michigan
Estimated Basin Area (mi^2)	5,000	9,000	9,000	95,000	11,000	12,000
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
Net Thickness (ft)	100-600	20-200	200-300	50-200	120-220	70-120
Total Organic Carbon (%)	4.5	4.0 – 98	0.5 – 4.0	3 – 12	1 – 14	1 – 20
Total Porosity (%)	4 – 5	2 – 8	8 – 9	10	3 – 9	9
Gas Content (scf/ton)	300 – 350	60 – 220	100 – 330	60 – 100	200 – 300	40 – 100
Well Spacing (acres)	60 – 160	80 – 160	40 – 560	40 – 160	640	40 – 160

Seeking to more accurately assess the decline trends and estimated ultimate recoveries (EURs) for shale plays, Baihly, et al. (2010) compared production trends for horizontal wells in the Barnett, Fayetteville, Woodford, Haynesville, and Eagle Ford plays to examine whether there had been improvements in production and potential EURs. While the decline curves for these five plays all follow the same general pattern illustrated in Exhibit 1-5, these authors did discern some notable patterns among the plays.

Initially, production rates in all of these plays tend to increase quickly and peak after about two months, and then production rates drop quickly before flattening out. Initial production rates vary across the plays, with the highest rates in the Haynesville, followed by the Eagle Ford, Woodford, Fayetteville, and then the Barnett. This ranking likely reflects both formation conditions and operational practices. Initial production rates over the first month increased for all of these plays, primarily due to improvements in drilling, completion, and stimulation and gains in knowledge.

Exhibit 1-5 30-day average production rate of representative wells (MIT, 2011)



1.5 Best Practices

In 2011, the Secretary of Energy formed a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production. In August 2011, the Shale Gas Production Subcommittee released its first 90-day report presenting 20 recommendations intended to reduce the environmental impacts of shale gas production. (SEAB 2011a) The Subcommittee stressed the importance of continuous improvement based on best practices and tied to measurement and disclosure. The recommendations were made in ten areas:

- *Improve public information about shale gas operations*: create a portal to share public information, including data from state and federal regulators
- *Improve communication among state and federal regulators*: continue annual support to STRONGER and the Groundwater Protection Council
- *Improve air quality*: take measures to reduce emissions of air pollutants, ozone precursors, and methane
- *Protect water quality*: adopt a systems approach to water management based on consistent measurement and public disclosure
- *Disclose fracturing fluid compositions*: accelerate progress in disclosure of all chemicals used in fracturing fluids
- *Reduce use of diesel fuel*: reduce use of diesel engines for surface power and replace with natural gas or electric engines where possible

- *Manage short-term and cumulative impacts to communities, land use, wildlife, and ecologies*: pay greater attention to combined impacts from drilling, production, and delivery activities and plan for shale development impacts on a regional scale
- *Organize for best practice*: create an industry organization for continuous improvement of best practice
- *Research and development needs*: significantly improve efficiency of shale gas production through technical advances (SEAB, 2011a)

On November 18, 2011, the Subcommittee released its second 90-day report (SEAB, 2011b) that focused on the recommendations from the first report (SEAB, 2011a). Noting that they had not prioritized their original recommendations, and that all of these recommendations required actions by some combination of federal officials, state officials, and public and private sector entities, the second report classified the recommendations into three categories:

1. Recommendations ready for implementation, primarily by federal agencies
2. Recommendations ready for implementation, primarily by states
3. Recommendations that require new partnerships and mechanisms for success

The Subcommittee recognized that successful implementation of its recommendations requires cooperation among and leadership by federal, state and local entities, reiterating from their first report their belief that a process of continuous improvement involves collaboration among industry, regulators, and affected communities and public interest groups. The Subcommittee expressed concern that advisory committee recommendations could be ignored and affirmed their responsibility to assess and report progress in the implementation of their recommendations. They viewed action as necessary in making progress toward reducing environmental impacts, and avoiding a risk to the future potential benefits of shale gas as a domestic energy resource.

Observing that natural gas is poised to enter into a "golden age," but that "this future hinges" on environmental concerns to be overcome, the International Energy Agency (IEA) proposed a set of "Golden Rules," which are principles by which policy-makers, regulators, operators, and other stakeholders can address environmental impacts. (IEA, 2012) The IEA sees water use, treatment and disposal of wastewater, and methane and air emissions as the major environmental impacts of unconventional gas production. The Golden Rules include

- *Measure, disclose, and engage*: Collect baseline and operational data, disclose, and engage local communities and other stakeholders.
- *Watch where you drill*: Minimize impacts with well siting and monitoring.
- *Isolate wells and prevent leaks*: Establish robust rules for operations and performance, and monitor to contain fracturing within producing formations.
- *Treat water responsibly*: Reduce use of fresh water, store and dispose of wastes safely, and minimize chemical additives.
- *Eliminate venting, minimize flaring and other emissions*: Set a target of zero venting and minimal flaring, and minimize combustion emissions.

- *Be ready to think big*: Seek economies of scale in developing local infrastructure and consider cumulative and regional environmental impacts; specifically, the impacts of water use and disposal, land use, air quality, traffic, and noise.
- *Ensure a consistently high level of environmental performance*: Balance prescriptive regulations and performance-based regulations (through robust regulatory regimes), including emergency response plans, continuous improvements, and independent evaluation and verification.

1.6 U.S. Statutory and Regulatory Framework

Multiple federal agencies have authority for unconventional natural gas development and production. The Environmental Protection Agency (EPA) regulates deep underground injection and disposal of wastewaters and liquids under the Safe Drinking Water Act (SWDA), as well as air emissions under the Clean Air Act. OSHA is responsible for quantifying standards for application in the oil and gas industry. On public lands, federal agencies are responsible for the enforcement of regulations that apply to unconventional gas wells. These agencies include the EPA, the Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration (OSHA), and the U.S. Forest Service (USFS). The BLM is responsible for protecting the environment on its lands during all oil and gas activities. The USFS is responsible for managing development on federally owned lands along with the BLM. (NETL, 2009a) If any types of oil and gas activities are proposed to take place within national park boundaries, the NPA may be able to apply regulations to protect park resources and visitor values, but the applicability of those regulations depends on each case.

Exhibit 1-6 gives some examples of the applicability of federal regulations to unconventional gas development, and Exhibit 1-7 provides the gaps in regulatory coverage under federal authority.

Exhibit 1-6 Selected federal regulations that apply to unconventional oil and gas development (CRS, 2009; NETL, 2009a)

Regulation	Applicability
Clean Air Act (CAA)	Places requirements on air emissions from sources of emissions at well sites. Addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally there is no distinction made between conventional and unconventional wells under the CAA.
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under CERCLA, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act (CWA)	Pollutant limits on produced water discharge under National Pollutant Discharge Elimination System; storm-water runoff containing sediments that would cause a water-quality violation require permits under CWA decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act (EPCRA)	Facilities storing hazardous chemicals above the threshold must report such and provide MSDS to officials and fire departments.
Endangered Species Act (ESA)	Section 7 prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat. Section 9 prohibits the taking of a listed species. Under Section 10, the Fish and Wildlife Service and National Marine Fisheries Service may issue a permit, accompanied by an approved habitat conservation plan that allows for the incidental, non-purposeful "take" of a listed species under their jurisdiction.
National Environmental Policy Act (NEPA)	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act (OPA)	Spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act (RCRA)	Subtitle D concerns non-hazardous solid wastes. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. The EPA has determined that other Federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act (SDWA)	Underground Injection Control (UIC) program preventing the injection of liquid waste into underground drinking water sources. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

Exhibit 1-7 Gaps in regulatory coverage under federal regulations (GAO, 2012b)

Regulation	Applicability
SDWA	Hydraulic fracturing with fluids other than diesel fuel does not require a UIC permit.
CWA	Federal storm-water permits are not required for uncontaminated stormwater at oil and gas construction sites or at oil and gas well sites
CAA	Emissions of hazardous air pollutants from oil and gas wells and their associated equipment may not be aggregated together or with those of pipeline compressors or pump stations to determine whether they are a major source. In the Risk Management Program, many naturally-occurring hydrocarbons in oil and gas are not included in the threshold determination of whether a facility should be regulated.
RCRA	Oil and gas exploration and production wastes are not regulated as hazardous waste.
CERCLA	Liability and reporting provisions do not apply to injections of fluids authorized by state law for production, enhanced recovery, or produced water.
EPCRA	Oil and gas well operations are not required to report releases of listed chemicals to the toxics release inventory (TRI).

The Western Interstate Energy Board (McAllister, 2012) described the importance of unconventional gas reservoirs, technical aspects of hydraulic fracturing, regulation, and potential environmental impacts. Although there are a number of other federal regulations that the unconventional gas industry must comply with, the SDWA is "of greatest importance to the sector." (McAllister, 2012) While state laws and regulations can vary, stringency has increased in recent years. State agencies typically oversee the well itself while local governments are generally responsible for upstream activities, such as road access to drilling sites. The potential environmental impacts include water and air quality, as well as seismic activity and noise. (McAllister, 2012)

In response to concerns raised by the rapid growth in the use of fracturing, the potential impacts to groundwater and drinking water resources, and calls for increased government oversight, the Congressional Research Service (CRS) reviewed past and proposed treatment of hydraulic fracturing under the SDWA. (Tiemann and Vann, 2012) The SDWA is the principal federal statute for regulating the underground injection of fluids. The Energy Policy Act of 2005 excluded hydraulic fracturing fluids and proppants (except diesel fuel) from the definition of "underground injection." Therefore, the EPA has no SDWA authority to regulate hydraulic fracturing unless diesel fuel is included in the waste fluids to be injected underground.

Two federal agencies have recently taken regulatory actions related to shale gas production. The EPA has applied new source performance standards and expanded mandatory greenhouse gas (GHG) reporting to include unconventional natural gas production. The BLM has proposed regulations for hydraulic fracturing on public and Indian lands.

In 2009, the EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule at Title 40 Code of Federal Regulations (CFR) Part 98 requiring the reporting of GHG data from large U.S. sources. This rule also requires suppliers to collect timely and accurate data to inform future policy decisions. (EPA, 2009) The petroleum and natural gas industry is covered under Subpart

W, and unconventional natural gas production is included under provisions for onshore production, natural gas processing, natural gas transmission and liquefied natural gas storage and import/export. Annual carbon dioxide, methane, and nitrogen oxide emissions must be reported separately for each of these segments. (EPA, 2012a)

On April 17, 2012, the EPA promulgated a final rule at 40 CFR Parts 60 and 63, entitled "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," under the CAA provisions for new source performance standards. (EPA, 2012b) The EPA expects the rule to reduce volatile organic compound (VOC) emissions by nearly 95 percent, mainly through "green" or "reduced emissions" completions that capture natural gas that currently escapes to the air. Reductions in VOC emissions will help reduce ground-level ozone in natural gas production areas and help protect against potential cancer risks from several air toxics, including benzene. Green completions also reduce methane emissions. The EPA estimates the combined rules will yield a cost savings of $11 to $19 million in 2015, because of the value of natural gas and condensate that will be recovered and sold, and the value of the climate co-benefits at $440 million annually by 2015. (EPA, 2012b)

The BLM oversees more than 750 million acres of federal and Indian mineral estates nation-wide, and on May 11, 2012, published a proposed rule to regulate hydraulic fracturing on public land and Indian land entitled "Oil and Gas Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands" at 43 CFR Part 3160. The rule would require public disclosure of the chemicals used in hydraulic fracturing on public land and Indian land, strengthen regulations related to well-bore integrity, and address issues related to flowback water (fluids used in hydraulic fracturing that are recovered from the well, which must then be disposed of). (BLM, 2012)

The BLM used comments on its proposed draft rule to make improvements and on May 24, 2013, published a supplemental notice seeking additional comments. (BLM, 2013) The updated draft included provisions to ensure the protection of usable water zones through an expanded set of cement evaluation tools, including a variety of logging methods, seismograms, and other techniques. Detailed guidance on the handling of trade secret claims modeled on State of Colorado procedures was added to address concerns that industry had voiced on the disclosure of fluid constituents that were considered to be proprietary. The BLM also sought opportunities to reduce cost and increase efficiency through coordination with individual states and tribes. (BLM, 2013)

States have the power to implement their own requirements and regulations for unconventional gas drilling under federal oversight. All of the states that produce gas have at least one agency to permit drilling wells, and many federal regulations for oil and gas production allow states to implement their own programs as long as these programs have been approved by the appropriate federal agencies. (NETL, 2009a) While state requirements differ, any requirements set forth in federal regulations must be met at a minimum – in other words, state requirements can be more stringent than federal regulations, but they cannot be less stringent than federal regulations.

The National Energy Technology Laboratory (NETL) and the Groundwater Protection Council (GWPC) evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy for protecting water resources. (NETL, 2009b) NETL reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. The report presented five key messages:

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of best management practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.
5. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

NETL (2011) concluded that oil and gas field activities are best regulated and managed at the state level where regional and local conditions are better understood. Effective regulatory programs use a set of tools that include formal and informal guidance, field rules, and BMPs, in addition to the regulations themselves. (NETL, 2011)

The National Conference of State Legislatures (Pless, 2012) introduces domestic natural gas production, describes legislative involvement at the state level, and summarizes the development of state legislation. Pless (2012) calls attention to public health and environmental impacts including protection of surface water, water withdrawals, air quality, habitat, and seismic activity. As of May 2012, which is when the most current data was available, legislatures in 19 states had introduced at least 119 bills and 9 states had enacted legislation. State policy actions fall into four categories:

1. *Increasing Transparency*: Disclosure of fracturing fluid chemical and additives.
2. *Generating Revenue through Taxes and Fees*: Severance taxes for resources "severed" from the earth can provide significant revenue streams and impact fees can benefit local communities.
3. *Water Quality Protection*: Leak and spill prevention, wastewater transportation, waste treatment and disposal regulations, and well location restrictions help protect water quality.
4. *Monitoring to Improve Knowledge Base*: Water withdrawal and quality monitoring can protect water resources. Some states have instituted moratoria on drilling until more is known about the impacts, including New Jersey and Vermont. Other states, such as Illinois, Michigan, New York, North Carolina, Ohio, and Pennsylvania, have legislation pending various moratoria. New Jersey's moratorium was for one year, while Vermont's

completely prohibits hydraulic fracturing within the state. Pending legislation would provide for impact studies and assessments, prohibit hydraulic fracturing, or establish moratoria pending the outcome of other studies.

Pless (2012) then tabulated the state legislative proposals in each of these categories as well as legislation addressing authority to regulate. Almost half of the pending legislation addressed water quality protection.

The U.S. Government Accountability Office (GAO) released a report in 2012 that analyzed the requirements for oil and gas development activities. Six states, which have requirements above and beyond federal requirements, and which have updated their requirements in the recent past, were included: Colorado, North Dakota, Ohio, Pennsylvania, Texas, and Wyoming. GAO also analyzed federal and state environmental and public health requirements (summarized in Exhibit 1-8). Of the six reviewed states, Colorado, Ohio, and Pennsylvania have also voluntarily agreed to have parts of their oil and gas regulations reviewed by STRONGER. (GAO, 2012b) As of December 19, 2013, the STRONGER website states that "22 state regulatory programs, representing over 94% of domestic O&G production," have volunteered and have been successfully reviewed." (STRONGER, 2013)

Exhibit 1-8 Environmental and public health requirements established by the EPA and six states

Regulation		EPA Requirements	State Requirements
Siting and site preparation	Identification or testing of water wells prior to drilling of production wells	No	CO, OH, WY
	Required setbacks from water sources	No	CO, ND, PA, OH, WY
	Stormwater permitting	No	CO, ND, PA, WY
Drilling, casing, and cementing	Requirements relating to cementing/casing plans	No	CO, ND, PA, OH, TX, WY
	Prescribed placement of surface casing relative to groundwater zones	No	CO, ND, PA, OH, TX, WY
Hydraulic fracturing	Requirements to disclose information on fracturing fluids	No	CO, ND, PA, OH, TX, WY
Well plugging	Requirements for notification, plugging plan or method, witnessing, and reporting	No	CO, ND, PA, OH, TX, WY
	Programs to plug wells that are not properly plugged and have been abandoned	No	CO, ND, PA, OH, TX, WY
Site reclamation	Requirements for backfilling, regarding, recontouring, and alleviating compaction of soil	No	CO, ND, PA, OH, TX, WY
	Revegetation requirements	No	CO, ND, OH, PA, WY
Waste management	Pit lining requirements	No	CO, ND, PA, TX, WY
	Underground injection (except injection of diesel)	SDWA	CO, ND, OH, TX, WY
	Direct discharge to surface water	CWA	CO, TX, WY allow in certain cases
	Requirements for discharge to POTWs or CWT facilities	CWA	OH, PA (POTWs) CO, PA, WY (CWTs)
	Recycling or other reuse	CWA	CO, ND, OH, PA, TX, WY
	Solid waste disposal	No	CO, ND, OH, PA, TX, WY

Regulation		EPA Requirements	State Requirements
	Hazardous waste disposal	No	No
Managing air emissions	Requirements for CAPs	CAA	CO, ND, OH, TX, WY
	Requirements for HAPs	CAA	Maybe
	Requirements related to H_2S gas	No	CO, ND, OH, PA, TX, WY
	Requirements related to flaring	NSPS	CO, ND, OH, PA, TX, WY

Another analysis was completed by Resources for the Future's (RFF) Center for Energy Economics and Policy website (RFF, 2012), which looked at requirements in 31 U.S. states that either have shale gas production development or could have some in the near future. This review examined similar items related to shale gas development, organized into five general categories (RFF, 2012):

- Site development and preparation
- Well drilling and production
- Flowback and wastewater storage and disposal
- Well plugging and abandonment
- Well inspection and enforcement

In June 2013, RFF released a full report containing an analysis of state regulations and requirements pertaining to shale gas development, which synthesized much of the information available on the website tool into an actual document. (RFF, 2013) This analysis determined that there is little similarity in the way states are regulating the various categories of shale gas development. The report did not suggest that one method was better than another, but instead identified the differences from state to state. (RFF, 2013) The state-by-state breakdown of the analysis from RFF can be found in the tables in Section 1.9, at the end of this chapter. Exhibit 1-4, below, provides one more example of the variation among state requirements. This table presents a comparison of hydraulic fracturing chemical disclosure regulations among eight states that are producing natural gas from shale play formations. (KPMG, 2012)

Exhibit 1-9 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.*

1.7 Federal Research and Development Programs

In 2011, the Department of Energy (DOE) delineated the technical challenges for unconventional gas development as part of the R&D program managed by NETL under the Energy Policy Act of 2005. The technical challenges for tight gas include improved understanding of the geologic environments and the environmental and safety risks, and the development of improved technologies for drilling, sensors, development and production. For coalbed methane, the challenges include improved understanding of the resource, water management, and improved drilling and production, including multi-seam completions. Shale gas has many of the same challenges, including improving understanding of the risks, gaining better understanding of the geologic environments, water management, and improved drilling, development, and production technologies. (DOE, 2011)

The DOE shale gas program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop oil and gas technologies under Section 999 of the Energy Policy Act of 2005. The work focuses on safety, environmental sustainability, and calculating the risks of oil and gas exploration and production undertakings. DOE has funded a number of technology investigations through NETL that deal with produced water management. DOE has been developing a tool that can be used to help the operators of oil and gas operations to meet challenges presented in reducing, reusing, and disposing of produced water from wells. (DOE, 2013a) Fact sheets (NETL, 2013) have been produced for various practices for produced water during the operation of wells, including:

- *Water Minimization*: Reducing the volume of produced water both entering the well and flowback at the surface.
- *Water Recycling and Reuse*: Investigating alternative uses for produced water, such as underground injection, use in agricultural settings, and use in industrial settings.
- *Water Treatment and Disposal*: Discovering methods to remove impurities from the produced water and permanently dispose of the produced water.

NETL is also conducting research to improve the assessment of air quality impacts in the field with a mobile air monitoring laboratory, and then using these data to model atmospheric chemistry and chemical transport to better understand local and regional impacts. (DOE, 2013b) These are some of the goals of this research:

- *Document Environmental Changes*: Distinguishing the changes that occur during each phase of shale gas production (e.g., site construction, drilling, well completion, early production, and production after site remediation).
- *Develop Technology and Management Practices*: Mitigating undesired environmental changes
- *Develop Monitoring Techniques*: Increasing sensitivity and speed while decreasing costs

Projects include efforts to determine air quality, detect fugitive emissions, detect unwanted migration of production fluids, locate existing wells and pipelines, and document changes in avian populations. (DOE, 2013b) Additionally, DOE is collaborating with other agencies on the EPA's hydraulic fracturing study. (EPA, 2012c)

The EPA cooperates with key stakeholders to make sure that unconventional gas resources are managed responsibly and do not inflict unnecessary damage on the environment and on the public. (EPA, 2013) In 2010, at the request of Congress, the EPA initiated a study to better understand any potential impacts of hydraulic fracturing on drinking water and ground water. The overall purpose of the study is to elucidate the relationship, if any, between hydraulic fracturing and drinking water resources, and to identify the driving factors that affect the severity and frequency of any impacts. (EPA, 2011) In their plan, the EPA designed their study to provide decision-makers and the public with answers to five fundamental questions associated with the hydraulic fracturing water life cycle:

- *Water Acquisition*: What are the potential impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- *Chemical Mixing*: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources?
- *Well Injection*: What are the possible impacts of the injection and fracturing process on drinking water resources?
- *Flowback and Produced Water*: What are the possible impacts of surface spills on or near well pads of flowback and produced water on drinking water resources?
- *Wastewater Treatment and Waste Disposal*: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

In December 2012, the EPA published the first progress report for their study (EPA, 2012c) describing 18 research projects that are underway, including analyses of existing data, scenario evaluations, laboratory studies, toxicity assessments, and case studies. The EPA plans to publish an additional report in 2014 to synthesize the results of the long-term projects and the information released in the 2012 progress report. (EPA, 2011)

The USGS operates both the Energy Resources Program (ERP) and the John Wesley Powell Center for Analysis and Synthesis. The ERP performs oil and gas resources assessments for the United States as well as the world, synthesizing information used to develop energy policies and resource management plans, as well as researching hydraulic fracturing and produced water. (USGS, 2010; USGS, 2013a) The USGS has developed a screening process that can be used to determine whether unconventional gas resources exist in a given location. The process of hydraulic fracturing and the resulting produced water and other fluids play a large role in the exploration and development of unconventional resources. (USGS, 2010)

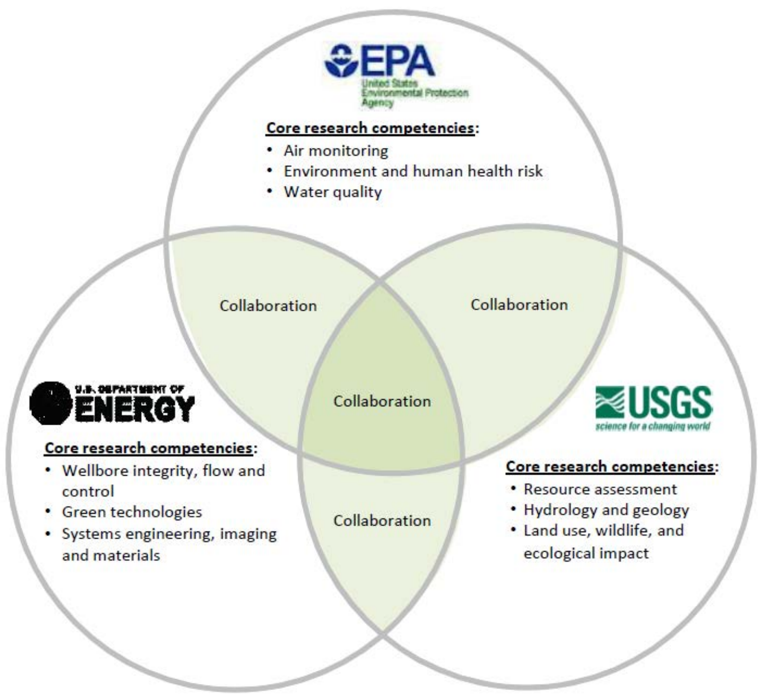
Current working groups of the Powell Center for Analysis and Strategy include one assessing the potential effect of developing shale gas resources on surface and groundwater and another investigating seismicity resulting from the injection of fluids. (USGS, 2013b) The water quality investigation includes a number of objectives: (USGS, 2012)

- *Hydraulic Fracturing*: Gain better understanding of the hydraulic fracturing process in the U.S.
- *Water Quality*: Investigate surface and ground water quality near unconventional gas production, possible water quality changes due to production operations, and gather baseline water quality data near the production operations.

- *Data Gaps*: Determine areas where further investigation is necessary for evaluation.
- *Future Work*: Ascertain future work that can help increased understanding of how unconventional gas production effects water quality.

In March of 2011, the White House released a plan (Executive, 2011) that presented ways to make America's energy supply safer and stronger, give energy consumers options to lower energy usage and costs, and work toward a future with clean energy. DOE, Department of the Interior (DOI), and the EPA were charged with formulating a research plan that will examine the most pressing issues related to unconventional oil and gas resources and how these resources can be developed responsibly. (DOE/DOI/EPA, 2012a) Each of the involved agencies brings to the table certain core competencies that are utilized in the development of this plan, as seen in Exhibit 1-5.

Exhibit 1-10 Core competencies of DOE, DOI, and the EPA in support of the Multi-Agency Collaboration (DOE/DOI/EPA, 2012a; DOE/DOI/EPA, 2012b)



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1.9 State Regulatory Requirements

Exhibit 1-11 Selected state site development and preparation requirements (RFF, 2012)

State	Pre-Drilling Water Well Testing	Water Withdrawals	Setback Restrictions from Buildings	Setback Restrictions from Water Sources
Alabama		x	x	x
Arkansas		x	x	x
California		x	x	x
Colorado	x	x	x	x
Georgia		x	x	x
Illinois	x	x	x	x
Indiana		x		
Kansas		x		x
Kentucky			x	x
Louisiana		x	x	x
Maryland		x	x	x
Michigan		x	x	x
Mississippi		x		
Montana		x		
Nebraska	x	x		
New Jersey		x	x	
New Mexico		x	x	x
New York	x	x	x	x
North Carolina		x		
North Dakota	x	x	x	x
Ohio	x	x	x	x
Oklahoma	x	x		
Pennsylvania		x	x	x
South Dakota		x		
Tennessee		x	x	x
Texas		x	x	x
Utah		x		
Vermont		x		
Virginia	x	x	x	x
West Virginia	x	x	x	x
Wyoming		x	x	x

Exhibit 1-12 Selected state well drilling and production requirements (RFF, 2013)

State	Natural Gas Wells and Shale Gas Production	Cement Type Regulations	Casing and Cementing Depth	Surface Casing Cement Circulation Regulations	Intermediate Casing Cement Circulation Regulations	Production Casing Cement Circulation Regulations	Venting Regulations	Flaring Regulations	Fracking Fluid Disclosure
Alabama	x	x	x	x	x	x	x	x	
Arkansas	x		x	x		x			x
California	x	x	x	x	x	x			
Colorado	x		x	x	x	x	x	x	x
Georgia		x	x	x		x			
Illinois	x		x	x		x		x	x
Indiana	x	x	x	x	x	x			
Kansas	x	x	x	x	x	x	x	x	
Kentucky	x		x	x	x		x	x	
Louisiana	x		x	x	x	x	x	x	x
Maryland	x	x	x	x	x	x			x
Michigan	x	x	x	x	x	x	x	x	x
Mississippi	x		x	x		x	x	x	
Montana	x	x	x	x			x	x	x
Nebraska	x	x	x	x	x	x	x	x	
New Jersey			x						
New Mexico	x		x	x	x	x	x	x	x
New York	x	x	x	x	x	x	x	x	x
North Carolina			x	x		x			
North Dakota	x		x	x	x	x	x	x	x
Ohio	x	x	x	x	x	x	x	x	x
Oklahoma	x		x	x	x	x	x	x	x
Pennsylvania	x	x	x	x	x	x	x	x	x
South Dakota	x	x	x	x	x	x	x	x	

State	Natural Gas Wells and Shale Gas Production	Cement Type Regulations	Casing and Cementing Depth	Surface Casing Cement Circulation Regulations	Intermediate Casing Cement Circulation Regulations	Production Casing Cement Circulation Regulations	Venting Regulations	Flaring Regulations	Fracking Fluid Disclosure
Tennessee	x		x	x			x	x	
Texas	x	x	x	x	x	x	x	x	x
Utah	x	x	x	x			x	x	
Vermont									
Virginia	x						x	x	
West Virginia	x	x	x	x	x	x	x	x	x
Wyoming	x	x	x	x	x	x	x	x	x

Exhibit 1-13 Selected state flowback and wastewater storage and disposal requirements (RFF, 2013)

State	Fluid Storage Options	Freeboard Requirements	Pit Liner Requirements	Flowback/ Wastewater Transportation Tracking	Underground Injection Wells for Flowback and Produced Water Permitted Statewide
Alabama	x	x	x	x	x
Arkansas	x	x	x	x	x
California	x				x
Colorado	x	x	x	x	x
Georgia	x	x	x		x
Illinois	x		x	x	x
Indiana	x				x
Kansas	x	x	x	x	x
Kentucky	x	x	x	x	x
Louisiana	x	x	x	x	x
Maryland	x	x			x
Michigan	x		x	x	x
Mississippi	x	x	x		x
Montana	x	x	x		x
Nebraska	x	x	x	x	x
New Jersey					x
New Mexico	x	x	x	x	x
New York	x	x	x	x	x
North Carolina	x				
North Dakota	x		x	x	x
Ohio	x			x	x
Oklahoma	x	x	x	x	x
Pennsylvania	x	x	x	x	x
South Dakota	x		x		x
Tennessee	x		x		x
Texas	x			x	x
Utah	x	x	x		x
Vermont					x
Virginia	x	x	x		x
West Virginia	x	x	x	x	x
Wyoming	x		x		x

Exhibit 1-14 Selected state well plugging and abandonment requirements (RFF, 2013)

State	Well Idle Time	Temporary Abandonment
Alabama	x	x
Arkansas	x	x
California	x	
Colorado	x	x
Georgia	x	
Illinois	x	x
Indiana	x	x
Kansas	x	x
Kentucky		x
Louisiana	x	x
Maryland	x	x
Michigan	x	x
Mississippi	x	x
Montana	x	
Nebraska	x	x
New Jersey		
New Mexico	x	x
New York	x	x
North Carolina	x	
North Dakota	x	x
Ohio	x	x
Oklahoma	x	x
Pennsylvania	x	x
South Dakota		x
Tennessee	x	x
Texas	x	x
Utah	x	x
Vermont	x	x
Virginia		
West Virginia	x	
Wyoming	x	x

Exhibit 1-15 Selected state well inspection and enforcement requirements (RFF, 2013)

State	Accident Reporting Requirements	Number of Regulating State Agencies	Number of Wells per Inspector
Alabama	x	2	501 to 1,630
Arkansas	x	3 to 6	141 to 360
California		3 to 6	0 to 30
Colorado	x	2	501 to 1,630
Georgia	x	1	0 to 30
Illinois	x	2	N/A
Indiana	x	2	31 to 140
Kansas	x	2	501 to 1,630
Kentucky	x	3 to 6	N/A
Louisiana	x	2	361 - 500
Maryland	x	1	0 to 30
Michigan	x	1	141 to 360
Mississippi	x	2	141 to 360
Montana	x	2	N/A
Nebraska	x	2	31 to 140
New Jersey	x	0	0 to 30
New Mexico	x	2	1,631 to 2,980
New York	x	1	N/A
North Carolina		1	0 to 30
North Dakota	x	2	0 to 30
Ohio		2	31 to 140
Oklahoma	x	2	501 to 1,630
Pennsylvania	x	2	141 to 360
South Dakota	x	1	0 to 30
Tennessee		2	31 to 140
Texas	x	2	501 to 1,630
Utah	x	2	N/A
Vermont		1	0 to 30
Virginia	x	3 to 6	501 to 1,630
West Virginia	x	1	N/A
Wyoming	x	3 to 6	501 to 1,630

Exhibit 1-16 Selected state moratorium and tax requirements (RFF, 2013)

State	State and Local Bans and Moratoria	Severance Tax Calculation Method	Severance Tax Rates in Percentage Terms	Severance Tax Rates in cents/Mcf
Alabama		Pct of gas value	7.01% to 9.00%	17.21 to 22.1
Arkansas		Pct of gas value	3.81% to 5.00%	9.41 to 12.3
California		Fixed amt per unit	0.02% to 0.53%	0.05 to 1.3
Colorado	1	Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Georgia		None	None	None
Illinois	1	Pct of gas value	0.02% to 0.53%	0.05 to 1.3
Indiana		Fixed amt per unit	0.54% to 1.20%	1.31 to 3.0
Kansas		Pct of gas value	7.01% to 9.00%	17.21 to 22.1
Kentucky		Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Louisiana		Fixed amt per unit	5.01% to 7.00%	12.31 to 17.2
Maryland	1	Pct of gas value	5.01% to 7.00%	17.21 to 22.1
Michigan	1	Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Mississippi		Pct of gas value	5.01% to 7.00%	12.31 to 17.2
Montana		Pct of gas value	7.01% to 9.00%	17.21 to 22.1
Nebraska		Pct of gas value	1.21% to 3.80%	3.1 to 9.4
New Jersey	1	None	None	None
New Mexico	1	Pct of gas value	1.21% to 3.80%	3.1 to 9.4
New York	1	None	None	None
North Carolina	1	Fixed amt per unit	0.02% to 0.53%	0.05 to 1.3
North Dakota		Fixed amt per unit	1.21% to 3.80%	3.1 to 9.4
Ohio	1	Fixed amt per unit	0.54% to 1.20%	1.31 to 3.0
Oklahoma		Pct of gas value	5.01% to 7.00%	12.31 to 17.2
Pennsylvania	1	None	None	None
South Dakota		Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Tennessee		Pct of gas value	1.21% to 3.80%	3.1 to 9.4
Texas	1	Pct of gas value	7.01% to 9.00%	17.21 to 22.1
Utah		Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Vermont	1	None	None	None
Virginia		Pct of gas value	0.54% to 1.20%	1.31 to 3.0
West Virginia	1	Pct of gas value	3.81% to 5.00%	9.41 to 12.3
Wyoming		Pct of gas value	5.01% to 7.00%	12.31 to 17.2

2 Greenhouse Gas Emissions and Climate Change

Greenhouse gas (GHG) emissions are released by the natural gas supply chain, and the extent to which these emissions contribute to climate change has been investigated by government and university researchers. There are five major studies that account for the GHG emissions from upstream natural gas. (Upstream natural gas includes the construction and completion of gas wells, as well as subsequent production, processing, and transport steps.) While a number of studies have been conducted on this topic, these five studies represent the breadth of all natural gas life cycle work and point to the methane emissions from unconventional well completions and workovers[1] as a key difference between the GHG profiles of conventional and unconventional natural gas. Other key emissions occur during steady-state operations, such as emissions from compressors and pipelines. The assumptions and parameters of the five studies vary, but, given their uncertainties, four of the five studies conclude that the GHG emissions from a unit of delivered unconventional natural gas are comparable to (if not lower than) those from a unit of conventional natural gas. The fifth study concludes that the high methane emissions from unconventional well completion and a lack of environmental controls at unconventional extraction sites translates to higher GHG emissions from unconventional natural gas than from conventional natural gas.

2.1 A Life Cycle Perspective

A system-level perspective is necessary to account for all sources of GHG emissions in the production of unconventional natural gas, and to evaluate their relative contributions and mitigation opportunities. Life cycle analysis (LCA) is one type of systems approach, and accounts for the material and energy flows of a system from cradle to grave, where the cradle is the extraction of resources from the earth, and the grave is the final use and disposition of products.

The Department of Energy's (DOE) National Energy Technology Laboratory (NETL) used LCA to calculate the environmental impacts of natural gas production and use for electric power generation. NETL documented this work in a series of reports between 2010 and 2014:

- *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant.* DOE/NETL-403-110509 (NETL, 2010)
- *Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production.* DOE/NETL-2011/1522 (NETL, 2011)
- *Role of Alternative Energy Sources: Natural Gas Technology Assessment.* DOE/NETL-2012/1539 (NETL, 2012)
- *Life Cycle Analysis of Natural Gas Extraction and Power Generation.* DOE/NETL-2014/1646 (NETL, 2014)

The GHG results in the NETL 2014 report supersede the GHG results in the previous NETL reports. (NETL, 2014) Together, these reports provide an in-depth assessment of the GHG impacts of unconventional natural gas production with traceable and transparent documentation

1 "Workover" is a generic industry term for a variety of remedial actions to stimulate or increase production. As applied here to shale gas wells, it means hydraulic fracturing treatments after the initial drilling and first hydraulic fracturing of the well.

of the methods, data sources, and results of an LCA approach, and serve as a basis for comparison of results from similar studies.

NETL's life cycle model of upstream natural gas production is based on a network of unit processes. Each unit process accounts for the raw materials, energy consumption, and environmental emissions of a specific activity in the natural gas life cycle. NETL's model has over 30 unit processes that are directly related to the natural gas life cycle. Furthermore, most of these unit processes have secondary and tertiary unit processes that account for the energy and material flows of upstream energy and material production. The unit processes are based on engineering principles that make it possible to adjust parameters in order to represent specific scenarios. The following examples describe the boundaries and parameters for key unit processes in NETL's natural gas model. This is not an exhaustive listing of all unit processes in the model, but summarizes key components of the model:

- *Well construction* accounts for the steel and concrete used for a wellbore and casing. It includes parameters that scale the steel and concrete requirements according to well depth. The use of steel and concrete is not a direct source of GHG emissions, but, from a life cycle perspective, the fuels and materials used for steel and concrete production do produce GHG emissions. When connected to other unit processes in the model, the construction requirements are scaled to a unit of natural gas production based on the lifetime production rate of the well.
- *Well completion* accounts for the impulse of natural gas that escapes the well during development. Shale gas wells have higher completion emissions than conventional wells due to the natural gas entrained in the flowback water from hydraulic fracturing.
- *Well workovers* account for the impulse of natural gas that escapes the well during the re-fracture of an unconventional well, or the maintenance of the wellbore of a conventional well. For shale gas wells, workovers includes hydraulic fracturing treatments after the initial drilling and first hydraulic fracturing of the well.
- *Liquid unloading* accounts for the impulse of natural gas that escapes the well during the removal of liquids that gradually accumulate in a wellbore of a conventional well.
- *Venting and flaring* accounts for emissions from the venting or flaring of natural gas that escape a well during completion, workover, or liquid unloading, as well as natural gas that is captured during steady-state production or processing. This process is applied at multiple points in NETL's model, particularly, any instance where venting can be controlled. If capture equipment is not used, natural gas is vented directly to the atmosphere. If capture equipment is used, vented streams are flared before being released to the atmosphere. This unit process includes parameters that account for the share of gas that is vented versus gas that is flared. For example, if 15 percent of the gas vented during the completion of an unconventional well is flared, NETL's model tunes the associated venting and flaring process so that 15 percent of completion emissions are converted to CO_2 via flaring, and the remaining 85 percent of completions emissions are released to the atmosphere.
- *Acid gas removal* accounts for amine solvent consumption, the combustion of natural gas used to heat a reboiler, and emissions of volatile organic compounds from the absorber tower. Most natural gas processing plants use acid gas removal systems that have an absorber tower that contacts a stream of amine-based solvent with a stream of raw natural

gas. The acid-rich amine stream is then sent to a stripper tower with a reboiler. The reboiler heats the stream, which drives acid gas from the solvent and allows the solvent to be returned to the scrubber. In NETL's model, this process includes parameters for amine consumption rate and reboiler duty.

- *Pipeline operation* accounts for the natural gas and electricity used to power compressors, and the fugitive emissions of methane from the pipeline transmission network. It includes parameters for natural gas transport distance, fugitive emissions through compressor seals, and the mix of gas- and electrically-powered compressors.

The flexible, consistent framework of NETL's model allows different natural gas sources to be compared on a common basis. NETL has published results for three conventional gas types (onshore, associated, and offshore) and four unconventional types (tight gas, coalbed methane, Barnett Shale, and Marcellus Shale). NETL's results also include an average domestic mix scenario, which is an aggregate of all gas types, weighted by their 2010 supply share.

Exhibit 2-1 shows key parameters in NETL's natural gas model and demonstrates how differences among extraction technologies are handled. In addition to expected values, the parameters for average production rate and flaring rate have low and high bounds that account for uncertainty.

Exhibit 2-1 Key parameters for natural gas extraction (NETL, 2014)

Property (Units)		Onshore	Offshore	Associated	Tight Gas	Barnett Shale	Marcellus Shale	CBM
Natural Gas Source								
Contribution to 2010 U.S. Domestic Supply		22%	12%	6.6%	27%	21%	2.5%	9.4%
Average 30-year Daily Production Rate (Mcf/well-day)	Low	46	1,960	85	77	192	201	73
	Expected Value	66	2,800	121	110	274	297	105
	High	86	3,641	157	143	356	450	136
Expected Estimated Ultimate Recovery (BCF)		0.72	30.7	1.32	1.20	3.00	3.25	1.15
Natural Gas Extraction Well								
Flaring Rate (%)		51% (41 - 61%)			15% (12 - 18%)			
Well Completion (Mcf natural gas/episode)		37.0			3,600	9,000		49.6
Well Workover (Mcf natural gas/episode)		2.44			3,600	9,000		49.6
Lifetime Well Workovers (Episodes/well)		1.1			0.3			
Liquids Unloading (Mcf/episode)		3.57		n/a				
Lifetime Liquid Unloadings (Episodes/well)		930		n/a				
Valve Emissions, Fugitive (lb. CH_4/Mcf)		0.11	0.0001	0.11				
Other Sources, Point Source (lb. CH_4/Mcf)		0.003	0.002	0.003				
Other Sources, Fugitive (lb. CH_4/Mcf)		0.043	0.1	0.043				

The parameters for the volume of natural gas vented during well completions and workovers, the frequency of well workovers, and the flaring rates of captured gas are key drivers of NETL's GHG results. (NETL, 2014) To characterize these parameters, NETL uses factors from the technical support document that the Environmental Protection Agency (EPA) uses in support of its national GHG inventory of the petroleum and natural gas sectors. (NETL, 2014; EPA, 2010).

New data for natural gas extraction emissions became available after the release of EPA's 2010 technical support document. EPA revised its emission factor for unconventional well completions and workovers in 2012 (from 9,175 to 9,000 Mcf of natural gas per episode). (EPA,

2012) Additionally, new parameters for liquid unloading emissions and unconventional workover frequency were developed based on data collected by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) from gas producers in 2010 and 2011. (Shires et al., 2012) These parameter changes are represented in Exhibit 2-1.

The supply contributions from seven natural gas sources to the domestic supply, as shown in Exhibit 2-1, are representative of the 2010 United States (U.S.) natural gas supply, and were derived from data in the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). (2012) The production rates for each natural gas source are expressed as daily rates and estimated ultimate recovery (EUR) and are representative of single wells over a 30-year time frame. (NETL, 2014) The average daily production rate can be reconciled with the EUR by factoring the expected value for daily production rate by 10,950 days (the number of days in 30 years) and converting from thousand cubic feet (Mcf) to billion cubic feet. While the contributions to the domestic supply mix are representative of 2010 production, the production rates are representative of average 30-year performance. The different time frames represented by the 2010 contributions to the U.S. supply and 30-year production rates do not represent an inconsistency from an LCA perspective. The supply contributions are used to calculate an aggregated environmental profile of seven natural gas sources in a specific year, while the production rates are used to apportion episodic emissions that occur over a 30-year period (e.g., construction, completion, workover, and liquid unloading emissions) per unit of produced natural gas.

The expected flaring rates for conventional and unconventional wells are 51 percent and 15 percent, respectively. (EPA, 2010) The flaring rates are lower for unconventional wells because early development activities in unconventional plays did not follow best practices for emission controls. The flaring rate represents the portion of captured gas that is flared instead of directly vented to the atmosphere. For example, of all the gas that escapes during the completion or workover of an unconventional well, 15 percent is combusted by flaring and the remaining 85 percent is vented to the atmosphere. (NETL, 2014) As reduced emission completions become standard industry practice, average flaring rates will increase. (Shires et al., 2012) Section 2.3 includes a discussion on how flaring rates are variable, and could be as high as 97 percent for unconventional wells. Such an increase in flaring *rate* does not necessarily contradict IEA's "Golden Rules" (IEA, 2012), as discussed in Chapter 1. If a given amount of natural gas is lost by a natural gas system, it is preferable from a climate change perspective to flare it to CO_2 instead of releasing it to the atmosphere as methane (NETL, 2014). In contrast, IEA's recommendation is based on the goal of zero venting, in which flaring is not required (IEA, 2012). Zero venting is the ultimate goal, but if venting happens, then it is environmentally preferable to flare it.

A key distinction between conventional and unconventional wells is that unconventional wells require more reservoir stimulation than conventional wells. The key obstacle during the exploration and development of conventional wells is finding productive gas formations – formations that do not require stimulation once they have been drilled. In contrast, unconventional formations are easier to locate than conventional formations, but require hydraulic fracturing or other stimulation techniques to cause gas to flow to the surface, and periodic workovers to boost the performance of wells with declined production rates. (NETL, 2014) The workover rates of unconventional wells, and shale gas wells in particular, is highly uncertain. Shale gas wells are a new extraction technology and few shale gas wells have been in operation for 30 years (the time period of NETL's natural gas LCA). Data collected by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) show that the workover rates for shale gas wells may be one-tenth of the unconventional workover rates calculated by the EPA in 2010. (Shires et al., 2012; EPA, 2010)

Exhibit 2-2 shows the upstream GHG emissions from eight sources of natural gas: three conventional extraction scenarios, four unconventional extraction scenarios, and a liquefied natural gas (LNG) import scenario. The blue bars represent the GHG emissions from raw material acquisition (extraction and processing), and the orange bars represent the GHG emissions from the transmission of natural gas by the U.S. natural gas pipeline system. These results do not include the distribution of natural gas, which is an additional transport step beyond transmission that moves natural gas to small-scale users such as commercial or residential customers. The horizontal black line in Exhibit 2-2 shows the emissions from the 2010 domestic natural gas mix, which was calculated by applying the 2010 supply contributions to the seven gas types (as defined in Exhibit 2-1). These emissions are expressed in terms of 100-year global warming potential (GWP) as recommended by the Intergovernmental Panel on Climate Change (IPCC). (IPCC, 2007) GWPs normalize GHG species to a common basis. For example, the 2007 version of IPCC's GWPs show that the radiative forcing of CH_4 is 25 times greater than CO_2 over a 100-year period; to arrive at a common basis, the life cycle results for methane are multiplied by 25 so CO_2 and CH_4 can be expressed in common units – carbon dioxide equivalents (CO_2e). More details on GWPs are provided in Section 2.3.

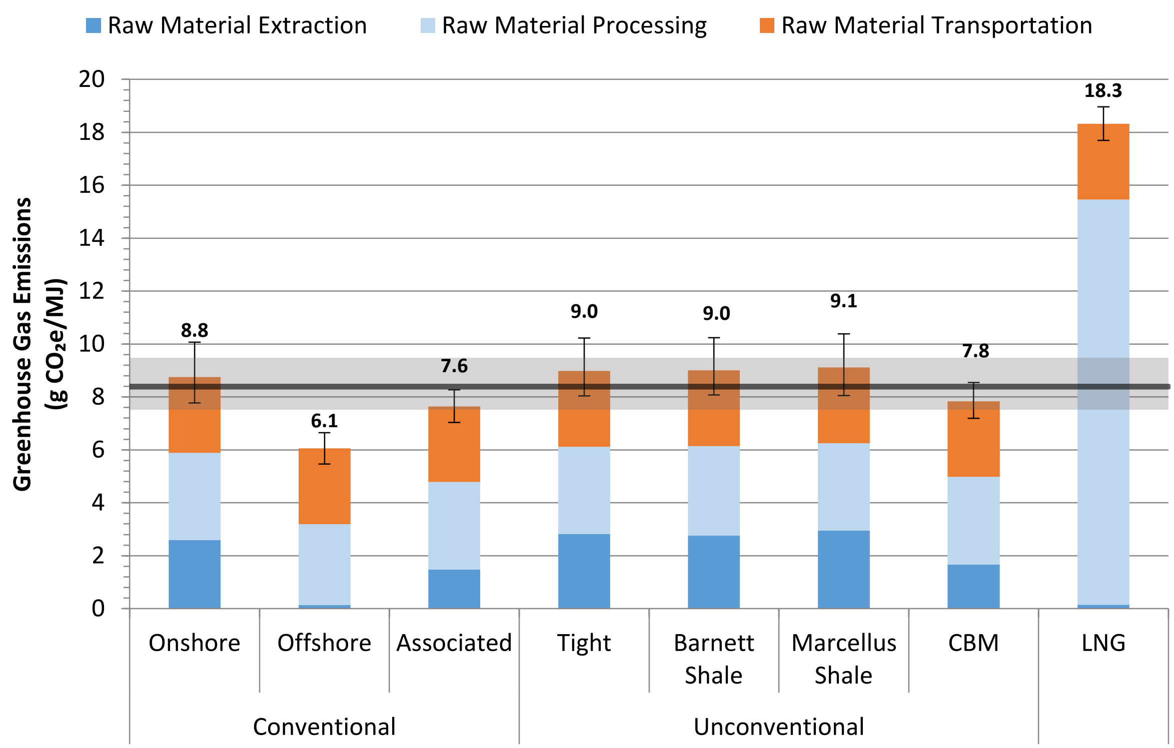
In general, unconventional technologies require stimulation of the gas-containing formation before gas will flow freely to the surface. For shale gas, the current stimulation technology is horizontal drilling with hydraulic fracturing. Tight gas, another unconventional technology, uses *vertical* drilling with hydraulic fracturing. Coalbed methane (CBM) is another unconventional technology that uses hydraulic fracturing, but requires the removal of naturally-occurring water from a formation before gas will flow freely, and has lower production pressures than shale gas and tight gas wells. The escape of gas during the completion of unconventional wells and occasional maintenance activities (e.g., workovers) explain partly why the GHG emissions from unconventional natural gas are believed to be different than those from conventional gas. (NETL, 2014) Other differences between technologies are related differences in producer practices. For example, as noted above, the flaring rates of unconventional wells may be lower than those of conventional wells because early development activities in unconventional plays did not follow best practices for emission controls.

The results in Exhibit 2-2 show that the GHG emissions from unconventional gas are not necessarily higher than those from conventional gas. The uncertainty ranges for the GHG emissions from shale gas (Barnett and Marcellus) and tight gas are within the uncertainty range for onshore natural gas (a conventional technology). Further, the GHG emissions from CBM (an unconventional technology) are lower than onshore natural gas. GHG emissions from CBM wells are lower than other unconventional sources because CBM formations have lower pressures and do not release large pulses of natural gas emissions during well development and maintenance.

The GHG emissions from offshore production, as shown in Exhibit 2-2, are lower than other natural gas sources because higher production rates and safety requirements justify the costs of loss reduction technologies. This contrast shows that existing technologies are effective at reducing GHG emissions, and suggests that comparable controls are technologically feasible for shale and tight gas production.

In addition to its characterization of domestic upstream natural gas, NETL has also developed life cycle data for imported LNG, including the GHG emissions from offshore extraction in Trinidad and Tobago, liquefaction, seaborne transport, and regasification. These data were developed when LNG imports were a potential input to the U.S. energy supply, and LNG exports were not a consideration. (NETL, 2014) The burdens of liquefaction, ocean transport, and regasification significantly increase the upstream burdens of LNG relative to natural gas that is not liquefied. However, the life cycle emissions from LNG should be evaluated using a basis for comparison that includes the combustion of natural gas to produce electricity or another form of useful energy, not merely the upstream portion of the supply chain. (NETL has not published any LCAs of LNG exported from the U.S., but the technologies for exported LNG are identical to those for imported LNG.)

Exhibit 2-2 Upstream GHG emissions for different sources of natural gas (NETL, 2014)



The liquefaction of natural gas for shipment is an energy-intensive process that uses natural gas as the key source for refrigeration energy. The Sabine Pass Liquefaction Project has proposed the construction of a natural gas liquefaction and export terminal in Louisiana. If the Sabine Pass liquefaction facility is constructed, it will produce 3.8 million metric tons of CO_2 emissions per year while exporting 16 million metric tons of natural gas per year (assuming it operates at 100 percent capacity). Most of the CO_2 emissions will come from the combustion of natural gas in refrigeration compressor turbines and power generation turbines. (FERC, 2011) These data show that the liquefaction facility consumes 8 percent of incoming natural gas as fuel required for liquefaction. Not only do these data demonstrate the loss rate of natural gas at a liquefaction facility, they also demonstrate the CO_2 emissions associated with natural gas combustion at a liquefaction facility.

2.2 Key Contributors to Natural Gas GHG Emissions

The key drivers of GHG results for all natural gas sources is demonstrated by a comparison of the results for two disparate gas production technologies: onshore conventional and Marcellus Shale natural gas. Exhibit 2-3 and Exhibit 2-4 show upstream GHG emissions for the two gas types. These boundaries are also referred to as "cradle-to-gate," where the cradle is the extraction of natural gas from nature and the gate is the delivery of natural gas to a power plant via a natural gas transmission pipeline. These results use the same boundaries as Exhibit 2-2, but show more detail on the contribution of specific unit processes in the supply chain.

Exhibit 2-3 Detailed GHG results for upstream conventional onshore natural gas (NETL, 2014)

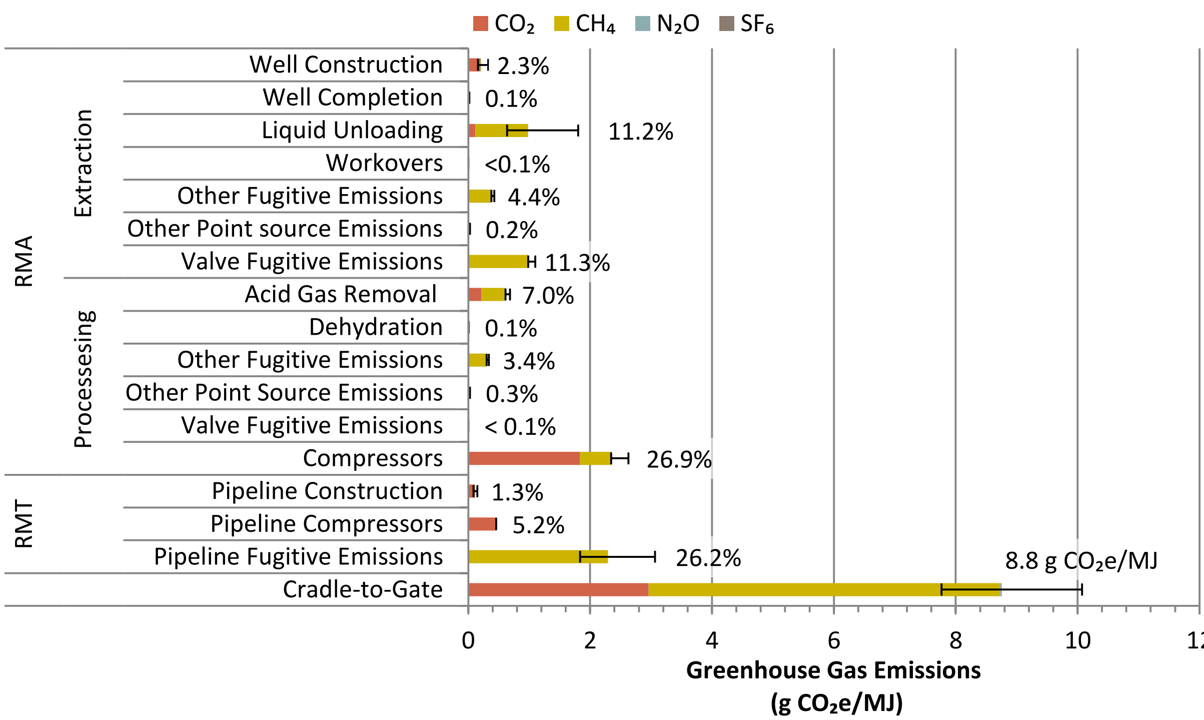
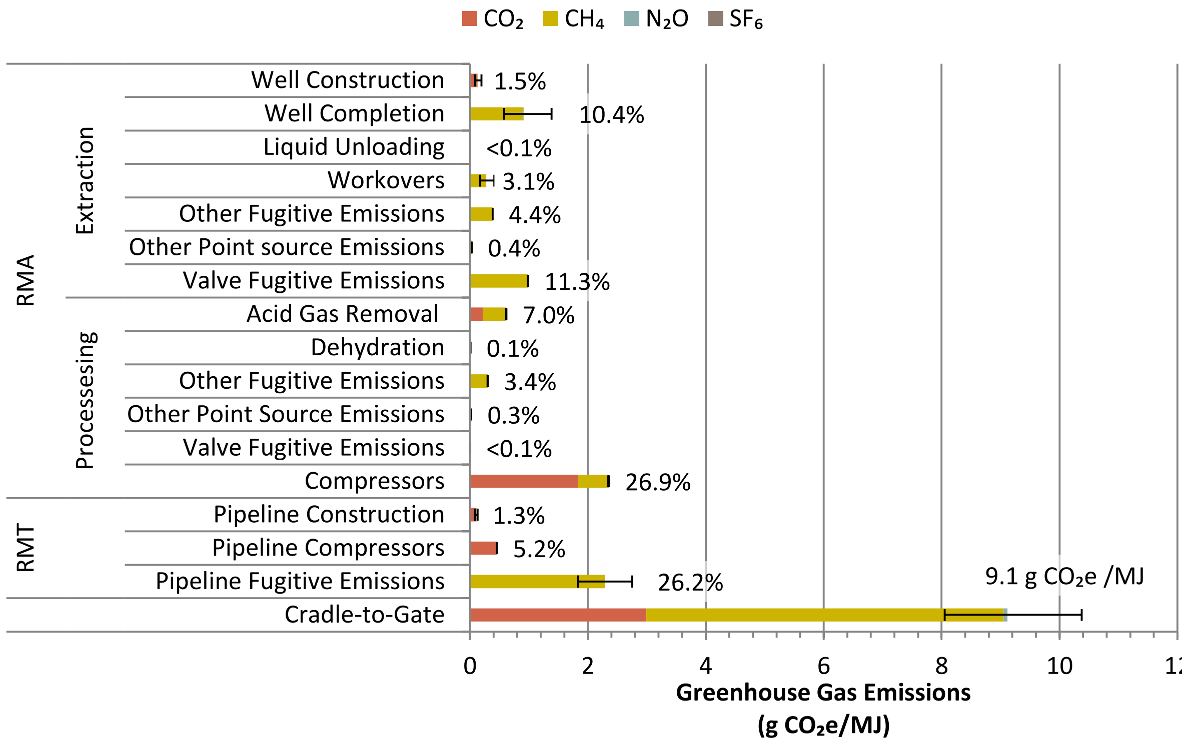


Exhibit 2-4 Detailed GHG results for upstream Marcellus Shale natural gas (NETL, 2014)



The above exhibits show how important methane (CH_4) is to total upstream GHG emissions. In most energy systems, CO_2 is the key GHG of concern, but for upstream natural gas, methane accounts for the majority of GHG emissions. Non-routine emissions ("episodic emissions") are significant for conventional and unconventional natural gas sources. The episodic emissions from liquid unloading[1] account for 11.2 percent of upstream GHG emissions from conventional onshore extraction. The episodic emissions from well completion and workovers account for 13.5 percent of the upstream GHG emissions from Marcellus Shale natural gas. Well construction, on the other hand, accounts for a smaller contribution (approximately 2 percent) to upstream GHG emissions.

The above results show that compressors are a key contributor to GHG emissions for both conventional and unconventional technologies. Natural gas is compressed for transport from the processing facility to the consumer, so upstream GHG emissions are sensitive to pipeline distance and the number of compressors that the gas must pass through. NETL's LCA uses a default distance of 971 km for natural gas pipeline transmission, which NETL calculated by solving for the distance at which the per-mile emissions were equivalent to U.S. annual natural gas transmission methane emissions. The energy intensity of compression and the fugitive methane emissions from compressors contribute to upstream emissions. (NETL, 2014) In addition to being a source of methane emissions, compressors are also a source of CO_2 emissions. The majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by

[1]Liquid unloading is a type of periodic well maintenance activity that is unique to onshore conventional wells and allows natural gas to escape. Liquid unloading removes fluids that accumulates in a wellbore. If liquid unloading is not performed, the fluids in the wellbore can impede natural gas production. EPA's data for well emissions indicate that liquid unloading is not necessary for unconventional wells. (NETL, 2011a)

natural gas pipelines, but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. (Hedman, 2008) Approximately three percent of compressors used by the natural gas transmission network are electrically driven. NETL's model uses the average U.S. electricity grid mix (representative of 2009 data) to account for the life cycle GHG emissions from electricity generation and transmission. (NETL, 2014)

Note that the GHG emissions from pipeline construction, pipeline compressors, and pipeline fugitive emissions are identical between the two natural gas types shown in Exhibit 2-3 and Exhibit 2-4; however, since the percent contributions shown in these exhibits are relative to total upstream GHG emissions, the percent contributions from pipeline activities to total upstream GHG emissions are different for each natural gas type.

As shown in Exhibit 2-4, water delivery and water treatment account for 2.1 percent of the upstream GHG emissions from Marcellus Shale natural gas extraction. The water inputs for the completion of a horizontal, shale gas well ranges from 2 to 6 million gallons, and substantial flowback water is produced by shale gas wells. (GAO, 2012) While water supply can be an issue (see Chapter 4, Water Use and Quality), the GHG emissions associated with these water burdens are relatively small over the lifetime natural gas production rate of a well, and compared to other life cycle GHG emissions.

The sensitivity of upstream GHG results to key parameters is shown in Exhibit 2-5 and Exhibit 2-6. Each of the parameters shown in Exhibit 2-5 and 2-6 was increased by 100 percent while holding all other parameters constant, which provides an understanding of how each parameter affects the GHG results. For example, if the amount of natural gas produced by a conventional onshore well increases by 100 percent (doubles) and all other parameters are held constant at their expected values, the upstream GHG emissions per unit of natural gas delivered decrease by 10.7 percent. That is, a higher production rate reduces the amount of episodic emissions apportioned to each unit of natural gas produced. Sensitivity is different than uncertainty, so these tornado graphs do not represent likely uncertainty ranges around key parameters. Rather, the tornado graphs show which parameters are key drivers of GHG results. (NETL, 2014)

Exhibit 2-5 Sensitivity of estimated GHG emissions to parameter changes to conventional onshore natural gas (NETL, 2014)

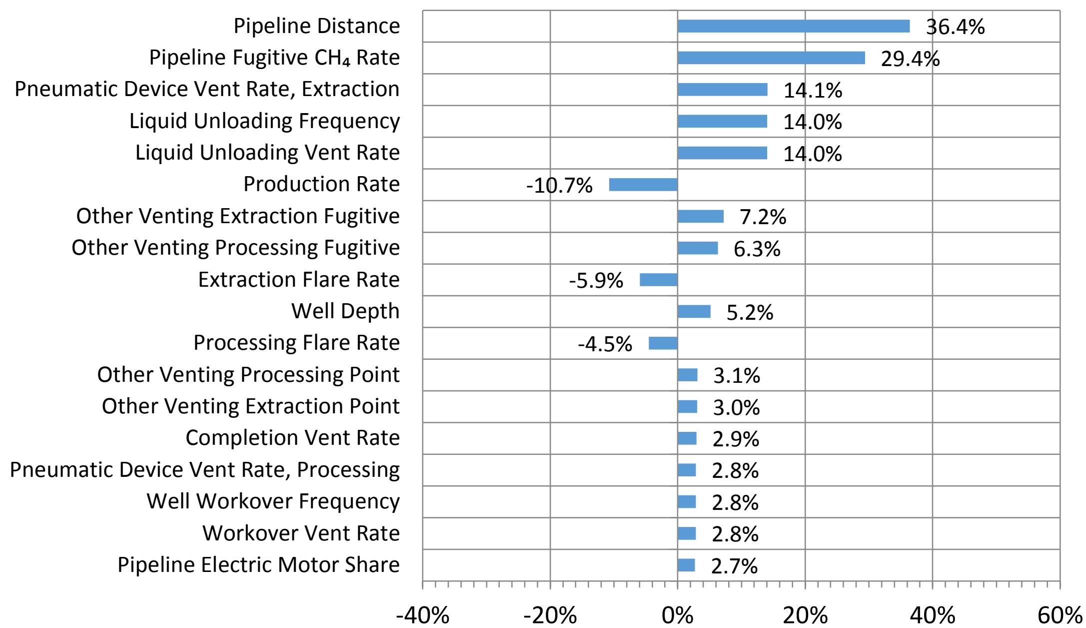
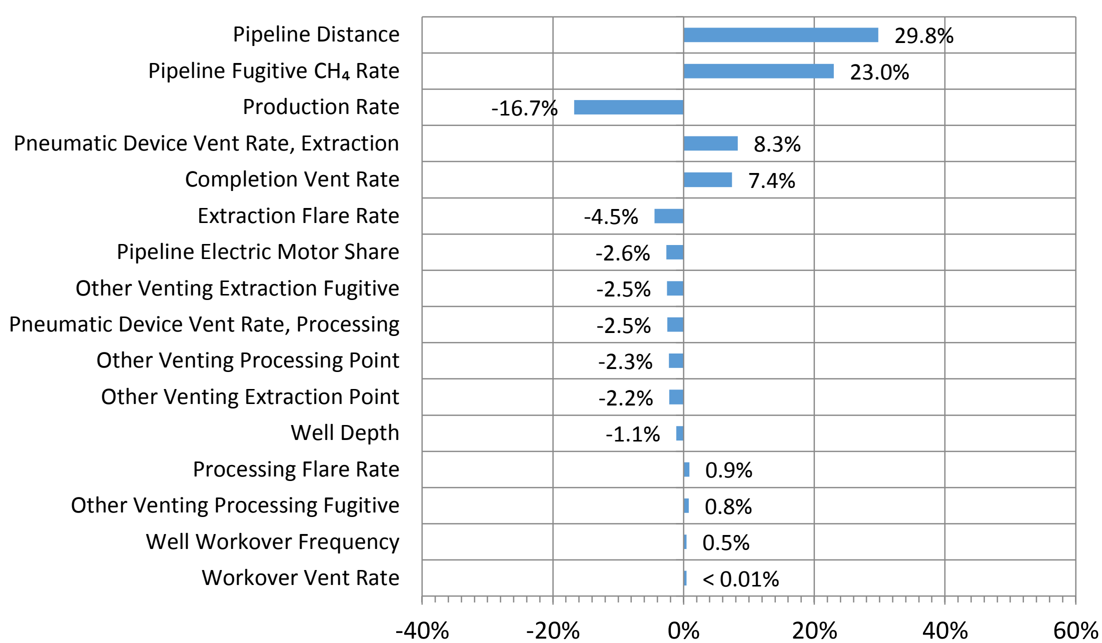


Exhibit 2-6 Sensitivity of estimated GHG emissions to parameter changes to Marcellus Shale natural gas (NETL, 2014)



For both natural gas production types, conventional onshore and Marcellus Shale, the GHG results are sensitive to production rates and episodic emissions (either liquid unloading or workovers). Production rate (the amount of natural gas produced by a well during its lifetime) is an important variable in NETL's natural gas model, because it is used as a basis for apportioning episodic emissions. For example, workover vent rate multiplied by the workover frequency and divided by lifetime production rate equals the workover emissions per unit of gas produced. Based on the relationship between production rate and life cycle GHG emissions, a highly productive well with measures for reducing emissions from episodic activities will have significantly lower life cycle GHG emissions than a poorly producing well with no measures for reducing episodic emissions. (NETL, 2014)

According to NETL's model, when natural gas is delivered to a power plant or other large-scale consumer, 92 percent of the natural gas extracted at the well exits the transmission network. The 8 percent share that is not delivered to the user is vented (either intentionally or unintentionally) as methane emissions, flared in environmental control equipment, or used as fuel in process heaters, compressors and other equipment. For the delivery of 1,000 kg of natural gas to a power plant, 12.5 kg of methane is released to the atmosphere, 30.3 kg is flared to CO_2 via environmental control equipment, and 45.6 kg is combusted in process equipment. When these mass flows are converted to a percent basis, methane emissions to air represent a 1.1 percent loss of natural gas extracted, methane flaring represents a 2.8 percent loss of natural gas extracted, and methane combustion in equipment represents a 4.2 percent loss of natural gas extracted. These percentages are on the basis of *extracted* natural gas. Converting to a denominator of *delivered* natural gas gives a methane leakage rate of 1.2 percent. (NETL, 2014)

The above results for uncertainty and sensitivity clearly point to the significance of production rates and episodic emissions. Data for these variables are limited, especially for the relatively new activity in the Marcellus Shale play. NETL's upstream GHG results for Marcellus Shale use an EUR of 3.25 billion cubic feet of natural gas. This EUR is based on sharply declining production curves projected over a 30-year period. The long-term performance of Marcellus Shale wells is uncertain, so NETL bounds its Marcellus Shale production rate parameters with an uncertainty range of +/- 50 percent. (NETL, 2014)

The factors for episodic emissions are based on the supporting documentation for the EPA's national GHG inventory. The EPA's emission factor for unconventional well completions and workovers is 9,000 thousand cubic feet (Mcf) of natural gas emissions per episode, which was developed from a series of presentations by their Natural Gas STAR (EPA Science to Achieve Results) program. The data behind this emission factor are highly variable, ranging from 6,000 to over 20,000 Mcf per episode (6 to 20 million cubic feet per episode), and include data collected in the 1990s. (EPA, 2010; Cathles, 2012) It should also be noted that this emission (9,000 Mcf/episode) and other emissions from unconventional extraction operations can be captured and flared using current technologies (Cathles, 2012); as shown by NETL's sensitivity analysis in Exhibit 2-6, an increase in flaring rate will significantly reduce the GHG emissions from unconventional natural gas production. Other data points for unconventional emissions are summarized in the following section, but further data collection and research is necessary to reduce the uncertainty associated with this emission factor and other emissions from unconventional natural gas extraction.

2.3 Other Natural Gas Analyses

At least four other research teams have performed system-level LCAs of natural gas production using methodologies similar to the one used and documented by NETL. The results of three of the non-NETL studies, given their uncertainties, are generally consistent with NETL's analysis and indicate that the GHG emissions from unconventional production are comparable to, if not lower than, conventional production. The widely cited exception is the study by Howarth, et al. (2011a) that shows higher emissions for unconventional gas relative to conventional and higher emissions for both relative to the other studies.

Researchers at Carnegie Mellon University (Jiang et al., 2011) estimated the GHG emissions from Marcellus Shale natural gas and compared it to U.S. domestic average natural gas. They concluded that development and completion of a Marcellus Shale natural gas well has GHG emissions that are 11 percent higher than the development and completion of an average conventional natural gas well. This 11 percent difference is based on a narrow boundary, representing only the differences in well development and completion for Marcellus Shale and conventional natural gas. When the life cycle boundaries are expanded to include combustion to generate electricity, the percent difference between the GHG emissions from Marcellus Shale and conventional natural gas is reduced to 3 percent. In other words, as the boundaries of the systems are expanded, the differences between conventional and unconventional wells are overshadowed by other processes in the natural gas supply chain. (Jiang et al., 2011)

Researchers at Argonne National Laboratory estimated the GHG emissions from shale gas and compared it to conventional natural gas and other fossil energy sources. (Burnham et al., 2011; Clark et al., 2011) Their results show that shale gas emissions are 6 percent lower than conventional natural gas, but the overlapping uncertainty of the results prevents definitive conclusions about whether shale gas has lower GHG emissions than conventional gas.

Researchers at the Science and Technology Policy Institute applied Monte Carlo uncertainty analysis to a set of six natural gas LCAs and concluded that the upstream GHG emissions from conventional and shale gas are similar. (Weber and Clavin, 2012) The six studies include four of the studies mentioned herein (Burnham et al., 2011; Howarth, 2011a; Jiang et al., 2011; NETL, 2012) as well as studies conducted at University of Maryland (Hultman, et al., 2011) and Shell Global Solutions. (Stephenson et al., 2011)[1] Weber and Clavin recommend the use of efficient technologies for converting natural gas to electricity, heat, or transportation applications. They also recommend implementation of reduced emission completions (RECs) for the development of shale gas wells.

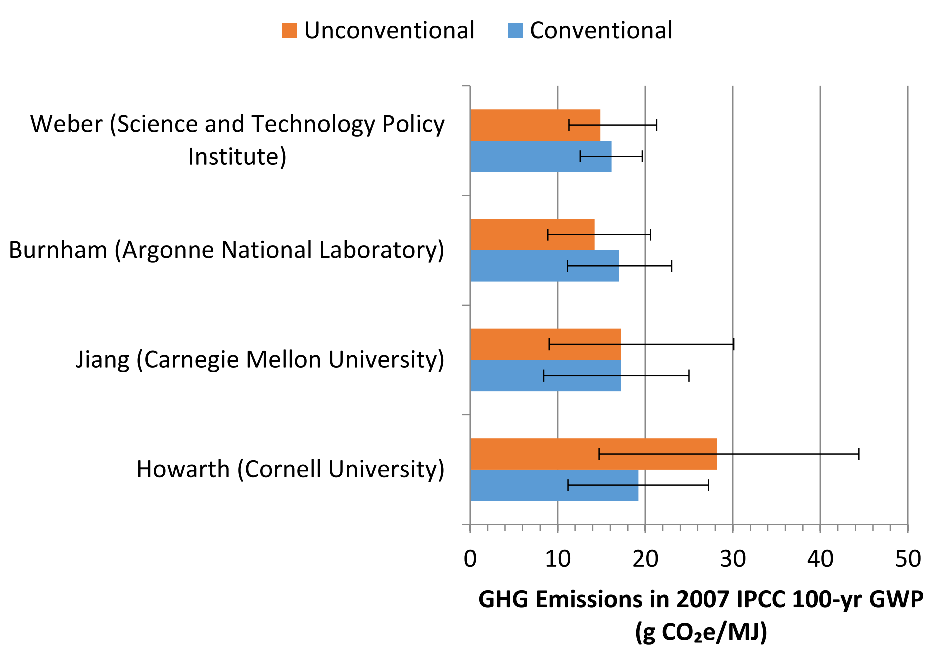
Research conducted by Robert Howarth at Cornell University (Howarth et al., 2011a) concludes that the high volumes of gas released by hydraulic fracturing make the life cycle GHG footprint of shale gas significantly higher than conventional gas. According to Howarth's analysis, 3.6 to 7.9 percent of natural gas extracted from shale gas wells is released to the atmosphere as methane. (The midpoint of Howarth's range of leak rate is included in Exhibit 2-8, which compares the leak rates calculated by various authors.)

[1] The analysis by the University of Maryland concludes that unconventional natural gas has upstream GHG emissions that are approximately 2 percent higher than those from conventional natural gas; the analysis by Shell Global solutions concludes that unconventional gas has upstream GHG emissions that are 11 percent higher than those from conventional natural gas. These two analyses do not contradict nor expand upon the conclusions of the other upstream natural gas analyses discussed in this report, so they are not discussed further.

The boundaries of these LCAs are not identical. Carnegie Mellon University (Jiang et al., 2011) and the Science and Technology Policy Institute (Weber and Clavin, 2012) use the same boundaries as NETL (NETL, 2014), but Argonne National Laboratory's analysis includes scenarios for vehicles that use compressed natural gas (Burnham et al., 2011) and Howarth's analysis includes distribution of natural gas beyond the natural gas transmission network in order to include small scale end users. (Howarth et al, 2011) Fortunately, the transparency of these analyses allows boundary reconciliation, so the World Resources Institute (WRI) converted them to an upstream basis (from natural gas extraction through natural gas delivery via pipeline). (Bradbury et al., 2013) Exhibit 2-7 shows the GHG results as compiled by WRI's study. These results use a 100-year time scale to show GHG emissions in terms of carbon dioxide equivalents (CO_2e) per megajoule (MJ) of delivered natural gas. While WRI shows these results on the basis of similar boundaries, each author used a different basis for calculating uncertainty. The error bars shown in Exhibit 2-7 are a mix of data, parameter, and scenario uncertainties.

WRI also reconciled NETL's upstream natural gas results, shown in Exhibit 2-7. However, WRI's reconciliation is representative of NETL's 2012 natural gas analysis. NETL's current results, representative of modeling updates made in 2012 and 2013, have expected values that are lower than other authors. More details on NETL's natural gas analysis are provided in Section 2.2.

Exhibit 2-7 Upstream GHG comparison between conventional and unconventional natural gas (Bradbury et al., 2013)



The authors shown in Exhibit 2-8 identify extraction, processing, and transport as sources of methane leakage, but, other than well completion emissions, do not specify the sub-activities that contribute to methane leakage. As identified by NETL's model, the top four contributors to methane leakage from unconventional natural gas are completions, workovers, pneumatically-controlled valves used at extraction, and compressors used during processing and pipeline operations. (NETL, 2014)

Because of the potency of methane as a GHG, methane leakage rates dominate the GHG emissions from upstream natural gas systems. Exhibit 2-8 compares the methane leakage rates for conventional and unconventional natural gas extraction, as calculated by three analyses. As discussed earlier, NETL's leakage rate for the 2010 supply mix of all domestic natural gas sources is 1.2 percent and is expressed in terms of methane emissions per unit of natural gas delivered to a large-scale consumer. Jiang does not explicitly report a methane leakage rate. The boundaries on these leakage rates are from extraction through delivery. (Bradbury et al., 2013)

Exhibit 2-8 Comparison of leakage rates from upstream natural gas (Bradbury et al., 2013)

Author	Methane Leakage Rate	
	Conventional Onshore	Unconventional
Weber (Science and Technology Policy Institute)	2.80%	2.42%
Burnham (Argonne National Laboratory)	2.75%	2.01%
Howarth (Cornell University)	3.85%	5.75%

The differences in GHG emissions and methane leakage rates among natural gas analyses are driven by different data sources, assumptions, and scopes. (Bradbury et al., 2013) Other differences among these analyses, as identified in literature, are summarized below.

Most analysts use IPCC GWPs to scale methane to an equivalent quantity of CO_2. Howarth does not use IPCC GWPs, but uses GWPs developed by Shindell, a National Aeronautics and Space Administration (NASA) scientist whose calculations account for the heating and cooling effects of aerosols in addition to GHGs. (Howarth et al., 2011a) On a 100-year time frame, the IPCC and Shindell GWPs for methane are 25 and 33, respectively. (Bradbury et al., 2013; Howarth et al., 2011a; MIT, 2011) Howarth uses a methane GWP that is 32 percent higher than used by others, but further analysis and reconciliation is necessary to determine how much Howarth's unique GWP contributes to the difference between Howarth's and others' GHG results; the choice of GWP factors is one of several modeling and data choices unique to Howarth's analysis. Howarth acknowledges the uncertainty in GWPs and defends his use of Shindell GWPs on the basis that they are representative of the most recent science. (Howarth et al., 2012)

GWPs will change as our scientific understanding of climate change progresses. The IPCC recently finalized its fifth assessment report on climate change, which includes GWPs that will supplant the GWPs from the fourth assessment report (released in 2007).The fifth assessment report increases the 100-year GWP of methane from 25 to 28. Further, if the global warming caused by the decay of methane to CO_2 is to be included within the boundaries of an analysis, the fifth assessment report recommends a 100-year GWP of 30 for methane. The GWP of methane is a function of the radiative forcing directly caused by methane in the atmosphere, as well as the radiative forcing from products of methane decay. IPCC increased the GWP of methane based on new data that shows that the lifetime of methane in the atmosphere is 12.4 years (a 12-year lifetime was used in the previous version). IPCC also increased the GWP of methane based on revised assumptions about relationships among methane, ozone, and water vapor in the atmosphere. (Stocker et al., 2013)

There is uncertainty as to how much methane is released during the initial flowback of water from an unconventional well. The emission of natural gas from flowback water accounts for most of the emissions from the completion of shale gas wells. The EPA's emission factor for natural gas released from the flowback from unconventional completions is approximately 9,000 Mcf per episode. The data behind the EPA's emission factor are highly variable, ranging from 6,000 to 20,000 Mcf per episode, and include data collected in the 1990s. (EPA, 2010) NETL uses the EPA's emission factor for flowback emissions. (NETL, 2014) Carnegie Mellon University's analysis of upstream natural gas assumes that flow back methane emissions are equal to the total gas produced during the first 30 days of production (4,100 Mcf per episode). (Jiang et al., 2011) Howarth averages the flowback emissions from two shale gas wells and two tight gas wells, and concludes that flowback emissions are 1.6 percent of the total gas produced by a well during its entire life. (2011a) Howarth does not explicitly state a flowback emission factor in terms of Mcf per episode, but applying Howarth's 1.6 percent loss factor to the four wells cited in Howarth's analysis translates to flowback emissions of 47,000 Mcf/episode. Another data point is an emission factor of 5,000 Mcf per episode, which was developed by Southern Methodist University for the Environmental Defense Fund (EDF), and is representative of shale gas development in the Barnett Shale. (Armendariz, 2009) The flowback emissions used by other authors discussed in this report are not clearly stated in their work.

Howarth does not use the EPA's emission factor to characterize flowback emissions. Rather, Howarth compiles data from five basins where unconventional extraction is occurring (Barnett, Piceance, Uinta, Denver-Jules, and Haynesville) and assumes a10-day period in the last stages of flowback during which gases "freely flow." The data that Howarth uses to characterize the Haynesville basin are especially high, ranging from 14 to 38 million cubic feet per day. (Howarth, 2012) Other analysts claim that the flowback fluid does not contain as much gas as indicated by Howarth's data. During flowback, non-gaseous material obstructs the wellbore and prevents the release of methane and other gases. (Bradbury et al., 2013; Cathles, 2012; O'Sullivan and Paltsev, 2012)

EUR is used to apportion the one-time impact of flowback emissions per unit of natural gas produced. (Howarth, 2012; Hughes, 2011; NETL, 2014) NETL uses EURs of 3.0 and 3.25 billion cubic feet for Barnett Shale and Marcellus Shale, respectively, based on 2009 production data for the Barnett play (levelized over 30 years of production), and a decline curve analysis[1] of initial production rates reported by producers in the Marcellus play. (NETL, 2014) Jiang et al. use an EUR of 2.7 billion cubic feet over a 25-year period, and note that some producers have EURs as high as 7.3 billion cubic feet. (2011) Howarth points to the uncertainty in lifetime production rates for unconventional wells, and contends that the EURs used by NETL and Jiang are too high. (Howarth, 2012) To represent the EUR of all unconventional wells, Howarth uses a value of 1.24 billion cubic feet, which is based on a decline curve analysis of Barnett Shale wells. (Hughes, 2011) The variability in EURs for shale gas wells is due to a lack of long-term historical production data. Shale gas wells use new technologies to extract natural gas from previously unproductive geological formations; EURs are merely estimates of long-term performance using initial production data and assumptions about long-term performance. (NETL, 2014) As shale gas extraction develops, the uncertainty in EURs will be reduced.

[1] The production rate of a well declines as the well gets older. A decline curve analysis plots the production rate of a well over time; the area under the curve represents the total lifetime production of the well. By knowing the initial production rate of a well and then assuming a shape for the production curve, the total lifetime production of the well can be estimated.

Flaring is the controlled combustion of natural gas that cannot be easily captured and sold. Unconventional gas is sometimes flared during well completion. Flaring is an important safety practice, and it also reduces the GWP of natural gas extraction and processing operations by converting methane to CO_2. Again, as discussed in Section 2.1, zero venting is the ultimate goal, but if venting happens, then it is environmentally preferable to flare vented gas because flaring reduces the GWP of the vented gas (NETL, 2014) NETL (2014) and O'Sullivan and Paltsev (Bradbury et al., 2013) assume a 15 percent flaring rate. NETL's flaring rate of 15 percent is based on the EPA's inventory documentation for the oil and gas sector (EPA, 2012a), and is representative of an emerging industry for unconventional natural gas extraction where best practices are not yet implemented. As unconventional extraction grows and best practices are implemented, the flaring rate will likely increase. Industry representatives claim that the flaring rates for unconventional natural gas extraction are as high as 97 percent. (Bradbury et al., 2013) Howarth's model assumes that all methane losses are directly released to the atmosphere and are not flared. (Cathles et al., 2011) Howarth cites personal communication with producers who say they do not flare emissions during unconventional well development. Howarth also contends that the methane released during unconventional well development is quickly mixed with the atmosphere and does not pose a safety hazard that would require flaring. (Howarth et al., 2012)

Most natural gas analyses use the EPA's national GHG inventory to calculate natural gas pipeline emissions. The national inventory data accounts for the different fates of methane (fugitive emissions, venting from compressors, and combustion in compressors) during natural gas transport. (Bradbury et al., 2013; NETL, 2014) Howarth does not use guidance from the national GHG inventory to account for the sources of methane emissions during natural gas transmission. (Howarth, et al, 2011; Cathles et al., 2011) Howarth assumes that the difference in methane between the inlet and outlet of the pipeline is equal to methane emissions from pipeline operation. This mass balance approach does not account for the consumption of methane by pipeline compressors. (Cathles et al., 2011) Pipeline compressors combust methane for compression energy, converting methane to CO_2 in the process. (NETL, 2014) Howarth acknowledges the limitation of his approach, but also points out that the EPA inventory data is more than ten years old and relies too heavily on voluntary industry reporting. (Bradbury et al., 2013; Howarth, 2012)

Howarth includes two phases of natural gas transport: transmission and distribution. (Howarth et al., 2011; Cathles et al., 2011) Transmission moves natural gas from a processing plant to large-scale consumers near cities or export terminals; distribution is an additional step that moves natural gas to commercial or residential consumers. (EIA, 2008) Howarth points out that heat generation, which includes a large share of small residential and commercial consumers and requires a natural gas distribution network, accounts for the largest share of natural gas consumption in the U.S. (2012) Other natural gas analyses focus on the use of natural gas for power generation, which does not require natural gas distribution. (NETL, 2014; Bradbury et al., 2013)

Exhibit 2-9 compares the modeling choices and parameters of four LCAs that include shale gas. This includes the LCAs conducted by NETL (2012), Carnegie Mellon University (Jiang et al., 2011), Argonne National Laboratory (Burnham et al., 2011), and Cornell University. (Howarth et al., 2011a) The analysis conducted by the Science and Technology Policy Institute (Weber and Clavin, 2012) is not included in Exhibit 2-9, because it is a meta-analysis of six other analyses (including the four analyses mentioned above), thus has broad, derivative parameter ranges.

Exhibit 2-9 Comparison of Modeling Choices and Shale Gas Parameters Used by Four LCAs

Modeling Choices and Shale Gas Parameters	Authors			
	NETL	Jiang et al.	Burnham et al.	Howarth
Upstream Natural Gas Boundaries	Extraction through *transmission*			Extraction through *distribution*
100-year Global Warming Potentials (GWP)	2007 IPCC GWPs (CH_4 is 25x CO_2)			Shindell GWPs (CH_4 is 33x CO_2)
Estimated Ultimate Recovery (EUR) per Shale Gas Well	3.0 BCF (Barnett); 3.25 BCF (Marcellus)	2.7 BCF	3.5 BCF	NA[1]
Well Lifetime	30 years	25 years	30 years	NA[2]
Natural Gas in Flowback Water from Well Completion	9,000 Mcf/well	4,100 Mcf/well-day x 9.5 days = 38,950 Mcf/well	9,175 Mcf/well	1.6% of lifetime production (47,000 Mcf/well)[3]
Flaring Rate of Natural Gas in Flowback Water from Well Completion	15%	76%	41%	0%

[1] *Howarth does not specify an EUR in his analysis. (2011) A straight average of the lifetime production rates in Table 1 of Howarth's analysis gives an EUR of 3.1 BCF. Hughes attributes an EUR of 1.24 BCF to Howarth's work. (Hughes, 2011)*

[2] *Howarth does not specify well lifetime as a modeling parameter.*

[3] *Howarth expresses natural gas losses in terms of percentage of lifetime production. (2011) The emission factor shown here (47,000 Mcf/well) is not specified in Howarth's analysis, but can be calculated solely from the production and loss rates shown in Table 1 of Howarth's analysis.*

As shown by the comparison of the above LCAs, there is significant uncertainty in the emissions from unconventional natural gas extraction. This uncertainty will be reduced as more data are collected. Collaboration between the University of Texas and EDF is a recent example of how data collected at natural gas extraction sites can inform natural gas analysis. Emissions were measured at 489 natural gas wells across the U.S., and include conventional and unconventional extraction technologies. Based on these measurements, the University of Texas calculated that the total methane emissions from natural gas extraction represent a 0.42 percent loss of methane at the extraction site; this loss factor is an aggregate of conventional and unconventional wells and represents only the natural gas production activities at the extraction site, not processing or pipeline transmission. The measurements also include emissions from 27 unconventional completions and show that environmental control equipment can reduce the methane emissions from unconventional completion to levels that are 97 percent lower than the completion emissions currently estimated by the EPA. The University of Texas and EDF have published only one paper about their research to this point, although additional papers are expected. (Allen et al., 2013)

A survey conducted by the API and ANGA is an example of how data collected by industry can inform the emission factors used by analysts. These organizations surveyed 20 member companies to collect data from 91,000 domestic natural gas wells. Based on the survey, API and ANGA conclude that the rate of workovers for unconventional wells (also known as "refracture frequency") is one-tenth of the rate specified by the EPA documentation of the oil and gas sector. (Shires et al., 2012)

Brandt et al. (2014) reviewed 20 years of technical literature on natural gas emissions in North America and demonstrated that the methane emission factors used by different authors are highly variable. One source of variability is the way in which methane emissions data are collected; some emissions are measured at a device level (e.g., the flowback stream from a hydraulic fracturing job), while other emissions are measured at regional boundaries (e.g., atmospheric sampling in a region that has natural gas production). Theoretically, if these two types of measurements are scaled correctly, they should result in similar methane emission factors; however, the two methods lead to GHG results that differ by a factor of ten. Brandt et al. (2014) conclude that improved science for determining methane leakage will lead to cost-effective policy decisions. (Brandt et al., 2014)

Improper well construction and fractures in rock formations can also result in methane emissions from the target formation during production. The current life cycle models for shale gas extraction do not include ground water as a source of GHG emissions. Methane migration as a potential source of drinking water contamination is discussed in greater detail in Chapter 4, Water Use and Quality.

2.4 Mitigation Measures

The EPA's New Source Performance Standards (NSPS) regulate emissions from the oil and gas sector. The new regulations are applicable to new or modified wells. The final NSPS rule that was established in August 2012 focuses on RECs, compressor seals, storage tanks, and pneumatic controllers. The schedule for NSPS compliance is staggered; some emission sources were to be reduced within 60 days from the publication of the NSPS rules, on October 15, 2012, but all emission reductions must be achieved by January 1, 2015. (EPA, 2012) These targets for emission reductions are described in more detail below.

RECs use portable equipment that is brought onsite to capture gas from the solids and liquids generated during the flowback of hydraulic fracturing water. RECs equipment includes plug catchers and sand traps that remove drilling cuttings and finer solids that result from well development. Three phase separators are used to separate gas and liquid hydrocarbons from flowback water. These separation processes are necessary only during completions and workovers to prevent the release of methane and other gases to the atmosphere and to reduce the need for flaring. (EPA, 2011a)

Compressor seals include the wet seals used by centrifugal compressor and the rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases methane to the atmosphere. By replacing wet seals with mechanical dry seals, the methane emissions from centrifugal compressors can be reduced. (EPA, 2011b) Reciprocating compressors prevent methane leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of methane. (EPA, 2006c)

Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of methane and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can reduce emissions from natural gas production. (EPA, 2006b) The captured emissions can be combusted onsite to provide process energy or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers vents methane to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas. (EPA, 2006a)

Since the regulations focus on RECs, they are more applicable to unconventional wells. However, the regulations also mandate emission reductions from pneumatically-controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional technologies.

The 2012 NSPS regulations do not cover emissions from liquid unloading or natural gas pipeline transmission. Participants in the EPA's Natural Gas STAR program have demonstrated that automated plunger lift systems can remove liquids from the wellbore at optimal frequencies that prevent the venting of natural gas to the atmosphere. Other technologies for reducing emissions from liquids unloading include the use of smaller diameter tubing that maintains production pressures at levels that reduce the frequency of liquid unloading, and foaming agents that reduce the density and surface tension of accumulated liquid. (EPA, 2011c) The replacement of wet seals and rod packing on transmission pipeline compressors, and applying the same type of improvements that can be applied to compressors at extraction and processing sites, can further reduce pipeline emissions and product losses.

The goal of NSPS is to reduce methane emissions from the targeted sources (completions, compressors, pneumatic valves, and storage tanks) by 95 percent. NSPS implementation is applicable only to extraction and processing activities and, based on NETL's natural gas model, could reduce upstream GHG emissions from the domestic natural gas mix (which includes conventional and unconventional technologies) by 23 percent. (NETL, 2014)

From a national perspective, a reduction in methane emissions from natural gas systems could reduce the annual U.S. GHG inventory. In 2011, natural gas systems (processes for the extraction, processing, transport, and storage of natural gas) released 145 teragrams of CO_2e of methane to the atmosphere. (EPA, 2013) The total U.S. GHG inventory in 2011 was 5,800 teragrams of CO_2e, (EPA, 2013) so methane from natural gas systems is 2.5 percent of the total GHG inventory. As discussed above, NSPS reductions can reduce upstream GHG emissions by 23 percent, which means they can reduce the entire U.S. GHG inventory by 0.6 percent.

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3 Air Quality

Greenhouse gas (GHG) emissions from natural gas systems have received significant attention in current literature; however, they are not the only type of air emission from natural gas systems. The two key sources of non-GHG emissions are:

- *Uncaptured Venting*: Releases natural gas, which is a source of volatile organic compound (VOC) emissions.
- *Fuel Combustion*: Produces a wide variety of air emissions, including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM).

VOCs and NO_x react in the lower atmosphere to produce ground-level ozone, a component of smog that adversely affects human respiratory health. The reaction between VOCs and NO_x is unique, because it represents an interaction between two emission sources (in this case, uncaptured venting and fuel combustion). The other emissions from fuel combustion have a variety of human health and ecological impacts. CO affects human health by reducing the oxygen-carrying capacity of blood. SO_2 leads to soil or surface water acidification (via acid rain). PM is linked to poor heart and respiratory health. (EPA, 2012a; GAO, 2012)

3.1 Uncaptured Venting

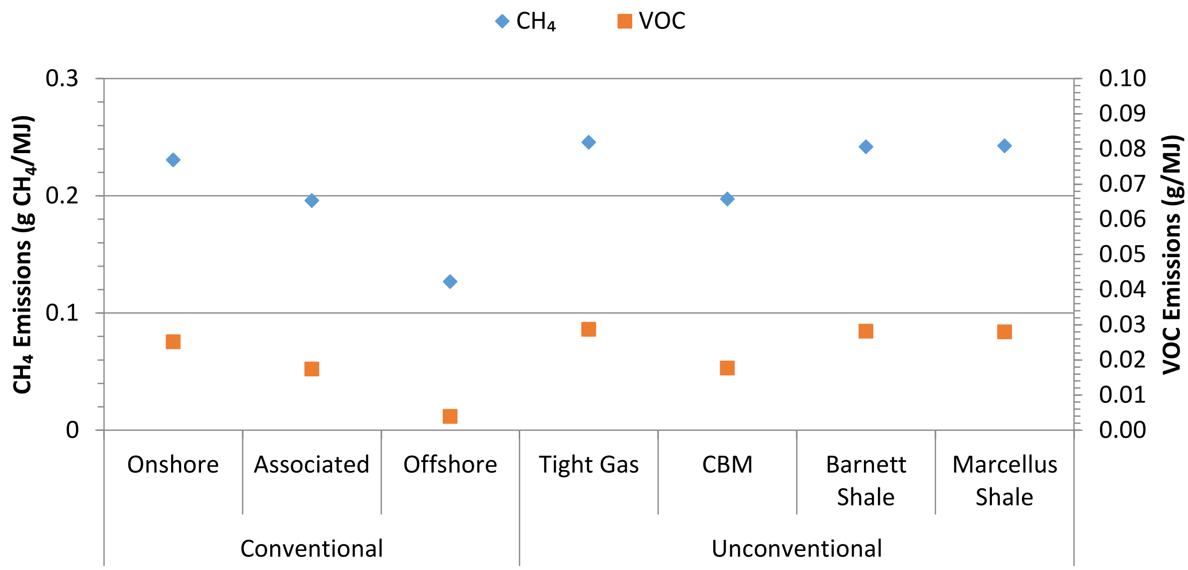
The venting of natural gas during the extraction and processing of natural gas is a key source of VOC emissions. VOCs, like methane, are a naturally-occurring component of natural gas[1] and react with other pollutants to produce ground-level ozone. Since VOCs come from the same sources as methane, an understanding of the sources of methane emissions from natural gas provides a basis for understanding the sources of VOC emissions from upstream natural gas. For example, a single instance of well completion with hydraulic fracturing can vent millions of cubic feet of raw natural gas. (NETL, 2014) This vented natural gas is mostly methane, but also contains heavier hydrocarbons that are classified within as VOC emissions. Similarly, the fugitive emissions of natural gas from valves, compressors, and other natural gas distribution and processing equipment releases VOCs in addition to methane.

As shown by Exhibit 3-1, the pattern of VOC emissions among natural gas types follows the same pattern as methane emissions among natural gas types. The National Energy Technology Laboratory's (NETL) model uses a bottom-up[2] approach that uses a combination of engineering calculations and Environmental Protection Agency (EPA) emission inventory data to estimate emissions from natural gas systems. The emissions from onshore conventional natural gas are comparable to those from Barnett and Marcellus Shale natural gas, which corroborates the conclusion that emissions from unconventional extraction are not necessarily higher than those from conventional extraction. (NETL, 2014)

[1] Unprocessed natural gas has an average VOC composition of 18 percent by mass, and processed natural gas has a VOC composition of 5.6 percent by mass. (NETL, 2014)

[2] A "bottom-up" model is a compilation of sub-processes that are linked together to represent an entire system. Bottom-up models are flexible and can be used to identify the key contributors to overall system behavior. In contrast, "top-down" models use data collected around a system boundary. Top-down models are useful for understanding total system behavior, but cannot be used to assess relationships between sub-processes and total system behavior.

Exhibit 3-1 Comparison of methane and VOC emissions from upstream natural gas



The emissions from offshore natural gas extraction (also shown in Exhibit 3-1) are relatively low because offshore platforms have high production rates that justify capital expenditures on loss reduction technologies. The confines of offshore extraction platforms also present a safety challenge that requires prevention of flammable gases such as methane or VOCs. (NETL, 2014) The success of offshore platforms at mitigating natural gas losses illustrates that existing technologies are effective at reducing VOC emissions from natural gas extraction. There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.

The emission reduction opportunities for VOCs are the same as those for methane emissions because vented natural gas is a source of both VOCs and methane. Reduced emission completions (RECs) use portable equipment that capture and flare natural gas during well development. Optimized timing of plunger lifts for liquid unloading prevents unnecessary venting of natural gas from conventional onshore wells. New technologies for valve control use compressed air instead of natural gas, which prevents the venting of natural gas from the bleeding of pneumatic control lines. Dry seals for centrifugal compressors and routine maintenance of rod packing in reciprocating compressors can reduce VOC emissions from upstream natural gas. These emission reduction opportunities are targeted by the EPA New Source Performance Standards (NSPS), and can reduce venting emissions, including VOCs, by 95 percent. (Clark et al., 2012; NETL, 2014)

Another source of VOC emissions from the oil and gas sector is venting from condensate storage tanks. (EPA, 2012b) NETL's life cycle analysis (LCA) of natural gas does not include emissions from storage tank venting and assigns all storage tank VOC emissions to the condensate rather than the natural gas. (NETL, 2014) This choice allows the analysis to focus on the gas and its uses, but a comprehensive assessment of upstream unconventional natural gas production would factor for storage tank venting. For example, the Marcellus region has dry and wet gas. The shale gas extracted in New York and northeastern Pennsylvania is dry; it is mostly methane and does not contain natural gas liquids (NGLs) that require storage. The shale gas extracted in southwestern Pennsylvania, on the other hand, is wet gas. (MCOR, 2010) Wet gas has NGLs in addition to methane. If stored in tanks with uncontrolled venting, the NGLs from wet gas become a source of VOC emissions.

There is a separate market for NGLs from shale gas, and their production affects the economics of gas production. Shell Chemical announced plans to build an ethane cracker in southwest Pennsylvania using shale gas condensates as a feedstock. The cracker would convert NGLs to valuable petrochemical materials. (Ordonez, 2012) If NGLs are valuable raw material, then it motivates industry to improve VOC recovery at natural gas extraction and processing sites. (FERC, 2012) The use of condensate storage tanks represents a regional variation. If natural gas is produced in a region with wet gas, then the production of natural gas could result in VOC emissions from condensate storage tanks. If natural gas is produced in a region with dry gas, then the production of natural gas does not result in VOC emissions from condensate storage tanks.

A study conducted by Southern Methodist University for Environmental Defense Fund (EDF) also used a bottom-up approach to calculate air emissions from natural gas extraction. The analysis focused on gas extraction in the Barnett Shale region. It categorized emissions into point, fugitive, and intermittent sources. Point sources include steady-state operation of compressors and condensate storage tanks. Fugitive sources include uncaptured gas venting from steady-state production processes. Intermittent sources represent the gas vented to the atmosphere during well development or occasional maintenance activities. The study concluded that venting from condensate storage tanks is a key contributor the VOC inventory in the Barnett region. These VOC emissions are especially high in the summer when high ambient temperatures increase the venting rate of condensate storage tanks. The rate of VOC emissions from condensate storage tanks in the Barnett region has a smog-forming potential comparable to the on-road vehicle emissions from the five-county region that includes Dallas-Fort Worth. (Armendariz, 2009) This does not necessarily mean that the VOC emissions from condensate storage tanks in the Barnett Shale region can cause the same level of smog generated by on-road vehicles in the Dallas-Fort Worth area. Smog formation is a multivariable phenomenon; VOCs cause smog only when they are in the presence of NO_x emissions. (EPA, 2012a)

In contrast to bottom-up methods for calculating air quality emissions, the National Oceanic and Atmospheric Administration (NOAA) (Pétron et al., 2012) modeled air quality from natural gas activity using a top-down method that divided total measured emissions from an entire region by total natural gas produced by the region. The goal of the analysis was to assess the effect of rapid growth in the oil and gas industries on air quality in the Rocky Mountain region, which had over 20,000 wells in 2008. Air quality data were collected from a 300-meter tall tower (located 35 kilometers north of Denver) and "automobile-based on-road" air sampling equipment. Pétron et al. concluded that four percent of extracted natural gas (a combination of methane and VOCs) is vented. (Pétron et al., 2012) This result is higher than the natural gas leakage rates calculated by NETL and other authors (which range from 2 to 3 percent), but is within the range of natural gas leakage rates calculated by Howarth (3.6 to 7.9 percent). A more detailed discussion of natural gas leakage rates is included in Chapter 2.

The NOAA analysis (Pétron et al., 2012) was one of the first studies that used actual field measurements to calculate the leakage rates from unconventional gas. However, it is based on data from tight gas production, so the conclusions do not necessarily apply to shale gas production. Further, researchers at Massachusetts Institute of Technology (MIT) point out that natural gas extraction is not the only activity in northeastern Colorado that produces methane and

VOC emissions. (O'Sullivan and Paltsev, 2012) When the air quality data were collected in 2008, most wells in the region were in tight sand formations that produced oil and gas. (O'Sullivan and Paltsev, 2012) In addition to wells, the region also includes midstream processing and gathering pipelines. (O'Sullivan and Paltsev, 2012)

Michael A. Levi, an analyst at the Council of Foreign Relations, challenges the NOAA (Pétron et al., 2012) conclusions. Levi claims that NOAA relies on "unsupported assumptions about the molecular composition of vented natural gas." (Levi, 2012) Levi applies a molar ratio between methane and VOCs that he believes is more consistent with the sampled region to calculate methane emissions that are more consistent with bottom-up models of natural gas production. Levi's conclusions do not explicitly explain the tradeoff between methane and VOC emissions (given a fixed volume of vented natural gas, the volume of methane decreases as the volume of VOCs increases). Applying a lower methane-to-VOC ratio to top-down emission data will *reduce* the calculated methane emissions, but will *increase* the calculated VOC emissions.

The Arkansas Department of Environmental Quality (ADEQ) conducted an air emissions study in 2008 using a hybrid of bottom-up and top-down modeling approaches. (ADEQ, 2011) The study was funded by a grant from the United States (U.S.) The EPA and had the goal of assessing the effects of shale gas development in the Fayetteville Shale. The Fayetteville Shale is in north central Arkansas. ADEQ's study used two methods for calculating air emissions from shale gas: (1) a system-wide inventory based on emission factors and (2) ambient air monitoring. The application of emission factors to represent all natural gas development and production activity in an entire region is an example of a bottom-up modeling approach, while the interpretation of ambient air data is an example of a top-down modeling approach. Both of these approaches are described in more detail below.

ADEQ developed a system-wide inventory of shale gas development in the Fayetteville Shale by scaling emissions factors by 2008 gas development activity. Emission factors are observed or calculated emissions for a specific process. ADEQ focused on processes specific to hydraulic fracturing, and the operation of compressors.

ADEQ calculated annual air emissions from all hydraulic fracturing in the Fayetteville Shale by applying an emission factor of 5,000 Mcf to the 704 new wells that were completed in 2008. The chosen emission factor of 5,000 Mcf/episode was taken from a similar analysis on Barnett Shale (Armendariz, 2009) and represents the volume of natural gas vented to the atmosphere during the hydraulic fracturing of a single well. ADEQ's emission factor represents the volume of natural gas (which includes methane and VOCs) released during hydraulic fracturing, and has the same boundaries as the completion emission factors for unconventional wells as discussed in Chapter 2 (for example, NETL uses a shale gas hydraulic fracturing emission factor of 9,000 Mcf/episode) and shown in Exhibit 2-1. ADEQ's emission factor (5,000 Mcf/episode) is discussed in this chapter because it was developed with the goal of evaluating shale gas emissions with impacts other than climate change.

ADEQ calculates total compressor emissions by factoring the combustion emissions from the operation of a single compressor by the 356 compressors used for natural gas distribution in the Fayetteville Shale. The emission inventory concluded that the VOC emissions from compressor stations are the largest source of VOC emissions from shale gas development in the Fayetteville Shale. (ADEQ, 2011)

ADEQ used photoionization detectors to measure ambient VOC emissions the Fayetteville Shale. A total of 14 air sampling sites were set up, including six drilling sites, three hydraulic fracturing sites, four compressor stations, and one control site. Elevated levels of VOC emission were measured near the drilling sites, but were near minimum detection limits near all hydraulic fracturing sites, compressor stations, and the control site. ADEQ concluded that the open storage tanks for drilling mud and cuttings are the likely cause of elevated VOC emissions around the drilling sites. No data were collected on the composition of VOC emissions, so further data collection is necessary to assess the potential impacts of drilling VOCs on public health. (ADEQ, 2011)

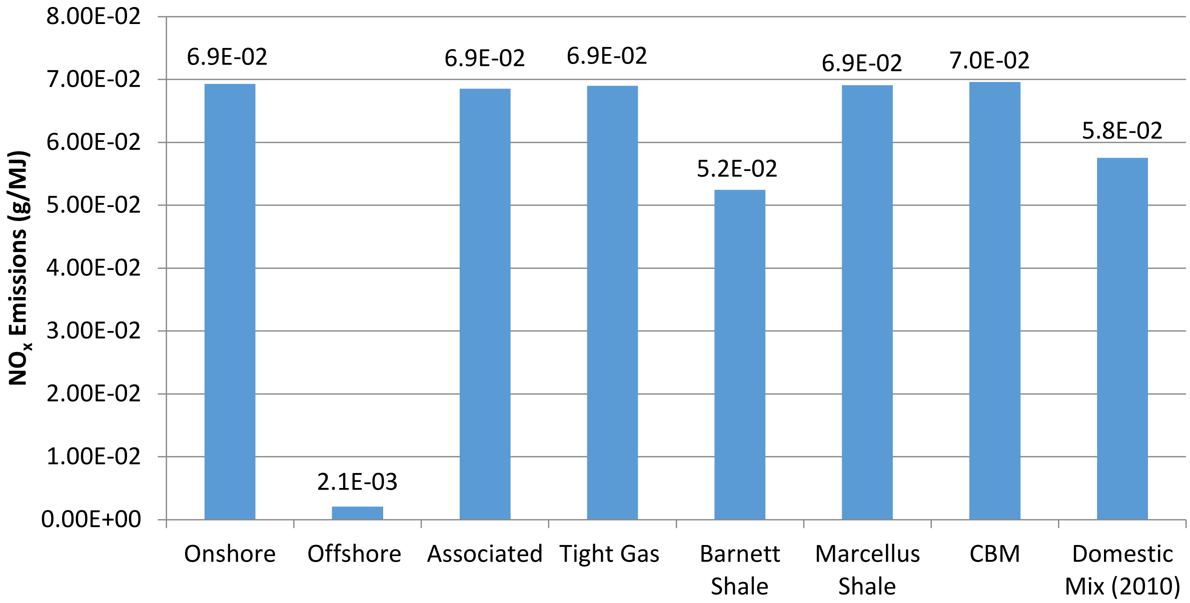
ADEQ did not identify condensate storage tanks as a significant source of VOC emissions from the development and operation of shale gas wells. The Fayetteville Shale produces dry natural gas, with heavy hydrocarbons (i.e., hydrocarbons with a higher mass than methane) comprising less than 0.5 percent of raw natural gas. The separation and storage of heavy hydrocarbons can be a significant source of VOC emissions for some regions. However, due to the low concentration of heavy hydrocarbons, the extraction of natural gas in the Fayetteville Shale does not have storage tanks for NGLs. (ADEQ, 2011)

3.2 Combustion Emissions

The combustion of natural gas in compressors and gas processing equipment produces NO_x and CO. The combustion of diesel in drilling equipment produces NO_x and CO, as well as significant quantities of PM and SO_2 emissions. The generation of grid electricity (used by a small share of natural gas compressors) produces all of these air pollutants as well.

NETL's assessment of natural gas compares NO_x emissions among different natural gas types and concludes that the NO_x emissions from unconventional natural gas are comparable to those from conventional natural gas. This is illustrated in Exhibit 3-2, which includes direct NO_x emissions from extraction activities as well as indirect NO_x emissions from the generation of electricity and other ancillary processes. Most of the natural gas sources have NO_x emissions in the same order of magnitude. A key exception is the emissions from offshore extraction; offshore extraction platforms use centrifugal compressors, which have lower combustion emission factors than the reciprocating compressors used at onshore extraction sites. (NETL, 2014)

Exhibit 3-2 Direct and Indirect NO_X emissions from natural gas extraction and processing (NETL, 2014)



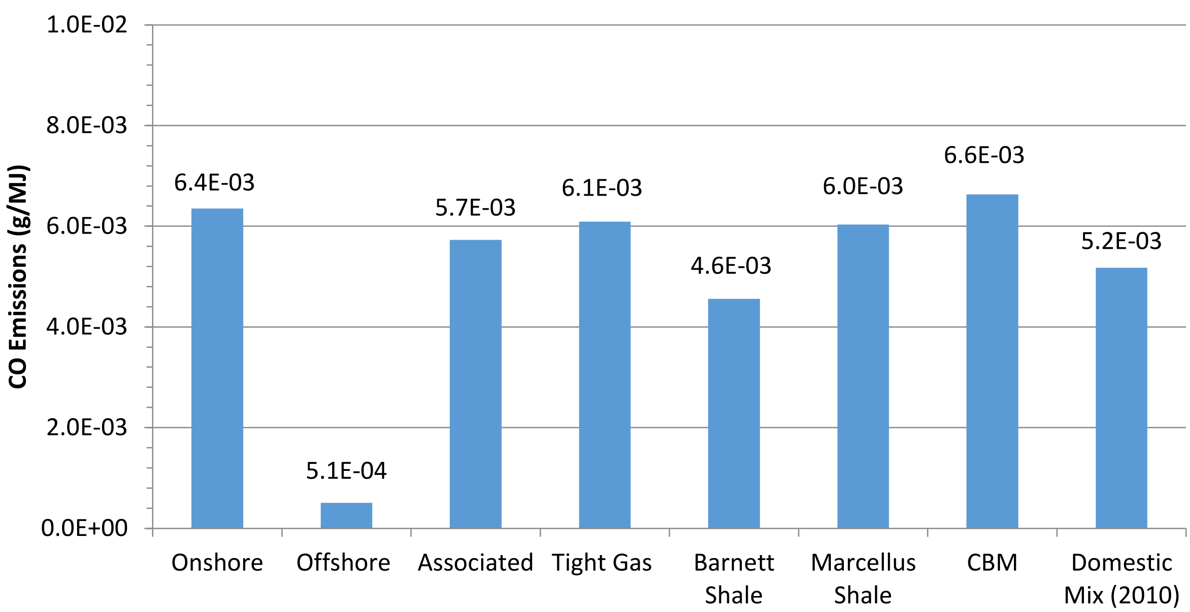
The EDF analysis of the Barnett Shale also applied a bottom-up approach to calculate combustion emissions from natural gas production. They calculated region-wide compressor exhaust emissions of 46 tons of NO_x emissions per day. For comparison, they point out that the combined NO_x emissions from all airports in the Barnett region, which include Dallas Love Field and Dallas-Fort Worth International Airport, produce 14 tons of NO_x emissions per day. The NO_x inventory from shale gas production in the Barnett Shale is at least three times higher than the NO_x inventory from area airports. (Armendariz, 2009)

There are options for reducing NO_x emissions from natural gas production. The NO_x emissions from compressor engine exhaust can be reduced by installing non-selective catalytic reduction pollution control technology. Another option for NO_x reduction is the replacement of gas-fired compressor engines with electrically-powered compressors. (ADEQ, 2011) Extraction sites in remote areas may not be near the electricity grid, but if electricity is available, the use of electrically-powered equipment can be a cost-effective way to reduce direct combustion emissions. This is a feasible option for Barnett Shale wells that are near the Dallas-Fort Worth metropolitan area. (NETL, 2014)

Currently, there is no evidence of widespread use of electrically-driven compressors in the Barnett Shale, but for its characterization of Barnett Shale natural gas operations, NETL's model applies a 25/75 percent split between electrically- and gas-powered compressors, respectively. The use of electrically-powered compressors by Barnett Shale operations explains why NETL's calculated NO_x emissions are lower for the Barnett Shale scenario than for other natural gas extraction scenarios (as shown in Exhibit 3-2). (Again, the one exception to this conclusion is offshore natural gas, which uses centrifugal compressors that have lower NO_x emissions than the reciprocating compressors used by onshore natural gas operations.) Increased use of electricity for natural gas compression will increase *indirect* emissions of NO_x. However, depending on the mix of fuels and combustion technologies used for electricity generation, the total NO_x emissions from systems that use electrically-powered compressors can still be lower than the total NO_x emissions from systems that use only natural gas as an energy source. (NETL, 2014) As discussed in Chapter 2, natural gas pipelines can also use electrically-powered compressors as a way to meet local emission regulations and limit the use of internal combustion engines. (Hedman, 2008)

NETL's conclusions for CO emissions are the same as their conclusions for NO_x emissions. (NETL, 2014) The CO emissions from unconventional natural gas are comparable to those from conventional natural gas. This is illustrated in Exhibit 3-3, which compares CO emissions among different natural gas extraction sources. (Again, offshore extraction has low CO emissions, because it uses centrifugal compressors.)

Exhibit 3-3 CO emissions from natural gas extraction and processing (NETL, 2014)



The combustion of natural gas does not produce significant PM and SO_2 emissions, but the use of diesel engines by drill rigs produces PM and SO_2 emissions. ADEQ's assessment of Fayetteville Shale identifies the use of drilling rigs during well completion as the largest source of PM emissions from gas production. (ADEQ, 2011) NETL's assessment of natural gas shows that PM emissions are of the same order of magnitude for all natural gas sources (on the order of magnitude of 0.0001 grams per MJ of gas extracted).

Indirect energy consumption can also affect the air quality profile of a gas extraction technology. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that comprise a regional electricity grid. For example, NETL's results show variance in SO_2 emissions among natural gas types. The SO_2 emissions from Barnett Shale are an order of magnitude greater than the SO_2 emissions from other onshore natural gas extraction technologies. This difference is due to the use of electricity by a portion of the compressors in the Barnett Shale. The fuel mix for grid electricity includes the combustion of coal, which is a source of SO_2 emissions. (NETL, 2014)

3.3 Air Quality Studies on Venting and Combustion Emissions

Due to concerns about the air quality impacts from shale gas development, the East Texas Council of Governments commissioned an air quality assessment of the Haynesville Play, which had nearly 3,000 shale gas wells as of December 2012. (Environ, 2013) The air quality assessment collected data for VOC, NO_x, and CO emissions. The largest sources of these emissions were fugitive releases and combustion emissions from gas processing equipment and compressors. Compressors and gas processing equipment account for 79.7 percent of NO_x emissions and 90.1 percent of VOC emissions. Fuel consumption by drilling rigs accounts for a smaller share of emissions – drilling rigs account for 16 percent of NO_x, and 1.2 percent of VOC emissions. Hydrofracking accounts for less than 2 percent of NOx emissions and less than 1 percent of VOC emissions. The authors acknowledge that there is significant uncertainty associated with future year projections of regional air emissions, but conclude that continued development of Haynesville Shale gas, even at a slow pace, will be large enough to affect the ozone levels in northeast Texas. (Environ, 2013)

Litovitz et al (2013) estimated the air pollutants from shale gas extraction in the Pennsylvania portion of the Marcellus Shale. They estimated VOC, NO_x, PM, and SO_2 pollutants by analyzing data for diesel trucks, well development (including hydraulic fracturing), natural gas compressor stations, and other natural gas extraction activities. They then scaled their estimates to the county and state levels. They concluded that compressor station activities account for at least 60 percent of extraction-related emissions; development activities, which include hydraulic fracturing, account for, at most, a third of extraction-related emissions. To provide a basis for comparison, they compared the estimated pollutants from shale gas production to other industrial activities in Pennsylvania. The estimated emissions of VOC, PM, and SO_2 from shale gas production account for less than 1 percent of total air pollutants from all industrial sectors in Pennsylvania. NO_x emissions represent a higher share of total industrial air pollutants, at 2.9 to 4.8 percent of total industrial air pollutants. Shale gas air pollutants may be a small portion of state-wide industrial emissions, but they are not evenly distributed across the state. In counties with the most shale gas extraction, county-aggregated NO_x emissions are higher than the NO_x emissions from a major source, such as a power plant. (Litovitz et al, 2013)

Further data collection efforts are necessary to characterize the regional variation in the volume and composition of vented natural gas. The University of Texas at Austin is leading a team of engineering firms and producers to measure methane emissions from hydrofracked wells in the Barnett, Eagle Ford, Fayetteville, Haynesville, Denver-Julesberg, and Marcellus regions. (Dittrick, 2012) NETL has air quality sampling in progress, which is using mobile equipment to measure VOCs and other air quality metrics in the Marcellus region. (NETL, 2013)

The Secretary of Energy Advisory Board (SEAB) views shale gas production as a key opportunity for increasing the U.S. natural gas supply, but recommends the use of emission control technologies. SEAB recommends the use of state and federal regulations for timely implementation of emission control technologies. For example, the EPA's NSPS rules and National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for the oil and gas sector will reduce smog precursors and other harmful pollutants. As noted by SEAB, a limitation of the new NSPS[1] rules is that they do not apply to existing shale gas wells unless the wells are re-fractured. Further, producers should also be expected to "collect and publicly share" emissions data. (SEAB, 2011)

[1] Since NSPS rules reduce total gas leakage, they have the two-fold benefit of reducing methane emissions (as discussed in Chapter 2) as well as VOC emissions. NSPS implementation has climate and air quality benefits.

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4 Water Use and Quality

In the broadest terms, the literature describes water quality and the treatment and management of wastewaters as the central issue in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of fresh water, and deep underground injection wells for wastewater disposal are more readily available, the central issue is the availability of water for drilling and hydraulic fracturing and the impacts this could have on established users. Drilling and hydraulically fracturing a shale gas well can consume between 2 and 6 million gallons of water and local and seasonal shortages can be an issue, even though water consumption for natural gas production generally represents less than 1 percent of regional water demand. Water quality impacts can result from inadequate management of water and fracturing chemicals on the surface, both before injection and after as flowback and produced water. Subsurface impacts can result from the migration of fracturing fluids, formation waters, and methane along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

4.1 Water Use for Unconventional Natural Gas Production

Water is used in unconventional natural gas production and, to a lesser extent, in the associated infrastructure for gas processing and testing pipelines. (KPMG, 2012) The vast majority of water is used for drilling and, more importantly, for hydraulic fracturing. Of the total water used by the shale gas industry, hydraulic fracturing jobs consume about 89 percent, and drilling uses 10 percent with infrastructure uses consuming the remainder. (Hayes and Severin, 2012) Water mixed with mud and chemicals is circulated through the drill string and borehole during drilling to cool the drill bit, circulate rock cuttings up out of the borehole, and control fluid pressures in the borehole. Water is the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume, with the remainder a mixture of chemicals that dissolve some of the rock formation around the fractures, protect the drilling equipment, and control the fluid properties of the mixture. More details on the types of chemicals and other agents used during well drilling and hydraulic fracturing are provided in Section 4.2.1.

The Sierra Club outlined the potential environmental impacts of water used for unconventional natural gas development. (Segall and Goo, 2012) Segal and Goo cited the Secretary of Energy Advisory Board (SEAB) in reporting that hydraulic fracturing uses between 1 and 5 million gallons of water per well. (2011) Reduced surface water availability can harm ecosystems and human communities; groundwater withdrawals can permanently deplete aquifers. Hydraulic fracturing fluids, flowback water, and produced waters can pose risks to water quality; proper treatment of these fluids is essential to protecting water resources.

4.1.1 Water Consumption

The United States (U.S.) Department of Energy (DOE) examined current and potential future impacts on the U.S. energy sector from three climate trends, increasing air and water temperatures, decreasing water availability, and increasing intensity and frequency of storms. (2013) The DOE found that, among other impacts, unconventional oil and gas production is vulnerable to decreasing water availability. Disruption of energy infrastructure in coastal regions due to storms and sea level rise could also disrupt production. The DOE cites two recent events as examples of impacts from decreasing water availability. In 2011, Grand Prairie, Texas (followed by other local water districts) restricted the use of municipal water for hydraulic fracturing. And in the summer of 2012, operators in Kansas, Texas, Pennsylvania, and North Dakota faced higher water costs and were denied access to water usage for at least six weeks due to drought conditions. (DOE, 2013)

The Government Accountability Office (GAO) examined the environmental impacts associated with commercial oil shale development, because oil shale, like natural gas from shales, uses substantial amounts of water. (2010) Most importantly, the GAO noted that the magnitude of impacts on water availability and quality from oil shale development is unknown. While water would likely be available during initial development of an oil shale industry, the size of the industry, particularly in Colorado and Utah could eventually be constrained by the availability of water. Similar concerns have arisen for shale gas development in arid regions.

Water consumption per well can vary due to four sets of conditions:

- *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

Drilling a shale gas well can consume anywhere from 65,000 to more than 1 million gallons of water, depending on the depth and horizontal length and the geology of the formations through which the hole is drilled (see Exhibit 4-1). Hydraulic fracturing can use anywhere from 2 to 6 million gallons of water, which can be more than 95 percent of the water use per borehole as a single borehole can be hydrofractured multiple times. (CRS, 2009) Nicot and Scanlon note that water use per well has increased over the last ten years as the lateral lengths and number of fracking stages increased. (2012)

The U.S. Environmental Protection Agency (EPA) has estimated that if 35,000 wells per year were hydraulically fractured in the U.S., these wells would consume the equivalent of the water consumed by 5 million people. (Groat and Grimshaw, 2012) This scale of development was achieved during early shale gas activity; approximately 35,000 shale gas wells were drilled in 2006. (Halliburton, 2008) No data could be found on the number of shale gas wells developed each year since 2006. However, the decline in the number of active natural gas drilling rigs over that last few years indicates a decline in the number of shale gas wells that are drilled annually. The weekly natural gas rig count has decreased nearly four-fold since early 2007, from approximately 1,600 to 400 active rigs. (EIA, 2014)

Exhibit 4-1 Average fresh water use per well (DOE, 2009; Mathis, 2011; GAO, 2012a)

Shale Play	DOE (2009) (gallons)			Mathis (2011) (gallons)			GAO (2012a) (gallons)		
	Drilling	Fracking	Total	Drilling	Fracking	Total	Drilling	Fracking	Total
Barnett	400,000	2,300,000	2,700,00	250,000	3,800,000	4,050,000	250,000	4,600,000	4,850,000
Eagle Ford	---	---	---	125,000	6,000,000	6,125,000	125,000	5,000,000	5,125,000
Fayetteville	60,000	2,900,000	3,060,000	65,000	4,900,000	4,965,000	---	---	---
Haynesville	1,000,000	2,700,000	3,700,000	600,000	5,000,000	5,600,000	600,000	5,000,000	5,600,000
Marcellus	80,000	3,800,000	3,880,000	85,000	5,500,000	5,585,000	85,000	5,600,000	5,685,000
Niobrara	---	---	---	300,000	3,000,000	3,300,000	300,000	3,000,000	3,300,000

Published estimates of water use typically rely on operator reports. DOE (2009) noted that the volumes reported are "approximate" and come from Chesapeake Energy (Satterfield, et al., 2008) and personal communications with operators. Mathis (2011) also presented Chesapeake Energy data. The GAO cites data reported by Apache Corporation. (2012a) Nicot and Scanlon cite data that the Texas Railroad Commission collects from operators. (2012)

Coalbed methane (CBM) wells can also be hydraulically fractured, but use significantly less water than shale wells. Published reports indicate that a hydraulic fracturing treatment in a CBM well can use between 50,000 and 350,000 gallons of fluids and 75,000 to 350,000 pounds of sand proppant. Operator data suggest that the maximum average injection volume is 150,000 gallons per well and the median volume of 57,500 gallons per well. (EPA, 2004)

If the amount of water used for shale gas production seems high, it is still less water-intense than the production of many other sources of energy, or the amount of water needed to produce an amount of energy, typically expressed in gallons per million British thermal units (gal/mmBtu). Mielke, et al., summarized the water intensity of various energy sources (see Exhibit 4-2). (2010) Natural gas is among the most water-efficient resources, including coal, oil, nuclear, and synthetic fuels. Conventional natural gas production requires some water for drilling, primarily for drilling mud, and to cool and lubricate the drill bit, but otherwise may use between 1 and 3 gallons/mmBtu for processing and pipeline transport. (Mielke, et al., 2010) Similarly, water intensity for shale gas drilling ranges between 0.1 and 1.0 gallons/million Btu, but hydraulic fracturing has an intensity of about 3.5 gallons/million Btu. With per-well reserves ranging from 2.0 to 6.5 BCF [billion cubic feet], shale gas uses between 0.6 and 1.8 gallons/mmBtu with the additional water relative to conventional production needed for hydraulic fracturing. (Mielke, et al., 2010)

Just as water demand varies by shale play and local conditions, the water intensity also varies by play, for example, water intensity in the Fayetteville at 1.7 gallons/million Btu and the Barnett at 1.5 gallons/million Btu) are greater than in the Marcellus (1.3) or the Haynesville (0.8). These differences, in part, reflect greater reserves per well in the latter two plays. (Mielke, et al., 2010)

In contrast to shale gas, petroleum from oil shales takes more water for mining and processing or retorting, which uses steam. Oil shales are either mined with surface retorting or undergo *in situ* retorting to release the oil for extraction through wells. Although data are limited due to the lack of commercial production, available estimates indicate a water intensity of oil shale mining between 7.2 and 38 gallons per million Btu, and 9.4 to 16 gallons per million Btu for *in situ* production. (Mielke, et al., 2010)

Exhibit 4-2 Ranges of water intensity of energy sources (Mielke, et al., 2010)

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

Furthermore, water use for the major shale plays is a very small fraction of total water use in the regions around the plays. Exhibit 4-3 lists the various uses for water in four representative plays, as percentages of the total use. The Barnett Shale, for example, underlies the Dallas-Fort Worth metropolitan area, so more than 80 percent of water in the area goes to public supplies. In contrast, the Marcellus underlies both populated and industrialized areas where more than 70 percent of water is used for power generation. The Fayetteville area, underlying a rural and agricultural area in Arkansas, consumes more than 60 percent of its water for irrigation. In the Haynesville, beneath eastern Texas and western Louisiana, water is used for multiple purposes, but more than 45 percent goes to public supply. Shale gas production typically consumes less than 1 percent of total water demand, except in arid regions like the Eagle Ford where it is 3 to 6 percent.

Exhibit 4-3 Total water use for four major shale plays ([1]Arthur, 2009; [2]Chesapeake Energy, 2012a; [3]Chesapeake Energy, 2012b)

Play	Public Supply (%)	Industry & Mining (%)	Power Generation (%)	Irrigation (%)	Livestock (%)	Shale Gas (%)	Total Water Use (Bgals/yr)*
Barnett[1]	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]*

Nonetheless, water presents logistical and cost challenges to shale gas operators. IHS estimates that lifecycle water management costs, including sourcing, treatment, transport, and disposal, can account for 10 percent of the operating cost of a hypothetical well in the Marcellus. (2012)

4.1.2 Sources of Water and Environmental Impacts

Unconventional natural gas producers generally withdraw water from local surface and ground water sources for drilling and hydraulic fracturing. So, while production uses a relatively small fraction of local withdrawals, seasonal and local impacts have been cited as a concern, as well as the longer term prospect for water supplies in some areas.

Water withdrawals from surface water sources like streams and rivers can decrease downstream flows, which can render these sources more susceptible to changes in temperatures. Warmer temperatures in summer months can affect the reproduction and development cycles of aquatic species. Reduced in-stream flows can damage riparian vegetation and affect water availability for wildlife. Water withdrawals from shallow aquifers can affect these resources by lowering water levels and reducing flows to connected springs and streams, compounding the effects on surface water bodies. Deeper aquifers are also susceptible to longer-term effects on groundwater flow, because recharge to deeper aquifers by precipitation takes longer. Surface and groundwater withdrawals can also impact the amount of water available for other uses, including potable water supplies. Fresh water is a limited resource in arid and semiarid areas where expanding population and shifting patterns in land use place additional demands on water supplies. Prolonged drought conditions and weather projections associated with warming climates may exacerbate the future availability of water in some parts of the country. (GAO, 2012a)

Water demand for unconventional natural gas production is not confined to shale gas and hydraulic fracturing. Gas production from coalbed methane formations poses risks to aquifers as water in the coal bed is removed to lower reservoir pressures, and induces methane to desorb from the coal. According to the U.S. Geological Survey (USGS), dewatering coalbed methane formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation. (GAO, 2012a)

Water rights and supplies, which are typically regulated at the state level, reflect the greater general availability of water in the eastern U.S. Historical trends in water use have created doctrinal differences in water laws so that east of the Mississippi River, where water tends to be more plentiful, states apply a riparian doctrine, where a water user who owns land adjacent to a water body has a right to make reasonable use of that water. In the West, where water can be scarcer, states apply a doctrine of prior appropriation, where a water user's reasonable and beneficial use of water remains subject to state permits that are generally issued on a first-come, first-served basis. (CRS, 2009) In some states, water rights are allocated according to water budgets for individual basins or watersheds, as determined by a state hydrologist or water authority.

4.1.3 Shale Play Water Supply Examples

Case studies of the larger and more active shale gas plays provide a geographically distributed overview of the water demand and supply issues.

4.1.3.1 Barnett Shale

The Barnett Shale is a Mississippian-age shale that occurs at depths between 6,500 and 8,500 feet and thicknesses between 100 and 600 feet in the Fort Worth Basin in northcentral Texas. (DOE, 2009) The Barnett covers 48,000 square kilometers (km^2) and underlies 20 counties, including the Dallas-Fort Worth metropolitan area. However, production from the Barnett comes primarily from the six counties surrounding Fort Worth (Wise, Denton, Parker, Tarrant, Hood, and Johnson). (Galusky, 2009)

Nicot and Scanlon quantified water use in the three Texas plays (i.e., Barnett, Eagle Ford, and Haynesville) based on operator data submitted to the Texas Railroad Commission. (2012) With more than 14,900 wells as of June 2011, water use per well ranges from 0.75 to 5.5 million gallons, while median water use per horizontal well is 2.8 million gallons. (Nicot and Scanlon, 2012)

In 2007, 59 percent of the water used in the Barnett came from surface water, 41 percent from groundwater, and less than 1 percent from reuse and recycling, which was projected to require less than 1 percent of regional surface water supplies and less than 10 percent of groundwater. (Galusky, 2007) Public water supply in the Dallas-Fort Worth metropolitan area is the largest user, making up almost 83 percent of total demand in the area. (Arthur, 2009)

A combination of growing population, drought conditions, and natural gas production raised concerns about the sustainability of local groundwater resources. (Bené, et al., 2006) The area has depended on the Trinity and Woodbine aquifers for more than a century, and this has resulted in declining water levels. As pressure on these aquifers has increased, additional surface water resources have been developed. In 2006, local natural gas producers formed the Barnett Shale Water Conservation and Management Committee (www.barnettshalewater.org) who have made it their mission to develop best management practices for water use.

Between April 2006 and November 2013, the Barnett Shale Water Conservation and Management Committee has released at least 17 reports on water management, recovery and reuse, and alternative sources. (BSWCMC, 2013) One of their first initiatives was to commission a study on present and projected water use (Galusky, 2007), including projections published by the Texas Water Development Board (TWDB). (Bené, et al., 2006) Bené, et al. note that water demand projections depend on population growth estimates, while demand for other uses, including shale gas projection, are driven by economic assumptions. (2006) They projected growth of total water use in the area from about 1.0 billion barrels (423.6 billion gallons) per year in 2000 to 16.3 billion barrels (684.3 billion gallons) per year in 2025, a 62 percent increase. They conclude that projections of groundwater use are regionally sustainable, but that continued development will have localized impacts. Further demands on the western parts of the Trinity aquifer in response to population growth, the Trinity aquifer may not be a reliable, long-term source of water for all users. Additional sources and distribution infrastructure could become necessary.

In 2009, Galusky revisited his original assessment in the wake of declining natural gas prices in 2008-2009, as the number of well completions in the Barnett dropped by more than half in 2009, to fewer than 1,500 from about 3,000 in 2008. (2009) The previous forecasts (Galusky, 2007; Bené, et al., 2006) indicated that the fraction of total freshwater from all sources would be less than 2 percent over the course of drilling the Barnett Shale. Galusky concluded that water use for Barnett Shale gas production may be less than 1.5 percent of regional supplies during periods of peak demand. (2009) Nicot and Scanlon also concluded that water use for shale gas production remains comparatively minor (less than 1 percent) at the regional and state levels, relative to irrigation (56 percent of state-wide water use) and municipal supplies (26 percent state-wide). (2012) However, they note that shale gas does consume a much higher percentage of localized water use. In some counties within the Barnett region, shale gas production uses more than 40 percent of groundwater, and as much as 29 percent of total net water use. Projected net water use in some counties could reach as much as 40 percent of the total during peak production years.

4.1.3.2 Eagle Ford Shale

The Eagle Ford Shale is a Cretaceous age formation that trends in an arc parallel to the Texas Gulf Coast from the Mexican border into east Texas, about 50 miles wide and 400 miles long with an average thickness of 250 feet at a depth of approximately 4,000 to 12,000 feet. It underlies 25 mainly rural counties, passing south of San Antonio and ending west of Houston. The major uses for water in the region are irrigation (66 percent) and public supply (17 percent). Water for shale gas production consumes between 3 and 6 percent of the total water use; the primary sources are groundwater from the Carrizo-Wilcox aquifer in the northern portion of the play, and the Gulf Coast Aquifer to the south. (Jester, 2013)

“Water availability” is defined by the TWDB as “how much water would be available if there were no legal or infrastructure limitations.” In contrast to water availability, the TWDB defines “water supply” as the amount of water that is provided by existing wells, pipelines, and other infrastructure. The TWDB projects that water availability from the Carrizo-Wilcox aquifer will decline slightly, by about 1 percent, between 2010 and 2060; water availability from the Gulf Coast aquifer will decline by 15 percent over the same period, mainly due to restrictions on withdrawals to prevent land surface subsidence. Despite the declines in water availability from the Carrizo-Wilcox and Gulf Coast aquifers, the TWDB projections show that the water available from these aquifers will exceed the water supply capacity within the Eagle Ford region through 2060. (TWDB, 2012)

In 2010, the mining sector, which includes natural gas wells, accounted for 1.6 percent of Texas’s water demand. The TWDB projects that this demand will be 1.3 percent of state water demand in 2060. Irrigation and municipal use account for the majority total water used in Texas. In 2010, irrigation and municipal users accounted for 56 and 27 percent, respectively, of state water demand. The TWBD projects that in 2060, irrigation and municipal water demand will each represent a 38 percent share of state water use (or, in total, 76 percent of state water use). (TWDB, 2012)

The Eagle Ford Task Force, appointed by the Texas Railroad Commission, evaluated data on water usage in the Eagle Ford region and concluded that the Carrizo Wilcox Aquifer contains enough water to support continued oil and gas development. Groundwater supplies about 90 percent of the water; oil and gas production, among other mining activities, will consume about 1.5 percent of total water usage in 2060. Water use for hydraulic fracturing is forecast to increase for about the next ten years to about 271 million barrels (11.4 billion gallons) per year, and then decline as water recycling technologies improve. (Porter, 2013)

Nicot and Scanlon quantified net water use for shale gas production using data from Texas, which is the dominant producer of shale gas in the U.S. (2012) Water use in the Eagle Ford play is increasing rapidly; cumulative use (2008 – mid-2011) has been 11.4 million barrels (4.8 billion gallons). Further, the authors point to counties where projected local use represents a very high proportion of total water use. Projected net water use for shale gas production in peak years could consume more than 30 percent of net water use (DeWitt County – 35 percent; Dimmit County – 55 percent; and Karnes County - 39 percent). In LaSalle County, net water usage may climb as high as 89 percent of net water use, relative to 2008 total net water use. Potential impacts are primarily in competition with other users for surface water resources, which are sensitive to public supplies for increasing populations and cyclic periods of wetter and drier weather. Stress to groundwater supplies shows as impacts to surface water features like springs and streamflows and, in some cases, land subsidence. (Nicot and Scanlon, 2012)

4.1.3.3 Fayetteville Shale

The Fayetteville Shale is a Mississippian age formation that straddles some 9,000 square miles of eastern Oklahoma and northern Arkansas at depths between 1,000 and 7,000 feet with a pay zone thickness between 20 and 200 feet. (DOE, 2009) Pay zones are areas within a shale gas formation that, due to lithologic or fracturing differences, tend to produce more gas or produce gas more economically. Total water use in the region in 2005 was 31.9 billion barrels (1.34 trillion gallons). Irrigation accounts for 62.9 percent of water use in the region and power generation another 33.3 percent. Shale gas production accounts for less than 1 percent of water use. (Arthur, 2009)

Veil calculated the total water demand for natural gas production from the Fayetteville based on historical drilling records and estimates of water consumption per well. (2011) A high-production scenario consumes an annual volume of 4.1 to 5.8 billion gallons per year. Assuming drilling and water use are distributed evenly through the year, this translates to between 11.2 and 15.8 million gallons per day, less than one percent of total state-wide water use in Arkansas. Veil concluded that there is sufficient water available to support natural gas development, but noted that not all sources of surface water will be sufficient, nor that water should be withdrawn at the same rates through the year. Veil recommends that gas producers plan ahead and store water during wet periods to ensure its availability when needed.

4.1.3.4 Haynesville Shale

The Haynesville Shale (also called the Haynesville/Bossier) is a Jurassic-aged formation that underlies 9,000 square miles of eastern Texas and northern Louisiana at depths of 10,500 to 13,500 feet with an average thickness of 200 to 300 feet. (DOE, 2009) Total water use in the

Haynesville region that covers eight parishes in northwestern Louisiana and six counties in eastern Texas totals 2.15 billion barrels per year (90.3 billion gallons). The major users are public supply (45.9 percent), industry and mining (27.2 percent), and power generation (13.5 percent). Shale gas production consumes approximately 0.8 percent. (Arthur, 2009)

The Texas portion of the Haynesville used 1.7 billion gallons (2008 – mid-2011). In 2017, the projected peak production year, water demand could exceed 136 percent of total county water use for San Augustine County, Texas, 55 percent in Shelby County, and 30 percent in Panola County. Greater precipitation in the Haynesville region than in the Eagle Ford makes surface water resources more abundant, but use for shale gas production can impact local streamflows. Similarly, groundwater resources remain readily available, but future conflicts with other users, including public supply and industrial users are possible. (Nicot and Scanlon, 2012)

4.1.3.5 Marcellus Shale

The Marcellus Shale is a Middle Devonian-age formation that sprawls across 95,000 square miles, underlying parts of six states, including 10 counties in southern New York, 32 counties in central Pennsylvania, 29 counties in northern West Virginia, five counties in western Maryland and Virginia, and three counties in eastern Ohio. The Marcellus is between 50 and 200 feet thick at depths varying from 4,000 to 8,000 feet. (DOE, 2009) Total annual water use in the region is 85 billion barrels (3,750,000,000,000 gallons). The major consumers are power generation (71.7 percent), industrial and mining (16.1 percent), and public supply (12.0 percent). (Arthur, 2009) Shale gas production consumes 0.19 percent. (Groat and Grimshaw, 2012)

Representative of the Marcellus region, Pennsylvania receives more than 40 inches per year in annual precipitation, and has abundant supplies of water with more than 1.9 trillion barrels (80 trillion gallons) as groundwater, and 58.1 billion barrels (2.5 trillion gallons) in surface waters. Despite the size of the groundwater resource, groundwater withdrawals make up just 7 percent of supply, and surface water withdrawal accounts for more than 9 percent of the annual total. As an indicator of water supply for shale gas production, between 2008 and 2010, water for hydraulic fracturing in the Susquehanna River Basin in Central Pennsylvania came from surface water sources (71 percent) and municipal supplies (29 percent). (Abdala and Drohan, 2010)

Despite the ease of water availability in the Marcellus region, water resources agencies and citizens in the Marcellus region have expressed concerns over the local availability of water supplies for natural gas production. Hydraulic fracturing may need up to 3 million gallons of water per treatment and, under drought conditions or in areas with stressed water supplies, adequate supplies for drilling and fracturing could be difficult. In addition to impacting local water resources, concerns include watershed degradation from heavy equipment movement on rural roads, and proper methods for disposing of potentially contaminated fluids from the shale gas wells. (Soeder and Kappel, 2009)

4.1.4 Potential Alternatives to Fresh Water Use

Increasing demand for water for drilling and hydraulic fracturing shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local fresh water sources. Potential alternative sources include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Water use for shale gas in Texas (Barnett, Eagle Ford, and Haynesville) is less than 1 percent of statewide withdrawals; however, local impacts vary with water availability and competing demands. Projections of cumulative net water use during the next 50 years for all plays total about 27.4 billion barrels (1.15 trillion gallons), peaking at 9.1 billion barrels (38.3 billion gallons) in the mid-2020s and decreasing to 23 Mm^3 [6 billion gallons] in 2060. The authors note that current freshwater use may shift to brackish water to reduce competition with other users.

Hayes and Severin report on an investigation of alternative sources of water in the Barnett that analyzed three potential sources: treated wastewater outfalls, small bodies of surface water outside state regulation, and small groundwater sources outside the main Trinity aquifer. (2012) Their results indicate that all three of these sources are susceptible to drought conditions, and that such fragmented sources involve dispersed ownership and increased costs to gather these waters.

One alternative source of water is seasonal changes in river flow; states and operators capture water when surface water flows are greatest. (DOE, 2009) This echoes a recommendation by Veil to operators in the Fayetteville to store water during wet periods to ensure its availability during drier periods. However, this requires operators to use or develop places to store water and adds costs for the collection and storage. (2011)

Drilling with compressed air offers an alternative to drilling with fluids, due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air-based drilling. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus Shale in New York. (DOE, 2009)

One of the preferred options is the reuse of produced water from prior hydraulic fracturing jobs. Mantell describes three factors that control the feasibility of reuse:

- *Quantity* of water produced, including the initial volumes of flowback water
- *Duration* of production and declines over time
- *Continuity* to keep tanks and trucks moving to increase efficiency (2011)

The Barnett, Fayetteville, and Marcellus all produce substantial volumes of water, starting with 500,000 to 600,000 gallons per well in the first ten days, or enough to meet 10 to 15 percent of the total water needed for a new well. The Haynesville produces less water, typically 250,000 gallons in the first ten days, or about 5 percent of the water for the next well. (Mantell, 2011)

The treatment of produced water is discussed below in the sections on flowback and produced water, and on recycling and reuse, below.

4.2 Potential Impacts to Water Quality

The GAO reviewed studies indicating that shale gas development can pose risks to water quality as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gasses and chemicals. Spilled, leaked, or released chemicals or wastes can flow into a surface waters or infiltrate into ground waters to contaminate subsurface soils and aquifers. (GAO, 2012a)

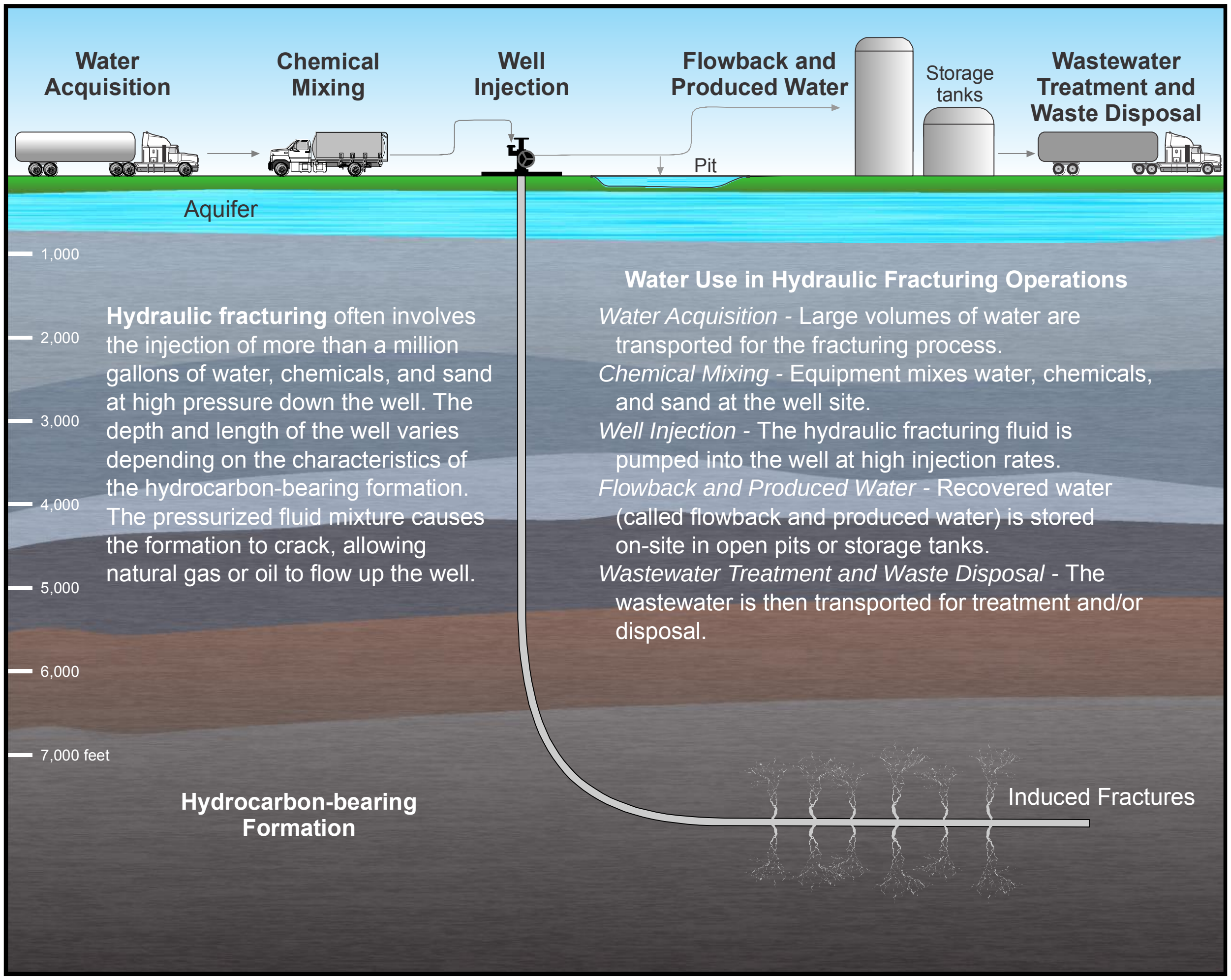
Vengosh, et al. describe three potential risks to the quality of U.S. water resources: (1) contamination of shallow aquifers, primarily due to inadequate well construction; (2) hydraulic pathways connecting deep gas-bearing formations with shallower aquifers; and (3) inadequate disposal of produced and flowback waters. (2013)

The EPA distinguishes four stages during hydraulic fracturing water cycle where the use of water and hydraulic fracturing chemicals could lead to possible impacts on drinking water quality:

- *Chemical Mixing*: Surface spills of hydraulic fracturing fluids on or near well pads and stormwater runoff can impact surface and ground water resources.
- *Well Injection*: Fluid injection and fracturing processes can result in loss and migration of fluids in the subsurface.
- *Flowback and Produced Water*: Surface spills of flowback and produced water on or near well pads can impact surface and ground water resources.
- *Wastewater Management and Disposal*: Inadequate management and treatment during wastewater transport and treatment or disposal can impact surface and groundwater resources. (2011)

These four stages occur in two interconnected environments, the surface where spills during chemical mixing and wastewater management pose potential risks to surface waters and habitats, and to ground waters. In the subsurface, water and chemicals can potentially leak along the well bore, propagating fractures, and existing pathways and fracture networks into shallower formations, including aquifers. Exhibit 4-4 illustrates these four stages in the use of water for hydraulic fracturing.

Exhibit 4-4 Water use in hydraulic fracturing operations (Source: NETL)



4.2.1 Chemical Mixing

Large quantities of fluids are essential to the drilling process. Drilling fluids circulate cuttings (rock chips produced during drilling, much like sawdust from drilling into wood) to clear the borehole as the drill advances, cool and lubricate the drill bit, stabilize the wellbore to prevent caving in, and control borehole fluid pressures. Drillers typically use lined surface pits or tanks to store water and drilling fluids. (DOE, 2009) Shale gas drilling poses potential risks to water quality from spills or releases of chemicals and wastes resulting from tank ruptures, blowouts, equipment or impoundment failures, overfills, vandalism, accidents, ground fires, operational errors, or stormwater runoff. (GAO, 2012a; Horinko, 2012)

The EPA describes four key properties that fracturing fluids should possess:

1. *Viscosity*: high enough to create fractures with adequate widths
2. *Penetration*: maximize the distance fluid travel to extend fracture lengths
3. *Transport*: ability to carry large amounts of proppant into the fractures

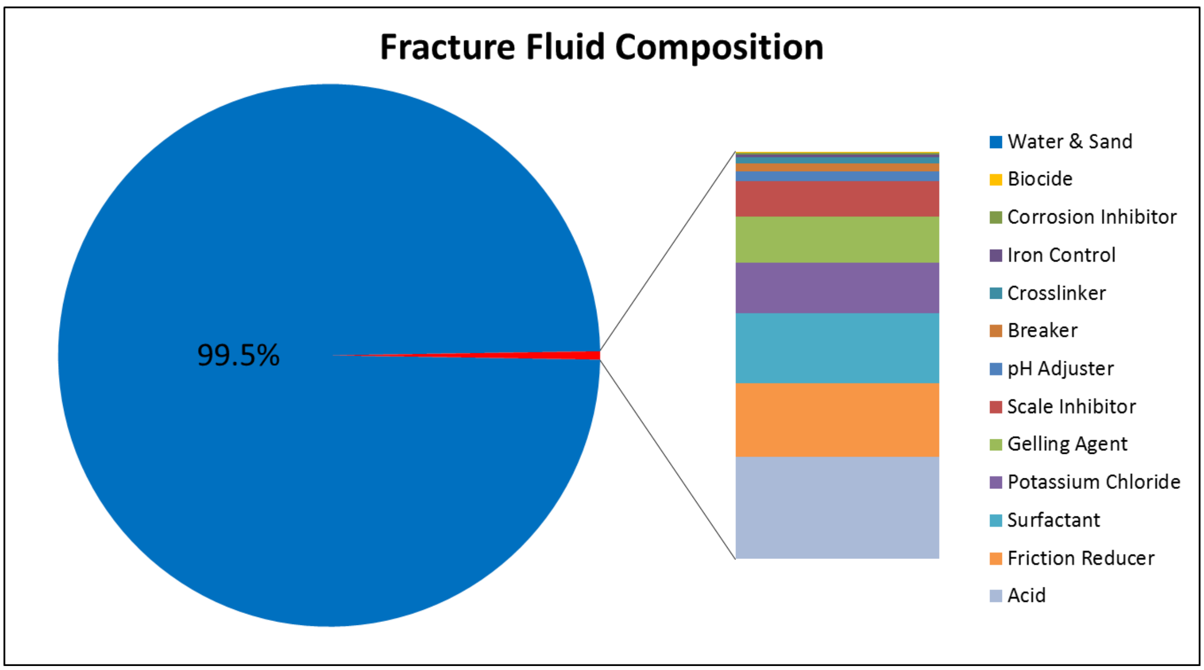
4. *Degradation*: minimize the amount of gelling agent to make degradation (or "breaking") easier and cheaper (2004)

Hydraulic fracturing can serve multiple purposes; most generally, it is used to increase the productivity of a well, either for injection (as in disposal wells) or extraction (or oil and gas production). In addition to increasing permeabilities 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, and can be used to manage pressure differences between the well and the formation. (EPA, 2004)

4.2.1.1 Shale Gas Drilling and Fracturing Fluids

Water typically makes up more than 98 percent of the fluids used for hydraulic fracturing. In addition to water, the fracturing process uses a proprietary mix of chemicals and other fluids, with each serving a specific, engineered purpose. Additionally, more than 1 million pounds of "proppants" may be used in hydraulic fracturing a well to prop the newly created fractures open and allow formation fluids to flow into the borehole. Proppants are compression-resistant particles, originally mainly fine-grained sand but now also including aluminum or ceramic beads, sintered bauxite, and other materials. (KPMG, 2012) In a representative example from a Fayetteville well, water and sand made up more than 99 percent of the volume with various chemicals making up the rest (see Exhibit 4-5).

Exhibit 4-5 Volumetric composition of a hydraulic fracturing fluid (DOE, 2009)



Each of these chemical additives serves a specific purpose, from corrosion and scale inhibitors to friction reducers. The specific compounds used for each drilling operation vary depending on local geologic and hydrologic conditions, and according to different operators. Exhibit 4-6 describes the types of compounds added to fracturing fluids and their purposes.

Exhibit 4-6 Fracturing fluid additives, main compounds, and purposes (DOE, 2009 and FracFocus, 2013)

Additive	Compound(s)	Purpose	Percentage of Fluid (% of volume)	
			DOE (2009)	FracFocus (2013)
Dilute acid	Hydrochloric or muriatic acid	Help dissolve minerals and initiate cracks in the rock	0.123	0.07
Friction Reducer	Polyacrylamide or Mineral oil	Minimizes friction between fluid and pipe	0.088	0.05
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	0.085	No data
KCl	Potassium chloride	Creates a brine carrier fluid	0.060	No data
Gelling agent	Guar gum or hydroxyethyl cellulose	Thickens water to suspend sand	0.056	0.5
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	0.043	0.023
pH Adjusting Agent	Sodium or potassium bicarbonate	Maintains effectiveness of other components, such as crosslinkers	0.011	No data
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	0.01	0.02
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	0.007	0.032
Iron Control	Citric acid	Prevents precipitation of metal oxides	0.004	0.004
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	0.002	0.05
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	0.001	0.001
Oxygen Scavenger	Ammonium bisulfate	Removes oxygen from the water to protect pipe from corrosion	No data	No data
Clay Control	Choline Chloride, Sodium Chloride	Minimizes permeability impairment	No data	0.034
Water and Proppant	Proppant: silica or quartz sand	Allows fractures to remain open so gas can escape	99.51	99.2

In order to provide the public information about chemicals used in hydraulic fracturing, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission manage a national hydraulic fracturing chemical registry called FracFocus (www.fracfocus.org). This site also offers general information on hydraulic fracturing, chemicals, their purposes, and groundwater protection measures. While it is not an official government information system, FracFocus is being used by states for official disclosure. Colorado, Oklahoma, Louisiana, Texas, North Dakota, Montana, Mississippi, Utah, Ohio and Pennsylvania use FracFocus to disclose chemical use. (FracFocus, 2013) The FracFocus website reports the average hydraulic fracturing fluid composition for U.S. shale plays, based on August 2012 data. The relative proportions of some additives have changed since the DOE shale gas primer was published, but the types of chemicals and their purposes remain essentially the same. (2009)

4.2.1.2 Coalbed Methane Drilling and Fracturing Fluids

CBM formations can be fractured with a variety of fluids, including gelled fluids, foamed gels, water with potassium chloride, and acids, or a combination of these fluids. Gellants (or thickeners) are added to water to increase viscosity; the selection of gellants is based on local formation conditions. Foamed gels, typically made by adding nitrogen or carbon dioxide as the foamant, use the bubbles in the foam to carry proppant into the fractures. Some CBM wells need no proppants, and so water, sometimes pumped from the formation itself, can be used for fracturing. Acids are used to dissolve limestone formations that overlay or are interbedded with the coal beds to increase permeabilities. Similar to the fluids used in shale gas production, other fluids can be added to these fracturing fluids to increase the efficiency and productivity of CBM wells. These additives include breakers to decrease viscosities, biocides, fluid-loss additives, friction reducers, and acid corrosion inhibitors, plus proppants. (EPA, 2004)

4.2.2 Well Injection

Underground migration of fluids, during and after hydraulic fracturing, poses a risk of contamination to groundwater quality by loss of drilling and fracturing fluids and migration of methane or saline fluids from the target formation.

4.2.2.1 Loss of Drilling and Fracturing Fluids

The GAO identified three primary pathways through which drilling and fracturing fluids can migrate through the subsurface and reach groundwater aquifers:

- *Inadequate or Improper Casing and Cementing*: The well must be isolated with casing and cement to prevent gas or other fluids to contaminate aquifers. Pathways can be created by inadequate depth to casing, inadequate cement in the space around the casing, or cement that degrades under borehole conditions.
- *Existing Fractures, Faults, and Abandoned Wells*: Drilling and fracturing can create connections with existing fractures or faults, or improperly plugged and abandoned wells, allowing gas and contaminants to migrate through the subsurface.
- *Fracture Growth*: Fractures induced by hydraulic fracturing can propagate out of the production zone, allowing contaminants to reach groundwater in an aquifer. (2012b)

Groundwater aquifers used as sources of drinking water typically occur at much shallower depths than the shale formations that produce natural gas. The primary barriers to subsurface contamination are proper siting, drilling, and completion of boreholes to ensure seals between the borehole and the rock outside the production zone, and the vertical separation between the geologic formations that produce shale gas and the shallower aquifers normally used as sources of drinking water.

Current well construction practices include multiple layers of protective steel casing and cement that protect fresh water aquifers and ensure that the producing zone is isolated from overlying formations. The casing is set while the well is being drilled and then, 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 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)

In addition to the engineered barriers in the casings and cements, the rock formations themselves act as natural barriers that contain natural gas and associated fluids in the target formation. Effective seals are what contain oil and gas and allow it to accumulate into economically extractable resources, just as is the case with aquifer formations that hold economic quantities of fresh water. In fact, the technology developments that have allowed extraction of natural gas from shale formations involve ways to release gas otherwise trapped in these formations for millions of years. (DOE, 2009)

In some shale plays, the vertical separation between the top of the shale formation and the deepest part of the aquifer can be more than two miles, reducing the likelihood of interconnections through the subsurface. Exhibit 4-7 lists representative separation distances for some of the major shale plays.

Exhibit 4-7 Vertical separation distances for groundwater over major shale plays (GAO, 2012a and DOE, 2009)

Shale Play	Depth to Base of Treatable Water (feet)	Separation Distance (feet)	Depth to Shale (feet)	Net Thickness of Shale (feet)
Barnett	1,200	5,300 – 7,300	6,500 – 8,500	100 – 600
Fayetteville	500	500 – 6,500	1,000 – 7,000	20 – 200
Haynesville	400	10,100 – 13,100	10,500 – 13,500	200 – 300
Marcellus	850	2,125 – 7,650	4,000 – 8,500	50 – 200
Woodford	400	5,600 – 10,600	6,000 – 11,000	120 – 220
Antrim	300	300 – 1,900	600 – 2,200	70 – 120
New Albany	400	100 – 1,600	500 – 2,000	50 – 100

In Chapter One, Background, Exhibit 1-2 illustrates the major components of the shale gas well construction process. Exhibit 4-8 below illustrates the multiple barriers created by the combination of multiple sets of casing and cement.

Exhibit 4-8 Components of the well construction process (Source: NETL)

Unlike shale gas plays, CBM formations tend to be shallower and the coal beds can lie within underground sources of drinking water. (EPA, 2004) For the three most productive CBM basins, coal seams in the San Juan Basin are found between 600 and 3,500 feet below ground, Powder River Basin seams lie between 450 and 6,500 feet below ground, and Black Warrior Basin seams occur between 350 and 2,500 feet. Because they are shallower than other gas wells, CBM wells can sometimes be drilled with water well equipment rather than the larger and more complex equipment needed for conventional and shale gas wells. (EPA, 2010)

Two types of well completions are used for CBM production, open-hole and cased. No lining material is installed in open-hole completions so that the gas can seep into the well bore and be brought to the surface. Cased completions are lined and then the casings are perforated in producing zones to allow the gas to flow into the well. Open-hole completions are used more often for CBM wells than conventional production, especially in the Powder River Basin. (EPA, 2010)

In evaluating reports from citizens about water quality issues, the EPA found no confirmed evidence that drinking water wells had been contaminated by hydraulic fracturing fluid injection in CBM wells. (EPA, 2004) The EPA noted that future CBM development may rely on deeper, thinner, tighter, and lower-rank coals, any of which would increase production costs, and that tighter coals could require hydraulic fracturing to produce gas economically. (2010) However, in terms of environmental impacts, the EPA subsequently focused on the discharge of produced water. (EPA, 2010)

4.2.2.2 Migration of Methane and Formation Fluids

A December 2008 explosion in a house in Geauga County, Ohio was investigated by the Ohio Department of Natural Resources (ODNR). (2008) Local responders had quickly recognized that natural gas was leaking into houses through water wells. The gas-bearing formation in the area is the Silurian “Clinton” sandstone, the local term for a sequence of inter-bedded sandstones, siltstones and shales. The ODNR determined that deep, high-pressure natural gas had over-pressurized the annulus of the English No. 1 Well, allowing gas to migrate from the well annulus into natural fractures in the bedrock below the cemented surface casing. This gas then migrated upward through fractures into the overlying aquifers and escaped from the aquifer through local water wells. The ODNR identified three primary contributing factors: inadequate cement of the production casing, hydraulic fracturing of the well with the inadequate cement, and shutting-in the well for 31 days after the fracturing, which allowed pressure to build. The ODNR determined that 22 domestic and one public water supply had been contaminated by natural gas charging from the English No.1 Well. The data indicated that ground water had not been contaminated by brine, crude oil, or fracturing fluids.

In January 2008, the ODNR announced implementation of new permit conditions for northeastern Ohio. Methane and formation fluids can migrate naturally within the subsurface, even without disturbance by drilling or hydraulic fracturing. Warner, et al., present evidence that pathways unrelated to drilling or hydraulic fracturing can exist between deep formations and overlying aquifers. (2012) Geochemical data and isotopic ratios indicate that mixing between shallow groundwater and brines from deeper formations can cause salinization of groundwater along naturally occurring pathways.

In the Fayetteville region, Kresse, et al., sampled and analyzed 127 domestic water wells to describe the general quality and geochemistry, and to investigate the potential impacts of gas-production on shallow groundwater in the area. (2012) Water-quality analyses from this study were compared to pre-development shallow groundwater quality samples. Among the results, the authors found higher chloride, major ion, and trace metal concentrations in the pre-development samples. Methane was also detected in a subset of the post-development samples, but based on carbon isotope ratios the authors concluded that the methane had biogenic origins. The groundwater-quality data collected for this study indicated that groundwater chemistry in the shallow aquifer system in the study area, including methane, was a result of natural processes.

Methane has also been found in water wells in Pennsylvania pre-dating the advent of Marcellus Shale gas development. Breen, et al., investigated occurrences of natural gas in wellwater in Pennsylvania. (2007) Gas occurrence in groundwater and accumulation in homes had become a safety concern; the investigators concluded that the weight of evidence pointed to gas from local underground storage fields as the likely origin.

In 2010 and 2011, the Center for Rural Pennsylvania analyzed water samples from private water wells located within 5,000 feet of Marcellus Shale gas wells. (Boyer, et al., 2012) Water from approximately 40 percent of these wells failed at least one Safe Drinking Water Act standard, typically for coliform bacteria, turbidity, and manganese, before gas well drilling. The results also showed dissolved methane in about 20 percent of water wells prior to the development of natural gas wells. Post-drilling analysis showed no significant increases in pollutants from drilling fluids and no significant increases in methane. There were outlier samples that exhibited high concentrations of total dissolved solids (TDS) and chloride after the nearby development of natural gas wells; Boyer et al. (2012) found no evidence linking these increased TDS and chloride concentrations to natural gas well development.

Duke University researchers studied shale gas drilling and hydraulic fracturing, and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York. (Osborne, et al., 2011) Methane concentrations were detected generally in 51 drinking water wells, but concentrations were higher closer to shale gas wells. A source of the contamination could not be determined and no evidence of fracturing fluids was found in any of the samples. Isotopic data for methane detected in shallow groundwater were consistent with deeper sources such as the Marcellus and Utica and matched the natural gas geochemistry from nearby gas wells. Lower-concentration samples from non-active sites had isotopic signatures reflecting a more biogenic or mixed biogenic-thermogenic source. The authors found no evidence of contamination of drinking water samples with deep saline brines or fracturing fluids.

Osborne, et al. describe three possible sources for the methane they detected. (2011) The first is physical displacement of gas-rich solutions from shale formations, which is unlikely due to the 1 to 2 km of strata above the shale. The second is leakage along gas well casings, with methane passing laterally and vertically into existing fracture systems. The third source is the formation of new fractures, or the enlargement of existing ones, due to hydraulic fracturing, thereby increasing the interconnectivity of the fracture system. They concluded that the higher concentrations measured in shallow groundwater from active drilling areas could result from migration from a deep methane source associated with drilling and hydraulic fracturing activities. In contrast, the lower-level concentrations in groundwater aquifers observed in the non-active areas are likely a natural phenomenon. More recently, Jackson, et al. examined concentrations of natural gas and isotopic ratios in drinking water wells in northeastern Pennsylvania and found methane in 82 percent of 141 wells. (2013) Concentrations averaged six times higher in wells less than 1 km from natural gas wells. These authors concluded that isotopic signatures, hydrocarbon ratios, and helium/methane ratios indicate a Marcellus-like source in some cases, suggesting that some water wells within 1 km of gas wells are contaminated by stray gasses.

Molofsky, et al. tested 1,701 water wells in northeastern Pennsylvania and found that methane was ubiquitous in local groundwater. (2013) Higher concentrations were found in valleys than in upland areas and particular water chemistries, which correlates more with topography and hydrogeology than Marcellus Shale gas extraction. The authors concluded that methane concentrations in water wells in this area could be explained without migration of Marcellus shale gas through fractures.

Vengosh, et al. (2013) review results from Osborne, et al. (2011) and Molofsky, et al. (2011) regarding the sources of possible methane contamination in drinking water wells in the Marcellus. Osborne, et al. found that elevated levels of methane correlated in water wells within 1 km of natural gas wells. (2011) Isotopic and geochemical signatures indicated that high levels of methane contamination in the closer wells had thermogenic sources rather than the mixed and biogenic sources in wells farther away. New noble gas data corroborate the conclusion that methane in the closer wells had a thermogenic origin. Vengosh et al. report that the most likely pathway for the methane was leaking through inadequate cement on casing, or through well annulus from intermediate formations. (2013)

4.2.3 Flowback and Produced Water

A large quantity of water, estimated to be at least 56 million barrels (2.4 billion gallons) per day is produced nationwide as a byproduct of drilling oil and gas wells. (GAO, 2012b) The five states with greatest produced water volumes in 2007 were Texas, California, Wyoming, Oklahoma, and Kansas, representing nearly 75 percent of total U.S. production. Texas alone, with more than 7.3 billion barrels, contributed 35 percent of the total volume. Produced water from unconventional natural gas production does not necessarily make a major contribution to the total volumes of nationally produced water from oil and gas production. Of the top 10 states for produced water, only five have major unconventional gas plays. (Clark and Veil, 2009) However, the volumes of produced water from unconventional gas production can present local and regional challenges.

4.2.3.1 Flowback Water

In the days and weeks following the injection of the 2 to 6 million gallons of water, chemicals, and proppants to hydraulically fracture a shale gas well, a fraction of this water is recovered as flowback water, while the remainder is temporarily lost into the formation. Estimates vary on what fraction of injected fluids return to the surface. The GAO reports that 30 percent to 70 percent of the original fluid injected returns to the surface; (2012a) IHS puts the figure between 20 and 80 percent; (2012) the Congressional Research Service (CRS) reports that this figure can range from 60 percent to 80 percent. (2009)

Gregory, et al. tabulate a typical range of concentrations for some of the common constituents of flowback water from the Marcellus Shale (Exhibit 4-9). (2011) The “low” concentrations were measured in early flowback from one well; “medium” concentrations were from late flowback from the same well; the “high” concentrations were measured in several wells with similar TDS concentrations.

Exhibit 4-9 Typical concentrations for common constituents in flowback water (Gregory, et al., 2011)

Constituent	Low (mg/L)	Medium (mg/L)	High (mg/L)
Total Dissolved Solids (TDS)	66,000	150,000	261,000
Total Suspended Solids (TSS)	27	380	3,200
Hardness (as $CaCO_3$)	9,100	29,000	55,000
Alkalinity (as $CaCO_3$)	200	200	1,100
Chloride	32,000	76,000	148,000
Sulfate	ND	7	500
Sodium	18,000	33,000	44,000
Calcium (total)	3,000	9,800	31,000
Strontium (total)	1,400	2,100	6,800
Barium (total)	2,300	3,300	4,700
Bromide	720	1,200	1,600
Iron (total)	25	48	55
Manganese (total)	3	7	7
Oil and grease	10	18	260
Total Radioactivity	ND	ND	ND

ND = Not Detected

The drillers may temporarily retain the flowback and brine in lined retention ponds before reuse or disposal; the pits must be reclaimed when operations end at that site. The well operator must then separate, treat, and dispose of the natural brine co-produced with the gas.

Flowback water can make treatment more difficult because it contains extremely high amounts of TDS. The longer the fracturing fluid remains below ground in contact with the shale, the higher the TDS, metals, and naturally occurring radioactivity it can pick up from the formation. (Abdalla, et al., 2012) The additives for hydraulic fracturing in a 3 million gallon fracturing job would yield about 15,000 gallons of chemicals in the waste or about 0.5 percent of the total volume. (CRS, 2009)

4.2.3.2 Produced Water

Once the well begins to produce natural gas, it also yields formation fluids called produced water. (IHS, 2012) Because produced water has been held in hydrocarbon-bearing formations, the fluids found in oil and gas bearing formations typically include a variety of hydrocarbons and water or salt water brines. The properties of produced water vary considerably depending on the geologic formation, the location of the field, and the types of hydrocarbons being produced. Produced water volumes and chemical properties can also vary throughout the producing lifetime of a formation. (Clark and Veil, 2009)

The quality of produced water is typically poor, and generally cannot be used for other purposes without treatment. The GAO described the range of possible contaminants that includes, but is not limited to

- *Salts*: chlorides, bromides, and sulfides of calcium, magnesium, and sodium
- *Metals*: barium, manganese, iron, and strontium
- *Organics*: oil, grease, and dissolved organics
- *Naturally Occurring Radioactive Materials (NORM)*: including radium and radon
- *Production Chemicals*: including those used for hydraulic fracturing (2012b)

CBM wells produce more water than other forms of unconventional natural gas. Water pressure in the coal seam helps keep the gas attached to the coal; lowering the pressure by pumping out water helps release the gas. (Guerra, et al., 2011) Water production from CBM wells normally starts at high volumes, but then falls as the coal seam is depressurized. Produced water from CBM wells varies in quality from very good (meeting state and federal drinking water standards) to very high in TDS with concentrations up to 180,000 parts per million (ppm), which is not suitable for reuse. (ALL Consulting, 2003) Exhibit 4-10 tabulates representative produced water quality data for the San Juan and Powder River Basins, which together represent nearly 70 percent of CBM production.

Exhibit 4-10 Chemical constituents in CBM produced waters

Constituent	San Juan Basin		Powder River Basin	
	Minimum (mg/L)	Maximum (mg/L)	Minimum (mg/L)	Maximum (mg/L)
Total Dissolved Solids	180	171,000	244	8,000
Barium	0.7	63	0.06	2
Calcium	0	228	5	200
Chloride	0	2,350	3	119
Iron	0	228	0.03	11
Magnesium	0	90	1	52
Potassium	0.6	770	2	20
Sodium	19	7,130	89	800
Sulfate	0	2,300	0.01	1,170

The treatment of CBM produced water is discussed below in the section on wastewater management and disposal and, in particular, in the section on discharge to surface water or evaporation.

4.2.4 Wastewater Management and Disposal

The oil and gas industry applies a three-tiered approach to the management of produced water that follows a hierarchical pollution prevention approach:

- *Minimization*: mechanical and chemical alternatives to water use
- *Recycle/Re-use*: re-injection 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 (NPC, 2011; Veil, 2011)

How operators manage, treat, and dispose of produced and flowback water is mainly an economic decision made within the limits of the applicable federal and state regulations. For example, underground injection is most often the lowest-cost option, ranging from $0.07 to $1.60 per barrel. Trucking costs for an injection well can significantly increase total costs. In Texas, trucking costs can range from $0.50 to $1.00 per barrel; in Pennsylvania the same costs can run from $4.00 to $8.00 per barrel. Water treatment can cost from $6.35 to $8.50 per barrel and advanced treatment by reverse osmosis and ion exchange can cost an additional $0.20 to $0.60 per barrel. (GAO, 2012b)

The GAO reports that other factors that influence water management options:

- *Geology*: availability of injection wells and their distances from producing wells
- *Climate*: arid climates are more favorable for evaporation from surface impoundments
- *Regulations*: federal and state regulations control the use of management methods
- *Risk Management*: legal liabilities from surface discharges and impoundments (2012b)

Exhibit 4-11 (DOE, 2009) outlines the main water management technologies by shale play.

Exhibit 4-11 Produced water management by shale gas basin (DOE, 2009)

Shale Gas Basin	Water Management Technology	Availability	Comments
Barnett	Class II injection wells	Commercial & non-commercial	Disposal into Barnett and underlying Ellenberger Group
	Recycling	On-site treatment & recycling	Reuse in subsequent fracturing
Fayetteville	Class II injection wells	Non-commercial	Disposal into two injection wells owned by a producing company
	Recycling	On-site recycling	Reuse in subsequent fracturing
Haynesville	Class II injection wells	Commercial & non-commercial	N/A
Marcellus	Class II injection wells	Commercial & non-commercial	Limited use of Class II injection wells
	Treatment and discharge	Municipal and commercial treatment facilities	Primarily in Pennsylvania
	Recycling	On-site recycling	Reuse in subsequent fracturing
Woodford	Class II injection wells	Commercial	Disposal into multiple confining formations
	Land Application	N/A	Permit required through OK Corporation Commission
	Recycling	Non-commercial	Water recycling and storage at central location
Antrim	Class II injection wells	Commercial & non-commercial	N/A
New Albany	Class II injection wells	Commercial & non-commercial	N/A

Different management methods invoke different sets of statutory and regulatory controls. For example, underground injection is regulated by the EPA and the states under the Safe Drinking Water Act, while discharges of waters are regulated under the Clean Water Act and the National Pollutions Discharge Elimination Systems. Other management practices can be regulated by state authorities. (GAO, 2012b) The sections below summarize each of the common management methods.

4.2.4.1 Minimization

The water use minimization options available to unconventional natural gas producers mainly involve mechanical and chemical alternatives that reduce the amount of water needed for drilling and hydraulic fracturing. Down-hole mechanical blocking devices such as packers and plugs can cut the amount of water needed in the borehole during development. Other materials, like carbon dioxide (CO_2) or nitrogen can be used in place of water, as can gelled fluids. However, gelled fluids can be more likely to damage the formation and increase the amounts and types of chemicals used. (NPC, 2011) In places like Wyoming where infrastructure, including pipelines and CO_2 are readily available, CO_2 has already been used for fracturing. However, substituting

CO_2 for water on a larger scale would need large investments in infrastructure to deliver the CO_2 to drilling and fracturing sites. (MIT, 2013)

4.2.4.2 Recycle and Reuse

Shale gas producers have begun reusing produced water for hydraulic fracturing. Water is typically treated first, and then mixed with fresh water if salt concentrations remain high. For reuse to become widespread, among shale gas operators, new, low-cost treatment technologies will be needed. Re-use has become more common among shale gas producers in Pennsylvania, in part due to a change in the state's surface water discharge standards that made treatment and discharge comparatively more expensive. (GAO, 2012b)

The feasibility of using produced and flowback water for shale gas production depends on the volume and quality of the re-used water. Operators benefit from larger volumes of water that stabilize the logistics of collecting, storing, and transporting the water, keeping tanks and pits in use and trucks moving. Water quality is important for reuse, particularly the TDS, mainly the salt content, and total suspended solids (TSS), or the amount of fine-grained particulate matter in the water, to control the drilling fluid chemistry and remove some of the contaminants that can return to the surface with the produced water.

Accenture divides water treatment technologies into two categories, the first for removing inorganic materials, primarily salts, and the second for organic materials, including oil and grease. (2012) The unconventional gas industry has concentrated on developing technologies to deal with the inorganic materials given the high TDS in flowback water from shale gas development. Accenture describes four types of treatment technologies available to shale gas operators:

- *Filtration* removes suspended solids with anything from simple household water filters to more complex and efficient designs. Shale gas operators use filters with pore sizes between 0.04 and 3 microns.
- *Chemical Precipitation* removes scale-forming elements like calcium, magnesium, barium, strontium, iron, manganese, and other metals. By adding chemicals and adjusting pH values, these constituents precipitate out of solution and settle out where they can be collected as sludge for disposal.
- *Thermal-based Technologies* remove salts from waters with very high TDS levels. By heating the water to almost the boiling point, the water vapor can be collected as distilled water or evaporated to the atmosphere. The residual solids collected as a concentrated brine or crystalline salt.
- *Membrane Filtration Technologies* have limited use in shale gas production as they are ineffective at filtering TDS concentrations greater than 35,000 to 45,000 ppm. Reverse osmosis is a common membrane filtration technology.

Produced water from the Barnett is generally high in TDS, but low in TSS and moderate scaling tendency. The preferred management method is disposal by underground injection. The large volumes of produced water and the availability of Class II disposal injection wells in the Barnett region limit the reuse of water. One operator reports treating and reusing about 6 percent of the total water needed for drilling and fracturing in the Barnett. (Mantel, 2010)

Fayetteville Shale produced water is generally of excellent quality for reuse, having very low TDS, low TSS and low scaling tendency. Since TSS levels are low, very limited treatment (filtration) is needed prior to reuse. The volume of water generated is typically sufficient to justify reuse. (Mantell, 2010) One operator is currently meeting approximately 6 percent of its drilling and fracturing needs in the Fayetteville with produced water reuse, and has a goal of 20 percent reuse in the play. (Veil, 2011) As with the Barnett, logistics and economics are the primary limiting factors that prevent higher levels of reuse in the Fayetteville. (Mantell, 2010)

The Haynesville Shale produces a smaller volume of produced water initially, relative to other major plays, but it is of very poor quality. TDS levels are immediately high, TSS is high and the produced water has high scaling tendency. The quality and volume factors combined with an adequate underground injections infrastructure make produced water reuse in the Haynesville challenging. Low produced water volumes, poor produced water quality and the associated economics have prevented successful reuse of produced water to-date in the Haynesville. (Mantell, 2010)

The Marcellus Shale is ideal in terms of produced water generation in that it produces significant volumes of water during the first few weeks and then water production typically declines quickly. Marcellus produced water is good quality with moderate to high TDS, low TSS, and moderate scaling tendency. Operators manage TDS by blending previously produced water with freshwater and the TSS is managed with filtration systems. Scaling is managed through precise monitoring and testing to ensure the compatibility of the blended produced and fresh water. (Mantell, 2010) The proportion of flowback water now reused in Pennsylvania is estimated to be as high as 75 percent. (Abdala, et al., 2012)

Veil examined the flowback and water management technologies and methods used today, and likely to continue to be used in the Marcellus region. (2010) He concluded that the region has sufficient water supplies and coordination with authorities like the Susquehanna River Basin Commission and the Delaware River Basin Commission has not become an obstacle. Marcellus operators have had some success reusing water from previous hydraulic fracturing with lower-TDS fresh waters, which would cut costs and reduce the volumes of fresh water needed.

Treatment of shale gas wastewater became an issue in Pennsylvania in 2011, where there are limited wastewater disposal options. Operators were sending wastewater to municipal wastewater treatment plants, which then treated the water and discharged it to rivers that supply drinking water populations across Pennsylvania and Maryland. The media reported concerns that these treatment plants were neither designed nor capable of treating drilling wastewaters. In March 2011, the EPA wrote to environmental officials in Pennsylvania noting "variable and sometimes high concentrations of materials that may present a threat to human health and aquatic environment, including radionuclides, organic chemicals, metals and total dissolved solids" were present in the wastewater, and urged increased water quality monitoring, particularly for radionuclides. Subsequent concerns about elevated bromide levels in state waterways prompted Pennsylvania regulators to request that operators stop sending their wastewaters to municipal treatment plants that may not be prepared to treat it. According to the Marcellus Shale Coalition, Marcellus operators complied with the state's request within two days. (Williams, 2012)

4.2.4.3 Disposal

By far, the preferred disposal method for the oil and gas industry as a whole is underground injection. In 2007, more than 98 percent of produced water from on-shore wells was injected underground. (Clark and Veil, 2009) The EPA and states regulate this practice under the Safe Drinking Water Act and the EPA's Underground Injection Control program. (EPA, 2013) Among the six classes of wells recognized by the EPA, oil and gas-related wells form Class II, which includes wells for enhanced recovery, disposal, and hydrocarbon storage.

Class II injection wells are specifically designed and constructed to inject fluids into permitted zones and prevent migration of injected fluids into underground sources of drinking water. Most produced water generated onshore is used to maintain reservoir pressures and drive oil toward producing wells for enhanced oil recovery. (Clark and Veil, 2009) Produced water does not need treatment before injection, but operating requirements to prevent plugging may cause water to be treated to control solids and dissolved oil, inhibit corrosion and chemical reactions, and retard microbial growth. Settling tanks, chemical additives, and filtration may also be used. (GAO, 2012b)

In the Marcellus, only about 5 percent is disposed of without treatment via underground injection. (Abdala, et al., 2012) The current disposal practice for Marcellus Shale liquids in Pennsylvania requires processing them through wastewater treatment plants, but the effectiveness of standard wastewater treatments on these fluids is not well understood. In particular, salts and other dissolved solids in brines are not usually removed successfully by wastewater treatment, and reports of high salinity in some Appalachian rivers may be associated with the disposal of Marcellus Shale brines. Concerns in Appalachian States about the possible contamination of drinking water supply aquifers have limited the practice of re-injecting Marcellus fluids. (Soeder and Kappel, 2009)

4.2.4.4 Discharge to Surface Water or Evaporation

A very small fraction, less than 1 percent, of onshore produced water is discharged to surface water bodies, generally in the western states when the TDS content is low. Treatment for surface discharge includes settling and filtration of solids, and salt removal with chemical additives. Other methods used to remove salts and other contaminants include thermal distillation, reverse osmosis (filtration), and ion exchange (only at low concentrations). (GAO, 2012b)

Surface water discharge for unconventional natural gas production is associated mainly with water produced from CBM extraction. The EPA (2010) estimated that more than 47 billion gallons of water were produced from coal seams in 2008 and about 45 percent, or about 22 billion gallons, was discharged to surface waters. Currently, allowing surface water discharges is made by either state agencies or the EPA regional offices, depending on the state's permitting authority. (Clark and Veil, 2009) More commonly, for example, in the Powder River Basin, produced water is held in ponds or pits for evaporation. Some of this water is used for irrigation when it does not require treatment to meet water quality standards. (GAO, 2012b)

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5 Induced Seismicity

Induced seismicity is ground motion (earthquakes) caused by human activities. There is little question that energy extraction and fluid injection have the potential to cause seismic activity. Earthquakes have been detected in association with oil and gas production, underground injection of waste waters, and possibly with hydraulic fracturing. Hydraulic fracturing involves injecting large volumes of fluids into the ground. These injections are short-lived and are injected at lower pressures, so it is likely that they do not constitute a high risk for induced seismicity that can be felt at the surface. In contrast to hydraulic fracturing, wastewater disposal from oil and gas production, including shale gas production, is typically injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity.

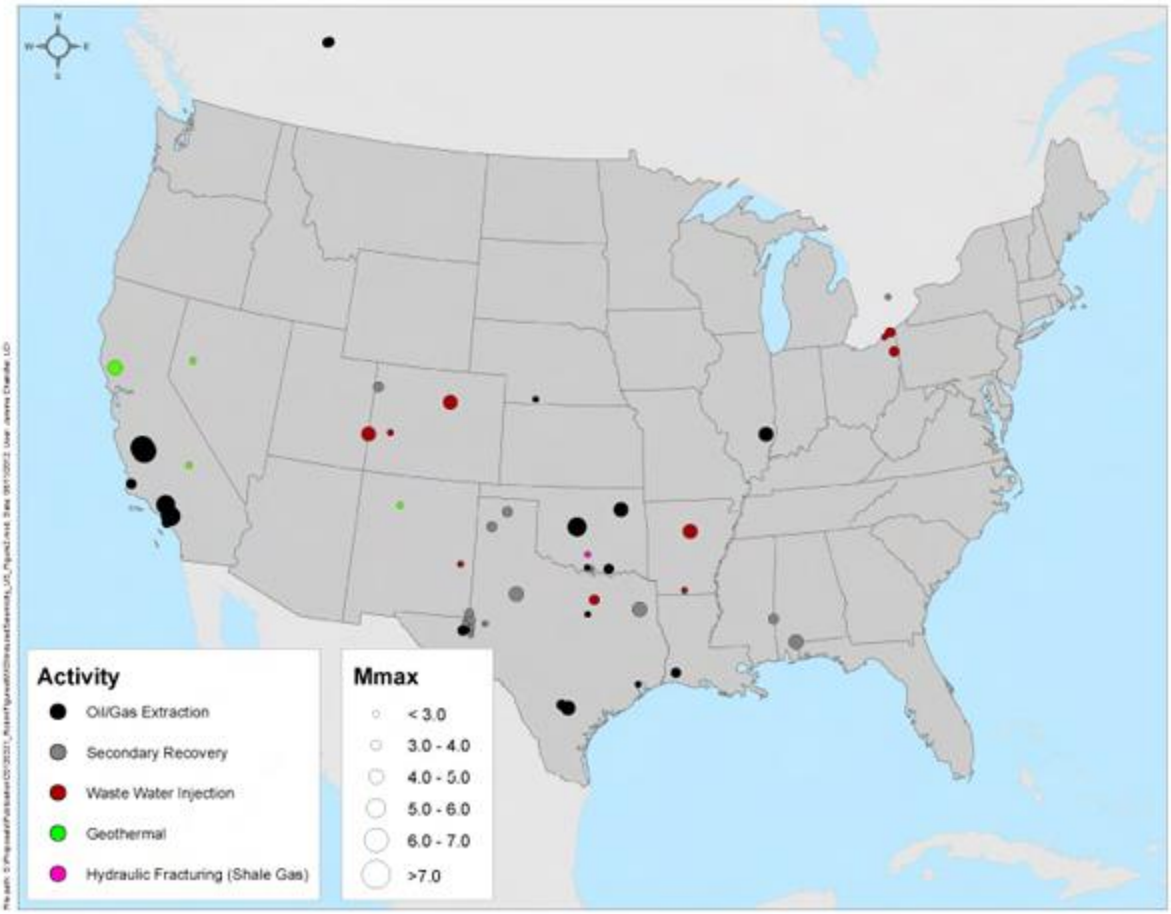
5.1 Induced Seismicity and Energy Technologies

Seismic activity, an earthquake, is the vibration of mechanical energy passing through the earth, much like sound waves vibrate through the atmosphere. More than 1.4 million earthquakes greater than magnitude (M) 2.0 (Richter Scale) are measured world-wide each year. Most earthquakes are caused naturally by the sudden slipping and shifting of large masses of rock along geologic faults. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people. Magnitudes greater than 3.0 tend to produce noticeable shaking. Magnitudes greater than 5.0 can cause structural damage to some buildings and property.

Earthquakes related to human activities are called "induced seismicity" and are typically small, short-lived events. Causes for these events include underground nuclear tests, explosions for mining or construction, and the weight of water in large reservoirs impounded behind dams, in addition to fluid withdrawal and injection associated with water and oil and gas production and wastewater disposal. Occurrences of seismic activity induced by human activity have also been documented since the 1920s. Induced seismicity associated with oil and gas production was first observed in the 1930s.

The National Research Council (NRC) (2012) describes events caused by or likely related to energy development in at least 13 states involving oil and gas extraction, secondary recovery, wastewater injection, geothermal and hydraulic fracturing for shale gas. Exhibit 5-1 shows sites in the United States and Canada with a history of incidents of induced seismicity caused by or related to energy development operations. The reporting of small events is limited by the availability of sufficiently sensitive seismic monitoring networks. However, the 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.

Exhibit 5-1 Locations of induced seismicity associated with energy technologies (NRC, 2012)



The Groundwater Protection Council (GWPC) (2013) provides an updated overview of induced seismicity in a white paper summarizing a 2013 special technology transfer session on "Assessing and Managing Risk of Induced Seismicity by Injection." In the white paper, multiple presenters evaluated the risks of induced seismicity, and reviewed the recent (NRC, 2012) case study examples of induced seismicity. The major issues and findings discussed in the special session include the following:

> Hydraulic fracturing involves injection of fluids at high rate for a short period of time. In nearly all cases, the potential for felt seismicity is very low, although a few cases have been observed where unique conditions were present. However, these have not led to any significant surface damage. The NAS [National Academy of Sciences, National Research Council] report concluded that hydraulic fracturing does not pose a high risk for induced seismicity.
>
> Tens of thousands of disposal wells are employed each day to inject produced water and other wastewaters into formations that are not hydrocarbon bearing. Most of these pose low risk of induced seismicity, but given the ongoing injection and cumulative formation pressure build up over time, there is some potential that disposal wells can contribute to induced seismicity. Most wells are completed in areas and geological formations that are not likely to lead to induced seismicity,

> but several well-documented examples are described in this white paper where seismic activity was linked to disposal wells (e.g., Ohio, Arkansas, Oklahoma, and Texas). These are typically due to some geological anomalies or faults in those locations. (GWPC, 2013)

The United States (U.S.) Government Accountability Office (GAO) (2012) concluded that the energy released by hydraulic fracturing does not produce enough ground motion to be felt at the surface. However, disposal of waste fluids through underground injection (see also Chapter 4, Water Use and Quality), which is commonly used throughout the oil and gas industry, including unconventional natural gas production, has, in some instances, been associated with perceptible earthquakes. The existing research does not establish a direct link between hydraulic fracturing and increased seismic activity, but to the extent that increased hydraulic fracturing increases the amount of water disposed of through underground injection, it could contribute to increased seismicity.

5.2 Hydraulic Fracturing for Unconventional Gas Production

Thompson (2011) outlined four differences between hydraulic fracturing and other types of induced seismicity:

1. *Different Type of Stress Release* – Hydraulic fracturing creates small fractures through tensile (extending) stresses where fractures spread as their walls are stretched apart whereas induced seismicity causes shear stresses that cause movement along faults.
2. *Limited Distances from the Wellbore* – Operators avoid creating fractures that propagate adjacent formations, which would waste fluids and energy outside the target formation and potentially allow gas to escape. Typically, shale gas fracturing penetrates 15 feet into the formation from the borehole and fracturing fluids on the order of 100 feet from the hole.
3. *Limited Volume of Fluid* – The amount of fluid used for hydraulic fracturing tends to be only what is needed to stimulate production.
4. *Limited Period of Time* – Hydraulic fracturing is normally completed within a period of hours or days. The operator’s objective is to drill and fracture the well as efficiently as possible and turn well operations around to extracting natural gas as quickly as possible.

The seismic behavior of hydraulic fracturing shale gas wells is recorded and understood through microseismic monitoring. During hydraulic fracturing, very small earthquakes, or microseismic events, are created by the high-pressure injection of fluids into the target formation. The increased pore pressure causes small natural fractures in the formation to slip, causing “microearthquakes” that are measured and recorded with sensitive sensing equipment and processing algorithms. The location and magnitude of microseismicity is used by oil and gas operators to help identify the orientation and spacing of the hydraulic fractures in the formation, in addition to helping guide horizontal well directions and well spacing, and in planning subsequent fracturing treatments. (Warpinski, et al., 2012; NRC, 2012)

Warpinski, et al. (2012) reviewed thousands of fracture treatments in six major shale basins in North America and found that the seismicity from hydraulic fracturing is small and does not create problems under normal circumstances. Only three incidents of induced seismicity associated with shale gas production and hydraulic fracturing have been documented world-wide, and only one of these was in the U.S. The other two occurred in the Horn River Basin in British Columbia, Canada, and Blackpool, Lancashire, United Kingdom. (NRC, 2012)

The single incident in the U.S. occurred in January 2011, when the Oklahoma Geological Survey (OGS) responded to a resident of Garvin County, in south-central Oklahoma, who reported feeling a number of earthquakes and observed that hydraulic fracturing operations were active nearby. The OGS found that there had been nearly 50 earthquakes ranging from M 1.0 to M 2.8 and that 43 of the quakes were large enough to be located. The majority of the earthquakes seems to have happened within about 3.5 kilometers of a shale gas well and had started about seven hours after the first hydraulic fracturing began. The correlation in space and time with the hydraulic fracturing suggested to Holland "that there is a possibility these earthquakes were induced by hydraulic fracturing. However, the uncertainties in the data make it impossible to say with a high degree of uncertainty whether or not these earthquakes were triggered by natural means or by the nearby hydraulic-fracturing operation." (Holland, 2011)

Davies, et al., (in press) proposed three mechanisms by which hydraulic fracturing could trigger seismic events by increasing fluid pressure in a fault zone. First, fracturing or pore fluids could enter a fault. Second, with a direct connection between the fault and the fractures, a pulse of fluid pressure could be pushed to the fault. Third, fracturing could increase fluid pressure in the fault. The fluids or fluid pressure could follow three types of pathways: directly from the borehole, through newly created fractures, or through existing fractures or faults. Thus, a borehole could intersect the fault or be some distance from it. Theoretically, these mechanisms and pathways could produce the three documented examples of seismicity "probably induced by hydraulic fracturing." (Davies, et al., in press)

The Energy Institute at The University of Texas at Austin funded an initiative to promote fact-based shale gas policies and regulations. (Groat and Grimshaw, 2012) Their report focused on three of the major shale gas plays, the Barnett, the Haynesville, and the Marcellus. Based on their review of the published literature, they found a broad consensus and drew five conclusions:

1. The amount of fluid pumped during the hydraulic fracturing process is of orders of magnitude less than that required to propagate fractures upwards to fresh water aquifers.
2. Tensile fractures created by hydraulic fracturing will have a very short life of enhanced permeability if they are not propped open by injected proppant particles.
3. Gas production will lower pressure in the fractured reservoir and drive fluid flow in and down, even after production has ceased.
4. Many of the fracturing fluid chemicals will rapidly dissipate during fracturing by reaction with the fractured rock surface, and some chemicals will be adsorbed on organic components and clay minerals.
5. After fracturing, any residual, depleted, fracturing fluid would mix with formation brines (as is seen in changes over time in the flowback water) and upward migration will essentially be impossible without very high driving pressures that do not exist. (Groat and Grimshaw, 2012)

The 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, 2012) The NRC noted that the very low number of felt events compared to the large number of hydraulically fractured shale gas wells is likely due to the short durations for injecting fluids, the limited volumes of fluid used, and the small spatial area affected by hydraulic fracturing. (NRC, 2012)

5.3 Underground Injection of Liquid Wastes

In contrast to hydraulic fracturing for shale gas production, wastewater disposal from oil and gas production, including shale gas production, is typically injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Many of the well-documented instances of induced seismicity associated with fluid injection involve large amounts of fluids injected over long periods of time. (NRC, 2012)

Underground injection of fluids is a common practice in the U.S. The U.S. Geological Survey (USGS) (Nicholson and Wesson, 1990) lists a variety of examples of deep well injection operations, including wastewaters, solution mining, geothermal energy extraction, enhanced hydrocarbon recovery, and the underground storage of natural gas. The U.S. Environmental Protection Agency (EPA) Underground Injection Program (2013) regulates the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. The EPA and 39 states regulate more than 150,000 Class II injection wells for disposal of oil and gas wastewaters. The increase in hydraulic fracturing for shale gas production has increased public awareness of induced seismicity from underground injection of fluids, so the EPA has added injection-induced seismicity as a research focus of its National Technical Workgroup. (EPA, 2013)

Horton (2012) describes an increase in seismic activity in northcentral Arkansas following the installation of eight wells for the disposal of hydraulic fracturing wastewater from the Fayetteville Shale. While the area is prone to natural earthquake activity, the rate of M 2.5 and greater earthquakes increased after the first disposal well started operations in April 2009. While there was one earthquake in 2007 and two in 2008, the number jumped to 10 in 2009, 54 in 2010, and 157 in 2011. Some 98 percent of the recent earthquakes happened within 6 kilometers of one of three of the eight disposal wells. Horton concludes that this “close spatial and temporal correlation supports the hypothesis that the recent increase in earthquake activity is caused by fluid injection at the waste disposal wells.” (Horton, 2012)

Frolich (2012) analyzed data from 67 earthquakes with M 1.5 and greater in the Barnett Shale region that occurred between November 2009 and September 2011. He found that the 24 events with the most reliably identified epicenters were located in eight groups within 3.2 kilometers of one or more injection wells. All of the wells nearest the earthquake groups had injection rates greater than 150,000 barrels per month; however, not all wells with these injection rates were accompanied by earthquakes. Frolich hypothesizes that injection triggers earthquakes only if injected fluids relieve friction on a suitably oriented fault that is already under regional tectonic stress.

Between March 2011 and March 2012, the Ohio Department of Natural Resources (ODNR) recorded 12 low-magnitude seismic events ranging in magnitude from 2.1 to 4.0. Between the establishment of the ODNR “OhioSeis” seismic network in 1999 and 2011, no earthquake activity was recorded in the Youngstown area. The ODNR did note three earthquakes recorded in the area between 1986 and 2000 with magnitudes between 3.0 and 5.2, but the 2011-12 events all occurred within a mile of the Northstar 1 deep injection well, which began operations in December 2010. (ODNR, 2012)

Some 35 separate inspections of the well in 2011 all concluded that the well was operating within its permitted injection pressure and volume and tests showed that the injections were within the permitted depth intervals, albeit with inconclusive results regarding the fluid volume reaching the bottom of the well at 9,184 feet depth. In late 2011, additional seismic monitoring equipment deployed in the area measured an M 2.7 earthquake at a depth of 2,454 feet below the injection well. The ODNR (2012) determined that a "number of coincidental circumstances appear to make a compelling argument for the recent Youngstown-area seismic events to have been induced." These circumstances include the spatial proximity of the seismicity to the well and the temporal proximity to the start of injection, as well as evidence of higher-permeability zones in geophysical well logs.

The ODNR (2012) outlined circumstances that must be met for an injection well to induce seismicity:

- A fault must exist in the underlying basement rock
- The fault must be in a near-failure state of stress
- An injection well must be drilled deep and near enough to the fault to communicate hydraulically with the fault
- The operator must inject enough fluid at high enough pressures for an adequate amount of time to cause movement (failure) along the fault

The well was shut down on December 30, 2011. On December 31, an M 4.0 earthquake in the Youngstown area led the State of Ohio to declare moratorium on deep injection wells. Since the Youngstown event, Ohio has initiated a set of reforms to its Class II deep injection well program that include additional geologic and geophysical data, well testing, monitoring, and operational controls.

Keranen, et al., (2013) interpreted three earthquakes that occurred near Prague, Oklahoma, east of Oklahoma City, in November 2011 with magnitudes between 5.0 and 5.7 as induced by increased fluid pressures from underground injection. The initial rupture was within 200 meters of active injection wells and within 1 kilometer of the surface; they interpreted the lowered effective stress on nearby faults as the result of 18 years of injection. They described an increase in significant earthquakes in the U.S. continental interior concurrent with an increase in the volumes of fluids related to unconventional resource production being injected into the subsurface. The authors concluded that this indicates that decades can pass between the start of injection and incidents of induced earthquakes.

Following publication of the abstract for Keranen, et al., (2013) and subsequent news articles, David Hayes, Deputy Secretary of the U.S. Department of the Interior, clarified some points about the USGS's work. (Hayes, 2012) Among the preliminary findings he described, he stated:

> USGS's studies do not suggest that hydraulic fracturing, commonly known as "fracking," causes the increased rate of earthquakes. USGS's scientists have found, however, that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells.

Hayes (2012) went on to explain that injection of wastewater is known to have the potential to cause earthquakes. However, of the 150,000 Class II wells in U.S., including some 40,000 for oil and gas operations, only a tiny fraction have induced earthquakes large enough for public concern. He noted that there are no methods available to anticipate whether or not an injection will trigger earthquakes large enough to cause concern. The USGS is working with the U.S. Department of Energy (DOE) and the EPA to better understand induced seismicity.

In March 2013, the OGS (Keller and Holland, 2013), concluded that the Prague event resulted from natural causes, and that further study will improve monitoring and understanding of seismicity in Oklahoma. These authors analyzed earthquake and 3-D reflection seismology, formation data, and historical data, observing that the Prague event was consistent with what is known about natural earthquakes in Oklahoma.

The NRC (2012) found that underground injection of wastewater poses some risk for induced seismicity, but that very few events have been documented over the last several decades compared to the large number of operating disposal wells. The NRC also noted that "the long-term effects of a significant increase in the number of wastewater disposal wells for induced seismicity are unknown." (NRC, 2012)

The NRC (2012) presented their findings, identified gaps in knowledge or information, proposed actions, and recommended further research to address induced seismicity potential in energy technologies. Referring to all energy technologies, they proposed that a local seismic monitoring array be installed in locations where a relationship may exist between extraction/injection and seismic activity. When seismic events appear to be associated with hydraulic fracturing and are cause for concern for public health and safety, an assessment should be performed to understand the causes of the seismicity. Regarding disposal injection wells, the NRC recommended adoption of a best-practices protocol, and where operations could induce unacceptable levels of seismicity; full disclosure and public discussion are needed before operations begin. The NRC outlined practices to consider induced seismicity, and develop technology-specific best practices protocols to reduce the possibility of and to mitigate the effects seismicity. They refer to a recent protocol for geothermal systems developed by DOE for geothermal systems. (Majer, et al., 2012)

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6 Land Use and Development

Although not as controversial as other environmental impacts, like water quality and greenhouse gas emissions, land use and development issues include property rights and use of public lands; local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations. Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6 to 8 wells. (NETL, 2009)

6.1 Property Rights and Public Lands

The Citizens Marcellus Shale Coalition (CMSC) explored two issues related to impacts on public lands and the other industries that rely on these lands. They also explored the impacts on private property rights. (2011) The Coalition stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

Stolz (2011) noted that local disturbances result from the large amounts of land that are needed for well pads and impoundments, and also from the fact that the pad remains active as long as a well can be re-stimulated. Regionally, he expressed concern that access to leased areas (on both private and public lands) becomes restricted, and public lands and parks, in particular, are no longer "public," because safety renders them off-limits.

A presentation by William Lanning of the Bureau of Land Management (BLM) explained that and oil and gas development on lands owned by the federal government is managed by agencies including BLM or the United States (U.S.) Forest Service (USFS). (2013b) For resources that are either privately owned or owned by the state, development and regulation is many times managed at the state level, but federal agencies still control the oversight of the development at a high level. (BLM, 2013b)

An Environmental Protection Agency (EPA) report stated that BLM is the main federal agency in charge of managing and conserving both the surface and resource rights on federal lands. (2008) A particular issue that BLM has managed is split estate lands – when the surface is owned privately but underground minerals are owned by the federal government. The federal rights to the resources take primacy over the individual in such cases. BLM has suggested a number of possible ways to resolve split estate lands, including more involvement of the private owners in the process and public education.

6.2 Surface Disturbance

The Sierra Club expressed concern with regional transformation and landscape change from increasing shale gas production. (Segall and Goo, 2012) Regionally, hundreds of thousands of new wells and the accompanying infrastructure can require significant construction activity in rural areas with thousands of trucks moving on a growing network of roads. (Segall and Goo, 2012) Locally, each well pad covers about three acres with an equivalent amount for infrastructure, and much of this area remains disturbed through the life of the well, as long as 20 to 40 years.

The development process begins with preparation and construction of access roads and the well pad site. The operators clear vegetation and level the ground surface, creating additional space for the trucks and drilling rig. As drilling proceeds, the operators bring in equipment to mix the water, additives, and sand needed for hydraulic fracturing – tanks and pumps, as well as water and sand storage tanks, additive storage containers, and monitoring equipment. Based on the geological characteristics of the formation and climatic conditions, operators may excavate pits or impoundments, or use tanks, to store freshwater, drilling fluids, or drill cuttings. Operators may also install pipes temporarily to move materials on- and off-site. (GAO, 2012)

Because operators must manage large volumes of drilling and hydraulic fracturing fluids, and flowback and produced waters, operators commonly construct lined pits or impoundments on-site at drilling locations, particularly in rural areas. In urban settings, operators may use tanks due to space restrictions. (DOE, 2009)

As is the case with other construction activities, erosion controls may be needed to contain or divert sediment away from surface water or else precipitation and runoff can carry sediment and other pollutants into nearby surface waters. (GAO, 2012)

A BLM presentation stated that the use of land for oil and gas development should have as small a footprint as possible, and the development should be viewed as a temporary use of the region. (2013a) The three phases of land use include planning before development, minimizing impacts during development, and restoration of the land following completion.

Drohan and Brittingham investigated topographic and soil characteristics that could affect infrastructure development and reclamation success of shale gas pads in Pennsylvania. (2012) They determined that the development related to a single shale gas pad ranges from 0.1 to 20.5 hectares with a mean size of 2.7. More than half of the pads in Pennsylvania are built on slopes with risks of excess surface water movement and erosion. About three-quarters of the pads are built on soils without drainage problems, while almost a quarter are built on potentially wet soils. Aerial photographs show that some pads have been restored and planted with grass. Some crop production could be observed on restored agricultural lands. Poor soil reclamation may limit re-vegetation of grasslands and forests.

The low natural permeability of shale requires closer well spacing intervals than conventional gas reservoirs do in order to optimize production. However, the horizontal drilling technology now used in shale gas plays allows for more wells to radiate outward from a single pad. For example, 6-to-8 horizontal wells can be drilled from a single pad and equal the production of 16 vertical wells developed on 16 pads to cover an area of 1 mile by 1 mile (259 hectares). This also reduces the miles of roads and pipelines, and the amount of infrastructure needed. (DOE, 2009) An assessment of impacts from oil and gas development in the EPA's Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming) agreed that using horizontal drilling allows a number of wells to be drilled from a single pad, which would lower the amount of land required. (EPA, 2008)

Considine et al. analyzed notices of violations (NOVs) issued by the Pennsylvania Department of Environmental Protection (PADEP) from January 2008 through August 2011, that were related to Marcellus shale gas drilling. (2012) While 62 percent of the NOVs were administrative or preventative, the remaining 38 percent represented 845 polluting environmental events that produced 1,144 environmental violations. The Considine et al. study categorized these environmental violations into major and non-major events and identified 25 major events. Major events included "major site restoration failures, serious contamination of local water supplies, major land spills, blowouts and venting, and gas migration." (2012) Violations related to site restoration made up two of the 25 major violations (land spills and water contamination comprised 17 of the 25, or 68 percent) and 39 percent of minor violations, comprising the most frequent category of minor violation.

Site restoration events result when the operator does not restore a drilling site in accordance with PADEP guidelines, including removal of drilling equipment and waste and restoration of 70 percent of the perennial cover within nine months. Erosion was a problem cited in most NOVs; in some cases, equipment was not removed or vegetation was not restored. Land disturbances have an environmental impact, but they can be remediated with minor reclamation efforts and are not as serious as spills and water contamination. (Considine, et al., 2012)

6.3 Cumulative Landscape Impacts

Slonecker, et al. quantified the landscape changes and consequences of Marcellus Shale and coalbed methane (CBM) natural gas extraction in Pennsylvania. (2010) Because the combined effects of these two methods create potentially serious patterns of landscape disturbance, disturbance patterns were digitized and used to measure changes. By 2010, 300,000 hectares, or 0.41 percent of the land area, in Bradford County and 223,000 hectares, or 0.85 percent of the land area, in Washington County had been disturbed by shale and CBM natural gas production. Their results illustrate the effects of natural gas extraction in Pennsylvania on the landscape, primarily in disturbance to agricultural and forested areas.

Drohan, et al. examined land cover change due to shale gas exploration in Pennsylvania, with an emphasis on forest fragmentation. (2012) This development has taken place mostly on private property and on agricultural and forest lands. Most drill pads have one or two wells; fewer than 10 percent of pads have five or more wells. As of June 2011, the development of all permits granted would convert between 644 and 1,072 hectares of agricultural land and 536 to 894 hectares of forest, plus at least 649 kilometers of new roads and additional pipelines. Drohan, et al. recommended a regional strategy to help guide infrastructure development and manage habitat loss, farmland conversion, and risks to waterways. (Drohan, et al., 2012)

A report compiled for the U.S. Department of Agriculture (USDA) examined the impacts of natural gas development at a site in the Monongahela National Forest. (Adams et al., 2011) Adams et al. estimated that a total land area of 1.4 hectare (ha) would be cleared, including the well pad site and access road. Major impacts that were investigated include the erosion of soil and sediment, water quality, and vegetation condition. The actual land area cleared for the well pad and access road ended up being 0.83 ha, .57 ha less than what was originally estimated.

Silt fences were installed around the well pad and near the road to minimize the loss of sediment; however, these measures were not very effective due to a number of factors. The amount of sediment trapped by some of the fences allowed a conservative estimate of 2.1 tonnes per hectare of soil material eroded. The authors reported an unexpected severe impact to vegetation which was attributed to both the accidental and purposeful release of drilling fluids to the air. In some regions there was no reported effect the following year, but in others the impacts continued the following year. There were other reported impacts that were unexpected, including heavier than predicted use, procedural and technical changes, and vehicular accidents. (Adams et al., 2011)

Stormwater runoff from drilling sites and related infrastructure can impact water quality and ecosystems along local waterways. A site without runoff controls can allow as much as 16 times the runoff of an equivalent vegetated area and natural gas drilling requires about seven to eight acres per well pad. Stormwater flowing across drill sites may contain pollutants from the stored fracturing fluid and produced water on-site. On the other hand, horizontal drilling reduces the number of well pads needed to reach the target formation, so the amount of surface disturbance is less than that needed for purely vertical drilling. (Horinko, 2012)

6.4 Habitat Fragmentation

The construction and installation of an infrastructure that is necessary for development of the natural gas resources can lead to a habitat being converted from a large contiguous patch of similar environment to a number of smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as development of these resources proceeds. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from impacts to surface water availability from withdrawals and quality from erosion and chemical spills. Water use and quality are discussed further in Chapter 4.

6.4.1 Description of Habitat Fragmentation Impacts

There are a number of impacts associated with the development of gas drilling sites and gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed or land clearing must take place in order to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations. (Resources for the Future, 2013)

Before fragmentation takes place, a given habitat is considered to be a single, contiguous region consisting of a type of landscape or environment. Anthropogenic activities and infrastructure can intersect and divide a landscape into a series of smaller, unconnected patches that become more isolated than they were previously. (USGS, 2012) Forested areas are particularly vulnerable when land is cleared and leveled for the installation of infrastructure such as roadways and pipelines, leading to a decrease in the forest cover available for plant and wildlife species, and ecosystems. (USGS, 2012; GAO, 2012)

Processes having to do with shale gas production can have impacts on habitat and landscapes during all aspects of the operation, including exploration, development, operations, and closure. (NETL, 2009) Land, especially land with vegetative growth already present, must be cleared and then graded or leveled so that infrastructure may be installed. Gaining access to the drilling sites means that new roads must be constructed. This results in land disturbance and fragmentation through a habitat. Pathways for pipelines to transport extracted natural gas must also be constructed, leading to similar disruptions as that of road installation. Other necessary pieces of shale gas production infrastructure, including storage tanks and well pads, also lead to habitat fragmentation. (GAO, 2012)

The New York State Department of Environmental Conservation (NYSDEC) released a draft Supplemental Generic Environmental Impact Statement in 2011 to examine potential environmental impacts that could result from shale gas drilling operations in the Marcellus Shale of New York. (NYSDEC, 2011) The study determined that permitting shale gas drilling operations utilizing high-volume hydraulic fracturing techniques would lead to “significant” environmental impacts, including habitat fragmentation and declines in wildlife population and overall biodiversity. There would be both short- and long-term impacts due to the activities associated with the shale gas drilling process, mainly those discussed in the previous paragraphs. (NYSDEC, 2011)

A United States Geological Survey (USGS) report released in 2012 examined the effect of natural gas extraction between 2004 and 2010 on landscapes in two Pennsylvania counties: Bradford County in northeastern Pennsylvania and Washington County in southwestern Pennsylvania, both of which are located in the interior of the Marcellus Shale region. (2012) The authors used a number of landscape quantification metrics to analyze the landscape changes over the time period. Forest regions are especially affected by habitat fragmentation, as large contiguous tracts of forest are broken up into smaller, more isolated patches of forest as a result of drilling infrastructure. Exhibit 6-1 provides a depiction of the effect that drilling infrastructure such as roads, well pads, and pipelines can have on forested land. (USGS, 2012) The graphic shows forest area in McKean County, Pennsylvania, where natural gas development has taken place and fragmented the habitat into smaller patches. There were four results that pertained to forest fragmentation from this study:

- There were a greater number of individual forest patches, each averaging less area in 2010 than in 2001.
- There were over 300 more individual sections of forest in Bradford County in 2010, with an average area almost three hectares less in 2010.
- There were over 1,000 more individual sections of forest in Washington County in 2010, with an average area almost 7.5 hectares less in 2010.
- Much of the increase in the number of individual forest patches was due to the construction of pipelines for product transport. (USGS, 2012)

Exhibit 6-2 shows cumulative impacts for a non-forested area in Wyoming, which shows some of the increased erosion and soil runoff due to the lack of stabilizing vegetation. Areas like this may require different remediation and site restoration approaches.

Exhibit 6-1 The effect of landscape disturbances on forest habitat (USGS, 2012)

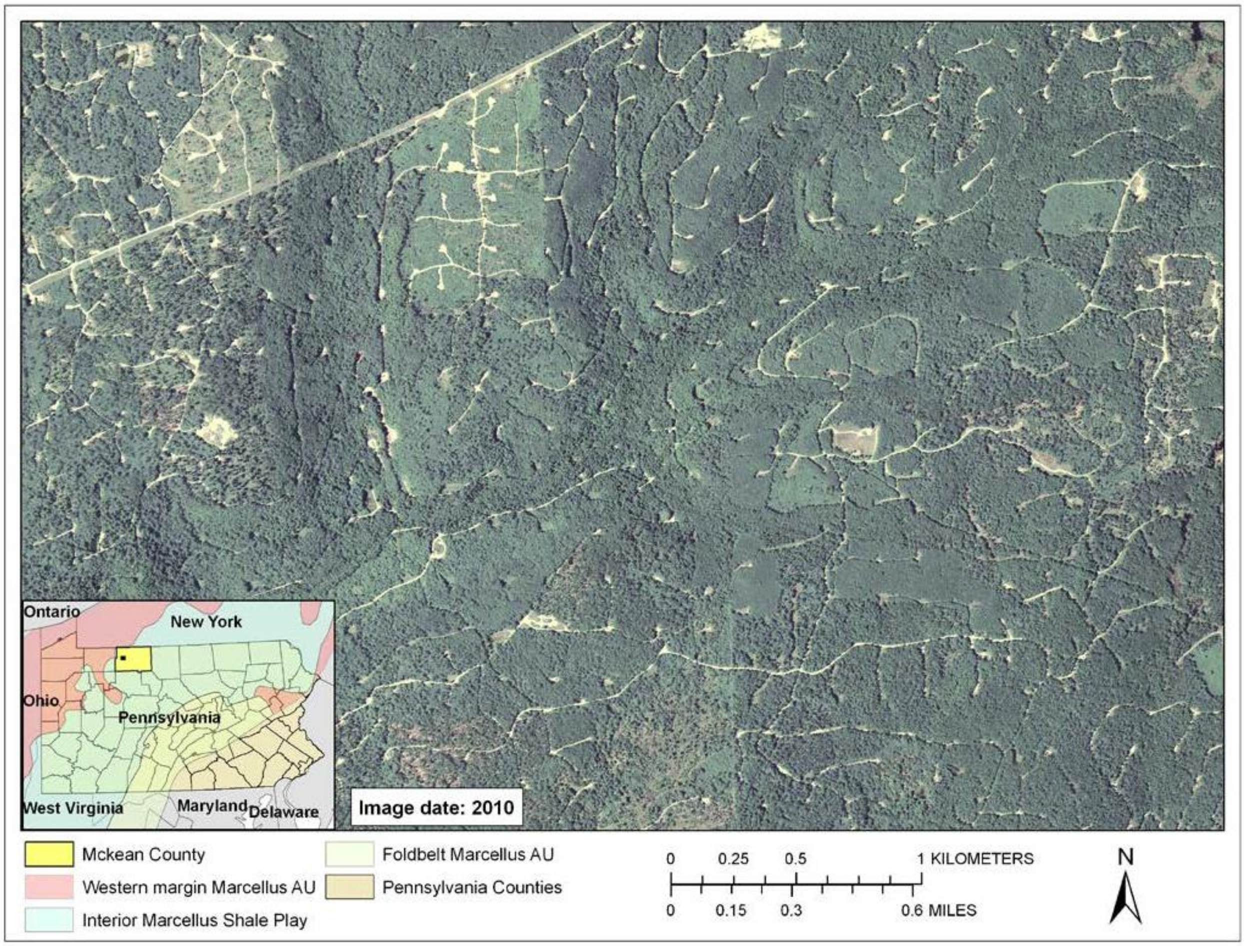

Exhibit 6-2 The effect of landscape disturbance on non-forest habitat (Wyoming, USA) (USGS, 2013)

The Wilderness Society performed an analysis of the impacts that oil and gas development can have on wildlife due to habitat fragmentation using metrics for road density and distance to the nearest road. (2008) The scenario simulation involved randomly locating well pads on a map grid, creating road segments to service the well pads from existing roadways, and converting the data for comparison with current development. (The Wilderness Society, 2008) The report found that habitat fragmentation and impacts on wildlife happen even at low well pad density and though this analysis and available literature can help inform BLM decisions, site-specific evaluations are the best way to determine the extent of fragmentation, and the impact that development may have. (The Wilderness Society, 2008) There were seven recommendations to allow impact analysis under the National Environmental Policy Act (NEPA):

- Analyze the impacts of all the available development alternatives
- Evaluate the development impacts at maximum well pad density
- Include possibilities that do not develop important wildlife habitats
- Ensure that analyses are done at the scale of the landscape
- Make use of Geographic Information Systems (GIS) in analyses
- Recognize more involvement from the public and other stakeholders when landscape analysis is utilized
- Monitor wildlife indicators to measure the effect of any habitat fragmentation (The Wilderness Society, 2008)

A study by The Nature Conservancy (2010) analyzed Marcellus Shale development in Pennsylvania and projected the impact it would have on natural habitats. Each current Marcellus well pad and accompanying infrastructure results in approximately 8.8 acres of cleared forest and 21.2 additional acres of forest edge habitat. They estimate that by 2030, 60,000 new wells will be drilled, resulting in 6,000 new well pads, if there are 10 wells per pad; 10,000 new well pads, if six wells are drilled per pad; and 15,000 new well pads, if four wells are drilled per pad. (The Nature Conservancy, 2010) This amount of development would result in 10,000 – 25,000 miles of installed pipeline. The amount of new forest edge habitat as a result of increased development, a range of 400,000 to 1,000,000 acres, would result in increased predation, changes in the local environment, and increased nonnative species. (The Nature Conservancy, 2010)

According to a Government Accountability Office (GAO) report it is difficult to quantify the long-term effects of shale gas production, because there has not been sufficient time to evaluate these effects. (2012) The data does not yet exist to enable a reliable evaluation of what may be the long-term effects of shale gas development. A joint study by the Houston Advanced Research Center and the Nature Conservancy evaluated how surface disruptions, such as the installation of a well pad and drilling rig and the noise levels from equipment running at the drill site, would affect a species of prairie chicken. (GAO, 2012) It was determined that the noise did not seem to negatively affect the chickens; however, the drilling rig being there in general led to the chickens temporarily vacating the vicinity. (GAO, 2012) The longer the operations are in place, the easier it will be to quantify the long-term effects of shale gas production.

The examination of a natural gas development site in the Monongahela National Forest provided evidence that the installation of a pipeline to transport extracted gas created 3,000 meters of forest edge habitat from approximately 2 hectares of cleared right-of-way. These forest edges can provide easy access for predators to nests as well as openings for invasive species. (Adams *et al.*, 2011) An assessment performed by the EPA stated that there are concerns over migratory disruption, habitat disruption, and locations where some animals spend the winter that stem from oil and gas development. (2008)

Many development operations have been in practice for far longer than shale gas drilling, such as conventional natural gas production and other unconventional gas production (tight gas and coalbed methane). The impacts of habitat fragmentation due to these similar processes are far better known, and, therefore, habitat fragmentation impacts and mitigation measures can be understood fairly well. Habitat fragmentation impacts vary greatly depending on the landscape, the extent of exploration, production, and development, and any existing infrastructure or corridors in the vicinity prior to the development of gas resources.

6.4.2 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be required to identify best management practices. (2011)

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company (PXP) proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons. (Cardno ENTRIX, 2012) The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations. (Cardno ENTRIX, 2012)

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) Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present in a given site.

The Western Governors' Association released a handbook outlining the best management practices for coalbed methane development in 2006 to be shared amongst the Association's shareholders. (2006) The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. A number of subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible. (Western Governors' Association, 2006) Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems. (Western Governors' Association, 2006) Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities. (Western Governors' Association, 2006) Again, these best management practices have been developed in areas of coalbed methane production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site. (NETL, 2009) Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible. (NETL, 2009)

With approximately 33 units of the National Park System in or near the Marcellus Shale, the U.S. Department of the Interior National Park Service (NPS) found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact state oil and gas agency to express concerns and issues.
3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts. (Moss, 2012)

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers a number of practices that can be implemented or planned in order to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad. (BLM, 2013a) There are also multiple examples of reclamation practices, both at the drill site and on access roads, which can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible. (BLM, 2013a) Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible. (BLM, 2013a) It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options. (BLM, 2013a)

6.5 Traffic, Noise, and Light

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, NYSDEC identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among potential environmental impacts. (2011) Significant adverse impacts in terms of damage to local roads and state roads could also result. Among mitigation measures described for environmental impacts, the NYSDEC would impose measures to reduce adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-3 tabulates the number of truck trips for a typical shale gas well.

Exhibit 6-3 Truck trips for a typical shale gas well drilling and completion (MIT, 2011)

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10 – 45	10 – 45
Drilling Rig	300	60
Drilling Fluid and Materials	25 – 50	200 – 400
Drilling Equipment (casing, drill pipe, etc.)	25 – 50	200 – 400
Completion Rig	15	30
Completion Fluid and Materials	10 – 20	80 – 160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150 – 200	300 – 400
Fracture Water	400 – 600	3,200 – 4,800
Fracture Sand	20 – 25	160 – 200
Flowback Water Disposal	200 – 300	1,600 – 2,400
TOTAL	1,160 – 1,610	5,850 – 8,905

The large volumes of water involved in fracturing operations can create high volumes of road traffic. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater can and does significantly reduce the road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic. (MIT, 2011) An assessment performed by the EPA in their Region 8 stated that the trucks and roads that are used during oil and gas development processes have an effect on the surrounding environment through localized noise pollution. (2008)

The Eagle Ford Shale Task Force Report for the Railroad Commission of Texas identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development. (Porter, 2013) Exhibit 6-4 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford.

Exhibit 6-4 Loaded truck trips per gas well (Porter, 2013)

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges. (Porter, 2013)

Upadhyay and Bu surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. (2010) They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, concluding:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose most salient visual impacts, rather than the drill pads themselves
- Timelines for site restoration of visual impacts vary significantly

Upadhyay and Bu recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward. (2010)

The Resources for the Future report also gave a number of options in their survey of experts under the category of community disruption. (2013) Included in this category, as well as habitat fragmentation, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (air pollution, water pollution, etc.) risks.

The Secretary of Energy Advisory Board (SEAB) recognized that shale gas production brings both benefits and costs to communities, often rapidly, including places that are unfamiliar with natural gas operations. Impacts include traffic, noise, and land use, with little or no allowance for planning or effective mechanisms to engage stakeholders. The SEAB does not believe that these kinds of issues will solve themselves or that regulation or legal action will solve them. State and local governments should lead experiments with alternative mechanisms for addressing these issues constructively and seeking practical mitigation. The federal government may also help through mechanisms like the U.S. Department of Interior's Master Leasing and Development Plans, which might help improve planning for production on federal lands. (SEAB, 2011)

6.6 References

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